S U S T E L N E T

Policy and Regulatory Roadmaps for the Integration of Distributed Generation and the Development of Sustainable Electricity Networks

A REVIEW OF FOUR EUROPEAN REGULATORY SYSTEMS AND THEIR IMPACT ON THE DEPLOYMENT OF DISTRIBUTED GENERATION

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ABSTRACT

This report performs a comparative review of the regulatory regimes for four EU Member States, Denmark, Germany, the Netherlands and the UK with specific regard for how regulation impacts on distributed generation in each of these countries. It addresses both the positive and negative aspects of policy and the impacts each factor has on the potential for increasing and decreasing barriers to the greater use of distributed generation in each Member State, and of how different policies might tie together to produce a regulatory design which can aid the achievement of energy systems which are more sustainable.

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Preface

Technological developments and EU targets for penetration of renewable energy sources (RES) and greenhouse gas (GHG) reduction are decentralising electricity infrastructure and services. Although liberalisation and internationalisation of the European electricity market has resulted in efforts to harmonise transmission pricing and regulation, no initiative exists to consider the opening up and regulation of distribution networks to ensure effective participation of RES and distributed generation (DG) in the internal market. The SUSTELNET research project provides the analytical background and organisational foundation for a regulatory process that satisfies this need.

Within the SUSTELNET research project, a consortium of 10 research organisations analysed the technical, socio-economic and institutional dynamics of the European electricity supply system and markets. This has increased the understanding of the structure of the current European electricity sector and its socio-economic and institutional environment. The underlying patterns thus identified have provided the boundary conditions and levers for policy development to reach long term RES and GHG targets (2020-2030 timeframe). It was consequently analysed what regulatory actions are needed on the short-to-medium term to reach the existing medium-term goals for 2010 as well as likely scenarios for longer-term goals.

Regulatory Road Maps
The main objective of the SUSTELNET project was to develop regulatory road maps for the transition to an electricity market and network structure that creates a level playing field between centralised and decentralised generation and network development. Furthermore, the regulatory road maps will facilitate the integration of RES, within the framework of the liberalisation of the EU electricity market.
Participatory Process
To deliver a fully operational road map, a participatory regulatory process was initiated throughout this project. This process brought together electricity regulators and policy makers, distribution and supply companies, as well as representatives from other relevant institutions. This ensured a good connection with current industry, regulatory and policy practice, created involvement of the relevant actors and thereby will enhance the feasibility of implementation.

Newly Associated States
The SUSTELNET project also anticipates the enlargement of the EU by providing support to the Newly Associated States (NAS) with the preparation of a regulatory framework and thus also with the implementation of EU Directives on energy liberalisation and renewable energy in four Accession Countries (The Czech Republic, Poland, Hungary and Slovakia).

Project Structure
The SUSTELNET project was divided into two phases. During the first phase, the analytical phase, three background studies were produced:

- Long- term dynamics of electricity supply systems in the European Union.
- Review of the current electricity policy and regulation in the European Union and in Member States.
- Review of technical options and constraints for the integration of distributed generation in electricity networks.

In the second phase, the participatory regulatory process phase two activities took place, during which there were extensive interactions with regulators, utilities, policy makers and other relevant actors:

- Development of a normative framework: criteria for, and benchmark of distribution network regulation.
- Development of policy and regulatory road maps.

This Report

This report was produced during the analytical phase of the project and is part of the study on the review of the current electricity policy and regulation in the European Union and in Member States.

Executive Summary

The Member States clearly demonstrate the considerable differences in the contexts and frameworks in which distributed generation (DG) has to operate, and the variety of factors that can impinge on its successful addition to distribution networks.

The key factors are shown to be:
- the governance system - what is the hierarchy of legislative power in relation to DG outcomes
- connection charging
- use of system charging
- the macro incentives and extent to which performance based regulation is in place
- dispatch - how electricity is sold
- how DG benefits are valued
- the political will to promote DG

The key differences divide between the UK and the Netherlands versus Germany and Denmark. The two latter countries are interesting because support schemes are in place to promote DG but not necessarily to incorporate them into the electricity networks most efficiently or to establish mechanisms whereby they can transfer into the mainstream energy markets.

A key issue is the extent to which current regulation tends to favour the status quo. This largely tends to favour the centralised production of power and reduces the potential options available to DNOs by locking them into doing the same thing while trying to reduce costs. Regulation which takes a more neutral line between the use of centralised and distributed power may provide more choice for the DNOs, resulting in the increased availability of different paths towards achieving their goals of ensuring profitability whilst maintaining levels of service and investment in their networks and in doing so meeting other goals of regulation, namely with regard to reducing overall customer costs and reducing environmental impacts.

The mechanisms in place in both Germany and Denmark pay high tariffs to renewable energy sources and CHP to overcome the significant barriers to their establishment. The mechanisms employed in the UK, and the Netherlands rely more strongly on competitive means to reduce prices. Whilst Denmark and Germany have enjoyed greater success in helping new technologies to establish capacity, it is clear that the overall cost to the consumer in each of these nations could be reduced by increased use of regulatory regimes that provide incentives to DNOs to employ a more 'holistic' approach to network design, and which allow the full benefits of distributed generation to be taken into account in the regulation of electricity supply. It is also clear that many of the barriers that must be overcome are created by regulatory systems which place a range of disincentives between DNOs and the desire to see increased distributed generation attached to their networks.

Whilst some Member States have been at the forefront of the electricity supply liberalisation process, others have required considerable pressure from the EU to begin the process of opening their markets. The results of the liberalisation process can be seen to be largely positive with regard to achieving the primary aim of driving down prices for consumers, though less consideration has been given to other positive goals such as the environment. Whilst other EU regulation has addressed these goals, the need for consensus in creating EU legislation has meant that these allow considerable leeway for a range of different options without addressing many fundamental issues such as the historical structure of centralised electricity supply and how the legacy of its operation continues to impact on the running of supply industries today.

It is apparent that regulation needs to evolve such that it allows distribution networks operators to have access to a wider range of options and incentives available in choosing the most efficient ways to run their businesses.

List of Abbreviations

APX	Amsterdam Power Exchange (APX)
BM	Balancing Market
BSC	Balancing and Settlement Code
BSUoS	Balancing Services Use of System Charges
CC	Competition Commission (UK)
CHP	Combined Heat and Power
DG	Distributed Generation
DNO	Distribution Network Operator
DTe	Dienst Toezicht en Uitvoering Energie (Netherlands)
DUOS	Distribution Use of System Tariffs
EA	Energy Authority (Denmark)
EA	Electricity Association (UK)
EEC	European Economic Community
EEG	Renewable Energy Law (Germany) (Erneuerbare Energien Gesetz)
ESI	Electricity Supply Industry
ERA	Energy Regulatory Authority (Denmark)
FCO	Federal Cartel Office (Germany)
GSA	Grid Supply Area (UK)
GSP	Grid Supply Point (UK)
HVDC	High Voltage Direct Current
IEA	International Energy Agency
ISPs	Imbalance Settlement Prices
LUP	Uniform Producer Tariff
MEA	Ministry of Economic Affairs (Netherlands)
MS	Member State (of the EU)
MSC	Market Surveillance Committee
NETA	New Electricity Trading Arrangements (UK)
NGC	National Grid Company Ltd (UK)
NMa	Competition Authority (Netherlands)
OTC	Over the Counter
PBR	Performance based regulation
PRP	Programme Responsible Parties (Netherlands)
RAB	Resource Asset Base (UK) or Regulatory Asset Base (Germany)
RES	Renewable Energy Sources
RPI-X	Retail Price Index minus X
SO	System Operator
TNO	Transmission Network Operator
TSO	Transmission System Operator
TUOS	Transmission Use of System Tariffs
UoS	Use of System

1. Introduction: Aims and Objectives

The objectives of the SUSTELNET research project are to:

- Analyse the long term technical, socio-economic and institutional dynamics that underlie the changes in the architecture of the European electricity infrastructure and markets;
- Develop medium to long-term transition strategies/road maps for network regulation and market transformation to facilitate the integration of RES and decentralised electricity systems;
- Lay the foundations for and map out a regulatory process on the regulation of distribution networks in the EU, involving distribution and supply companies, national regulators and national and EU policy makers.
- Lay the foundations for and map out a regulatory process on the regulation of distribution networks in NAS and their integration with EU MS, involving distribution and supply companies, national regulators and national policy makers in NAS.
- Develop a common policy and regulatory roadmap for the NAS towards the integration of DG into the energy system in harmonisation with EU strategies.

This review document sets out;

- the economic regulation of the electricity system in Denmark, Germany, the Netherlands and the UK and its impact on distributed generation (DG)
- the regulatory characteristics which appear to be most favourable and most malign to the deployment of distributed generation.

