



Enhancement of sustainable electricity supply through improvements of the regulatory framework of distribution networks for distributed generation

Regulatory Improvements for Effective Integration of Distributed Generation into Electricity Distribution Networks

Summary of the DG-GRID project results

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This document is summarising the results of the DG-GRID project and is based on the following DG-GRID reports:

- D1 *Regulatory Review and International Comparison of EU-15 Member States* by Klaus Skytte and Stephanie Ropenus, Risø, October 2005.
- D2 *Assessment and Recommendations Overcoming in Short-Term Grid System Regulatory and other Barriers to Distributed Generation* by Klaus Skytte and Stephanie Ropenus, Risø, October 2005.
- D4 *Review of Innovative Network Concepts* by Goran Strbac, Nick Jenkins, Tim Green, Danny Pudjianto, Imperial College London and University of Manchester, December 2006.
- D5 *Regulating Innovation & Innovating Regulation* by Dierk Bauknecht (Oeko-Institut), Uwe Leprich (IZES), Philipp Späth (IFZ), Klaus Skytte (Risø), January 2007.
- D7 *Method for Monetisation of Cost and Benefits of DG Options* by D. Pudjianto, D.M. Cao, S. Grenard and G. Strbac, University of Manchester and Imperial College London, January 2006.
- D8 *Costs and Benefits of DG Connections to Grid System* by D.M. Cao, D. Pudjianto, G. Strbac from Imperial College London and A. Martikainen, S. Kärkkäinen and J. Farin from VTT, December 2006.
- D9 *The evolving role of the DSO in efficiently accommodating distributed generation* by J.C. Jansen, A.J. van der Welle and J. de Joode, ECN-E--07-063, June 2007.
- D10 *Business models for DSOs under alternative regulatory regimes* by J. de Joode, A.J. van der Welle and J.C. Jansen, ECN-E--07-038, August 2007.
- D12/13 *Guidelines for improvement on the short term of electricity distribution network regulation for enhancing the share of DG* by Tomás Gómez (IIT-Comillas), Juan Rivier (IIT-Comillas), Pablo Frías (IIT-Comillas), Stephanie Ropenus (RISØ), Adriaan van der Welle (ECN) and Dierk Bauknecht (Öko-Institut), June 2007.

Project objectives

The objectives of the DG-GRID project were:

- To review the current EU MS economic regulatory framework for electricity networks and markets, and identify short-term options that remove barriers for RES and CHP deployment.
- To analyse the interaction between the economic regulatory framework, increasing volume share of RES and CHP and innovative network concepts in the long-term.
- To assess the effects of a large penetration of CHP and RES by analysing changes in revenue and expenditure flows for different market actors in a liberalised electricity market by developing a costs/benefit analysis of different regulatory designs and developing several business models for economic viable grid system operations by DSOs.
- To develop guidelines for network planning, regulation and the enhancement of integration of DG in the short term, but including the opportunity for new innovative changes in networks in the long-term.

DG-GRID project partners

- Energy research Centre of the Netherlands (ECN) (coordinator)
- Öko-Institut e.V., Institute for Applied Ecology, Germany
- Institute for future energy systems (IZES), Germany
- RISØ National Laboratory, Denmark
- Imperial College London, United Kingdom
- Instituto de Investigación Tecnológica (ITT), University Pontificia Comillas, Spain
- Inter-University Research Centre (IFZ), Austria
- Technical Research Centre of Finland (VTT), Finland
- Observatoire Méditerranéen de l'Energie (OME), France.

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Abstract

The growth of distributed electricity supply of renewable energy sources (RES-E) and combined heat and power (CHP) - so called distributed generation (DG) - can cause technical problems for electricity distribution networks. These integration problems can be overcome by reinforcing the network. Many European Member States apply network regulation that does not account for the impact of DG growth on the network costs. Passing on network integration costs to the DG-operator who is responsible for these extra costs may result in discrimination between different DG plants and between DG and large power generation. Therefore, in many regulatory systems distribution system operators (DSOs) are not being compensated for the DG integration costs.

The DG-GRID project analysed technical and economical barriers for integration of distributed generation into electricity distribution networks. The project looked into the impact of a high DG deployment on the electricity distribution system costs and the impact on the financial position of the DSO. Several ways for improving network regulation in order to compensate DSOs for the increasing DG penetration were identified and tested. The DG-GRID project looked also into stimulating network innovations through economic regulation. The project was co-financed by the European Commission and carried out by nine European universities and research institutes.

This report summarises the project results and is based on a number of DG-GRID reports that describe the conducted analyses and their results.

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Executive Summary

According to several directives of the European Union (RES Directive, CHP Directive and Electricity Directive) electricity supply from renewable energy sources (RES) and combined heat and power (CHP) should be considered in the operation and planning of the electricity infrastructure. Furthermore, costs and benefits to the distribution network induced by the various distributed generation (DG) technologies should be taken into account in the electricity network regulation. In practice, however, current electricity network regulation often does not consider regulatory mechanisms to ensure effective participation of RES and CHP in liberalised electricity markets.

The DG-GRID project, a project co-financed by the European Commission and carried out by nine European universities and research institutes from eight EU Member States (Austria, Denmark, France, The Netherlands, Spain, Finland, Germany, United Kingdom), analysed the technical and economical barriers for integration of distributed generation into electricity distribution networks.

Technical and economical barriers

The main technical barriers to integrate DG into the electricity distribution networks are related to voltage management and thermal rating issues in rural areas and system fault level issues in urban areas.

Distribution networks are regulated monopolies. The economical barriers are therefore mainly regulatory barriers. The main findings of a survey on the regulation of networks with respect to distributed generation among EU-15 were the following:

- The lack of incentive for the distribution system operator (DSO) to be proactive is one of the major barriers across the EU-15.
- The structure and amount of the connection charges, entry barriers to the market, procedural barriers for network access, and physical and network constraints are also dominating barriers.
- The degree of access to ancillary services and balancing differ a lot across the EU-15 Member States (MS).
- Only a few Member States have barriers with respect to procedural barriers to market access and lack of benefit for the DG.

Impact of DG on network system costs

An increase of DG can have an impact on distribution networks system costs that can turn out into extra costs or reduced costs (benefit) for the operator of distribution network (DSO). Considering the main technical issues, the DG-integration costs are related to upgrading of circuits and substations in rural networks and replacement of switchboards in urban networks. With a strong growth of DG connections a large amount of investment is needed to upgrade current network assets when network operators use the traditional 'fit and forget' approach, i.e. passive network operation philosophy. If an active network management philosophy is adopted, the amounts of DG that can be accommodated with limited investments will be larger. Instead of increasing the capacity of the network, the operational management is then changed: voltage and fault level control is applied as well as active involvement of distributed generators (and consumers) in optimising the economic operations of the system.

DG influences three kinds of DSO costs:

- *Reinforcement costs*: the incremental costs related to network reinforcements necessary to integrate DG into the network. The incremental costs are zero for low DG penetration levels. Once investment is required the incremental cost increases progressively, both in rural and

urban networks. If DG is more densely connected (i.e. more concentrated), this cost increase will be larger. If active network management is applied in most cases the reinforcement costs will be lower compared to passive network management.

- *Energy losses*: with low DG penetration energy losses decrease and the costs for compensating these losses will become smaller. However, if more DG penetrates the network energy losses will increase resulting in higher operational costs. With active network management the increase of energy losses will start at lower DG penetration levels and the increase will be larger.
- *Capacity replacement value*: DG may result in smaller electricity flows from higher to lower voltage levels postponing the need to reinforce the system in case of load growth or to reduce the investment required in case of equipment replacement.

The type of DG (non-intermittent and intermittent) influences network capacity and energy losses. The effects are different for rural and urban networks, also because of the different types of DG connected.

Improving distribution network regulation

A growing number of EU Member States have implemented economic incentive (price or revenue cap) regulation for the DSO business and apply a system that allocates DG integration costs to DSOs. These regulatory regimes do hardly allow for network integration of DG. They do not address the issue of integrating rising levels of distributed generation in system operation. Moreover, they do make too little allowance for the cost impacts thereof for the DSO and for the (potential) benefits of DG for active management of distribution networks. This, in turn, may entail aversion on the part of DSOs to readily facilitate the network integration of new DG plants and may as well inhibit the adoption of efficient active network management practices. Especially, holding on to passive network management may imply higher than optimal network costs and, consequently, higher network charges to the end users.

An alternative regulatory regime would have to at least neutralise the negative total impact of (increasing) DG on the DSO's allowable costs. The regulator may choose initially for slightly offsetting the negative impact in order to stimulate DSOs to change their behaviour in favour of DG. Furthermore, the alternative regime should remove any existing biases against the introduction of active network management, so that the DSO can make an economic decision when weighing the pros and cons of against passive network management. The regulatory context is of key importance to the choice of a business model by the DSO. Therefore, changing the regulatory regime may influence the DSO business model, i.e. the contractual relationships between the DSO and his business partners: the transmission system operator (TSO), DG operators, electricity suppliers and end users.

Regulatory components that can take DG into account or are positive towards DG development and can be considered in the alternative regulatory regime are:

- Allowance in the regulated asset base (RAB) and allowable operational expenditures (OPEX).
- Allowance by way of a new component in quality of service performance regulation.
- Allowance through including of a factor in the productivity benchmark analysis.
- Allowance of a DG performance factor outside the benchmarking procedure.
- Allowance by way of direct revenue driver (with possible network dependency).
- Shift from building blocks approach to total expenditures (TOTEX) approach.
- Shift from frontier benchmarking to average benchmarking.
- Shallow connection charges in tandem with time-variable use of system charges with locational signals.
- Responsibility for DSO of distribution losses with time-variable incentives.

Impact of DG on the DSO business

DSOs that cannot profit from the DG capacity replacement value and operate under a passive network management regime will generally not profit from the presence of DG in their distribution network. Although low DG penetration levels do benefit the DSO somewhat, higher penetration levels result in a negative overall impact. The concentration of DG within the network is a particular influential factor: the more concentrated the presence of DG in the distribution network, the more negative the impact. The driver for the generally positive results for low penetration levels and the generally negative results for high penetration levels are distribution losses.

DSOs operating under an active network management philosophy are generally confronted with comparable results as the passive network management case. Penetration of DG in the network is favourable for the DSO for low penetration levels, but becomes unfavourable the higher the penetration rate, and the more concentrated the DG in the network.

The added value of DG with respect to the investment deferral for connections to the higher voltage network levels can be substantial. However, the realization of this positive value for the DSOs is dependent on a larger number of non-DG related factors (e.g. load growth dynamics and the status of interconnection equipment).

The regulatory framework for distribution networks can take DG development into account. There is however no 'one size fits all' solution for neutralizing the negative impact of DG penetration on DSO's revenue. Since the negative impact of either operational expenditures (distribution losses) or capital expenditures (network upgrades) in some specific cases (for mostly cases with high penetration rates and concentrated DG units) is very dominant, a specific regulatory arrangement with compensatory elements based on either 'DG energy produced' or 'DG capacity connected' cannot fully compensate the DSO without unnecessarily 'subsidize' other DSOs. The regulatory arrangement most successful is the combination of a special DG allowance and a direct DG related revenue driver. When applying this option DSOs will be able to recover their costs. It should be noted that a mediocre 'overcompensation' of DSOs for the negative impact they experience from DG penetration of the network might work effectively as an incentive to fully facilitate DG connection within their distribution network.

Regulation and network innovation

There are several technological options to accommodate a rising DG share more cost efficient. When it comes to implementing these technologies, DSOs play a key role. Yet they also have a role to play in developing these technologies. However, most regulatory regimes give incentives for short-term efficiency but not for long-term development and innovation. Therefore, many DSOs are being risk averse resulting in a low innovation business.

Network regulation can play a role in promoting network innovations. Network regulation can enable and incentivise network operators to develop and implement innovative network concepts. Network regulation can provide additional tailor-made instruments for DSOs to get involved in R&D and take the risk to try out new approaches to running their network.

In the long run developments in the electricity sector may go beyond incremental innovations in some parts of the network, developed and implemented by individual network operators, but may lead to an overall transformation of the network structure, involving a large number of actors and including both transmission and distribution networks. This poses a new challenge to network regulation. In order to promote a long-term transformation of the network, the regulatory process needs to be complemented by instruments that go beyond one regulatory period, enable the regulatory process to deal with future structural changes and future uncertainty and provide coordination mechanisms for the stakeholders involved (network and plant operators, technology developers etc.).

Recommendations

Based on the results of the analysis conducted in the DG-GRID project, 11 recommendations are formulated for improving network regulation in the short-term to enhance the share of distributed generation (DG) in EU-15. General recommendations are formulated at the EU level. However, the specific implementation of most of these recommendations corresponds to national regulators. For this reason on each of the particular regulatory topic recommendations have been formulated for a selected number of EU Member States (Austria, Denmark, France, Finland, Germany, Spain, The Netherlands and the United Kingdom).

The 11 recommendations address two main issues: (1) how DSO regulation should be changed for enhancing the share of DG and (2) what economic signals should be given to DG to achieve its active integration in distribution networks? Two recommendations relate to DSO unbundling.

1. Introduction

In European member states, the public goal of a sustainable electricity system is strived for through a number of technology-specific member state support schemes for renewable-based electricity generation (RES-E) and co-generation of electricity and heat (CHP). This drives the growth of distributed generation (DG) - generators connected to the distribution network - to significant levels. Most EU member states implemented specific regulation to allocate (part of) grid integration costs caused by distributed generators to operators of distribution networks, i.e. distribution system operators (DSOs) in EU legislation. These costs may be substantial and, if allocated fully to the DG operator, cause an economic barrier to connect to the network. To guarantee non-discriminatory network access these costs may also be allocated to the DSO.

A growing number of EU member states have implemented economic incentive (price or revenue cap) regulation for the DSO business and apply a system that allocate DG integration costs to DSOs. But these DG related network costs are not taken into account explicitly in network tariff calculation. As a result, if DG integration costs are allocated to the DSO, increasing DG deployment may have a negative impact on the DSO revenues and DSOs may raise objections to further DG deployment. However, according to European regulation DG should be considered by DSOs when planning the development of the distribution network. This means that DG should be involved in the cost-effective operation of the network and DSOs may profit from DG related benefits for the network. This may require a change in the planning and management of the network. DSOs will not easily change the way they operate the network business. Most DSOs have been risk averse resulting in a low innovation businesses. Furthermore, under the current economic incentive regulation cost reductions from innovations have to be passed on to the consumers through lower network tariffs after each regulatory period. In many EU member states current distribution network regulation is not really stimulating DSOs to innovate their network business

In the DG-GRID project, a project co-financed by the European Commission¹ and carried out by nine European universities and research institutes², the impact of a high DG deployment on the electricity distribution system costs and the impact on the financial position of the DSO were analyzed. Furthermore, several ways for improving network regulation in order to compensate DSOs for the increasing DG penetration were identified and tested. The DG-GRID project looked also into stimulating network innovations through economic regulation. Changing the DSO business is a prerequisite for DG integration into distribution networks.

What is Distributed Generation?

According to the EU Electricity Directive distributed generation are all power plants connected to the distribution system. Each different type of distributed generation has, however, its own technical and commercial characteristics. Table 1.1 makes a distinction between large and medium/small-scale RES and CHP supply technologies. The medium and small scale-units of both RES and CHP sources are considered as distributed generation. There are three typical characteristics that distinguish DG from centralised large-scale generation:

¹ The DG-GRID project is supported by the European Commission through the Intelligent Energy Europe program. The sole responsibility for the content of this paper lies with the authors. It does not represent the opinion of the Community. The European Commission is not responsible for any use that may be made of the information contained therein.

² Energy research Centre of the Netherlands (ECN); Öko-Institut e.V., Institute for Applied Ecology, Germany; Institute for future energy systems (IZES), Germany; RISOE, Denmark; University of Manchester/Imperial College, United Kingdom; Instituto de Investigación Tecnológica (IIT), University Pontificia Comillas, Spain; Inter-University Research Centre (IFZ), Austria; VTT, Finland; Observatoire Méditerranéen de l'Energie (OME), France.

- Distributed generation is connected to the distribution network (usually at voltage levels of 110 kV and lower) and is often operated by independent power producers, often consuming a significant share of power themselves. The large-scale units are connected to high voltage grid levels and operated by incumbent utilities (sometimes a joint venture with a large industrial consumer). DG has, as it is connected to lower voltage networks, to cope with a number of specific network issues that are of less relevance to centralised generation capacity.
- A second distinction is the location of the electricity supply. DG is usually generated close to the source and not so close to the demand site. Especially wind power is usually generated remote from the more populated regions. The consequence is that wind power plants are connected to weak (low voltage) electricity grids, i.e. grids with low consumption, having all kinds of impacts on the functionality of the distribution grid. Combined heat and power (CHP) is usually connected closer to the customer but often primarily sized to local heat demand and not to local electricity demand.
- A third aspect is the intermittent nature of electricity supply from RES and CHP. In contrast with electricity supply from conventional large power plants the electricity supply from wind and photovoltaic (PV) installations is far less controllable due to influence on weather conditions. But also the controllability of power supply from CHP and small hydro-power might be poor, because of the dependency on heat demand or water flow respectively.

Table 1.1 *Categorisation of Sustainable Electricity Supply Technologies*

	Combined Heat and Power (CHP)	Renewable Energy Sources (RES)
Large-scale generation	<ul style="list-style-type: none"> • Large district heating* • Large industrial CHP* 	<ul style="list-style-type: none"> • Large hydro** • Off-shore wind • Co-firing biomass in coal power plants • Geothermal energy
Medium/small-scale generation (Distributed Generation)	<ul style="list-style-type: none"> • Medium district heating • Medium industrial CHP • Commercial CHP • Micro CHP 	<ul style="list-style-type: none"> • Medium and small hydro • On-shore wind • Tidal energy • Biomass and waste incineration/gasification • Solar energy (PV)

* > 50 MW_e

** > 10 MW_e

What is the current situation?

The situation of DG penetration in power systems of 15 European member states in 2005 is shown in Figure 1.1. The figure shows that ten countries have a DG share over total capacity above 10%, and half of them are over 20%. Differences between member states can be explained by different potentials for RES and CHP and from different energy policies in the past. The DG share in electricity supply has the potential to increase rapidly. This can be derived from the policy objectives for renewable energy (20% in 2020) and energy efficiency improvement and also from the support mechanisms for RES and CHP EU member states have implemented.

