October 2002 ECN-C--02-075

DECENTRALISED GENERATION: DEVELOPMENT OF EU POLICY

Report in the framework of the DECENT project

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Acknowledgement

The project 'DECENT - Decentralised Generation Technologies: Potentials, Success Factors and Impacts in the Liberalised EU Energy Markets' was co-funded by the European Commission, DG TREN, under the Fifth Framework Programme, contract no. NNE5-1999-593.

The project was carried out by:

- IZT - Institute for Futures Studies and Technology Assessment, Berlin, Germany (co-ordinator).
- ECN - Energy Research Centre of the Netherlands, Petten, The Netherlands.
- COGEN Europe - European Association for the Promotion of Cogeneration, Brussels, Belgium.
- RISØ - RISØ National Laboratory, Roskilde, Denmark.
- Unit[e] - Unit Energy Europe AG, Bad Homburg, Germany.
- Jenbacher AG - Jenbach, Austria.

The activities of ECN Policy Studies for the DECENT project are co-financed by the Dutch Ministry of Economic Affairs. The study was carried out by ECN Policy Studies under ECN project number 7.7249.

The report has been written in full responsibility of the authors, including any flaws or inaccuracies.

Abstract

The DECENT project has identified the main barriers and success factors to the implementation of decentralised generation (DG) projects within the EU and has formulated a number of related recommendations to EU and Member State policy makers to enhance the feasibility of DG projects within the internal energy market.

The report formulates detailed recommendations in order to tackle barriers to DG grid connection and system integration, to improve DG authorisation and permitting procedures, and to enhance the financing of DG. Furthermore, it provides an analysis of the importance of DG technologies for improving security of supply, the prospects of EU energy technology R&D, and a view towards 2020.

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GLOSSARY

BSC	Balancing and Settlement Code
CHP	Combined Heat and Power
DG	Decentralised Generation
DSO	Distribution System Operator
ICT	Information and Communication Technology
IPP	Independent Power Producer
MS	Member States
Mtoe	Million tonnes of oil equivalent
NETA	New Electricity Trading Arrangements
RES	Renewable Energy Sources
TSO	Transmission System Operator

SUMMARY

In the coming 20 years, decentralised generation (DG) is expected to play an increasingly important role in the European electricity infrastructure and market. DG technologies have the potential to significantly contribute to savings in CO_2-emissions and energy consumption. This applies both for renewable energy and decentralised combined heat and power (CHP) applications. DG technologies are expected to play a key role in strategies needed in order to meet the EU Kyoto-target for greenhouse gas emissions reduction and the 22% target for the share of electricity from renewable energy sources in 2010. The prospects of DG depend to a great extent on local market regulations and infrastructures. The current liberalisation of the European electricity market is changing market conditions and thus provides both threats and opportunities for DG.

DG can be defined as small-scale generation connected to the distribution network or at the customer side of the meter. The application of DG is often highly location specific and depends on diverse issues such as the possibilities of technical implementation, resource availability, environmental aspects, social embedding of the project, regulation and market conditions. These factors vary considerably among technologies and among the EU Member States.

The DECENT project has identified the main barriers and success factors to the implementation of DG projects within the EU and has formulated a number of related recommendations to EU and Member State policy makers to enhance the feasibility of DG projects within the internal energy market.

Most of the barriers that have been identified are attributable to electricity regulatory regimes that hardly recognise the values of DG, in particular those related to environmental benefits, to electrical or grid services, and to security of supply in the EU. It is therefore essential that future energy policies for the electricity sector acknowledge and value the qualities of DG. Considering the ongoing trend of liberalisation and the increased use of market mechanisms as policy instruments it is recommended to take an approach to policy development that is market compatible. The ultimate goal should be to design markets that ensure a level playing field for centralised and decentralised generation. Markets must be open and transparent, and should give fair chances to different types of actors. Finally, in the long run, the environmental values of DG should be acknowledged in a market compatible manner while energy prices reflect external costs.

Tackling DG grid connection and system integration barriers

DG grid connection and system integration can be improved by enhancing the transparency on the terms, conditions, and procedures for connection. Particularly important in this regard is the standardisation of the technical interface between DG and the grid, and the existence of clear non-discriminatory rules on the allocation and sharing of connection costs. These cost allocation rules should take into account the benefits of DG to the network, such as avoided grid investments and grid losses. However, the application of these recommendations may be insufficient when network companies have incentives not to connect DG under the applicable regulatory regime. Economic regulation of network companies should therefore be neutral to the integration of DG into the network. Furthermore, stricter unbundling of network operations and ownership from generation and supply of electricity is a prerequisite to prevent such incentives on the part of network companies.

Improving DG authorisation and permitting procedures
Acquiring authorisation and planning consents for the establishment of DG installations is a major barrier to many projects, due to non-transparent and time-consuming procedures, as well as local opposition. Furthermore, network planning and spatial planning and planning of the use of renewable energy sources (RES) currently take place in a non-co-ordinated manner, thus raising the cost of DG integration. The means to overcome this barrier are streamlining planning and authorisation procedures for small-scale RES and combined heat and power (CHP) production, involvement of local actors, pro-active designation of areas for DG development in spatial plans for RES and heat planning for CHP, and finally co-ordination of spatial planning, network planning and integration of RES.

Enhancing the financing of DG
Due to the lack of a level playing field in present electricity markets, and because the external cost of electricity production are not reflected in the prices, many DG technologies need financial support to be viable under current market conditions. In the long run, internalising the environmental benefits of DG should diminish the need for support. However, in the meantime, support mechanisms should be market compatible and in line with the trend of liberalisation. To reduce the uncertainty to investors, support policies should take into account and anticipate the future harmonisation of support frameworks across the EU. With a view to providing a more stable long-term policy framework, it is desirable that long-term targets for the integration of renewables and cogeneration are fixed at the EU level. As many DG projects are set up by small-scale players, it is important to reduce the transaction costs in using support mechanisms and in operating on the electricity market.

Recommendations for further research
There are many subjects that are important to the integration of DG in EU electricity systems which could not be studied within the DECENT project, but which deserve further attention in future research projects. First, given the expected growth of the market share of intermittent renewables and heat-based CHP, the costs of imbalances will become increasingly important, and the application of priority dispatch mechanisms may become increasingly less feasible. Therefore, further research on technical and market solutions to balancing problems is crucial. Secondly, it is recommended that further research on the role of information and communication technology (ICT) in co-ordinating market and network operations should be conducted.

1. INTRODUCTION

1.1 Why decentralised generation?

The term Decentralised Generation (DG) summarises the grid-connected or stand-alone generation of electricity using small, modular technologies close to the point of consumption. Therefore DG includes not only electricity generated from renewable energy sources (RES), but also cogeneration technologies such as gas turbines or reciprocating engines, and new technologies such as fuel cells. DG can be located near end-users within an industrial area, or inside a building and in this sense DG differs fundamentally from the traditional model of centralised electricity generation and delivery. DG is emerging because of its environmental benefits, its flexibility to increase generation capacity, and due to technology development. As the structure of the European electricity markets has been developed from a centralised paradigm, DG developers and operators often have to face additional barriers.

DG technologies have the potential to significantly contribute to savings in CO_2 emissions and energy consumption. This applies both for renewable energy and decentralised combined heat and power (CHP) applications. DG technologies are expected to play a key role in strategies needed in order to meet the EU Kyoto-target for greenhouse gas emissions reduction and the 22% target for the share of electricity from renewable energy sources in 2010. The prospects of DG depend to a great extent on local market regulations and infrastructures. The current liberalisation of the European electricity market is changing market conditions and thus provides both threats and opportunities for DG.

1.2 The DECENT project

A key factor for the efficient mobilisation of the existing DG potential is a thorough understanding of success factors on the project level. Therefore the objectives of the DECENT study were to identify success factors and impeding factors for decentralised generation in the liberalised European energy markets, and to analyse policy implications for the setting of the appropriate frameworks. To that end the study has employed a bottom-up approach, directly accessing the experience gained with decentralised generation technologies on project and regional level through extensive case studies, expert interviews, and a literature review. Based upon this information, the relevant barriers and success factors for DG in the EU have been described and analysed in the DECENT Final Report (Jörß et al, 2002).

The current report is built upon and supplements the Final Report. Its main purpose is to elaborate the key regulatory issues arising under EU and Member States' electricity policy and regulation relating to DG and to make recommendations to the relevant decision makers to enhance the feasibility of DG projects within the internal energy market. Wherever possible, the analysis has taken into account the country-specific rules and policies in the elaboration of the relevant market structures and regulatory regimes. However, within the framework of the DECENT project, it was not possible to examine in detail the systems of all 15 EU Member States, and therefore, recommendations directed at national or local level have been formulated in general terms.

1.3 Introduction to the legal framework for DG

There is no specific DG policy in any EU Member State nor at EU level. The market position of DG is particularly influenced by policies promoting or supporting renewables and CHP, by the ongoing liberalisation of the electricity-market, and related developments such as the Florence

regulatory process, which aims at harmonising transmission pricing for cross-border electricity trading. Because policy development takes place within a legal framework, and should be analysed as such, every policy component discussed herein is correlated to the applicable rules at EU level and to some extent at national level. Despite the local character of many DG installations, the 'policy environment' is varied and multi-dimensional, with numerous inter-related components as indicated in Figure 1.1 and described in Appendix A.

DG is both subject to the general electricity and gas market regulations, and to specific legislation for renewables or CHP. Therefore, in some ways it is not possible to articulate a 'single policy' for DG, given that it does not fit into existing responsibilities and institutional structures. Nevertheless, steps should be taken to counteract the fragmentation of the current situation and to increase co-operation and co-ordination.

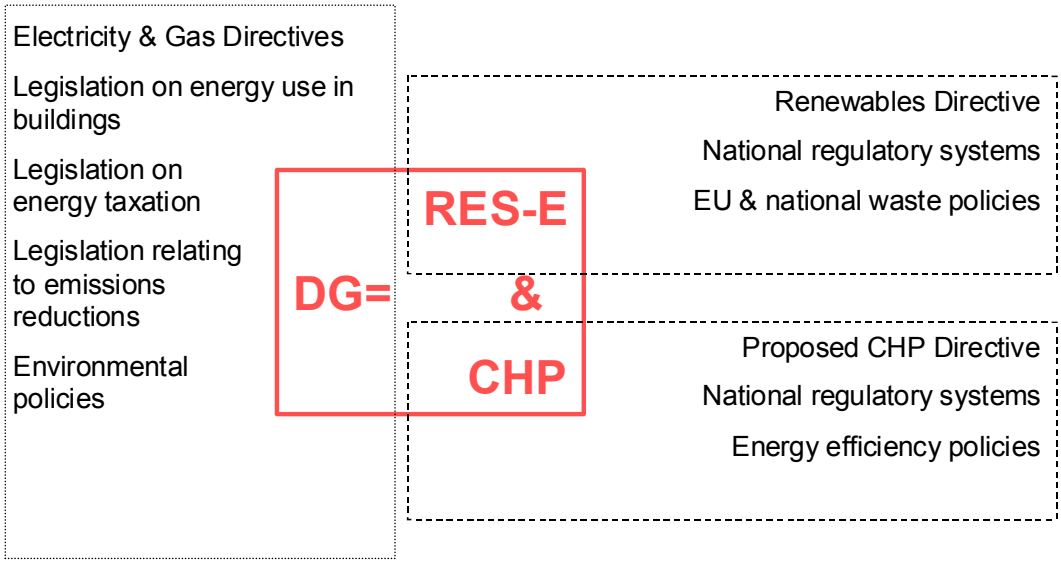

Figure 1.1 *DG and the legal and regulatory environment*

In terms of EU energy legislation, the Electricity Directive 96/92/EC[1] and Gas Directive 98/30/EC[2] have general relevance to electricity producers using DG, and they contain specific references to the treatment of electricity from renewable energy sources and/or combined heat and power production. The transposition of the Electricity Directive in the EU Member States are probably most significant for DG in the area of network access and unbundling requirements. However, as has been pointed out by the European Commission itself, issues relating to national network access fall primarily within the competence of national authorities.

The most significant existing EU legislation for purposes of clarifying the regulatory issues relating to DG is therefore the EU Renewables Directive of 2001,[3] and in particular its provisions relating to 'grid system issues' (Article 7 of the Renewables Directive). Similar rules are also under development for CHP, in accordance with the proposed Directive on the promotion of cogeneration based on useful heat demand.[4] In its explanatory memorandum, the European Commission has explained this similarity as follows:

[1] Directive 96/92/EC of the European Parliament and the Council of 19 December 1996 concerning common rules for the internal market in electricity, OJ L 27/20 (1997).
[2] Directive 98/30/EC of the European Parliament and the Council of 22 June 1998 concerning common rules for the internal market in natural gas, OJ L 204/1 (1998).
[3] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal energy market, OJ L 283/33 (2001).
[4] *See* European Commission, Directive of the European Parliament and of the Council on promotion of cogeneration based on useful heat demand in the internal energy market, COM(2002) 415 final.

> "Cogeneration producers are generally faced with the same difficulties as producers of electricity from renewable energy sources in relation to grid system issues. As a consequence, this proposal in many respects bases itself on the same provisions as those contained in the [Renewables Directive]". [5]

In addition to the above, this report considers the possible impact of the relevant provisions in the recently proposed EU legislation to complete the internal energy market. This is primarily because the amended proposal for a Directive to amend the Electricity and Gas Directives[6] contains provisions which define 'distributed generation'[7] and which set forth some proposed common rules on how DG should be treated. Moreover, both the Renewables Directive and the proposed CHP Directive contain cross-references to the Electricity Directive, meaning that the various (proposed) Directives must be considered together to understand the (anticipated) legislative framework at EU level.

1.4 Guide to the reader

The report is structured as follows. Chapter 2 builds on the barriers and success factors identified in earlier stages of the DECENT project. The analysis focuses on the EU legislation relating to DG and addresses the way and extent to which EU rules and policies relating to DG are being translated into Member States rules and policies, and applies these to the various stages in the development of DG projects. These stages include authorisations and permitting, interconnection, contracting, financing, and operation. For each of these stages, recommendations are formulated.

Chapters 3 and 4 address two longer-term policy fields that have an influence on DG development. In Chapter 3, the impact of DG on the security of supply, and the consequences of the EU Green Paper on this issue are explored. Chapter 4 takes EU technology R&D policy as a starting point, and compares current EU R&D programmes and priorities to the findings of a survey on future expectations of DG technology developments.

Next, Chapter 5 presents an outlook towards four different 'visions' for DG in the year 2020, and assesses the consequences of these expected developments for current policy recommendations.

Chapter 6 concludes with identifying the three main priority areas of policy development for DG, and highlighting the key recommendations for each of these areas.

Finally, Appendix A to this report gives an overview of the variety of existing and draft legislation, measures and communications at EU level that are relevant to DG.

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[5] Ibid., at 15.
[6] COM(2002) 304 final (7 June 2002).
[7] Under the proposed Article 2(32) of the amended proposal, 'distributed generation' shall mean 'generation plants connected to the low-voltage distribution system'. This term was selected by the European Commission in favour of the earlier proposed term 'embedded generation'.

2. ANALYSIS OF SUCCESS FACTORS AND BARRIERS TO THE IMPLEMENTATION OF DG PROJECTS

This chapter describes and analyses the main success factors and barriers to the implementation of DG projects. Figure 2.1 outlines the various stages in initiating and operating a DG project that are taken as the basis for the analysis. These stages include authorisations and permitting, grid interconnection, contracting, financing, and operation. For each stage, the main barriers and success factors are listed, based on the analysis of case studies in a previous phase of the DE-CENT project (Jörß et al, 2003). The case studies, which are referred to in the analysis, are also described in more detail in (Jörß et al, 2003).

For each of the DG project stages, the barriers are linked to the main policy areas and the main actors that determine the result of the relevant project stage. On this basis, it is possible to identify the main criteria for policy improvements per project stage. Furthermore, depending on the political level at which the relevant policies per project stage are defined, as well as the key actors involved, it can be decided at which level a policy response is warranted.

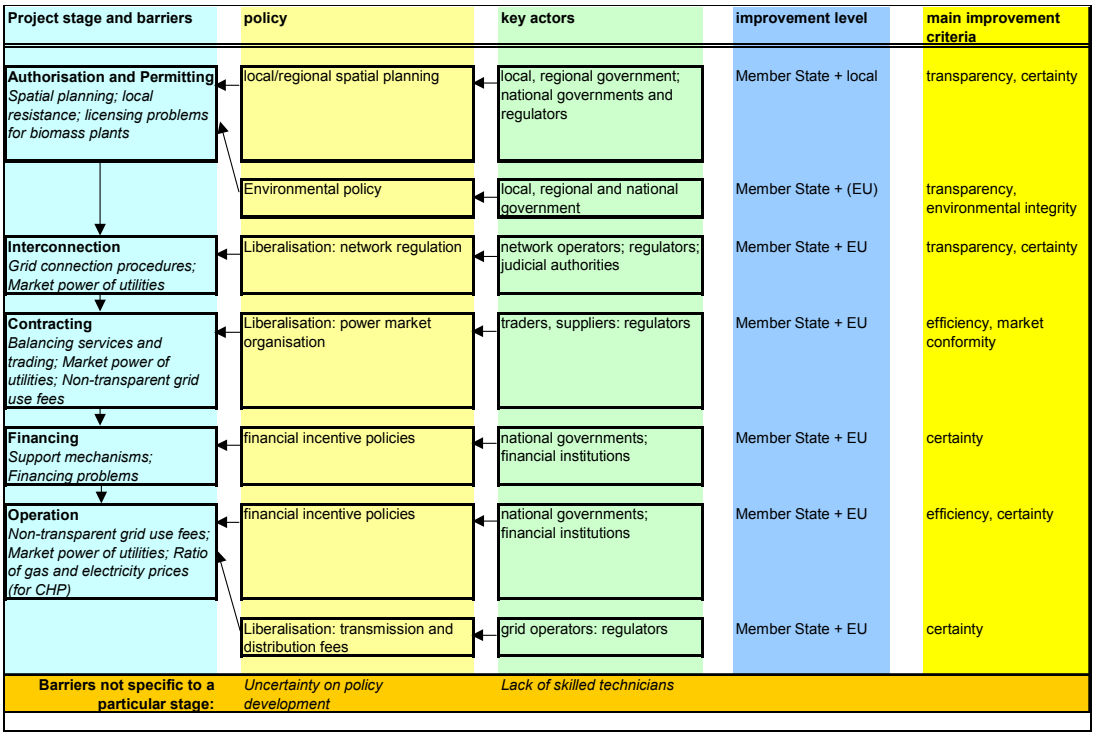

Figure 2.1 *Actor-phase diagram for DG in a liberalised market*

2.1 Authorisations and permitting

In the authorisation and permitting stage, there can be substantial delays and transaction costs due to numerous and possibly lengthy procedures. A variety of authorisations, licences, consents, or permits are required, usually issued or granted by various authorities. In particular, operators of DG installations usually must obtain at a minimum a construction and/or operating license. A distinction can be made between the following main types of authorisation or permits:

- An authorisation or license to engage in the business of electricity generation and related authorisations (e.g. heat production), which are normally required or exempted under procedures pursuant to the national energy legislation.
- Construction and/or building permits linked to spatial planning procedures and regulations.
- Environmental permits.

In some countries, DG installations are exempted from national authorisation procedures and would need only the second and third types of permits. The associated procedures vary strongly among DG technologies, EU Member States, and often within a single Member State among different regions, or municipalities. The local level is very important in this context because local governments are responsible for issuing the permits, and because local opposition can successfully delay or even prevent the issuance of the permits. In addition to the general procedural efforts that are needed to obtain the required permits, a considerable amount of RES developers - being small independent power producers (IPPs) - suffer of a lack of financial resources and flexibility needed for the long procedures. Transparency and a clear timeframe of authorisation and permitting procedures are important to reduce the scope for lengthy procedures.

2.1.1 Construction permits and spatial planning

Renewables

Permitting and planning requirements appear to be a barrier especially for hydropower and wind power. For PV developments above 100 kW or in the MW size, there may be construction problems since most roofs built in the last two decades are not designed to carry high additional loads. Moreover, green-field developments can face permitting problems with respect to surface sealing and spatial consumption.

Spatial planning appeared as a barrier in three case studies, concerning offshore wind in Denmark, and onshore wind in France and in The Netherlands. In all three cases, the planning process took several years. The Middelgrunden offshore wind farm was the first private offshore wind farm in Denmark, and no planning rules had been established for this kind of plants. Lack of experience on the authorities' side was also a problem in the Lastour wind farm project (Southern France) where the delay was caused by the necessary adaptation of the spatial plan. However, since then (1999), regulations for wind farms have been introduced in France, providing more clarity. The wind farm Zwaagdijk in the Netherlands has been applying for planning permission for 6 years. The planning permission procedure required the municipal zoning plan to be adjusted. This includes public appeal procedures and final approval from the provincial council.

In contrast, case studies on wind projects in Spain, Germany and Finland did not encounter such serious difficulties in the planning stage. The case study on the Keyenberg wind farm (Western Germany) has benefited from the German spatial planning scheme, which encourages local planning authorities to identify priority sites for wind power development. In Spain (El Perdon wind farm) the planning provisions were also described as transparent. The Spanish situation is quite different from that in most other countries. The (wind farm) developer selects a site, but in many cases this concerns common land, without private interests, and therefore only the regional government has to consent. Large developers dominate the market, and they often in-

volve regional governments, local industrial partners and local utilities in the organisational structure of the proposed project to ensure the required support.

As far as planning processes are concerned, Doyle (2001) confirms that the time until approval is much shorter in Germany (up to 6 months) than in the UK (up to 3½ years) and The Netherlands (up to 6 years). In each country, the key problem lies in another part of the planning process: planning permission (UK), revision of the legally binding local plan (Netherlands) and the construction permit (Germany).

Most (environmental) licensing problems encountered in the case studies were related to biomass plants (see the next section). In addition, the Tzschelln hydro plant (Eastern Germany) case study illustrates how small hydro development can be delayed by a negative attitude in the administration of the German federal state of Saxony[8]. The granting of the permit has been in question for a long time and is still to be decided upon in a legal case.

More in general, problems can occur because permitting or licensing processes are not well suited to the concept of smaller, decentralised generation facilities. There may be several applicable and potentially overlapping permits, codes, and requirements for a DG project, each with its own separate process, constituency and decision-makers (ADL, 1999).

The way in which the spatial planning and licensing process is conducted is essential for the duration and complexity of the procedure. Differences between Member States occur in the following key issues:

- Who takes the lead in identifying suitable sites? In some countries, such as in The Netherlands and the United Kingdom, existing land use plans must be revised to include RES projects (wind or hydro). If project developers are the ones that identify possible sites and have to appeal for such revisions, this is a lengthy process, which may also incur significant additional costs for the DG developer.
- The government level on which the planning authority is placed (in most cases local, sometimes regional) and the amount of experience or competence of local authorities. Local governments need to balance potentially conflicting interests. Doyle (2001) states that for both the UK and The Netherlands, the main issue that causes rejection or long delays is the balancing of local visual impact arguments against higher level benefits on a case by case basis.
- The criteria used for the environmental impact assessment and/or construction permit. In some countries, municipalities have considerable freedom in setting requirements for permits. Various different licenses may be required, such as a building permit, and environmental permit, and depending on the size also an environmental impact assessment.
- The transparency of necessary procedures and the certainty/time of approval (under conditions). Keeping in mind that many DG developers are small actors that are not dealing with these procedures on a regular basis, transparency is an important requirement. In some countries, national planning procedures can be improved on specific issues such as reception points and deadlines.

CHP

As for renewable electricity, permitting and licensing procedures may also form a barrier to the development of decentralised CHP projects. The DECENT case studies have provided little evidence that decentralised CHP schemes in buildings, or on commercial or industrial premises, have been hindered by authorisation procedures. This is because the CHP installations were normally located within existing buildings or their license application was included in a wider application for a construction permit. This does, however, not exclude regulatory obstacles, such

[8] Within the federal state of Saxony, a generally negative image of small hydro plants prevails within the administration, following the 'bad behaviour' in the early 90s of some hydro plant operators, which sometimes let parts of rivers fall dry in order to maximise power production.

as lengthy procedures to obtain operating permits, during the authorisation of decentralised CHP plants as referred to in the Commission's CHP Strategy (European Commission 1997). This can be illustrated with the practices in Greece, where CHP developers have complained about centralised and lengthy procedures to obtain the relevant permits although funding for projects has been authorised.

EU legislation

In line with Article 5(2) of the Electricity Directive, many countries have laid down specific criteria for the grant of authorisations for the construction of new generating capacity in their territory. The Directive lists certain acceptable criteria for the grant of authorisation, but these are often supplemented by countries in their national legislation. In some energy laws, exemptions from certain application requirements, for example, financial or technical background requirements, are expressly waived for applicants for installations using RES and/or CHP. For example, the requirement of 'availability of sufficient funds' need not be proved in certain countries by applicants for licences for electricity generation from renewable resources, unless the installed capacity of the electricity-generating equipment is higher than a specified amount. Another example would be rules that require an expedited treatment (with time deadlines) for the processing of licence applications.

Under Article 6(1) of the Renewables Directive, the main obligations on the Member States are to "*evaluate* the existing legislative and regulatory framework with regard to authorisation procedures … with a view to reducing regulatory and non-regulatory barriers …", and to *publish* a report on the relevant findings of this evaluation and on actions taken (as described in Article 6(2)). Specifically, Article 6(1) of the Renewables Directive provides:

> "Member States or the competent bodies appointed by the Member States shall evaluate the existing legislative and regulatory framework with regard to authorisation procedures or the [tendering] procedures laid down in … Directive 96/92/EC, which are applicable to production plants for electricity produced from renewable energy sources, with a view to:
> - reducing the regulatory and non-regulatory barriers to the increase in electricity production from renewable energy sources,
> - streamlining and expediting procedures at the appropriate administrative level, and
> - ensuring that the rules are objective, transparent and non-discriminatory, and take fully into account the particularities of the various renewable energy source technologies."

Similar rules relating to CHP can be found in the Article 9 of proposed CHP Directive, with one additional limitation (or objective); namely that the evaluation should be also be conducted with a view to "encouraging the design of cogeneration installations to match economically justified demands for heat output and avoiding production of more heat than useful heat".