For each country a detailed report describing the characteristics of the regulatory system in their country and the implications of this for DG was prepared. This document will not attempt to bring together the fine detail found in each of these reports but will cover the key issues of the broader picture created by those papers. Readers are referred to those submissions if more detailed information is required. These documents are available via the project website at http://www.sustelnet.net.

Distributed generation is used throughout to refer to any generation that connects directly to the distribution grid. It should be noted that some countries apply different rules to different technologies attaching to the distribution grid, and that this may provide advantages for these technologies which directly relate to their connection to the distribution grid, whilst not providing the same advantage for different technologies, even where these connect to the same distribution grid.
Distribution network operator (DNO) is used to apply to any company which is responsible for the ownership of the physical connections which form the distribution network. Potential for confusion exist relating to the Danish situation wherein DNOs are frequently owned by distribution companies, which are effectively the companies which supply electricity to consumers. These are generally referred to as suppliers or supply

companies in the other countries reviewed here. Every effort has been made to draw the distinction between these two in the text.

1.1 Learning from Each Other for the Benefit of DG

As a result of the Energy Directive, liberalisation can be regarded as heading broadly down the same path across the European Union although member states have very different feelings about doing so. Moreover, Member States are at very different stages along that path and with regard to the development of their electricity supply industries as discussed in the document 'Long-term Electricity System Dynamics'. The situation of DG in each country is thus very different as a result of past and current different support programmes for DG but also because of the energy industry characteristics (types of generation) and situation (capacity, proximity to power pools etc). This means that the attitude and approach to DG within the nascent economic regulation systems is also different and at different stages. It is hoped that Sustelnet will enable Member States to learn from the successes and failures of economic regulation in other countries with respect to DG, through the production of benchmarking criteria for network regulation, and through the development of regulatory road maps for EU and NAS countries.

1.1.1 Summary of Country Position with Respect to Liberalisation

Table 1 sets out fundamental differences between countries which have a major implication for the development of DG. For example, whether distribution companies are separated from supply companies (those companies that sell electricity to customers only); whether customers are captive to a seller of electricity whether it is a supply company or a joint distribution/supply company and whether distribution network operators are expected to create shareholder dividends for private investors.

- The UK – The electricity supply industry was privatised in 1990 with various limitations placed on cross-ownership of utilities. The Utilities Act of 2000 however, effectively re-regulated the industry. Generation and supply is competitive while the distribution and transmission networks are monopolies and regulated. Integrated ownership is possible although with strict separation of management and accounting. The exception to this is the national grid companies which have no ownership of other actors within the electricity supply industry, such as DNOs and generation.
- The Netherlands, Germany and Denmark – the legal, management and account unbundling of generation, transmission, distribution and supply companies is required, though ownership separation is not.

Table 1 Country Characteristics

Country	Unbundled distribution and supply		(Private) shareholders with imperative to maximise shareholder price	Ownership of generation and distribution network in the same firm	Effective competition in supply
	Legally	Ownership			
The UK	yes	yes	yes	no	yes
Netherlands	yes	no	yes	yes	yes
Denmark	yes	no	some	yes	yes
Germany	yes	no	some	yes	no

1.2 Renewable Energy Policy

The most significant difference between national approaches to the issues of DG is reflected in the national approach to renewable energy policy as a whole. Within the German and Danish systems, barriers which arise from the regulation of the electricity networks are circumvented through new regulation which acts to remove or to minimise to some extent the barrier wherever possible. The costs of this approach are passed on to the consumer with the primary concern being to more easily facilitate an increase in the use of renewables and CHP.

The general approach of policy in the Netherlands and the UK does not follow this pattern. In these nations, the primary motivation of renewable energy policy is a focus on minimising costs to the consumer through the continuous application of the competitive process. While there are important policies in support of renewables or CHP, it is not considered vital that economic regulation complements these policies.

Sustelnet is focussing on how regulation of the electricity industry affects DG. It is not analysing or comparing the policies in support of distributed generation within member states. Nevertheless, it is clear that if support mechanisms are generous or if a member state has powerful provision for support mechanisms, there may be a temptation on the part of Government to simply pay more for distributed generation to ensure that it is deployed rather than deal with the often complex barriers to distributed generation incorporated within economic regulation. Sustelnet would argue that this approach will make it harder for distributed generation to become a ‘mainstream’ supply source in the longer term. This, in turn, means that customers will have to pay more over the longer term than is necessary to support distributed generation. Moreover, conventional power will not have to compete on a level playing field but is ‘helped’ by regulation.

In conclusion, ensuring that the electricity system regulations are ‘neutral’ is important. Learning from other countries ‘mistakes’ or successes is likely to make that objective easier.

1.3 Key Issues

This paper sets out the key issues within regulation for the deployment of distributed generation. They are:

- Governance
- Network Issues
    - ◊ Connection Costs
    - ◊ Use of System charges
- Incentivisation of Distribution Network Operators (DNOs)
- The Dispatch System
- Monetised Network Benefits of DG
- Legal Questions

2. Governance[1]

The governance structure of regulation of the electricity industry has significant potential to impact on the implementation of DG. The legal structure within which a national regulator operates, the powers of that regulator, its relationship with Government or other actors, including those who have power to overturn its decisions and affect its aims such as competition bodies, its level of independence, legal status and resources are all significant for both the operation of, and in achieving change within, the national electricity supply industry (ESI).
There is strong variance in the nature and role of the regulator across the four states considered in this study.

2.1 Denmark

The Danish system of governance is complex (See Annex 1). The regulator is the Energy Regulatory Authority (ERA), but, roughly speaking, powers are divided between the ERA, the Energy Authority (EA) and the System Operators. The Ministry of Economic and Business Affairs delegates authority to use powers granted by the Electricity Supply Act to the Energy Authority. The Energy Authority is charged with oversight of licensing and the general economic regulation of the DNOs, whilst the objective of the ERA is primarily to undertake an inspection and complaints function in the field of energy in accordance with the Electricity Supply Act and the Heat Supply Act.

ERA handles the specifics of economic regulation, and deals with complaints arising from the regulatory process. Under the new Electricity Supply Act, the Minister can authorise an organisation under them to exercise the powers held by them under the Act. The powers of the Minister can be regarded as stemming from the large number of authorisations made by the Act and as a result the Minister's powers are significant, which has resulted in considerable criticism. The Act widened the powers of the ERA to

[1] Governance is defined as the hierarchy of legal powers available to enforce actions on the electricity industry.

allow it to more proactively respond to problems in the regulatory regime, rather than act merely in response to formal complaints.

The subordination of the ERA to the EA, and of both to the Minister appears to allow the Minister to exert considerable control over those extensive areas where the Acts authorisations apply. The effect of this is that the Ministry has effective control of how the electricity networks are run. This means that Government policy tends to be followed through by the network policy. In this sense, economic objectives of regulation are secondary.

The day to day regulation of DG is mainly governed by the SO to the extent that it is not covered by the extensive secondary legal regulation. DG has the status of a priority producer, offering it some protection from the general regulatory regime and from the demands of the market.

2.2 Germany

The situation in Germany has some parallels with the Danish situation. As with Denmark, most DG is given priority access to markets in that it is compulsory for DNOs to purchase electricity from renewable energy sources. The body of support to DG also insulates it to some extent from the main body of electricity sector regulation. However, Germany differs fundamentally from each of the other states assessed here in that it has no distinct regulatory body; instead there exists a complex series of distinct regulatory and mediating bodies, backed by a body of law and the court system. As a result of this the German competition authority, the Federal Cartel Office (FCO) has a more significant role in regulation – and apparently a more pro-active approach to becoming involved – than the corresponding competition authorities in other nations.

A framework agreement on access prices and conditions (Verbändevereinbarung) forms the basis of policy, though this is not binding in law. This is backed by various codes, including the Distribution Code, which sets the technical and organisational conditions for use of, and access to, the distribution networks. The Ministry of Economics may issue a statutory ordinance if it is felt that the voluntary framework is not producing the expected results.

One such ordinance, the Bundestarifordnung Elektrizität (BTOElt), issued in 1990, sets down conditions for tariff charging for low voltage supply, insisting that tariffs be transparent and cost reflective. Tariffs generally, along with conditions for market access were not regulated as a result of the 1998 liberalisation however, and these remain fixed within the Verbändevereinbarung.

Grid charges are monitored by the FCO and by consumer groups, though the power of the FCO may be severely curtailed by the enactment of May 2002 Bundestag legislation if this is also approved by the other German house, the Bundesrat. The legislation amends the energy law and will legally formalise the conditions of the Verbändevereinbarung.

A Price Control Authority checks prices. The resources supporting this though are very poor, with 1-3 civil servants to regulate 120 utilities. The most significant pressure on DNOs to keep tariffs low appears to come through media coverage of pricing issues.