It should be noticed that within a country the DG share of specific distribution networks may vary strongly, because of the geographically uneven distribution of renewable energy sources (e.g. wind) and heat demand (e.g. industry, horticulture greenhouses).

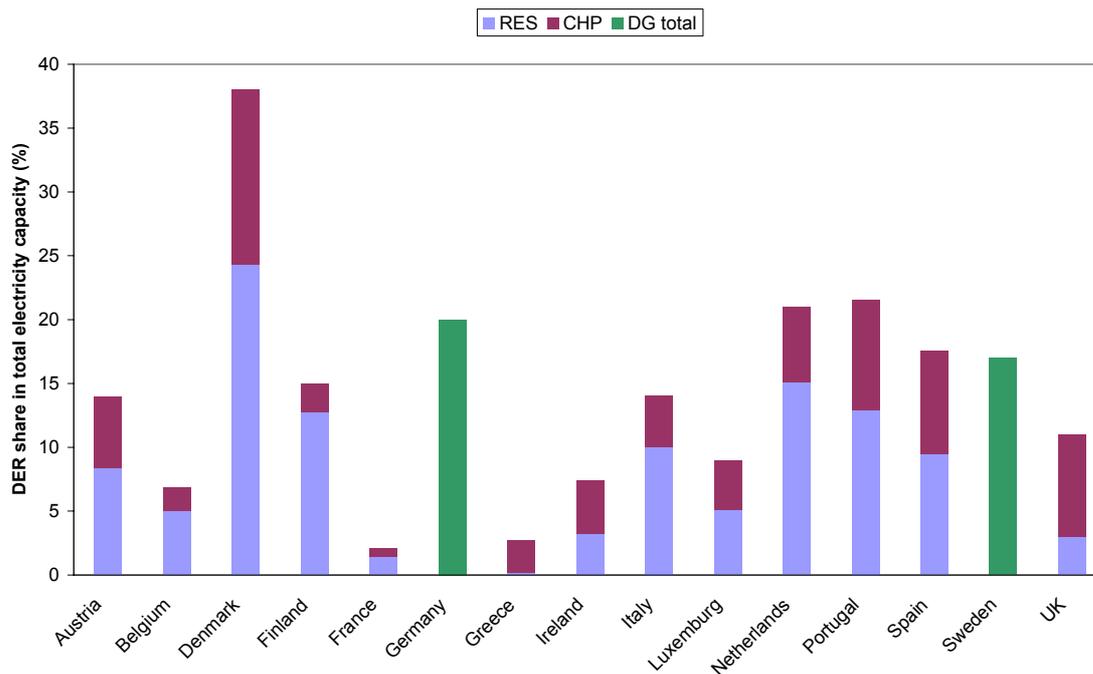


Figure 1.1 *DER share of total generation capacity in 2005*

This report

This report presents an overview of the DG GRID project results. The report summarizes results of different analyses and studies performed within the framework of the project. For details on these analyses and studies this report refers to specific documents listed in Appendix A and available from the project website (www.dg-grid.org).

This report starts with the main recommendations for policy makers, regulators and DSOs (Chapter 2). The way of arriving at these recommendations is explained in the following chapters of this report. Chapter 3 covers the technological and economical barriers for DG integration. Chapter 4 looks at the impact of high DG penetration on the distribution system costs. The quantitative analyses presented in this chapter are based on two case studies: the UK network and the Finnish network. Chapter 5 discusses the role of DSOs in efficiently accommodating distributed generation in the network infrastructure. After introduction of two alternatives for DSO business models (Section 5.1), this chapter provides an overview of the regulatory framework for DSO currently applied in EU Member States (Section 5.2) and identifies possible solutions for integrating DG in DSO economic regulation (Section 5.3).

Using the results of the analyses on the impact of DG growth on the distribution system costs, Chapter 6 analyses the economic impacts on the DSO business under a current economic incentive regulation regime (Section 6.1). In Section 6.2 several options for regulatory improvements that will remove a potential barrier for further DG deployment are ‘tested’. Finally, Chapter 7 discusses how regulation can stimulate distribution network innovation and looks at the role of regulation in the long-term planning of the electricity supply system.

2. Recommendations based on main findings and conclusions

The DG-GRID project resulted in 11 recommendations for improving network regulation in the short-term to enhance the share of distributed generation (DG) in EU-15. These recommendations are mainly based on the research carried out under the DG-GRID project. General recommendations are formulated at the EU level. However, the specific implementation of most of these recommendations corresponds to national regulators. For this reason on each of the particular regulatory topic recommendations have been formulated for a selected number of EU Member States (Austria, Denmark, France, Germany, Finland, Spain, The Netherlands and the United Kingdom). More details and recommendations for these countries can be found in DG-GRID report D12/13 (see Appendix A).

This chapter provides an overview of the 11 recommendations addressing two main issues:

1. How DSO regulation should be changed for enhancing the share of DG?
2. What economic signals should be given to DG to achieve its active integration in distribution networks?

The recommendations are divided into three categories and presented in the sections below: DSO unbundling (Section 2.1), DSO revenues and incentives to integrate DG (Section 2.2) and DSO incentives for innovation (2.3).

2.1 DSO Unbundling

Liberalisation of the electricity industry requires the adoption of unbundling. If the DSO is part of a vertically integrated company, it shall be independent in terms of its legal form, organisation and decision making from other activities not relating to the operations of the distribution network (Directive 2003/54/EC, Art. 15). The effectiveness of the unbundling provision of the EU Directive is highly dependent on its actual enforcement by the Member States. A lack of unbundling at the distribution level may negatively impact the access conditions for new DG operators trying to penetrate the market. This can cause severe problems for new DG operators when DSOs display anticompetitive behavior by favoring their own DG units or DG sites owned by their previously affiliated companies.

RI: *It is recommended to adopt measures for achieving a higher level of national compliance with the requirements of both legal and functional unbundling and for obtaining more transparency on the actual state of unbundling (not only in law, but also in fact) in the individual MS. This could be done via a semi-annual benchmarking conducted by the national regulatory authority or another independent body as a supplement to the yearly evaluation in the EU Benchmarking Report. In addition, a separate report dealing solely with the progress in unbundling could be published yearly to shed light on major shortcomings and to identify best practices in the Member States.*

If measures to enhance the implementation of legal and functional unbundling at the national level are not deemed sufficient in the long term to achieve non-discriminatory network access and transparency, a decision with regard to tighter unbundling provisions has to be taken at the EU level. The unbundling requirements then chosen must apply to all operators and to all national markets in order to avoid inconsistencies between the national dimension of regulatory competences and the EU dimension of a single energy market (European Commission, Directorate-General for Energy and Transport, 2007).

R2: Regarding the exemption clause contemplated in the Directive 2003/54/EC on unbundling for DSOs with less than 100,000 connections, it is recommended to leave it to the discretion of the Member States, provided that transparent procedures for planning, operation and accounting are in place. It is vital that the regulator adopts the necessary measures and procedures to ensure egalitarian conditions to network access where vertical integration of small DSOs is granted. What these measures should consist of is a country-specific issue dependent on the existence of entry barriers, network charging methodology and national regulatory framework (e.g., network regulation and support mechanisms/prioritized access) in place.

One aspect which should be highlighted in this respect is the kind of connection charging philosophy. In the absence of transparency, a deep charging method may provide vertically integrated DSOs with more incentives and scope for discrimination than a shallow charging approach³.

2.2 DSO revenues and incentives to integrate DG

The second regulatory category is related with DSO revenues and incentives to integrate DG. Recommendations are formulated to improve network planning taking into account DG, to design regulatory arrangements for compensating extra costs incurred by DSOs due to DG, and to improve DSO performance in quality of service taking into account DG. Article 14/7 2003/54/EC Electricity directive stipulates that DG should be considered by DSOs when planning the development of the distribution network optimising the need for upgrading or replacing network capacity.

R3: Some recommendations to implement in practice the Article 14/7 mandate are the following ones.

- *Incentive regulation based on price or revenue caps rather than rate of return regulation puts more pressure on DSOs for network efficient investment.*
- *Under incentive regulation, allocation of allowed investment budgets for the next regulatory period for individual DSOs is recommended. DSOs will be allowed to keep efficiency gains, for more than one regulatory period, due to efficient integration of DG, as incremental profits.*
- *It is recommended to implement use-of-system charges for DG and/or support mechanisms applied to DG, differentiated by time of use and voltage levels, together with economic incentives to DG for providing ancillary services to help DSOs to operate the network, for instance, providing voltage control and reactive power support, with a more active management of the network by DSOs. This will lead to a better optimization of the use of existing facilities, minimizing the requirement for new installations.*
- *The revision of planning and security criteria used by DSOs in order to include the potential benefit of DG deferring or reducing network investments is recommended. Engineering Recommendation P2/6 in UK can be an example to follow.*

DSOs with high levels of DG penetration, defined as the energy generated by DG locally with respect to the local energy consumption, for instance higher than 15-20%, should be compensated for incremental capital expenditures (CAPEX) and operational expenditures (OPEX) due

³ Shallow connection charges include only the cost of connecting the customer to the nearest point in the distribution network. Deep connection charges include any cost of reinforcements of the existing network that has been induced by the DG plant.

to DG, mainly because network investment and energy losses costs. There are several options to achieve this objective. In UK, a revenue increment per each kW of connected DG has been included in the DSOs remuneration. In addition, if a DG connection scheme qualifies as a Registered Power Zone (RPZ), the revenue increment is increased for the first five years of operation. DG-GRID project has investigated DSO revenue drivers based on the feed-in capacity and the energy delivered by DG modulated according the DG penetration levels. Other options such as allowance for these extra costs in the Regulated Asset Base are more appropriate for rate of return regimes.

R4: *It is recommended that the specific regulatory mechanism to compensate DSOs for incremental CAPEX & OPEX due to DG, should be designed taking into account the particular DSO regulatory framework in each country.*

Among these extra costs are incremental energy losses.

R5: *DSOs with distribution areas with high DG penetration/concentration levels could be compensated for incremental energy losses. For instance, a DSO revenue driver, in €/kWh, associated with DG production (kWh) located in those areas can be implemented. This compensation would mainly come from those generators connected in those areas that would be charged with a fee (€/kWh) proportional to the value of the incremental losses they produce in the network. On the other hand, it is recommended to implement use-of-system charges for DG and/or support mechanisms applied to DG, differentiated by voltage levels, to take into account that DG connected in lower voltage networks can reduce losses at higher voltage levels.*

DSOs have to meet quality of service targets in terms of i) duration and frequency of supply interruptions, and ii) voltage quality keeping voltage disturbances within certain limits. The potential advantages of having DG as a new control source should become a DSO opportunity instead of a threat.

R6: *DG can help to improve reliability indices working in islanding mode in case of network outages. DG can provide ancillary services such as voltage control, frequency reserve, or black start to improve voltage quality. To achieve this aim, it is recommended to implement:*

- *performance based regulation for quality of service targets that provides explicit incentives to DSOs for improving quality of service levels.*
- *incentives for DSO innovation programs that promote a deep transformation from passive to active management increasing DG participation in network control and DG contribution in case of network disturbances.*
- *incentives to DG for providing ancillary services to help DSOs to operate the network, for instance, providing voltage control and reactive power support, frequency reserve, islanding operation, etc. to improve quality of service levels.*

R7: *Incentives to promote DSO innovation for efficient integration of DG should be incorporated into network regulation. Some of the instruments to implement them can be:*

- *R&D investments can be included in the Regulated Asset Base as a separate item with higher rates of return or with a partial pass-through. An example is the Innovation Funding Incentive (IFI) in UK. A DSO is allowed to spend up to 0.5% of its revenue on eligible IFI projects.*
- *Selection of performance indicators that can be improved through network innovation. Several countries have implemented performance regulation to improve quality of supply.*
- *Regulators may work with DSOs formulating and testing new regulatory instruments, and developing new regulatory scenarios with a shared vision, in order to explore deeper and long-term network transformations.*
- *The selection of the most appropriate instruments in each country would take into account the type of DSO incentive regulation in place and the national regulatory framework.*

2.3 Economic signals to be given to DG for its efficient integration

The third category of proposed regulatory recommendations refers to the economic signals to be given to DG for its efficient integration. These economic signals encompass, electricity market prices, revenues from support mechanisms and connection charges and use-of-system (UoS) charges for DG.

R8: *DG (RES/CHP) support mechanisms, especially with high DG shares, should be made compatible with energy market prices and network UoS tariffs that promote efficient DG operation and network location. Regarding DG operation to achieve efficient market integration it is recommended:*

- *RES-E and CHP market stimulation systems should be smartened to better reflect the social value of the MWh injected in the system. In case of high DG penetration, avoid fixed production payment mechanisms, such as constant feed-in tariffs or feed-in subsidies as a general rule.*
- *Implement feed-in tariffs with time discrimination or feed-in premiums on top of market prices that promote efficient DG operation, i.e. higher production at peak hours, and storage and controllability capabilities in medium and large size DG installations.*

Connection charges are paid just once when DG require network access. Use-of-system (UoS) charges are periodically paid by network users, usually end consumers, and, in some MS, also DG. UoS charges should, as far as possible, (i) reflect the cost incurred to provide the network user with the network transport and system service, and (ii) ensure full recovery of the DSO's total acknowledged revenues.

R9. *To create a level playing field for DG integration, DG connection charges, paid just once when the connection is required, should be regulated, based on simple rules mainly recognizing shallow costs, i.e. the direct costs of connection. Calculation rules should be transparent and standardized by national regulation. Other costs for network reinforcements and upgrades due to DG connections should be socialised among the network users and paid through the Use of System (UoS) charges.*

R10: *It is recommended that DG pay or receive UoS charges. DG use of system charges should be cost reflective (positive or negative):*

- *DG UoS charges should be differentiated by time of use and voltage levels. DG connections at lower voltage levels and DG production at load peak hours should be incentivized.*
- *Differentiated DG support mechanisms, such as feed-in tariffs by voltage levels can be used to achieve the same effect that differentiated DG UoS charges.*
- *DG UoS charges calculation methods should be in line with the other elements of the national regulatory framework: DG connection charges, DG support mechanisms, DG network services, etc.*

DG can contribute significantly to TSO/DSO ancillary and network services.

R11: *DG through aggregators can participate in balancing and reserve markets. DG can provide voltage support and compensate energy losses as required by DSOs. In the future, with higher levels of network automation and DG controllability, DG would help to solve congestion management, and to improve quality islanding. Commercial arrangements between TSO/DSO and DG to recognize such contribution can be:*

- *Regulated payments to DG, for instance acknowledged in the UoS charges.*
- *Bilateral contracts between DG and DSO.*
- *DG participation in markets: i) energy balancing and reserve markets; and ii) network related markets, such as local balancing, reactive power, congestion management, or energy losses compensation.*

3. Technical and economical barriers for DG integration

This chapter discusses the technical and economical barriers for DG integration. Section 3.1 describes five main drivers that influence the development of the electricity supply system, in particular power generation (e.g. increasing DG) and network development. Increasing the levels of DG in a network causes technical difficulties that, if not solved, cause a barrier for DG deployment. Technical barriers and how to solve them are discussed in Section 3.2. Section 3.1 and Section 3.2 are based on DG-GRID report D4 (see Appendix A).

Within the project a survey was conducted on regulation of distribution networks with respect to distributed generation among the EU-15. The results of this survey and the identified economic and regulatory barriers are described in Section 3.3. Finally, in Section 3.4, an assessment is made of the economical barriers for DG integration. Section 3.3 is based on DG-GRID report D1 and Section 3.4 on DG-GRID report D2 (see Appendix A).

3.1 Drivers for change

The position of generation relative to demand is the dominant factor driving the design and operation of electricity networks. Furthermore, the type of generation technology deployed, together with the pattern of usage, will make an impact on the actual network operation and development. Finally, advances in technology may open up new opportunities for achieving further improvement in efficiency of operation and investment in transmission and distribution networks.

Five main drivers have been identified that may change the conventional philosophy system operation and development:

1. Most generation, transmission and distribution systems in Europe have been considerably expanded in late 1950s and early 1960s. These assets are now approaching the end of their useful lifetime. It is expected that a significant proportion of these assets will need to be replaced in the next two decades.
2. European governments are committed to respond to the climate change challenge. The energy sector, and in particular the electricity sector, will be required to deliver the changes necessary. Since the 80s of the last century, deployment of distributed generation of various technologies (in particularly generation from renewable energy sources and CHP) has been promoted to improve system efficiency and to reduce carbon emissions. These generation technologies range from kW size (e.g. domestic PV and micro CHP systems) to several hundred MWs (e.g. wind generation connected to EHV (extra high voltage) distribution networks), as shown in Figure 3.1. This figure also illustrates the fact that locations and sizes of future generation will have an impact on network design and investment. Developments in distributed generation are in line with the need to improve security of supply since an increase in the penetration of different forms of generation increases fuel diversity. Furthermore, a number of DG technologies would generally improve efficiency of operation of the system by reducing the amount of fuel that needs to be imported and burnt. This trend is expected to accelerate in the next decade and beyond as a key part of future energy policy.
3. The introduction of competition and liberalisation of electricity markets demands open-access for all types of generators including large and small scale generating plants. This raises complex challenges on the planning and operating transmission and distribution networks to facilitate this open-access policy in an efficient manner. More complex operation and control strategies supported by adequate investment in network infrastructure are needed to manage network congestion efficiently while also improving security and quality of supply.

4. There have been some major advances made in information and communication technologies (ICT) that in principle could enable the development of significantly more sophisticated approaches to control and management of the system and hence increase the efficiency of operation and utilisation of network investments.
5. There has been significant research and development effort invested in the development of a number of control devices and concepts, such as FACTS (flexible alternated current transmission systems), storage and demand-side management which could be used to provide real time control of power flows in the network increasing utilisation of transmission circuits. Similarly, greater automation of distribution network control could facilitate an increase in utilisation of network circuits.