The proposed amendments to the Electricity Directive (as of June 2002) contain an affirmative obligation that is more firm than found in either the Renewables Directive or the proposed CHP Directive. Article 5(3) would require that:

> "Member States shall take appropriate measures to streamline and expedite authorisation procedures for small and/or distributed generation. These measures shall apply to all facilities of less than 15 MW and to all distributed generation."

Recommendations

The provisions in the Renewables Directive provide a good basis for Member States to review and improve their administrative procedures for planning and permitting processes in terms of

speed and transparency. Given the subsidiarity principle, there is not much scope for additional Commission action at this stage, except that the communications towards Member States should stress that they should start their evaluation in a timely manner to ensure the issuance of a first report to the Commission by October 2003.

Within most Member States, however, there is ample scope for improvement of authorisation and permitting procedures depending on specific national administrative systems. Most of the recommendations below are addressed to the local or regional governments within the Member States. As a consequence of the country specific nature of administrative procedures, the recommendations are stated in general terms.

- Permitting or licensing procedures should be transparent and efficient. In some countries, national planning procedures can be improved on specific issues such as clear reception point for applications, and reasonable deadlines.
- Local authorities should take a lead with a pro-active planning strategy, as is the case in other planning policies such as housing. Integration and thus pre-selection of potential sites for DG use, especially wind power, into spatial plans helps to avoid conflicts between DG use of sites and nature protection, or other uses. In Germany this tool proved successful since on one hand it enables local authorities to channel wind power development to preferred sites (and simultaneously to bar other sites). On the other hand siting efforts for wind developers are considerably reduced.
- Because of the small scale of DG installation and their operators, Member States (national governments) could introduce fast-track authorisation procedures.
- The work of planning authorities could be facilitated by improving the database or resource potential to better enable them to reach balanced decisions. This could for instance be done through public inventorying of data on exploitable natural potentials (which is partly done for wind and hydro power) or even heat demand (potentials for small-scale heating grids to be served by biomass or CHP).
- If the competence of local authorities is a barrier, training programmes for personnel that issue the permit could be established.
- Local support is essential, because this is the level where most individual projects are submitted for approval. Energy agencies could set up public information campaigns to inform about the benefits and drawbacks of renewable electricity and CHP.

These provisions are already partly incorporated in the Renewables Directive and could also be integrated into the proposed CHP Directive and the amended proposed directive on Energy Performance of Buildings. The European Commission could also require Member States to conduct feasibility studies for CHP ('heat planning', 'energy planning' or the like) in regional and local spatial planning procedures. This could be a more specific requirement than the current requirement to assess the national potential for CHP as stated in the proposed CHP Directive. Through its energy framework programmes, the European Commission could foster international exchange programmes on best practices in authorisation procedures.

2.1.2 Local resistance

Despite the broadly accepted environmental benefits of DG, local resistance can be strong. Reasons vary between technologies: source of air pollution closer to the people (CHP, biomass), danger of smell (biomass), noise (CHP, wind), ecosystem protection (hydro, wind), integrity of landscape (wind, green field PV) etc. Local resistance can constitute a high barrier to project development, since neighbourhood participation rights in spatial planning and licensing/siting processes have generally grown strong, and neighbourhood resistance might also be reflected in non-co-operation of local authorities.

In this respect, it can be expected that there is a relationship between a country's population density and the amount of public opposition - the 'not in my backyard' syndrome is less impor-

tant when there are enough locations available that are reasonably far away from anybody's backyard.

No project failure due to local resistance was encountered in the case studies. However, reports of projects (esp. wind and hydro) prevented due to neighbourhood or environmentalist pressure group resistance are numerous e.g. in Germany and in the UK. Difficulties were encountered in Silbitz (Germany) where the local acceptance was set back by the fact that despite of the developer's wish to communicate the plant as 'green bio-energy' the (wood) waste incineration character of the project was a major drawback.

There is also some case study evidence pointing in the opposite direction. Several of the studied projects would never have succeeded without the engagement of motivated persons or local/regional authorities. These examples also show several approaches of involving local people in the project.

The developer of the Lumijoki offshore wind turbine is a company, founded by environmentally engaged people from the plant's neighbourhood. The company issued shares to people that would be mainly environmentally motivated to participate. The developer of the Keyenberg wind farm in Germany also tried to engage the neighbourhood in the project by granting easier access to investment: the minimum investment for local investors was reduced from €10,000 to € 2,500. The investor did not face major resistance against the project.

The FIRE study (Langniss, 1998), also concludes that the financial involvement of local people can help reducing the barriers to renewable projects, because if local people can acquire equity shares of the project, their interest in the project's success will be large. Another benefit is that project developers can - in an early stage - learn from local shareholders what the specific concerns of the local community are, and take these into account. Doyle (2001) even suggests that there would be quite a strong correlation between the share of wind power development in a country and the degree of local ownership.

Recommendations

The main recommendation, targeted to Member States, in order to reduce public opposition is to involve local actors. Schemes to ensure financial involvement in RES developments or benefits to the neighbourhood can help significantly to reduce local resistance and foster local support. Some examples for such schemes were identified in the case studies and in (Langniss, 1998). Table 2.1 presents these schemes and shows that they can be applied by the project developers themselves without intervention from national or regional governments. In this case, ways should be found to communicate this information to them.

Table 2.1 *Examples of schemes to involve local actors in the development of a RES project*

	Scheme for involving local actors	Responsible
1.	Grant easier access to the financing scheme for local investors, by giving them favourable conditions. For instance the minimum share can be lower for local people than for strangers or they receive preferential dividends (Germany).	Project developer
2.	Give site owners the opportunity to bring the ground into the project as part of the equity instead of selling it (Spain).	Project developer
3.	Offer local owners an arrangement where they get the equity by contributing in kind instead of in cash (Denmark, farmers committing to deliver raw materials).	Project developer
4.	Address local people and bodies preferably when acquiring equity (Italy).	Project developer
5.	Involve environmental NGOs in the development process (ask them to approve a design and communicate about this)	Project developer

Given the diversity of local and regional conditions, it is probably best to leave the elaboration of these activities at the Member State or regional level. Therefore, we recommend Member States to stimulate local involvement by:

- Involving national or regional energy agencies in providing and disseminating this information. Energy agencies could also fulfil a mediating role between project developers and other stakeholder with respect to the recommendations in the above table. The role of regional energy agencies is also emphasised in (EEA, 2001). The EU financially supports the establishment of regional energy agencies through its SAVE - ALTENER programme.
- Starting education and information campaigns to raise interest and informed debate amongst the general public. At the local level, it is important to show non-energy benefits, such as the provision of local jobs.

2.1.3 Permitting problems for biomass plants based on wood or waste

In most countries, the use of solid biomass relies on industrial waste wood, which triggers the discussion 'waste or biomass?' While wood waste is attractive through the negative or neutral fuel price, it has its disadvantages through licensing difficulties and a bad public reputation of waste incineration. In addition the future development of prices for biomass waste / wood fuel is uncertain.

Permitting problems were observed in the case studies on the Lelystad biomass project (Netherlands) and in the Silbitz biomass project (Germany). In Lelystad, the permitting process took one year. Every new biomass project must decide beforehand on the fuel input, be it biomass or waste, in order to obtain a specific license. Most exploiters of biomass installations therefore prefer an open license, to maintain the flexibility to use the cheapest fuel (biomass or waste) from the market. However, an open license involves stringent emission demands, and requires an exhaust gas cleaning installation, which makes the plant more expensive. Another complicating factor is when pre-treatment of supplied biomass takes place in the plant area. In that case, the plant would be considered a waste treatment installation instead of a biomass plant. As a consequence, the province (region) instead of the municipality would have to grant the relevant permits.

The Silbitz biomass project did have its difficulties in obtaining the operation license, but the processes was facilitated through relatively clear definitions of waste categories in German legislation regarding the eligibility for RES support and on conditions for an operation permit. The plant needs an operation license covering possible emissions to air and water. The permit is to be granted if the emission standards are met and the local pollution standards are not endangered. The plant is classified as a type of residues/waste processing plant. This enhances possible public alert, and makes the licensing process more difficult. Authorities were very cautious in the licensing process, which slowed down the process considerably.

EU legislation

In the Renewables Directive, the following definition of biomass has been adopted:

> "the biodegradable fraction of products, waste and residues from agriculture (including vegetal and animal substances), forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste."

As far as emission permits are concerned, it has been decided that all fuels that satisfy the definition of 'clean biomass' given below, have to comply to the emission requirements in the Directive on limitation of emissions from Large Combustion Plants[9].

[9] 2001/80/EC of 23 October 2001.

Article 2(11): biomass means products consisting of any whole or part of a vegetable matter from agriculture or forestry which can be used as a fuel for the purpose of recovering its energy content and the following waste used as a fuel:

a. Vegetable waste from agriculture and forestry.
b. Vegetable waste from the food processing industry, if the heat generated is recovered.
c. Fibrous vegetable waste from virgin pulp production and from production of paper from pulp, if it is co-incinerated at the place of production and the heat generated is recovered.
d. Cork waste.
e. Wood waste with the exception of wood waste, which may contain halogenated organic compounds or heavy metals as a result of treatment with wood preservatives or coating, and which includes in particular such wood waste originating from construction and demolition waste.

All other biomass and waste streams have to comply to the more stringent regime set up in the Directive on incineration of waste[10].

At the moment, the EU waste policy lacks clarity on the distinction between waste disposal (removal) and useful application of waste by co-incineration. There is no clear guideline that states a caloric value. The distinction is important, because waste that can be co-incinerated (useful application), is allowed to be transported through Member States, while waste to be disposed may not.

Recommendations

At EU level, the biomass definition as stated in the Renewables Directive has provided sufficient clarity. On the other hand, the waste policy should include a criterion to distinguish between disposal and useful application. This should be accompanied by measures that ensure that the waste hierarchy referred to in the Renewables Directive is observed, as creating a caloric threshold for useful waste may divert waste above the threshold from the recycling stream.

Again it must be noted that permitting regimes are country specific, and closely related to government structures. Therefore the following recommendations are stated in general terms, and are meant for national governments of the different Member States:

- Clear definitions on waste categories and on licensing conditions may help to overcome the licensing barrier for biomass plants based on waste materials.
- Develop a simple and standard biomass acceptance procedure, based on quality assurance at the biomass fuel supplier's side, thus relieving the biomass plant operator from the responsibility of demonstrating fuel quality.
- Simplification of the permitting regime will be a great step forward, because the number of different laws and rules that might apply to a biomass installation is very confusing.

2.2 Grid connection

What all DG technologies have in common is that due to their decentralised character, they will need (to negotiate on) access to and use of the transmission and distribution networks. Even for installations operating in island-mode, access to the grid is often required for back-up power. Non-discriminatory access to the grid and transmission and distribution services[11] is therefore fundamental to ensure that DG can compete with other sources of electricity on an equal basis. Consequently, the provision, pricing and regulation of connection to the grid and of transmission and distribution network services is very important for the penetration of DG in the EU

[10] 2000/76/EC of 4 December 2000.

[11] Transmission and distribution services refer both to transportation services and to services related to the safe and reliable operation of the grid, such as frequency control, back-up power provision, voltage support, etc.

electricity market. As the structure of the European electricity markets has been developed from a centralised paradigm, DG developers and operators often face additional barriers relative to centralised plants. These barriers to the use of the grid can be distinguished in barriers relating to the connection to the grid and barriers relating to the use of transmission and distribution services. Barriers relating to the use of system are considered in Section 2.5.1. The current section considers barriers to connection to the grid.

As the case studies from several countries and technologies illustrate, negotiations on the costs of interconnection to the network can be a lengthy process, involving contractual matters including liabilities and the allocation of costs for feasibility studies, necessary grid reinforcements and line extensions. Some examples are given below:

- Pozoblanco CHP (Spain): The terms of grid access were an important barrier to the development of this project and increased its costs considerably. The project developer wanted to have a connection at the shortest possible distance, but the distribution company would only grant this if they paid for a grid upgrade. Connection was finally granted at a sub-station (which was not the closest possible point) and this made it more expensive and bureaucratic because they had to apply for a lot of passage permissions.
- Lastour wind farm, France: the project was complicated by a dispute on costs of both upgrade of existing grid and new line from power plant to grid that had to paid by the developer.
- Lumijoki offshore wind turbine, Finland: The terms of grid access were under heavily dispute with the grid company. The grid connection fee was subject to a court trial.
- St Pancras Housing London (UK) and the public hospital in Ronse (Belgium): In both cases, the project developers anticipated from the outset that the grid operators would make grid connection so difficult that they ruled out the possibility to export electricity to the grid. The resulting design of the CHP scheme dimensioned on electricity demand reduced the efficiency and profitability of both installations. In order to achieve maximum efficiency, CHP schemes should normally be designed to meet the heat demand on site, and to export electricity surpluses to the public grid.

Such grid connection issues are covered by regulation in Member States to a different degree.[12] Furthermore, the technical requirements for connection imposed by the grid operator may be subject of dispute and can cause uncertainty about the cost of connection. Technical issues, which are disputed, are e.g. capacity of grid, necessary upgrades, point of connection, interconnection voltage, line protection technology, reactive power behaviour and islanding options. Below we analyse the main grid connection issues emanating from the case studies somewhat further.

[12] The COGEN Europe study on administrative obstacles to decentralised CHP (COGEN Europe 1999) identified in three Member States (France, Netherlands and the UK) high connection costs, high costs of grid reinforcement charged on the CHP developer, complex and lengthy administrative procedures etc. The study emphasises that CHP developers are faced with many of the same problems in the three countries although important differences in rules and general framework conditions also exist.

Connection charges

Negotiations on the cost of connection can often be lengthy process. This is partly due to the lack of transparency in the cost calculation methods. Two main types of connection charges with different economic rationales can be distinguished: *shallow* and *deep* connection charges.

- *Shallow* connection charges only bring into account the cost of line extension to the nearest connection point and the equipment needed to connect the line to the rest of the grid. No charges are made for adjustments, reinforcements and upgrades necessary to facilitate the integration of a generator into the grid beyond the point of connection. The costs of such grid adjustments are recovered by the grid operator through the grid use tariffs and are thus socialised among all users of the grid[13]. The grid is considered a pure public good. Shallow connection charges can be standardised relatively easily. For example, in the Netherlands the cost of the line from the cut (the point of connection to the grid) to the plant is standardised per meter[14]. Also in Germany and Denmark, only direct connection costs are borne by the RES developer, while all costs incurred by necessary grid reinforcements are to be borne by the DSO.
- *Deep* connection charges, used for instance in the United Kingdom, bring into account all the cost of integration of a generator into the network, including the cost of all adjustments beyond the point of connection to the network. Not only will the cost of deep connection charges usually be higher, it will also be much more uncertain as the cost will be highly specific per location, generation capacity and mode of operation. Thus the cost have to be independently assessed for each new generator. The methodology of assessing which technical adjustments are necessary and how the cost of these is going to be assessed is often non-transparent. With deep connection charges the costs are not socialised[15].

Point of connection

With shallow connection charges a project developer would generally aim to connect to the nearest point on the grid, as this is the cheapest solution from the project developer's point of view. However, determining the point of connection with deep connection charges is more complicated, because the location specific cost of grid adjustments will be taken into account both by the generator and the network operator. Both the project developer and the network company will seek to minimise their cost. This problem of conflicting interests between the grid company and the project developer regarding the point of connection, and the according allocation of cost is illustrated in the case study on the Pozoblanco CHP project.

The cost of grid adjustments for different points of connection is related to the costing methodology and furthermore depends on existing grid expansion and capacity plans. These plans generally do not account for the connection of decentralised electricity sources. The grid operator has an interest to align the point of connection and the technical adjustments as much as possible with the existing grid structure and plans for grid expansion and upgrades. The DG operator on the other hand merely wishes to minimise their cost of connection.

Safety and liability issues

The power system is a complex web of assorted hardware, including generators, power lines, substations, transformers, switches, breakers, fuses, and other components, including users'

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[13] Shallow connection charges have benefits for DG operators in that they reduce the uncertainty relating to the cost of connecting to the system. On the other hand DG operators will not be credited for possible benefits they bring to the system. Moreover, if DSOs are subject to regulation that requires them to cut their cost annually they may be reluctant to connect a DG operator when this entails grid adjustments. This disincentive to connect may cause DSOs and TSOs to obstruct or slow down connection procedures.

[14] Tariff Code 2000, Dte, 2000.

[15] Deep connection charges have also been identified as barrier in a recent Ofgem consultation. Interestingly, all the distribution network operators denied that deep connection charging policies constituted a barrier. The view of the majority of generators was that they constitute a significant barrier. See Ofgem (2002) "Distributed generation: price controls, incentives and connection charging: Further discussion, recommendations and future action." http://www.ofgem.gov.uk/docs2002/26distributedgeneration.pdf.

loads. All this operates in a synchronous mode, using 50 Hz in Europe. Rules and standards for grid connection are aimed at maintaining the reliability and integrity of this electrical power system. The question is whether these rules are adequate or too strict. Part of the problem is that, historically, electricity systems have been conceived to be operated in a centralised manner and the utility operating the network was used to deal with big centralised generation plants and had little experience with smaller ones. In such a system the power flows in only one direction: from the power station to the network and to the customer. Some utilities are still used to this traditional centralised approach of distribution of electricity, and grid connection requirements are often designed to be appropriate to big units of a few hundred MWe, but not to small ones.

Moreover, grid operators are responsible for a safe and reliable operation of the network. As they are often under pressure of price regulation they will try to shift as many of the costs and risks of safety measures to the users to the grid, mainly to producers. The cost of safety measures related to network connection may entail special safety and contingency equipment in the connection to the grid and adjustments elsewhere (in the case of deep connection charges), demands on the operation of the plant, etc (ADL, 1999). Necessary safety measures are generally determined by the grid operator taking a very risk averse approach. Moreover, a connection contract may specify conditions on the liability in case safety conditions are not met by the operator of a plant. The safety requirements on equipment and operation can compound the cost of connection. Moreover, the basis of establishing the necessary measures is not always transparent.

Lack of transparency

When establishing the cost of connection to the grid it is important that both the procedures for requesting and negotiating connection and the cost assessment methodology are transparent and non-discriminatory. Whenever they are not transparent the scope for discriminatory practices is also larger. As described in the paragraph on connection charges, grid operators may have incentives to obstruct connection by delaying the connection procedures in the case of shallow connection charges. Moreover, the case studies provide a number of examples where connection was delayed by the grid companies. Clear procedures (including deadlines) can reduce the scope for this kind of antagonism. Furthermore, in the case of deep connection charges the transparency of the methodology of establishing the technical needs for grid adjustments and the costing of these adjustments is key to the negotiation on grid connection cost between the generator and the grid operator. The Netherlands, UK and Norway are amongst the few exceptions, where information on grid connection costs is publicly available. In the absence of any standard conditions, new entrants will face uncertainty with regard to the cost of connection. This uncertainty constitutes a barrier for any new CHP and RES projects.

On the other hand clear cost allocation rules between developer and (distribution) grid operator have proved to reduce uncertainty, thus facilitating DG development (e.g. the German case studies Tzschelln hydro, Keyenberg wind farm, Silbitz biomass). In these cases, the German Renewable Energies Act stipulates that only direct connection costs have to be borne by the developer, while grid reinforcement costs are to be borne by the grid operator. In addition, a clearing office has been installed at the German Ministry of Economics for the settling of disputes and ambiguities.

Business practices

It is not perceived to be the core business of grid operators to facilitate and optimise the integration DG into their networks. The priority is the operation of the grid and maintenance of the assets. Furthermore, there is no incentive structure to stimulate the fast and efficient handling of connection procedures. Therefore, connection requests by DG have a relatively low priority.

Benefits of connection
Benefits of connection of DG may arise from deferral of transmission and distribution network upgrades and expansion, decongestion, improved local reliability, and the provision of ancillary services to the grid[16] (Van Sambeek, 2000). These benefits are usually not reflected in the connection charges, which only take into account the cost of connection. Particularly in the case of deep connection charges there is scope to take into account the benefits of decentralised capacity, as the methodology of assessing the (full) cost of connection including necessary adjustments beyond the point of connection (cut) is more geared to also incorporating the benefits of avoided future upgrades and capacity expansion. However, it depends on the type of regulation on the grid companies whether or not the grid company has an incentive to pass these benefits on to the DG operator. For example, when the grid company is subject to price regulation (such as in the Netherlands and the UK) and if a grid company may incorporate the benefits of deferred upgrades/expansion in its rate base, then it has a clear incentive to connect DG where such benefits are likely to accrue. Regulation is needed to ensure that the benefits are shared between the DG operator and the grid company.

Lack of price signals
DG operators seek to minimise the cost of connection to the network. Network operators also seek to minimise the cost of connecting DG to their network and seek to minimise the amount of effort involved in handling connection requests and in integrating DG in their grid planning. As described before the aims of both actors are often difficult to reconcile as a result of non-transparent procedures and cost assessment procedures. Above it is indicated that transparent cost assessment methodologies and connection procedures can facilitate the negotiation on grid connection between the DG operator and the network operator. However, this negotiation only takes place after a connection request has been submitted for a specific location, which cannot take into account the full additional cost or benefits to the network. Both the network operator and the DG operator could benefit greatly if the cost of connecting to the network per location are known in advance. For example, the network operator could indicate on which locations it would like to encourage or discourage the connection of DG, and provide incentives through the connection charges accordingly. This means that where connection to the grid entails a benefit, e.g. though avoided or deferred grid investments, DG operators receive a bonus for connecting[17]. Likewise, where there are cost associated to connecting a generator beyond the point of connection (cut), e.g. necessary grid reinforcements, there should be an indication on the size of these costs to provide DG operators incentives to connect elsewhere. By providing clear geographically differentiated incentives for the connection of DG to the grid, connection can be done in a more optimal way, while minimising the cost to the DG operator and the grid operator. Moreover, transparency on the feasibility and cost of connecting on a specific location will provide more *ex ante* certainty to DG project developers on the feasibility of their project.

DSO (Distribution System Operators) incentives
The incentives arising from price regulation on network companies determines the attitude of grid companies to the connection of DG. Most network companies in the EU are subject to some kind of price regulation. The price that can be charged for transmission and distribution in these regulatory models is based on the operational cost, the capital cost and an allowable return on capital. Thus the main issue is how grid connections and reinforcements are incorporated in the asset base of grid companies. Furthermore, DSOs mostly charge fees for transporting electricity in one direction from the transmission system to the consumer (Mitchell, 2000). If demand diminishes due to DG the capital cost per kWh distributed from transmission to the consumer increases. However, when the distribution fee is fixed (or discounted each year, such as in the UK and the Netherlands) the DSO reduces its return on capital. The DSO may therefore

[16] The costs and benefits from DG to the grid can be measured against the cost of providing grid services according to the centralised capacity plans. Deferring of avoiding (parts of) the implementation of these plans may lead to cost reductions (benefits), while necessary extra reinforcements may increase the cost of connecting.
[17] Preferably based on the actual benefit incurred to the system.

have an incentive not to connect DG in the first place. Price regulation should thus be altered in such a way that this discriminatory effect on DG is removed.

Co-ordination of spatial planning and network planning

The location of DG projects is often constrained by spatial planning and resource availability. This is particularly the case for RES projects using wind and biomass resources. In response to the challenge of integrating wind development sites into spatial plans and overcoming local resistance to wind parks governments at various levels have moved to appoint specific locations within their jurisdiction for wind development. The sites that are appointed on this basis or that most eligible from a resource point of view are not always the most optimal sites from a network integration point of view, thus raising the cost of implementation through connection charges. It would therefore be prudent to seek co-ordination between the designation of wind and other DG development sites and the cost of connection at various locations. Of course, for this it is necessary that the cost of connection are known to those involved in spatial planning. Ex ante price signals in the network could greatly enhance transparency in this regard. Vice versa, it would be commendable to take the designated wind/DG development areas into account in the grid planning by network operators. This can minimise the cost of integration of DG into the network in the long run. This is not to say that the integration of DG will always lead to a least cost electricity planning option. Indeed there may be extra cost involved in taking DG into account. How to allocate these cost between the users of the network (shallow connection charges) and the DG operator (deep connection charges) will have to be discussed in the framework of national electricity regulation.

EU legislation

The EU Renewables Directive is the most significant and specific EU legislation on the matter of grid connection issues for DG. This binding legislation is substantively linked with the European Commission's proposed directive on CHP, which contains a section on 'grid system issues' that is very similar to the section in the Renewables Directive. In brief, the binding obligations relating to grid system issues under the Renewables Directive require Member States to adopt a legal framework or require distribution system operators (and TSOs):

> "To set up and publish their standard rules on the bearing of costs of technical adaptations, such as grid connections and grid reinforcements (Article 7(2))."
>
> "To provide any new producer wishing to be connected with a comprehensive and detailed estimate of the costs associated with the connection (Article 7(4))."
>
> "To set up and publish their standard rules relating to the sharing of costs of system installations, such as grid connections and reinforcements, between all producers benefiting from them. (Article 7(5))."

The obligations relating to cost-sharing rules in Article 7(5) represent a new element of EU electricity legislation: equivalent rules do not appear in the Electricity Directive or the current proposed amendments to the Electricity Directive (as of June 2002). Specifically, Article 7(5) of the Renewables Directive requires a mechanism that takes into account the benefits that "initially and subsequently connected producers … derive from the connections":

> "Member States shall put into place a legal framework or require transmission system operators and distribution system operators to set up and publish their standard rules relating to the sharing of costs of system installations, such as grid connections and reinforcements, between all producers benefiting from them."

> "The sharing shall be enforced by a mechanism based on objective, transparent and non-discriminatory criteria taking into account the benefits, which initially and subsequently connected producers as well as transmission system operators, and distribution system operators derive from the connections."

The implementation of these cost-sharing rules in the Member States will most likely take place as part of the development of the overall set of rules applying to connections and connection costs. Article 7(2) of the Renewables Directive sets forth the Member State obligations in this respect:

> "Member States shall put into place a legal framework or require transmission system operators and distribution system operators to set up and publish their standard rules relating to the bearing of costs of technical adaptations, such as grid connections and grid reinforcements, which are necessary in order to integrate new producers feeding electricity produced from renewable energy sources into the interconnected grid."
>
> "These rules shall be based on objective, transparent and non-discriminatory criteria taking particular account of all the costs and benefits associated with the connection of these producers to the grid. The rules may provide for different types of connection."