The lack of a regulator has had a number of implications for German policy relating to DG. Fundamentally, it means disputes between generators and a utility are settled through the courts rather than through a ruling from the regulator and through the establishment of general practices overseen by the regulators, as tends to occur elsewhere. There is a resulting cost in terms of transparency, time and capital.

2.3 The Netherlands

Historically, the central government maintained an arm's length relationship with the electricity sector when it was owned exclusively by lower governmental authorities (provinces and municipalities). Many regulatory powers are still invested directly with the government, through the Ministry of Economic Affairs (MEA). Promotion of competition in the sector has moved to the forefront of the government's policy. The regulator, Dienst Toezicht en Uitvoering Energie (DTe), which is integrated into the Dutch Competition Authority (NMa), is empowered to fix charges for the use of electricity networks. It also determines electricity supply tariffs for captive customers, pursuant to powers delegated by the MEA. However, the tariff-setting powers are temporary until end of 2003, when the market is scheduled to be fully opened. The powers of the DTe also extend to licensing (DNOs and suppliers of small consumers), compliance monitoring, and imposition of both instructions on utilities and penalties for failure to comply with these instructions. Nevertheless, the DTe is still responsible to the Minister. Moreover, the NMa may make instructions to the DTe, and it is the NMa which is responsible for overseeing disputes relating to network access. Strong fluctuations in electricity markets in 2001 saw the formation of a market surveillance committee (MSC), which analyses the operations of the electricity market and reports to both the DTe and the NMa.

There is an expectation at the DTe that both the NMa and DTe will become independent of government at some point.

Competition and the development of markets are the primary objectives of the regulatory system. Nevertheless, the effect of this regulatory set-up is reasonable flexibility, in terms of its ability to respond to problems within the electricity sector, as defined by Ministers, though clearly this is at the cost of regulator independence.

2.4 The UK

The UK's regulator, Ofgem, can be regarded as strongly independent. It is bound by statutory duties which can be changed only through legislative action, something which the government is reticent to do in order to avoid interfering with Ofgem's independence. The result is the creation of a strongly independent regulator, but one which is tied to a fixed list of duties which can make it inflexible. The primary duty is to 'protect the interests of customers wherever possible by competitive means'. Since those Duties have no specific requirements for DG, no particular policies to support them are pursued. The Government is able, via the Utilities Act, to provide Guidance to the Regulator on social and environmental matters. However, the regulator must decline to fulfil them if they do not fit within the Duties.

The Regulator has powers to define or interpret Duties. If disagreed with, Ofgem's decision can be passed to the Competition Commission who will make a ruling. This does happen in major cases but generally, given Ofgem's powers of intervention with companies and the length of time that decisions are taken, companies are very circumspect about doing so.

The effect of this governance is that the regulatory system is inflexible, and this is a problem given the changing nature of the electricity industry and its uncertain technological development.

This is often to the detriment of Government policies because, while they may have been elected to do something, if it is not within the Duties:

- it is difficult for Government to obtain legislative time in parliament to pass new legislation to require the regulator to take a particular step
- there appears to be no redress for Government if Duties appear to encompass a certain area but are not adopted by the regulator (i.e. if the Regulator does a bad job)

The Regulatory Office is however substantial with 300 people working for it and a £30 million budget (€45m). All decisions are consulted on but the regulator does not have to undertake a cost benefit analysis of its decisions, as all other Government departments do.

There is a Competition Commission (CC). Complaints about the regulator's decisions are sent to the CC and their say is paramount. Nevertheless, the CC is still secondary to the Regulator in terms of day to day governance of the network.

2.5 Conclusion

Both Denmark and Germany appear to be more willing to change network regulations concerning DG to try to address barriers to its increased use, and both have a regulatory regime in place that can be considered to be more flexible to change than is the case elsewhere, most notably the UK. However, this occurs because Governments are able to ensure environmental goals take precedent. In the case of Germany, the downside of this is a lack of transparency in the running of the network. Likely changes to increase the independence of the regulator in the Netherlands may result in changes to their operational characteristics, with implications for the future flexibility of respective national systems.

At one end of the system, independent economic regulation means that the only way that Government policies can be implemented is through new legislation. This seems too inflexible. Electricity systems are changing rapidly. New technologies are developing; it is unclear how networks may develop. It is vital that economic regulation does not determine technological outcome. Thus, regulation needs to be able to work with uncertainty and be flexible to change.

A regulator, with clear duties and reporting requirements including the cost of their operation and public consultations about their decisions has benefits. Moreover, an independent economic regulator can gain the support of business which is wary of Government interference and changing policies, though this is not to say that such a regulator would be welcome in all Member States. In Germany the majority of established companies appear to favour the status quo, whilst support for change comes largely from newer entrants.

Countries show disparity with regard to the interaction of the Regulator and the competition authority. The latter is pre-eminent in Germany and the Netherlands, while in the UK it has final powers but only after disputes have been passed to it.

A clear framework of how Governments may intervene with regulators would seem the most appropriate way forward.

3. Network Issues

Network Issues are comprised of connection costs and use of system (UoS) charges. These are regulated and not market based. The extent to which the benefits which DG brings to networks are recognised is also a network issue and is also relevant to incentivisation and potential incentivisation of DNOs and to the increased economic stability of DG projects. These benefits are discussed in section six below. Benefits can accrue to the generator either through a market (for example, ancillary services) or by regulation (e.g. loss reduction).

DG connects to the distributed network. It is therefore vital that connection rules complement the deployment of DG. The cost of connection is closely linked with the policy and charging for use of the system (UoS). From the perspective of the DNO, a new power plant will affect the cost of operating and maintaining the network. This cost can, either partially or wholly, be paid for in the connection charge or in the use of system charge.

Policies for connection charging for DG in the four EU member states can be split into two groups: those with deep connection charges (i.e. those which charge the generator all the costs to the network of that power plant connecting) and those with shallow connection charges (i.e. those which charge only the cost of connecting to the nearest point and none of the costs which occur within the network). The deep connection charge incorporates the use of system charge with respect to capital assets but not the use of system charge related to transporting the kWh through the network. Shallow connection charges do not include the use of system charge for the capital assets or for transporting through the network. Those countries which have a shallow connection charge therefore tend to have a different UoS policy.

In addition, countries vary considerably between those which have clear connection rules for renewables and CHP (although not fixed costs) and those (i.e. the UK and the Netherlands) where DG have to connect under general connection rules.

Furthermore, the importance of these costs to the DNO depends on whether they have shareholders; are likely to be taken over or to relinquish share ownership; and whether customers are effectively captive, even if in principle there is competition in supply. There is significant variance in these factors, over the four EU Member States.

3.1 Connection Issues

3.1.1 Denmark

In general terms, Denmark, Germany 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 and the developer must also fund upgrades to the system grid. If the DNO wishes the developer to connect at another point then the DNO picks up all costs of grid connection. This point of connection also has implications for the settlement price, with the settlement price dropping as the voltage of the specified grid connection increases[2].

Wind turbine developers are compelled to pay costs only to the edge of the specific planning zones allocated for turbine construction, with DNOs paying all other connection costs which are then passed on to consumers. Connections from the perspective of the

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[2] See Danish case study for more details. The settlement price is the sum paid to the developer which includes fuel costs, operation costs, long-term investment cost, any avoided losses and costs of grid extension. It corresponds to the long term marginal cost of producing and transporting electricity and is separate from a UoS charge.

generator are therefore transparent and reasonable. When wind turbines are established outside these areas, the developer must pay.

Danish distribution companies are owned by the consumers (co-operative), the municipalities or as an independent institution and have a somewhat different perspective from generators. It is important to note the differences between distribution companies, which are the effective suppliers of electricity, and the distribution network operators (DNOs) which are the companies which own and are responsible for maintaining the physical connections which form the distribution network. In the Danish supply industry, DNOs are subordinate to these distribution companies. These DNOs operate the 4-10kV grid. The 1999 Electricity Supply Act caused the break-up of the traditional distribution companies, but these have further been subject to mergers in response to the greater level of competition engendered in the system. Municipalities own approximately 50% of distribution companies, and the sale of supply companies is strongly disincentivised (see Section 5.5).

Denmark has several measures to promote DG, some which add costs to the DNO and others which don't. For example, as we saw above, connection costs are passed on to the consumer and disincentives to DNOs are further reduced through a scheme run by the two Danish system operators to ensure that cost burdens are more evenly dispersed amongst distributors rather then being borne entirely by those in windier regions.

The nub of the issue relates to:

- Whether DNOs have sufficient incentives to design an efficient and secure operation
- Whether the way DNOs work to a regulated return is more successful than most incentivised systems in place in countries such as the UK and the Netherlands

With respect to the first bullet point, in principle, a Danish DNO should, at the technical level, be trying to design a network for the most efficient and secure operation. The Danish DNO is incentivised as they are only allowed to partially pass on costs to the consumer, thus the costs to the DNO are lessened by designing the most efficient network improvements in each circumstance. However, in some circumstances the DNO may have the choice between two technical options one of which is cheaper for the DNO; in this case the DNO will tend to choose this option regardless of the overall efficiency of the options.