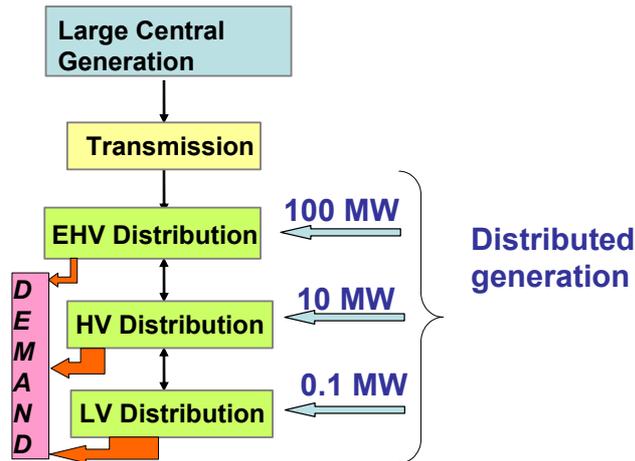


Figure 3.1 *Connection of various forms and sizes of distributed generation to distribution networks*

EHV: Extra High Voltage; HV: High Voltage; LV: Low Voltage.

Note: Some of the very large wind farms may be connected directly to transmission networks.

The need to respond to climate change, improve efficiency of the system and increase fuel diversity and enhance security of supply, coupled with rapidly aging assets and recent development in ICT, opens up the question of the strategy for infrastructure replacement in particular the design and investment in future electricity networks. This coincidence of factors presents an opportunity to re-examine the philosophy of the traditional approaches to system operation and design and develop a policy that will provide secure, efficient and sustainable future energy supply. This however does not necessarily require a radical change in the system, although like-with-like replacement at the distribution network level is unlikely to be optimal. Furthermore, not all technical solutions may be an appropriate way forward for DG integration in the context of the existing European energy systems.

3.2 Technical barriers for high DG deployment

Even if there may be a multitude of technical considerations associated with the connection of increased levels of DG, the main technical barriers recognised by Jenkins et al.⁴ are as follows:

- Voltage management and thermal rating issues in rural areas.
- System fault level issues in urban areas.

⁴ Jenkins, N., R.N. Allan, P. Crossley, D. Kirschen, and G. Strbac (2000): *Embedded Generation*, Institution of Electrical Engineers, London.

Based on these main technical issues, it is assumed that the reinforcement costs are limited to the upgrade costs of circuits and substations in rural networks, and the replacement cost of switchboards in urban networks.

Voltage rise and thermal rating issues

In most cases, the distribution network is designed for unidirectional flows of power from the high voltage levels to the lower voltage levels, and from the substation end of distribution circuits down to the connected load at the extremities of the circuits. When power is required to flow in the opposite direction, then voltage management and thermal rating difficulties can arise. These are most often encountered when there is insufficient local load to absorb the output from circuit connected DG and power is pushed 'back up' in the circuit. Voltages rising to unacceptably high levels, in excess of the statutory limits, occur particularly in long overhead lines because of their high impedance.

Load flow equations can be used to quantify the amount of generation that can be connected to the distribution network without triggering any reinforcement cost, as well as the impact of alternative control actions. The general practice in the distribution networks is to limit the capacity of the connected DG based on the extreme conditions of minimum load and maximum generation. The maximum size of generation that can be accommodated, without reinforcing the network, is thus limited by the voltage limit. If generation capacity is larger and should be connected to the network, the basic solution chosen to overcome voltage rise issues is to upgrade the existing circuit in order to decrease its impedance.

Contribution of DG to system fault level

In general, the connection of rotating machinery (both generators and motors) to distribution networks contributes to system fault levels. This additional 'fault in-feed' can result in system fault levels being increased beyond the rating of existing switchgears, in which case the switchgear is required to be replaced with equipment of a higher fault rating. In most cases, a rise in system fault level requires the switchgear to be replaced with equipment of a higher fault rating, i.e. replacement of the entire switchboard of a substation.

Alternative network designs

There are a number of alternative approaches that remove the above mentioned technical barriers for DG deployment and lead to closer integration of DG in the system operation and development:

- *Active management of distribution systems* increases the amounts of DG on 11 kV and 33 kV networks that can be accommodated. Typical examples are voltage control in rural systems and fault level control in urban systems through network switching.
- The *active network management* philosophy is based on the concept of *intelligent networks* where technological innovations on power equipment and ICT are combined to allow for a more efficient use of distribution network capacity. In addition, it involves the active involvement of both consumers and distributed generators: load and generation characteristics are taken into account in network operations and planning. When confronted with new connections the *active* DSO explicitly recognizes the network contribution of electricity consuming and producing entities in its network planning and includes this in investment decision-making.
- High numbers of small generators pose problems to system operators as they displace large central generation which presently is used for system control. The *Virtual Power Plant concept* is to aggregate small generators either for the purposes of trading electrical energy or to provide system support services.
- The *micro-grid concept* is based on the assumption that large numbers of micro-generators are connected to the network and that these can be used to reduce the requirement for Transmission and High Voltage distribution assets. The individual micro grids are arranged

to be able to operate autonomously in the case of loss of supply from the higher voltage networks.

3.3 Regulatory and other economical barriers for DG integration

The technical barriers to the deployment of large amounts of DG in the current network are strongly connected to economical barriers as the networks are part of an economical chain dedicated to the delivery of energy from producers to consumers. Moreover, since the networks are natural monopolies, they are regulated in order to guarantee reasonable network tariffs, equal access for different producers (conventional large-scale generators and distributed generators) and traders, and optimal quality of the network. The economical barriers are therefore mainly regulatory barriers. Because regulation differs across countries, a survey on the regulation of networks with respect to distributed generation was carried out among the EU-15 MS. The network regulation was reviewed and a comparison was made between the different systems. This resulted in the identification of regulatory barriers for connection of DG to the distribution network. The main findings were that:

- *The lack of incentive for the DSO to be proactive is one of the major barriers across the EU-15.*
- *The structure and amount of the connection charges, entry barriers to the market, procedural barriers for network access, and physical and network constraints are also dominating barriers.*
- *The degree of access to ancillary services and balancing differ a lot across the EU-15 MS.*
- *Only a few Member States have barriers with respect to procedural barriers to market access and lack of benefit for the DG.*

A lack of incentive for the DSO constitutes a major barrier in most Member States. Many national legal regimes still do not include any explicit incentive schemes for DSOs to connect DG units to their grids. This is also interwoven with the high connection charges prevalent in some Member States. Often, the DSOs maintain a passive operation philosophy rather than treating DG as an active control element in the operation and planning of their network. Many DSOs regard DG as an additional complexity and thus fear additional costs. Moreover, as for example in Austria, some DSOs also try to secure sites for their own affiliated companies which impedes penetration of new market entrants even more.

Connection charges are regarded as a major barrier to DG deployment in most of the Member States according to the conducted survey. There are different problems in relation to them: first, in some countries connection and use of system (UoS) charges are relatively high, in particular if they are based on deep connection costs. This implies a potential discrimination of new market entrants. Especially if the DSO has a lot of freedom in determining the connection and UoS charges, such as in Sweden and Finland, it bears the danger that some type of DG may be discriminated. Another way of discrimination might occur through location dependent UoS charges which discriminate against generation in certain areas. As DG sites are often located rather remotely, this may impose an additional barrier for their deployment. Secondly, a lack of transparency concerning the calculation of charges constitutes another barrier. Last, the regulatory regimes on connection charges vary a lot from Member State to Member State. E.g. in Belgium the tariff is subject to approval by the federal regulator. However, in Austria, there is uncertainty with regard to pay-back on grid investments whereas UoS charges are strictly regulated based on benchmarks, and in Finland there are only some general instructions on the structure of the charges by the regulator.

Aggravation of *market access* is another main obstacle identified by the Member States. Here, entry barriers can take a variety of ways: a high degree of concentration on the power markets and economies of scale of incumbents render it very difficult for small DG units to establish

themselves on the market. Moreover, there are high trading fees on the spot markets. The fulfilment of market operation requirements may further hinder the access to wholesale markets.

Procedural barriers to network access mainly consist of delays, the longevity and complexity of authorization procedures. Here, a special case is Germany which until July 2005 was the only country that had no regulated network access. Rather, conditions had to be negotiated between the involved parties. There was an agreement between industry associations that laid down the principles of network access and calculating grid charges. As a consequence, network access has been a main obstacle to the development of competition. The lack of regulated access has also been a problem for DG.

Naturally, for DG deployment the adequate *physical infrastructure*, i.e. networks, is a basic condition to connect new sites. One major problem is the limitation in the network's capacity to absorb new generation. There may arise problems of voltage control (an ancillary service), as for example in Greece and Spain, when new units are connected to the grid. Weak *balancing mechanisms* are to be taken seriously as they eventually may endanger the short-term security of supply in the case of interruptions due to failures. In addition, technical difficulties can lead to network connection delays, as e.g. in Ireland, which is detrimental for new DG operators.

Procedural barriers concerning the wholesale market and the lack of benefit for DG's are only regarded as important barriers in very few Member States.

The *lack of benefit for DG* does not constitute a major barrier thanks to the promotion of DG by national support mechanisms. Only Austria, Belgium, Greece and Luxembourg regarded this as a major barrier particularly related to the uncertainty on the degree to which benefits are passed through to the DG operators and that they are not sufficiently rewarded for their positive net impact (i.e. avoided net losses and grid expansions). In Greece the major problem is that the state owned companies virtually still hold a nearly-monopoly which does not leave much scope for new independent DG units. Concerning *procedural barriers to market access*, restrictions on the eligibility of market access constitutes a problem in Ireland.

As a conclusion, the four major regulatory barriers for connection of DG consist of a lack of incentives for the DSO, connection charges, procedural barriers and access to energy and balancing markets (see Table 3.1).

Table 3.1 *Presence of the main barriers in EU-15*

Barrier	AU	BE	DK	FI	FR	DE	GR	IRL	IT	LUX	NL	P	ES	SE	UK
Connection charges	✓	✓		✓		✓	✓	✓			✓			✓	✓
Physical/technical network constraints	✓				✓		✓	✓					✓	✓	✓
Procedural barriers network	✓				✓	✓	✓		✓		✓	✓	✓		
Lack of unbundling		✓				✓	✓			✓					
Lack of incentive for proactive DSO role	✓	✓		✓	✓	✓	✓	✓		✓		✓	✓		✓
Power market entry barriers	✓	✓		✓			✓				✓	✓		✓	✓
Procedural barriers market							✓	✓					✓		
Lack of benefit for DG	✓	✓					✓			✓					

3.4 Assessment of the economical barriers for DG integration

At present most DG is more costly than conventional power generation. In addition, it might be costly to deploy DG in distributed networks with limited capacity. Therefore, barriers such as deep connection costs and high system charges are sometimes making the DG even more costly.

The question is if regulation should be made to remove these barriers for DG? The heart of that issue is whether DG is solely a private good or if it also exhibits characteristics of a public good. This determination clarifies whether it can be justified to support DG at the internal power market, at whatever rate private valuations dictate.

The low environmental externalities of many DG technologies are widely accepted. However, DG also contributes to the local security of supply and reserve capacity. Although security of supply and reserves are not often described as public goods, it is precisely for this reason that DSOs are charged with the responsibility of securing sufficient reserves to maintain system reliability.

In economic terms, a public good is non-excludable in the sense that once it (e.g., environmental benefits or system reserves) is provided, even those who would fail to pay for it could not be excluded from enjoying the benefits (the 'free-riding problem'). In this case the public value of DG can often be much higher than the private value to any individual customer. Thus, customers, acting only in their own self-interest, would not purchase sufficient DG to maintain a sustainable environment, security of supply, or system reliability.

The different barriers for promoting DG come from the problem of undersupply of DG through reliance of the private provision of the public good. This can be resolved through market intervention and regulation. Therefore, there is a political wish to regulate in order to promote DG. Acceptance of the positive externalities of DG and its public good aspect has to be implemented in the entire system - from DSO to regulating authorities. To the extent that this is achieved - which is no simple enterprise as there are still many vested interests present - the remaining national barriers protecting the incumbent utilities are likely to become much smaller.

The policy for this regulation has to be looked at in a system analysis perspective. The barriers can be grouped into DSO, market and network access aspects. These groups can encompass both the local and the European level which has to be taken into consideration to take appropriate policy action.

Table 3.2 provides a more detailed overview of the different kinds of barriers with regard to DG deployment that are prevalent in the individual Member States. Simultaneously, it is evident that even though there are major problems which many countries have in common, they also vary a lot from Member State to Member State. Concerning network constraints, some MS are e.g. struggling with connection delays whereas in other MS the main issue may be the limitation in the network's capacity or maintenance problems. Some aspects have to be tackled at the level of the EU but other aspects should be tackled at the national level according to the Subsidiarity principle (see also Chapter 2).

Table 3.2 *Barriers for DG*

Barrier	
Connection charges	<ul style="list-style-type: none"> • Relatively high • Discrimination • Lack of transparency
Network constraints	<ul style="list-style-type: none"> • Limitation in network's capacity • Connection delays • Maintenance • Balancing mechanism
Procedural barriers network	<ul style="list-style-type: none"> • Delayed or complex authorization procedures
Lack of unbundling	<ul style="list-style-type: none"> • Problems resulting from previous vertical integration
Lack of incentive for proactive DSO	<ul style="list-style-type: none"> • Lack of opportunity for pay-back of grid investments • No incentives in regulatory system/ DSO's regard DG as additional complexity in their system • Securing of own sites by DSO
Market access	<ul style="list-style-type: none"> • Lack of transparency • High trading fees
Entry barriers	<ul style="list-style-type: none"> • Dominant position of incumbents • No direct/ difficult access to wholesale market • Trading mechanism for DG not fully developed/ use of 'mediator' for market • Access
Lack of benefit for DG	<ul style="list-style-type: none"> • Uncertainty (support mechanisms) • Lack of reward/ revenues for connecting DG

4. Impact of DG on the distribution network system costs

An increase of DG can have an impact on distribution networks system costs that can turn out into extra or reduced costs (benefit) for the operator of distribution network (i.e. the distribution system operator; DSO). This cost impact has been identified and evaluated and is reported in DG-GRID report D8 (see Appendix A). On the one hand, the cost of DG connections is obtained by calculating the cost of network reinforcement needed to mitigate technical problems that are caused by its connection. On the other hand, the benefit DG can provide for the DSO is determined by computing the reduction in some operational network costs (distribution losses) and the ability of DG to release network capacity which can be used to accommodate future loads.

All costs and benefits are dependent on the interplay between different DG characteristics, network characteristics and distributed generation technologies. Different DG characteristics are the level and location of DG and whether they produce at constant load or only at intervals. The latter is referred to as the distinction between intermittent and non-intermittent DG. Network characteristics are the network management approach, active or passive, and whether the network is located in an urban or rural area. Finally, distributed generation technologies are taken into account, in this survey PV, CHP and small hydro. These technologies are strongly connected to the DG characteristics as they shape the characteristics of the distributed generation units.

The impact on system costs is evaluated with a generic distribution network model in two case studies: the UK network and the network in Finland. The objectives of the case studies were to identify how different parameters influence the benefits and costs for the network. The generic distribution network model is introduced in Section 4.1. Results of the two case studies are presented in Section 4.2.

4.1 Generic distribution network model

For quantification and analyses of the impact of DG on distribution network system costs, without necessarily conducting studies on many specific and real but complex distribution systems, representative generic distribution network models have been developed. The models are designed to capture the principal characteristics of distribution networks and can be applied for accurate investigations involving a variety of operating conditions in order to capture the temporal and spatial impacts of DG on the network.

A number of load flow studies were performed on a generic network model to assess the impact of DG on losses, flows and voltages, network investment schemes, and network management approaches in the distribution network. The studies include evaluation of network operation within a year time span. Moreover, a methodology for quantifying the value of various active distribution network management approaches in an entire distribution network was also developed. Active management approaches range from local to area voltage and flow control achieved by means of a coordinated voltage control policy and by curtailing distributed generation output, if necessary. Furthermore, fault level management was included and achieved by splitting substation busbars to reduce fault levels (see Section 3.2).

In order to understand the impact of DG supply on the costs and possible benefits for a DSO a number of different situations were studied and parameters were varied:

- Rural electricity and urban electricity network.
- Intermittent and non-intermittent DG supply.

- Different network control schemes i.e. active and passive control.
- Four different DG penetration levels.
- Four different situations regarding the distribution of DG across the network, varying from dispersed locations (low ‘density’) to more concentrated (low-medium and medium-high ‘density’) and highly concentrated (high ‘density’).

The impact of different micro-generation technologies such as PV, CHP and small hydro on distribution networks was studied separately.

4.2 Results of cases studies for the UK and Finnish distribution network

The generic distribution network model was used to analyse the impact of increased DG deployment on distribution network costs in UK and Finland. The main objective of these analyses was to identify the most important parameters that influence the economics of the network.

These studies resulted in the identification of the following key drivers affecting the network system costs:

- *DG penetration level and DG density*: Greater installed capacity of DG and denser DG penetration (i.e. DG more concentrated) will result in more feeders with voltage rise problems in rural networks and will require that more protection assets are updated in urban networks. Hence the reinforcement cost will increase as the DG penetration level increases. DG will contribute in the reduction of system losses when DG reduces power flows across distribution networks. This is likely to happen when the penetration level is relatively low and DG is distributed judiciously in distribution networks. However, the studies have demonstrated increase in losses with high penetration of DG and high density of DG allocation.
- *Network management philosophy (active vs. passive networks)*: Under the traditional ‘Fit and forget’ approach, i.e. passive network operation philosophy, a large amount of investment is needed to upgrade current network assets. The benefit of active network management (ANM) for reducing these upgrade costs is clear for UK networks and Finnish rural networks. When it is assumed, however, that the entire switchboard must be replaced if required, then in most cases, reinforcement costs for Finnish urban networks when using ANM are larger than the reinforcement costs with passive network management (PNM). Evaluation of the benefits of ANM should consider the ANM implementation cost, which covers additional control and communication devices on the networks. Although losses in ANM are higher than those in PNM due to the continued use of smaller sized assets, the cost of losses is much smaller in comparison with investment costs. However, the application of active network should not be justified only with the reduction of cost in distribution network but also with its benefits for transmission and the overall system. In the highly distributed power system, controllability of DG facilitated by active network to support transmission and distribution system operation is essential.
- *DG technologies and the correlation between DG output and peak load*: The effect from non-intermittent and intermittent generation on the distribution network capacity and losses depends on the variability of imbalance between load and generation occurring. Some renewable technology depends on the location of energy source and seasons. CHP has more flexibility in where it can be located than hydro power generation, so it can have an impact on both rural and urban network. Hydro power is only for rural network. The Micro CHP applied in the UK case and small hydro power applied in the Finnish case both have similar effects on network loss reduction and network capacity replacement because of the coincidence of DG maximum output with peak load. Photo voltaic (PV) has weaker effect in UK since the maximum output of PV occurs in summer while maximum load is in winter.