In other words, we can distinguish between the Directive's rules on '*cost-sharing'* and rules on '*cost-bearing'* in the area of connections. The latter is the general category, whereas the former is a refinement or subset of the latter. Both types of rules seek to refine the rules applying in the Member States to the allocation of costs of connections for producers using RES. Similarly, the Article 8 of the proposed CHP Directive would introduce obligations relating to connection costs and cost-sharing rules similar to Articles 7(2) and 7(5) of the Renewables Directive.

These more specific rules in the Renewables and proposed CHP Directives are a considerable improvement over the relevant provisions relating to connections in the present Electricity Directive. As has been duly noted, the Electricity Directive's rules on operation of the transmission system require the system operator to draw up clear technical rules on interconnection (Art. 7(2)). A similar rule does not apply to distribution system operators.

Improvements in the Electricity Directive can be expected in light of the Commission's proposals of June 2002. The proposed amendments to the Electricity Directive would require (under Article 22(1)(g)) that national regulatory authorities monitor the electricity market with respect to 'terms, conditions and tariffs' for connections:

> "Member States shall designate one or more competent bodies as national regulatory authorities. These authorities shall be wholly independent of the interests of the electricity industry. They shall at least be responsible for continuously monitoring the market to ensure non-discrimination, effective competition and the efficient functioning of the market, in particular with respect to:….the terms, conditions and tariffs for connecting new producers of electricity to guarantee that these are objective, transparent and non-discriminatory, in particular taking full account of the benefits of the various renewable energy sources technologies, distributed generation and combined heat and power."

Further explanation of the rationale for this proposal is provided in the Commission's explanatory memorandum of June 2002:

> "Amendment 57 [of the European Parliament] states that costs of connecting producers of electricity from renewables and combined heat and power shall be objective and non-discriminatory. The Commission is of the opinion that the costs of connection of all producers should be non-discriminatory, but that, in addition, the specific

characteristics and the costs and benefits of connecting producers from renewables and combined heat and power to the grid should be taken into account. This is reflected in Article 22. The explicit reference to ensure no obstacles exist to the stimulation of dispersed generation, is taken on board in Article 22(1g) as well, where the regulators shall monitor the measures taken by Member States to ensure that the benefits of connecting renewables producers and distributed generation to the system are taken in account. (Article 22(1g) electricity)."

On the technical side, under the auspices of the European Committee for Standardisation CEN, a European-wide standard on requirements for grid connection for micro-cogeneration systems for domestic use and with installed capacity up to 10 kW_e is currently under development[18]. Initially, this standard will not be established as a full-fledged EN norm, but as a so-called CEN Workshop Agreement (CWA). This project would be a first step to the creation of cheap, reliable, and safe standards in the domestic micro-CHP sector. Obviously, this sector is only a limited segment of the total DG market. The development of technical standards for other types of DG installations is still to be addressed.

Recommendations

The Renewables Directive provides a legal basis for the Member States to take steps to accelerate the removal of barriers to network access and the associated costs allocated to producers of renewables-based electricity. The related national administrative actions or procedures (e.g., the formation of working groups on DG or the institution of formal regulatory reviews by regulators) can easily be extended by the relevant national authorities to cover other forms of DG. With respect to the reporting obligations under the Renewables Directive, Member States should observe their reporting deadline of October 2003.

- As a first step to improving access to the grid, transparency on connection procedures and cost assessment methodologies, as well as the cost of connection at various locations in the grid should be improved. This will provide more certainty to project developers as to the cost of grid access that may be anticipated in the implementation of a project and reduce project risks.
- Second, due to the lack of transparency on cost assessment methodologies, it is not always clear whether the costs are assessed in an economically efficient manner. Cost assessment should take least cost central capacity planning as the baseline/benchmark against which the costs should be assessed. Consequently, after the costs have been accurately determined according to efficient economic principles, rules have to be devised to distribute the cost amongst the users of the grid. Preferably these cost allocation rules should follow the principle of economic efficiency. However, it is recognised that if this path is followed (e.g. through deep connection charges) the cost of connection to the grid may become prohibitively high to certain DG investors. Therefore, in view of the aim to increase the share of DG in the internal market, and to improve the effectiveness of support policies to this end, it may be commendable to socialise part of the cost of connecting DG to the grid. In finding the balance between socialisation of cost and direct attribution of cost to DG operators the principles of equity and fairness to market actors and consumers/society should be taken into account.

Based on the above, we can identify five general criteria for improving regulation with regard to grid access for DG. These are transparency, economic efficiency, effectiveness, equity, and predictability. These principles should also be taken into account in the monitoring of the policies and regulations put into place by the Member States pursuant to Article 7 of the Renewables Directive. These criteria can be put into operation to respond to the barriers identified above in the following ways:

[18] http://www.cenorm.be/standardization/tech_bodies/workshop/otherthanict/ws5.htm

- There should be uniform *technical* standards for interconnection to the grid. This would reduce the scope for dispute on the technical requirements associated with grid connection. In the process leading to this standardisation, it is important that all relevant stakeholders are involved in the discussion so that the standards do not introduce a bias in favour of any particular party.
- There should be transparent and efficient rules relating to the allocation of costs of technical adaptations, such as grid connections and grid reinforcements to all users of the grid, including future generators. More specifically, these rules on allocation of costs should define not only the respective obligations of the DSOs and the DG producers (cost-bearing rules)[19], but also the framework for determinations to be made on the sharing of costs among initially and subsequently connected producers (cost-sharing rules).[20]
- There should be clear procedures and norms for dispute settlement in case of disagreement on the cost of connection. To enforce these procedures and norms and to provide a depository for complaints, an independent dispute settlement entity can be established by the Member State governments. The national energy regulators can also fulfil this function.
- System operators should publicly provide an *ex ante* indication of favourable and problematic sites for grid connection based upon geographically differentiated price signals to DG project developers. The Electricity Directive can be amended in Articles 9 and 12 to require Member States to ensure that information on free grid capacities is made available to developers of new capacity while respecting confidentiality. The national regulators can require DSOs and TSOs to provide such information publicly, for example through their websites.
- Price and quality regulation should provide incentives to network companies to deal with connection requests in a fair and efficient manner. Two issues play a role here: first, a network company should not have any economic incentive to avoid DG connection, and second, business practices should be encouraged to take a proactive and service oriented stance towards facilitating DG connection. Both aspects need to be taken into account by national regulators in defining the regulatory models for network companies.
- Co-ordination between spatial planning, network planning and RES interconnection. The interactions between spatial planning, network planning and RES siting and interconnection are numerous and cross various administrative levels. In order to achieve good co-ordination good co-operation between the administrative bodies, network companies and regulators, is necessary. Most likely several iterations in adjusting all these planning efforts are necessary to minimise the overall cost of network expansion, DG implementation and ensure public acceptability. This recommendation is particularly addressed to local and regional governments, TSOs, DSOs, Member State governments, and regulators.
- The EU should undertake responsibility for setting technical specifications to impose safe and realistic grid connection requirements for decentralised producers, which would be less restrictive**.** To be effective, the specifications should be safe and fit for the purpose, low-cost, reliable and widely accepted. Such requirements could be issued as EN norm through Cenelec, the European Committee for Electrotechnical Standardisation. The European Commission should support the definition of such standards by initiating exchange programmes and projects on this matter.

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[19] Examples of cost-bearing or cost allocation rules can be seen e.g. in Germany and Denmark. In Germany, for grid connection of new RES capacity covered by the Renewables Energies Act, all costs incurred by necessary grid reinforcements are borne by the grid operator, while direct connection costs are borne by the RES developer. In Denmark, grid extensions for the connection of off-shore wind farms are considered a public good, and thus borne by the grid operator.

[20] In the United Kingdom, amendments made in the spring of 2002 to the Electricity (Connection Charges) Regulations require an electricity distributor to recover certain amounts from subsequent users of electric lines and plants first provided to another person in making an initial connection, such that refunds can be made to the person who previously had to bear the expenses of the initial connection. At present, these rules allowing partial reimbursement of initial contributors only apply to households (domestic premises). The regulator OFGEM has taken action in June 2002 to extend the reimbursement mechanism to DG as part of the wider initiative to remove inappropriate charges and perverse incentives that might inhibit the development of DG.

The UK provides a first example of how some of these recommendations can be implemented at the Member State level. In March 2002 the UK energy regulator Ofgem published proposals outlining short and long term measures to provide a fair and transparent regulatory regime for distributed generation[21]. The proposals for immediate action include:

- As an interim arrangement, prospective decentralised generators should have the choice of paying the costs of connection 'up-front' or paying only for the 'shallow' costs in this way, the balance being collected through an 'annualised connection charge' negotiated with the DSO.
- Making it easier for domestic Combined Heat and Power (DCHP) customers, who have a heating system which can generate its own electricity, to connect to the networks by establishing a standard set of procedures.

2.3 Market access and contracting

Liberalisation and restructuring of the electricity markets in the EU has been vastly increasing the possibilities of old and new actors in the electricity sector for contracting. In principle this also applies to the possibilities of decentralised generators to contract their output. To reap the full benefits of trade and competition, with the associated plurality in contract forms, strict unbundling of generation, trading and supply from transmission and distribution activities is a prerequisite. Non-discriminatory access to the market (e.g. electricity exchanges) and grid services is of key importance. However, strict unbundling is no guarantee for a level playing field for decentralised generation in the internal market. Many barriers with respect to the physical interconnection of decentralised generation remain even in a strictly unbundled industry. Furthermore, grid use tariffs may also discriminate in favour of centralised generation. In addition, electricity markets have always been developed from a centralised perspective. Therefore these markets often do not take the specific characteristics of decentralised generation into account. The terms of market access and the design of the markets may thus put decentralised generation at a disadvantage compared to centralised generation. In other words, there is no level playing field between centralised and decentralised generation. Below a number of issues relating to market access and contracting possibilities for DG in liberalising electricity markets are elaborated in more detail.

2.3.1 Balancing and settlement systems

Balancing and settlement systems serve to maintain system balance and to provide a system for the settlement of the cost incurred in maintaining system balance. At the basis of a balancing and settlement system is the responsibility for certain actors in the electricity supply chain to balance their own or another party's supply and consumption. This is referred to as balance responsibility. Failure to meet this balance responsibility results in penalty payments. The level of these penalty payments may be determined through a balancing market in which short-term electricity supply and demand bid in order to restore system balance. Several countries have now instituted such a balancing market. Balancing markets and associated settlement systems are an important condition for the liberalisation of electricity markets as they provide the freedom for generators and consumers to select the party to whom they want to transfer their balance responsibility. The free transfer of balance responsibility is important for contract freedom as contracted power has to be balanced on both the supply and demand side. As liberalisation proceeds and the electricity market is further opened more and more generators and consumers are given balance responsibility.

The main problems with respect to the integration of DG into balancing and settlement systems is that intermittent RES (solar, wind) and heat driven CHP cannot always adjust their loads to

[21] Ofgem (2002) Distributed generation: price controls, incentives and connection charging. Further discussion, recommendations and future action.

match a pre-specified load pattern as stipulated in bilateral power contracts or as bid into the spot market a day ahead. This results in high penalty payments for these sources in the settlement process. These imbalance cost reduce the value of the electricity that is produced from these intermittent sources. This loss in value in turn needs to be compensated through support mechanisms or in the market for renewable energy.

Example: New Electricity Trading Arrangements in the UK

The problems above are particularly important in the UK under the New Electricity Trading Arrangements (NETA), and also in the Netherlands. The example of NETA will be used as an illustration. The scheme was introduced in early 2001. NETA is based on bilateral trading between generators, suppliers, traders and customers, and include long-term forward and futures markets, a short-term power exchange, a balancing mechanism to ensure system stability, and settlement rules. The balancing mechanisms and the settlement rules are incorporated in the Balancing and Settlement Code (BSC). Under the balancing mechanism, participants are asked to give estimates of their likely electricity production. If their real production is below the estimate, they have to buy additional electricity from the balancing mechanism. If they produce more, they spill their surplus into the grid. In both cases, they are penalised under the settlement rules, because the feed-in price they receive is very low, and the top-up price can be extremely high. In general, generators prefer to have a position of overproduction and spill electricity into the system, rather than having to buy expensive top-up electricity.

Under NETA, CHP producers that chose to contract ahead in bilateral markets participate in the balancing system. This has, however, often damaging effects, because their electricity output is designed to follow the heat load and therefore often not sufficiently predictable. In order not to be penalised, most CHP producers have chosen not to participate in the balancing system. The same problems have been reported from the Netherlands.

Decentralised CHP producers in particular could also join with other decentralised generators and aggregate their electricity output. The co-operation with specialised intermediate agents like green power traders, certificate traders or associations of intermittent producers could potentially provide relief from the need to participate actively in market schemes. This would imply additional costs but allow them to respond better to the balancing system. It has, however, been reported that there are not enough such services offered under NETA. This raises doubts whether aggregation is a commercially attractive and viable option in this case.

Most CHP producers in the UK have therefore chosen for a contract with suppliers to sell their output locally. This situation compares with the previous situation, before electricity market liberalisation. However, less local distributors seem to be willing to take the risk of having CHP generators in their production portfolio, because they see them as a risk factor in a system that heavily penalises imbalances.

The example of NETA shows that the design of electricity trading schemes and particularly the associated balancing and settlement systems can seriously reduce the commercial value of the electricity output from decentralised CHP, and thus the economic viability and survival of these schemes. It also shows that the effort to participate in any electricity market can constitute a high hurdle for decentralised CHP producers. These problems could explain why a report from the UK's electricity regulator OFGEM on the impact of NETA on small generators has shown that average output from small generators dropped by over 40% in the three months since NETA came in, up to 60% for CHP[22]. NETA therefore has seriously reduced decentralised electricity production in the UK.

[22] OFGEM (2001) Report to the DTI on the Review of the Initial Impact of NETA on Smaller Generators. Published on http://www.ofgem.gov.uk/docs2001/52_small_gens_review.pdf

EU legislation
The EU rules on balancing and ancillary services are not yet well developed. Although the Electricity Directive contains some rules about distribution system operation (Article 10-12), these are not very detailed at present and do not contain obligations on provision of ancillary services at the level of distribution (defined in the Directive as medium-voltage and low-voltage transport). Similarly, in the Renewables Directive, there are no explicit references to provision of ancillary or balancing services. In Section 2.5.1 a description is given of the current discussions at EU level on the operation of the balancing market, and the related proposed amendments to the Electricity Directive.

One response to the balancing problem for DG operators is to use the possibility of *priority dispatch* under the Electricity Directive and Renewables Directive, as described below. Under priority dispatch, renewable and CHP-based electricity may be exempt from their balancing responsibility. Effectively this means that other actors are required to assume balance responsibility on their behalf. Furthermore, eligible generators receive a price for the electricity they deliver to the grid. This price may be the market price, the avoided cost to the utility, or a higher premium price, while the power (including the respective payment obligation) is passed on to all power traders (in the form of an environmental Public Service Obligation) or to captive customers.

The Electricity Directive explicitly opens up the possibility for Member States to require (transmission and distribution) system operators, when dispatching generating installations, to give priority to generating installations using renewable energy sources or waste or producing combined heat and power in Articles 8(3) and 11(3). This is merely an option for Member States to consider, and its use would constitute an exception to the normal rule that the dispatching of generating installations should take place on the basis of criteria, which take into account the economic precedence of electricity.

The Renewables Directive goes further by requiring, in Article 7, transmission system operators to give priority dispatch to generating installations using renewable energy sources "insofar as the operation of the national electricity system permits". Furthermore, Member States *shall* take the necessary measures to ensure that TSOs and DSOs in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources, and they *may* also provide for priority access to the grid system for such electricity.

The proposed CHP Directive contains only the equivalent of the first sentence of Article 7(1) of the Renewables Directive: it would require that the Member States *shall* take the necessary measures to ensure that TSOs and DSOs in their territory guarantee the transmission and distribution of electricity produced from cogeneration. It appears that the proposed amendments to the Electricity Directive (as of June 2002) would not explicitly impose further prioritisation obligations.

Discussion of the instrument priority dispatch
As long as DG constitutes only a small fraction of electricity production, priority dispatch can be a useful instrument to shield DG from the effects of market mechanisms that have been tailored to centralised supply. However, as the share of DG increases so do the imbalances caused by these sources, and consequently the cost of these imbalances to the operation of the electricity system. Not allocating these costs to the sources that cause the imbalances will provide no incentive to intermittent generators to improve the controllability or predictability of their electricity supply. This is, however, needed in view of the longer-term development of the electricity system.

In Denmark approximately 15% of total electricity consumption is by now covered by wind-generated power production. However, wind power capacity is unevenly distributed at the two separate power supply systems in Denmark and therefore more than 20% of total power con-

sumption in the Western power area is supplied by wind power and only approximately 8% in the Eastern supply area. Now and then this causes economical and technical problems in the Western area. Economical problems are encountered when unexpectedly much wind power is supplied to the power system and the systems operator has to sell this 'excess' production at the Nordic power market to a low price. Through the Public Service Obligation this loss will have to be covered by all electricity consumers. Technical problems might occur when wind power generates an excess supply at a time when all available power transmission lines from Denmark are utilised to the limits for export and when conventional power plants already do operate at the lowest possible production. Presently the systems operators are analysing possible actions to be undertaken in this case to prevent the technical power system from becoming unstable or in a worst case to break down.

Another problem associated with priority dispatch is the valuation of the electricity. Most priority dispatch schemes are linked to feed-in tariffs. The basis for the feed-in tariff can be the avoided cost to the utility, a premium price based on the energy source, or some kind of proxy for the price of wholesale power. As becomes clear from these examples the valuation of the electricity from DG is not through the market. Thus, in two ways priority dispatch keeps DG out of the market of which it is ultimately to become part:

1. Exemption from balancing responsibilities.
2. Valuation of electricity from DG is not based on the market.

Thus in the medium-term, as the share of RES and CHP in the internal market increases,[23] electricity policy should be targeted towards integrating intermittent RES and CHP in the balancing and settlement system. More research as to how this may be done is needed. In the meantime the priority dispatch provision can be used to temporarily exempt intermittent sources from their balancing duties. In the medium term, however, the cost of this exemption to the rest of the system may rise to the level where a solution needs to be found to integrate intermittent RES in the balancing system.

Recommendations

To overcome the barriers to the contracting of DG and to minimise the cost of integration of DG in the electricity market, there are several measures that can be undertaken.

- In the short term, priority dispatch can be a feasible measure to reduce the cost of balancing and contracting to DG developers and operators. As stated in the Renewables Directive, Member States can ensure that TSOs and DSOs in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources, and they may also provide for priority access to the grid system for such electricity.

The EU R&D programmes should support research aiming at solving the balancing problem in the longer term:

- Research on technical solutions to imbalances: due to the intermittent nature of mainly wind real cost are incurred by the electricity system as a whole. These costs are not resolved through priority dispatch. In order to enable DG operators to limit imbalances research technical solutions to these imbalances (e.g. storage) is needed.
- Research on market solutions to balancing problems: As described before, in the short run priority dispatch may be a mechanism to shield DG from the effects of balancing and settlement systems which have not been geared up to integrate DG. However, as the share of RES and CHP in the generation mix increases so will the need to integrate these sources into balancing systems. More economic research should be directed at how intermittent renewables and CHP can be treated in balancing and settlement mechanisms.

[23] Given the indicative EU RES-E target of 22% and the unofficial CHP target of 18% respectively.

2.3.2 Transaction costs

Most DG projects are small-scale projects, developed and operated by small-scale actors. Due to the small scale of most DG projects transaction costs of participating in power markets and complying with the balancing and settlement system are often high. Whilst their core business often is not electricity generation, they would need to get acquainted with the trading system and rules, and spend additional resources in participating in the trading systems. In order to profit from the possibilities of the power market, transaction cost should be lowered and DG should be allowed to participate in the balancing market.

Most DG developers and operators in the case study pool are rather small actors compared to typical utility size actors. Combined with the fact that most projects are small scale by themselves as well, the transaction cost for contracting are relatively high compared to bulk power trading. The main conclusion that can be drawn from the case studies is thus that because of the small scale of the project and the RES operator transaction cost of contracting output per unit of power delivered are relatively high compared to centralised production.

Recommendations

Aggregation of DG output can reduce the transaction cost of contracting. Furthermore, aggregation can reduce the cost of imbalances in the balancing and settlement system, first of all because a designated party that assumes balancing responsibility for a whole portfolio of DG can afford to build up knowledge on the balancing system and actively participate in it. Second, imbalances may average out in the aggregation of loads and predictability of aggregated production may increase.

An additional problem in some countries is the lack of availability of momentary load and price data to DG operators. Because of this lack of information they are not able to respond to changing market and balancing situation on the system. It can be anticipated that in the short run it is not feasible to give every small actor access to all market and system data at low cost. For example, membership fees to power exchanges are still prohibitively high. Once again, aggregation of supply can provide a solution to this problem.

The structure of the power market should allow for this kind to aggregation to take place, for instance in the framework of power exchanges and balancing and settlement systems.

2.3.3 Gas liberalisation

In the context of contracting the DG installations fuel and production, the Gas Directive is of relevance as well. Article 18(2) of the Gas Directive requires Member States to designate all gas-fired power generators as eligible customers. However, gas consumption thresholds for CHP installations may be introduced which then prevent certain CHP installations' eligibility. Such a threshold would, if implemented[24], contribute to a market distortion between gas-fired power producers above and below the threshold. However, the proposed amendments to the Electricity Directive, reflecting the agreement at the Barcelona Summit on 15-16 March 2002, foresee that in the course of an accelerated market opening all non-domestic customers, including CHP operators, shall be eligible customers as of 1st January 2004 as the latest. Thus, the present distortion would, provided the amendment is adopted, disappear in a reasonable timeframe.

2.4 Financing

The starting point to the discussions on financing DG is the principle that in the long run, DG should be integrated into current electricity markets not through subsidies or support mecha-

[24] According to COGEN Europe, the Netherlands, France, Denmark and Spain have made use of this provision and have introduced threshold values.

nisms, but rather upon the recognition of the environmental and other values of DG and the internalisation of external costs.

Renewable energy and CHP technologies are often characterised by high capital requirements. This capital carries a cost in the form of dividend, interest and debt payments. The costs and financial feasibility of renewable power projects are therefore particularly sensitive to the financing conditions. The key to financing any project is the expected future cash flows. These cash flows principally depend on the contracting possibilities, support mechanisms, and market developments. In addition, the financial risk (certainty of the cash flows) and the technical risk of a project play an important role. The market structure and applicable regulatory regimes therefore directly and indirectly affect the financing conditions.

2.4.1 Financing issues, barriers and solutions

At the moment, many RES projects are economically viable only with support mechanisms. However, even with support mechanisms the profitability of RES projects is often rather low compared to alternative investment options. This reduces the attractiveness of financing RES projects. In addition, many RES projects are relatively small compared to other utility investments, which increases the transaction cost of financing. Many investors also perceive the political risk of RES projects as high. The small size of projects, the perceived risk, the low returns and the relative unfamiliarity of financiers with RES projects increase the cost of financing. A new and unique financing solution has to be found for every project. Financing therefore often relies on committed actors, which are not solely and primarily motivated by profit, but also by local and environmental concerns.

As in the case of decentralised RES, the profit margin of small CHP projects is comparatively small[25]. Furthermore, a key barrier to the financing of CHP projects is the risk due to the current energy market conditions: unpredictability, instability, unfavourable gas-electricity price ratio, and lack of integration of external environmental costs of energy production in the market prices for energy.

In this context, it must be mentioned that recently, (Awerbuch, 2000) and (Lovins et al, 2002) have argued that the attributes of DG technologies, especially their vulnerability to risks, are profoundly different from those of traditional centralised technologies. Therefore, this should be recognised explicitly in financial evaluations and comparisons. Adopting other, perhaps more appropriate techniques of financial analysis, i.e. a portfolio approach using risk-adjusted valuation procedures, may alter the comparison between traditional and innovative generation in favour of DG.

Some developers who used project financing had difficulties in providing loan security. Examples are found in the case studies on the Lumijoki wind plant (Finland), WISTA PV plant (Germany), Port Mort hydro plant (France), Harboøre biomass CHP and Boeschistobel landfill gas CHP. Lenders have strict and demanding requirements on income from projects that are often very difficult to meet, because of uncertain policy and market developments. This introduces a relative bias towards equity finance, which in turn becomes less attractive as profit and tax benefits are spread out over more equity, thus lowering the return. Stable market conditions can soften some of the loan conditions, increase the debt ratio, and thus lower overall financing cost. However, most case studies did not encounter any significant problems in financing. This was mainly due to feed-in tariffs, which provided long-term revenue security to the projects under consideration.

[25] Except for specific cases where there is a relatively cheap supply of fuel (waste), combined with a demand for both the electricity and the heat produced.

As elaborated in Section 2.1.2, financing often relies on committed actors, which are not solely and primarily motivated by profit, but also by local and environmental concerns. Local communities have in several countries proven to be a good source of equity. Financing schemes attractive to private investors have been successful both in Germany and Denmark (closed funds or co-operatives) supported by both the taxation system and motivation for green or neighbourhood investment. Involvement of local communities has the additional benefit of reducing local resistance during planning procedures as local actors are economically engaged in the project. Local involvement in financing renewables projects can be encouraged through a range of information activities. Regional energy agencies could play a role in this. With a view to reducing the transaction cost such regional energy agencies could also play a role in facilitating the financing through local actors.

EU legislation

EU legislation does not directly provide common rules on the financing of DG projects, although the EU Treaty rules on state aid are applicable to the various support mechanisms and other benefits to the extent they constitute state aid. As indicated above, most RES and CHP projects are dependent on support schemes for financing. In most Member States, support schemes seem to be subject to frequent changes. These changing market conditions can cause significant uncertainty about the future value of a project, and can complicate financing. The Renewables Directive provides a basis for the development of a harmonised framework for support schemes and the creation of a single market for RES. The Renewables Directive also establishes indicative targets for the penetration of RES for each Member State. To meet these targets, Member States are already adjusting their national renewable energy policies.