The second bullet point is discussed under the broader section 4, headed 'incentivisation of DNOs'.

3.1.2 Germany

The German approach is also based on shallow connection charging, with the Renewable Energy Law (EEG) indicating that while DG developers cover only the costs of connecting their plant to the grid, DNOs must provide any necessary grid extension, where this does not entail excessive cost. However, considerable problems have arisen from the interpretation of how costs should be broken down between DNOs and DG developers, with some DNOs ruling that the developer must pay for any new line connecting to the grid, significantly raising the cost burden for the developer. Whilst court cases have so far favoured DG, DNOs 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.

Developers have increasingly had to surrender rights under the EEG in order to secure connection more rapidly. An institution set up to address the problems relating to contentious costings has so far proved to be ineffective, and it is possible that the EEG may need to be clarified if the problems stemming from it are to be resolved. It is also noteworthy that technologies which are not amongst those defined as renewable within the EEG, whilst still enjoying right to grid access, are not subject to any guidance as to the splitting of costs, effectively meaning that different DG technologies are subject to different regulatory regimes with regard to connection costs.

Connection costs are not fixed so that there should be an incentive for developers to connect to economic sites. Nevertheless, the DNOs are required to connect from that site. Again, as with Denmark, there does not appear to be a strong incentive for DNOs to design and operate their network in a least cost, secure way which also takes account of the future or expected increase of DG.

While the shallow connection is paid for by the developer and the reinforcement costs paid for by the DNO – these are effectively recouped through their addition to the Regulatory Asset Base (RAB) of the DNO since the UoS charge paid by customers is related to the RAB. The additional administrative costs will fall to the DNO in which the power plants are developed and in this sense certain DNOs suffer. Nevertheless, on balance independent DG should not be a major cost to the DNOs.

Nevertheless, for those DNOs which own generation, often DG, there is a clear disincentive for them to allow competitive DG to connect to their networks.

3.1.3 The Netherlands

Connection charges in the Netherlands' shallow tariff system are regulated below 3MVA, subject to negotiation or regulation in the range 3-10MVA, dependent on circumstances, and negotiated over 10MVA. The aim of regulated tariffs is to protect consumers from monopolistic firms. As a result, consumers with similar connection profiles in a region pay identical connection charges rather than actual connection charges. Thas is, the connection charges are averaged. The problem of cross subsidising between cheap existing connections and expensive new connections rises under this system.

Under the current regulatory framework DNOs have no incentives to expand the network, which can lead to inefficiencies. While DNOs are obliged by law to connect any interested consumer to the net, they have the freedom to achieve this in whichever way they find most convenient. They generally have two options: the expansion of the network to the consumer or the connection of the new consumer to the existing network. In the latter case, DNOs can recover all costs from the consumer through the connection tariff. Furthermore, when the connection between the consumer and the grid has a length of more than 25 meters, then the costs of the excess of cable can also be passed down to the consumer. In the other case, the costs raised by the upgrading of the grid are deep investments and maybe recoverable through the transport tariff (see DNO incentivisation Netherlands – Section 4.4.3). As the connection of new capacity generate an increase in what is collected through the transport tariff, when a consumer has to connect to the network the DNO will choose not to expand the network and therefore save itself the capital costs of expanding and all the risks that this entails.

DNOs have a monopoly in connection. As a result, although negotiated connection charges are generally cost reflective, negotiation over connections has led to accusations of high connection costs, most notably for generation facilities located some way from the distribution networks. Due to their monopoly position, DNOs can inflate costs.. Legislation is expected which will allow developers to facilitate their own connection, thus opening the process to competition, and hopefully to reduced costs. Since some distribution networks have already connected a large number of DNOs – particularly in regions with many horticultural greenhouses – these DNOs may discourage new DG, because the capacity of the distribution network has to be expanded and until an incentive is introduced to finance this expansion there is no fundamental driver pushing the DNOs to facilitate expansion.

3.1.4 The UK

The UK 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. This has a number of detrimental effects for DG:

- it places considerable power in the hands of the DNO. No standardisation of connection costs between DNOs is in place and very little information is available in the public domain to provide guidance to new generators wishing to connect to the distribution network. There is no incentive for the DNO to minimise the cost of connection. On the contrary, there is a strong possibility that the DNO may charge the generator for some system reinforcement which they, the DNO, would otherwise have to undertake. The generator is always able to appeal a cost of connection but this takes time and is costly.

- While the cost of connection and any reinforcements to the system are paid for within deep connecting charging, a DG plant may increase operational and maintenance costs of the DNO. As DNOs are benchmarked against each other, they wish to minimise increases in operational expenditure
- The connection work must be signed off (i.e. agreed as secure) by the DNO before the generator can begin operation, thus if there is any problem, or if the DNO is not incentivised, or indeed is disincentivised with regard to DG, it is in a position to discourage it.
- The use of deep connection charging leads to the problem of the 'first-comer' situation, in which the first generator to connect in a particular location may have to bear the total costs of upgrading the grid. Any future developers wishing to establish generating capacity are then able to take advantage of the upgrades at very low comparative costs. However, the deep connection cost can often disincentivise any initial developer thereby placing a brake on all development.
- DNOs, under their License, are required to facilitate competition in generation. Deep connection charging, by creating the first comer problem – wherein the first DG developer bears the majority of connection costs – arguably acts to reduce the level of competition, something which is against their License, and also conflicts with the statutory duties of the UK regulator to ensure competition, and is in conflict with the aims of UK energy policy.

3.1.5 Conclusion

Connections are important in two areas:

- the area related to the cost to the developer of connections and what that implies for total deployment and the outputs competitiveness;
- the area related to incentives to the DNO for connection and therefore the extent to which DNOs facilitate DG.

In relation to connection costs to the Developer:

A system of shallow connection charging is to the advantage of DG provided a generator UoS charge is not exorbitant. The use of deep connection charging results in a financial burden that will frequently see the abandonment of development of a potential DG project. Whilst a system of shallow connection charging is not without its problems, and may result in an increased financial burden to the consumer, a judgement must be made as to the weight to be given to achieving the full range of goals that form both general energy policy and specific renewable energy policy at respective national levels. It can also be posited that the use of a system of shallow connection charging is in line with the mandates of a liberalised market in that removal of the significant barrier that can be created through the use of deep charging acts to increase the potential for competition within an electricity sector, and thus more easily lends itself to greater customer choice.

The type of use of system charge and how it is linked with connection charging will be of fundamental importance.

In addition, the extent to which costs are transparent and verifiable is of fundamental importance.

In relation to incentives on DNOs to connect:

As has been shown by the UK case, if there are no incentives to connect and the DNO is trying to maximise private shareholder dividends, they will do all they can to minimise costs on them and this will limit deployment. Thus, DNOs must be given provision to connect. One obvious way to do this is to allow DNOs any costs of extending or strengthening the network to be added to the RAB. However, this occurs in Germany and is only effective when the UoS charge does not create other noteworthy barriers to increased DG. This emphasises the importance of the relationship between connection and UoS charging.

Furthermore, costs of connection must be transparent.

In addition, where DNOs also own DG, there is a clear disincentive for them to allow new, competitive DG on to their networks.

Similarly, the extent to which DNOs have private shareholders and captive customers is also fundamental. If a DNO has private shareholders, they will wish to reduce costs so that dividends are high. If the costs of DG are socialised across all customers on a national basis this problem is significantly reduced since all DNOs would pay an equal cost of connection. Similarly, if a DNO owns generation, and has the potential to effectively capture customers, there will be less incentive to keep costs low. However, if customers are not captive and costs of DG are not socialised across all customers, then there will be pressure to minimise costs.

Thus, if DG is to be supported, one can see from the various country case studies that there must be an incentive to connect, UoS has to be complementary and certain costs have to be socialised.

3.2 Use of System Charging

UoS charging is fundamentally linked to connection charging. When a generator connects, they create a cost of connection and this can be, as we have heard, shallow or deep, this creates a cost of transport or operating the network (energy) and then an additional cost of maintenance. DNOs also have to be sure that their networks have enough capacity to be able to transport the peak demand of customers. Any under-sized network is a source of reduced revenue so that capacity is important. Most UoS charges have an energy and a capacity component but they can also have much more detailed costs related to, for example, metering and billing. Countries differ in this respect.

Nevertheless, the UoS charge is a regulated component of the tariff charged to the customer.

UoS can be used to maximise benefits that DG brings to the network, whether by technology, siting or time. None of the four countries does this, although the UK is discussing it.

