Annex II – DG System Integration in Distribution Networks

Final Report

Guideline and Recommendations for DER System Integration in Distribution Networks

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prepared
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1. Introduction

ENARDs vision is to facilitate the uptake of new operating procedures, architectures, methodologies and technologies in electricity transmission and distribution networks, such as to enhance their overall performance in relation to the developing challenges of network renewal, renewables integration and network resilience. The scope of ENARD Annex II is distributed energy resources (DER) system integration into low and medium voltage networks including technical, economical, organisational and regulatory aspects and related active distribution network operations.

Due to current energy related framework conditions and technical developments the penetration of DER and especially Distributed Generation (DG) in distribution networks increases continuously and it can be expected that this increase will continue in the future.

These results in a growing density of electricity resources within distribution networks, where technical issues related to the bidirectional power flow, reliability aspects (power quality and continuity of electricity supply), stability aspects, network capacity, the management of network, energy and load are becoming increasingly important. The common strategy to view distributed electricity production as a “negative” load and the therefore resulting „fit & forget“ philosophy is not a sustainable and applicable solution for the future. Under such conditions, a significant rise of the share of DG would only be possible with a very cost intensive extension of network capacity. In addition, modelling, information and communication technology (ICT), market and regulatory aspects play an important role when dealing with the growing share of DG in distribution networks.

Beyond that, the share of electricity in the overall energy consumption will further increase[1] and hence a new wave of distributed electricity feed into distribution networks has to be anticipated. These developments are supported if distributed power generators are enabled and secured by network operators.

In addition to the network operators‘ key task - which is setting up and operating a secure network at any point of time in all regions of the grid area - operators have to guarantee a high level of “electricity product” quality in case of an increase of customers demand especially for business and industry consumers. Increasing loads will eventually require a reinforcement of the network, and network operators (and in the end connected grid users) will have to bear these costs, if regulators do not defray these expenses.

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[1] see Key World Energy Statistics 2007, International Energy Agency, page 28

Network operators have been confronted with reductions of accountable network costs by regulators for years. This increases the pressure on network operators: There could be a critical point where too low investments for grid expansion causes reduced voltage quality and reduced security of supply and become a real threat. The population could be exposed to a limited economic growth due to a lack of quality of supply. In order to prevent and counteract this trend more cost-efficient solutions for network support must be found.

Research on integration of DER in distribution networks has been progressing over the past years, but has not managed to progress from a theoretical concept to practical real life experience with active networks. There is virtually no global collaboration at the scientific level.

Therefore the objectives within IEA ENARD Annex II are:

- to build up and exchange knowledge on DER system integration aspects and existing active network approaches amongst the global players in distribution networks,
- to develop guideline(s) for network operators and political decision makers on how to manage and implement the transition from a passive to an active distribution network,
- to promote implementation possibilities for active distribution networks as an overall goal of this Annex II.

In the present report, based on the analysis of national experiences, guidelines and recommendations for the organisational framework, business models and the operation and control of active networks with a high penetration of distributed energy resources will be presented.

2. DG System Integration and Active Networks

Integration of distributed generation was and is one of the main drivers for major changes within the electricity distribution systems and the path towards active network operation and Smart Grids respectively. Within the present chapter DG system integration related terms and possible benefits of active networks will be defined. In addition the relationship between future network operation, technical, economical and regulatory framework will be discussed.

2.1 Distributed Generation, Active Network Operation and Smart Grid Definitions

Among others the main driver for the change of network operation and planning in distribution networks is the increasing share of distributed generation. The new possibilities and needs due to large scale DG motivated the development of solutions for active integration of DG units into network operation and the active operation of distribution networks, the so called active networks. This led finally to the more generally used term of Smart Grids.

A Smart Grid is based on an intelligent system composed of grid based energy conversion, transmission, distribution and monitoring/control system which enables a cost and energy efficient balancing between a high number of consumers, generators and in future more storage (e.g. e-mobility). Finally one of the Smart Grids objectives is the integration of a high share of distributed generation (additionally in future plug-in hybrids and electric vehicles).

To find a common understanding of the terms used in the present report within ENARD Annex II following definitions were found:

Distributed Generation

Distributed generation (DG) includes low power capacity generation units which are connected to medium or low voltage networks.

Distributed Energy Resources

Distributed Energy Resources (DER) includes distributed generation and additionally energy storages and flexible loads connected to regulated medium voltage and low voltage networks. DER is considered to be a resource for active power.

Active Networks

Active networks use monitoring, regulation and control mechanisms to actively influence network parameters during operation of the network with contribution of generators, loads and storage devices. In an active grid, the loads, generators and storage devices can be controlled in real time by means of information and communication technology (ICT). (Remark: A passive grid is the most commonly used way to realize/manage low and medium voltage networks: In a passive grid a feeder is connected to a transformer and that transformer is the pre-dominant or even only source of transmitting power to the feeder and the only means to control the state of the feeder (e.g. voltage control))

Smart Grid

Smart Grids on the medium and low voltage levels are active power networks, with a coordinated network management, based usually on bi-directional communication, between

- components embedded in the network
- generators
- energy storages and
- consumers

to enable an environmentally friendly, energy-efficient and cost-effective system operation that is ready for future challenges of the energy system.

2.2 Possible Benefits of Active DG System Integration and Smart Grids

Active distribution systems and Smart Grids respectively are introducing a new way of grid operation. Active networks use monitoring, regulation and control mechanisms which are actively influencing network assets, generation units, storage devices and consumers so that reserves (e.g. in the allowed, standardized voltage band above and below nominal value) are better utilized. Therefore it is necessary to incorporate network users and network components into the monitoring and control mechanism via information and communication technologies.

As network expansion – at least on the highest voltage levels - are getting more difficult, not only due to the difficulty to find investors for a strongly cost regulated grid but also due to lengthy transmission line authorization procedures, the development of new network monitoring and control approaches is a promising alternative. This should

- enable a higher contribution from distributed generation (renewable energy resources, CHP - Combined Heat and Power)
- and allow the handling of an increased consumers electricity demand

with minimum network reinforcement by the means of active distribution networks.

The following overall benefits of Smart Distribution Grids and active network operation can be identified:

- Active networks are a fundamental prerequisite to reach a higher share of renewable energy carriers, improved energy efficiency goals and the EU-required CO_2 reduction.
- Active networks enable the integration of a higher share of distributed generation (mainly based on production by renewables) into the existing electricity and power system. Optimised electricity supply will be reached through an improved interaction of distributed generation with consumption at distribution network level and combining them with conventional power plants.
- Cost for DG network integration can be lower than the cost for network reinforcement and lead to an optimized utilization of existing network assets.
- Active networks are a platform for efficient energy use, better utilisation of available energy and new services and markets (e.g. flexible tariffs, new business models for consumers, storage devices and generators)
- Active network solutions can be utilised to overcome limitations (e.g. voltage limits, capacity limits) and utilise the existing network components better
- Active networks enable participation of consumers by flexible demand (via advanced smart metering infrastructure)
- Active networks can improve security of supply (e.g. one of the main Smart Grids drivers in the U.S) and power quality. Both is a fundamental basis for the efficient production of economic goods.
- Active networks give incentives for the optimization of the entire energy system due to a systemic view on network, consumer, storage and generation
- Active networks can contribute to the reduction of dependency on energy imports (e.g. important for the European Union) from the outside.
- Active networks are enabling the integration of a high share of plug-in hybrids and electric vehicles.

2.3 Active Networks in the Context of Technical, Economical and Regulatory Framework

The realization and handling of Active Networks and Smart Grids are strongly system based. They influence the transmission and distribution system, individual network components, generation, consumption and storage as well as power markets and all associated businesses. Due to the fact that network operation is a regulated market also regulatory aspects must be considered. Finally for the future planning and operation of electricity networks three fundamental points are crucial:

- The technical,
- the economic (commercial)
- and the regulatory framework.

In order to find new solutions for active network operation there is a strong relationship between these three aspects. Business models in the natural monopoly of the electricity network are strongly influenced by the national and European legal frameworks and the guidelines from the regulatory authorities. New regulatory (e.g. new network interconnection requirements) as well as new business models (e.g. virtual power plants) can be drivers for the development of new technologies. On the other hand new technologies and innovations including new functionalities can be the basis for new regulatory and economic framework (see Figure 1).

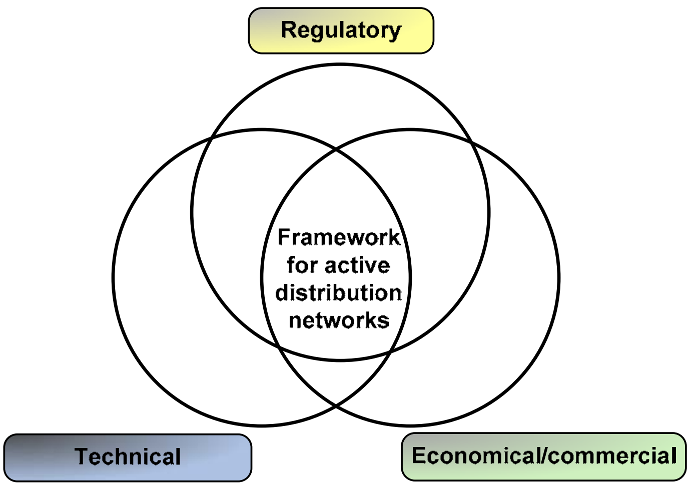

Figure 1: Interdependencies between regulatory, technical and economical aspects

This systemic view causes several challenges:

- The optimal development of technical solutions for the transition from passive to active distribution system must be found.
- More complex requirements for maintenance and system operation need to be fulfilled.
- Higher transmission capacities for networks are required
- There is a need for new contract models between grid users, power providers and associated business models.
- In many countries the willingness to participate in demand side management and demand response as well as the question who is going to pay for the expenses for the additional infrastructure is not clearly answered yet.
- Standards and market rules for the interaction and integration of generation units, consumers, storage devices and network assets must be adapted and introduced.
- Integrated and standardized communication interfaces need to be implemented and financed.
- Adapted legal and regulatory framework need to be developed.

3. Current Status of DG System Integration – ENARD Annex II Members Experiences

This chapter documents the current status and experiences of the IEA ENARD Annex II member countries in DG system integration based on the analyses of different questionnaires addressing DG system relevant issues. Two aspects are analyzed in the following sections:

- Network Operation and Control (Technical Aspects)
- Power Markets and Regulatory Aspects (Economical and Regulatory Aspects)

3.1 Network Operation and Control

3.1.1 General description of present electricity networks

The present electricity network structures in the participating countries share many common features but also differ in some essential ways.

Generally, power systems are traditionally divided into electricity transmission and distribution network based systems. This kind of division is determined by network structures. Typically, some kind of regional network can be seen between transmission and distribution levels. Often, one talks about “regional networks”, “sub-transmission” or similar.

Networks can also be characterized according to different classes of voltage levels: HV (High Voltage), MV (Medium Voltage) and LV (Low Voltage). Sometimes, in addition to these, EHV (Extra High Voltage) is also mentioned. In practice, MV and LV levels are associated to distribution network whereas EHV and HV levels to transmission network. Additionally, both HV and MV can be found in regional networks.

Figure 2 illustrates the variety of voltages in participating countries.