Harmonisation of the renewables support framework

Because policies are being revised, developed, accelerated or amended in view of the Renewables Directive, uncertainty arises about the shape of future policy frameworks in certain Member States. As described above, the policy conditions and support framework for renewables and the rest of the electricity market are fundamental to the risk and financing of RES projects. Currently, in many EU countries regulatory risk is one of the major complicating factors in financing. Not only can this potentially stop or delay projects, it also raises the cost of financing as increased risk needs to be compensated by increased returns. To minimise the cost of financing, financiers would benefit from stable long-term policy conditions.

In view of the current policy and market developments in the Member States it can be anticipated that the required regulatory certainty for low-cost project development is still far away. Through the international trading of RES, the policy conditions affect not only the value of renewable energy in their own countries but also in the other Member States. As the trading of RES across the EU is likely to increase, the effectiveness of policies will be more and more dependent on policies in other countries. Therefore, in the transition to a harmonised support framework and EU market for RES, regular adjustments to the national support mechanisms may be made to compensate for the effects of policy developments in other Member States. This could lead to prolonged fragmentation into national markets. Furthermore, it causes the value of RES to vary as policies adjust. This policy-induced uncertainty regarding the value of RES in the Member States complicates financing and increases the risk premium.

Investors in countries, which have a support framework that is not linked to the trading of RES or green certificates, such as feed-in systems, will perhaps be less exposed to this regulatory risk pertaining to policy interactions between Member States. Nevertheless, the effectiveness of such policies to reach their policy targets will be affected by EU-wide trade. Thus indirectly these countries are affected and they will need to respond to the international policy developments. The difference with trading based regimes is that the uncertainty of policy interactions may be not directly noticeable on the project level.

Harmonisation of the support framework and the creation of an EU market for RES can reduce this uncertainty, as a large market with sufficient liquidity will provide efficient incentives for investment. In a truly harmonised EU market there would be one equilibrium price for RES, which would provide the investment incentive for all EU countries. Moreover, in such an EU market forward markets can arise which provide a very clear financing benchmark of the future value of RES in the EU market. However, when Member States continue to pursue their own course a fragmented and uncertain market is likely to persist.

The Renewables Directive aims to provide a framework for the future harmonisation of RES support schemes in the EU. To provide a basis for harmonisation, the Directive stipulates that the Commission will present a report on the experience gained with the application and coexistence of different support schemes in the Member States (Art 4(2) and Art 8). This report is due in 2005. Based on the findings from the Commission, the report may be accompanied by a proposal for a Community framework for RES support schemes. The Directive also stipulates that such a proposal for a harmonised support framework should allow a transition period of at least 7 years in order to maintain investor confidence. Thus the process of harmonisation will only commence 3 years from now and will then take at least another 7 years to complete. In the first 3 years uncertainty is likely to persist because of development and amendments of national policies. In the following 7 years of transition uncertainty for new investments may be caused by the uncertain outcome of the harmonisation process. This uncertainty may be reduced somewhat by clearly indicating the targeted support framework at the beginning of the harmonisation process, and accelerating the process as much as possible.

For CHP, harmonisation of support schemes will also become increasingly important under the proposed CHP Directive. Similar to the Renewables Directive, the European Commission will provide for an evaluation of existing national CHP support schemes in the proposed CHP Directive. Member States will be requested to provide reports on the design and the success and shortcomings of national support mechanisms. Based on the findings, a decision could be taken on a Community framework for national CHP support schemes.

Recommendations

Following from the discussion above several recommendations for policy development or improvement can be derived to improve the conditions for financing CHP and RES projects:

- Involvement of local actors in financing, as described in Section 2.1.2. Local involvement in financing renewables projects can be encouraged through a range of information activities, in which regional energy agencies can play a key role. Regional energy agencies can be a facilitator to reduce transaction costs in many ways; through providing information about support schemes, bringing project developers, manufacturers, financiers and local communities in contact with each other. National or regional governments, but also industry organisations can play a role in setting up these agencies.
- Harmonisation of RES support framework and creation of a single market for RES. The continued changes in national support frameworks during the transition to a harmonised EU market for RES cause uncertainty with regard to the value of renewables. The creation of a single market for RES would provide clear short and longer-term price signals for investment in new RES across the EU. This argument calls for a quick harmonisation of EU support frameworks and RES markets, particularly for new plants. It is recognised that for existing plants the certainty provided by old support schemes is fundamental to their economics. Therefore, as the Renewables Directive indicates, a transition period is necessary during which these existing plants can continue to operate under the old support framework. To stimulate new capacity, however, the creation of a single market for RES is desirable. Although this can be achieved by harmonisation of support schemes, an important first step is the establishment of common rules for international trade in renewable electricity.

- This recommendation addresses both the Member State governments as well as the Commission. From the Member States it requires that they develop their policies taking into account the developments in other countries and that the co-ordinate their policy making with other countries. From the Commission it requires that it pays particular attention to the interaction of policy schemes in the reporting under the Renewables Directive, and that - where it can - it accelerates harmonisation.
- Standard financing concepts: For small actors, transaction costs could be decreased by standard financing concepts or contracts. National energy agencies could be assigned the task of developing such contracts in co-operation with the market actors and promoting them.
- The allocation of State aid for RES and CHP should continue only as long as current market distortions exist and external costs are not internalised. In the long run, when tradable CHP certificates these mechanisms, new taxes on energy products and CO_2 trading mechanisms are established, these mechanisms should be phased out.
- More people could benefit form existing national experiences with (innovative) financing concepts for CHP through exchange programmes and enhanced networking. In this respect, Community programmes and initiatives such as SAVE or ALTENER are a suitable tool to spread innovation and knowledge.

2.4.2 Support mechanisms

Within the EU Member States a broad variety of financial support mechanisms are in place or in preparation that are designed to improve the economics of a DG installation usually in order to account for the external environmental benefits. The form of these support schemes is usually differentiated between RES and CHP and further between different technologies and installation sizes. Support schemes can include price-oriented instruments like fixed feed-in tariffs, investment subsidies, production subsidies, fuel subsidies, soft loans, ecotax exemptions or other taxing/depreciation schemes, or quantity-oriented instruments like tender/fixed price systems or quota/green certificate systems. This is illustrated in Figure 2.2. It is beyond the scope of this report to discuss the various policy instruments for renewables and their relative merits and disadvantages more extensively.[26]

	Price	Quantity
Supply	Feed-in tariff / green prices (Germany, Austria, Spain, France, Greece, Portugal, Finland)	Tender (Ireland) Obligation for producers (Italy)
Demand	Price support of the demand (Netherlands)	Obligation [%] for consumers or suppliers (Denmark, UK, Sweden, Austria, (small hydro), Belgium)

Figure 2.2 *Classifying renewables support mechanisms*

Despite the success of feed-in tariffs in stimulating the development of RES projects in the case studies a few comments need to be made. In the short term, fixed feed-in tariffs give maximum investment security to RE developers. However, as the contribution from renewable sources to

[26] *See, e.g.,* Van Dijk et al,(2002).

the generation mix increases, the cost of a fixed feed-in tariff system could become too high in the longer term, and political support for the system will diminish. Thus the long-term investment security is low because of the inherent political instability of the system. Furthermore, utilities that are located in areas with a large potential of renewable energy sources will likely be offered more renewable electricity, and will therefore have to pay more premium tariffs. In a liberalised electricity market this puts these utilities at a competitive disadvantage relative to utilities in areas with low renewable energy potentials.

The limited success of CHP support schemes with regard to small-scale, decentralised CHP producers could be explained through high transaction efforts, complicated regulation and lack of long-term clarity on the support conditions prevent the satisfactory uptake of support schemes for decentralised CHP.

The decision to grant state aid to DG, and the design of the support schemes is essentially a responsibility of the Member States. The European Commission has already contributed its part by explicitly providing much scope for national support schemes for DG in its Community Guidelines for State Aid for Environmental Protection.

EU legislation

The current version of the 'Community guidelines on State aid for environmental protection' set out the main conditions under which Member States can grant firms aid in a variety of forms to promote environmental protection. The approach looks favourably upon aid for renewable energy sources and CHP. Member States can choose between several options for granting such aid up to certain thresholds.

Recommendations

When designing support mechanisms, Member States should take into account the specific needs of the actors developing and investing in DG, such as:

- Uncertainty of continued availability and amount of subsidies.
- Uncertainty of continued availability of soft loans.
- Small-sized developer/operator cannot make use of accelerated depreciation rules.
- High efforts to handle tax refunds.

Furthermore, procedures, eligibility and the term for support should be clear to investors from the outset of developing the project. This should provide more certainty for investors.

In view of the ongoing liberalisation and integration of EU electricity markets policies should increasingly focus on setting the market conditions in which CHP and RES can be developed, without or with less support. Under such conditions, much could be left to the interplay of market forces and by using tools such as CHP certificates, guarantees of origin for RES, or CO_2-trading schemes.

2.5 Operation

Article 7(6) of the Electricity Directive requires that, unless the transmission system is already independent from generation and distribution activities, the (transmission) system operator shall be independent at least in management terms from non-transmission activities. An amendment to the Electricity Directive to establish a similar rule applying to DSOs has been proposed by the European Commission, but does not currently exist. In order to recover the cost of network services, transmission and distribution system operators set tariffs for the use of the grid. In all EU Member States the grid use tariffs are regulated, except for Germany. The grid use fees and the procedures on how they are regulated may have a high impact on DG viability, particularly when a producer is not operating under a feed-in system and has to trade its electricity on the market. The structure and the level of the tariffs for decentralised generators determine the cost

of electricity from decentralised generation on the electricity market. Users of the electricity network may broadly pay for the following network services: grid use fees, ancillary services and back-up power.

It is anticipated that the importance of grid use fees for DG will increase with ongoing liberalisation and with the implementation of green certificate schemes. In green certificate schemes generators have to sell their electricity on the normal power market. Grid use tariffs may define the cost of trading on the electricity market, and therefore impact the value of DG electricity on this market.

All users of the grid pay for the provision of ancillary services by the TSO. These ancillary services include balancing power, and voltage and frequency control. DG can provide some of these ancillary services. However, in many cases there is no market through which DG can be remunerated for delivering these services. In the case where markets for ancillary services do exist DG often do not have access to them, such as in the case of balancing markets. Issues relating to balancing and settlement systems are more extensively discussed in Section 2.3.1.

Most projects in the case studies operate under a feed-in scheme; the power is sold under regulated tariffs to the grid operator so that active trading of the electricity as indicated above did not take place (case studies from Austria, Denmark, France, Germany, Italy, Portugal and Spain). Therefore, the issue of grid use tariffs, ancillary services and provisions with respect to back-up power requirements did not show up as a major concern in this research. Nevertheless, because of their potential discriminating effect, we look at the effects of grid use fees on DG in more detail below.

2.5.1 Grid use fees

In order to be able to establish business contacts, access to the grid, and transparent, and non-discriminating grid use fees are crucial. In all market segments, the market power used by incumbent utilities has been a continuing problem.

Excessively high network tariffs discourage third party access and electricity exports from DG operators, and form a barrier to competition because they could provide revenue for cross subsidy of affiliated businesses in the competitive market. Network tariffs and the related regulatory procedures have thus also a high impact on the viability of decentralised CHP projects.

In general, excessive tariffs for network use of decentralised electricity producers and third party users of the grid can be attributed to the following:

- The network operator may not deduct the avoided cost savings when billing network charges to decentralised producers, thus obtaining additional revenue at their cost.
- The network operator may charge the use of all voltage levels to electricity exports from decentralised generators. It can be questioned whether this is justifiable.
- The network operator may charge extremely high prices for back-up and top-up services.

Non-transparent cost calculation methods for network charges make it virtually impossible to smaller generators or any new entrants into the market to verify whether such charges have been calculated in a non-discriminatory way and reflect a fair account of the real costs that various users (both electricity consumers and producers) cause in the grid.

Decentralised generators have the potential to avoid costs of the system operator:

- First, in terms of network capacity, because decentralised autoproducers normally also consume part or all of their electricity production on-site. This avoids electricity imports through the transmission and distribution system, and thus investment into transport capacity. Moreover, electricity exports from DG producers stay within the low-voltage network, where they are consumed. This means, also the exported part of electricity avoids transport capacity at higher voltage levels of the system.
- Second, the reduced need for electricity imports from remote areas and passing through different voltage levels reduces transmission losses. In total, losses in the European transmission systems are normally in the magnitude of 1-2% of the total power transported. The relative additional losses of additional transports can however be much higher[27]. Transport losses on the low voltage grid may be about 2%, at medium voltage levels approximately 1%. Also, transformation across from the high voltage grid through a medium level to the low voltage network can imply losses of roughly 2%[28]. In Germany, transmission losses amounted to about 4.7% in the Western part of the country, and 9% in the East in 1995. In 1999, total transmission losses in the entire country were 5.5%. The Western level is considered to be close to the technically achievable optimum[29]. These losses have to be recovered by additional generation, which network operators usually have to buy from generating companies for this purpose, and thus have to deal with costs of losses. Decentralised generators, by preventing these losses, help the network operators avoid parts of these costs.

As regards the Member State level, for transmission, charges are generally made separately for export to the grid (producers) and for reception from the grid (consumers). Charges to exports to the grid are zero in most Member States, or represent a much lower proportion of total overall tariffs.

For transmission between most Member States there are international 'postage-stamp charges', see Table 2.2, meaning that there is no variation in transmission tariff by location. For Greece, Ireland, Italy, Sweden and the UK transmission charges vary by location, usually on a zonal basis, to provide incentives to generators to choose the correct locations. For distribution (within a country), there are generally postage-stamp charges with no separation of export and reception of electricity or locational signals, although for Italy there is a distance related component. For both transmission and distribution, Member States usually base their tariffs on a combination of capacity (€/KW/year) and flow (€/MWh) charges, although there are variations in the balance between these parameters. Transmission and distribution tariffs can be added together to produce a network charge for customers connected at different voltage levels[30].

[27] Haubrich, H.J.; Fritz, W. (1999) Study on Cross-Border Electricity Transmission Tariffs by order of the European Commission, DG XVII / C1. Final Report. (http://europa.eu.int/comm/energy/en/elec_single_market/florence/cbett_en.pdf).

[28] Deutscher Bundestag (1994) (Ed.) Mehr Zukunft für die Erde. Schlussbericht der Enquete-Kommission des 12. Deutschen Bundestages "Schutz der Erdatmosphäre. Bundesanzeiger Verlagsgesellschaft, Bonn.

[29] Press Information from VDEW (1997 and 2000) on http://www.vdew.de.

[30] Commission of the European Communities (2001) *First report on the implementation of the internal electricity and gas market*. Commission Staff Working Paper.

Table 2.2 *Transmission charges by Member State*

Country	TSO	Transmission Charges
Austria	Concession	
Belgium	Subsidiary of existing companies (ELIA)	
Denmark	West: Eltra East: Elkraft	Postage stamp
Finland	Fingrid	Postage stamp
France	An independent part of EDF. State owned	Postage stamp
Germany	Several	Postage stamp
Greece	Independent Body. 51% State owned	
Ireland	New state owned company	
Italy	Independent Body	Postage stamp with distance correction
Luxembourg		
Netherlands	TenneT	Postage stamp and point tariff
Portugal	REN	Postage stamp
Spain	REE	Postage stamp
Sweden	Svenska Kraftnät: 100% state owned	Nodal tariff with geographical difference
UK	National Grid Company; Scottish Power; Scottish & Southern Energy; Northern Ireland Electricity	Connection charges and zonal use-of-system charges

Tariffs for use of distribution networks for CHP electricity exports vary significantly between EU Member States. Prohibitive distribution network tariffs have been found in Belgium, which also does not apply any distinction between CHP plants of different sizes. In general, the criteria used for determining network charges for CHP electricity exports remain unclear, and in a number of countries this information is difficult to obtain[31]. For instance, four out of 10 German network operators simply refused to submit the basis of their price calculation to the German Cartel Office - entrusted to exercise regulatory functions in the energy sector - which wanted to investigate excessive network charging[32]. Under these circumstances, control of network operators is virtually impossible. Generally, unusually high network tariffs have been reported from Austria, Germany, Spain and Portugal. On the other hand, Denmark and the UK feature relatively low charges.

In Germany, grid use fees hardly play a role for DG operators due to the fixed feed-in tariffs combined with priority dispatch for RES fixed by law and the common feed-in agreements for DG. Since the introduction of the liberalised system in Germany, new power traders and retailers are complaining about high, discriminatory fees for grid use especially in distribution grids. However, this does not concern especially DG but rather generally the access to the power customers in competition to the local ex-monopoly utility. In addition, not all distribution grid operators have published general tariffs for use of the grid. This has led to several investigation cases led by the cartel authorities. As mentioned, DG is concerned only so far as specialised green power traders and retailers offering RES and CHP based power supply are concerned.

[31] Initial conclusions from research undertaken in the STAGAS project (SAVE), unpublished.
[32] National Economic Research Associates (2002) Global Energy Regulation N° 34, March 2002.

EU legislation

Article 16 of the existing Electricity Directive relates to 'access to the system'. Under the proposed amendments to the Electricity Directive, Article 16 would oblige the adoption of a system of regulated TPA based upon regulator-approved tariffs or methodologies. The proposed Article 16(1) is as follows:

> "Member States shall ensure the implementation of a system of third party access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users. Member States shall ensure that these tariffs, or the methodologies underlying their calculation, are approved prior to their entry into force by a national regulatory authority referred to in Article 22(1) and that these *tariffs* are published prior to their entry into force."

In other words, the approval would thus be given *ex ante*. This would provide more security and predictability to decentralised producers, who may lack the resources to enter into open dispute and legal action against the network operators on an *ex post* basis, i.e. after the connection has been made already.

The EU rules on balancing and ancillary services are less clear. Although the Electricity Directive contains some rules about distribution system operation (Article 10-12), these are not very detailed at present and do not contain obligations on provision of ancillary services at the level of distribution (defined in the Directive as medium-voltage and low-voltage transport).

Similarly, in the Renewables Directive, there are no explicit references to provision of ancillary or balancing services. However, fees charged for transmission and distribution services are referred to generally in Article 7(6), which provides:

> "Member States shall ensure that the charging of transmission and distribution fees does not discriminate against electricity from renewable energy sources, including in particular electricity from renewable energy sources produced in peripheral regions, such as island regions and regions of low population density."
>
> "Where appropriate, Member States shall put in place a legal framework or require transmission system operators and distribution system operators to ensure that fees charged for the transmission and distribution of electricity from plants using renewable energy sources reflect realisable cost benefits resulting from the plant's connection to the network. Such cost benefits could arise from the direct use of the low-voltage grid."

The European Commission has only recently begun to discuss publicly the operation of the balancing market in considering the implementation of the internal market in electricity and gas. In its first report on the subject in December 2001, it reviewed the three main approaches used by TSOs in the Member States for determining imbalance charges. In so doing, it referred to the special needs for back-up supply due to variations in the output of wind turbines.[33]

The discussion at EU level is reflected in the proposed amendments to the Electricity Directive (version of June 2002), which include new draft provisions relating to the provision of balancing services by DSOs. The obligation under the proposed Article 11(4) provides flexibility to the Member States because it is stated in a conditional sense:

[33] European Commission, First Report on the implementation of the internal electricity and gas market, 3 Dec 2001 (working paper), at 5.

> "Where distribution system operators are responsible for balancing the electricity distribution system, rules adopted by them for that purpose shall be objective, transparent and non-discriminatory, including rules for the charging of system users of their networks for energy imbalance. Terms and conditions, including rules and tariffs, for the provision of such services by distribution system operators shall be established in accordance with Article 22(2) in a non-discriminatory and cost-reflective way and shall be published."

The proposed Article 22(2) would ensure a role for the regulatory authority in such cases:

> "The national regulatory authorities shall at least be responsible for fixing, approving or proposing prior to their entry into force, the methodologies used to calculate or establish the terms and conditions for :
> a) connection and access to national networks, including transmission and distribution tariffs,
> b) the provision of balancing services."

However, in Member States where DSOs are not responsible for balancing, the obligation under Article 11(4) presumably would not apply. Likewise, in such countries, there would appear to be little impetus for adopting measures to implement Article 22(2) with respect to regulatory powers over the provision of balancing services by DSOs.

The proposed amendments to the Electricity Directive would not make changes to the definition of ancillary services (described above). The European Parliament made a proposed amendment to delete the definition of ancillary services[34], but the Commission rejected this[35]. The proposed amended Electricity Directive also does not provide a definition of 'balancing services'. Presumably, the Commission's discussion of the topic in the report of December 2001 is relevant, even for DSOs. In that paper, the Commission expressed concerns about the asymmetric prices for balancing energy "with very high top-up prices and low spill prices especially during individual balancing periods".[36]

However, the proposed amendments to the Electricity Directive would not extend to DSOs the existing rules on TSOs about "ensuring the availability of all necessary ancillary services"(Art. 7(3)). The proposal also would not impose explicit general duties on DSOs to provide terms and conditions explicitly on the provision of back-up, top-up or standby power.

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[34] The European Parliament adopted the following texts on its sitting of 13 March 2002 concerning the Commission's Amendment proposal of March 2001:
P5_TAPROV(2002)0106 Internal market in electricity and natural gas.
P5_TAPROV(2002)0107 Cross-border exchanges in electricity.

[35] COM(2002) 304 final - 2001/0077 (COD) - Amended proposal for a Directive of the European Parliament and of the Council amending Directives 96/92/EC and 98/30/EC concerning rules for the internal markets in electricity and natural gas, 7.6.2002.

[36] Ibid. at 5.

In contrast, the proposed CHP Directive does contain an obligation relating to 'back-up or top-up supply' which is not mentioned in the Renewables Directive, but which is arguably an important service for promotion of both CHP and RES. The proposed Article 8(6) provides:

> "Unless the cogeneration producer is an eligible customer under national legislation in the sense of [the Electricity Directive], Member States shall take the necessary measures to ensure that the tariffs for purchase of electricity to back-up or top-up electricity generation are set on the basis of published terms and conditions. Such tariffs and terms and conditions shall be fixed or approved in accordance with objective, transparent and non-discriminatory criteria by an independent regulatory authority prior to their entry into force."

This proposed formulation of the concept is weakened by the opening clause. In the amended proposals to amend the Electricity Directive, the definition of non-household customers includes producers.[37] The proposal is that Member States should ensure that all non-household customers should be eligible customers from 1 January 2004. The clear implication is that the obligation of Article 8(6) of the CHP Directive would not apply in countries that have transposed the customer eligibility requirements as proposed in the amended draft Electricity Directive. In other words, if the amendments to the Electricity Directive were adopted and implemented in a given Member State, CHP producers in that Member State would not be entitled to benefit under this (conditional) rule in the CHP Directive after January 2004.

In addition to new rules on network access and balancing services, the proposed amendments to the Electricity Directive would require the application of new minimum criteria. These criteria are designed to ensure the independence of DSOs in cases where they are not fully independent in terms of ownership from other activities (proposed Article 10). However, the proposal also makes clear that a combined TSO/DSO is acceptable, provided that it meets all of the minimum criteria (see Article 12a).

Recommendations

The following general principles can be formulated to remove the barrier imposed by excessive grid use fees for DG:

- Stricter separation of generation, trade and supply from transmission and distribution activities (unbundling).
- Grid use fees should be transparent.
- Regulation should take into account the full benefits and cost of decentralised generation for network operation, considering the impact on ancillary services, decongestion, back-up power requirements, etc.
- Tariffs should provide a level playing field between centralised and decentralised generation so that both can compete in the electricity market on fair terms.

These principles are operationalised in the proposed amendments to the Electricity Directive, which are expected to tackle the main underlying problems and will provide national governments with the possibility to prevent excessive, non-transparent and discriminatory grid use fees imposed on DG producers.

For renewable electricity, this is also covered by the Renewables Directive in Article 7(6), which prohibits discriminatory transmission and distribution fees. For CHP, this could alternatively be achieved through the proposed CHP Directive.

[37] A 'non-household customer' is defined in the proposal to amend the Electricity Directive as "any natural or legal person purchasing electricity which is not for its own household use and shall include producers and wholesale customers".

However, given the reluctance of some Member States to exercise their control functions, and the seemingly strong resistance of some grid operators against transparency of prices and price calculation methods, stronger mechanisms could be necessary to protect DG producers against abusive grid use tariffs. For instance, annexes to the amended Electricity Directive could specify the requirements for the calculation and publication of grid use tariffs and their approval through electricity regulators in more detail. These could set out a minimum catalogue of items and information that communications on grid use tariffs need to contain.

2.5.2 Ratio of gas and electricity prices for CHP

The economies of CHP projects are characterised by a high initial investment, the depreciation of which depends heavily on the following factors:

- fuel price,
- electricity price,
- price for top-up and back-up electricity,
- yearly hours of operation,
- efficiency of the scheme,
- support schemes and other additional incentives.

Many private sector companies try to reduce their financial risks to the largest extent possible and accept payback periods of not more than 2-3 years. Public authorities and private individuals have a higher tolerance in this respect and are more willing to accept reduced profitability.

During the last two years, soaring gas prices and sharp drops in electricity prices have had a negative impact on the depreciation of many CHP installations. These price developments were on the one hand a result of uneven liberalisation of gas and electricity markets. Fierce competition in the electricity sector, together with existing production over-capacities in some countries, turned out into extremely low electricity prices. At the same time, far less competition and market opening in the gas sector, and the continued link between the oil and gas prices, caused the latter to climb significantly. The effect of this combination - reduced profitability of decentralised CHP plants - was most noticeable in countries such as Netherlands, Germany, or Spain, where the bad gas-electricity price ratio generated a stalemate in the development of new projects.

The changing ratio between natural gas and electricity prices in the last years has therefore made operation of natural gas fired CHP hardly feasible. This appears to be the major barrier for CHP development presently, and has led already to the decommissioning of CHP plants. The CHP plants studied in the case studies were either developed way before the present increase of the ratio between gas and electricity prices (and are already written off) (e.g. Alkmaar CHP (Netherlands), Ronse CHP (Belgium)) or operate in a specialised high price niche (Pozoblanco CHP, Spain) or are operated with very little or no expectation of pay-back to the investor (Bocholt fuel cell (Germany), Schonungen CHP (Germany), St.Pancras CHP (UK)).