If the only form of revenue raising by the DNO is one type of UoS charge, their actions will be inflexible since they have no choice. If the objective is flexible and active DNOs, then the UoS charge must also be flexible.

3.2.1 Denmark

The Danish system can be regarded as offering the simplest treatment of DG with regard to system charges. 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 DNO's depreciation and return on the investment in meters including installation costs; billing and reading of meters (see previous section).

The DNO 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. DNOs 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.

3.2.2 Germany

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

- 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 is effectively an exit charge which also has 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 DNOs have the incentive not to exceed the average. If DG can contribute to decrease the system losses in this case, then DNOs have an incentive to support them.

Furthermore, the charges for metering and billing used to have a high margin; as a result DNOs 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.

A central problem with the German system remains that the allocation of costs are not transparent.

3.2.3 The Netherlands

The system in the Netherlands is slightly more complex. All tariffs are calculated by application of the Tariff code. Specific tariffs are calculated by the DNOs, and then approved by the 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.

Producers that have connections to the high voltage grids or have a generation capacity of more than 150 MW have to pay the National Uniform Producer Tariff (LUP), which account for the 25% of the sum of the total transmission dependent costs of these grids. Consumers bear the rest of these high voltage grids and the costs of the lower voltage grids. Since DG is smaller than 150 MW and connected to the lower voltage grids, DG profits from this LUP. This system would appear to show parallels with the application of Transmission Network Use of System charging in the UK.

3.2.4 The UK

The charges associated with the use of system in the UK have changed radically as a result of the New Electricity Trading Arrangements (NETA), put in place in March 2001. Prior to NETA all distribution use of system (DUOS) and transmission network use of system (TNUOS) charges were passed to the consumer. This meant the absence of any incentive to the DNOs:

- to find cheaper operating procedures;
- to develop a market for distributed services; and
- a failure on the part of the DNOs to understand and appreciate the potential network benefits of DG.

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 theory, small generators should help suppliers avoid some BSUOS costs, to this end they may bid to the National Grid Company (NGC) as suppliers of system and ancillary services. However, in order to do this, the bidder must be a BSC signatory, and the high cost of becoming such a signatory acts to deter distributed generators from being able to bid. Thus while bids have been made, none have thus far been successful. However, as the NGC provides system and ancillary services there is still no recognition of these advantages or incentive to the DNOs to establish a market for distributed benefits. Additionally, the BSUoS can reflect costs in the UK's balancing system poorly, and acts to create surpluses. These surpluses are distributed amongst Balancing and Settlement Code (BSC) signatories and under current regulation DG is counted as a negative, acting to penalise suppliers with DG in their portfolio.

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 DNO and is the sole revenue raiser for the DNO. The DNOs incentive is therefore 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 covers cost of transportation of kWh + maintenance + depreciation + losses + a fixed return to the DNO.

With respect to the losses, a loss adjustment factor is used. Any reduction in losses is incentivised but reduction in losses from DG is taken out of the equation, negating any incentive on DNOs to use DG to reduce losses.

This is a very inflexible way for DNOs to raise revenues but works reasonably well with deep connection costs. This would have to change if a shallow system came into being since the difference between shallow and deep would have to be incorporated into DUOS. This can be done in a number of ways:

- averaged and paid by generators only
- specific to generators costs only (more a different means of paying for connection)
- averaged and paid by demand customers across the network only (i.e. socialised)
- Some in between measure

The socialised payment of connection, described in the section above, would be the equivalent of the third bullet point.

3.2.5 Conclusion

- Socialised UoS ensures that regional differences do not act as penalties.
- Germany and the Netherlands have the components of the UoS broken down. However, as generators do not pay UoS charges this means there is little impact for the way in which DNOs interact with DG.
- If connection is deep, then UoS covers all costs of network operation and maintenance.
- If UoS is not used to incentivise technologies, siting, demand management and timing of generation, then DNOs will be limited in their ability to actively manage network.

4. Incentivisation of DNOs

Incentivisation of DNOs is reliant on a broad number of factors – most of them being discussed above. In addition, the DNOs also usually have to submit to a ‘higher’ level of incentivisation, for example, the Retail Price Index-X system (RPI-X) in the UK and Netherlands, which also has implications for their attitudes to DG.

The overarching incentivisation together ‘sums’ the incentives for those DNOs to promote or hinder DG. Similar mechanisms will have very different effects depending on the characteristics of the DNO. For example, a DNO will act very differently if it has private shareholders, can exert strong control over its customers and owns generation compared to a DNO which has private shareholders but has little control over its customers. In addition, the incentivisation mechanisms for stimulating the behaviour of DNOs will have less impact on DG in countries which have strong financial support for DG. For example, in Denmark and Germany, the support for DG softens the profit-oriented manoeuvres of the relevant DNOs.

4.1 Price Caps

The UK and the Netherlands all employ the RPI-X or price cap mechanism as their primary price control regulation. That is network companies in these countries are allowed to keep any surplus achieved by reducing costs in excess of those demanded by the respective regulators, with the figure redrawn on a regular basis to allow these gains in efficiency to move to the consumer. The effect of this in the UK and the Netherlands appears to have been to lock the DNOs into focusing on trying to do the same thing in each of the price control review periods, but with greater efficiency and reduced costs. The effect, as detailed in both the UK and Netherlands reports is to lock the DNOs into the same actions and to reduce the potential for innovation in the way that the system can operate.

4.2 Benchmarking

Benchmarking of companies, providing there are incentives to do better than the other benchmarked companies, is another form of regulation. Benchmarking occurs in Denmark, although there are no penalties attached to failure to achieve greater efficiencies, though there is potential for penalties to be used should a DNO consistently fail to meet required efficiencies. Germany also has a Comparison Market Concept, similar to the Danish system but it is unclear how penalties work with respect to this. The absence of a German regulator and the absence of a rigorously regulated system for price setting mean that it is not possible to quantify how penalties apply within the system. The UK DNOs are benchmarked with respect to operational expenditure, but this is just one tool within the overall RPI-X mechanism. The 'frontier' company then sets the revenue allowed for operational expenditure (Opex) which then feeds in to all other companies. The effect is that a company which has higher Opex costs will end up with a lower return for its shareholders.

Benchmarking clearly offers a way to rank companies and this can be useful for regulators within some type of price control mechanism. Nevertheless, the impacts can be detrimental in that they, broadly, incentivise doing the same things more efficiently. This is very anti-innovation and unhelpful to distributed generation and a move to 'active' management of networks, which is very much about doing new things, dealing with new technologies and concepts.

4.3 Performance Based Regulation

Performance based regulation (PBR) has been used in a very limited manner in the partner countries. In the UK, 2% of DNO revenues are linked to various performance requirements to do with quality of service (for example, number of customer minutes lost) but none to do with DG. There are also performance linked incentives related to the transmission networks.

The Netherlands also has some specified performance outcomes related to quality of service but these are not yet related to monetary incentives, so have little effect. However, it is intended that PBR is the basis of the 2003 price control.

PBR is one way to combine the benefits of benchmarking whilst combatting the detrimental approach to innovation of both RPI-X and benchmarking.

4.4 Network Benefits

Few countries monetise network benefits. This is discussed in depth in section 6.

4.5 Incentivisation of DNOs in the Four Member States

4.5.1 Denmark

Denmark has approached the question of promotion of DG with respect to both technological development and the various institutional aspects that those technologies have to interact with. There are numerous rules for the connection of DG and reimbursing and spreading of costs which means that on the whole the Danish DNOs do not have high costs related to DG since they can pass them on to customers. Nevertheless, what does not appear to have occurred is some holistic incentivisation for the DNOs to develop strategic and structured networks which over the longer term may be technically preferable or of lower cost to the consumer. Thus, the networks that DNOs have are not necessarily those that they would have created had they had different incentives or different rules.

Denmark has begun a system of benchmarking which includes DG costs. While currently this does not appear to provide a direct penalty to 'poor' DNOs, it potentially could do. If this were the case, then it is to be hoped that some performance based incentive to run an efficient network would be included.

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 DNOs 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 DNOs tariffs are too high they may instruct the DNO to lower the tariffs and thereby meet the income framework. If the DNO fails to comply with this direction, the ERA has the power to revoke the DNOs licence.

4.5.2 Germany

Germany has a greater variety of mechanisms than other countries.

Connection costs may be added to the UoS charge, as we saw above. A DNO's UoS charge is derived from the regulatory asset base (RAB) and there is therefore an incentive to connect since this can be added to the RAB.

However, there is benchmarking between DNOs. The FCO currently contrasts best practice amongst networks with similar market structure though the focus seems 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 on consumers. In this situation, the incentive would not be for DNOs to connect.