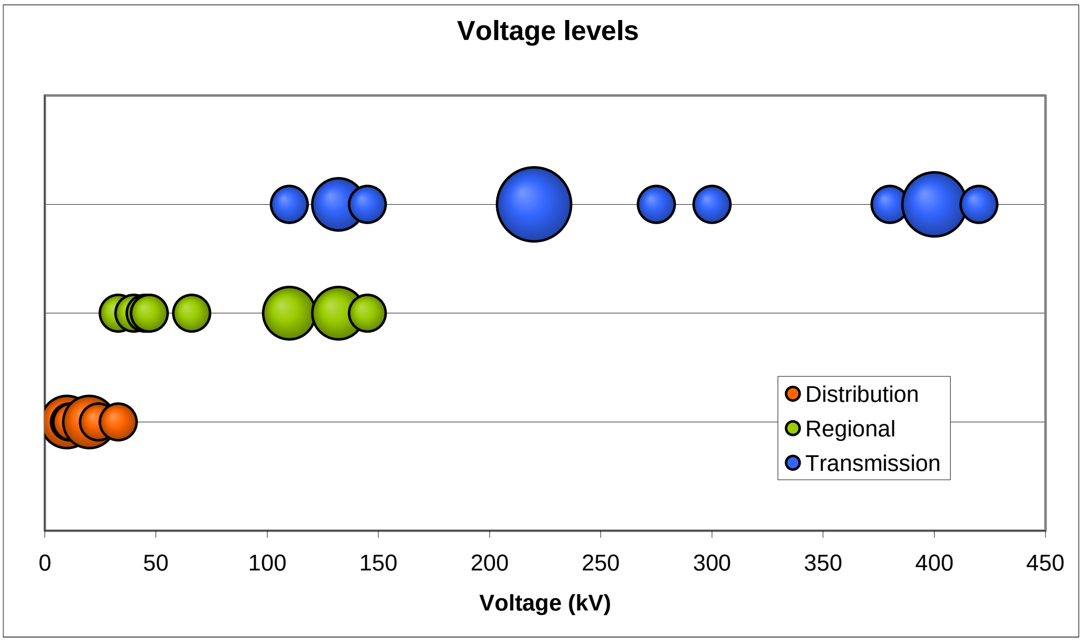

Figure 2: Voltage levels and their association to different networks in ENARD Annex II participating countries. The size of the bubble indicates the number of countries in which each voltage level is used.

The **structure of the distribution system** varies depending on country and also on local circumstances. A quite typical approach is to construct a distribution network in an open-loop/open-ring meshed way but operate it normally as radial. This means that the ring connection switch is normally open but can be quickly closed during and after disturbances in order to have again voltage on parts of the feeder which would be disconnected. Truly meshed (closed loop) networks are applied for instance in city centres and industrial areas. In Denmark, for example, all voltages above 0.4 kV are normally operated in a meshed (closed-loop) way. In many other countries the majority of distribution networks are operated radially, i.e. with open-loop distribution networks.

In a distribution network **earthing practices** see two prevailing techniques: Isolated network and compensation through Petersen coil[2]. In addition, direct earthing is used in one country. The usage of these two techniques depends mostly on the type of network – overhead lines or underground cables. As a general trend, the amount of cabling in distribution grids seems to be increasing due to the pressure of avoiding long interruptions caused by the failure of overhead distribution lines. Hence the usage of reactive power compensation to maintain voltage levels in distribution can also be forecasted to increase.

[2] Petersen coils are used to limit the arc currents during earth faults. A Petersen coil consists of a reactor connected to the star point of the three-phase power system. Inductance of the reactor is adjusted to match the line capacitance.

To summarize the general facts about distribution network among participating countries – allowing some exceptions – might be: "*radially used open-loop network, isolated on rural and compensated on urban areas, operated on voltages between 10 and 40 kV*"

3.1.2 Active network concept

The definition of the term "active network" is not unambiguous among participating countries. The term may be understood to include things such as flexible loads, distributed generation, smart metering and advanced distribution automation. It is also noted that the definition varies depending on the point of view: an academic definition of active networks may differ from those of a distribution network operator.

However, there are some issues that are widely mentioned among participating countries when defining the concept of active network. The keyword seems to be the *management of network* with new kind of components. The need for *flexibility* is also mentioned often regarding loads but also the operation of the network. *Controllability* is a third common part of definitions.

Less widely mentioned, however important, further definitions include for instance:

- Control of voltage and frequency by distributed generation as well as other components
- Automatic reconfiguration of the network after an event
- Online analysis of protection operation and fault location
- Investments in information and communication infrastructure
- Smart measurements and data gathering

There seems to be a consensus on the fact that the distribution network will have to be more active in the near future. At least four drivers can be seen for this transition:

- First of all, installing more DG in present networks requires more active network management. DG is further required in order to fulfil goals for an increased percentage of renewable energy based production and on reduced CO_2 emissions.
- The increasing attention on long customer interruptions and resulting penalties for distribution network operators (such as in the Nordic European countries) requires improved reliability of supply. This can be achieved with more investments in distribution automation to transform the network in a more active one. For instance improved fault location methods and more intelligently placed and operated switches along the distribution network can be used to shorten interruptions of power supply.
- A wide-scale introduction of plug-in hybrids and electric vehicles is possible in the near future. There is consensus that the impact on the

power system could be enormous. Similarly to DG integration, more active management of electric vehicles plugged to the grid would be needed.

- Smart meters are currently mandated and/or rolled out practically in all participating countries. The current status and timescales are different, but evidently the progress is towards equipping each electricity customer with a smart on-line meter. Depending on the meter types, a two-way communication may be included which would enable new possibilities for controlling and incentivizing loads to be more flexible and pro-active.

Currently, geographically local electricity systems can be considered to be the prime candidates for active networks. They are typically built for managing local constraints. A classical example at the moment would be an islanded distribution network that is energized with wind power together with suitable controllable devices such as storage, reactive power / voltage compensators or flexible loads. There are also applications in which a certain amount of DG can be shed based on the state of the network or in which the lines are rated dynamically based for example on temperature or wind speed in order to assure the maximum interconnection of DG and maximum distribution of power from DG.

Thus the present active network applications can be defined in a condensed way as “monitoring, communication and control advances for avoiding and managing grid constraints”. This would seem to be the direction of necessary progress in the near future as well instead of large system wide rollouts of active network.

Currently, there is no large-scale application of such systems that could be called active. However, switching loads has been used in most of the countries for longer times. This can be done with a time based switch or based on different tariff time intervals e.g. during nights when tariffs are usually low or during lunch hours when tariffs are often high. Switching can also be done via a remote communication system. The main goal of such a system has been to reduce load peaks. Considering the development of active networks, it seems that in many cases the equipment needed for load control might already be available. On the other hand, these systems are often old (from 1970s), perhaps not enough flexible and adaptable to today’s standards and they are not in wide-scale usage at the moment. In many cases the actual amount of loads connected to such system is unclear. In any case, similar types of much more flexible control actions related to loads are expected to be possible in the near future with two-directional smart meters.

As a conclusion, the active network according to participants could mean “managing a flexible and controllable distribution network for meeting the evident development in near future”.

3.1.3 Backup units

In most countries different kinds of backup units are in use. Generally, the responsibility of ensuring the supply to critical loads is on the customer side. Thus backup generator sets – ready to feed in power at times when the network cannot supply power to consumers - are used for instance in hospitals, airports, data centres etc. Smaller customers can ensure their supply mainly with static UPS systems.

Although the network operators are not responsible for backup units, the tightening requirements of avoiding longer interruptions are steering their interest towards owning and providing backup units. Since the network operators are typically not allowed to own power generation, there are slightly different approaches to the issue of backup generation. One common definition is that DSO can own mobile backup units. Permanently installed backup units are under operated and used under the control of the individual consumers.

Consumer backup units are usually not allowed to run at the same time, when the power is provided via the network connection. Instead, they must be equipped with changeover switches which change the connection of the critical load between the regulated distribution network and the backup unit. In other words, today usually the customer backup unit cannot feed in power to a working distribution network system. In some cases it can be possible to use backup unit in parallel as well which would make it similar to distributed generation unit. This kind of system is in use at least in one country where backup units are also delivering regulation power.

Mobile backup generation of network operators are placed in the network according to the local situation. Backup units may be used when unplanned sudden grid outages occur as well as for planned maintenance purposes. DSOs can also own and maintain some of the customer backup units according to separate agreements.

When considering the transition towards active network, backup units might offer one suitable technique since they are typically quickly started and often, they are already equipped with communication for starting. Thus they might be suitable for usage in the active network concept for adjusting and optimizing the local state of the network. However, beside the positive effect of increasing the security of supply, these units are typically diesel generator sets which are not very environmentally sound at least if used for longer periods.

3.1.4 Storage systems in distribution network

A storage system is understood as a system able to store electric energy, in other words able to feed power back to the power system over a given time interval based on its storage capacity and actual level. Systems for storing non-electric forms of energy, for instance heat boilers are considered as load management systems when applying the active network management philosophy.

Today, storage systems are not practically applied in real-world networks of participants. However, pilots and case projects where usage of network in an islanded mode is studied, often use energy storages for maintaining the power balance. A typical application may be a geographical island with wind power together with some storage and for instance a diesel backup unit.

It seems that the first real-world introduction of storage in the distribution grid will likely be for market purposes rather than system security of supply purposes. This means that especially hard to predict generation can be better sold to the market when balancing power from storage systems is used in parallel.

In the future storage systems are likely to play an important role as the share of DG increases. Storage is definitely needed together for stabilizing purposes with fluctuating energy sources such as wind power. Another interesting aspect is that depending on the type of storage system they may be able to offer some ancillary services for the network operation. Storage could for instance offer quickly to release reserves or even support the management of fault currents.

Also electric vehicles might become important storage components in the network. As they are charged regularly they form a natural energy storage which could be utilized in an intelligent way. However, in contrast to permanent local storage they are “mobile”, i.e. they may be charged and discharged at different locations connected to the grid. This must also be taken into account and increases the complexity to maintain a secure electricity supply.

3.1.5 Islanded operation of distribution network

When discussing islanded operation of distribution network, it is necessary to differentiate between intended and unintended islanded operation.

- Unintended islanding refers to a situation, in which a DG unit remains connected to the network following a fault or in case of disconnection for maintenance purposes without having a working connection of the (islanded) grid to the main power system. DG can thus energize a part of the network alone. Usually unintended islanding is not allowed due to power quality issues and practical safety hazards.
- Intended islanding is a situation planned by the network operator. Using DG for feeding into a part of the network during longer interruptions would

be very beneficial from all aspects. However, for this the power quality and correct operation of protection must be assured.

Generally, there is a clear consensus on islanded operation[1] among participating countries. A distribution network is not allowed to be run as an island – with the exception of the case in which a network operator operates the backup generation during a long interruption. Similarly, most countries see the islanded operation of distribution network as an interesting possibility: they are studying these possibilities.

Small island systems are reported on geographical islands in which often a combination of wind and diesel generation is applied.

There are interesting differences regarding the countries' experiences on islanding detection. While the need for a loss of mains protection is generally recognised, countries have a variety of requirements and practises ranging from to the absence of a dedicated loss of mains protection to complex requirements. Some participants reported real problems with unintended islanding, whereas others stated that there are no problems.
Some conclusions can be drawn regarding the answers:

- The occurrence of an unintended island is a rare phenomenon which must be however avoided due to the implied safety risks for persons and equipment.
- A few real cases showed that by using only general voltage and frequency protection relays without loss of mains detection system, the formation of an island is possible.
- The use of voltage and frequency relay is therefore not sufficient for the prevention of unintended islanding.
- It seems that there is no universal loss of mains protection. Depending on the network operation practices, DNOs have been requiring different protections systems.
- The requirements for small generators are more uniform among countries than those for larger generators.
- For large generators (with a significant impact on the network, e.g. on the voltage profile) which support the system, reliability considerations must be taken into account. In such cases, the loss of mains protection might need to be more complex to avoid unnecessary disconnections.
- Problems are reported more on areas where the share of DG has been so far low. The protection methods applied on these areas are usually simpler, which is one reason for problems. This can be explained by lack of experiences on real installation cases.

[1] A situation during which the connection to the main power system is lost and local generation remains feeding a part of the network alone or together with other generation units.

- Areas with high share of synchronous generation, mostly small-scale hydro power, seem to be more prone to islanding problems. This is due to the characteristics of synchronous generation.