Community and national policies and experiences
The effects of energy market liberalisation and the lack of internalisation of external costs generally figure among the most commonly cited problems for CHP. A study[38] evaluating the impact of the liberalisation of the electricity market on the CHP and district heating and cooling sector has made analyses of the economic viability of CHP in the internal electricity market. The study states that electricity markets in Europe currently are made up of a complex structure of new and depreciated power production. These markets are characterised by low power prices as a consequence of price competition often at short-term marginal production costs in saturated markets. Therefore, many CHP plants built under different political and economic framework conditions have come under pressure. Likewise, the economic interest in establishing new CHP capacity has diminished.

The opening of gas markets to competition is also important for the economics of CHP due to the widespread use of natural gas in CHP plants. Market opening should in principle in the longer-term lead to lower gas prices and therefore be beneficial also for CHP plants. So far, no significant price cuts in gas prices for CHP can be identified. On the contrary, some CHP plants have during the past year experienced higher gas prices which are still being linked to the oil price. Restructuring the gas market trough unbundling, transparent price setting etc. will increase competition and weaken this linkage to the oil price.

Recommendations
Community measures to correct the imbalance in the gas-electricity price ratio could tackle the problem from both ends. With regard to the electricity price, it should better reflect the external costs, notably environmental costs, in the future. New efficient gas fired CHP technologies, in principle, should be competitive to new efficient condensing power plants. However, if the electricity prices do not reflect real costs (including internalisation of external costs), only large gas fired CHP plants are feasible. Internalisation of external costs would make a larger number of CHP plants economically viable than is the case to date. The proposed Directive on a new taxation scheme of energy products (see A.4) would be a crucial step in this regard, as it would lead to a harmonised solution across the Community, and could be of-set by reducing statutory charges on labour. The full external (environmental and other) costs of electricity production, such as determined through the ExternE project[39], should be taken into account when fixing the new tax levels.

A second economic mechanism to internalise environmental costs into the electricity price is the envisaged European CO_2 trading scheme. The pilot phase of the scheme (2005-07) will affect decentralised CHP production (only the upper range of CHP plants included into DECENT because small scale is excluded from the scheme), and certain activities in the refinery, ferrous metal, mineral, pulp and paper industry. In order to make decentralised CHP eligible under this trading scheme, two conditions would need to be set:

- Firstly, the discriminatory treatment of CHP according to the suggested provisions of the Emissions Trading Directive (see chapter A.5) needs to be removed. The approach and wording of the Directive needs to be redesigned such a way that the CO_2 savings achieved by new CHP installations are rewarded, and the increased on-site fuel consumption through CHP is not penalised.
- Secondly, after the pilot phase, the trading scheme should be expanded to include also smaller CHP units wishing to participate in the scheme.

[38] "Evaluation of the impact of the European electricity market on the CHP, district heating and cooling sector", Cowi Consulting Engineers and Planners et. al., SAVE programme, 2000.
[39] http://externe.jrc.es/. The ExternE project is the first comprehensive attempt to use a consistent 'bottom-up' methodology to evaluate the external costs associated with a range of different fuel cycles. The European Commission launched the project in collaboration with the US Department of Energy in 1991.

With regard to the gas price, the current status of liberalisation of the gas markets is largely insufficient. The Commission's proposal for further liberalisation of this market is an appropriate measure supposed to bring about important price drops in the medium term. The Commission should also support efforts to de-link the gas price on the world markets from the oil price.

2.5.3 Biomass fuel supply

The use of biomass for power/heat production has a very large potential in the EU Member States. However, severe problems to be overcome in development and operation are posed in securing fuel availability and organising (and financing) fuel logistics. Biomass plants that use 'fresh' biomass residues as fuel have to cope with high fuel costs. The uncertainty of the fuel market development is a major impediment for the development of solid biomass plants in Germany.

In all biomass case studies, fuel supply plays an important role. For the Mortágua biomass project (Portugal), fuel logistics are a major problem due to a lack of involvement of local authorities in the planning of the plant. These local actors were expected to contribute to the fuel supply of the plant, but as a result of poor information, they tended to ignore the plant. For the Silbitz biomass plant in Germany the price of biomass fuel determines the financial viability of the project. Its economics are based on the current situation that clean wood residues (for which the plants are licensed) will be available at low price levels, i.e. a negative price (premium) or a small positive price.

Recommendations
Involve forestrial/agricultural actors for biomass supply. The Tyrol biogas case study (Austria) shows, how early involvement of the local agricultural association contributed to the project's success.

2.6 Barriers and success factors not specific to a particular stage

2.6.1 Local or regional benefits of decentralised generation

A number of local and regional benefits can be related to the use of decentralised generation of power. In many cases these local/regional benefits are not accounted for in the economic calculations of the DG-plants, mostly because they might be difficult to evaluate in concrete terms. But if these benefits are monetarised they could turn out to be the crucial part making some DG-projects economically viable. In the following some of these local/regional benefits are mentioned.

Generation of local welfare and employment
Many decentralised plants are established in (remote) rural areas, often characterised by a weak regional and economic development. Thus biomass and biogas plants could generate additional income and employment to farmers in these areas, as could be the case for wind farms as well if owned by local farmers. In the case of wind energy, some parts of the turbine are often manufactured locally. Thus decentralised generation might substitute other social and economic measures for increasing local welfare.

Distributed generation
As shown by a number of studies (e.g. the EU-project REVALUE[40]), the establishment of decentralised plants might lower transmission losses because in many cases a large part of the decentralised generated power is used within a close distance from the place of generation. Other

[40] Mitchell, C et al. The value of renewable energy (REVALUE2). EU research project JOR3-CT98-0210, February 2001, http://users.wbs.warwick.ac.uk/cmur/publications/revalue.htm.

advantages might accrue as well e.g. less need for reinforcing the grid at weak points in rural areas.

A 'green' profile
A positive image is often related to the use of environmentally friendly decentralised generated power, which may be especially important for companies with a 'green' profile.

This is often the case for photovoltaic installations (PV), which would usually be uneconomic if only calculated as an electricity generator. If PV (or other DG) becomes part of a company's PR strategy, the systems border is widened and the installations might turn out to be economic viable. This process can be seen e.g. for the PV strategies of retail companies and service station operators in Europe. Similar examples can be found if PV is integrated into buildings and the modules take over a building's function, like roofing or facade.

Environmental benefits
Strategies for developing DG are often seen as part of greenhouse gas reduction strategies, thus normally the value of CO_2-substitution is taken into account. But this might not be the case for other local/regional environmental benefits, as reduction of SO_2 and NO_x.

Recommendations
If local/regional benefits are taken into account these might turn otherwise not economical DG-projects into economic viable ones. Factors as local welfare generation, benefits for the power system of decentralised generation, local/regional environmental benefits and positive PR for companies and individuals of utilising 'green' technologies are important to address and evaluate specifically in DG projects, thus widening the scope and system borders of decentralised technologies.

2.6.2 Uncertainty on policy development

Uncertainty on policy development is one of the key barriers for the development of DG projects. It is mainly caused by the current transitional phase of electricity and gas market liberalisation across the EU, entailing comprehensive legislative reforms at the national level, but also independently from EU influences by short-term, disruptive national policy design. For renewables, the adoption of the Renewables Directive has started a transition towards a harmonised market and support framework for RES. Although this is expected to provide investor security in the medium term, the case studies revealed that at the moment, there is much uncertainty on the development of national and EU-wide support schemes.

Uncertainty makes it impossible to assess the costs and benefits associated with the development and operation of a DG project, and therefore to evaluate the risks and calculate the payback period for the initial investment. DG projects in general are characterised by a high initial investment. Finance providers for DG projects therefore require a high certainty about their economic prospect. For instance, whilst the Dutch government CHP policy covers only a period of 3 years, finance providers have to do economic project appraisals for a 10-year period. This situation appears to be generally more detrimental to smaller DG operators with less financial reserves to withstand temporary market turbulence.

Renewables
Each Member State has specific conditions for the development of RES. Where some countries have ample of wind resources, others may have more biomass, and where the one country has a large potential for RES, the other may have only a very limited potential. Moreover, the technological and institutional infrastructure vary per Member State. As a consequence different Member States employ a different portfolio of support schemes in order to promote the use of RES. Whereas to date these portfolios are mostly aimed at developing the national RES poten-

tial with the aim of reaching national RES targets, the liberalisation of the EU electricity markets and the Renewables Directive now provide the possibility to reach national targets through European trade of renewable electricity. The trading of renewable electricity across the EU exploits the benefits of varying local circumstances by first using the least expensive options available in the EU. An assessment of the benefits from a harmonised EU RES trading scheme has been made in the REBUS project (Voogt et al, 2001), which demonstrated that significant cost savings can be achieved through trading. At the same time a harmonised market would provide clear short- and long-term price signals to investors to establish new plants.

However, in absence of a harmonised trading framework, and given the differences in support schemes between Member States, the value of RES varies per country according to the support mechanisms that are in place. Due to the trading these differences in the value of renewable electricity affect the effectiveness of support mechanisms in the different Member States. This may cause policy makers to constantly adapt the national support frameworks in view of developments in the other Member States, which causes policy uncertainty. Of course such uncertainty predominantly plays a role in the transition to a harmonised market and support framework for RES. In a completely harmonised market the price signal should be the same in each country. Thus while the transition period allowed for in the Renewables Directive was meant to provide enough certainty to provide investors confidence in the transition to a harmonised market, the effect may be limited. Due to the prolonged transition, adaptations in the national support policies are likely to continue which leads to uncertainty, particularly for new projects.

Although most of the case studies in this research were operating under a guaranteed feed-in scheme, in several other cases it was indicated that the uncertain policy framework conditions were indeed a major barrier in developing the project. Both the Lumijoki offshore wind turbine and Magliano Hydropower (Italy) had to deal with uncertainty regarding the revenues, respectively the amount of subsidies and the duration of the Power Purchase Agreement. For the Lastour wind farm (France) an incomplete legal framework (at that time) caused the uncertainty. Similar problems occur now for offshore wind because of its recent market introduction, for instance the Middelgrunden offshore wind farm in Denmark.

On the other hand, studied cases in Spain and Germany in general were reported not to suffer from uncertainty because of the long time horizon of the German Renewables Act and the Spanish decree on renewables. Also, for the fuel cell in a hospital in Bocholt, the high uncertainty of state support mechanisms was offset by utilities' subsidies and producer's export subsidy.

CHP

Only the following categories of decentralised CHP projects - which are rather the exception than the rule - will normally have a chance to be built when the long-term costs and returns are uncertain. It is no surprise that the case studies in DECENT belong to these categories.

- Very profitable schemes with a short payback-period which can, for instance when the scheme is operating 6000 or more hours per year or under a favourable gas-electricity price ratio.
- Schemes that for other reasons do not rely on a secure and short payback. These include CHP units built and operated by non-profit making actors such as private households or public authorities (Hospital in Ronse (B), dwelling in Unterfranken (D), St Pancras Housing in London, hospital in Alkmaar (NL)), and national pilot projects or RTD actions, etc. (Diary industry in Pozoblanco (E), hospital in Ronse (B)).

EU legislation

As regards policies at the Community level, a great deal of regulatory and economic uncertainty has been caused by initiating the process of liberalising the electricity and gas markets through the Electricity and Gas Directives. This situation will probably continue for at least some years, as the Directives are still being implemented in several countries. Also, the Commission presses ahead with its proposals on completing the internal energy market, suggesting that the current

degree of liberalisation is limited and that a more complete opening of the markets could be achieved in less time. Uncertainty on policy developments forms intrinsically part of this process, because the relevant Directives need to be transposed into national law, leaving scope for national deviations and delays.

Apart from the liberalisation of European energy markets, other Community policies relevant to decentralised generation are very new. Most policy papers, legal proposals and final legislation on climate protection, CHP, renewable energies, energy efficiency or state aid for environmental protection are from 2000 or 2001. Extended periods of uncertainty about policy developments and support frameworks for DG can therefore be expected also in these policy areas, simply as a result of their novelty and the national implementation processes which some of them will require.

It needs to be kept in mind, however, that the outreach of Community legislation and policies is limited. National policies and administrative practices are essential for preventing or neutralising much of the uncertainty-related blockages to the development of DG projects. In this respect, the currently revised EU state aid guidelines explicitly allow a broad variety of national support schemes to help the sector bridge these difficult times.

Recommendations

There are several mechanisms to reduce the perception of uncertainty of DG project investors/developers to a level where they would be more likely to make decisions in favour of the project.

Principally, the source of the uncertainty could be removed. A swift process of policy development and implementation reduces the period of transition associated with any process of political change. The sooner the situation returns back to normal routines, i.e. to more reliable and well-known the conditions, the better are the chances that DG projects could be developed. With regard to the Community level, is thus important that Community policies deemed to have an impact on DG are devised and implemented as fast a possible. This also accounts for policies having a negative impact as this accelerates obtaining certainty. This means, the second stage of the liberalisation of energy markets, the proposed CHP Directive, and other relevant pieces of EU legislation should not suffer any unnecessary delays.

More stability could equally be achieved through the introduction of time frames for EU policy provisions, similar to the Community Guidelines on State aid for environmental protection-where it clearly says these will be in force until 2007. For CHP, provisions on a mandatory minimum duration of specific regimes, such as state aid programmes to support CHP, could still be stipulated in the envisaged CHP Directive. For the Renewables Directive, this could be included in the reports.

Recognising that the economics of many projects is dependent on the policy conditions under which they were set up, a transition period is warranted during which these policy conditions may remain intact for certain existing plants. However, as indicated in the section on financing, the stimulation of new RES plants would benefit from reduced uncertainty through a swift harmonisation of the EU renewable electricity markets.

Yet, in the long run it will be necessary to shape electricity, gas and heat markets to promote DG under market conditions. Examples of market-conform mechanisms include CO_2-emission trading and Green and /or CHP certificates. These create added value to renewable electricity or CHP by internalising their external environmental benefits. Especially combined with mandatory national targets and annual timetables for DG Development until 2010 (the year when the Community's 18% CHP target and 22% renewable electricity target are to be achieved) and beyond, such a system could achieve relative predictable conditions under (uncertain) market conditions and set the basis for coherent, measurable national policies to develop DG. For CHP, it

could be set up through provisions in the proposed CHP Directive. Yet, the need for such measures at the Community level would need to be balanced against the desirability of subsidiarity.

2.6.3 Market power of utilities

As described earlier, DG operators can be, and often are, exposed to market power exercised by incumbent utilities e.g. during the project phases connection to the grid, contracting, and operation. Here, incumbent utilities, usually grid operators integrated with generation and retail departments, can use their position to distort the markets and treat new generation or retail competitors in a discriminatory way. The newcomers' position is further weakened when they are small IPPs, lacking the resources and standing to risk a legal dispute.

EU legislation

In order to avoid misuse of the established position of integrated utilities the Electricity Directive requires unbundling of accounts for generation, transmission, distribution and non-electricity activities of integrated electricity undertakings (Article 14). In addition, TSOs are subject to limited obligations on unbundling of management. Article 7(6) requires that, unless the transmission system is already independent from generation and distribution activities, the (transmission) system operator shall be independent at least in management terms from non-transmission activities. As mentioned above, a similar rule does not presently exist in the Electricity Directive with respect to DSOs, but this has been included in the amended proposal to amend the Electricity Directive (see the proposed Article 10(2)). As mentioned above, the case studies show that DG projects are often seen by incumbent integrated distribution utilities as an unwelcome competition in the generation (and sometimes retail) sectors. Therefore they are exposed to prohibiting business practices in during grid connection, grid use, and contracting.

Stricter unbundling rules, such as those presently proposed, is therefore likely to be a step ahead in the direction of reducing unfair market power of established integrated utilities against DG projects. However, it remains in doubt whether legal unbundling will be sufficient to lead to a factual non-discriminatory behaviour of the distribution companies.

2.6.4 Specific difficulties of small Independent Power Producers

A high share of DG developers/operators consists of relatively small independent power producers and not based on nor affiliated with established electricity undertakings. Developers and investors often act with a high level of (environmental) commitment are ready to accept profitability conditions lower than conventionally calculating large businesses. They may also be prepared to accept a higher risk because they still need to establish a market position.

The characteristics of who the DG developers and operators are, is differing considerably between Member States, determining factors seeming to be historical development of DG, profitability of DG, and political backing, and, based on the previous factors, utilities' attitudes towards DG. It is presumed that DG will remain to a relatively high extent a business of 'non-economically' behaving actors as long as the short-term profitability of DG will improve considerably.

Specific difficulties do materialise during permitting, grid connection, contracting, and operation, depending on how clear, transparent and calculable the respective regulations are and how fair the market partners behave.

2.6.5 Lack of the skills required to plan and install a CHP plant

The realisation of CHP projects comprises of a number of phases and requires in many cases the development of tailored solutions. Except for packaged, 'plug and play' type CHP units, for in-

stance small engines for domestic use which are readily available on the market, many schemes will combine different individual components according to the specific requirements. The installation of a CHP unit includes feasibility studies, evaluation of different variants, correct sizing of the unit, purchase of components, installation, connection to the electricity network, connection to the gas network (if the unit is gas-fuelled), connection to the local heat network, contractual matters with electricity and gas companies, maintenance, etc.

The swift realisation of a good quality project therefore requires expert knowledge, which - as the case studies in Ronse (B), St. Pancras (UK) show - is sometimes lacking. There is no doubt that these projects would never have been realised without the high personal commitment of individuals, who were ready to acquire the knowledge to realise the projects. In the case of Ronse it was largely individual commitment that initiated the knowledge transfer from the Netherlands to Belgium necessary to realise the project. Likewise, the availability of specialists from the SenerTec Service Centre in Schonungen (D) can explain much of the smooth installation and the success of this project.

At the Community level, various activities and programmes exist to enhance the European dimension of training and education, such as the Leonardo Da Vinci and Socrates research programmes, and the activities of the CEDEFOP, the European Centre for the Development of Vocational Training. Despite these efforts to support and link national training schemes at the Community level, these are not sufficiently connected with regard to CHP. There appears to be no common European knowledge basis for CHP, and transfer of skills and know-how is insufficient.

The international project 'Educogen' started from the assumption that the development of cogeneration in Europe requires the availability of a sufficiently large body of skilled professionals. The project aimed to address the European education landscape on CHP and help train the next generation of European engineers and technicians on CHP through a complete educational package on energy efficiency and decentralised power production. Educogen was supported under the SAVE II programme, and created a European educational tool on cogeneration, including some of the most innovative technologies, which has proven very popular[41].

Recommendations

The probably most important incentive to develop a sound knowledge and skill base for installing CHP schemes are strong national policies stimulating growth in this sector. A high demand for the installation of good quality by CHP schemes will open new market opportunities. Market actors will seek to acquire the necessary skills and know-how to be successful in this market. For instance, the Educogen project indicates that Denmark and the Netherlands managed to achieve significant growth in CHP through decisive national policies, without more or better CHP engineering courses being offered in their schools than in France or Belgium. Education and training on CHP are thus a result of, rather than a precondition for, the promotion of CHP through national policies.

In this regard, any Community policy promoting CHP will also promote the development of skills to plan and install CHP plants. An important precondition for the acquisition of better-quality skills is that only CHP plants that meet stringent quality criteria are promoted.

[41] http://www.cogen.org/projects/educogen.htm.

3. SECURITY OF SUPPLY IN RELATION TO THE DEPLOYMENT OF DECENTRALISED ENERGY TECHNOLOGIES

In this chapter the importance of security of supply in relation to the deployment of decentralised energy technologies will be discussed. The reason for this is that security of supply is an important driver for EU energy policy and thus may influence the playing field for DG in the medium to long term. In addition, a highly reliable supply of power can be a niche market for DG technologies such as fuel cells in the short term.

3.1 Introduction

Back in the late 70's and early 80's security of supply was an important issue to address. But in the subsequent period of 15 to 20 years, interest in security of supply appears to have diminished, mainly because environmental issues gained prominence. But recently, the issues of security of supply have attracted attention again. This was especially a result of the publication in 2000 of the EU Commission's Green Paper 'Towards a European strategy for the security of energy supply'[42] and its subsequent proposals in September 2002 for Directives on safeguarding of security of natural gas supply and on alignment of measures on security of supply for petroleum products.

Security of supply will be addressed mainly in relation to two aspects:

- The dependence of the energy supply on imported fuels.
- The availability of the required energy production capacity, especially seen in relation to possibilities and threats at the liberalised power market.

In the next two sections these two above-mentioned issues will be addressed in general. Following that the pro and cons of decentralised generation will be discussed in relation to security of supply.

3.2 The dependence of the energy supply on imported fuels

At present the energy demand in the EU is covered by 41% oil, 22% gas, 16% coal, 15% nuclear energy and 6% renewables. If a business as usual scenario is envisaged in 2030 the energy picture will be dominated by fossil fuels: 38% oil, 29% gas, 19% solid fuels, 8% renewables and 6% nuclear energy.

The business as usual scenario of the EU final energy consumption until 2030 is shown in Figure 3.1, below.

[42] COM(2000) 769.

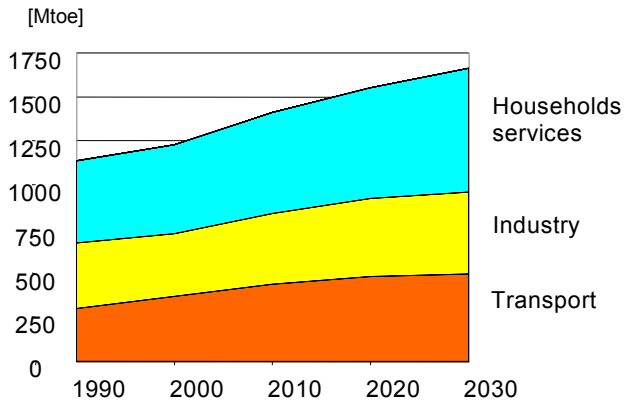

Figure 3.1 *Business as usual scenario for final energy consumption in the EU-30 until 2030 (Source: Green Paper on Security of Supply)*

The expected increase in the business as usual scenario is a little more than 1% p.a. The business as usual development in the EU energy supply is shown in Figure 3.2.

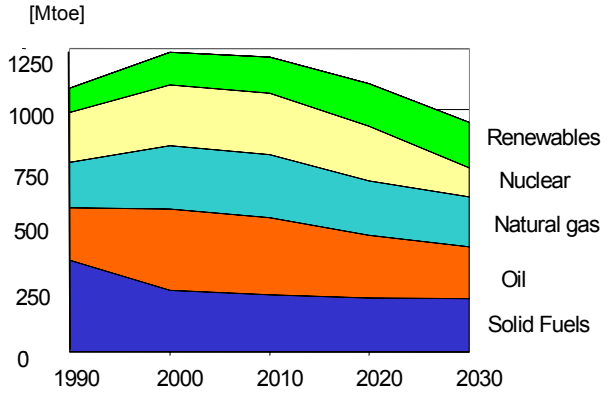

Figure 3.2 *Business as usual scenario for energy supply originating from within the EU-30 until 2030 (Source: Green Paper on Security of Supply)*

As shown in Figure 3.2 the supply of EU energy resources will have its peak in 2000-2010 and then it will gradually decline to 2030 to a level lower than in 1990. The total picture for the EU dependence on energy resources from abroad is shown in Figure 3.3, below.

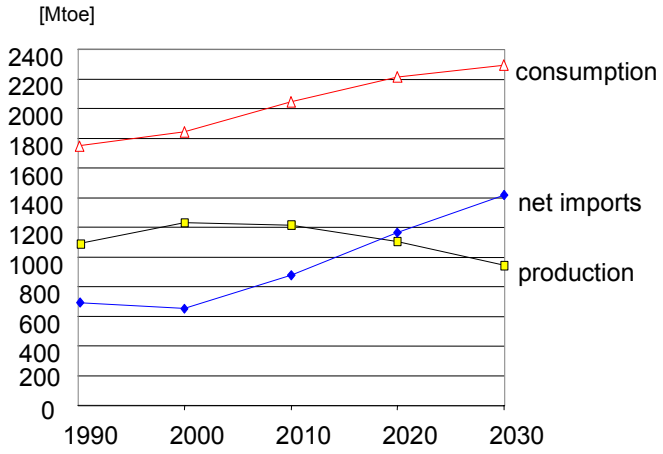

Figure 3.3 *The EU-30 dependence on imported energy resources (Source: Green Paper on Security of Supply)*

Referring to Figure 3.3 net imports of fuels in the business as usual scenario will gradually increase to approx. 60% of final energy consumption in the EU. In 2000 approx. 35% of total EU energy consumption was imported, thus the expected reliance on resources from abroad will be significantly higher in 2030.

To lower this dependence on energy resources from outside the EU, the green paper has outlined some of the elements of a long-term energy strategy:

- Because the possibilities of increasing the energy supply from EU sources are limited the focus will primarily be on demand policies.
- With regard to energy demand, the Green Paper is highlighting changes in consumer behaviour, especially through the use of taxation instruments.
- With regard to energy supply, especially utilisation of new and renewable energy sources are highlighted.

Thus although decentralised technologies and especially renewables have an important role to play with regard to diversifying the energy supply, in general changes in energy supply is not expected to be significant in improving security of supply. This might partly be explained by the narrow definition of security of supply adopted[43], where mostly the dependence of imported fuels are included, while more subtle characteristics of decentralised generation are not taken into account.

In this chapter the use of decentralised generation technologies, including those based on renewable energy sources, will be evaluated with regard to their significance for the EU security of supply, not only related to the dependence on imported fuels but also addressing the value of decentralised generation in the power system in a wider context.

3.3 The availability of the required energy production capacity

One thing is that the required fuels are available from indigenous sources in the EU. This does not necessarily imply that the required energy production is available when and where it is needed. This can be caused by two reasons:

- Due to a fluctuating inlet of energy sources (e.g. lack of wind, solar or precipitation) the needed energy production is not available.
- Due to lack of investment in new technologies the required production capacity is not available.

This problem is not treated in the EU Green Paper, but is an important issue especially in relation to the development of the power markets. Liberalisation of the electricity markets has been going on for some time now. A considerable number of European countries already have liberalised or are in the transition phase of liberalising their electricity generating industry, and electricity exchanges are being developed to facilitate liberalised electricity trade.