DG can act to decrease system losses or reduces the peak load a DNO might need to purchase from a higher voltage network. As grid charges are calculated based on the annual peak load, reducing the peak load that the DNO has to purchase from the TNO acts to reduce the costs to the DNO. Though reduced costs due to reduced peak loads are supposed to be passed on to the generator, inexact regulation, and the absence of regulatory enforcement means that DNOs may not pass on all of these savings to the DG operator. Whilst the DNO may enjoy some benefits, these are not likely to be substantial enough to significantly incentivise the DNO to favour DG.

However, there are three areas of concerns. Firstly, the lack of transparency and certainty in governance. This is discussed in detail in the opening section. Secondly, the lack of unbundling which has occurred in the German electricity industry. This means that at a very fundamental level, DNOs may view new DG as competitors. Thirdly, the costs associated with the number of individual DG developments act to increase DNO administration costs which act as a further disincentive, and one that creates a burden on a geographic basis.

Thus, Germany in some ways has a great deal of support for DG. But it also has significant barriers in place for the development of an electricity system where DG can take its place as an equal part of that network.

4.5.3 The Netherlands

The system in the Netherlands shows some parallels with the UK in that they both have a price cap, benchmarking and PBR. However, in the Netherlands, DNO incomes rely on minimising both operational expenditures and expenditure on capital assets. The benchmarking process considers the capital and operational costs together; hence DNOs are forced to reduce these expenditures in comparison with other companies in order to increase profits.

Restrictions on their profits apply through the imposition of maximum tariffs, determined by an X-factor. The facts that DNOs are encouraged to minimise capital costs or, which is the same, network investments and that currently the Dutch regulatory system lacks minimum performance standards raises the problem of the quality of the system. The firms under the current regulatory framework are encouraged to invest in reducing the levels of future investment that might be required and investments in line with statutory obligations such as compulsory connection costs. However investment in quality of supply is not effectively addressed and no penalties relate to performance relating to it.

Long term cost-planning has also been undermined by wholesale unbundling of the sector. Furthermore, it is unlikely that the regulator will develop future scenarios which will act to secure future investment, and it is thus unlikely that the benefits of DG to the network will be taken into account by the regulator and that some fiscal incentive to the DNO relating to the addition of DG will be added to the regulatory framework.

The only stimulus within the current Dutch system to encourage DNOs to favour the addition of DG to their networks is the direct one relating to the possibility that they might lower operational costs.

4.5.4 The UK

In the UK, the specific incentivisation mechanism for a DNO is based on its Regulatory Asset Base (RAB), and income is linked to sales, the RPI-X 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 DNO as no increase in RAB attends it.

A system of benchmarking DNO operational expenditure against other DNOs 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.

As mentioned in section 4.3, some PBR occurs in the UK, but does not apply with regard to DG.

4.5.5 Conclusion

Price caps and benchmarking, while giving the regulator benefits, tends to act in an anti-innovation manner. When combined with PBR however, this anti-innovation bent can be altered.

5. The Selling of Electricity

One key aspect of regulation which is fundamentally important to DG – and which is now a feature of regulation applying to DG in each of the four Member States – is the affirmation of guaranteed access to networks. This can be divided between connections –

discussed above – and the ability when generating to be able to sell the electricity. The EU Renewable Directive requires all generators are guaranteed access – and all Member States reviewed here do so. However, it is also possible to grant priority access, in this case Denmark and Germany.

5.1 Denmark

As the settlement prices under the Danish subsidy mechanism are higher than the market price of electricity and as the priority production gives rise to some additional cost, a special "priority production tariff" is defined. The consumers are charged with the priority production tariff for a certain percentage of their consumption. Thus, the cost of handling the priority production is equally distributed or socialised amongst all customers. There are though, exemptions for the largest consumers.

The costs elements included in the priority production tariff are:

- The legally defined settlement price to the producers;
- Balancing services related to priority production; and
- The System Operator's (SOs) administrative expenses related to priority production (but not the DNO's).

As the two parts of Denmark are not directly interconnected, the SO in the part of Denmark in excess of priority production (the western part) sells the excess amount on Nord Pool while the SO in the part of Denmark in shortage (the eastern part) buys the same amount on Nord Pool. Because the price on the spot market is below the tariffs paid to priority producers, the physical equalisation is accompanied by a financial part where the eastern SO pays the difference between the price on the spot market and the priority production tariff to the western SO.

This dispatch model has several advantages and disadvantages. The major point of criticism has been that the design of the model was a threat to a well-functioning market as priority production is treated in a closed system totally separated from the market for electricity. As the percentage of priority production which the consumers are to buy lies between 29.3% in July and 57.8% in February 2002 there is considerable shrinkage in the market for electricity, thus watering down the level of competition. When the model was designed it was also discussed that the SO should buy the priority production, on-sell it to Nord Pool and charge the consumers for the price difference. The SO would then be a major player on the Nord Pool. Since the SO is supposed to be neutral this was not an acceptable model. Furthermore, it could be claimed that the model would constitute a hidden export subsidy.

On the other hand, the market is not distorted by large amounts of subsidised production, only reduced.

One area of concern is that the DNOs' costs in relation to the dispatch model are not included, and thus not reimbursed in the model.

Various thoughts have been made about a new model for handling the prioritised production. An option to move to a tradable green certificate was abandoned due to uncertainties in its effects on Danish renewable energy policy goals.

The model is special in the sense that it lacks incentives. The wind turbines are settled in accordance with a predetermined tariff no matter how they behave. They can stop production or produce full load without being faced with any economic consequences this causes to the system. In principle the same applies for the DG other than wind turbines. These entities, often small scale CHP, are also settled in accordance with a predetermined tariff, but the tariff is differentiated in accordance with load periods defined by the SO company. This provides the SO with a rough instrument to fit the production into the consumption pattern.

The DNOs can pass on their expenses in relation to the buy-up of the production from priority producers (but not the administrative costs) to the SO. In principle, the same applies for the SO's expenses, which can also be passed on to the consumers. The costs of discrepancies from the planned production or consumption levels are normally defrayed by those responsible for the production or consumption, but this is not the case with wind turbines. As a consequence, the system lacks incentives to promote a technological development such as storing facilities or steering mechanisms that can contribute to reducing the costs to society.

5.2 Germany

In Germany, balancing is not a relevant issue for CHP plants and plants which fall within the regulation of the Erneuerbare Energien Gesetz (EEG). These simply feed their output into the grid and the DNO has to deal with any problems this creates with regard to balancing its total output. Under the EEG, the DNO has to remunerate renewables for their electricity at a fixed rate irrespective of the load profile. Consequently, the renewables operator does not have to bear the risk of intermittence and this has impacts on the incentive structure of DNOs as discussed below.

In the case of CHP, it is also the DNO which is in charge of balancing. However, the calculation of the capacity component of the compensation for avoided network costs gives CHP operators an incentive to coordinate their generation with the load on the system at least to some extent.

Balancing can be an issue for DG plants not covered by the EEG and CHP legislation. Generally, the balancing requirements are very high in the German market, mainly as a result of the very short balancing period of 15 minutes laid down in the VVII+/ Grid Code. One of the main improvements of VVII as compared to VVI is that it gives grid users the possibility to bundle their feed-in or take-off together, so that in a given balancing period the lower load of one grid user can be offset by another user increasing his load. As a consequence of being part of a balancing pool, grid users have a lower risk of imbalance. Especially for plants with a high load variation, this is a significant advantage.

There is a tolerance of 5% for imbalances between feed-in and take-off, i.e. grid users that are within a 5% band of their notified load just have to pay for balancing energy, whereas grid users that exceed the 5% limit also have to pay a capacity component for the reserve capacity that was required to cover their imbalance. This provides valuable flexibility. There is a spread between system sell and system buy prices to prevent grid users from exploiting the balancing system by exceeding their contracted output on purpose.

One of the main problems has been the high prices for balancing energy. Most grid operators charge fixed prices that are not market-based. A properly functioning balancing market is developing only slowly. Once again the weak regulatory framework is one of the main obstacles. There have been repeated complaints that the providers of balancing energy abuse their market power and the Federal Cartel Office has been repeatedly called upon to investigate balancing prices.

The creation of the existing markets is mainly a result of the FCO requiring such markets in response to TNO mergers, and it is possible that a single unified German balancing market may still occur. The further development of these markets should reduce the costs of balancing energy, which will improve the market position of distributed plants that are exposed to these markets, especially if they have a high load variation.

Reserve capacity is relevant in two different ways. First, for plants covering an on-site demand (no matter whether or not part of their output is exported) the price of top-up and back-up power is relevant. Second, if the DNO has to call reserve capacity from the TNO to offset a DG plant outage, this will increase the grid charges he has to pay to the TNO. The DNO can therefore reduce the capacity component of the compensation for avoided network costs. There are three different levels, depending on the hours per year, below 200h/a, 200h/a – 400h/a and 400h/a – 600h/a. If the reserve capacity is called more than 600h/a, the plant operator has to pay the full grid charge for the reserve capacity, which means that there will be hardly any compensation left.