The decoupling protection usually includes under- and overvoltage relays as well as under- and overfrequency relays. In addition, loss-of-mains protection relays mainly based on ROCOF (Rate of Change of Frequency) and VS (vector shift) are commonly used in most countries..
However, there are large differences on the protection philosophy between countries. The complexity of the loss of mains protection depends on the performance level which is desired. By using tight settings of the protection relays, the formation of an island can be avoided but at the same time, the number of nuisance trippings can increase. For large installations (having a significant impact on the network), more complex loss of mains protection may be required to ensure that these installations are only disconnected when absolutely necessary in order to avoid additional disturbances on the network. As an example, the use of remote tripping allows to disconnect a generator connected to a feeder depending on the circuit breaker operation in the substation.

One interesting issue is the possibility of integrating the protection functions to DG unit's inverter or other equipment and to avoid the installation of a disconnector permanently available by the DNO. In several countries this is allowed for small-scale PV generation (usually up to an installed power of 30 kW), when the generator complies with strict safety requirements (e.g. fail-safe loss of mains detection system). Benefits can be seen as the inverter can be able to perform same functions as normal interconnection relay. However, the first question arising would be the possibility of the DSO to disconnect the unit or to assure the connection state of the unit. Practical safety requirements, for instance the need of visible and lockable disconnection point, may need to be considered (like in some countries already mandatory). This issue could be covered more detailed in further work.

3.1.6 Network operators' role in owning generation units

In many participating countries DSO need to separate the power distribution business from electricity production. As a result of this, many DSOs cannot own DG units or participate in their operation. Today, however, some units connected to higher voltage levels, can participate for balancing purposes. In many countries with the mandatatory unbundling requirement a DNO cannot have the role of a power balance group which allocate generation schedules based on ¼ hour or hourly intervals.

The most essential exception is the backup units as described earlier. Backup units can be owned and operated by DSO under various circumstances or restrictions such as mobility of the units as mentioned before.

At least in one country there has been some interest on replacing long rural power distribution lines with local DG units located near the consumers. This could be profitable on some rural areas with very long lines feeding actually very low loads. The changes in the urban structure with migration towards bigger cities are continuously making this option more attractive. However, there are no practical solutions on managing the energy chain in present market structure: A consumer cannot choose the energy supplier freely if the electricity is generated and available only locally.

3.1.7 Virtual power plants

Similarly to the concept of active network, the definition of virtual power plant (VPP) is not always clear among participants. However, the possibility of acting as VPP by forming aggregated units for the energy market seems to exist in almost all countries. Applications of aggregation include both loads and generation units. However, practical examples on the distribution network level are still quite rare. For generation units connected to the transmission level, it is quite common to use structures similar to VPPs.

Similarly to storage systems, VPPs are likely to be introduced as economical solutions for market purposes. The typical application of VPP in distribution systems seems to be a group of DG producers that are doing business together because each of them would not be able to participate in the power market alone. A VPP could also be a combination of suitable loads such as refrigerators or water boilers acting as storage devices with (time-) flexible consumption. As discussed earlier, in some countries there are presently structures for controlling these kinds of loads.

In the case of DG-dominated VPP structure the main focus seems to be on managing the commercial questions and assuring the access to the power market. Control of VPP generation is not yet a topic today. However, in the case of load-dominant VPP structures, a control system able to switch or influence parts of the total VPP load at certain times during the day and during certain system states is a key possibility. A load based VPP could offer ancillary services for instance during network disturbances

There are no clear future expectations on VPP. However, a growing interest can be seen from the answers. Legislation needed for VPPs is mentioned as one source of uncertainty.

3.1.8 Level of distribution automation

As a general note, the degree of automation is lower in distribution voltage levels compared to high transmission voltage levels. Practically in all countries the HV transmission level is highly automated whereas LV distribution is not automated or automated only to a small degree.

Fault location measures are typically used on the MV level. Automated reclosings are also applied for clearing temporary faults. Actual problems regarding the impact of DG on reclosing were not reported, however it was mentioned that reclosing mechanisms are not used at all on feeders including DG or that longer reclosing times can be applied in the presence of DG. Reclosings are typically not used in underground cable distribution networks. After unplanned disconnection of DG units their reconnection is typically allowed within some minutes. 10 minutes of normal operation circumstances seems to be common.

Generally, it can be clearly seen that the level of automation on distribution voltage levels will be increasing in the near future. The number of additional breakers, switches, measurements, communication and protection devices along feeders will increase. Functions applied today on higher voltage levels will be applied on distribution mainly to cope with the increasing share of DG connected to distribution grids.

The roll-out of automatic meters will evidently bring possibilities for more automation on LV level as well.

3.1.9 Voltage control

Voltage control is presently done in similar ways in the various participating countries. Main transmission system transformers as well as distribution transformers are usually equipped with tap changers. However, only main transformers at primary substations have tap changers of an on-load type.

DG units are operated at fixed power factor set point one if this is technically possible. Many countries do, however, mention the quite common need of using different power factor for keeping the voltage levels within their limits. In these situations DG may be forced to use different power factor. Practically, a modified power factor means a modified generation/consumption of reactive and active power. In some cases connection requirements lead to the fact that DG must participate within certain ranges of active/reactive power. There are also comments on conflicts and different interests in cases in which DSOs cannot ask directly for a security of supply based amount of reactive power from DG (for example in many cases there are no incentives for DG operators to participate in voltage control).

Similarly to protection requirements, a wider co-operation on European level regarding the requirements on voltage control participation would be useful as there are significant differences. Research on this area seems to be intense and DG is expected to participate in the voltage control actively in many countries.

Voltage problems are reported especially in rural areas and in weak networks. Voltage rise due to DG is the most obvious problem, but voltage quality related problems are also mentioned. Power electronic equipment such as SVCs or STATCOMs are applied in some cases even in the distribution grid at the moment, but they could be used more commonly to overcome voltage problems.

3.1.10 Voltage/VAr support

DG might offer some ancillary services for networks in the form of voltage or VAr support. However, this is not very common at the moment among participating countries. At least in one country CHP-based generation can offer different ancillary services, among these are voltage and VAr support. There are also ongoing studies in some other participating countries.

More ancillary services produced by DG are expected in the future (see Figure 3).

	Technology Type					
Ancillary Service	**Wind: Ind. Gen.**	**Wind DFIG**	**Biomass**	**Land Fill Gas**	**Solar PV**	**Hydro**
Size	***0.01–1MW***	***1–100MW***	***1 – 100MW***	***1 – 10MW***	***<100 kW***	***> 1MW***
Frequency	✓	✓	✓	✓	✗	✓
Reserve	Possible	Possible	Possible	Possible	Possible	Possible
Reactive	✗	✓	✓	✓	✓	✓
Network Support	✓	✓	✓	✓	✗ ✓	✓
Black Start	✗	✗	Future islanding?	Future islanding?	✗	Future islanding?

Figure 3: Possible ancillary services depending on generation unit size and technology type (Source: Goran Strabac, EU project DISPOWER)

3.1.11 Network planning aspects

There seem to be different approaches on network planning among participants. What is common is the usage of computer modelling and information systems for network planning and operation purposes. There are, however differences within the study methods applied. In most countries, DSOs rely on steady-state studies[3] only. However, some countries state also that simulation tools are used for DSO's purposes.

Using DSO-external consultants for DG interconnection planning seems to be quite common. In addition to missing competence, another reason for using consultants may be the need of objectivity. Larger DSOs may be able to do some simulations by themselves, but especially smaller ones are using external consultants.

Present planning tools for DG installations seem to be adequate especially on areas where the amount of DG is higher. Areas with low share of DG consider the usability of systems more problematic. This situation seems similar to the one described in protection chapter: countries that have longer experience on DG integration have already solved some of the problems. Co-operation and information exchange is certainly useful on this area as well.

DSOs operating also on higher voltage levels (regional distribution levels of figure 1) are in general more capable of managing the calculations for DG purposes. This can be explained because the planning and operation of a distribution network due to the impact of DG is getting similar to the one of transmission networks. In other words, operators used and forced to manage more complex networks and systems are better prepared than those focusing only on traditional unidirectional, radial distribution without any or only very little connected DG.

Generation shedding is one possible tool for optimal network operation. Shedding means that DG unit may be disconnected or its output power may be decreased during or before certain critical network conditions. In some areas shedding is currently applied together with line monitoring in order to not exceed line capacities. The possibility of shedding was also mentioned while waiting for the required network reinforcements; the DG producer can operate with lower output power until the reinforcement is completed. Generally, shedding is directly related to the concept of active networks as it requires monitoring, measurements and smart control.

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[3] Transient and subtransient stages are neglected and studies are made with steady-state values only. In other words, time variable is neglected.

3.1.12 Metering

Metering is very topical at the moment. Most countries have different rollout plans for providing customers with remotely readable (smart) meters. A smart meter is definitely a tool for active operation of the network. In many cases, smart meters can be seen as first step towards active networks. However, having smart meters is not the same as a Smart Grid or an active network.

Clearly, the increasing amount of smart meters means more information accessible by the network operator and other market stakeholders. An efficient AMM (Automatic meter reading) system is essential for providing this information. A future AMM based process might enable more proactive system management for network operators, which would further enable active (i.e. SmartGrids based) network operation.

Figure 4 presents some rollout timetables for smart meters in some participating countries. The purpose is to show the general increasing trend and time horizon. Individual country names are not mentioned as some information may be incomplete.

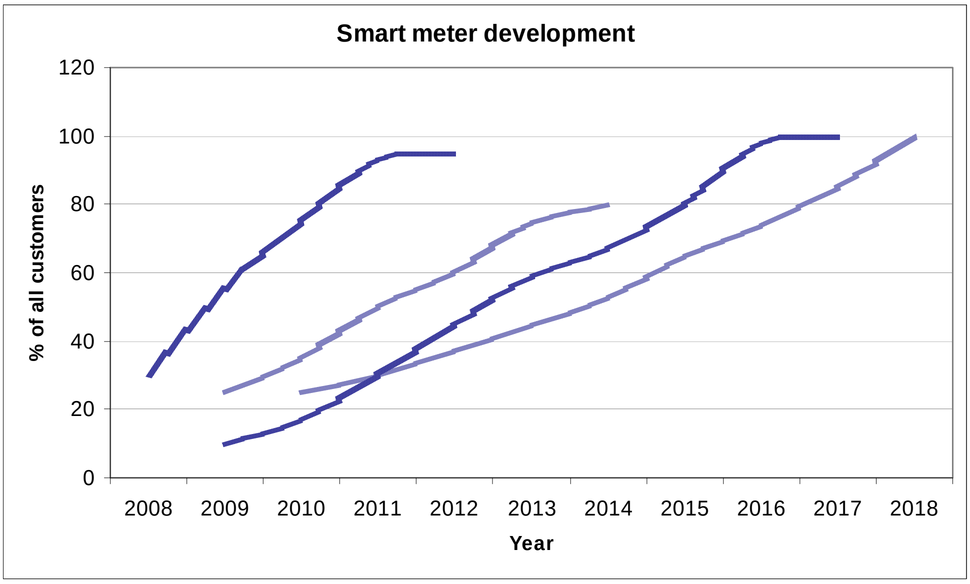

Figure 4: Some smart meter rollout plans indicating the general development

Traditionally and already for some years in the past, remote meters have been applied for large customers. This is true for all participating countries. I.e. remote metering itself is not a new issue. However, bringing this functionality to all customers including all small households brings many new challenges but also possibilities. First of all, the amount of captured meter data increases exponentially. Information systems need to be upgraded for managing the masses of measurement data. Also the communication techniques are different as there are no dedicated communication channels to small customers. In addition, since the number of meters is large meters needs to be installed an operated economically. Thereby the process of bringing remote meters to all customers is difficult and it cannot be seen as an extension of earlier measurement system.

The definition of “smart meter” is a special issue. In the answer sets there are different definitions ranging from remote reading to the possibility of controlling loads. General view would seem to be that merely automatic reading does not make metering “smart”.

Generally, the functionalities required include functions such as:

- Bidirectional communication possibility (from and to customer)
- Remote disconnection/connection of the customer
- Recording of (quarter) hourly load profiles
- Meter software update possibility
- Flexible tariff structures programmability
- Power quality metering possibility
- Controlling parts of customer loads

In most cases, the local DSO is responsible for metering DG units. This includes installing and maintaining the meter, reading, recording and communicating the data. In the case of generation-only customers the situation is similar among participating countries. The size of the generation unit may affect the need of “on-line” metering.