The two cases studies provided insight in the impact of DG supply on three different kinds of DSO costs:

- *Reinforcement costs*: the incremental costs related to network reinforcements necessary to integrate DG into the network.
- *Energy losses*: the impact of DG on network losses. If losses decrease the costs for compensating these losses will become smaller. However, DG supply may also cause energy loss increase resulting in higher costs.
- *Capacity replacement value*: DG may result in smaller electricity flows from higher to lower voltage levels postponing the need to reinforce the system in case of load growth or to reduce the investment required in case of equipment replacement.

The results of the impact analyses carried out on the generic UK and Finnish networks on these three kinds of costs are described in more detail in the sections below.

4.2.1 Reinforcement costs

Rural networks

In the two case studies all DG is assumed to be connected at medium voltage level circuits. The incremental cost of rural network asset reinforcement is zero for low DG penetration levels in both the UK and Finnish networks. That means that the current networks have the ability to accommodate small amounts of DG without any reinforcement being necessary. Once investment is required for UK networks with passive management (for example due to voltage rise problems) the incremental cost impact varies from € 20 to € 84 per kW⁵ of installed DG capacity, depending on the overall DG penetration level. In networks applying active management with medium and high DG installation, incremental cost impact from € 16 to around € 65 per kW for both intermittent and non-intermittent cases with considering costs associated with active networks operation. The incremental investment costs in medium and high DG penetration scenarios with passive management for Finnish rural networks range from € 122 to € 236 per kW. With active management, the incremental investment cost drops to approximately € 11 to € 81 per kW for the intermittent cases and € 15 to € 100 per kW for the non-intermittent cases. The comparison of non-zero incremental cost between UK and Finnish rural networks is shown in Figure 4.1.

⁵ For conversion of British Pounds into euros the following conversions was used: £ 1 = € 1.50.

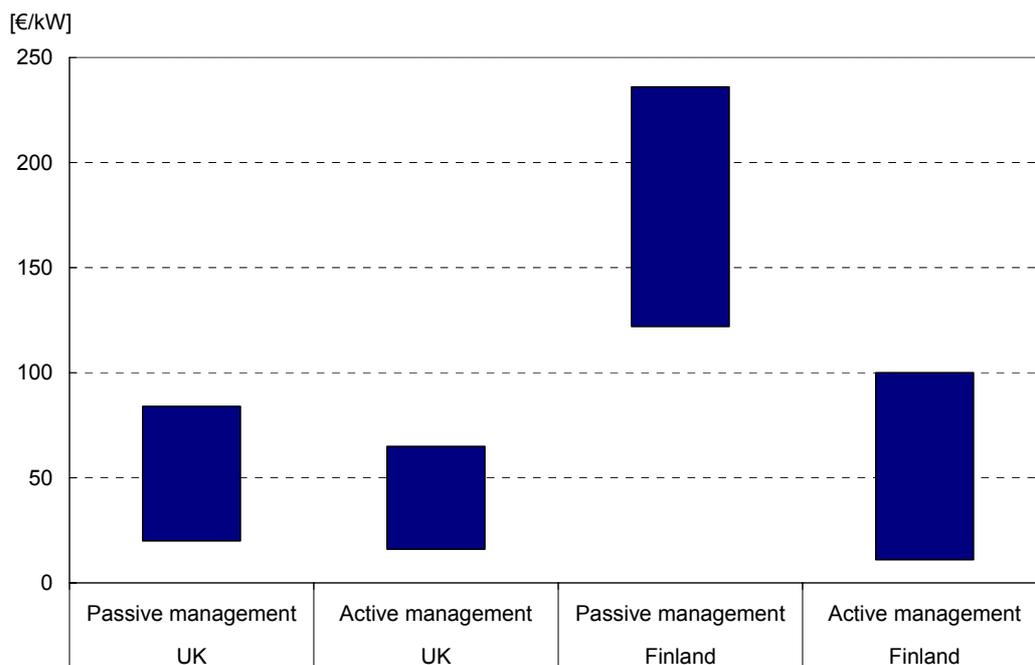


Figure 4.1 *Incremental cost comparison between UK and Finnish rural networks when network assets replacement is required*

The results in Figure 4.1 show that the cost of DG penetration strongly depends on the characteristics of the networks (i.e. UK versus Finnish network). Additionally, the benefit of active management to investment cost saving is higher in Finnish rural networks than the corresponding benefits in the UK.

The values for passive management in the Finnish case are much larger than those in the UK case. This is caused mainly due to following reasons:

- The average length of overhead lines which experience problems is around 20 km in UK rural networks while this value for Finland is from 30 km to 70 km which are 1.5 to 3.5 times of UK cases. With the same order of magnitude of unit reinforcement cost per kilometre, circuit replacement will result in more investment costs with longer lines.
- Most of the loads in the Finnish network model are located close to the substation and only a small amount of loads can be used to absorb DG connected at the end of the feeder. In this case, DG connection will trigger voltage rise problems and hence require circuit reinforcement in any scenario. Also, the voltage rise problem is more severe and reinforcement costs are higher compared with the UK cases since in the UK rural network model, the loads are mainly distributed increasingly or uniformly along the feeder.
- The third reason is due to assumptions in the circuit reinforcement options. For UK case, we assumed the size of circuit can increase linearly. So we increased the problem circuit size linearly until the voltage problems are resolved so that minimum cost option can be obtained for circuit reinforcement. But for Finnish case, indivisibility of circuit sizes was assumed. This means very big circuits might be needed, with high reinforcement cost, if the second biggest size circuit can not solve voltage rise problem.

Urban networks

For urban networks, without any headroom left for accommodating the increase in fault level, DG connections will immediately cause switchboard reinforcement in passive networks. Under these conditions, the incremental cost in UK urban networks varies from approximately € 59 to € 472 per kW. With 10% headroom available in the switchgear rating, the incremental cost is in the range of € 0 to € 243 per kW for the UK. For Finnish urban networks the incremental cost is from approximately € 11 to € 50 per kW for both headrooms. With active management, urban

networks incremental reinforcement cost in the UK can be reduced into the range of € 24 to € 190 per kW. An exception to this is the Finnish case with a low ‘DG density’, a relative low DG penetration level and with 10% headroom. Other cases show for the Finnish network that the cost is bigger with active network management than the corresponding value with passive network management with the value for active network management varying from € 16 to € 70 per kW. Figure 4.2 gives the range on these values.

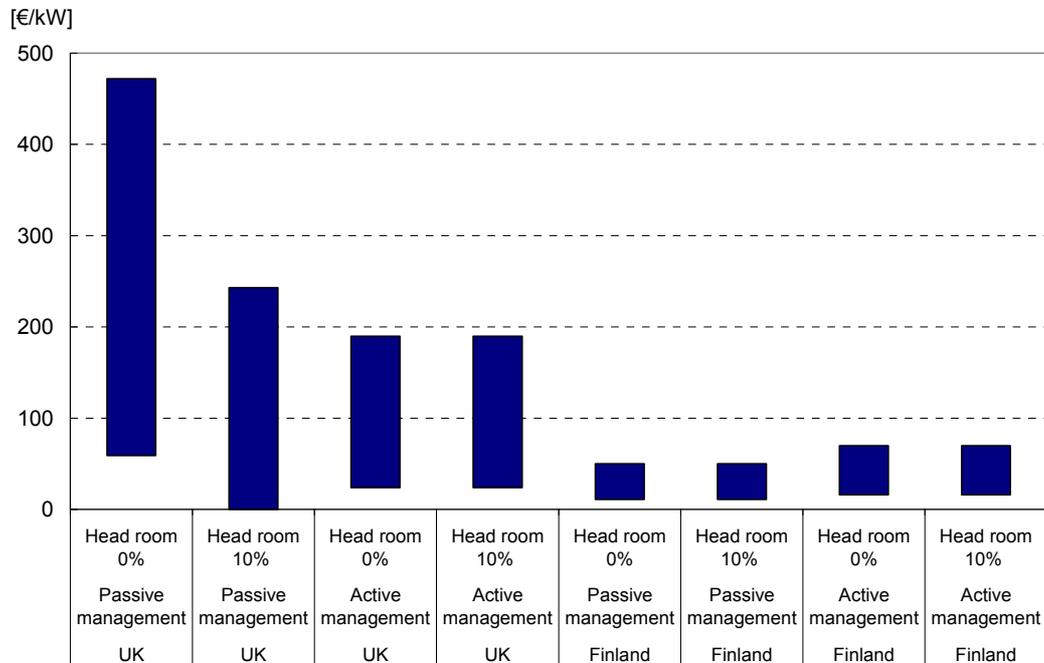


Figure 4.2 Incremental cost comparison between UK and Finnish urban networks

From results shown in Figure 4.2, we can see the same unit DG penetration can lead to much more network reinforcement costs in UK urban networks than in Finnish urban networks. This is caused by the network model characteristics as well as the reinforcement cost of switchboard in either network.

The UK generic distribution network model covers 3 voltage levels of 11 kV, 33 kV and 132 kV when considering DG effect on network fault level. Therefore the reinforcement cost on switchboard includes more than one voltage level in large amount of DG penetration case, for example 7.5 GW and 10 GW of DG in the two high DG density penetration scenarios in which the maximum incremental costs occur. Also the cost of switchboards is very high in higher voltage level substations (about € 1.6 million for 132/33 kV). This can be seen in Figure 4.2 for the UK situation. In the Finnish case only fault level rise at 20 kV voltage level networks is considered and the whole switchboard cost is € 380,000. Apparently more complex networks and more expensive assets contribute to more reinforcement costs. Generally it can be concluded that active management application can reduce reinforcement cost if there is still headroom left.

4.2.2 Impact on network losses

The impact on network losses of DG connected at medium voltage level in the UK case is shown in Figure 4.3. Initially energy losses are reduced with the increase of DG supply. With a further growth in DG supply the energy losses start to increase again. The figure clearly indicates that, if DG is more concentrated on the network, the loss reduction is smaller (or does not occur at all) and losses become bigger with increasing of DG supply. The previous section explained that reinforcement costs can be reduced if active network management is applied. The consequence however is an increase of energy losses, as is illustrated by Figure 4.3.

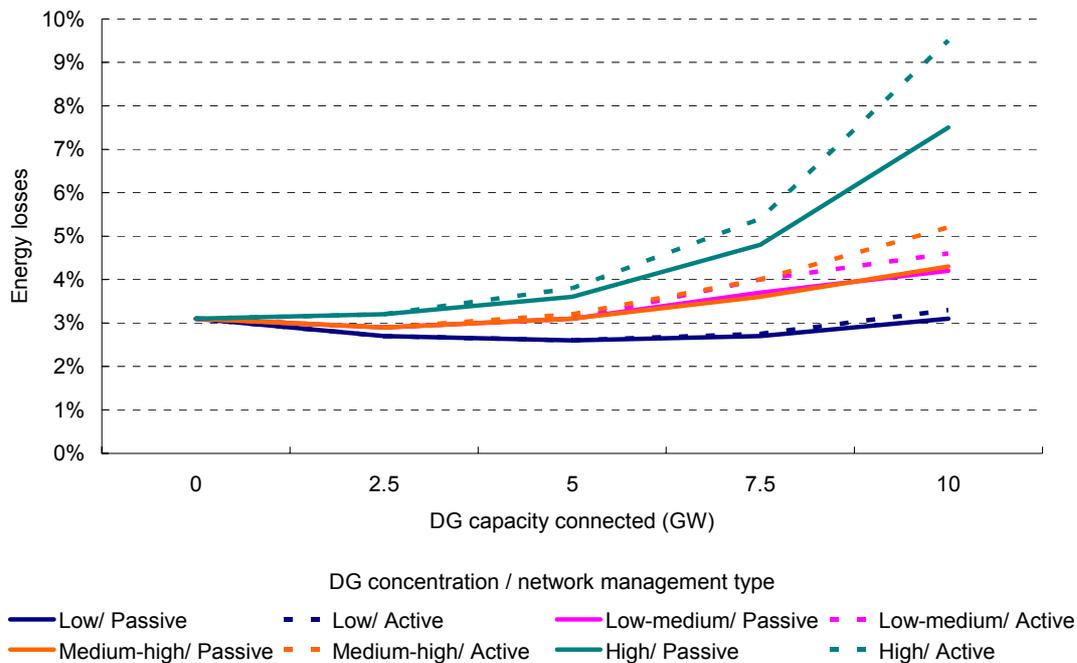


Figure 4.3 *Energy losses on UK medium voltage level networks (maximum load is 50 GW)*

The changes in energy losses due to DG supply on medium voltage networks in UK and Finland are shown in Figure 4.4. This figure shows ranges from a small loss reduction (negative values) to an increase of energy losses (positive values). The differences in energy loss changes between the UK and Finnish network can be explained by differences in network characteristics, DG supply levels and demand patterns.

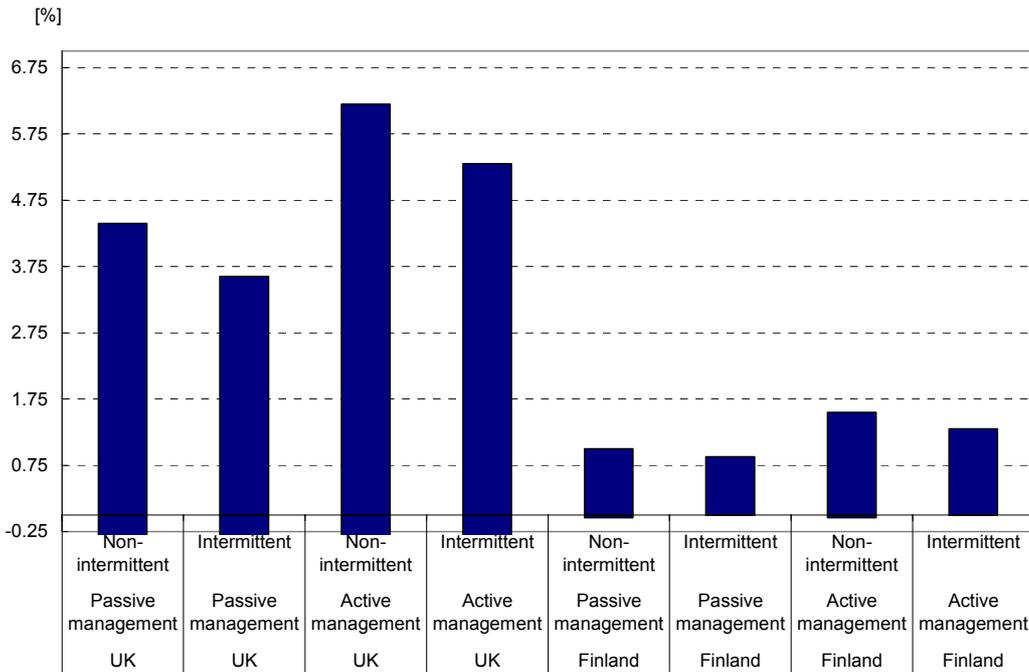


Figure 4.4 Range of the changes in energy losses due to DG supply on UK and Finnish medium voltage networks (positive value means absolute % loss increase and negative value means absolute % loss decrease)

The benefit related to energy loss reduction or extra costs due to energy loss increase depends on how DSOs compensate for their energy losses. In some EU MS the TSO buys electricity from large generators and includes these costs in their system costs that are passed on to DSOs. In other countries DSOs might purchase the electricity directly from generators. If the electricity price is variable in time, the impact of DG supply on the economic benefit or costs for the DSO might be much stronger than the energy loss changes indicated in Figure 4.4. After all, the electricity price peaks in periods of high electricity demand when energy losses are also relatively high.

4.2.3 Capacity replacement value

Because distributed generators are located near to consumers, the net demand to be supplied from transmission and distribution networks can decrease, postponing the need to reinforce the system in case of load growth or to reduce the investment required in case of equipment replacement. The incremental benefit of DG on network capacity replacement costs for the UK case remains around € 113 per kW. Only in the case of high DG supply and high DG ‘density’, when large reversed power flow occurs, the value drops to € 45 per kW. This value for Finnish rural networks varies from around € 0.4 to € 14 per kW for rural networks and from € 0.4 to € 10 per kW for urban networks apart from the case with a high DG ‘density’ for which almost all the DG capacity scenarios with negative values occur. In other words, too high DG penetration will not bring benefit of network reinforcement deferral. The incremental benefit on UK network capacity replacement is much bigger than Finnish case. This is because DG connection can bring more contribution to capacity replacement for UK networks because it covers from 11kV to 132kV voltage level networks including more expensive substations. For Finnish case, only 110kV/20kV substations capacity is considered to be replaced.

It should be noted that the network replacement costs are mainly driven by demand increase and aging of the distribution assets and not by the increase of DG supply. Therefore the DG capacity

replacement value will only be transferred into an economic benefit when the development and condition of the network requires a replacement or upgrade of distribution assets.

4.2.4 Impact of micro or mini generation on network losses and capacity reduction

Because small scale generation (often called micro or mini generation with a capacity of a few kW) is connected directly at low voltage networks where the most distribution network customers are connected, these generations could contribute effectively to the reduction of network losses. In the UK, on average the losses can be reduced - in absolute values - by 0.4%-0.8% depending on the production profiles of the micro generation. While the benefit of small hydro power generation in Finnish rural networks in term of losses is around 0.2%.

The benefit of micro or mini generation on network investment deferral strongly depends on the production profiles of micro generation and load profiles of demand customers. The benefit from PV is zero in the UK. And micro-CHP incremental benefit is from € 53 to € 186 per kW for the UK case. The incremental benefit from small hydro power generation in Finland is about € 15 per kW for low DG 'density' and € 31 per kW for the high 'DG density' situations. In both cases, micro generation brings positive value to the UK and Finnish network capacity replacement.