5.3 The Netherlands

In the Netherlands, before the opening of the market, distributed generation (mostly co-generation plants) received feed-in tariffs for their electricity produced. With the liberalisation of the electricity markets, distributed resources no longer benefit from these specific remuneration fees and, as a result, have to trade the electricity produced in the wholesale market, mostly with the interference of an electricity supplier. Furthermore, system imbalances have to be corrected in a balancing market.

Decentralised trading arrangements were implemented in the Dutch power market when the new Dutch electricity act was put into force in 1998. As a result, the day-ahead market in the Amsterdam Power Exchange (APX), the bilateral Over the Counter (OTC) market and Tennet's balancing market are the three main markets that exist where electricity is currently traded. The first two differ in the types of market design, contracts traded, liquidity and transparency. The third is a balancing market design to handle the deviations between actual demand and projected demand, as well as the under-generation and over-generation due to plant failures. This market is relevant for intermittent energy sources. The first and third are discussed below.

APX

The APX was implemented by a number of interested market parties in order to create a trading place that would provide an indicative wholesale price of electricity in the Dutch market. The APX went live in May 1999; it is day-ahead and trades physical contracts. The volume of electricity traded in the day-ahead market has been increasing steadily and reached around 10% of the total electricity consumed in the beginning of 2002.

The access of distributed resources to the APX can increase market liquidity and reduce market power from large producers in its day-ahead market. In July 2001 several price spikes were observed in the day-ahead market of the APX and it was suggested that large producers were manipulating market prices. A wider introduction of distributed resources may help mitigate the exercise of market power by reducing concentration levels in that market.

However, transaction and information costs are barriers that impede the participation of distributed resources in the power exchange. For example, access fees contribute to transaction costs. Any market party that wants to trade in the APX has to pay a one-off entrance fee of 12,500€, and then 25,000€ per year, which represents a significant sum for small generators.

The aggregation of many small distributed resources under the control of a single manager can facilitate market entrance by reducing these transaction and information costs. Today the electricity suppliers act as aggregator of DG. The large electricity supplier may behave dominant which put DG owners in a dependable position

Balancing Market

Tennet, the Transmission system Operator (TSO) is responsible for resolving internal transmission constraints and maintaining the balance of the power system. In the first case Tennet relieves internal congestion by re-dispatching electricity, i.e. decreasing production in the up-stream area and increasing it in the downstream area. In the second case, if any deviation from the planned production and consumption exists, then Tennet will automatically compensate by increasing or decreasing production/demand depending on the situation. Tennet performs these activities through the Regulating, Reserve and Emergency power markets, which basically work as typical markets. While the internal transmission constraints are relieved through reserve power, the imbalances are resolved through the regulating and sometimes also reserve power. The differences between them rely on the contract practices and on the technical requirements of the power plants that provide the electricity. Emergency power aims at preserving the system balance when no appropriate regulating and reserve power is left.

The imbalance price is determined by the price ladder (supply curve), which includes the upward and downward power bided by market parties, and demand or supply of power depending on the imbalance situation (demand). Basically an imbalance price is determined for each situation in the following way:

- If a market party supplies more than its planned production in a situation of under balance he receives the upward regulation price, which is identical to the dispatch price of positive power.
- If a market party supplies too much electricity in a situation of over balance he pays the downward regulation price, which is identical to the dispatch price of negative power
- If a market party supplies to little electricity in a situation of under balance he pays the upward regulation price
- If a market party supplies too little electricity in a situation of over balance he pays the downward regulation price.

Intermittent DG, such as wind and sun, are significantly sensitive to balancing prices, especially because of their volatility and high peaks. Two different issues are important to mention from this system that can be seen as benefiting intermittent DG. First is the fact that owners of intermittent DG can cover themselves, as the Dutch wholesale market allows intra-day trading though the OTC market until one hour before the dispatch of the electricity. The other is the fact that the balancing market values the generation that helps the market positively, i.e. if a producer generates more than planned in an over balance market, it gets a positive price. This is one important advantage over the UK's NETA system.

The method implemented by Tennet to solve internal transmission constraints does not provide specific incentives to install additional generation capacity at congested locations to reduce transmission line constraints. A single market price exists in the Netherlands, and therefore transmission constraints are not explicitly signalled. As a result, the additional costs of upgrading the grid or the benefits of increasing generation in constrained sectors are distributed to all market participants. This system may lead to inefficiencies in the power sector, and discourages the implementation of distributed generation.

5.4 The UK

The fundamental idea of NETA is that it should be cost-reflective and promote reliability of power. It is a competitive mechanism which benefits those with economies of scale. NETA incorporates a number of hurdles for small generators and when aggregated, these hurdles become an important barrier to their deployment. Most small generators do not sell through NETA but via a supplier. This supplier is often in a monopoly position and the grid supply area, where the small generator is sited, and therefore has power over the price it is prepared to pay the renewable generator.

In the UK, all power is bought and sold through a system of bilateral trading arrangements, ranging from long-term agreements running over a number of years, through to on-the-day operation, and, through the use of the Balancing Market (BM), as near to real-time as possible. The National Grid Company is responsible for the balancing and system operation while Elexon (a wholly owned subsidiary of NGC) is responsible for the administration of NETA. NETA itself is governed by a Balancing and Settlement Code (BSC) panel, as discussed below. All trade is bilateral between a generator and a supplier who/which have signed the BSC.

The BM is notified of all trade 1 hour before 'real time'. When the buyer or seller of electricity does not do what they said they would do within the half-hour trading time (either generates too much or too little or buys too much or too little) there is an imbalance. The system operator then has to buy more (or less electricity) to make up for the imbalance. The SO take bids to balance for each half-hour. The cost of buying more or less generation leads to imbalance settlement prices (ISPs) for each half-hour. The generators or suppliers who are out of balance then have to pay the ISP (i.e. system sell price or system buy price) for that half an hour.

Barriers for small generators from NETA fall into three areas:

- the disproportionate costs which occur because of scale (e.g. cost of BSC membership to annual generation)
- the costs for small generation which occur now but which are expected to reduce considerably or disappear entirely as NETA 'settles down' (e.g. the cost of consolidation, the move from a 3.5 hour to a one hour gate closure)
- the costs which are related to NETA not being cost reflective and which are not expected to change

NETA is a system which is supportive to economies of scale and reliable power, the opposite of most sustainable energy technologies. While prices have come down, other Government objectives – because they are not addressed by NETA – have suffered.

The key issue of contention with respect to distributed generation is that the cost imposed through the balancing mechanism is greater than the cost of intermittent power to the system. PIU and others say that NETA is not cost-reflective while Ofgem maintains that it is. If it is finally shown that NETA is not cost-reflective, then it means that those areas that Government does have policies on (ie renewables) are paying more than they should do relative to other forms of generation that the Government is not supporting.

The disproportionate costs due to scale will continue. The costs which are expected to reduce (ie consolidation) or disappear have not yet done so, although have improved with one hour gate closure, and it is not certain that they will do so or when they will do so. Finally, the non-cost reflectivity of NETA for intermittent electricity will have to be sorted out. Together, these factors act as a considerable barrier to the deployment of small generators.

6. Network Benefits of DG

6.1 Network Cost Benefits

A key characteristic of regulation relating to DG is that it can often fail to credit network cost benefits, to the obvious demerit of DG operational cost effectiveness. Network benefits can either come under direct regulation (e.g. losses) or via markets (e.g. ancillary services). It is a complex area since benefits will alter depending on technology, siting and timing of generation output. It should also be noted that it is possible for too much DG load to exist in particular parts of a network, leading to electricity to have to be transformed upwards to higher voltages with resulting losses and thus increased costs. This has occurred in some areas of Denmark with high wind loads but sparse population.

As noted above, the German system (both markets and regulation) accounts for benefits, but can fail to ensure that these are passed in totality to the DG operator.

Theoretically, the UK's New Electricity Trading Arrangements (NETA) should allow the system and ancillary benefits provided by DG to be recognised, but failure to win a contract for them means that no market for them exists and therefore no benefits accrue to the generator. Losses are accounted for in regulation in general. However, any reduction of losses by DG is netted out through the process that takes into account how losses are calculated, and therefore no real incentive exists.

The Network Code in the Netherlands allows DNOs to pass through benefits from DG; historically however, they have failed to do so until complaints, largely from those employing industrial co-generation led to a temporary agreement which compensates DG supplying the low and medium voltage grids at 0.1€ct/kWh.

The issue has proved to be controversial in Denmark. Whilst the network benefits of DG are recognised, it has proven difficult to precisely define their extent. Additionally, it is also recognised that the benefits vary with different DG technologies. Thus the settlement price agreed is different for different technologies, and in each case does not appear to be based on specific figures but on what can be agreed at the political level.