In the case of a customer owning both consumption and generation, the type of measurement may become a question. Should the metering be done separately for loading and generation or should a net measurement principle be used? In some cases this may relate to the business models and electric market aspects of DG. For promoting small-scale generation, the net measurement can be more beneficial for the producer depending on the feed-in tariff or market value principles for DG.

3.1.13 Communication

Communication capabilities of DG unit could enable more efficient integration of the unit. At the moment the degree of communication varies according to the size of the unit. For instance larger units participating on balancing market are equipped with communication accessible by the TSO. For future purposes, for instance voltage control, at least some form of regional communication will probably be required for smaller units as well. In one country there is a system in which all wind power units above 10 MVA are connected to a control structure of the TSO. Thus also communication channels are required to and from these generation units.

At the moment there are no dedicated standards for communication between DG and other parties. Normal communication methods and standards are applied where communication is needed.

Generally, standardized communication between DG and DSO/TSO is seen important, especially in future. International co-operation on the subject is anticipated since such standards cannot be developed on national level. There are already some working groups on this issue.

Participants consider technical aspects, mainly possibilities of integrating more DG to existing networks, most important benefit offered by more wide-scale communication at the moment. Other possible benefits can also be found on the market integration of DG.

3.2 Power Markets and Regulatory Aspects

The objective of this activity within IEA ENARD Annex II was to gather and compare information of the different contributing countries with respect to organisational, regulatory and commercial aspects of energy markets. This information is analysed with a specific focus on existing energy markets (i.e. markets related to services for the power system) and how distributed generation is (or is not) integrated in these existing markets.

As there are only few examples of commercial activities concerning active network management, some scoping research to identify the barriers/drivers to commercial arrangements for active networks has been carried out initially. This required a description and analysis of the existing relationships between different players in the energy market, e.g. DSOs and generators/loads and maybe suppliers and customers (including generators through existing power purchase agreements/bilateral contracts), thus existing market models of electricity markets in general have been analysed.

3.2.1 Description of the current power systems and electricity markets

3.2.1.1 Production mixes

Historically the TSO activities and the commercial generation activities in each country in Europe were carried out in an integrated company. Along with the opening of the power markets in the 90ties, the TSO activities were unbundled from generation activities. Before the time of unbundling and opening of markets, the TSOs, often integrated with the power production companies, had full control over the bulk majority of the power production. The TSOs could at all times optimise the power production to the load demand. Historically the general rule of thumb was that the TSOs should use the large power plants to secure that the demand and generation of power are in balance every second (power cannot be stored).

Today national and cross-border markets set the market prices for electricity in Europe. Today markets do the main part in keeping a balance between supply and demand, i.e. balancing the power system total load and generation. This is both by bilateral power exchanges and via power exchanges such as Nord Pool Spot, EEX, BelPEx, APX, etc. Thereafter TSOs (still responsible for the power system stability) may buy power or frequency-deviation dependent reserves to balance and stabilize the power system in a very short term perspective. This is done via mostly national balancing markets, also called regulating power markets

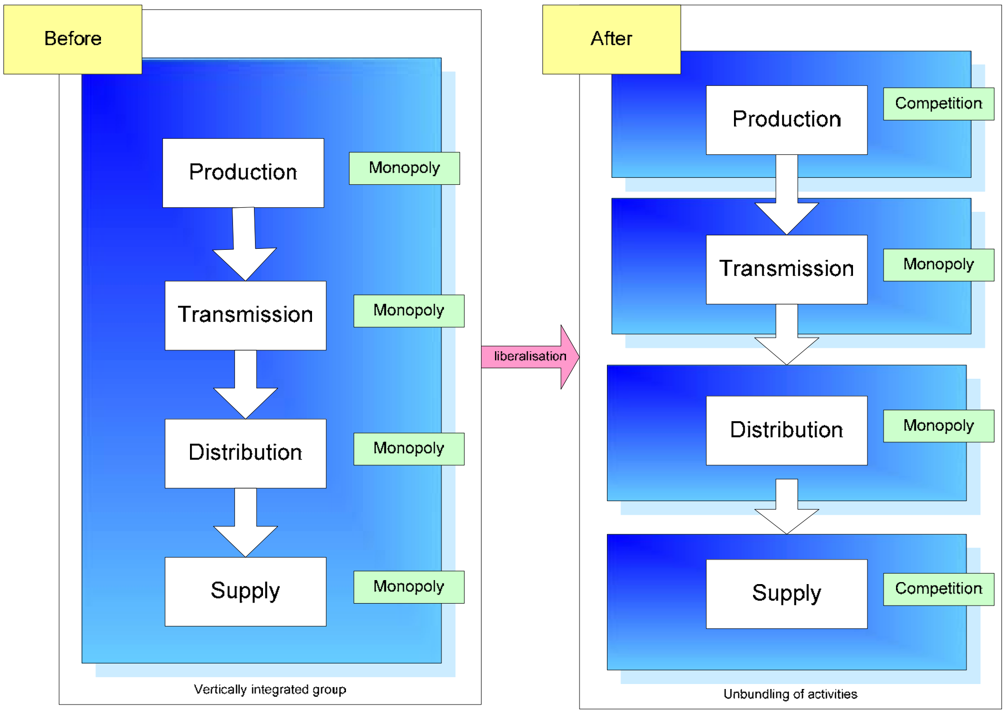

Figure 5: Interaction between power system stakeholders before and after the unbundling in Europe (source: VITO).

In some areas with a high degree of fluctuating power production TSO have large expenses to balance the power. In some areas the power from the fluctuating power sources is reduced, in other areas regulating power from fast reacting power generation or from large loads is bought to balance the power system.

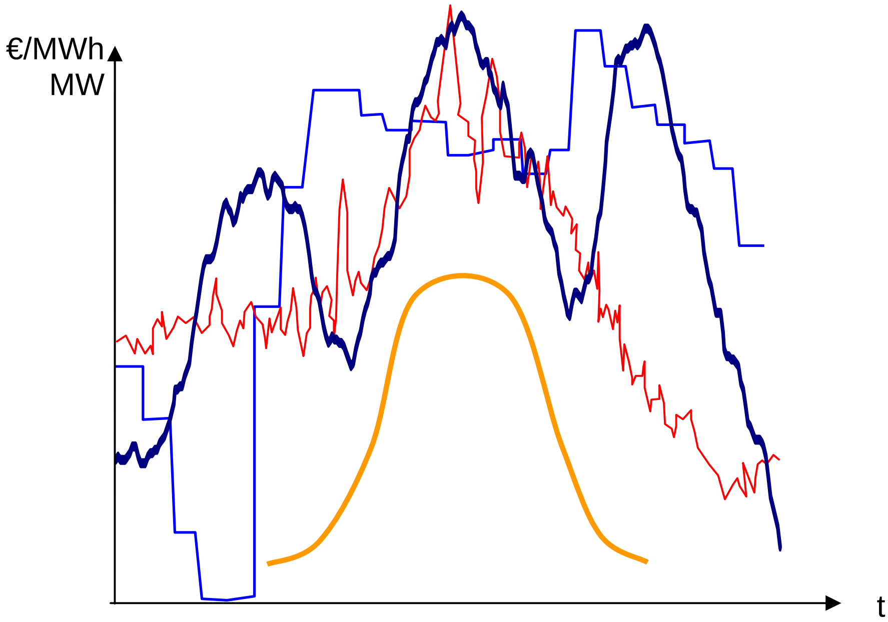

Figure 6: Dynamics in wind power and solar power compared to power markets. The figure illustrates the dynamics in a hourly power market price (light blue) with the dynamics from the wind power production from one offshore wind power site (red), all wind production in West Denmark (dark blue) and the average dynamics of solar power (yellow).

Today, only few TSOs buy regulating power for power system balancing from DER. Currently most TSOs have bilateral contracts with large power producers in order to purchase balance power. Historically this was the only alternative, but in a future perspective using the balancing power from DER´s may be the cheaper alternative. In the Nordic countries regulating power is managed on market terms for suppliers who are able to provide at least 10 MW generation or load. These 10 MW may be aggregated among smaller generators (e.g. virtual power plant), and have to be available within 15 minutes from the time the TSO request the power.

3.2.1.2 Trend

The mix of different dominant power sources in the national power systems also defines how we think about power market solutions.

The current primary power sources are
- Wind
- Photovoltaic
- Hydro
- Wave

- Concentrated Solar Power (CSP - thermal)
- Thermal (Nuclear, Coal, Gas, Biomass)
- Combustion (Oil, Gas)

Until 2015 the most dominant combinations for power production will be Wind-Thermal, PV-Thermal or Hydro-Thermal.

The dominances of these combinations are concentrated in regions depending on the natural available resources (see figure 5).

Figure 7: Dominant production mixes in Europe

From 2025 on, many parts of the Wind-Thermal dominant areas may have a Wind-PV-Combustion dominance, because the low marginal price for power production on Wind and PV makes the investment in thermal power plant not profitable.

Going forward from 2025 electricity storage in hydro storage, hydro pump storage or in batteries (e.g. of electric cars) may influence the production mix and the way the electrical markets set the price on power.

3.2.1.3 Different markets today

Historically, the TSO has set the price for the power to the DSOs, who again set the price for the end customer. The regulatory matters were either taken care of by the national or local governments or by the end customers through ownership of the power utilities.

Historically, the TSOs role to balance power depended solely on the development of the power demand. In order to maintain the power system balance to cope with this demand, the TSOs expanded grids to allow the connection of more generation resources and to strengthen and stabilize the power system. When connecting the predominantly national systems to neighboring systems, it was necessary to make arrangements for cross-border pricing of power and emergency cross-border power reserve transfers after unintended events.

Since the start of unbundling in the power system the development has lead to power exchanges, explicit cross-border capacity auctions, implicit market coupling, wholesale/retail markets, markets for ancillary services and balancing markets.

Today the TSOs role to balance power depends on the combination of the market design and the amount of fluctuating power sources (e.g. from wind power). The more fluctuating power is feeding into a system and if there is no local fluctuating power balancing mechanism, the larger will be the deviations between predicted and real-time power balances. I.e. the larger these deviations, the more the TSO need to buy regulating power to balance the system.

In areas with little fluctuating power the market design is decisive for how the TSO buys reserves to balance and stabilizes the power system. E.g. if the bulk of the power consumers are priced differently for example during day and night periods, the power system stability is challenged at the shift from day to night price.

The studies and discussions in this IEA ENARD Annex II have shown that the future market designs in each market must be designed to meet the production mix in the region, today, tomorrow and in the transition periods from today towards tomorrow.

In systems with a high degree of fluctuating power sources the markets must react faster to the change of power produced into the system. Thus the consumption must likewise be able to react to the same change in power production. Otherwise seen from a socio-economical perspective, more expensive alternatives may be to either reduce and/or stabilize the power output from the fluctuating resources or start fast reacting power sources (e.g. combustion engines or gas turbines) to balance the power in very short term intervals. So basically with the political agenda to reduce emission of green house gases, if there is not enough CO_2-neutral power production to balance the system and to stabilize the frequency, consumption has to participate in doing so (see **Fehler! Verweisquelle konnte nicht gefunden werden.**).