5. The DSO's role in efficiently accommodating DG

Chapter 3 showed that current regulation of distribution system operators (DSOs) by EU member states does hardly allow for network integration of distributed generation (DG). It does not address the issue of integrating rising levels of distributed generation in system operation. Moreover, it does make too little allowance for the cost impacts thereof for the DSO and for the (potential) benefits of DG for active management of distribution networks. This, in turn, may entail aversion on the part of DSOs to readily facilitate the network integration of new DG plants and may as well inhibit the adoption of efficient active network management practices. Especially, holding on to passive network management may imply higher than optimal network costs and, consequently, higher network charges to the end users.

This chapter discusses the evolving role of the DSO in efficiently accommodating distributed generation and is based on DG-GRID report D9. In Section 5.1 two future DSO business models are elaborated based on a baseline regulatory policy scenario and an alternative policy scenario fostering active network management. The two business models explain how the contractual relationships between the DSO and his business partners may develop in the medium term under alternative passive and active operational management approaches. Also the effects of smart metering, unbundling of system support services and making use-of-system charges that are time and location dependent are considered. The contractual interfaces will be described between DSO, TSO, DG operator, suppliers, and end users under two different sets of policy scenario assumptions.

Economic regulation imposed on the business operations of a DSO determine how the DSO is affected in his financial position when underlying factors driving DSO revenues and expenditures change. The amount of DG connections and the supply of electricity by DG units are such underlying factors. Section 5.2 elaborates on the prevailing regulatory frameworks for DSOs and provides an overview of characteristics of distribution network regulation in eight EU Member States. Finally, in Section 5.3, alternative regulatory regimes are investigated for DSOs which does make allowance for the DSO's performance in terms of network services to DG, at least neutralising the negative total impact of increasing DG on the DSO's allowable costs and remove any existing biases against the introduction of active network management.

5.1 Future DSO development

The regulatory context is of key importance to the choice of a business model by the DSO. Therefore, prospective DSO business models have to be linked to alternative regulatory policy scenarios. Two prospective DSO business models are outlined: one pertaining to the baseline policy scenario consistent with passive network management (PNM) and the other to a policy scenario fostering active network management (ANM).

5.1.1 Baseline and alternative policy scenarios

For both medium term policy scenarios up to year 2020 a number of common assumptions have been made:

- *Competition policy*: Overall competitiveness of the European economy is being promoted through liberalisation of the EU electricity and gas markets as well as by separation of energy production, transportation and distribution activities. The electricity transmission and distribution networks will be fully unbundled (through ownership unbundling) from commercial activities of the electricity industry including electricity generation, trade, and retail supply. Operating transmission and distribution networks will be regulated as it is now the

case. More competitive electricity markets will provide opportunities for third party aggregators to offer DG value enhancing services for e.g. accessing power exchanges or forward power markets, or the provision of balancing and ancillary services. This does not only apply to the active network management scenario but also to the passive network management scenario.

- *An enduring, strong societal support for DG:* The strong societal pressure to enhance the role of DG in the generating mix is assumed to endure. Three major policy drivers will keep the pressure on: (i) the climate change issue, (ii) the long-term energy supply issue, (iii) industrialisation policy in MS with strong representation of DG stakeholders. As a result, on average market support mechanisms remain slowly subsiding but quite significant value driver to distributed generators, i.e. especially renewables-based and less so conventional CHP operators inter-connected to distribution networks.
- *Implementation of smart metering:* Smart metering at the customer's end of the DSO's network does at the very least provide information on power ejections from and injections into the grid at the at the customer's end for short time intervals soon after each interval has lapsed. This enables DSOs, and where applicable electricity suppliers to obtain automatic meter readings for billing purposes and consumers to be informed about their consumption over short time intervals. Smart metering at the network user's point of common coupling with the network fits entirely into both the passive and active network management scenario for making DSOs able to deal with the fluctuations in energy supply of DG by making customers more sensitive to changes in energy prices. For the business model analysis it is relevant how the institutional arrangement of smart metering will be organised. For DG operators and large consumers it is assumed that they themselves have to arrange for metering equipment and for certified meter reading companies that will have to provide the DSO with meter readings.

The two policy scenarios relate to the prevalence/absence of an emerging and enduring strong societal pressure to genuinely integrate DG into the operational management of regulated electricity networks in a cost-efficient way. Integration would be incentivised by governments through network regulating agencies and DG support agencies using appropriate, wide-ranging packages of incentives and penalties. This condition is considered essential for overcoming the strong institutional inertia inhibiting genuine integration of DG in power network operations.

Baseline policy scenario

The baseline policy scenario presumes that all joint scenario assumptions that have been explained above will be met but that no appropriate fine tuning of DSO and DG market support regulation will be implemented, necessary for bringing about genuine integration of DG in network management practices. The baseline scenario implies that current 'fit and forget' practices prevailing in operational network management all over Europe, will endure. Under this operational philosophy the integrity and reliability of network services rely primarily on a very robust way of planning network expansion and network reinforcement that can successfully face any plausible future demand for network services without pro-active reliance on network services from distributed energy resources.

In the baseline scenario distributed generation will penetrate fast but even so the prevailing passive network operational philosophy will not be changed. Network operators will meet increasing operational challenges because of penetration of DG. They will tend to address these challenges primarily by robust conventional network reinforcement meeting at least the (N-1) contingency rule, but also gradual replacement in MV and LV distribution networks of obsolete components by controllable components such as on-line tap changing transformers and installing more network monitoring sensors. Moreover, DSOs will keep on lobbying for more stringent grid codes and will, when possible, at times tacitly obstruct grid access of distributed generators by erecting 'red tape' barriers.

Alternative policy scenario

In the alternative policy scenario network regulatory agencies and DG support agencies will implement dedicated government policies to foster integration of DG in network operational management. Government policies will stipulate fast implementation of smart metering programmes targeted at all network users including retail customers. This will enable not only trading operations (accounting records of e.g. power quantities at quarterly, half or full hour time intervals) but also near real-time remote control by network operators and commercial third parties. In the alternative policy scenario the (genuinely) unbundled DSO will provide access for both DSO and (at a regulated fair charge) third parties to the meter interface at the customer's doorstep on a level-playing-field basis subject to protocols ensuring explicit customer consent and absence of privacy infringements. Network regulators will strongly stimulate through appropriate incentives and penalties introduction of smart network tariffs such as time- and location-differentiated use of system charging. This will proceed in an indirect way through smart output-based incentives promoting efficient DG integration. Also formal DSO investment planning procedures will be mandated to explicitly include DG flexibility into peak demand and system reliability risk assessment guidelines.

Moreover, DG support mechanisms will not only minimise abnormal profits by DG plant owners. DG support mechanisms will also be designed smart to foster the disposition of DG to enhance the social value per unit of generation (avoided consumption) including the provision of ancillary services that enhance social value. For example, in the case of production subsidies (feed-in tariffs; feed-in premiums) such technology specific subsidies per MWh will be time-differentiated. This could for example be aligned to movements of the commodity price on the power exchange, as could be the number of guarantees of origin (GOs) issued per eligible MWh generated in countries with a Renewable Portfolio Standard as main support mechanism.

On the one hand, smart network tariffs in tandem with smart DG market support policies as well as DG-integrative network management practices will strongly induce DG operators to liaise with commercial providers of specialist operational services including notably DG aggregation services. On the other hand, pushed by the regulator and by more responsive and reliable DG behaviour, network operators will gain more confidence in relying on active network management philosophy using ICT infrastructure.

5.1.2 DSO business models

The diagrammatic representations of the business models (Figure 5.1 and Figure 5.2) show:

- Solid arrows: financial flows between the DSO and third parties. Black-arrow labels summarise the nature of the product/service provided in reverse direction. With the exception of remuneration of production factors under direct management of the DSO (salaries of own staff and return on capital invested), the diagrammatic representations of the financial flows visualise his major revenue in-flows and expenditure out-flows.
- Intermittent arrows: data communication flows between the DSO concerned and external parties for remote-control network operations. This gives additional visualisation of aspects of a DSO business model related to passive and active network management.

Note that no market-oriented data flows will be shown, so as to keep the complexity of the representations within reasonable proportions. For the same reason, financial and network information flows between other actors in the business model diagrams are not shown. Moreover, in order to not render the diagrams overly complex, internal financial flows such as salary payments are not shown either. The resulting two diagrams, Figure 5.1 and Figure 5.2, highlight some key differences between the ANM and PNM business models of a DSO.

Passive network management business model

The baseline DSO business model assumes continuation of a passive network management philosophy. In the baseline policy scenario the DSO is less able to address mounting network con-

straints as a result of high penetration of distributed generation in their networks, unless they undertake massive grid reinforcement programmes. The baseline scenario may imply higher Use of System (UoS) tariffs and hence a less economic viable environment for DG operators. These likely implications and the slower implementation of smart metering and monitoring systems in the baseline policy scenario as compared to the scenario with active network management may attenuate the fast penetration of DG. Hence, although there will be appreciably more penetration of distributed generators than at present, DG penetration will be less in the baseline scenario than in the ANM policy scenario. The diagrammatic presentation of the baseline DSO business model is shown in Figure 5.1.

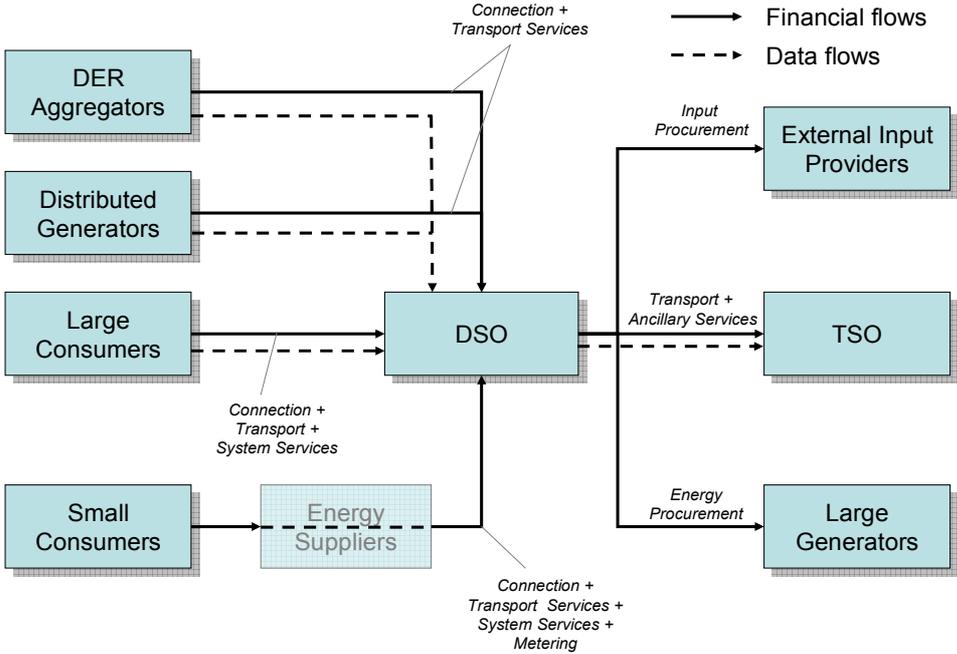


Figure 5.1 DSO business model under the baseline policy scenario

The business model encompasses the following major components:

- *Revenues:*
 - The DSO imposes regulator-approved connection charges (C) and use-of-system (UoS) charges to distributed generators (DG). By definition, the connection charges for distribution generators are shallow.
 - The DSO imposes regulated connection, (cascaded) Use of System charges to end consumers connected to the distribution network.
 - Through intermediation of suppliers of retail consumers in the DSO area, the DSO receives regulated metering charges for the allowable cost to recover the up-front procurement cost of the meter at the retail consumer’s doorstep and the allowable recurrent metering costs.
- *Expenditures on outsourced goods and services:*
 - The DSO passes on payments for approved transmission-system ancillary services charges and use of transmission-system charges from consumers to TSO.
 - The DSO contracts large generators to deliver the energy needed to cover losses in the distribution system, either directly or indirectly through brokered trades or power markets.
 - The DSO incurs expenditures for non-power material inputs including payments to network equipment vendors, outsourced maintenance and ICT providers, spare parts and consumables.

In accordance with grid code requirements, the DSO has network-related data exchanges with TSO, distributed generators and large distributed electricity customers. Suppliers (of profiled, small customers) are assumed to have no generation facilities within the purview of the DSO. They do not physically cater the profiled customers, but are rather the administrative interface between their customers and the DSO.

Active network management business model

The active network management business model is depicted in Figure 5.2 below. It contains the same type of revenue and expenditure flows as the corresponding baseline model. Yet in the ANM policy scenario, as a result of active network management conducted by the DSO, a range of new financial flows appear. Also the role of conventional flows may change in significance as explained below. Changes compared to the baseline business model are highlighted in blue fonts.

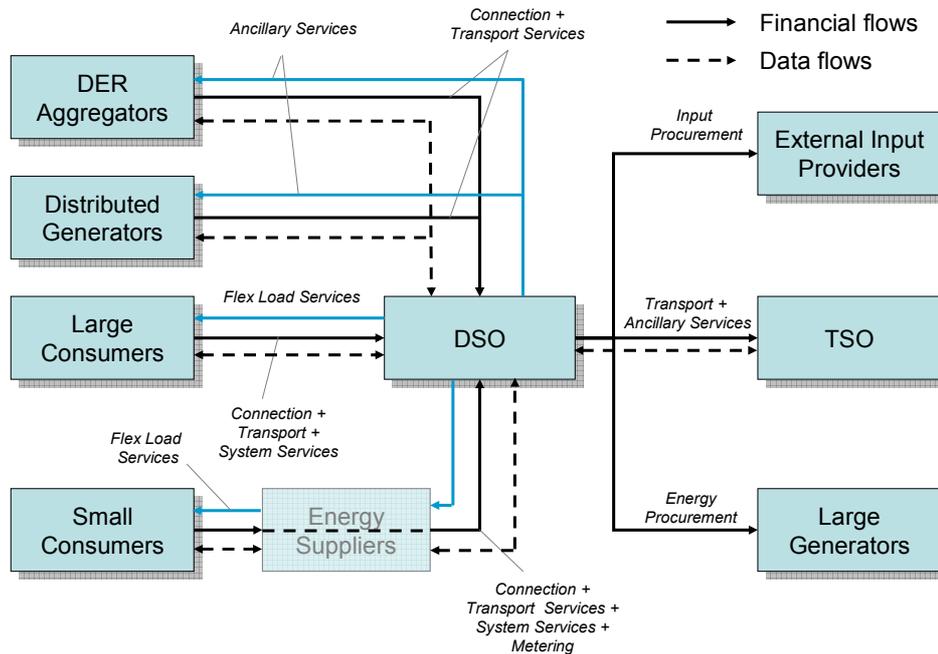


Figure 5.2 *DSO: Future business model with active network management*

- *Revenues:*
 - The DSO imposes regulated connection and use-of-system charges to distributed generators. These will also be charged to suppliers owning DG assets in the purview of the DSO. Connection charges for distributed generators will be shallow with at least partial socialization of concomitant reinforcement costs in UoS, UoS will be ‘smartened’: time-variable UoS charges with locational signals will be introduced, which will greatly improve cost-reflectivity of distribution network services rendered to distributed generators. As DG aggregators will command a significant role, so will be the financial flows between DG aggregators and the DSO.
 - The DSO imposes connection, (cascaded) Use of System charges and metering charges to end-consumers connected to the distribution network. Due to complexity of operational management, charges for DSO arranged ancillary services will be appreciably higher. Conversely, charges for TSO arranged services might well be lower than in the baseline as localised ancillary services as compared to system-wide ancillary services may gain in significance.
 - Through intermediation of suppliers of retail consumers in the DSO area, the DSO receives metering charges for the allowable cost to recover the up-front procurement cost of

the meter at the retail consumer's doorstep and the allowable recurrent metering costs. Allowable DSO revenues for metering services rendered will be higher than in the baseline due to appreciably higher demand for metering services by suppliers on behalf of their customers which contractually consented to delivery of load flexibility services.

- *Expenditures on outsourced goods and services*
 - The DSO passes on payments for TSO-arranged ancillary services charges and use of transmission-system charges from consumers to TSO. In the ANM policy scenario the importance of transmission-network facilitated generation and TSO-arranged ancillary services will be appreciably less compared to the baseline, and so will the related financial flows from DSO to TSO.
 - The DSO contracts both DG and large generators to deliver the energy needed to cover losses in the distribution system. For large generators this will proceed either through direct bilateral contracts or indirectly through brokered trades and/or power markets. As Section 4.2.2 showed, the impact of active network management on distribution network losses is somewhat ambiguous. Energy losses will reduce if DG starts to contribute to the network. However, if DG increases energy losses will increase too, because of the larger load flows over the network. Smart regulation can help to reduce energy losses under active network management.
 - The DSO incurs expenditures for non-power material inputs including payments to network equipment vendors, outsourced maintenance and ICT providers, spare parts and consumables. The composition of the financial flows concerned will be quite different from the baseline, while at this stage it cannot be assessed how the total amount concerned will compare in the active network management policy scenario to the baseline. Investment in network reinforcement (including upgrading of switch gear and transformers and ICT infrastructure) in network sections where DG feeds in is poised to rise. On the other hand, investment in network expansion of higher voltage distribution network sections can be postponed.

Active network management will imply new expenditure flows. DSO-arranged ancillary services provided by DG (including compensation for distribution network losses), flexible loads (large consumers and willing retail consumers remotely controlled by their suppliers). Figure 5.2 shows that, in principle, DG aggregators may play their part in arranging the provision of certain ancillary services and as intermediary in the financial settlement of ancillary services on behalf of their DG clients. The associated financial costs have to be recovered by the DSO through allowable network tariffs as explained above.

Policy and regulatory requirements

To create a favourable business environment to bring about a paradigm shift in DSO operational management from PNM to ANM, concurrent, fine-tuned, smart public interventions are warranted on a broad front of the policy framework regarding electricity network regulation and DG market stimulation. Such interventions include:

- Smart stimulation of DG, especially renewables based DG that allows for the time-variable social value of DG produce as for instance indicated by the baseload price.
- Proper introduction of smart metering of adequately high resolution.
- Fostering of time- and location dependent use-of-system charging by DSOs, for instance by making DSOs accountable for distribution system power losses in a time-variable way with higher (lower) rewards for lower than (distribution network dependent) standard losses at times of high local energy demand and vice versa for higher than standard losses.
- Facilitate the recovery of justifiable IT-related cost warranted by ANM.