Clearly, it is to the advantage of DG to have its benefits recognised. Further to this, and fundamentally to the operation of electricity supply industries, the absence of a mechanism to reflecting the true costs of generation undermines the operation of the market, and acts to reduce competition, to the eventual demerit of the consumer.

The actual operation of a mechanism to recognise the network benefits of DG is another issue. It is clear that there is the potential for a significant degree of complexity in calculating project specific benefits, but this does not justify their absence.

6.2 Avoided Network Investments (ANI)

In an ideal world, DG also has the potential to enable network operators to reduce investments in network infrastructure, thereby enabling cost savings. Recognition of these benefits is not as straightforward as it might be however. Such recognition depends on whether the system allows the benefits to be recognised within the regulatory framework. Essentially it relates to whether the regulatory system as a whole, and particularly the incentivisation basis for DNOs, is sufficiently flexible to allow DNOs to be able to consider various modes of operation. Systems which do not allow a DNO to place any value on ANI are failing to recognise all the costs within a system. A system which offers the opportunity for the DNO to be incentivised by a range of different options, and which allows it to take into account the full range of variables inherent in the maintenance and development of its system could allow the DNO to recognise the value of avoided network investments. Such recognition should lead to increased cost-transparency within the system, and reduced prices across for the consumer as well as movement towards decentralised power usage and a more sustainable future.

In the UK, no benefits accrue directly to DG as a result of any reduction it might lead to in the need for increased investment in the network. The current system of regulation in the UK is such that DNOs are incentivised to pursue increased investment in the network as this leads to an increase in the RAB upon which their incomes are based. The DNOs do not gain from increased DG, and actually lose through any displacement of investment this causes. Thus the potential benefit of increased DG deriving to the system as a whole is obstructed by the regulatory system. Changing the system to allow DNOs to accrue some of the benefits that increased DG might bring in terms of the need for reduced network investments, and passing some of these benefits on to both the DG operator and the consumer acts to make the system more competitive, more efficient and thus more beneficial to the consumer.

The Danish regulatory system does include provision for recognition of the benefits of avoided grid extensions. However, the level of DG now operating in Denmark has made it difficult to determine whether there are any benefits arising from specific projects. It is thus unclear whether the system is recognising the full value of the avoided investments and passing these benefits on to the generators. This has clear implications for the economics of new generators.
In the Netherlands, the system in place does not recognise the possible benefits DG generates as avoided network investments. DNOs in the Netherlands, in response to the regulatory pricing system, are encouraged to minimise network expansion costs, in order to increase their benefits. In spite of this, in the case DG generates the avoided network expansion no regulatory instrument exists that would pass on the benefits to the

generators. In other words, no instruments such as locational pricing or negative connection costs exists that would compensate DG.

For recognition of the avoidance of network investment to be occur, it is necessary for the DNO to realise the value of the ANI. This occurred in the past, within vertically integrated companies owning generation, transmission and distribution facilities, such as Pacific Gas and Electric. If connection charges are deep the DNO will not place any value on ANI. If the incentivisation of the DNOs is not holistic, then the potential for all factors within the system to be accounted for in motivating the actions of DNOs is reduced.

7. Potential Impacts of EU Regulation

The Electricity Directive 96/92/EC and Gas Directive 98/30/EC both have general relevance (and contain specific references to) the treatment of renewable energy sources (RES) and/or CHP in the EU Member States. However, the most significant existing EU legislation addressing the regulatory issues for DG is the EU Renewables Directive of 2001. This is binding legislation that must be implemented by the Member States not later than 27 October 2003.

In addition, the European Commission has proposed two directives that would directly affect the investment of certain DG installations. First, the proposed directive on CHP contains a section on grid issues very similar to that in the Renewables Directive, and which recognises that both RES and CHP face similar problems in this respect. Second, the proposal for a Directive to amend the Electricity and Gas Directives contains a definition of DG and various related rules.

Considering, these various existing and proposed EU directives we can identify six relevant regulatory topics:

- Priority Rights
- Connection Rules
- Ancillary and Balancing Services
- Authorisation procedures
- System Access
- Unbundling Rules

These are discussed in turn.

7.1 Priority Rights

The Electricity Directive 96/92/EC allows Member States to require electricity system operators, when dispatching generating installations, to give priority to generating installations using renewable energy sources or waste or producing CHP. That is, Member States have the option to prioritise electricity from RE and from CHP. Denmark and Germany have taken this option; the Netherlands and the UK have declined it in order to favour more competitive mechanisms for the support of sustainable electricity sources. The costs associated with such priority are passed on to all consumers, though until the passing of the 1998 German Energy Act, costs in German were passed on only at the regional level.

The Renewables Directive contains additional rules on prioritisation, and it can be expected that the national regimes will be adjusted accordingly.

7.2 Connection Rules

Conditions for connection are now clearly addressed within the regulatory framework of each of the four countries detailed here. Access to the grid is guaranteed in each of the four countries. However, Article 7(5) of the Renewables Directive requires implementation of a cost sharing mechanism that takes into account the benefits that "initially and subsequently connected producers … derive from the connections". It is clear from the descriptions given above that the point if largely moot for those countries which provide shallow connection costs, but is of particular relevance for the UK, with the regard to the 'first comer' problem detailed above. Adoption of 'shallow-ish' connection cost charging would appear to bring the UK into line with the directive however.

7.3 Ancillary and Balancing Services

EU legislation requires that TSOs shall be responsible for ensuring the availability of all necessary ancillary services, defined in the Electricity Directive in only general terms. But common rules on the provision and regulation of balancing services by TSOs and DSOs are still under development in the form of amendments to the Electricity Directive. The Renewables Directive does oblige Member States to put in place a legal framework which acknowledges the potential for cost benefits to the network from renewable energy sources. The approach of the four case study countries reviewed here is mixed with regard to recognising these network benefits, as has been detailed above. It is difficult to know what the legal status of some nations is with regard to compliance with the directive. For example, does the UK's system, wherein DG operators have a right to bid to provide ancillary services, but where they are in practice limited from doing so, achieve compliance with the directive?

The proposed amendments to the Electricity Directive, if adopted, would establish some common rules relating to certain balancing issues, but these are still being developed.

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7.4 Authorisation Procedures

Essentially, Article 6(1) of the Renewables Directive requires that Member States act to expedite penetration of renewables and CHP through the removal of regulatory and non-regulatory barriers to their use, to ensure the streamlining of procedures relevant to them, and to ensure the rules concerning them are objective, transparent and non-discriminatory.

The approach of the four Member States represented in this document displays a wide variance to compliance with this aspect of the renewables directive. Germany and Denmark can be regarded as being the most active in removing barriers to the growth of both RES and CHP, with both acting not only to remove barriers but also to provide considerable operational advantages to various technologies, and a willingness to raise costs to the consumer in order to ensure economic benefits to project developers outweighing the eventual costs which can usually be related to both regulatory and non-regulatory barriers.

The Dutch 1998 Electricity Act formalised the purchase obligations on utilities and the mechanism for determining the related remuneration rule, as well as instituting a ministerial option for a green certificate trading system. These various duties on utilities and incentives for the protection of small installations producing "sustainable electricity" are in line with a long-standing Dutch tradition in this area".

In addition to the other barriers described in the text so far, despite long years of obvious failure, the UK planning system has yet to be improved. To further underline the inherent unresponsiveness of the UK system, it should also be noted that despite the imminent failure of the NFFO, the process to introduce a new renewable support mechanism took five years.

The lack of effective response to this aspect of the directive underlines what is effectively a vague instruction to Member States to take action, rather than an enforceable instruction.

7.5 System Access

Each of the four Member States guarantees access to the grid, in line with Article 16 of the Electricity Directive, although the effect and costs vary considerably across the countries.

7.6 Unbundling Rules

All countries meet the requirements of unbundling presently required by the existing Electricity Directive. Nevertheless, the lack of un-bundling in practise, the ownership of competitive DG, captive customers and so forth all act to undermine the incentives on DNOs to facilitate DG.

8. Conclusion

The Member States clearly demonstrate the considerable differences in the contexts and frameworks in which DG has to operate, and the variety of factors that can impinge on its successful addition to distribution networks.

These have shown to be:

- the governance system - what is the hierarchy of legislative power in relation to DG outcomes
- connection charging
- use of system charging
- the macro incentives and extent to which performance based regulation is in place
- dispatch - how electricity is sold
- how DG benefits are valued
- the political will to promote DG

It has been shown that economic regulation of distributed networks may undermine the development of distributed generation. It is essential if the individual Member States and the EU targets for distributed generation are to be met, that economic regulation must take a more neutral approach. Roadmaps for how such an approach might be delineated will be discussed in the second phase of Sustelnet.

Annex 1

The Danish Governance System