In the Northern part of Europe the Nordic countries together have established the NordPool power exchange, consisting of Norway, Finland, Sweden and Denmark. Although peaks and troughs in price-determination have been observed, the experiences gained until now have mostly been successful. But at the same time this power market is characterised by a considerable excess capacity of power. Thus until now the power market has mainly acted as an hour-to-hour market for operating existing power plants, while virtually no investments in new capacity have been initiated by the market.

[43] Pointed out in the hearing comments to the EU Green Paper.

Thus some important questions arise:

- Will decentralised technologies have any advantages compared to larger conventional ones in such a market, where you do not know if the market by itself will succeed in initiating the needed investments in new power capacity?
- Will fluctuations in production from technologies as wind power and photovoltaics be serious drawbacks compared to more conventional technologies in a liberalised market context?

In the next sections some of these characteristics for decentralised plants will be evaluated.

3.4 Evaluation of decentralised plants in relation to security of supply

3.4.1 Criteria for evaluating decentralised plants

In this section some of those special characteristics that decentralised generation possess will be pointed out in relation to security of supply, both with regard to the above mentioned dependence on energy resources from abroad and in ensuring that the necessary power capacity will be available.

Thus decentralised generation technologies will in the following be evaluated according to these criteria:

- Substitution of imported fuels. To what extent will the development of decentralised plants replace the use of fuels imported from abroad?
- Availability in ordinary operation, taking into account required major annual overhauls and capabilities for load management.
- Flexibility with regard to establishing new plants, especially with regard to lead times and the introduction into existing energy systems.
- Economic attractiveness on competitive terms, that is with out any subsidies. Economics comprise investments, operation, maintenance and fuel costs, including the uncertainty of the future development of fuel prices.
- Financial risks. The risk the investor is facing in terms of possible economic losses.
- Vulnerability, especially in relation to external occurrences.

In evaluating the decentralised technologies the reference will be establishing larger conventional fossil fuelled power plants. In the following each of the criteria will be discussed in more detail.

3.4.2 Substitution of imported fuels

What kind of conventional power production is replaced by decentralised production will depend on the hierarchy of load management. Assuming that the cheapest power production in terms of short-run marginal costs is hydropower and nuclear power, then all decentralised production will substitute fossil fuels.

But of course this does not necessarily mean that imported fossil fuels are replaced. If the decentralised plants substitute conventional base load plants probably coal, oil or gas will be replaced. If peak power production is substituted, then probably oil or gas will be replaced. If decentralised production replaces oil and gas this will at the margin substitute imported fuels. This will not always be the case if coal is the replaced fuel. Quite a number of Member States in the EU have a domestic coal production and in those cases an indigenous fuel could be substituted.
Thus expectedly the following will hold true for decentralised power production and substitution of imported fuels:

- If possible, small-scale hydropower will, for economic reasons, substitute peak power production from conventional plants. Thus it is expected that small hydro plants essentially will substitute imported fuels.
- Due to the fluctuating character of their power production, wind power and photovoltaics will mainly substitute peak power, essentially replacing imported fuels.
- Biomass plants are expected to be mainly based upon indigenous energy sources. Therefore, it is likely that biomass plants will have a positive impact upon security of supply substituting imported fuels.
- CHP-plants (excluding those based upon biomass) and fuel cells will expectedly mostly be based upon natural gas. A high efficiency in electricity production will be favourable with regard to security of supply, substituting more fuel than they consume, but essentially these plants will be neutral in terms of substituting imported fuels.
- Fuels cells are not restricted to use natural gas, but can use fuels as hydrogen, eventually produced by wind power, or gasified biomass. This means that fuel cells will have the possibility of substituting imported fuels. Though in general it is difficult to know to what extent the use of fuel cells will replace imported fuels.

3.4.3 Availability

In this analysis, availability comprises both availability of the energy production facility as well as availability of the energy production itself. What concerns the availability of production capacity this parameter is just as high for decentralised power plants as for conventional ones. For wind turbines the availability factor is 97-98%.

However, due to the fluctuating energy sources for wind power and photovoltaics the produced power is not always available when needed. Therefore these two technologies can only to a limited extent be used as a reliable power base - normally other sources of power production should be available within short notice if production from wind power or photovoltaics suddenly falls off.

Especially fuel cells but also CHP using natural gas have excellent load following capabilities - actually better than most coal- and oil-fired power plants. And of course this is even more the case for small hydro, which is capable of very fast load following. But due to seasonal changes in precipitation hydropower cannot be expected to be available always when needed. Finally with regard to load management biomass plants are expected to be at approximately the same level as a coal-fired power plant.

3.4.4 Flexibility

When new technologies are established at least two issues are important to consider with regard to flexibility:

- How can the new technology be absorbed by the existing energy system; is there 'room' available for the new capacity without interfering significantly with the operation of the present system? Or will the new plant have a considerable impact upon the functioning of the total energy system?
- When the investment is undertaken and the plant on stream what is the robustness of the plant if central parameters are changed compared to the expected development? A change in the fuel mix used by the plant could be such a case, relative prices changing in disfavour of the presently used fuel.

The establishment of wind power[44], photovoltaics and fuel cell plants will all tend to be marginal to the existing energy system, while this will also be the case for small-scale CHP and hy-

[44] Offshore wind power farms might not be considered marginal to the existing energy system.

dro power plants although to a lesser extent. Thus, it is reasonable to expect that small-scale decentralised plants will be fairly easy to introduce into the existing energy system. Most DG technologies have an advantage due to their modularity, implying that they can be dimensioned to the specific use.

What concerns robustness, all the considered decentralised plants generate power and some of them (fuel cells, CHP and biomass plants) produce heat as well. Thus they will all be sensitive to changes in the price of power and heat, as all conventional plants are as well.

Wind turbines, photovoltaics and small hydro plants are of course dependent on the availability of the natural resources, but they are totally independent of the price of other fuels. Thus the production costs of these decentralised plants will be robust towards changing fuel prices.

Biomass plants are almost totally designed to specific biomass fuels, although some flexibility does exist. But in general, it is difficult to convert a biomass plant to operate on another fuel. Thus a biomass plant does not have the possibility to use other fuels and whether the price of biomass will stay constant in the future is subject to considerable uncertainty. Finally, the situation is almost the same for CHP plants. Most of these plants are connected to natural gas with limited possibilities for changing to other fuels.

To a lesser extent the same can be said about fuel cells. Most fuel cells require hydrogen as input and the possibility exist to produce hydrogen from different sources. Though, the high-temperature fuel cells can use other fuels than hydrogen, e.g. natural gas, gasified biomass or gasified coal. But even for fuel cells the possibilities for changing fuels are limited.

3.4.5 Economic attractiveness

Except for CHP and perhaps small hydropower plants none of the decentralised technologies are economically attractive seen from an investor viewpoint unless some kind of subsidies are attached to them. But a number of economic advantages and drawbacks do exist for these technologies compared to large conventional plants.

- Wind power, photovoltaics and fuel cells are all technologies that are well suited for serial production and therefore candidates for serious price-reductions in the future. Though for wind power part of these benefits are already captured.
- Some of the mentioned technologies are that new, that considerable uncertainty does exist with regard to operational performance and lifetime of components. This is especially the case for more advanced types of photovoltaics and fuel cells.
- Wind power, photovoltaics and small hydro plants are virtually independent of the development of fossil fuel prices in the future.
- The economics of biomass plants are not directly depending upon fossil fuel price development, but indirectly the price of biomass could reflect changes in the price of other fuels. Finally the future price of biomass is by itself subject to considerable uncertainty.

Presently, the general lack of economic attractiveness (not including subsidies) does not make life easier for these technologies at the power market. The future development is expected to change this picture, making decentralised technologies closer to be economic competitive to conventional ones.

Finally, not only economic attractiveness can be seen as a barrier towards the deployment of decentralised generation, the framework conditions of the national power markets are highly important as well. Although economics of a decentralised plant might be equivalent to a large power plant, other considerations concerning the plants capabilities of contributing to the general load management or in keeping up the required reserve capacity might be more important in deciding what kind of plant to construct. Especially for utilities not facing a liberalised power

market such considerations might easily favour the large power plants, while for power companies taking part in a competitive spot market economics are the dominant issues, leaving systems considerations to the system operator.

3.4.6 Financial risk

Financial risks in new investments are related to relatively few but important parameters:

- The absolute size of the investment.
- The pay-back profile.
- The distribution between fixed cost and variable costs.
- Expectations to power market development.
- Expectations to the development of future subsidies, including the political perspectives.

In a liberalised power market investments are initiated when the spot price (short-term marginal costs) is equal to or higher than the expected long-term marginal costs[45] for investments in new plants. But a considerable risk premium has to be included due to uncertainty if the spot price in average will stay at or above this level or not.

In the perspective of this liberalised power market it is undoubtedly an advantage, that all decentralised technologies are small what concerns the absolute size of the investment compared to large conventional plants. Thus, although the relative risk is the same the absolute risk for decentralised technologies will be lower than for large conventional power plants. And therefore expectedly the risk premium in this respect should be lower for decentralised plants than for conventional ones.

But as mentioned above most decentralised plants cannot compete economically on their own relative to large power plants. Photovoltaics, biomass plants and to a certain extent wind power still has to rely on subsidies, feed-in tariff etc. Thus, the question is if the political decided subsidies are more or less reliable than spot market prices. A question that can only be answered in relation to the specific investment.

Finally, the highest risk is associated with those technologies that are most capital intensive and have the lowest O&M and fuel costs, that is wind power, hydro power and photovoltaics. Other technologies as CHP, biomass plants and fuel cells have the opportunity to cut down expenses by lowering energy production, implying lower fuel costs and O&M-costs.

As mentioned above changing input and/or output prices have a significant impact on the profitability of energy investments and are subject to considerable uncertainties. For decentralised plants the risk associated with the output price (power and heat prices) is the same as for conventional plants, while this is not the case for input prices. As for wind power, photovoltaics and hydropower these are independent of fuel inputs, while the future price of biomass is considered to be highly uncertain.

Finally, the development of the natural gas price will influence CHP plants and fuel cells as it will for conventional plants. Although fuel cells have the opportunity of using other fuels, thus are subject to a lower risk than CHP-plants. Against this stands a higher technological risk for fuel cells: These are highly advanced technologies and at present it is difficult to assess, if these plants will work properly all the way through their expected lifetime.

Thus with regard to financial risks a number of pros and cons exist for decentralised power plants. To conclude:

[45] The expected cost calculated per kWh, including levellised capital costs, O&M, fuel costs and a risk premium.

- Wind power, hydropower and photovoltaics are expected to be in the same risk category with low absolute risk, independent of fuel price volatility, but dependent of future subsidies, although the last-mentioned to a lesser extent for wind power and perhaps not at all for hydropower. In general financial risks are expected to be lower for these plants than for conventional ones.
- Biomass is expected to be the most risky of the decentralised investment, mainly due to the uncertainty related to the future biomass price. Investment in a biomass plant is considered to be a little more risky than investments in conventional plants.
- The only advantage for decentralised CHP-plants is that they are small in size, reducing the absolute risk compared to conventional plants. Otherwise decentralised CHP-plants are exposed to the same risk as conventional ones.
- Fuel cells have a number of advantages including small sizes, modularity and for some of them the possibility of fuel switching. On the other hand these technologies are highly advanced and reliable operation over the lifetime of these plants is not proven yet. Fuel cells are assessed to be at the same risk level as conventional plants.

3.4.7 Vulnerability

Compared with larger conventional plants (especially with nuclear plants) the vulnerability towards external disturbances is much lower for decentralised plants. With regard to accidents, terrorism or natural catastrophes the break down of one or more decentralised power plants will have only minor impacts upon the functioning of society. This is of course mainly due to the small sizes of these plants and the decentralised locations, but the low operational risks are important as well, especially compared to nuclear.

Thus, seen from the overall viewpoint of society, no accidents or catastrophes at decentralised power plants will have any significant impact upon the security of supply. On the contrary, decentralised power plants might have a role of stabilising the grid in situations with major power system failures, keeping up the power in their supply areas.

3.5 Conclusions and recommendations

Table 3.1 gives an overview of the results of the evaluation of decentralised power plants with regard to the above-mentioned criteria, in comparison with larger centralised fossil fuel fired power plants.

Table 3.1. *Overview of the evaluation results for decentralised technologies*

	Substitution of imported fuels	Availability	Flexibility	Economic attractiveness	Financial risks	Vulnerability
Wind power	High	Low	High	Low/ Neutral	Low/ Neutral	Low
Photovoltaics	High	Low	High	Low	Low/ Neutral	Low
Biomass	High/ Neutral	Neutral	High/ Neutral	Neutral/ Low	Neutral/ High	Low
Small hydro	High	High/ Neutral	High	Neutral	Low/ Neutral	Low
CHP	Neutral	High/ Neutral	High/ Neutral	High/ Neutral	Low/ Neutral	Low
Fuel cells	Neutral/ High	High/ Neutral	High	Low/ Neutral	Neutral	Low

Especially if security of supply is defined in a broader context than seen in the EU Green Paper, including not only the dependence on imported fuels, but the pros and cons of distributed generation as well, then a picture emerges mostly favourable of small-scale plants compared to

large conventional ones with regard to security of supply, although the picture is not totally clear. In the following some of the pros and cons are summarised:

- In general decentralised plants tend to substitute a high degree of imported fuels.
- Due to their small sizes they are fairly easy to introduce into an existing power system. Technologies as wind power, hydropower and photovoltaics are very robust towards future changes in fuel prices.
- With regard to capacity availability decentralised plants are at least at the same level as conventional ones. With regard to the energy production, wind power and photovoltaics are less available, due to their dependence on natural resources.
- Larger plants can to a much higher degree take advantage of economies of scale. With the exception of CHP and perhaps small hydropower plants most decentralised technologies do need some kind of subsidisation. Though wind power is moving fast towards being competitive with conventional plants.
- Though the analysis of financial risks shows an unclear picture, it tends towards a lower risk for most decentralised technologies compared with conventional ones.
- In general the vulnerability towards external disturbances is much lower for decentralised plants than for large centralised ones. Especially in situations with transmission line failures, DG may benefit by having the possibility of keeping up the power with in its supply areas.

Thus although the picture is a little bit scattered, in general the deployment of decentralised generation technologies will improve security of supply within the EU. To diminish some of the barriers for decentralised technologies to play a larger role in security of supply the following policy actions are recommended:

- The definition of security of supply should not be restricted to dependence of imported fuels, but should include other characteristics of decentralised generation as well, among these robustness towards external changes, availability of capacity and vulnerability.
- The possible deployment of decentralised technologies seems to depend heavily on the organisational set-up of the power industry in the member states. Although economics of decentralised plants might be equivalent to large power plants, other considerations concerning the plants capabilities of contributing to the general load management or in keeping up the required reserve capacity might be more important in deciding what kind of plant to construct, especially if the power industry is not taking part in a liberalised power market. Thus part of this barrier could be abandoned if the power industry was liberalised in all EU Member States.

4. EU ENERGY TECHNOLOGY R&D POLICY

4.1 Introduction

Technology research and development plays a key role in developing and implementing decentralised energy generation in the EU. Therefore, this chapter compares current EU R&D programmes and priorities to the findings of a survey on future expectations of DG technology developments.

One of the findings of the DECENT study "Future Decentralised Energy Systems 2020"[46], (Jörß et al, 2003) was that lack of R&D was considered one of the main barriers to the realisation of decentralised energy generation. In this study, for example the lack of R&D resources was highlighted as a barrier for the realisation of statements regarding:

- Development of new revolutionary wind turbine concepts.
- Cost reduction in biomass.
- Improvement of energy efficiency in CHP.
- Improvement in lifetime of CHP fuel cells.

In other words, the respondents considered R&D resources an important mechanism regarding research, technology and development activities involving considerable technological uncertainty and risk. The results from the future study are in line with the findings from success stories about renewable energies during the 1990s, in which the priority to research and development was one of the key actions for success within photovoltaics, solar thermal, biomass and wind energy (EEA, 2001).

In this chapter, the importance of R&D resources is further analysed in relation to the actual EU R&D policies and recommendations. The analysis is based on existing materials and reports rather than on new R&D indicators of decentralised energy projects compared to other (larger) energy projects.

In the first section, a short overview of the actual EU energy research is given, including its objectives, its institutional incentives and the political priorities in relation to renewables. Hereafter, the results from a quality assessment of retained proposals for the EU energy research are used to benchmark the findings from the DECENT future study. This leads to a description and comments on the future key actions for sustainable development of the 6th Framework Programme, which are foreseen to be launched end of 2002. Finally, some recommendations are made regarding the future EU energy research policy.

4.2 EU research and development policy

Economic and social development requires adequate availability of energy services, in particular sustainable energy production, transformation and consumption. Research, development and demonstration are needed to identify new pathways for European energy systems. For this reason, the EU has had research, technology and demonstration programmes for non-nuclear energy for many years.

[46] The DECENT future study was designed as an adapted Delphi investigation characterised by iteration. In an anonymous survey, 66 external experts have ranked central statements about the future development of decentralised energy generation. On this basis, the project team has constructed four scenarios for 2020, see Chapter 5, which have been further evaluated by a group of DG experts.

The actual European energy research has the following complementary objectives (European Commission, EUR 19466: 6):

- *Energy objectives*: Higher efficiency of energy use, a larger recourse to renewable energy sources (doubling the share of renewables of 6% in 2000 to 12% in 2010[47]), and greater security of supply.
- *Environmental objectives*: Reduction of negative impacts on environment and climate stability, in particular reduction of green house gases by 8% in 2008-2012 compared to 1990 (The Kyoto Protocol).
- *Socio-economic objectives*: consideration of the energy system on competitiveness in the global market, on employment, on reducing economic gaps of less-developed regions etc.

Historically, the demonstration programme, THERMIE was operated outside the Framework programme by the DG Energy, while the R&D programme JOULE was provided within the Framework programme by DG Research. In the 5th Framework Programme (1998-2002), JOULE-THERMIE was merged into one single programme ENERGY, which represents one of two sub-programmes within the specific programme 'Energy, Environment and Sustainable Development'.

The total budget for the 5th framework programme, including the Euratom programme is 14,960 million Euro, of which 2,125 million Euro are allocated to Energy, Environment and Sustainable Development. The sub-programme ENERGY receives 1,042 million Euro[48] while the other sub-programme Environment and Sustainable Development receives 1,083 million Euro. In comparison the Euratom programme receives 1,260 mil Euro.

ENERGY is divided into two key actions:

- *Key Action 5*: Cleaner energy systems, including renewable energies (479 million Euro).
- *Key Action 6*: Economic and efficient energy for a competitive Europe (547 million Euro).

The objective of *Key Action 5* is to minimise the environmental impact of the cost-effective production and use of energy in Europe. This will help the ecosystem by reducing emissions at local and global levels and by increasing the share of new and renewable energy sources in the energy system. It will also have socio-economic impacts by enhancing the capability of European industry to compete in world markets, helping to secure employment and promoting social cohesion with less favoured regions.

The objective of *Key Action 6* is a reliable, clean, efficient, safe and cost-effective energy supply and services for the benefit of its citizens. This is essential for the good functioning of society, the competitiveness of industry in European and world markets and the quality of local and global environment. Efficient end-use technologies are expected to count for 60% of the greenhouse emission reductions on the short term and for 30% on the long term. The focus of the EU strategy is the realisation of the significant economic potential of as much as 18% of the 1995 energy consumption in 2010. This addresses all stages of the energy cycle: production, distribution and final use.

According to the assessment report covering the period 1995-1999, the Non Nuclear Energy RTD programme of the 4th Framework programme gave a priority to renewable energy sources, with app. 45% of the total budget. For the 5th Framework programme, the support for renewable energy has been strongly requested by the European Parliament. Hence during 1999 the programme was shaped to assure an allocation of not less than 60% of funds to renewable energy,

[47] Resolution from the Council based on the white paper 'Energy for the future: Renewable sources of energy' (COM(97)599 final), in which the target of 12% of EU energy coming from renewables was put forward. In order to reach this ambitious goal, proactive steps were required, among others R&D funds for technological development, cost reduction and user experience.

[48] Including 16 million Euro for RTD activities of a generic nature.

of which 75% should be allocated to demonstration projects (Five Year Assessment Report Related to the specific Programme: Energy, Environment and Sustainable Development covering the period 1995-1999, June 2000: 56).

4.3 Assessment of non-nuclear energy proposals

Effective adjustment of the European energy research was the background for a qualitative assessment of energy proposals in 2001 (European Commission, 2001). The results have contributed to the redefinition of the energy work programme research, technology and development objectives and focused the calls for the remaining programme period.

The results from the pilot assessment are framed by five qualitative criteria derived from the programme criteria and objective:

- Innovation: scientific and technical value, novelty, consistency of proposal.
- Environmental impact: potential of reducing impacts on environment and global climate.
- Cost-effectiveness: reduction of costs with respect to conventional solutions.
- Problem-solving: capacity of addressing effectively the main problems.
- Socio-economic effects: anticipated effects on European society.

These criteria were used to assess proposals submitted, for which a score going from 0 to 3 was assigned (0 = not addressed at all; 1= below average; 2= average; 3 =best score). The assessment focused on sectors, which were grouped across the two key actions. These clusters do not include decentralised energy generation as a sector of its own, but do comprise different renewables as well as other specific problem areas such as storage and transmission. In the table below an overview of proposals and the scores of selected energy groupings are shown.

Table 4.1 *Ratings for selected groupings of energy proposals*

	Proposals submitted	Proposals retained	Innovation	Environment	Cost effectiveness	Problem solving	Socio-economics
Large scale generation	149	46	2	1.9	1.3	2	1.6
Fuel cells	58	15	2.5	2.2	2.1	2.6	2.6
Biomass	207	30	2.4	1.7	1.8	2.1	2.2
Solar energy	109	23	2.5	1.8	2.1	2.3	2
Wind	89	18	2.6	2.3	2.1	2.4	2.2
Integration and storage	142	46	2.4	2	1.9	2.6	2.6
Others	459	117	N.a.	N.a.	N.a.	N.a.	N.a.
Total	1,213	295	N.a.	N.a.	N.a.	N.a.	N.a.

Following three public calls (deadlines 15.6.99, 4.10.99 and 31.5.00 respectively), a total of 1,213 proposals were submitted, of which 295 were retained, or 24% of the total proposals. Fuel cells, biomass, solar energy, wind and integration & storage, which is important to renewables, accounted for 132, or 45% of total retained proposals. Large-scale generation comprising a wide range of technologies accounted for 46, or 16% of proposals retained. From the assessment (or the project overview from the 5th Framework website) it is not possible to get an overview of how many funds each energy groupings have received.

- *Large-scale generation* proposals cover a wide range of technologies and applications, including addition of biomass or waste to coal combustion, improvement of conventional plants, gas turbines etc. The quality of the proposals is somewhat below average, in particular regarding cost effectiveness.
- *Fuel cells* represent a promising energy in terms of high efficiency and environmental impact as they convert fuel (basically hydrogen) directly into electricity. Scores are higher than average.

- *Biomass*: A great variety of technologies can be utilised to transform biomass and waste into energy, in the form of electricity or heat or combined heat and power (CHP) or fuels. The emphasis of the programme is on electricity production and especially CHP. The quality of proposals is above average. Most of the proposals dealt with the utilisation of wastes. Very few proposals looked into the long-term perspective of energy crops.
- *Solar energy* or more specifically photovoltaics is expected to have the highest potential for cost reduction though learning and breakthroughs, but is still between 5-10 times more expensive than the conventional energy. Proposals include some highly innovative projects as for example the Wembley Stadium with an integrated PV façade. Scores are above average, except for environment.
- *Wind energy* represents a competitive technology on the global markets. Proposals focus on cost reduction, better diffusion of the technology and improvement of large wind farms and turbines. The scores are all above average.

4.4 Results from the DECENT future study

In the DECENT future study (Jörß et al, 2003), two criteria were used to identify the top statements[49]. These criteria were:

- Beneficial impact on global environment.
- Beneficial impact on cost of energy production.

Regarding the environment, fuel cells and wind have the highest high score in the quality assessment, while both biomass and photovoltaics have a lower score than large-scale generation. This partly contradicts the findings from the future study, where statements about biomass and photovoltaics are included in the top ten list along with statements about wind and fuel cells. For further details see the table below. It is worth mentioning that while the score of the quality assessment is the average of several proposals, the rating of the statements is exclusively made to this particular topic.

Table 4.2 *Top ten list of beneficial impact on global environment*

Rank	No.	Statement	E index
1	2	10% of Europe's electricity comes from wind power.	52
2	26	30% of fuel cell fuels in EU are derived from renewable sources.	45
3	1	10% of Europe's power demand is covered by energy from renewable sources.	40
4	3	50% cost reduction of wind produced electricity relative to 2001.	40
5	5	More than one-third of wind turbine capacity in Europe comes from offshore sites.	27
6	22	Widespread use of domestic and commercial fuel cell units.	22
7	10	20% of EU's electricity is based on biomass.	18
8	24	10% of Europe's domestic power demand is covered by fuel cells located in domestic houses.	15
9	9	Wide spread use of photovoltaics integrated into roof tiles.	15
10	8	50% cost reduction of electricity from photovoltaics relative to 2001.	10

Taking a closer look on *innovation*, the wind proposals in the quality assessment represent the highest score with 2.6 where trends have been towards larger turbines and offshore installations. It does not, however, include a totally new concept of wind turbine. Large-scale generation represent the lowest score with not more than 2 as several proposals focus on improvement of existing technologies towards higher efficiency and reduced emissions. It is therefore also interesting to notice that the *cost reduction* score is higher for all renewables than for large-scale generation.

[49] The ranking is based on the average index of beneficial impact on global environment. It is calculated based on the total numbers of respondents and weighted values of 100 (High), 0 (Medium), and -100 (Low), respectively.

All in all, proposals retained within key action 5 and 6 are characterised by high scores of innovation and cost reductions compared to large-scale generation. This is quite interesting compared to the future study where the beneficial impact on cost reduction were rated relatively low for most of the statements as can be seen from the table below.