5.2 Economic regulation of DSOs

When a distribution grid is already laid out in an area, it would never pay out for a competitor to invest in a parallel grid because of the high capital intensity of the electricity distribution network. Both parties will incur losses in that case. A DSO, being a monopoly firm, may tend to raise its distribution tariffs to appreciably higher levels than socially optimal. Therefore, the business operations of a DSO, in particular his revenues and/or specific tariffs, are regulated by the national regulatory agency of a member state. The DSO being a regulated organization, regulatory arrangements determine how the DSO is affected in his financial position when underlying factors driving DSO revenues and expenditures change.

Network regulation serves two main goals. First, it is to ensure efficient network operations (static efficiency) embracing current knowledge and, second, it should induce efficient long-term use of the system. The latter is to be effectuated through latest-vintage efficiency-raising network upgrading and expansion and, last but not least, introduction of innovative efficiency-raising network management approaches (dynamic efficiency). These twin goals incorporate the idea of equal and non-discriminatory access to networks.

5.2.1 Prevailing regulatory frameworks

Basically, two main types of tariff regulation can be distinguished. The first main category concerns ‘traditional’ cost-of-service regulation (also known as cost-plus, or rate of return regulation (ROR)), prescribing a regulated return of return. The second one is referred to as incentive regulation (in the Americas known as performance based regulation). Key characteristics of incentive regulation are that the regulator delegates certain pricing decisions to the firm and that the firm can reap profit increases from cost reductions⁶.

All regulatory approaches face (i) the problems regarding asymmetric information, such as (ii) the difficulty for the regulator to set the ‘right’ (optimal) rate of return, and (iii) the difficulty of determining a proper evaluation method for rate base assessments. Problems (ii) and (iii) result from (i).

Asymmetric information between the regulator and the regulated DSO is a key issue in the regulation of natural monopolies. In network regulation the main problem is the asymmetric information about efficient costs. The regulator’s perception of efficient costs determines his productivity norm and, consequently, the so-called X-factor to be imposed on the DSO concerned.

The second problem is the difficulty for the regulator in setting the ‘right’ (optimal) rate of return with which the rate base is multiplied to determine the capital expenditures of a DSO. Regulators do not use the actual rate of return for two reasons. Firstly, they will set an ‘efficient’ cost of capital that is based on market rates. Secondly, they seek to achieve consistency between the estimates for different companies. A problem for obtaining reliable market-based estimates of efficient cost of capital is that DSOs are seldom listed on the stock exchange.

The third problem is the difficulty to determine a proper method for assessing the rate base (RAB: regulated asset base). The literature distinguishes two main methods to assess rate bases: (i) building blocks and (ii) TOTEX.⁷ The building blocks method contains two separated components namely an allowance for OPEX (operating expenditures) and an allowance for CAPEX (capital expenditures). Applying the TOTEX approach implies that the two components are summed up and just the total expenditure level will be regulated, irrespective of its composition

⁶ Vogelsang, I. (2002): *Incentive regulation and competition in public utility markets: a 20-year perspective*, Journal of Regulatory Economics 22 (1): 5-27.

⁷ Ajodhia, V. (2006): *Regulating Beyond Price - Integrated Price-Quality Regulation for Electricity Distribution Networks*, PhD-thesis, Delft University.

into CAPEX and OPEX. Each method has its own advantages and disadvantages. It depends on the preferences of the regulator as to whether the building block or the TOTEX method is used.

*Traditional regulation*⁸

In the past, network-based services in energy markets were regulated on a cost-plus basis. Within this type of regulatory regime, the short-run focus of the regulator is on the determination of regulated tariffs in such a manner that the DSOs can cover their operating and capital expenses plus receiving a guaranteed return on investment. In more technical terms, this type of regulation looks as follows:

$$TAR_t = OPEX_t + r RAB_t \quad (1)$$

Equation 1 states that total allowed revenue (TAR) is equal to the total of current (allowed) operating expenditures (including O&M, depreciation costs etc.) plus the regulated rate of return (r) times the regulated asset base (RAB). Any new investments undertaken by the DSO will appear in the regulated asset base. The regulated asset base is a measure of the value, approved by the regulator, of the company's investment. Note that - to the extent that all investments are approved and the regulated rate of return is not set too low - no investment risk is borne by the DSO.

Provided the regulated rate of return is supra-competitive (e.g. as a result of the asymmetric information situation facing the regulator), the ROR mechanism incentivises unregulated monopolistic utilities to structurally over-invest in network capacity. This led to the introduction of incentive regulation. Currently, traditional regulation is in place only in a few EU member states. Most member states have adopted some kind of incentive regulation.

Incentive regulation

Incentive regulation provides explicit incentives by increasing the regulatory period in determining the allowed rates. In fact, for the duration of the regulatory period it decouples the direct link between costs incurred and revenues received by the DSO. The decrease of the frequency of regulatory reviews (typically to once every 3 to 5 years) enables the DSO to cash in on efficiency savings obtained in a regulatory period, i.e. a period spanning two subsequent 'rate cases'. After such a period, a revision of costs and investments takes place and a new revenue or price equation is established.

Broadly, one can distinguish two types of incentive regulation; *revenue cap and price cap*. Dependent on industry characteristics and national preferences cumulating in national laws, regulatory authorities make a choice between both forms of regulation. Both can either be based on frontier benchmarking (comparing the DSO's performance with his most efficient peers) or average benchmarking (comparing the DSO's performance with average performance among his peers). By making comparisons between firms, benchmarking is poised to reveal at least a part of the asymmetric information between regulator and DSO.

The crucial difference between yardstick competition (yardstick regulation) and benchmarking is that yardstick competition attaches direct financial consequences (a change of the X-factors) to the outcome of the benchmarking procedure. With only benchmarking this is not the case: the regulator has much more discretion to deny or adjust the outcome of the efficiency comparisons, which have been made.

The basic equation applied under respectively price and revenue cap regulation is the following:

⁸ Cunningham, S.W. and J. de Joode (2006): *Firm behaviour under incentive regulation: the inefficiencies of benchmarking*, IAEE conference, Potsdam.

$$P_t = P_{t-1}(1 + CPI - X) \quad (2)$$

$$TAR_t = TAR_{t-1}(1 + CPI - X) \quad (3)$$

The price cap equation (2) states that distribution tariffs (P) are allowed to increase with the rate of inflation (consumer price index, CPI) minus the X-factor, which represents the required rate of efficiency improvements as defined by the regulator. The revenue cap equation (3) is quite similar since it allows an increase in total allowed revenue by the same factor as in price cap regulation (CPI-X). Under revenue cap regulation, DSO tariffs need to be set at such a level that the level of total revenues does not exceed the cap.

However, there is an essential difference between price cap and revenue cap. In a pure revenue cap regime both the quantity of electricity sold and tariff can be determined, while under price cap regulation the price or tariff (basket) is fixed. Hence, under revenue cap regulation the firms can lower the quantity and thereby raise prices, whereas lowering the sales volume is not profitable in case of price cap regulation because it means lower revenues. On the other hand, a revenue cap approach is more readily consistent with the promotion of energy efficiency than is the case with a price cap approach.

Under current practices, regulators applying a revenue cap approach to network operators tend to set limitations to revenue caps that render monopolistic behaviour much harder to exercise. For example, in the Netherlands besides the allowed revenues of the TSO also the TSO's tariffs are determined by the regulator. So, the consequences of using a revenue cap in regulation depend highly on the details of the regime.

Apart from that, revenue caps are often less restrictive than it would seem a priori. Under a revenue cap system yearly adjustments might be made depending on the development of certain market indicators. The reason for this is the inability of the DSO to influence these developments. The possible volume adjustment factors include the total number of customers and the total load connected to the network.

The length of the regulatory period that indicates how frequent X-factors are re-assessed is an important regulatory parameter. An increase in the length of the regulatory period may well incentivise DSO more to improve efficiency since expected rewards upon such improvements will be higher. In that case the DSO will receive more rents. In setting the parameter value the regulator faces a trade-off between more efficiency incentivisation (a longer regulatory period) and rent extraction (a shorter one). On the one hand, DSOs need to be sufficiently incentivised to improve efficiency; on the other hand, end-consumers need to profit from efficiency improvements as early as possible.

Company-specific components might be introduced in the basic price cap or revenue cap equation regarding:

- Quality-of-service performance, i.e. the Q-factor.
- DSO-specific circumstances beyond the control of the DSO, e.g. network density, connection density and water crossings, subsumed by the Z-factor.

Total allowable revenues could for instance be determined as follows:

$$TAR_t = TAR_{t-1}(1 + CPI - X \pm Q) \pm Z \quad (3a)$$

5.2.2 DSO economic regulation in practice

Table 5.1 provides an overview of distribution network regulatory elements in eight selected EU member states: Austria, Denmark, Finland, France, Germany, the Netherlands, Spain and United Kingdom.

Of the EU member states considered, only Austria and Denmark currently apply an X-factor for an industry wide required efficiency improvement and X-factors for required efficiency improvement of individual DSOs. The Netherlands recently abandoned this approach and moved towards a common X-factor following observations that within-industry efficiency differences had been sufficiently reduced. It is noted, however, that the regulator in Germany and Spain respectively each plans to move to the inclusion of individual X-factor components. In the other countries a generic X-factor is used.

Regarding the correction for inflation, the majority of sampled countries use a standard consumer price index, but United Kingdom, Finland and Austria use different indices. Austria uses a weighted average of three different indices (wage index, building price index and consumer price index) whereas Finland only uses a building price index.

The length of the regulatory periods varies from 3 to 5 years. In some countries, the prevailing energy law allows the regulators to change the length between 3 and 5 years, dependent on the degree in which historical inefficiencies are (sufficiently) reduced. The reasons for choosing a particular period have already been presented in the previous section.

With only one exception, in all countries considered the regulator puts, at least part of, the responsibility for losses in the distribution system with the DSO. Spain has defined certain distribution loss standards, which are used to reward or penalize over- or underperformers. Hence, there is an incentive for Spanish DSOs to reduce distribution losses but in general the losses are fully passed-through to the end-consumers. In all other countries, the distribution losses are part of controllable operational expenditures and thus fully taken into account when determining X-factors. The price at which energy losses are valued for rate setting purposes varies: some regulators regulate this price (e.g., Austria), while other regulators require DSOs to compensate these losses by market purchases (e.g., the Netherlands).

Volume adjustment factors are applied in most of the countries considered. In Austria for example, the difference in estimated and realized volumes delivered is calculated each year within the regulatory period. Of the total difference obtained, 50% is compensated for in the price cap in the next year. Spanish DSO is compensated for volume changes to the tune of about 30%. In the UK in the determination of the efficient revenue of DSOs volume growth is also being taken into account.

Table 5.1 *Overview of characteristics of distribution network regulation in selected EU Member States*

	Austria	Denmark	Finland	France	Germany	Netherlands	Spain	United Kingdom
Common or individual X-factors	Both	Both	Common	Common	Both	Common	Common	Common
Type of regulation	Incentive: price cap	Incentive: price/revenue cap ⁹	Rate of return regulation	Rate of return regulation ¹⁰	Incentive: revenue cap ¹¹	Incentive: price cap with yardstick competition	Incentive: revenue cap	Incentive: price cap
Length of regulatory period	4 yrs	4 yrs	3 yrs	2 yrs	4 yrs	3 yrs	4 yrs	5 yrs
Inflation correction	Wage index (40%), building price index (30%) and consumer price index (30%)	Labour cost index (50%) and producer price index (50%)	Building price index	None	Consumer price index	Consumer price index	Consumer price index	Retail price index
Cost-basis	Totex	Building blocks	Building blocks	Building blocks	Totex	Totex	Unknown	Building blocks
RAB drivers	kWh and kW	kWh and kW	kWh and kW	kWh	kWh and possible additional factors	kWh and kW	kWh	kW
Distribution loss responsibility	DSO	DSO (adjustment for large spot price changes)	DSO	DSO	DSO	DSO	Passed-through to end-consumer	DSO
Volume adjustment factor	Yes	Yes	Not applicable	?	Yes	No	Yes	Yes

Source: DG GRID partner institutes, status beginning 2007.

⁹ Temporarily, incentive regulation is a price cap based on 2004 revenues in combination with rate of return regulation. RAB and annually adjusted capital cost factors are used for the RoR regulation. Benchmarking is carried out from 2007 and price caps will be adjusted in 2008 with individual X-factors.

¹⁰ The French regulatory office for energy (CRE) is making preparations for the implementation of incentive regulation.

¹¹ As from 2009 incentive regulation will come into force, now cost-plus regulation is used. Therefore, some characteristics are future but not current practice.

5.2.3 Network tariffs including assumptions about these tariffs in the DG-GRID project

The regulatory frameworks as outlined in the previous section focus mainly on the regulation of the costs of a DSO. Regulation of the costs means also regulation of the revenues of DSO, making DSO able to cover his costs. These revenues are obtained by charging (regulated) tariffs for all services connected with the transport of energy from all producers (conventional generators and distributed generators) to final electricity consumers.

The DSO provides direct electricity transport services to users of the DSO's network, i.e. final electricity consumers and distributed generators. Users of the DSO network pay for their connection: typically an initial and an annual fee, and variable use-of-system (UoS) charges. UoS charges might be based on the end user's energy consumption (kWh) or his system capacity requirement (kW). In principle, distributed generators might be exempted from paying UoS charges contingent on member-state-specific regulation.

Also varying among member states, distributed generators might only pay a 'shallow connection charge' covering the costs of connection from the generating facility to the nearest point of the DSO network or have to pay, alternatively, a 'deep connection charge' covering also (a major part of) the incremental grid reinforcement costs resulting from the additional DG connection or a 'shallowish' connection charge covering a minor part of the incremental grid reinforcement costs.

For the transportation of energy from the sources of production to the end users, the latter have to pay their DSO a transport charge. This charge is volume-based (MWh) and/or capacity-based (kW). The DSO passes on the transport charge component to cover services by the upstream transmission net to the TSO. Typically cascading transport tariffs are applied. This implies that the transport tariff end users are subjected to, includes a transmission network component even if the actual source of production is a nearby distributed generation facility.

To conclude, there are three revenue sources and charges for DSOs for supplying connection, system and transport services to producers and consumers. In order to not discriminate against capital-intensive technologies in terms of the upfront financing barrier, transparent shallow connection charges are preferred. The additional reinforcement costs for DSOs of connecting DG not covered by connection charges should be reimbursed by socialization in UoS charges. Yet the impacts on network costs of DG connection are quite location-specific. Hence, locational UoS charges are recommended, which means partial instead of complete socialization.

Balancing and ancillary services to ensure the reliability and quality of electricity supply are managed by the TSO and incorporated in the UoS charges. Localised ancillary services are typically delegated to the DSO. The DSO may or may not be incentivised to reduce losses incurred on his network. In member states where the latter case - no incentivisation - prevails, the TSO will include these losses fully in ancillary services charges to final consumers. For large power consumers connected to a particular DSO grid, the DSO collects ancillary services charges on behalf of his TSO. In turn, in some member states suppliers may act for small consumers as a go-between to collect use-of-system charges due on behalf of the DSO and, eventually, the TSO.

5.3 Possible options for integrating DG in DSO economic regulation

In Chapter 4 it has already been indicated how DG impacts on operational costs and investment costs of a DSO. Assuming that the regulator applies incentive-based regulation with a revenue cap that does not make allowance for the evolution of DG in the DSO's network, medium to high DG penetration levels may have an increasingly significant negative incremental bearing

on the DSO's overall costs. This will be discussed in more detail in the next chapter. It is however clear that in such a situation the DSO has no financial incentive to voluntarily accommodate further DG penetration.

It is further assumed that the building blocks approach and frontier benchmarking is applied. This base case will be the point of departure for investigating an alternative regulatory regime governing DSOs which does make allowance for the DSO's performance in terms of network services to DG. What features should the regulator aim for when designing the alternative regulatory regime? The alternative regulatory regime would have to at least neutralise the negative total impact of (increasing) DG on the DSO's allowable costs. Perhaps the regulator should slightly more than offset this negative impact initially in order to stimulate DSOs to change their behaviour in favour of DG. Furthermore, the alternative regime should remove any existing biases against the introduction of active network management, so that the DSO can make an economic decision when weighing the pros and cons of against passive network management.

In principle, the following avenues are open to regulators to design the components of the alternative regime:

- *Allowance in the regulated asset base (RAB) and allowable OPEX:* The allowance for DG in the RAB of the DSO depends on the chosen benchmarking approach. If a building block approach is applied, it is suggested to earmark justifiable projected investment costs that can be specifically attributed to network services rendered to DG and allow (the lion's share of) these costs to be passed through in the regulated asset base. Earmark also justifiable projected operating expenses that can be specifically attributed to network services rendered to DG for inclusion in the approved OPEX in the first year of the regulatory period under review. Justifiable costs should be based on expert judgement and ex post information over the previous year(s). If a TOTEX approach is applied, it is recommended to earmark projected total allowable DG-attributable costs per annum and allow remuneration of the DSO for the lion's part of these earmarked costs, provided these costs do not exceed a certain maximum percentage of total projected annual costs.
- *Allowance by way of a new component in quality of service performance regulation:* The Q-factor with a bonus-malus character accounts for (over/under)compliance with standards regarding (1) reliability, (2) power quality associated with power outages and voltage disturbances, and (3) consumer satisfaction with service. To the extent DG can be considered to exhibit positive externalities, a similar factor could be introduced regarding the DSO performance regarding network services to DG. The DSO could be benchmarked against the peer average regarding indicators such as the number of new DG connections and/or volume of DG MWh fed into the DSO network as a ratio of MWh consumed. This latter indicator could be made more sophisticated as an average score based on hourly (or shorter-interval) measurements. It is acknowledged that DG feed-in is in major part dependent on factors beyond the control of DSOs. Still, including a proper DG-performance factor in the Q-factor may well entice DSOs to stimulate a more evenly spread of DG through differentiation in UoS system tariffs to be charged to DG.
- *Allowance through including of a factor in the productivity benchmark analysis:* DG penetration can be considered as one of the inputs to the productivity benchmark analysis, which determines more or less the efficiency discount (X-factor). When a benchmark approach is followed by the national regulator, firms are compared to each other regarding their costs and, notably, their cost efficacy. The cost reduction that a firm should be able to achieve is based on an efficiency discount (X-factor), which is determined by the productivity change during that period. The productivity change, or rather the reciprocal factor cost efficacy, is the variable that is compared between firms. It is usually defined as the mutation in the standardized economic costs divided by a standardized and composite output variable. This output variable contains cost drivers like customer numbers, units of electricity distributed, and network length. The composition of the output variable differs somewhat between countries. It can be considered to add the capacity of DG on the network or the units of DG electricity distributed as components defining the composite output variable.