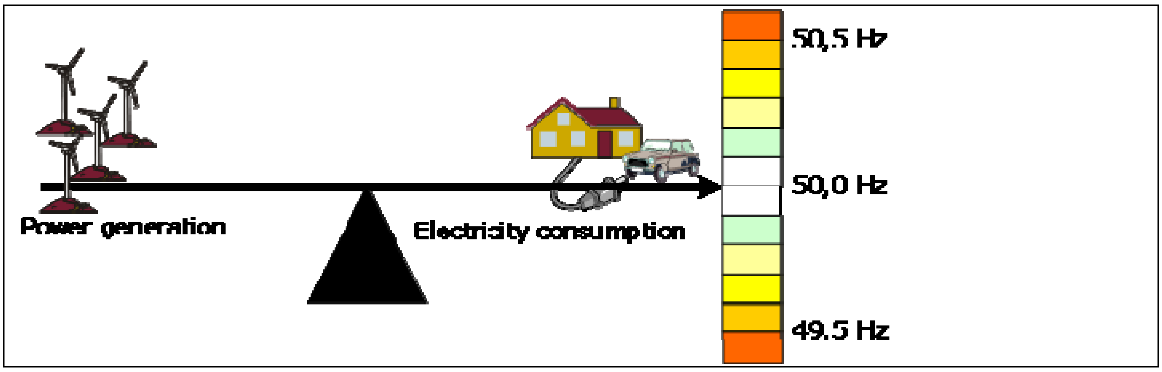

Figure 8: Consumption has to play an active role in future power system

Therefore a paradigm shift is expected, in order to be able to integrate more DER. This can be described by shifting *from the current power system control philosophy, where production follows load – to a future power system where load follows RES*.

This means that flexibility at the consumer side will become very important for the future electricity system. For a system with an increasing share of less predictable RES, this flexibility at the consumption side could be used for balancing the system or providing certain services for the system. This flexibility will thus represent a certain value for the electricity system and for certain market players that can make use of that flexibility at the consumption side. Furthermore, the amount of available flexibility can even be increased by using energy storage.

From a market point of view this is possible if regulators and lawmakers also make incentives to buy power from RES-e or other clean generation technologies when they are produced along with the incentives to promote RES. This means the markets must be designed to cope with the fluctuation of the RES-e or clean power in the local market. The price for the RES-e or clean power must be low enough compared to the non-RES/-clean power for the end customer to move his load to the period with RES power in the power system.

By making use of markets for DER it may enhance the integration of RES-e, as RES-e will be exposed to the same price signal as consumers and power generation already integrated into the market.

A more socio-economical trend is to activate DER, especially distributed loads with thermal or electrical storage (e.g. heat pumps, air conditioning, electric vehicles, electric boilers, etc.).

By actively utilising DER in the power markets with a large degree of the fluctuating power sources, the DER can shift loads to respond to the fluctuations in the power production. If the dynamics in the power market do not match the fluctuation of the power production though, there is the risk that too much load is shifted at the same time which can trigger instability in the power system frequency with the worst-case risk of over frequency trip (see **Fehler! Verweisquelle konnte nicht gefunden werden.**).

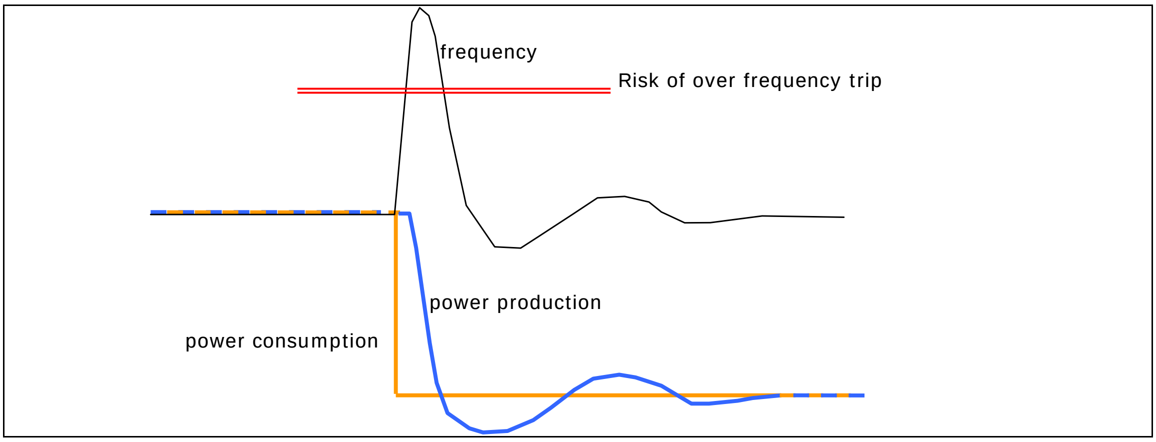

Figure 9: Ramping, power system balance and frequency. Too much load shift at the same time will change the frequency and in worst-case lead to frequency trip.

In the following, a number of existing marketplaces or market organisations are explained.

Wholesale Markets
Wholesale markets often refer to marketplaces where large quantities of a certain piece of goods are traded. This can be done over the counter (OTC or bilaterally) or anonymously on public exchange places. In the context of energy markets, this refers to trade between large market players such as producers with large centralized power production, energy suppliers or retailers (who buy electricity in bulk), and even industrial consumers, etc. In order to secure a proper integration of DER into the power system, the market players must be fully exposed to the dynamics of the power system. I.e. the incentives to adjust consumption or generation by the dynamics of the price signal should not be blurred by other price signals, e.g. feed-in tariffs or restriction in the regulative framework.

Retail Markets

Retail markets refer, in contrast with wholesale markets, to marketplaces where small quantities of a certain good are traded. In the context of energy markets, this refers to the contracts between a retailer or energy supplier and a customer or consumer at for instance household level. The retail market is the link between consumption of electricity and the power system. Retail markets must be designed in order to enable the consumers to react on the signal from the wholesale power market. In the wholesale power market the prices (spot, balance, etc.) will reveal the actual condition of the power system, and hence this price signal must also be visible in the retail market in order for consumption to be in synchronous with the supply side of the power system.

Markets for Power System Balancing

At the opening or deregulation of the power markets in Europe in the 90´ties, mainly (only) the major power generators supplied the balancing power - and still do. However as the share of DER will increase in the power system, it becomes more important also to integrate these into the balancing market. This is not only important to cope with situations where the gap between forecasted and actual power generation is huge, but also due to the competitive implications of having more than a few suppliers as providers of balancing power.

Markets for Frequency Balancing

More and more countries have realized that with larger amounts of DG it cannot only be the central power plants that deliver power balancing services. Most of the countries that have realized this have required DG to participate in the stabilization of the system during larger frequency events. But still most system responsible parties (TSOs) are solely responsible to buy power from the large central power plants to do frequency control. Only Denmark has so far opened a market for frequency control. DER and wind power plants can send bids and offer frequency control services in competition with the large central power plants.

3.2.1.4 Markets, not a national challenge

The question of proper integration of DER and especially RES into the power system is closely linked to the question of integration of national markets into wider regional cross-border markets and further into a European wide market. This work of integration of regional cross-border markets has been initiated by the work of ERGEG in the so-called Regional Initiatives.

As some DER are characterized as non-controllable (e.g. RES-e generation as wind and solar power), power systems with high share of non-controllable generation becomes more dependent of adjacent flexible power systems in order to absorb the power generated and/or to import power in situations with low RES-e generation. Therefore in order to support proper management and integration of DER, especially RES-e, the overall system challenge is not of national scope, but of supra-national scope, hence the question of integration of national power systems is even more relevant.

The need for cross-border integration raises the two-fold question of physical interconnection between adjacent areas and choice of congestion management to manage “the physics” and other operational constraints between the areas. Lately, the first question is addressed in the report for public consultation by ENTSO-e, Ten-Year Network Development Plan 2010-2020, realized by March 1st 2010. In this report an assessment of the need for new interconnection is done in order to support the integration of RES-e towards the 2020 goal.

Physical interconnection

In order to utilise the future huge volume of RES-e generation an increase in existing interconnector capacity is needed in addition to new interconnection of national power systems not currently connected, e.g. UK and Norway.

This is for three partly overlapping reasons:

- The location of RES-e generation is at locations where resources are naturally found and in most situations this is not coincident with the load centres. I.e. often, RES-E are far away from cities with a large concentrated number of consumers.
- The need for balancing power will increase, hence areas with technically capable power and frequency regulating generation will be (further) connected to areas of huge RES-e generation
- Excess supply/demand:
    - National generation of non-controllable RES-e might in some hours be above the national consumption of electricity, thus in order for a proper utilization of RES-e the excess of generation to national consumption must be exported
    - In some hours the generation of non-controllable RES-e will be (too) low, hence thermal or hydro backup capacity must be provided. If this capacity is located abroad, interconnection between areas becomes extremely important.

The two last points refer to the ability to exploit the mutual gains from trade of power. This has, however, already been done in the European power system for years, as generation in the national power systems based on e.g. thermal base load plants has been co-ordinated with hydro systems. Since the opening of power markets, this co-ordination has in Scandinavia been done via markets. Before this, bilateral agreements were put in place for this co-ordination task.

In the future, following trends can be expected:

- Mutual gains from power trade will be put in a more pan-European perspective as there will be a need to exchange more power, not only between national power systems, but between large exporting and importing areas as, e.g. between North-west Europe and the south-east areas of the Continent.

- North West Europe will be the main wind area with huge amounts of hard-to-control and hard-to-predict wind generation with low variable cost.
- Although being difficult to control and mainly due to the low marginal costs of this type of generation (but also due to the zero CO_2 emission) this wind based generation will for a long time in the future remain in the lower part of a European-wide cost merit order curve. Hence in order to support a system wide socio-economic generation of power, wind generation has to be used in a true marginal cost based power market before thermal power stations are activated.
- In opposite situations, during hours with low wind generation, import of power from areas with hydro/thermal power might be relevant instead of keeping more expensive or CO2-generating national back-up plants ready for generation.
- To support this European-wide least cost (or maximum market profit) co-ordination of generation, new interconnectors are needed.

Market coupling

Market coupling - or the variant of market splitting - is by many assessed to be the preferred solution in order to manage the exchange of power on interconnectors, both within and between the European countries.

Market coupling is a method of managing interconnector capacity by trading the access to this capacity simultaneously with the trade of power at a power exchange. This is called implicit auctions as opposed to explicit interconnector transmission capacity auctions. By using market coupling, the trading of interconnector capacity and power simultaneously guarantees that market players with the lowest marginal generation cost and/or consumers with highest willingness to pay get access to the interconnector capacity. This is to be preferred when socio-economic goals are the key drivers.

The relevance of market coupling is revealed especially in situations where the exchange of power causes congestions. In these situations the capacity on interconnectors becomes a scarce resource, and the methods to be used for allocation become very challenging.

As the share of non-controllable DG is expected to increase to higher levels in certain areas and/or countries, this will increase congestions in the power system, leaving the question of congestion management to be even more important than today.

Market coupling as a method is a very suitable way to manage the exchange between the different price areas of Europe simultaneously, due to the implicit trade of interconnector capacity and energy. This will secure that usually power will flow from areas with low marginal costs to areas with higher marginal cost, and hereby secure a maximum socio-economic profit. Also, this usually leads to a least cost merit order of the power system supply.

Best practises
Denmark West is well suited for studies of best practice interaction between high levels of non-controllable DG and market coupling, as Denmark West for the last decade has managed the interconnectors towards the Nordic area with market coupling and the share of wind to consumption on average has been around 25% per cent, in some hours approaching 100% of national load or more. Experience shows that high wind generation results in strong exports out of the area.

However:

- Market coupling alone may not secure that the actual exchange will flow from the surplus area to the deficit area when it comes to the actual operation hour and actual wind generation in that hour
- Exchange is based on *forecasted*, not *actual* generation, thus market coupling secures optimal planned utilization of transmission capacity, given the state of knowledge at the time of gate closure at the power exchange (up to 36 hours before operation hour), but cannot take deviations in forecasts into account: Deviations must be managed within intra-day or balancing markets.
- In order ensure cost-optimal utilization of actual generation and take deviations in forecasts into account, integrated balance markets schemes are urgently needed.

One notes of caution have to be raised:

- Day-Ahead market coupling may not be the sole and perfect solution for the use of the entire interconnectors capacity.
- Some specialists raise the point that market coupling - as opposed to explicit auctions - tends to decrease the liquidity in the financial hedging markets while this financial hedging practice is important in the whole sale power market.
- Explicit interconnector capacity auctions may attract financial traders, due to possibility for gains, caused by the element of uncertainty of accordance between differences in national spot market prices towards the “right price direction”.
- A solution of combining explicit and implicit auctions might be the optimum.