Only 9 statements were rated above or equal to zero. Topics on photovoltaics (no. 7 and No. 9) have high rankings, not surprisingly due to the implicit economy of scale. In the same field are topics such as fuel cells units with a 40,000 working hours (No. 23), 20% electricity based on biomass (No. 10), and 10% private micro CHP (No. 10). The new wind turbine concept is also expected to have beneficial impact on cost of energy.

Table 4.3 *Top list of beneficial impact on cost of energy*

Rank	No.	STATEMENT	C index
1	7	5% of Europe's electricity comes from photovoltaics.	33
2	8	50% cost reduction of electricity from photovoltaics relative to 2001.	18
3	25	75% cost reduction produced by stationary fuel cells relative to 2001.	18
4	9	Wide spread use of photovoltaics integrated into roof tiles.	15
5	3	50% cost reduction of wind produced electricity relative to 2001.	12
6	23	CHP fuel cell units will reach an expected life time of more than 40,000 working hours.	8
7	6	Development of a new revolutionary and competitive wind turbine concept.	5
8	10	20% of EU's electricity is based on biomass.	2
9	17	10% of private households in EU have micro CHP units installed..	0

4.5 The future of European energy research

The 6th Framework programme is currently being adopted and is expected to be launched end of 2002, dependent on the progress of the political debate and decision-making processes.

According to the modified proposal for a Council decision concerning the 6th Framework programme (COM, 2001, 709 final) a total of 16,270 million Euro has been allocated for the period 2002-2006, of which 1,850 million Euro is earmarked to Sustainable Development divided into three sub-programmes: Sustainable energy systems (630 million Euro), Sustainable surface transport (600 million Euro), and Global change and ecosystems (620 million Euro). In the table below an overview of funds for 5th and 6th Framework programme is presented.

Table 4.4 *Financial overview of 5th and 6th Framework Programmes*

Million Euro	5th Framework Programme	6th Framework Programme
Euratom	1,260	940
Sustainable development	2,125	1,850
Energy	1,042	630
Transport		600
Global change and ecosystems	1,083	620
TOTAL	14,960	16,270

As it can be seen from the table, there are fewer resources available for Sustainable development and in particular Energy in the 6th Framework Programme than in the previous one, although the total funds have increased. This implies a much more thorough prioritisation of resources in a situation where not more than 24% of total proposals tend to be approved.

The sub-programme 'Sustainable Energy Systems' is central to the support to decentralised energy systems. Among others, the strategic objective should address the increased use of renewable energy. Research priorities are for example[50]:

[50] Amended proposals for Council Decisions concerning the specific programmes 2002-2006 of the EU for research, technological development and demonstration activities 2002-2006 of 30.01.2002

- *Clean energy, in particular renewable energy sources and their integration in the energy system, including storage, distribution and use:* Increased cost effectiveness, performance and reliability of the main new and renewable energy sources; integration of renewable energy and effective combination of decentralised sources, with cleaner conventional large-scale generation; validation of new concepts for energy storage, distribution and use (short term).
- *Energy savings and energy efficiency, including those to be achieved through the use of renewable raw materials:* Improving savings and efficiency mainly in the urban context, in particular in buildings, through the optimisation and validation of new concepts and technologies, including combined heat and power and district heating/cooling systems; opportunities offered by on-site production and use of renewable energy to improve energy efficiency in buildings (short term).
- *Fuel cells, including their applications:* Cost reduction in fuel cell production and in applications for buildings, transport and decentralised electricity production; advanced materials related to low and high temperature fuel cells for the above applications (long term).
- *New technologies for energy carriers/transport and storage, in particular hydrogen:* Clean cost effective production of hydrogen; for electricity the focus will be on new concepts, for analysis, planning, control and supervision of electricity supply and distribution and on enabling technologies, for storage, interactive transmissions and distribution networks (long term).
- *New and advanced concepts in renewable energy technologies* with focus on technologies with a significant future energy potential and requiring long-term research. For *photovoltaics*: the whole production chain from basic materials to PV systems, as well as on the integration of PV in habitat and large scale MW-size PV systems for production of electricity. For *biomass* barriers in the biomass supply-use chain will be addressed in the following areas: production, combustion technologies, gasification technologies for electricity and H2/syngas production and biofuels for transport.

4.6 Conclusion

On the one hand, the above mentioned action fields of the programme reflect largely the findings of the DECENT future study. On the other hand, with less resources, enlargement, and globalisation resources should be focused and with a few, but well-defined targets. It would therefore be relevant to raise the following questions:

- How can a critical mass be developed within sectors of energy? For example fuel cells have a high score in the quality assessment, but to match international research and development, more focusing and concentration of efforts are needed.
- How should short term and long term impact be balanced and evaluated? For example the targets of the Kyoto Protocol requires actions to be undertaken now, but on the other hand profound changes in the energy system it needed for the longer run.
- How should environmental impact, innovation and cost reduction be balanced and evaluated and should other criteria such as socio-economics also be included?
- How should the balance between bottom-up approach of proposers/researchers and the top-down approach of society/politics be assessed and evaluated? For example, should the Commission take a more active role in bringing proposers together in clusters, including producers and users of technology.
- How can EU and Member State energy research be linked?

The future R&D priorities regarding renewables should take into consideration the questions raised above and develop criteria that reflect these concerns. The DECENT future study indicates that these criteria should emphasise both environmental concerns as well as activities aiming at cost reduction.

5. POLICY IMPLICATIONS OF A VIEW TOWARDS 2020

5.1 Introduction

This chapter presents an outlook towards four different 'visions' for DG in the year 2020, and assesses the consequences of these expected developments for current policy recommendations. These four visions - referred to as scenarios in the remainder of this chapter - are meant to illustrate possible futures of DG within the EU's electricity supply in the year 2020. It is not the aim of the scenarios to describe desirable futures, nor will it be analysed which steps have to be taken in order to reach any of the scenarios. The time horizon for the scenarios is 2020. The technical input for the scenarios was drawn from the DECENT future survey (see also Section 4.1). The scenarios were developed along two key drivers - the weight of the greenhouse effect on the political agenda and the degree of technological innovation (which corresponds to DG costs) - which have a substantial impact on Europe's future power market. The scenarios have an illustrative nature in order to portray the findings of the future survey and to sketch possible future trends in the electricity business. The scenarios are summarised in the next sections and in Figure 5.1, for a full description we refer to (Jörß et al, 2002).

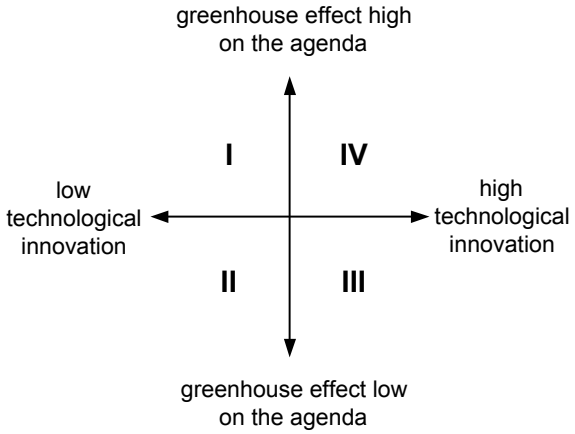

Figure 5.1 *Drivers for scenarios for DG futures in 2020*

EU and Member States policies and legislation shape the market for DG in two important ways. First, policy should reduce room for discrimination and unfair market behaviour and enhance transparency in order to create a level playing field on the electricity market for DG in comparison to other power producers. Secondly, policy should explicitly open up opportunities for Member States to establish national RES and CHP policies that facilitate DG development on the grounds of e.g. environmental protection, global warming or security of supply.

The first aspect - level playing field - is touched by the different scenarios only to a limited degree. While choosing two drivers for the identification of four scenarios, it was implied that the general wish for a liberalised energy market is constant through the scenarios. However, based on scenario specifications, e.g. assumptions on the number and type of anticipated characteristic actors, implications on the *need* for a smoothly functioning, undistorted internal energy market may be identified.

The second aspect - links to DG support policies - is more directly linked to the driver 'greenhouse effect on the agenda': The *need* for the adoption of these policy aspects into legislation

before 2010 will be linked to the weight the greenhouse effect has on the political agenda in the different scenarios.

It is important to note that many of the recommendations formulated in the previous chapters remain valid under all scenarios, because they aim at removing currently existing barriers, and creating a non-discriminatory playing field for DG. One could argue that once such a level playing field is established, the future role of DG depends on the evaluation of its costs versus its environmental benefits, which is exactly the difference between the four scenarios.

5.2 Scenario I - Green Power and Nuclear Ecology

Under this scenario, "there has been no substantial progress in the technological development of renewable energy technologies or combined heat and power production. The achieved cost reductions are minimal. On the other hand, the greenhouse effect is considered to be a very urgent issue. (…) The electricity business is split into the mainstream, which is dominated by big utilities and on the other hand the green power market with a large share of small idealistic companies trying to push renewable generation technologies. (…)"

For this scenario, the possibility for Member States to have RES/CHP support mechanisms at hand that are compatible with the internal market rules is vital, in order to be able address environmental needs within energy policy. In addition, removing market barriers against a level playing field for DG is helpful for the existing DG niches. Thus, all recommendations hold in this scenario.

In this scenario, local acceptance of renewable projects will be less of a problem, which means that the efforts in education and information activities are less crucial. All recommendations regarding streamlining of procedures still hold. Furthermore, given the (still) high costs of renewable technologies, financing will remain an important barrier, so the recommendations on this issue would gain more weight.

5.3 Scenario II - Huge Fossils

Under this scenario, "there has been no substantial progress in the technological development of renewable energy technologies or combined heat and power production. The achieved cost reductions are minimal. The greenhouse effect is not very present in the general discussion. Most decision-makers do not consider it to be an urgent issue. The European power market is dominated by several trans-national power companies holding a market share of more than 90%. Large power plants using fossil fuels and nuclear power are predominant in the electricity production. (…) Decentralised generation consequently plays a minor part in the electricity supply. (…)"

From the point of view of increasing DG penetration, this scenario presents the most difficult future. Promotional policies for RES and CHP have not been implemented, thus there is no need for enhanced environmental 'door openers' within the liberalisation framework. Grid connection issues for the distribution grid are deemed to be rather irrelevant. Generally a liberalised market is valued as bringing cost reduction to the customers. Thus, the policy recommendations lose some relevance.

In this scenario, DG benefits related to security of supply and regional development are still acknowledged. Therefore, education and information policies, as recommended, should stress these benefits to both (regional) policy makers and the general public.

5.4 Scenario III - Widespread Economic Niches

Under this scenario, "there has been an innovative push on renewable energy technologies. Great cost reductions have been achieved for both renewables and combined heat and power production. The greenhouse effect is not very present in the general discussion. Most decision makers do not consider it to be an urgent issue. (…) Due to computer aided power management systems it is easy to integrate decentralised power generation technologies into the existing supply concepts. Actors in the electricity business are mainly big utilities offering multi-utility services together with highly specialised, profit oriented service companies. (…)"

In this scenario, DG has to compete with other electricity generation technologies purely on the basis of costs. The environmental benefits will not be a reason for special government support, and DG technologies will be used in those niches where other benefits (e.g. reliability or self sufficiency) play an important role. All policy recommendations still hold; actions to increase public acceptance could be stressed, and all recommendations targeted to an easy and transparent access of DG to the electrical system are very useful.

5.5 Scenario IV - Hip Ecology

Under this scenario, "there has been a strong development in the fields of renewable energy technologies, fuel cells and other CHP technologies. Great cost reductions have been achieved and the greenhouse effect is considered to be an urgent issue. (…) Due to innovative technological developments and a strong environmental awareness in the public certain renewable energy technologies have gained an importance as status symbols for customers. (…) The profile of actors in the energy business has broadened. Although the major share of electricity is produced, distributed and sold by big trans-national companies a wide variety of small and medium sized companies have entered the market".

For this scenario, the possibility for Member States to have RES/CHP support mechanisms at hand that are compatible with the internal market rules is vital, in order to be able address environmental needs within energy policy. In addition, all provisions facilitating the easy access of DG to the electrical grid would have proven very useful. Thus all recommendations hold.

Summarising the robustness check, it can be stated that the relevance of the recommendations is reduced only in one of four scenarios developed in the DECENT future study.

6. CONCLUSIONS AND RECOMMENDATIONS

The DECENT project has identified the main barriers and success factors to the implementation of DG projects within the EU and has formulated a number of related recommendations to EU and Member State policy makers to enhance the feasibility of DG projects within the internal energy market. In this chapter, the three main priority areas of policy development for DG are identified. For each of these areas, the key recommendations are summarised.

6.1 General principles

Most of the barriers that have been identified are attributable to electricity regulatory regimes which hardly recognise the values of DG, in particular those values related to environmental benefits, to electrical or grid services, and to security of supply in greater Europe. It is therefore essential that future energy policies for the electricity sector acknowledge and value the qualities of DG. Considering the ongoing trend of liberalisation and the increased use of market mechanisms as policy instruments it is recommended to take an approach to policy development that is market compatible. The ultimate goal should be to design markets that ensure a level playing field for centralised and decentralised generation. Markets must be open and transparent, and should give fair chances to different types of actors. Finally, in the long run, the environmental values of DG should be acknowledged in a market compatible manner while energy prices reflect external costs.

It is not possible to articulate a "single policy" for DG, given that it does not fit into existing responsibilities and institutional structures. Nevertheless, steps should be taken to counteract the fragmentation of the current situation and to increase co-operation and co-ordination such that DG is more often treated in a non-discriminatory manner.

6.2 Priority: DG interconnection and system integration

Due to the relatively recent market introduction of most technologies, DG developers and operators are often not linked to established utilities, but work as independent power producers. Compared to other market actors, such as utilities, grid operators, fuel suppliers, and traders, these developers often have disadvantages in knowledge, experience and capacity. This can lead to a weak negotiation position when it comes to the terms and conditions of access to and use of the grid. DG operators can be confronted with market power from utilities or grid operators, in particular when the unbundling - separation between network operation and supply - has not been fully completed.

While the Electricity Directive requires network operators to maintain a secure and reliable system, it does not presently require DSOs to consider the benefits of DG in their grid development planning. The amended proposal to amend the Electricity Directive would make such obligations more explicit.[51] This is based on the recognition that DG complements and augments the existing network infrastructure, and thus influences its development. Therefore provisions that relate to the development of the grid through expansion, upgrades and connection are fundamental to DG. The Renewables Directive (Article 7) does provide a framework to facilitate in-

[51] The proposed Article 11(5) would provide: "When planning the development of the distribution network, energy efficiency/demand-side management measures and/or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator."

terconnection for RES developers, and similar provisions have been proposed for in the CHP Directive.

This leads to the following recommendations:

- Provide *transparency* on terms, conditions, and procedures for connection. Transparency reduces uncertainty and project risks for a DG developer, and prevents lengthy negotiations with the distribution network operator.
- Establish transparent and efficient rules relating to the allocation of costs of technical adaptations, such as grid connections and grid reinforcements, to all users of the grid, including future generators or consumers. Ideally, these rules should also acknowledge DG benefits to the network, such as avoided grid investments and grid losses. Examples for such cost-bearing or cost-allocation rules can be seen in Germany and Denmark, where all costs incurred by necessary grid reinforcements are to be borne by the grid operator, while direct connection costs are borne by the RES developer.
- Article 7 of the Renewables Directive requires Member States to set up a legal framework or require transmission system operators and distribution system operators to address these issues, and is proposed in the CHP directive. It is recommended to include similar provisions in the proposed amended Directive to amend the Electricity Directive, as this would have the advantage of covering all producers.
- Adopt uniform *technical* standards for interconnection to the grid. This reduces the scope for dispute on the technical requirements associated with grid connection. In the process leading to this standardisation it is important that all relevant stakeholders are involved in the discussion, so that the standards do not introduce a bias in favour of any particular party. EU wide standardisation could take the form of an EN-norm issued by CENELEC. For renewable electricity the Renewables Directive provides the basis for the implementation of such standards. It is recommended that the similar provisions be retained in the CHP Directive, as has been proposed.

However, the application of these recommendations may be insufficient when network companies have incentives not to connect DG under the applicable regulatory regime. In many countries, distribution network operators are subject to regulations requiring them to cut their costs annually. This may act as a disincentive to connect DG. Economic regulation of network companies should therefore be neutral to the integration of DG into the network. Price and quality regulation should provide incentives to network companies to deal with connection requests in a fair and efficient manner. Further research is required on different regulation models and cost allocation methodologies.

Once interconnected, the charges for using the network may impose additional barriers, addressed by the following recommendations.

- Stricter unbundling of (distribution) network operation and ownership from generation and supply should help ensure the independence of transmission and distribution system operators. This would prevent the influence of vested interest on the network operation, and significantly reduce the risk of excessive costs and other unfair conditions imposed on network use by independent electricity producers. However, Article 10 of the most recent proposal for an amended Electricity Directive (June 2002) gives Member States the possibility to exempt integrated electricity undertakings serving less than 100,000 customers from the duty of complete unbundling. Although this is a practical approach that protects smaller companies, specific rules are missing to ensure that access to, and use of, the network are provided under completely fair and transparent conditions in such cases.
- Introduce *ex ante* approval & publication of grid use tariffs reflecting long-term marginal avoided network costs as stated in the proposed amendments to the Electricity Directive (e.g., Recital 14).

- Ensure transparent, non-discriminatory and cost-reflective charges for back-up or top-up electricity generation. This is particularly important for CHP and is indeed addressed to some extent by the Article 8(6) of the proposed CHP Directive, which would require the Member States to take measures to ensure that tariffs for the purchase of electricity to back-up and top-up electricity generation are set on the basis published tariffs and terms and conditions. However, instead of an absolute requirement, this proposed rule in the CHP Directive has been made conditional and implicitly time-limited as it would apparently only apply to those Member States that have not transposed the customer eligibility requirements as proposed in the amended draft Electricity Directive. Thus, we recommend that this matter be addressed in the Electricity Directive such that it would apply to all DG installations on a non-conditional basis.

6.3 Priority: DG authorisations and permitting

Acquiring authorisation and planning consents for the establishment of DG installations is a major barrier to many projects, due to non-transparent and time-consuming procedures, and local opposition. Given the country-specific and local character of the planning and authorisation processes and institutions, the scope for EU legislation is limited. The provisions in the Renewables Directive provide a good basis for Member States to review and improve their administrative procedures for planning and permitting processes. The communication towards Member States should stress that they should start their evaluation timely to be able to issue a first report to the Commission by October 2003.

This leads to the following recommendations, formulated for the Member States.

- Streamline and expedite planning and authorisation procedures, in conformity with the requirements of Article 6 of the Renewables Directive and Article 5(3) of the amended proposal for amendment of the Electricity Directive[52].
- Review and improve national planning procedures on specific issues such as deadlines and clear reception points. Progress made on this issue is to be highlighted in the reports due according to the Renewables Directive, Article 6.
- Proactive designation of areas in spatial plans (RES) and heat planning (CHP) enables local authorities to balance the interests of different parties and reduces the siting efforts for DG developers.
- Involve local actors, because they can provide equity, and their involvement often reduces local resistance. Many schemes are possible, examples have been given in Chapter 2.1. Regional energy agencies can play a role in providing information, and the issue should be highlighted in the reports due according to the Renewables Directive, Article 6.
- One step further could be to co-ordinate spatial planning, network planning and integration of RES. When governments appoint specific locations within their jurisdiction for RES development, the most eligible sites are not always the most optimal sites from a network integration point of view. Those involved in spatial planning should have information on cost of connection (*ex ante* price signals in the network, facilitated by ICT). Network operators could take the designated DG development areas into account in their grid planning.

6.4 Priority: Financing DG

Due to the lack of a level playing field in present electricity markets, and because the external cost of electricity production are not reflected in the prices, many DG technologies need financial support to be viable under current market conditions. In the long run, DG should be inte-

[52] Article 5(3) of the amended proposal would require Member States to "take appropriate measures to streamline and expedite authorisation procedures for small and/or distributed generation. These measures shall apply to all facilities of less than 15 MW and to all distributed generation."

grated into current electricity markets, not through subsidies or support mechanisms, but rather, upon the recognition of the environmental and other values of DG, the internalisation of external costs, the creation of a level playing field, non-discriminatory and transparent treatment of DG, and proper incentivisation of distribution system operators.

This leads to the following recommendations.

- One of the major general problems of the development of DG installations is the uncertainty that is connected with the existing and future legislative framework. This concerns both the completion of the internal market and national or EU-wide support mechanisms for RES and CHP. A quick finalisation of the policy packages, especially the amendment of the Directives concerning the internal markets for electricity and gas and the discussed CHP Directive, would significantly contribute to a higher planning security and thus to easier financing.
- Support mechanisms should only be in place until DG technologies are financially viable due to internalisation of external costs and technology development. Examples of market compatible mechanisms are emission trading and Green or CHP certificates. These create added value for DG options by internalising their external benefits. Especially combined with mandatory national targets and annual timetables for DG development until 2010, such a system could achieve relative predictable conditions under (uncertain) market conditions and set the basis for coherent, measurable national policies to develop DG.
- With a view to providing a more stable long-term policy framework it is desirable that long-term (2020) targets for the integration of renewables and cogeneration are fixed at the EU level. This would give a clear signal to investors and lenders.
- To reduce the uncertainty to investors, support policies should take into account and anticipate the future harmonisation of support frameworks across the EU. Member States should anticipate harmonisation while the EU should provide clarity on harmonisation as soon as possible within the framework of the Renewables Directive. Note that after 2005, when the Commission will issue a report on the experiences gained and may include proposal for harmonisation, there is still a transition period of 7 years.
- As many DG projects are set up by small-scale players, it is important to reduce their transaction costs in using support mechanisms and in operating on the electricity market.

6.5 Other policy fields

6.5.1 The impact of DG on the security of supply

Security of supply as a factor for the development of decentralised technologies is not only related to the dependence on imported fuels but also to the value of decentralised generation in the power system in a wider context. Several pros and cons of DG technologies in improving security of supply have been identified.

In general decentralised plants tend to substitute a high degree of imported fuels. Due to their small sizes they are fairly easy to introduce into an existing power system. Technologies as wind power, hydropower and photovoltaics are very robust towards future changes in fuel prices.

With regard to availability of capacity, decentralised plants are at least at the same level as conventional ones. With regard to the energy production, wind power and photovoltaics are less available, due to their dependence on fluctuating natural resources. Although the analysis of financial risks shows an unclear picture, it tends towards a lower risk for most decentralised technologies compared with conventional ones.

In general, the vulnerability towards external disturbances is much lower for decentralised plants than for large centralised ones. Especially in situations with transmission line failures, DG may benefit by having the possibility of keeping up the power with in its supply areas.

Thus although the picture is a bit scattered, in general the deployment of decentralised generation technologies will improve security of supply within the EU. To diminish some of the barriers for DG to play a larger role in security of supply, the following policy actions are recommended:

- The definition of security of supply should not be restricted to dependence of imported fuels - as is the case in the Green Paper on security of supply - but should include other characteristics of decentralised generation as well, among these robustness towards external changes, availability of capacity and vulnerability.
- The possible deployment of decentralised technologies seems to depend heavily on the organisational set-up of the power industry in the Member States. Although economics of decentralised plants might be equivalent to large power plants, other considerations concerning the plants capabilities of contributing to the general load management or in keeping up the required reserve capacity might be more important in deciding what kind of plant to construct, especially if the power industry is not taking part in a liberalised power market. Thus part of this barrier could be abandoned if the power industry was liberalised in all EU Member States.

6.5.2 EU energy technology R&D

Technology research and development plays a key role in developing and implementing decentralised energy generation in the EU. This is confirmed by the DECENT future study, a survey conducted among a group of DG experts, who in particular stress the importance of R&D for PV and fuel cells, but also for achieving cost reduction in biomass technologies and for developing new wind turbine concepts. The analysis of current and planned EU R&D policies shows that these are to a large extent in line with these findings. On the other hand, with less resources, as announced in the future key actions for sustainable development of the 6th Framework Programme, EU enlargement, and globalisation, resources should be focused with a few, but well-defined targets. The DECENT future study indicates that these policies should emphasise both environmental concerns as well as activities aiming at cost reduction.

6.6 Recommendations for further research

There are many subjects that are important to the integration of DG in EU electricity systems which could not be studied within the DECENT project, but which deserve further attention in future research projects. First, given the expected growth of the market share of intermittent renewables and heat-based CHP, the costs of imbalances will become increasingly important, and the application of priority dispatch mechanisms may become increasingly less feasible. Therefore, further research on technical and market solutions to balancing problems is crucial.

- Research on technical solutions to imbalances: due to the intermittent nature of mainly wind real cost are incurred by the electricity system as a whole. These costs are not resolved through priority dispatch. In order to enable DG operators to limit imbalances, research on electricity storage is needed.
- Research on market solutions to balancing problems. Although in the short run, priority dispatch may be a mechanism to shield DG from the effects of balancing and settlement systems which have not been geared up to integrate DG, this will become more costly when the share of DG in the market increases. More economic research should be directed at how intermittent renewables and CHP can be treated in balancing and settlement mechanisms, how balancing costs should be allocated and how incentives can be given to different actors.

- Finally, it is recommended that further research on the role of information and communication technology (ICT) in co-ordinating market and network operations should be conducted. ICT systems can indicate what's happening on the networks, and thus provide greater transparency to network operators.

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EU ENERGY LEGISLATION APPLICABLE TO DG

A.1 Legislation to promote electricity from DG

A.1.1 Renewables Directive

On 27 October 2001 the Renewables Directive[53] entered into force. The Directive establishes the framework for renewable energy policy development in the Member States and for harmonisation of Member State support schemes in the longer run, and contains provisions on connection and access to the grid. Furthermore the Directive establishes indicative targets for each Member State for the penetration of renewable electricity.

The Directive considers the following renewable sources: wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases. Biomass means: the biodegradable fraction of products, waste and residues from agriculture, forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste. Support for biomass sources should be consistent with the waste treatment hierarchy.

The Commission monitors the progress of Member States towards achieving their national targets. Every 2 years the Member States and the Commission will report on the progress towards meeting the national indicative targets. If necessary for the achievement of the targets, the Commission will submit proposals to the European Parliament and the Council for mandatory targets.