- *Allowance of a DG performance factor outside the benchmarking procedure (Z-factor):* In benchmarking-based incentive based regulation, the X-factor is established on the basis of results of comparison of DSOs on historical productivity growth trends. By using productivity benchmarking, DSOs efficiency is determined only with regard to a few different input factors to preserve the explanatory power of the benchmarking analysis. As a result, outcomes of the econometric benchmarking analysis do not make proper allowance for other less important input factors and DSOs efficiency results have to be adjusted to take account of these DSO-specific explanatory factors, so-called Z-factors or structural factors. Examples of Z-factors are differences between urban/rural network parts, network density/average length of lines (Norway), relative importance of river crossings (Netherlands), connection density, subsoil conditions, etc. DG volume indicators, whether or not subdivided by DG technology, may be considered as well as an adjustment factor. For example, DG volume indicators *inter alia* one the following parameters could be chosen: $MW_{DG \text{ connected}}$, $MWh_{DG \text{ fed in}}$.
- *Allowance by way of direct revenue driver (with possible network dependency):* In principle, the regulator may allow DSOs DG-related revenue on a $\text{€}/kW_{\text{newly connected DG}}/\text{yr}$ basis. Newly connected DG units could for example be taken to refer to DG facilities connected in the current regulatory period. Besides or alternatively, it can be considered to allow the DSOs additional revenue by an amount of a $\text{€}/kWh_{DG}/\text{yr}$. These revenue drivers should be calibrated to broadly reflect ‘average DSO’ DG-attributable incremental costs, not allowed for by other incentives. Moreover, it could be considered to make allowance for the tendency of higher DG-attributable incremental cost the higher the DG penetration rate. This way, very cost-effective DG-integrating DSOs could earn surplus revenue. This type of incentive may not only make it more affordable for DSOs to accommodate DG, but may also stir cost-reducing innovation, as a comparative advantage in DG accommodation of DG under this type of regulation directly translate into higher DSO earnings.
- *Shift from building blocks approach to total expenditures (TOTEX) approach:* The building blocks approach has a significant bias against the introduction of active network management. The introduction of active network management can have diverging impacts on CAPEX and OPEX. As CAPEX is not benchmarked under the building blocks approach there is an incentive to raise CAPEX. This incentive does not exist when applying the TOTEX approach. Therefore there exist a bias in building blocks for carrying out network investments (CAPEX) and applying passive network management instead of increasing the network capacity by active network management and increasing OPEX to some extent. The TOTEX approach puts the constraint on the total level of expenses leaving flexibility to the DSO as regards the CAPEX/OPEX proportions and has, at least in the latter respect, a more neutral impact on the choice of network management approaches.
- *Shift from frontier benchmarking to average benchmarking:* There are two kind of benchmarking possibilities in incentive based regulation, DSO’s can be benchmarked either against their peers i.e. performance of the whole national DSO sector or against the performance of the most efficient DSO’s. The former way of benchmarking is called average benchmarking, while the latter is known as frontier benchmarking because the most efficient companies are on the efficiency frontier resulting from benchmarking analyses. Apart from the former reasons, average benchmarking is more favourable to network innovation as it is easier for DSOs to capitalize on the efficiency gains due to their innovation investments. DSOs investing in network innovation and developing competitive advantages vis-à-vis their peers have more certainty that they can benefit from such advantages under average benchmarking. After all, for obtaining higher profits it is easier to beat an average than to beat the top firms. For a DSO to beat the industry average his relative efficiency has to improve, for instance by successfully assuming the risks associated with introduction of firm-specific innovations.
- *Shallow connection charges in tandem with time-variable UoS charges with locational signals:* In order to not discriminate against capital-intensive technologies in terms of the upfront financing barrier, transparent shallow connection charges are recommended. Yet the impacts on network costs of DG connection are quite location-specific. Hence, *locational*

UoS charges are recommended. This applies both to DG and centralised generation. This is consistent with a regulation of the European Commission aimed at the transmission network level. In order to avoid discrimination among generators connected to different voltage levels, there is also a strong case for locational signals in distribution networks. More pressure should be exerted on EU MS to reconsider current industrial policy that implicitly favours centralised generation in regulatory competition with other member states. Moreover, incentives towards alignment of private with social objectives of DG generation management is introduced when *time-variable* UoS charging is made technically feasible and is subsequently implemented. Feeding in at times of high (low) local load should be encouraged (discouraged). At the same time, time-variable UoS charging stimulates the willingness to cooperate with active network management on the part of DG and may create opportunities to provide new information services for the DSO.

- *Responsibility for DSO of distribution losses with time-variable carrots and sticks:* Regulatory features assigning more responsibility to the DSO for losses in his network are to be recommended as this will stimulate efficiency of DSO operational practices from a social perspective. Introducing time-variable elements in such regulation, putting higher rewards (penalties) for losses below (above) a certain DSO-network-specific norm at times of peak demand will further enhance the efficiency value from a social perspective. Again, it will also incentivise innovation in network management.

6. Economic impacts of DG on the regulated DSO business

This Chapter describes a study with a financial model that looked into the impact of increasing DG penetration on the DSO business under varying parameters (network characteristics, DG technologies, network management type). For quantification of investments and operational costs results of the study on the impact of DG on the distribution network system costs were used (Chapter 4).

First, the economic impact of DG deployment was analysed under a typical current regulatory regime. This is described in Section 6.1. The results indicate that the DSO business is indeed affected by an increase in the level of DG penetrating the distribution network.

Out of the possible solutions for improving the regulatory regime (Section 5.3), the effectiveness of four improvement options were tested with the financial model, showing that the potentially negative impact of DG penetration on the DSO business can be neutralised. The results of this second analysis are described in Section 6.2.

6.1 Economic impact under a current regulatory regime

The incremental impact of DG penetration in the distribution network was analysed using a spreadsheet model representing the financial position of the DSO. Because the business of operating an electricity distribution network is considered a natural monopoly, network regulation is implemented. Different types of regulatory regimes exist (see also Section 5.2.1). For this analysis one specific type of incentive regulation was used: revenue cap regulation. This basically states that the DSO is only allowed a maximum total allowed revenue (TAR) for its services in one year, with the TAR in one year being equal to the TAR in the previous period corrected for (i) a requirement on improved efficiency performance, (ii) change in overall price level (inflation), and (iii) optional compensation schemes for developments in demand. Mathematically, this results in the following formula:

$$TAR_t = TAR_{t-1} (1 + CPI - X) \pm AF \quad (4)$$

TAR_t is the total allowed revenue in year t and is equal to total allowed expenditures, which is the sum of capital expenditures and operational expenditures. Capital expenditures are a function of the regulated asset base (RAB) and the weighted average cost of capital (WACC). The CPI (consumer price index) compensates for yearly rate of inflation. The X-factor represents the required yearly improvement in efficiency performance. Finally, an adjustment factor (AF), may be included to compensate for adverse movements in factors determining ex ante the revenue cap, for example growth in demand.

DSO economic model

The DSO model describes the financial accounts of one DSO over a longer period of time. It basically consists of a number of cost and revenue items that together determine the financial result of the DSO for a given number of consecutive years. These costs are: depreciation and financing costs of investment of network assets, operational and maintenance costs, energy procurement costs for compensating distribution losses, payments to DG operators to compensate for curtailments (only in case of active network management) and corporate tax.

In order to analyze the impact of a gradual penetration of DG in the distribution network assumptions were made on the realization of DG connections over a 12-year period. The total amount of DG capacity is assumed to penetrate the distribution network in a period of 10 years

linearly over time. Investments needed to facilitate DG penetration are assumed to precede DG connection one year ahead. Operational costs and benefits of DG penetration for the DSO are assumed to be incurred/realized at the same pace as DG capacity is connected. The model lists expenditures and costs and calculates the net present value of the annual net profit over 12 years. In order to get insight into the meaning of these figures and to answer the question of how much the DSO relatively gains or loses when DG enters the network, the incremental profit is related to the profit that a DSO can earn under ‘business as usual’ operations. Since a DSO is a regulated entity, this boils down to a regulated profit margin for every Euro invested in the network. Therefore we introduce the term ‘regulated profit’ ($\bar{\pi}$). This is defined as:

$$\bar{\pi} = RAB \cdot WACC \quad (5)$$

RAB is the regulated asset base and WACC the weighted average cost of capital.

Analysed cases

In total 32 different distribution network cases were analyzed on their impact on the DSO revenue by varying 5 different parameters:

1. DG level (low: 50 MW, medium: 100 MW and high: 200 MW on a distribution network with a total system load of 1155 GWh per year).
2. Concentration of DG on the network (low, high).
3. DG type (intermittent/non-intermittent).
4. Network type (rural/urban).
5. Management type (passive/active).

Furthermore, the impact of DG deployment on DSO revenues was analyzed including and excluding the potential value of deferred investment due to DG. The estimates of the potential value of deferred investments were made in a separate analysis. This analysis did however not distinguish rural or urban networks nor active or passive management, nor intermittency.

Results

The results of the analysis in Table 6.1 show that, if the potential value of deferred investments is not taken into account, DSOs operating under a passive network management regime generally do not profit from the presence of DG in their distribution network. Although low DG penetration levels do benefit the DSO somewhat, higher penetration levels result in a negative overall impact. The concentration of DG within the network is a particular influential factor: the more concentrated the presence of DG in the distribution network, the more negative the impact. The driver for the generally positive results for low penetration levels and the generally negative results for high penetration levels are distribution losses.

DSOs operating under an active network management philosophy are generally confronted with comparable results as the passive network management case. Penetration of DG in the network is favourable for the DSO for low penetration levels, but becomes unfavourable the higher the penetration rate and the more concentrated the DG in the network. However, it should be noted that the negative results are relatively small for the majority of the cases analyzed: the net impact of DG penetration is mostly within the range of 8% of the ‘business as usual’ profit DSOs make.

The added value of DG with respect to the investment deferral for connections to the higher voltage network levels can be substantial. However, the realization of this positive value for the DSOs is dependent on a larger number of non-DG related factors and is beyond the scope of this investigation (e.g. load growth dynamics and the status of interconnection equipment). However, considering the maximum replacement values of DG, it can be expected that the overall impact of DG penetration on the DSO business, can be neutral or positive in the majority of cases. Observing the differential impact on the DSO under passive and active network manage-

ment we conclude that there is an implicit incentive for the DSO to adopt an active network management approach in a number of cases, in particular in the case where DG penetration is low or mediocre.

Table 6.1 *Impact of DG deployment on the DSO's revenue relative to 'business as usual'*

Case	Parameter					Impact on DSO revenue	
	Level DG (MW)	Network type	Concentration DG	Type of DG	Management type	Excluding potential deferred investment [%]	Including potential deferred investment [%]
1	100	Rural	High	Intermittent	Passive	7.8	29.6
2	100	Rural	High	Intermittent	Active	9.2	31.0
3	100	Rural	High	Non-intermittent	Passive	-7.0	14.8
4	100	Rural	High	Non-intermittent	Active	-6.7	15.1
5	50	Rural	Low	Intermittent	Passive	2.1	12.9
6	50	Rural	Low	Intermittent	Active	2.1	12.9
7	50	Rural	Low	Non-intermittent	Passive	5.2	15.9
8	50	Rural	Low	Non-intermittent	Active	5.2	15.9
9	200	Rural	High	Intermittent	Passive	-16.2	1.0
10	200	Rural	High	Intermittent	Active	-21.6	-4.4
11	200	Rural	High	Non-intermittent	Passive	-44.7	-27.5
12	200	Rural	High	Non-intermittent	Active	-57.3	-40.0
13	100	Rural	Low	Intermittent	Passive	-4.3	17.6
14	100	Rural	Low	Intermittent	Active	-4.5	17.4
15	100	Rural	Low	Non-intermittent	Passive	0.3	22.2
16	100	Rural	Low	Non-intermittent	Active	0.3	22.2
17	100	Urban	High	Intermittent	Passive	-1.2	20.6
18	100	Urban	High	Intermittent	Active	4.6	26.4
19	100	Urban	High	Non-intermittent	Passive	-10.5	11.3
20	100	Urban	High	Non-intermittent	Active	-3.8	18.0
21	50	Urban	Low	Intermittent	Passive	-8.4	2.3
22	50	Urban	Low	Intermittent	Active	-1.6	9.1
23	50	Urban	Low	Non-intermittent	Passive	2.6	13.4
24	50	Urban	Low	Non-intermittent	Active	0.4	11.2
25	200	Urban	High	Intermittent	Passive	-26.4	-9.2
26	200	Urban	High	Intermittent	Active	-32.9	-15.7
27	200	Urban	High	Non-intermittent	Passive	-41.1	-23.9
28	200	Urban	High	Non-intermittent	Active	-51.9	-34.6
29	100	Urban	Low	Intermittent	Passive	-10.6	11.3
30	100	Urban	Low	Intermittent	Active	-2.3	19.6
31	100	Urban	Low	Non-intermittent	Passive	1.2	23.2
32	100	Urban	Low	Non-intermittent	Active	0.1	22.1

6.2 Improving regulation

The negative impact of DG integration on the DSO's revenue may hamper the deployment of DG resulting in a 'conflict' with the national and European policy objectives for CHP and RES-E. To solve this problem the extra costs of DG integration should be socialized among all customers connected to the network, i.e. electricity consumers and generators. The network costs for connecting and integrating DG is then treated in the same way as network costs related to electricity consumption. This reflects the role of the distribution network: providing access to the electricity market for consumers and (distributed) generators under similar conditions. The

extra network costs induced by DG connections can be allocated to consumers and DG operators through the use of system charges. These tariffs (connection charges and use of system charges) are calculated from the TAR by taking into account the number of connections, size of connections, amounts of kWh and kW_{peak}, etc.

With the revenue cap formula (Equation 4) as a starting point, out of the list of possible solutions presented in Section 5.3, five different ways to compensate for DG penetration have been identified. The spreadsheet model was applied to test the effectiveness of four improvement options (see below). The fifth option is to consider DG as a cost driver in the DSO benchmarking. The model is however not suited for analysing this option. Table 6.2 shows the DSO's revenue in case of DG penetration relative to 'business as usual' for the four regulatory improvement options in comparison to a reference case excluding the potential deferred investment value. The four options shown in Table 6.2 are:

1. An *allowance in the regulated asset base* (RAB) for the DSO for DG related investments. This option compensates for the negative impact of DG penetration on capital investment but not on operational expenditures. A pass-through of DG related investments less than 100% is used so that an economic incentive remains to limit these investments. A 30% pass-through is used for a low, 70% for a medium and 90% for a high DG penetration rate. This type of compensation measure can be described in a formula as follows:¹²¹³

$$TAR_t = TAR_{t-1}(1 - X) + y\% I_t^{DG} \quad (6)$$

where

y = Share of eligible DG related investments in distribution network assets

I_t^{DG} = Total eligible DG related investments in distribution network assets in year t

2. Including an *additional quality indicator* through which DSOs are compensated for higher DG presence in their distribution network:

$$TAR_t = TAR_{t-1}(1 - X + K_{Ind}) \quad (7)$$

The chosen value for the K_{Ind} is 0.75% for a DG penetration level of 11% and 1.5% for 23%, 5% for 46% and 10% for 91% respectively.

3. Allowing one or more *DG based direct revenue driver(s)* in the revenue cap formula:

$$TAR_t = TAR_{t-1}(1 - X) + F_1 \cdot kW^{DG} + F_2 \cdot MWh^{DG} \quad (8)$$

The allowance is based on the DG capacity ($F_1=2.5$ €/kW for a low, $F_1=2$ €/kW for a medium and $F_1=1$ €/kW for high a DG penetration) and the electricity supply of DG ($F_2=0$ €/MWh for a low, $F_2=2.5$ €/MWh for a medium and $F_2=3.5$ €/MWh for a high DG penetration).

4. A *combination of a special RAB allowance and direct revenue driver*. While the direct revenue driver in this scheme is still based on energy, the capacity based direct revenue driver is replaced by a special RAB allowance for DG related investments:

$$TAR_t = TAR_{t-1}(1 - X) + y\% \cdot I_t^{DG} + F \cdot MWh^{DG} \quad (9)$$

¹² Since the DSO model uses and presents nominal prices the revenue cap scheme included in the model does not contain a correction for inflation.

¹³ The assumption is made that demand growth is zero, therefore the adjustment factor AF (see equation 1) is equal to zero.

The rate for total eligible DG related investments (I_t^{DG}) is 50% and the direct revenue driver (F) has the value of 2 €/MWh.

As the results of the analysis of improvement options shown in Table 6.2 indicate there is no ‘one size fits all’ solution for neutralizing the negative impact of DG penetration on DSO’s revenue. Since the negative impact of either operational expenditures (distribution losses) or capital expenditures (network upgrades) in some specific cases (for mostly cases with high penetration rates and concentrated DG units) is very dominant, a specific regulatory arrangement with compensatory elements based on either ‘DG energy produced’ or ‘DG capacity connected’ cannot fully compensate the DSO without unnecessarily ‘subsidize’ other DSOs. The most successful regulatory arrangement is the combination of a special allowance and a direct revenue driver. When applying this option DSOs will be able to recover their costs. It should be noted that a mediocre ‘overcompensation’ of DSOs for the negative impact they experience from DG penetration of the network might work effectively as an incentive to fully facilitate DG connection within their distribution network.