3.2.1.5 Market and the dynamics in the power system

"The markets must follow the dynamics in the power system as much as

possible"

As the share of RES in the power system will increase, so will the dynamics both in terms of technical and market processes. Strong consideration regarding the ability of the current national market designs to be in line with those dynamics must be done.

Time resolution:

- Increase in share of non-controllable DG may increase gradient and time length of power change ramping from one market interval to the next as the impact of DG in the power system will increase with increased share of DG.
- Today's market design with hourly settlement may not be in line with high shares of volatile generation and capacity factors for wind power generators going from 0 to 100 per cent within a single hour, as the controllable generators will only react on between-hourly prices, not on within-hourly dynamics.
- This calls for consideration regarding a higher time resolution (for example 15 minutes or 5 minutes) in the power market design. Best current practice in Europe is currently the UK power system with ½ hourly market settlements.
- Many countries have quarter hour markets for regulating power which could be a natural first aim for the national wholesale and retail markets.

Gate closure:

- The share of non-controllable RES in the power system will increase. Thus the need for accurate forecasting of RES-output increases, if the cost of regulating power to balance the power system for some reason is disproportionate high.
- The current market designs in many countries force the generators (large controllable central power stations but also small non-controllable RES) to forecast generation up to 36 hours ahead of operation.
- This leads to an increased need for access to balancing power. However, forecast of wind generation cannot be very precise more than 5-6 hours ahead (not better than wind predictions)

- Several potential solutions for dealing with the balancing issue could be suggested:
    1. Get access to cost-efficient balancing power either by investment in low-cost regulation power generation or by allowing existing generation with low-cost power regulation to participate in the balance market or
    2. Invest in interconnectors which provide access to other control areas with generators with the ability to provide low cost balancing power or

3. Reduce the time span between time of gate closure and hour of operation.
4. This could be done either by creating rolling gate closure or move the current day-ahead gate closure closer to the operation hour

Which of these options to choose depends on the costs of each solution. Best practice today seems to be in the UK the Betta market place which is designed with rolling hourly gate closure

3.2.1.6 Different market needs

The concrete choice of the market design depends of the generation technologies in the concrete power system, cf. above. As the society asks for more RES in the system, this will lead to a less predictable power supply side. As a consequence the demand side should thus be better managed in order to match the intermittent supply side. Power systems with high shares of volatile and unpredictable power generation may need certain design features to be integrated in the market compared to a system consisting of only base load plants.

However, choice of design within one market area cannot be done without a view to the design in neighbouring areas, as efficient power market can only be developed based on international solutions with close integration of national market areas.
The discussion of market coupling as being the preferred solution or not, also points to this subject. A compatible design of certain elements within the entire market design on both sides of an interconnector can be a prerequisite for implementing market coupling is. Such elements could be:

1. The establishment of a trans-national power exchange with the right to manage interconnector capacity simultaneously with the trade of power.
2. Price formation designs based on marginal pricing (or price bids)
3. Coincident time for gate closure on the power exchange.

When considering the need to change the market design due to an increase of RES and DER, it is also necessary to consider the co-existence of power markets and technical challenges such as the need for peak-shaving due to local congestions or voltage control from DER due to larger fluctuation of power in distribution systems.

3.2.2 Integration of DG/DER in markets

Today not all markets and national power systems in Europe have a high share of DG and even fewer allow distributed load access (via aggregation business models) to the electricity markets. All countries in Europe, however, have power production connected to the transmission level and large customers on medium and high voltage (MV/HV) being active in the wholesale or retail power markets.

Use of online real-time/hour markets

- Only few consumers and DER in the distribution systems have access to hourly markets.
- No consumers and only few DER have access to/are used in sub-hourly (30 min, 15 min. or 5 minute) markets.

Use of market coupling

- This is currently emerging in Europe.
- Central European regulators wish more integrated markets, ultimately one integrated market in Europe.

3.2.2.1 Paradigm shift

As the share of RES and non-controllable DG will increase in the power system of the investigated countries (and others also) the need for a real integration of DER in the different markets within the power system also increases. This challenge will have impact on the future market design, hence the power system in the different areas are facing a shift in paradigm.

The size of the DER/DG and the extent to which distributed generation participate in the electricity markets vary considerably between the investigated countries. Electricity generation in 2007 as well as distributed generation's share of the total generation in the investigated countries is shown in the figure below. The values represent the historical development in the individual countries and should not necessarily be seen as a result of the current market design, subsidies for renewable energy etc.

Country	**Electricity generation in 2007**					**DG and share of total generation**	
	TWh	Nuclear	Thermal	Hydro	Wind	TWh	%
Austria	63.8	-	45%	55%	0%	6.8	11
Belgium	84.9	54%	43%	2%	1%	1.5	2
Denmark	37.0	-	81%	0%	19%	14.2	38
Finland	77.8	29%	53%	18%	0%	2.2	3
Italy	301.4	-	86%	13%	1%	NA	NA
Spain							

Sweden	145.1	44%	10%	45%	1%	1.4	1
Switzerland	65.9	40%	5%	55%	0%	NA	NA
Great Britain	400	16 %	79%	1%	1%	50	5%
Norway	137.4	-	1%	98%	1%	6.2	5

Note: Data based on statistics from UCTE and Nordel. Distributed generation is defined as generation connected to the distribution network in BE, DK, GB and IT (< 10 MVA) and < 10 MW in AT, FI and NO. Here DG from SE only involves wind turbines. The values for GB are based on the contribution to this report.

Market Access

Overall four different levels of market access for DG/DER can be detected:

- Power not sold in commercial electricity markets (negative loads/net metering) but consumed by the grid user directly connected to the DER.
- Power sold through a purchase agreement or legal framework (feed in tariff) independent on price signals in the market.
- DG/DER receive some form of subsidy or benefit compared to conventional generation but the generation is regulated based on price signals in the market.
- Same rules as conventional generation (no exceptions).

Generation from small producers such as PV-systems and CHP are in some countries left outside the market: I.e. they are seen as negative (non-controllable) loads (net metering). Net metering is used in Belgium, Denmark and Italy.

DER and Ancillary Services

In most of the investigated countries it is either not possible for DG/DER to be involved in power system balancing and the markets for ancillary services or the share is practically zero due to the requirements in the market. The units might for instance not have the adequate technical characteristics to provide the services. Ancillary services are typically contracted by the TSO, after a tendering procedure for a period of months up to several years.

Energinet.dk (the Danish TSO) has in the recent years been working to develop the models for buying ancillary services and give access for DG in order to strengthen competition and increase the security of supply in Denmark.

In Denmark, in addition to the spot market, local CHP plants operating on market terms can also take part in the reserve and regulating power market. A daily market for buying manual reserves was introduced by Energinet.dk on 1 February 2007. The market aims at ensuring that resources, such as electricity generation units and electricity consumption that can only be available for individual hours or days, can participate in the market for ancillary services. The daily market also paves the way for ongoing adjustment of reserve purchases to current needs. About 2/3 of Energinet.dk's demand for manual regulating reserves in Western Denmark are provided by local CHP plants.

Beginning September 15, 2009 a daily market for power providing frequency reserves has also been introduced in Denmark. Today, local CHP plants are therefore able to cover the entire need for primary regulation in Western Denmark in the winter period. As a consequence it is possible to dispose of the thermal generation from the CHP plants.

3.2.2.2 Barriers or incentives

Barriers for access to the markets places will continue to exist in every power market. However, in order for the DER to participate in the markets on proper conditions, “artificial” barriers must be removed, that is barriers that cannot be justified due to economic, technical, environmental or regulatory reasons.

An example of an artificial economic barrier is a tariff for supplying power to the grid or a tariff for not supplying power (imbalance settlement) that is way above true cost. Artificial technical barriers could be putting up requirements not necessary in order to manage the power system with appropriate level of security.

The removal of these kinds of barriers will provide DER the right incentives to supply services to the markets (leaving aside non-market based incentives initiated by energy policy goals, such as feed-in tariff or quota for renewable energy).

In the contributions from the countries different barriers are mentioned:

- One of the contributing countries notes that for generation from intermittent sources, a high penalty charge applies for energy not supplied when participating in wholesale electricity markets. This penalty charge can be justified if the charge corresponds with the associated costs for the power system of not supplying the power. If, however, that is not the case, this might constitute a barrier.
- Another country states that the development of DG is subject to several laws, rules and regulations, including that every DG unit has to have a contract with a balancing responsible party. Even though the regulator in that country introduced some simplifications for small-scale power generators, the process is still very complicated and may be a barrier to develop and put DG power into the market.

The drawback of keeping these barriers for DER´s might be higher prices on the power or services provided, either due to the fact that these resources with higher costs need to be activated and/or some markets will suffer from lack of competition due to too few suppliers (market power).

The benefit of integrating DER into the markets is twofold. Firstly, the behavior of every entity (DER´s, large central generators, etc.) in the power system should be in line with the actual state of power system, as they are exposed to the price signals from the markets. Secondly, the need for power and system services may be provided by the entity with the lowest marginal costs.

3.2.2.3 Potential

The potential benefit of proper integration of DER´s into the power system has to be acknowledged. The share of volatile and non-controllable DG's in the power system will increase, hence the need for "tools" with dynamic capabilities will also increase.

The presence of DER´s might represent a potential, not only due to the often low carbon merits of DG, but also due to the potential technical capabilities attributed. And these technical capabilities might be valued in terms of power system balancing, due to often low dynamic capabilities/high costs associated with fast regulation of base load units.

Examples of DER´s are:

- On the demand side large electric water boilers are in principal able to deliver fast response to changes in wind power generation.
- On the supply side, small gas fired units or hydro generators might also be able show steep power ramping gradients.

By taking full advantage of DERs (demand and production) in the power system the need to rely on large fossil base-load power plant for providing regulating power will decrease. This may not only reduce the cost of balancing power as stated above, but it may also help those thermal plants to be more carbon efficient, due to a more stable operation instead of ramping up and down, hence a reduction in fuel consumption.

3.2.2.4 Recommendations

There is a world-wide shared opinion that in order to bring down CO_2 emissions it is important – among other actions - to encourage and support the development of DER. It might even have positive effects on network operation. For this reason DERs may prove to be an attractive resource for the power system. For this reason TSOs, regulators etc. should pave the way to the markets for these resources. This can be done by removing barriers with an adjustment of the market design or regulatory elements. However, this support shall not be integrated at any price, but only be done if the net-benefit from the adjustments is expected to be positive.

The IEA ENARD Annex II group sees a need for:

- A new power balancing philosophy. Shifting *from the current power system control philosophy, where production follows load – to a future power system where load follows RES*.
- Dynamic markets. The markets have to follow the dynamics in the power system as much as possible
- Local markets to take care of local congestions and needs.
- Increased involvement of consumers in the markets.
- New groups of network customers (small DG and consumers) to share responsibility for power balancing, power quality and utilization of the network capacity.

3.2.3 Interdependence of markets and regulation

In the countries covering this inquiry, DG´s are supported either by feed-in tariffs, green certificates or an investment subsidy. This holds especially for RES-e generation. The support is motivated by the energy policy goals put up in every country (to secure compliance with EU 20-20-20 goals, only relevant for EU Member state countries).

Main points:

- Subsidies are a policy tool and are provided to support RES-e generators as the market price is often not high enough to make these generators profitable
- However, the support of RES-e generation may trigger huge amounts of power to be fed into the power system, leaving the power system with a balancing and stability challenge as these amounts may be above power consumption levels in some hours
- The actual use of financial support mechanisms is today purely national in scope. In a European perspective this means that RES-e generation are not necessarily located in areas where power is mostly needed and/or where input (e.g. wind) is naturally occurring in an efficient manner, but where the financial support of RES-e is favorable.