The Commission reports on the experiences gained with the application of national support schemes. Four years after the entry into force of the Directive the Commission will present a report on experience gained with the application and coexistence of the different support mechanisms in the different Member States. The report shall assess the success, cost-effectiveness of these systems and if necessary be accompanied by a proposal for harmonisation of support mechanisms through a framework for renewables support mechanisms in the EU. If further harmonisation of support schemes is deemed necessary the proposal shall include a transition period of at least 7 years for Member State schemes to be adapted.

Within two years after entry into force of the Directive Member States shall set up a system to guarantee the origin of renewable electricity. Guarantees of origin should be mutually recognised by the Member States.

Member States may grant priority access to the grid for electricity produced from renewable sources. TSOs shall give priority to renewable electricity generators in dispatching the electricity system. Member States shall put into place a legal framework or require transmission system operators and distribution system operators to set up and publish objective, transparent and non-discriminatory rules relating to the bearing of costs of technical adaptations, such as grid connections and grid reinforcements. Similar provisions apply to rules relating to the sharing of costs of system installations, such as grid connections and reinforcements, between all producers benefiting from them. Furthermore, Member States shall ensure that the charging of transmission and distribution fees does not discriminate against electricity from renewable energy sources.

[53] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal energy market, OJ L 283/33 (2001).

Member States shall evaluate the existing legislative and regulatory framework with regard to administrative procedures for the production of renewable electricity. The results of this evaluation should be reported to the Commission before October 2003. The Commission shall, in a summary report available before December 2005, and on the basis of the Member States' reports assess best practices with respect to administrative procedures.

A.1.2 Proposal for a CHP Directive

The Commission's intention to propose a directive on CHP has been indicated on various occasions, including in the 'Communication on the implementation of the first phase of the European Climate Change Programme'[54]. The proposed 'Directive on the promotion of cogeneration based on useful heat demand in the internal enegry market' was published on 23 July 2002.[55]

According to Article 1, the Directive would have the purpose "to create a framework for promotion of cogeneration based on useful heat demand in the internal energy market". Useful heat would be defined as "heat produced in a cogeneration process to satisfy an economically justified demand" whereby certain criteria for high-efficiency cogeneration have to be met. The Directive would cover all technologies currently used for CHP or which are under development. Its Annexes would suggest a methodology for determining the electricity production from CHP, the efficiency of CHP installations, efficiency reference values of separate heat and power production, and guidelines for determining national potentials for high-efficiency CHP. The Directive would include the following main parts:

- The Directive would distinguish three different classes of cogeneration, which would be subject to different efficiency requirements, namely industrial, heating, and agricultural CHP.
- Member States would have to establish systems to issue 'guarantees the origin' of electricity from cogeneration, to prove that electricity sold comes from CHP. These guarantees would need to specify the origin (fuels, date and place), quantity and efficiency of the CHP electricity produced. They should be recognised EU-wide.
- *Efficiency criteria for 'high-efficiency CHP'* would be different for existing and new installations. The efficiency of cogeneration would be compared with separate production of heat and electricity. For new CHP plants, the Directive would establish EU-wide reference values representing Best Available Techniques for separate production. Existing plants would be compared with efficiency values of existing separate production in each country. Compared to the reference values, new CHP should provide energy savings of at least 10% in order to qualify as high-efficiency CHP. For existing installations, this would be 5%.
- Member States would have to calculate, according to criteria set out in the Directive, their national potentials for high-efficiency CHP for at least the three different classes (industrial, heating and agricultural CHP), describe barriers to the realisation of this potential, and report regularly to the Commission on progress in realising their CHP potentials. The Commission would need to contrast this progress with the 18% Community goal for CHP and "consider whether it is appropriate to establish indicative objectives for each Member State". This latest provision, however, is part only of the preamble of the proposed Directive.
- Within their support policies for CHP, Member States would have to ensure that cogeneration is based on the useful heat demand and that opportunities to reduce energy demand have been considered. The Commission would have to evaluate the compatibility of these schemes with Community environmental and state aid policies. It also would have to analyse, for the first time 4 years after the Directive would come into force, the successes and effectiveness of national support policies. According to the preamble of the Directive, support schemes should concentrate on plants with a capacity of less than $50MW_e$ or, for bigger installations, for the amount of electricity produced by the capacity below this limit.

[54] COM(2001)580
[55] COM(2002) 415

- In terms of electricity grid system issues, transmission and distribution system operators would need to ensure the transmission and distribution of electricity from CHP. The Directive would make published rules and tariffs for system adaptations and the sharing of connection costs and benefits between all system users mandatory, based on objective, transparent and non-discriminatory criteria. It also would establish the possibility to require system operators to bear these costs partly or fully. System operators would need to provide CHP producers with comprehensive and detailed cost estimates prior to connection. CHP producers could be allowed to put connection works out for tender. Discriminatory transmission and distribution fees would be prohibited. National provisions could stipulate that tariffs for system use take into account 'realisable cost benefits', such as those resulting from the direct use of the low-voltage grid. For non-eligible customers (this includes, until further notice, all non-commercial customers), these would need to be published and approved by an independent regulatory authority. There would be a duty to monitor and benchmark tariffs and conditions for sales to, and purchase of power from, CHP producers, with three-annual reporting to the European Commission on the findings. Finally, Member States should facilitate grid access of CHP installations using renewables or with a capacity of less than 1 MW_e.
- Member States would need to evaluate their authorisation procedures for CHP applications. These should encourage CHP installations which are sized to match economically justified heat demands, reduce barriers to the increase of CHP, streamline procedures, and make sure that they take into account the particularities of specific CHP technologies. If appropriate in specific national legislation, standard rules for authorisation procedures should be introduced and the possibility of fast-track planning procedures for CHP producers should be considered.
- The Directive would create extensive reporting requirements on many of the requirements set out in the Directive. On the one hand, Member States would need to report to the European Commission, with the first report - with the exception of CHP statistics which would need to be submitted annually - being due two years after the Directive comes into force (i.e. possibly 2005). The European Commission, in turn, would report to the European Parliament and the Council two years later, this means probably 2007 and then every six years.

A.1.3 Community guidelines on State aid for environmental protection

These new Guidelines[56], which came into force in 2001, and will cease to be applicable on 31 December 2007, should help familiarise Member States and firms with the criteria used to deciding whether or not state aid measures for environmental protection are compatible with the rules of the common market, i.e. do not have adverse effects on trade between Member States and on competition. The Guidelines thus specify whether and under what conditions State aid may be regarded as necessary to ensure environmental protection and sustainable development without having disproportionate effects on competition and economic growth.

The context is that Member States are granting state aid more frequently in the energy sector and the aid they provide is often in forms which have been rather uncommon until recently, such as tax reductions, exemptions, or new forms of operating aid.

Under point 24, Member States action to promote renewable energy sources and CHP has explicitly the encouragement of the Commission "given the major advantages for the environment". If such measures constitute State aid, they are acceptable subject to certain conditions.

Investment Aid

Under point 30, 31 and 32 of the Guidelines, investments into energy-saving measures and the use of renewable sources are deemed equivalent to investments to promote environmental pro-

[56] 2001/C 37/03

tection. Because such investments help achieving economically the Community objectives for the environment they are eligible for investment aid at the basic rate of 40 % of eligible costs, defined as "extra investment costs necessary to meet the environmental objectives". Measures in support of RES are called one of the Community's environmental priorities, and in some case Member States will be allowed to grant investment aids up to 100% of eligible costs.

The rate of 40% also applies also to investments in CHP "if it can be shown that the measures are beneficial in terms of the protection of the environment because the conversion efficiency is particularly high, because the measures will allow energy consumption to be reduced or because the production process will be less damaging to the environment", and taking into account that more CHP is a Community priority for the environment. The rates can even be higher in assisted regions or if the investment is done by SMEs.

Operating Aid

With regard to operating aid in the form of tax reductions or exemptions, such support mechanisms are principally possible for RES. For CHP it should be clearly associated with a beneficial impact on the environment. Operating aid must be:

- Limited to compensating for extra production costs by comparison with the market prices of the relevant products or services.
- Temporary.
- As a general rule, be wound down over time.
- Limited to five years.

There are detailed provisions on operating aid in form of tax reductions and exemptions. Investment aid and operating aid cannot be combined, they are alternatives.

For RES, operating aid may take the form of:

- Subsidies compensating difference between renewable electricity production costs and wholesale electricity prices.
- Market mechanisms such as TGC and tendering systems.

At any case, the support level may not exceed 5 €ct/kWh (based on a calculation of avoided external costs).

The guidelines may create uncertainty for investors by making access to incentives dependent on Commission approval. They also leave much room for state-level specific incentive policies, such as the German feed-in tariffs, which were permitted under these guidelines.

A.2 Legislation to promote competition in the energy sector

The EU legislation on the internal energy market is laid down in a number of documents. The Electricity and Gas Directives are the most important ones, described in more detail in the next sections. The implementation of the Electricity and Gas Directives was monitored by the Commission and summarised in several working papers[57]. After several political initiatives to speed up the liberalisation process, the Commission has elaborated a set of proposals of new instruments for a completion of the internal energy market, further described below in Section A.2.3.

Also important are the Florence and Madrid regulatory processes in which national regulators try to harmonise national regulations, for electricity and gas respectively[58].

[57] Commission Staff Working Paper SEC(2001) 438 of 12 March 2001 'Completing the internal energy market' and Commission Staff Working Paper SEC(2001) 1957 of 3 December 2001 'First report on the implementation of the internal electricity and gas market'.

[58] See also http://europa.eu.int/comm/energy/en/elec_single_market/florence/index_en.html and http://europa.eu.int/comm/energy/en/gas_single_market/madrid.html.

- In 1998 the European Commission set up the Electricity Regulatory Forum of Florence. The Forum consists of national regulatory authorities, Member States, European Commission, Transmission System Operators, electricity traders, consumers, network users, and power exchanges. It was set up to discuss issues regarding the creation of a true internal electricity market that are not addressed in the Electricity Directive. The most important issues addressed currently at the Forum concern cross border trade of electricity, in particular the tarification of cross border electricity exchanges and the allocation and management of scarce interconnection capacity.
- In 1999 the European Commission took the initiative to set up the European Gas Regulatory Forum of Madrid. The Forum consists of national regulatory authorities, Member States, the European Commission, Transmission System Operators, gas suppliers and traders, consumers, network users, and gas exchanges. It was set up to discuss issues regarding the creation of a true internal gas market, which are not addressed in the Directive. The most important issues addressed currently at the Forum concern cross border trade of gas, in particular the tarification of cross border gas exchanges, the allocation and management of scarce interconnection capacity and other technical and commercial barriers to the creation of a fully operational internal gas market.

Thus the main focus has so far been transmission pricing. In the future, however, this could be extended to (access to) distribution grids.

A.2.1 Electricity Directive

The Electricity Directive[59] is the central piece of EU liberalisation legislation relevant to DG. It aims to create the conditions for the completion of a competitive electricity market as an element of the internal market within the EU territory. It establishes common rules for the generation, transmission and distribution of electricity, foreseeing a gradual transition from the former national, monopoly-based electricity systems with captive customers to a liberalised electricity market.

Articles 4-6 of the Directive give member states the choice between a tendering and/or and authorisation procedure for the construction of new generation capacity. All member States have chosen the authorisation procedure with the exception of Portugal, which opted for a mixed system consisting of tendering for the public system and authorisation for the private system. This means, except the part of Portuguese generation capacity which needs to be put out to tender, members states had to lay down objective, transparent and non-discriminatory criteria for the grant of authorisations for the construction of generating capacity. This potentially includes criteria relating to security of supply, environmental protection and energy efficiency. Member States are therefore explicitly authorised to devise criteria to support decentralised generation.
Article 8 of the Directive requires that dispatching of generation installations be based on objective, public and non-discriminatory criteria. Member states are given the opportunity to approve these criteria. Notably, they can require the transmission system operators to give priority to DG installations in the dispatching process.

A.2.2 Gas Directive

The Gas Directive[60] affects DG in so far, as operators of natural gas-fired DG installations participate in the natural gas market as gas consumers. Its importance is based on the increasing share of these installations within the CHP sector. Coal and heavy fuel oil capacity is being replaced by gas-fired units. Also, gas is the fuel of choice for most new CHP capacity.

[59] Directive 96/92/EC concerning common rules for the internal market in electricity.
[60] Directive 98/30/EC concerning common rules for the internal market in natural gas.

The Gas Directive is partly modelled on the Electricity Directive. It establishes common rules for the transmission, distribution, supply and storage of natural gas. Similar to the electricity sector, the open gas market should develop gradually through giving an increasing share of customers access to it. Large customers with high gas consumption levels will become first eligible, followed later on by groups of smaller consumers.

Article 18 is of particular relevance for CHP. This Article obliges Member States to designate gas-fired power generators as eligible customers irrespective of their annual consumption levels - except with regard to CHP, where Member States are allowed to set such thresholds for eligibility "in order to safeguard the balance of their electricity market". Such thresholds, which must not be lower than the generally applicable thresholds for eligible customers, have to be notified to the European Commission. This provision therefore allows Member States to discriminate against smaller CHP schemes. Provisions in the Netherlands, France, Denmark and Spain are based on Article 18.

A.2.3 Completing the internal energy market

The 'Proposal for a Directive amending Directives 96/92/EC and 98/30/EC' concerning common rules for the internal markets in electricity and natural gas'[61] forms part of a package published in 2001 which also includes a Communication from the Commission entitled 'Completing the internal energy market' and new measures on cross-border electricity exchanges.

In March 2002, the European Parliament came forward with many significant amendments to the proposed Directive, many of which were very supportive of CHP, distributed generation and the establishment of a level playing field in the markets. The Commission has rejected or weakened many of them when drafting the current, amended version of the proposal.

Also, intensive debate within the Council of Ministers has started, with differing positions and reluctance from certain Member States on specific issues. For instance, France was opposed to complete unbundling and opening of its electricity and gas markets, whilst Germany rejected the idea of a dedicated national regulatory authority for electricity and gas[62]. At the European Council in Barcelona in March 2002 Heads of Government decided to support the proposal to completely separate transmission and distribution from production and supply - yet leaving unclear what type of separation they had in mind - and to enforce non-discriminatory access for consumers and producers to the networks, based on transparent and published tariffs. Only a compromise could be reached as regards further market opening. Some of the items in the Barcelona conclusions were thus unclear and it is not known how exactly they will be integrated into the formal Common Position of the Council of Industry and Energy Ministers. The Danish Presidency is expected to concentrate all its efforts on reaching this agreement. It will use the Commission's amended proposal of the Directive as a basis for negotiations with the aim of, perhaps, producing a compromise draft in October 2002.

Once the Council's Common Position is published, the necessity of a second reading in the European Parliament is quite likely.

The Directive principally would aim to amend the existing Electricity and Gas Directives in order to achieve more and faster liberalisation both in the electricity and the gas markets of Member States. This would include faster market opening, fairer access to networks, further unbundling and more cross-border exchanges, but also complementary measures to protect the environment. All Member States would have to establish completely open markets by the beginning of 2005 (Electricity: non-domestic customers from 2003, all customers from 2005; gas: non-domestic customers from 2004, all customers from 2005). Because amendments to both Direc-

[61] COM(2001)125 final.
[62] France's position might have changed after national elections resulted in a strong right-wing government.

tives follow the same model, and are contained in the same document, the following overview will concentrate on the electricity side. Most amendments of the Gas Directive would be analogous (complete unbundling of transmission from supply activity, the creation of a powerful regulatory authority, and ex-ante approval of tariffs and conditions for connection and use of the networks[63]).

- In terms of unbundling, transmission and distribution system operators, which form part of an integrated electricity company, would have to be independent from other activities in the undertaking at least in terms of legal form, organisation and decision-making. A series of requirements and mechanisms would become mandatory in this respect. Member States could exempt distribution system operators with less than 100,000 customers from this provision. Integrated companies would also need to continue the existing separation of accounts for generation, transmission, distribution, and supply activities.
- Distribution system operators would need to consider energy efficiency/demand side management measures and/or distributed generation when planning the development of the network. This could supplant the need to upgrade or replace capacity.
- Regulated third party access to transmission and distribution networks would become mandatory. Network tariffs would need to be objective and non-discriminatory, and be approved and published before coming into force.
- Member States would need to designate national regulatory authorities, which are "wholly independent of interests of the electricity industry" with a minimum set of regulatory and supervisory powers vis-à-vis electricity undertakings, including:
  - The continuous monitoring the market to ensure non-discrimination, effective competition and the efficient functioning of the market.
  - The right to approve, propose, and also enforce, methodologies used to calculate or establish the conditions and tariffs for grid connection and use, and the provision of balancing services, before these come into force.
  - The function of a dispute settlement authority.
- A number of new concepts would be introduced, including 'distributed generation', and 'energy efficiency/demand side management'. Member States are principally authorised to impose on electricity companies' energy efficiency and climate protection duties as part of public service obligations and in the context of authorisation procedures.
- The explanatory statement to the proposed Directive points out that continued promotion policies in favour of CHP and renewables are justified because of their competitive disadvantage as long as external costs of energy systems are not internalised.
- Electricity suppliers would need to specify the 'percentage contribution of each energy source to the commercial fuel mix for the electricity supplied' and the 'relative importance of each energy source' for the production of greenhouse gases in their bills and all promotional material for final customers.
- Authorisation procedures for small electricity generators of less than 15 MW and all distributed generation facilities would need to be streamlined and expedited.
- Member States would resort to the publication of tenders for new generation capacity or energy efficiency/demand side management measures, but only for reasons of security of supply, environmental protection or the promotion of new technologies, and only if authorisation did not deliver the desired result.

A.3 Legislation on energy use in buildings

The original proposal for a Directive on the energy performance of buildings [64] from May 2001 has been substantially amended in early May 2002, taking account of amendments of the European Parliament's first reading and debates within the Council of Ministers. The Council is likely to adopt the Directive on its meeting on 25 November 2002. The Directive would need to

[63] The scope of the Gas Directive would be widened to include biogas, gas from biomass and LNG.
[64] Proposal for a Directive on the energy performance of buildings COM/2002/0192 final.

be transposed into national law, thereby effectively bringing it to action, within a maximum period of six years.

The basic objective of the Directive is to promote the improvement of the energy performance of buildings within the EU taking into account outdoor climatic conditions and indoor climatic requirements, local conditions and cost-effectiveness. It would define a methodological framework to calculate the integrated energy performance of buildings, for which it would set minimum requirements, both for new buildings and the renovation of existing buildings. When setting energy performance requirements, Member States would have the opportunity to differentiate between new and existing buildings, and between different categories of buildings, including apartment blocks, hospitals, education buildings, and hotels. The setting of national requirements should take into account 'best practice'. The calculation of the energy performance of buildings would have to take into account the positive influence of electricity produced by CHP and/or district heating systems.

The Directive also would create an energy certification system of buildings in order to make information on its energy performance easily accessible to consumers and the public, allow comparison, and recommend improvements.

For new buildings with a total surface area over 1000 m^2, Member States would have to demand technical, environmental and economic feasibility studies of decentralised energy supply systems based on, inter alia, CHP and district heating before the building permit is granted. The result of such an assessment should be made available to all stakeholders for consultation.

The Directive would establish regular inspection duties for boilers and central air conditioning systems[65] with the aim to reduce energy consumption and CO_2 emissions. Heating installations, which are older than 15 years, would be subject to a one-off inspection of the whole installation. The competent authorities should provide advice to the users on the replacement of the boilers and/or air conditioning system, and on alternative solutions.

A.4 Legislation on the harmonisation of taxation

The proposed Directive restructuring the framework for the taxation of energy products [66] aims to impose minimum tax rates on energy products, which could be offset by reducing statutory charges on labour. The proposal lists energy products covered and prescribes minimum levels of taxation for them. The proposal seeks to broaden the application of the Directive of excise duties to include coal, natural gas and electricity. It would cover motor and heating fuels. The harmonisation of national tax rates would occur in 3 two-year stages. The proposal includes the possibility of tax reductions or exemptions for CHP and electricity from renewable energy sources.

At the EU's Barcelona summit in March 2002, heads of government agreed that EU finance ministers should "reach an agreement on the adoption of the energy tax Directive" by December 2002," in parallel with "the liberalisation of industrial energy markets agreed at Barcelona". This marked the end of long-lasting objections against such a step by some Council members, notably Spain and the UK which refused to consider a tax until energy markets had liberalised. In May 2002 Spanish finance Minister presented fellow ministers with detailed proposals for the Directive. Included are recommendations for minimum national excise duty rates on various fossil energy products plus electricity, to be introduced within four years. The measure might be finalised by the end of 2002. In line with the original proposal, the Spanish proposal includes

[65] Only boilers with an effective output of more than 10 kW and air conditioning systems with an effective output of more than 12 kW.

[66] Proposal for a Council Directive restructuring the Community framework for the taxation of energy products COM(97) 30 final.

the possibility of tax reductions or exemptions for CHP and electricity from renewable energy sources. A long series of additional exemptions is also proposed, which have been opposed by the European Commission. Mandatory tax exemptions would include, inter alia:

- Energy products used for purposes other than as motor fuels or as heating fuels.
- Energy products used to produce electricity, and heat generated during its production. However, Member States would still be allowed to raise taxes for environmental policy reasons (eco-taxes) and would not have to respect the minimum levels of taxation laid down in the Directive.

In addition, Member States could chose to, partially or fully, issue tax exemptions for:

- Energy products used under fiscal control in the field of pilot projects for the technological development of more environmentally-friendly products or in relation to fuels from renewable resources.
- Forms of energy, which are of solar, wind, tidal, geothermal origin or from biomass or waste.
- Heat generated during the production of electricity.
- Natural gas in emerging gas markets where the share of gas in the domestic and industrial market is less than 10%, and for no longer than 10 years after the coming into force of the Directive.

Member States would be allowed to refund all or part of the tax paid in relation to firm's investments in improving the efficient use of energy. A refund would also be possible, when renewable energy sources were used, the tax paid by the consumer on electricity and heat generated during its production. In this case it is the producer who would receive the refund.

A.5 Legislation relating to emissions reductions

The proposal for a framework Directive for greenhouse gas emissions trading[67] has been published together with the Communication on the implementation of the first phase of the European Climate Change Programme[68], which reports on progress made in relation to the European Climate Change Programme (ECCP)[69]. With regards to the DECENT project, the number of decentralised CHP plants affected by the proposed Directive, in its initial phase, would be limited.

The proposal aims to establish a legal framework for a EU greenhouse gas emissions trading scheme to be launched by 2005 for a three-year pilot phase. The scheme would be limited to CO_2 emissions and apply to most installations regulated by Directive 96/91/EC on integrated pollution prevention and control (IPPC), plus some installations not covered by the IPPC Directive: combustion installations with a rated thermal input of > 20 MW, and certain activities in the refinery, ferrous metal, mineral, pulp and paper industry[70] - altogether some 4-5000 installations emitting approximately 46% of estimated EU CO_2 emissions in 2010. In practice, permitting procedures under IPPC could be combined with procedures to obtain the 'greenhouse gas emission permit' required for installations under this new Directive. The permit would be a prerequisite for continued operation of the installation, and would require it to hold enough CO_2 emission allowances to cover its emissions in a given period.

Yet, there would be one important difference. The IPPC Directive is based on an extended definition of pollution, which also covers greenhouse gas emissions. It normally requires installa-

[67] Proposal for a framework Directive for greenhouse gas emissions trading within the European Community COM (2001) 581.

[68] Communication on the implementation of the first phase of the European Climate Change Programme (COM(2001)580.

[69] Communication from the Commission on EU policies and measures to reduce greenhouse gas emissions: Towards a European Climate Change Programme (ECCP) COM (2000)88.

[70] If an operator has several production sites, these will be counted together.

tions to apply so-called Best Available Techniques (BAT) to reduce their greenhouse gas emissions to the largest extent possible. For greenhouse gas emissions from those installations covered by the new Emissions Trading Directive, however, the IPPC provisions do not apply. Instead, these emissions would be regulated by the new Directive, i.e. become subject to the emissions allowances and trading regime.

Member States would allocate CO_2 emission quotas to installations in line with national emission reduction targets under the EU Burden Sharing Agreement on the Kyoto Protocol, and the requirements set out in Annex III of the Directive. Notably, national allocation plans should be drawn up stating the total amount of allowances and the method to allocate them, based on objective and transparent criteria. The allowances could be gradually reduced in line with national CO_2 reduction targets. During the pilot period from 2005 to 2007 allocation would be at no cost. Based on the experiences made, the method of allocation in the period 2008-2012 would then be determined.

Companies that do not use their allowances could bank them from one year to the next, or sell them to another company that does not meet its CO_2 target and therefore requires additional allowances. The Directive would therefore create a European market for allowances, which would be recognised across the EU without further negotiation. Companies, which emit CO2 without holding the necessary allowances, would face penalties.

The EU-wide emissions trading scheme has been designed to be compatible with an envisaged broader international trading scheme under the Kyoto Protocol's flexible mechanisms, and also with national schemes in EU Member States. For instance, the UK has launched its national scheme in early 2002, whilst Denmark and Belgium are also preparing similar programmes.

CHP should principally be a winner in an emission trading scheme because it is an effective technique for reducing CO_2 emissions on a national or EU-wide basis. However, the scheme suggested appears not to reward new CHP installations. The installation of a CHP plant on an existing site where there has not been previously CHP will increase on-site fuel consumption, and thus CO_2 emissions, but at the same time this plant will reduce the total emissions by displacing central electricity generation elsewhere. Yet, because emissions allowances are allocated to operators of individual installations, the operator of the new CHP plant is likely to have to buy more allowances for his increased CO_2 emissions, despite the fact that his decision actually decreased the total emissions of CO_2. Conversely, the central power generator whose electricity has been replaced by the CHP plant will have allocations to sell on to the market.

In addition, the installation of CHP on some sites with combustion installation may raise their thermal input above the threshold of 20 MW. Thus this site would then become a site included in the emission trading regime. This change of status possibly causes two problems. Firstly, the site may not wish to change status and be a player in the scheme, and so will therefore not install CHP. Secondly, and more importantly, the site will need to receive an allocation. It is not clear in the proposal how this will be achieved.

With the current design, the emissions trading scheme is therefore likely not to encourage, or may even prevent, the new installation of decentralised CHP capacity.