Table 6.2 *The DSO’s revenue relative to ‘business as usual’ in the reference case (without potential deferred investment value) and four regulatory improvement options*

Case	Parameter						Reference	Improvement options			
	Level DG (MW)	Net-work type	Concen-tration DG	Type of DG	Mana-gement type	Impact on DSO revenue	Allow-ance in RAB	Quality indicator	Direct revenue driver	RAB and direct revenue driver	
1	100	Rural	High	Int.	Pas.	7.8%	10.6%	12.7%	9.9%	17.2%	
2	100	Rural	High	Int.	Act.	9.2%	10.6%	14.1%	11.3%	16.3%	
3	100	Rural	High	Int.	Act.	-7.0%	1.0%	11.5%	9.3%	9.1%	
4	100	Rural	High	Int.	Act.	-6.7%	-1.8%	11.7%	9.5%	7.3%	
5	100	Rural	High	Int.	Act.	2.1%	2.1%	4.6%	3.2%	4.5%	
6	100	Rural	High	Int.	Act.	2.1%	2.1%	4.6%	3.2%	4.5%	
7	100	Rural	High	Int.	Act.	5.2%	5.2%	10.1%	6.2%	9.8%	
8	100	Rural	High	Int.	Act.	5.2%	5.2%	10.1%	6.2%	9.8%	
9	100	Rural	High	Int.	Act.	-16.2%	2.8%	4.7%	5.4%	8.9%	
10	100	Rural	High	Int.	Act.	-21.6%	-6.6%	-0.2%	1.6%	1.7%	
11	200	Rural	High	Non-int.	Pas.	-44.7%	-18.3%	-1.8%	3.0%	-3.8%	
12	200	Rural	High	Non-int.	Act.	-57.3%	-36.4%	-13.6%	-8.2%	-19.0%	
13	100	Rural	Low	Int.	Pas.	-4.3%	-2.4%	1.9%	-1.3%	4.1%	
14	100	Rural	Low	Int.	Act.	-4.5%	-3.2%	1.7%	-1.5%	3.1%	
15	100	Rural	Low	Non-int.	Pas.	0.3%	3.7%	16.7%	14.5%	12.0%	
16	100	Rural	Low	Non-int.	Act.	0.3%	2.5%	16.6%	14.5%	11.2%	
17	100	Urban	High	Int.	Pas.	-1.2%	3.8%	4.1%	1.3%	11.7%	
18	100	Urban	High	Int.	Act.	4.6%	5.6%	9.5%	6.7%	10.8%	
19	100	Urban	High	Non-int.	Pas.	-10.5%	2.7%	9.0%	6.8%	9.8%	
20	100	Urban	High	Non-int.	Act.	-3.8%	-1.0%	13.7%	11.5%	8.2%	
21	50	Urban	Low	Int.	Pas.	-8.4%	-2.3%	-5.0%	-6.9%	3.9%	
22	50	Urban	Low	Int.	Act.	-1.6%	0.6%	1.3%	-0.1%	4.3%	
23	50	Urban	Low	Non-int.	Pas.	2.6%	2.6%	5.3%	1.5%	7.3%	
24	50	Urban	Low	Non-int.	Act.	0.4%	2.3%	5.3%	1.5%	8.2%	
25	200	Urban	High	Int.	Pas.	-26.4%	7.2%	-4.7%	-2.5%	9.7%	
26	200	Urban	High	Int.	Act.	-32.9%	4.2%	-10.9%	-9.0%	6.2%	
27	200	Urban	High	Non-int.	Pas.	-41.1%	3.4%	1.6%	5.5%	8.6%	
28	200	Urban	High	Non-int.	Act.	-51.9%	-2.8%	-8.4%	-2.8%	1.6%	
29	100	Urban	Low	Int.	Pas.	-10.6%	-4.4%	-4.0%	-7.6%	4.8%	
30	100	Urban	Low	Int.	Act.	-2.3%	-1.7%	3.3%	0.5%	3.8%	
31	100	Urban	Low	Non-int.	Pas.	1.2%	1.2%	17.6%	15.4%	10.6%	
32	100	Urban	Low	Non-int.	Act.	0.1%	1.2%	16.5%	14.3%	10.2%	

7. Regulation and innovation

Previous chapters looked at regulatory barriers that currently hamper the integration of individual DG plants into the existing grid. As the number of DG units connected to the grid increases, it will not be sufficient to address barriers to the integration of individual DG plants. Rather, the electricity network itself needs to change to accommodate a rising share of DG. This chapter discusses the necessary medium- to long-term changes to the grid structure and how these need to be promoted and accompanied by regulatory changes (i.e. regulatory innovations). Importantly, these regulatory innovations need to be developed in the short-term in order to achieve long-term changes, given the high path dependency of the electricity infrastructure.

Chapter 3 already explained that the increasing share of DG triggers the need for innovations in a relatively stable industrial sector (i.e. low technological development). Both the structure of the network and the way it is operated may drastically change in future. Especially if DG is to be integrated in an efficient way without affecting security of supply, the network needs to be adapted. There are already a significant number of technical solutions under discussion and under development (see Section 3.2). However, not all of them may be an appropriate way forward for DG integration in the context of the existing European energy systems.

In this chapter the focus is on the role of network regulation in promoting network innovations. When it comes to implementing network innovations, DSOs play a key role. Yet they also have a role to play in developing these innovations. Network regulation defines the framework within which network companies operate and the incentives of DSOs are mainly influenced by regulatory framework.

Section 7.1 will elaborate innovating network regulation, i.e. the need to give DSOs incentives for connecting DG, and, with an increasing share of DG, also for integrating DG into network operation. Section 7.2 will look at different regulatory mechanisms that are specifically geared towards promoting R&D and innovation (i.e. regulation to stimulate innovations). Finally, section 7.3 will argue that in order to promote a long-term transformation of the network, the regulatory process needs to be complemented by instruments that go beyond one regulatory period and enable the regulatory process to deal with future uncertainty.

7.1 Innovating regulation: taking into account DG

The relationship between DG and DSOs has in most cases been difficult. The main reason for that is the discrepancy of interests that arise under the standard regulatory frameworks. The incentives of network operators are mainly shaped by setting use-of-system tariffs. In Europe, this is increasingly done through an incentive regulation mechanism (see Section 5.2). For the development of DG, it is of great importance to try to minimise, or even dissolve those differences of interests by structuring incentive regulation accordingly. It is important to accurately analyse the effects of a DG extension on the DSOs' interests within every step of the incentive regulation mechanism and to develop approaches to systematically take into account additional costs for DSOs and to at least neutralise the negative incentives resulting from a volume reduction in the case of auto-generation or independent area networks

In Section 5.3 a number of options for innovations of the regulatory framework were listed that include DG into economic incentive regulation. Four of them were 'tested' in a financial model of the DSO business (Section 6.2). If national regulators implement these options in their distribution network regulation it will provide incentives for DSOs to integrate DG into the planning and operation of their network, i.e. DSOs will comply with article 14/7 of the 2003 EU electricity directive.

7.2 Regulating Innovation

Network regulation can play a role in promoting network innovations. Network regulation can enable and incentivise network operators to develop and implement innovative network concepts. Section 3.2 showed that technical barriers for connecting large number of DG can be overcome by innovative network concepts. Both the structure of the network and the way it is operated may change.

Rate-of-return regulation leads to a suboptimal level of R&D and innovation and incentive regulation can further exacerbate this effect. This is supported by an overview of current network regulation in the EU and a literature review. Network innovations have so far hardly been addressed by network regulators in Europe. Except for the UK, there are no innovation-specific regulatory instruments in the EU-15. Rather, in the majority of countries, the focus is on short-term cost reductions and network regulation tends to discourage rather than stimulate network innovations.

Regulatory approaches to innovation

In order to promote the innovations necessary for an efficient large-scale deployment of DG, network regulation can provide additional tailor-made instruments for DSOs to get involved in R&D and take the risk to try out new approaches to running their network. Especially as there is currently a lot of scope and need for network innovations to accommodate a rising share of DG, network regulation can pay explicit attention to innovation.

There are a number of approaches to regulating R&D and innovation in networks:

1. Separate R&D funding mechanism, e.g. in Italy and Denmark.
2. Mandatory R&D spending obligations to perform R&D as a percentage of total sales placed on generation, transmission, and distribution companies, e.g. in Brazil.
3. Including innovation costs in the regulatory asset base (RAB).
4. Separate treatment of innovation costs.
5. Extending regulatory periods.

Approaches 3 to 5 are analysed in some detail below.

Including R&D costs in the RAB

The third approach 'Including R&D costs in the RAB' recognises innovation related costs as an investment. It is likely to have a positive effect on R&D expenditures. Yet the risk of innovation is not adequately reflected in the regulated company's risk distribution and the company is mainly incentivised to spend on R&D rather than to develop useful innovations. The approach may be applied to some R&D expenditures that can clearly be identified, but needs to be complemented by other measures.

Separate treatment of innovation costs

Even though DSOs will in most cases not engage in basic research, but rather more advanced innovations closer to 'the market', the benefits of these, if any, can normally not be reaped in the short-term. These properties of R&D can justify a special treatment of innovation-related costs. There are several ways this can be done.

- Innovation RAB, that is separate from the normal asset base. The rate-of return applied to this RAB would be higher than the normal rate-of-return applied to the rest of the asset base.
- (Partial) cost-pass through to reduce the downside risk for companies.
- Positive incentives, e.g. an increased revenue allowance.

Extending regulatory periods

While it is plausible that the length of the regulatory period influences a company's propensity to innovate, simply extending the regulatory period to provide innovation incentives does not seem to be a solution for a number of reasons. Companies may also have an incentive to delay the adoption of innovations, as such a delay would also postpone the price reduction imposed by the regulator. There is also a trade-off between innovation incentives and shifting innovation benefits to consumers. Moreover, extending the regulatory period would not just affect innovations developed by a company, but would be valid for the business as a whole. What seems to be required, however, is a long-term framework, spanning several regulatory periods with clear and reliable objectives for DSOs. Developing such a framework could be complimentary to other innovation incentives in the regulatory mechanism, like the ones described in this section. Developing scenarios could be one way to draw up such a long-term framework.

Integrated approaches to innovation

A separate treatment of innovation can be justified and is likely to be more effective and efficient than the other two approaches ('including R&D costs in the RAB' and 'extending regulatory periods'). However, a separate treatment establishes a special regime outside or complementary to the standard regulatory mechanism (e.g. CPI-X) in order to stimulate innovation. Innovation is a niche activity and there is a danger that it is not sufficiently connected to a DSO's main business. Especially with regard to DG related innovations, these should become more of a normal business activity once DG is no longer a niche activity. We therefore present two regulatory approaches that have the potential to render network regulation more innovation-friendly, namely Output-Based Regulation and Yardstick Regulation.

The output-based approach is not based on (intermediate) innovation-outputs but rather on general performance criteria that should be defined such that they foster the development of innovations. There could be performance criteria that are specifically geared towards incentivising the efficient integration of DG. A possible performance criterion could be the share of peak load on a network covered by DG plants in relation to total DG capacity. This links back to the discussion above to include DG-related performance criteria in the benchmarking process.

Yardstick regulation is the second regulatory mechanisms with the potential to be more innovation-friendly than standard incentive regulation. This is a regulatory approach where the price-cap a company faces is not based on its own costs (plus an assumption as to the cost reductions the company should be able to achieve) but on an industry-wide cost level, in most cases the average costs of all network operators. Yardstick regulation may have positive effects on innovation. It is one of the main short-comings of 'traditional' incentive regulation with regard to innovation that it regularly reviews a company's cost to pass on to consumers any cost reductions that have been achieved during the previous regulatory period. As a result, a company can hardly benefit from successful innovations. Under yardstick regulation, there is no profit reduction as a consequence of reduced costs. On the contrary, if a company does not achieve cost reductions high enough to remain the average company it is assumed to be, it will earn below average profits. Yardstick regulation still gives an incentive for short-term cost reductions (potentially at the expense of innovation), but at the same time the company can also benefit from long-term cost reductions.

More research is needed to understand the innovation effects of output-based regulation and yardstick regulation and to come up with appropriate designs that can promote innovations (e.g. appropriate performance measures).

7.3 Innovating Regulation: Towards system transformation

In the long run developments in the electricity sector may go beyond incremental innovations in some parts of the network, developed and implemented by individual network operators, but may lead to an overall transformation of the network structure, involving a large number of actors and including both transmission and distribution networks. The question arises what the consequences should be for network regulation. If integration of DG requires network transformation this poses a new challenge to network regulation. It will become necessary to rethink network regulation as a whole, rather than merely changing some parameters in the CPI-X mechanism. In order to promote a long-term transformation of the network, the regulatory process needs to be complemented by instruments that go beyond one regulatory period, enable the regulatory process to deal with future structural changes and future uncertainty and provide coordination mechanisms for the stakeholders involved (network and plant operators, technology developers etc.).

The following table gives an overview of different modes of network regulation. While mode 1 can be associated with the monopolistic era, most systems are currently in mode 2 ‘Sweating the assets’, where efficiency improvements are the main focus. Some systems are moving to mode 3 ‘Renewing the system’, i.e. securing investment is gaining importance. DG integration may the electricity sector to mode 4 ‘Transforming the system’.

Table 7.1 *Four modes of network regulation*

	1. Building the system	2. Sweating the assets	3. Renewing the system	4. Transforming the system
Main objective	Building the electricity system, security of supply	Cost-reduction (OPEX), short-term efficiency	Supply security, efficient investment within the existing system (like-with-like replacement)	Supporting certain system transformations, e.g. towards sustainability, higher shares of RES/DG etc.

Incentive regulation seeks to emulate the price mechanism of the market in that it gives network operators financial incentives to become more efficient or achieve other targets defined by the regulator. Is this governance mechanism adequate when a transformation of the electricity network is required demand for close coordination of different actors changing different system components? While the regulatory mechanisms to promote innovation presented in the previous section may give the individual DSO an incentive to invest in (cost-saving) innovations so that he can benefit from the achieved cost savings, it is difficult for the individual company to know in which direction the system may be going and how his innovation project links up with other innovation projects and the overall system transformation dynamics. There are already a number of examples where different stakeholders are brought together to coordinate diverse network-related activities through facilitating exchange and providing platforms of debate, such as the EU Technology Platform ‘SmartGrids’ and the UK Electricity Networks Strategy Group (ENSG).

While regulators are just about to come to grips with the third mode ‘Renewing the system’, more work will be needed to spell out network regulation in the fourth mode ‘Transforming the system’. Two instruments can help to deal with the uncertainty of future system transformation:

- *Developing long-term visions through scenarios*: In order to decide on the best possible procedures and formula for the coming regulatory periods and to make sure that short-term regulatory developments are compatible with long-term visions, decision makers throughout the sector need to have a common understanding of possible long term developments. Such considerations about future developments - in order to make them negotiable - need to take on the form of more or less explicit hypotheses about future developments based on the (lim-

ited) knowledge available. Clusters of such hypotheses could be called scenarios. Scenarios need to address developments both on the supply side (like new generation technologies entering the markets) and on the demand side (like demand side management) and need to take network issues into account. The scenarios - if they earn some kind of legitimacy - could possibly co-ordinate the decisions of a multitude of actors and hence allow for governance towards future electricity systems, which complies with the overall political objectives such as increasing independence from fossil resources, increasing security and sustainability of supply etc.

- *Experimentation with new regulatory instruments in ‘Regulatory Innovation Zones’*: Another approach, that can be useful to deal with regulatory uncertainty, is to develop and test new regulatory instruments in ‘regulatory innovation zones’. While regulatory mechanisms like power zones (RPZ) and the Innovation Funding Incentive (IFI) mechanisms in the UK have been designed to set up niches for technical innovations, regulatory innovation zones would provide niches where the regulator can work with individual DSOs to develop and test new regulatory instruments to promote DG integration in the context of changing network architectures and control philosophies. As was pointed out by EU Technology Platform Smart-Grids “there is a strong need for pilot projects, not only in the technical sense but also at the markets and organisational level. For example, regulatory regimes should be revised, based on new knowledge about how regulation should work to provide incentives for innovation”.

Appendix A Overview of deliverables

Del. No	Deliverable name / Description	Authors	Related Work Package No.
D1	Regulatory Review and International Comparison of EU-15 Member States	Klaus Skytte and Stephanie Ropenus, Risø	WP1
D2	Assessment and Recommendations Overcoming in Short-Term Grid System Regulatory and other Barriers to Distributed Generation	Klaus Skytte and Stephanie Ropenus, Risø	WP1
D3	Workshop (with proceedings) on recommendations on removing regulatory and other barriers		WP1
D4	Review of Innovative Network Concepts	Goran Strbac, Nick Jenkins, Tim Green, Danny Pudjianto, Imperial College London and University of Manchester	WP2
D5	Regulating Innovation & Innovating Regulation	Dierk Bauknecht (Oeko-Institut), Uwe Leprich (IZES), Philipp Späth (IFZ), Klaus Skytte (Risø)	WP2
D6	Workshop with proceedings on innovative networks		WP2
D7	Method for Monetisation of Cost and Benefits of DG Options	D. Pudjianto, D.M. Cao, S. Grenard and G. Strbac, University of Manchester and Imperial College London	WP3
D8	Costs and Benefits of DG Connections to Grid System	D.M. Cao, D. Pudjianto, G. Strbac from Imperial College London and A. Martikainen, S. Kärkkäinen and J. Farin from VTT	WP3
D9	The evolving role of the DSO in efficiently accommodating distributed generation	J.C. Jansen, J.C., A.J. van der Welle and J. de Joode from ECN	WP3
D10	Business models for DSOs under alternative regulatory regimes	J. de Joode, A.J. van der Welle and J.C. Jansen from ECN	WP3
D11	Workshop on business models for grid systems operators (DSO's)		WP3
D12/ D13	Guidelines for improvement on the short term of electricity distribution network regulation for enhancing the share of DG	Tomás Gómez (IIT-Comillas), Juan Rivier (IIT-Comillas), Pablo Frías (IIT-Comillas), Stephanie Ropenus (RISØ), Adriaan van der Welle (ECN) and Dierk Bauknecht (Öko-Institut)	WP4
D14	Workshop on Guidelines for distribution network regulation		WP4
D15	Project website established and continuously updated		WP5
D16	Mid-term Seminar on preliminary project results		WP5
D17	Final Seminar with proceedings of seminars including presentations on CD-Rom and website		WP5
D18	Project presentations and materials		WP6
D19	Establishment of Advisory Group		WP7
D20	Proceedings of workshops incl. presentations on CD-ROM and website		WP7

Project reports and material presented at workshops and seminars are available from the project website (www.dg-grid.org)