Table 1: The actual use of financial support mechanisms in ENARD Annex II member countries

Country	Use of Aggregator/ BRP	Prioritized access/ purchase agreement	Market access	Subsidy for RES
Austria	BRP (balancing zone)	Only RES	Not directly (must be part of balancing zone)	Feed in tariff

Belgium	BRP	No	Through BRP	Green certificates for CHP/RES
Denmark	BRP	Small (and old) wind turbines and small CHP units are part of Purchase Obligation (PO).	Through BRP	Fixed subsidy and feed in tariff for PO production
Finland	BRP	No	Through BRP	Investment subsidy/tax exemptions
Italy	Yes	Energy off-take agreement/ purchase agreement	Directly or through Energy off-take agreement	Feed in tariff for plants up to 1 MW
Spain				Feed in tariff
Sweden	BRP	No	Through BRP	Investment subsidy/ Green certificates
Switzerland	Predominantly through a regulated “green power BRP”	Yes (but no critical system issue on national level)	Yes, but very exceptionally used.	Feed in tariff or green certificates
Great Britain	BRP	No	Through BRP	Feed in tariff for < 5 MW
Norway	BRP	<3MW	Through BRP	Investment subsidy for Wind Power

3.2.3.1 Mechanism that incentivises production not to over-produce

The challenge:

- The decision to invest in a RES-e generator and/or to generate power is therefore mainly triggered by the subsidy and not by the power market price.
- Compared to settlement by the power price, a subsidy has a downside in terms of management of the power system.
- In a well designed power market the power price for a given market interval will “tell” if there is excess supply of power – the price will decrease, signaling to generator unit operators to decrease generation and/or to power consumers to increase power consumption (either fully automated and/or manually).
- At every hour (or market interval) the power market price will reflect the actual balance between consumption and generation of power; in peak hours prices are high, and in off-peak prices are low, hence the power price will fluctuate in accordance with the actual power generation and load levels.

- The variations in power prices are used as an input by the generators in order to make decisions about generation of power and by customers to use electric energy or to wait.
- Most subsidies put in place until now have no sensitivity in accordance with the actual power generation and consumption level for a market interval. The subsidy is a policy decision and is usually a firm payment independent of the state of the power system. Thus investments/generation is triggered by the level of support and not by the actual need for power by the consumers.

Example of a challenge:
In many countries wind turbines are supported either by a fixed feed-in tariff or by a premium feed-in tariff. A fixed feed-in tariff is designed as a guaranteed price per kWh of power supplied by the generator. A premium feed-in is a payment in addition to the power market price.

This may trigger investment in large amounts of wind turbines. In some hours these wind turbines might generate more power above actual consumption; hence some of the power needs to be exported (or stored as energy to be released later). In these hours the market price will decrease, maybe close to – or below zero, signaling to an investor that there may be too much capacity within the power system. A feed-in tariff will not provide that signal, hence leaving the investment incentive unabated.

Possible solution:
- RES-e may need support in order to secure the energy policy goals, i.e. low carbon generation of power and decreased dependency of oil and gas. However, the support mechanism should be designed to cope with an economic efficient functioning - and in line with a secure operation of the power system, hence an overall success criteria would be that the support mechanism can cope with the dynamics in the power system.
- At best the support mechanisms must be international in scope and offer the same support independently of RES-e technology.
- This will secure that RES-e generation
  - is located in appropriate areas and exported to areas with relative deficit of power but still receiving a support due to the RES nature of the power, hence RES-e could be traded across national borders concurrently with the trade of the physical power
  - with the lowest cost would be installed in the power systems.
- If it is too ambitious to go for that solution, other solutions would be necessary to be realized in a shorter time frame.

Below, possible solutions are listed which are more or less ambitious in scope:
- In addition to the feed-in tariff, a limit in market-bid generation capacity could be put in place. This is what actual happens in Denmark when offshore wind farms are put up for tendering. Before the feed-in tariff is

set, the actual capacity of the wind farm is decided. The off-shore wind farms in Denmark are exposed to this mechanism.

- Suspension of the support by feed-in tariff in these hours where the market price drops to zero or below. This will create an incentive not to generate in hours where the value of power is zero (or below). This mechanism has been implemented in a forthcoming off-shore farm in Denmark.
- Instead of feed-in tariffs of investment support, a market for so-called Tradable Green Certificates (TGC) could be considered: A variant of this has been in place for some RES-e technologies in Sweden for some years.
    - The trade of physical power is separated from the subsidy, which is provided by selling of the certificate in a separate market for certificates.
    - A certain amount of RES-e power are decided as a share of consumption and if RES-e generation are beyond that level the price of TGC might drop to zero, indicating over-generation of RES-e power.

3.2.4 Monitoring of markets

At the moment it seems that feed-in tariffs are the preferred method of supporting massive introduction of RES-e. As this is the case and in order to create a proper balance between the functioning of the power system and support of RES-e, decision makers must be ready to change strategy when a certain level of RES-e generation are reached.

Up to a certain (low) level, RES-e could be supported by feed-in tariff and beyond that level new RES-e generators would be left to settlement by the market price. This strategy would require closer monitoring of the functioning of the power markets in order to decide at what level this should happen and when the level is reached. This could be a role for the TSOs as the TSOs are responsible for the (technical) surveillance of the power system. However, the role of market surveillance differs between the national TSOs, with TSOs in a few countries being responsible for surveillance and design of the power market, but in most countries this is a task of the regulator.

3.3 Active network readiness of Annex II member countries

An overview of the current status of the networks in the Annex II member countries and the readiness of the networks for active network operation can be seen in **Fehler! Verweisquelle konnte nicht gefunden werden.**. The different measures for active network operation considered in this overview, are based on the discussions regarding DG integration on technical, economical and regulatory (grid policy) level.

The measures highlighted in table 1 can divided into four different topics:

- Active Networks (Technical point of view)
- Integration of consumers into network operation (Consumer Involvement)
- Economic measures (Economy)
- Regulatory and grid policy measures

The colour code in table 1 is the following:

(red)	measure not available or used and not expected in future (from current point of view)
(orange)	measure not available or used but possible alternative for the future (from current point of view)
(yellow)	measure partly available or used and expected for the future (from current point of view)
(green)	measure available and used
	no information available

The general outcome of Table 2: Active network readiness of Annex II member countries is that currently no ENARD Annex II member country has widely implemented measures for active distribution network operation. The measures are mainly not available but expected for the future or partly available and used (studies and pilots) and expected for the future. Thus there is a lack of practical experiences and best practise examples at the moment.

Table 2: Active network readiness of Annex II member countries

DG System Integration in Distribution Network - Current Status of Measures for Active Distribution Network Operation

		ENARD Annex II Country											
Topic	**Measures**	**Austria**	**Finland**	**Spain**	**Italy**	**Switzerland**	**Sweden**	**Norway**	**Denmark**	**UK**	**Belgium**	**France**	**Description**
(Active) Networks	Commercial planning and design tools for active distribution network	Ongoing research projects	Ongoing research projects	Ongoing research projects	Ongoing research projects		Pilots are under evaluation	Ongoing research	Research	None known	ongoing research projects	Ongoing research projects	Are planning and design tools for acitve network operation on commercial bases available?
	Distribution automation	Curently just in HV	HV, MV	HV, MV	HV, MV	HV, MV	HV, MV	HV	HV, Some MV	HV, MV	HV, some MV	HV, MV	Is there distribution system automation or remote control respectively available?
	MV and LV load control	Ripple	Ripple	Ripple	no	Ripple	Radio		None	Radio	ripple	Ripple (boilers)	Availabilty and use of load control for network operation aspects in LV and MV networks?
	Distribution storage	None (studies)	None	None (studies)	None	Some small hydro storage	Some (hydro)	Some small hydro storage	None (studies)	Pilots	none (research projects)	None (studies)	Availabilty and use of storage technologiesl for network operation aspects in Distribution networks?
	Distribution islanding	Some during faults, projects planned	None yet, ongoing pilots	None (studies)	None (studies)	In emergency situation	None	Some small hydro storage	Islands during kable maintennce or repair	None	none (research projects)	Some (hydro plants in the alps)	Availabilty and use of intendet islanding operation of distribution networks and network areas respectively?
	Dynamic circuit rating on distribution level		None	None	None	None	None		None	Pilots	none	None	Real-time system that calculates, based on measured values, how much power can flow at the moment through a certain distribution line (/ cable)
	Distributed generation constraint schemes	Only by DNO in emergency situation	Possible (studies)	None	Remote tripping by DNO in emergency situation for previously agreed plants	Emergency only	None, but DNO has never the less ordered down Wind P on Gotland in times of excess of power	Some	In markets by BRP	Some	not really, some bilateral agreements with BRPs	None	Any mechanism that allows to dynamicly modify by another person than the owner of a distributed generation unit the output power of the distributed generation unit.
	DG participating in voltage control (active and reactive power control)	Possible (studies) sometimes fixed set points	Possible (studies)	Yes (power factor)	None (studies)	None	Some (hydro)	Some	Some, but not online	Dependent on size	none (research projects)	None (but to be implemented within a couple of years)	Are distributed generation units participating on voltage control on distribution network level?
	Feedback voltage control	Possible (studies)	some line drop compensation	None	"Current compound" control in OLTC in HV/MV substations	No	No	Ongoing research	Studies + demo	HV, MV, load-based	HV/MV + research	some line drop compensation	Distribution voltage control based on feedback of current (line drop compensation) or voltage measurements in the network
	Information and Communication Technologies in distribution networks	Partly at MV level but not for DER	On MV and also on LV level	Studies	Some	There are some test projects	Pilots yes	Some	MV grid, not with DER	For active networks, not for Smart Grids	HV/MV, emerging test projects	Advanced Control System implemented in MV	Is in distribution grids already information and communication technology available for using it in context of active network operation?
Consumer (Involvement)	AMR with bidirectional communication	Ongoing pilot projects	Rapidly increasing		Some	Large independent consumers are already equipped with AMR devices	All consumers unidirectional some biderectional	Increasing	Some emerging	Domestic by 2020	emerging	Ongoing pilot projects	Widely used Automated Metering with bidirectional communication at end user level
	Hourly or more often remote meter reading	Projects ongoing	Large customers, smaller increasing	All consumers by 2018	All MV consumers, LV 95% by 2011	Large independent consumers are already equipped with AMR devices	for all HV consumers	> 100 MWh all by 2016	All >100.000 kWh/year + more	>100kW, Domestic by 2020	> 100 kVA	MV customers + some LV	Is meter reading in short time intervalls (less then 1 hour) available?
	Remote disconnect	Mainly in MV in emergency case	Increasing with smart meters	All consumers by 2018	For contract management purposes only	Some consumers	No	Some loads. DER in emergency	Studies	Industrial, through connection agreements	no	None	Is remote disconnection of loads by distribution network operators used?
	Demand side management (demand response, load control)	Studies	Studies	Studies	Studies	No (only load shedding in emergency situations)	Yes and No recently (Febr 2010) price 10 folded for certain hours and energy intense industries shut down	Pilots and research	Studies	Major energy users	research test projects	Major energy users - not the responsability of the DNO	Are demand side management measures iike demand response and load shifting used in a wide range?
	Supplier freedom		Free choice	Free choice	Yes	Only for customers with a yearly consumption > 100 MWh	free choice for all			Free choice	Free choice	Free choice	Is a free choice of energy supplier on distribution system level available?
	Community energy trading			None	?	no				None	no	None	Is energy trading within a regional community possible?
Economy	Reserve services managed by third parties		None	None	no	no	no	Some	Some	Some	no, plans to investigate	None	Commercial entities sell reactive power and ancillary services from multiple providers or generators. (Currently it is usually handled directly between TSO and generation unit operator)
	dynamic energy price at distribution system level		None				HV consumers	Can be chosen	Studies		no, research projects	for major consumer?	Are dynamic electricity prices for consumers available ?
	dynamic network tarrifs at distribution system level		Studies	None		no	no	DG has to pay for variable losses	Studies	None	no, research projects	None	Are dynamic network tariffs for consumers available ?
	Fixed tarrifs for DER	for green electricity	Planned (2011)	Feed in tariffs	Various regimes, depending on the source (feed-in tariffs for renewables) and size of plants	For new renewable energy generation	no	local agreement with DNO <3 MW	Small RES	<5MW, fixed for 25 years	TGC but artificial feed in as for some technologies guaranteed price	Yes (wind PV, CHP, waste, diomass, biogas…)	Are the fixed feed in tariffs for DER available in the country?
	Market tarrifs for DER	yes (for example PV plants which are not in the fixed tariff (the amount of fixed tariff for PV devices has a cap))		Yes	Aggregators for smaller units	yes (for example PV plants which are not in the fixed tariff (the amount of fixed tariff for PV devices has a cap))	yes but also supporting schemes	>3MW		Aggregators for smaller units	yes, for > 10kVA and no net metering: contract with supplier	Mainly for CHP	Are market tariffs for Distributed Energy Resources used?

	Regulatory	Unbundeled DNO	Yes if less then 100000 costumers, above vertical integration is possible		Yes	Yes	yes (bookkeeping)	yes		By law	Regional monopolies separate from suppliers	yes	Yes (subsidiary)	Is the distribution system operator ubundeled?
		DG Integration incentives for DNOs	Curently no incentives	No	Curently no incentives	no	no	no		Yes, but still some barriers	Capacity incentives	no	Obligation, no incentives	Are there any incentives for DNOs concerning DG system integration (i.e. additional income for each kW installed DG capacity)?
		DG Integration incentives to participate in markets	partly profitable	No	by means of tariff	no	no	no	possible for all >3MW must participate	Possible for all. Mandatory >5MW		TGC	No	Are there any incentives for DG to participate in markets? Maybe it is more profitable.
		DG Integration incentives for TSO power system balancing	Ongoing research projects	None	None	no	The concept of the "virtual power plant" is mentioned in the grid rules documents but it is not used nowadays	no		Possible for all through BRP	Unknown	no	Dispachable install.	How well or how ready are DG used for Power System Balancing - manual reserves, automatic reserves, frequence reserves?
		National markets are coupled with neighbouring market areas		Nordpool	MIBEL	no	no	Nordpool	Nordpool	Nordpool + DE	No coupling	BELPEX (BE) + Powernext (FRA) + APX (NL), plans for coupling with Germany and Luxemburg	No coupling	How well or how ready are national markets to be coupled implicitly with neighbouring markets (not auctioned)?
		National markets are ready for real-time markets (1-5 minute price intervals)			None	unknown	no				Unknown	not yet	None	How well or how ready are national markets to shift to real-time markets (1-5 minute price intervals)?
Active Network Readiness Level														Genaral Status of Active Networks in the different countries

comment	measure not available or used and not expected in future (from current point of view)
comment	measure not available or used but possible alternative for the future (from current point of view)
comment	measure partly available or used and expected for the future (from current point of view)
comment	measure available and used
unknown	no information available

4. Targets for Future Network Operation with a high share of Distributed Generation

The measures presented in table 1 are seen as essential for reaching the targets for future network operation with a high share of distributed generation.

The initial source for this development of distribution systems comes from factors outside the actual network operation. Most importantly, climate change and needs of meeting the emission targets will evidently result in increased amount of renewable energy resources and distributed generation. Environmental aspects promote also the wide-scale usage of electric vehicles which seems possible at the moment and would have significant impacts on power distribution. Another important driver is the need of decreasing longer customer interruptions, often determined by regulation and penalties.

There will be more electricity consumption, new types of loads and components and more DG in the network. Efficient use of networks will be essential in the future. Active network solutions seem to be the direction of necessary progress in the near future.

- Networks will be more efficient if the DSO is able to take more system operation responsibility due to DG and active networks.
- Active networks enable:
    - more DG to be connected to the present network without increasing the actual grid costs
    - a better utilization of existing network infrastructure
    - improving security of supply.

- Active networks require:
    - Adapted technical equipment in DG units and loads
    - Better communication between DSO/DG and active load
    - More (remote) measurements in the network
    - More advanced control systems for DSO
    - New power and energy balancing techniques, for instance active loads
    - More intense end customer involvement
    - New protection strategies and equipment
    - New regulation and market models to allow DSO to take the necessary control actions (control of voltage, reactive power, current flow, etc.)

DG System Integration Vision

The vision of DG system integration is to find and establish solutions for a secure and sustainable electricity supply by active operation of distribution networks.

The essential issues underlying this vision are:

- Access for all grid uses/costumers to a secure, cost efficient and sustainable electricity supply
- Supporting a competitive, sustainable and efficient market place

Therefore active networks use measurements, regulation and control mechanisms to actively influence network parameters during operation of the network with contribution of generators and loads. In an active grid, the loads, generators and grid nodes can be controlled in real time by means of ICT technology in order to reach an energy and cost related overall optimization of the network.

An active network is able to react efficiently and flexible to new requirements from network participants (e.g. generators, consumers).

5. Technical, Organisational and Economical Barriers for DG System Integration

The challenges regarding wide-scale development of active networks vary quite a lot among the Annex II member countries. Some common issues can be found for instance on the area of planning the integration of distributed generation. The process of planning the new DG units may be too slow including all environmental and other aspects. Large DG investments may depend on public subsidies which may get outdated during lengthy permit process. Getting required permits may thereby take too much time. In addition, investments required in the network usually also take much time from the planning to the implementation stage: Investors and grid operators need to wait for these permit decisions as well.

Fixed feed in tariffs can be an incentive for distributed generation on the one hand but also a barrier for active network integration and power system balancing on the other hand (markets should follow the physical dynamics of the local system). Different DG support measures and levels of support differ on a regional, national and international level. So for the DSO there is an unclear situation for DG connection obligations. This often prevents the development of long-term strategies.

In most cases the planning principles applied on the distribution network level are mostly based on traditional worst-case scenarios, assuming that DG interconnection is planned according to the most difficult load situation. Such a principle does not support DG integration very well. More flexible connection principles would enable more DG but would also require more active network operation and control by the network operator.

More generally, DG is a challenge for network operators in geographic areas where DG installations have been low. This is one barrier that requires development of knowledge. One can also conclude, that DSOs should have more incentives to develop the integration of DG units. At the moment there are some clear contradictions between efficiency requirements and R&D possibilities of a DSO. Regulators play thereby an important role. Presently, typical DSOs consider DG more as harm than any kind of chance-oriented business possibility. It should be kept in mind that the DSOs must play an essential role when developing the active network concept.

The constraints of present networks are certainly a challenge in all those geographic areas where the amount of DG is increasing. On the other hand, in other geographic areas a very slow increase of DG itself is one kind of barrier: When the increase rate is slow, the general awareness is low and also the progress towards more active networks is hard to reach. Technical constraints as such can always be solved, but including the economical aspects makes the situation much more complex. DG is in many cases promoted with different actions but the grid integration and network reinforcement needs must also get more attention.

Smart meters can be an enabler for DG system integration: for a proper integration of DG one needs a flexible smart meter usually with bidirectional communication. But the barriers regarding smart meters and ICT solutions are:

- The cost for smart meters and who is going to pay; the goal should be that these meters are used by multiple parties.
- Different business models for the service of providing the metering (liberalized metering)
- Missing business models where network operators, DG unit operators and consumers all could benefit from socio economic and technical smart solutions

Energy policy is seen as a challenge in many cases. Clear requirements and visions may be missing, regulatory frameworks are often considered unstable, the long-term continuity of different subsidies is unsure, etc. At the moment a lot seems to be happening, especially related to climate change mitigation and related emission goals. The role of the different market players and the regulatory structure respectively, however, is not clearly defined internationally.

The following problems needs to be solved

- Unclear interfaces between DSO and TSO (TSO can benefit more from DSO active cooperation)
- There are too many different grid and renewable energy subsidy regulation and market participation models
- Uncertain regulatory framework for long term investments in electricity networks
- Unclear coverage of R&D demonstration costs by DSOs and related legal security and exceptions for demonstration/trial projects
- Benchmarking of DSOs without considering R&D efforts

From the electricity market point of view the following barriers can be identified:

- Aggregators in the market are not clearly defined (BRP, Aggregator, certain ESCO types…)
- There are no markets for ancillary services offered by DG on the distribution network level. Currently markets only consider HV transmission levels.
- Different connection regimes (deep, shallow…) – Who is going to pay the connection costs including the necessary grid expansion costs?
- Who pays for the network losses and how can they be reduced? – different options are possible (socialize it or let the actor pay who caused the losses)
- There is a need for local energy balance

6. Recommendations for future DG System Integration

The following recommendation for future DG System Integration where identified by the IEA ENARD Annex II experts: they were derived by analysing the current status, visions and the barriers towards an active integration of distributed energy resources into distribution networks.

- For long term planning of future networks and network operation approaches **clear national and international energy strategies are required**, considering security of supply (long term grid and generation development) and predictable for all actors. A clear commitment and vision for the future electricity mix (what amount by which energy resources? To what degree should a country be self-sufficient (per year or per second)) is needed. Out of that clear requirements for future distribution networks can be identified.
- From a global perspective too many different regulations models will make it difficult to harmonize rules and thus get a stable investment situation. Nevertheless a **clear structure and continuity of regulation models is required,** that is fair for DER; also, constantly changing regulatory frameworks represent a critical uncertainty for long term investments in electricity networks
- **clear handling of R&D and demonstration costs** by DSOs and related legal security and exceptions for demonstration/trial projects are required (e.g. benchmarking of DSOs without considering R&D efforts)
- Fixed feed in tariffs are a clear incentive for DG but in many cases act as barrier for active network integration and power system balancing (market should follow the physical dynamics of the system). The **different DG support measures and levels of support** (regional, national and international) **need to be harmonized**.
- **Markets must follow the dynamics in the power systems** as much as possible and need to be designed for active integration of DER into distribution networks. Following actors and aspects need to be considered:
    - Aggregators in the market need to be clearly defined (Balancing Responsible Parties (BRP), Aggregators, ESCO types…)
    - New ancillary services are required on the distribution network level - in the future new market and business models are required for actors involved in the distribution network
    - Harmonisation of different connection regimes (deep, shallow…) is required – Who is going to pay the connection and grid expansion costs?
- **New contract models and business models**, due to different technical and economical interests of DSO and DG (quality and security of supply versus maximizing DG power feed in) need to be introduced.

- Definitely there will be higher electricity consumption in general, new types of loads and components as well as more distributed generation in the network. Efficient use of electricity networks will be essential in the future. Networks will be operated more **efficient if DSOs are able to take more system operation responsibility for active network and active use of DG resources and demand response.**
- **The smart meter is a possible enabler for DG system integration**. A flexible smart meter with bidirectional communication can be a sensor and actor in future networks. Open questions are:
    - the cost for smart meters and who is going to pay – the goal should be multi use of infrastructure
    - business models for providing metering services (liberalized metering)
    - **Network operators, DG unit operators and consumers should all benefit**
- Measurements, communication and control techniques are essential for forming an active network as well as related standardization: interfaces, communication and grid codes. **Harmonized technical requirements and standards** (for DG, communication and smart metering equipment) **are needed** in order to ensure quality and safety of future active networks
- **Harmonized and more systematic procedures for establishing grid connections need to be established**, for instance information flow between DG unit operator and DSO.
- More focus should be put on the **interface between distribution and transmission networks**
- The use of storage and controllable loads, for instance electric vehicles must be increased. **New applications such as electric vehicles should not be seen only as a new load type but also as a possibility for active operation** (controlled battery feed-in to the grid).
- **Reactive power/voltage management will be more and more important.**
- **New and enhanced protection strategies and equipment is required** for networks with high share of DG.
- Due to the increasing system complexity, in general for future network operation DSOs as well as education institutions **need to build up new knowledge.**
- **More active network demonstration projects are necessary** to gather more practical knowledge and best practice examples for future network operation

7. Future Activities

The IEA ENARD Annex II activities identified a lack of practically implemented solutions for active DER network integration. Many theoretical research projects and some pilot projects are currently ongoing. Out of these projects it is not yet possible to identify general best practice examples. For that reason ongoing knowledge exchange as well as intensified dissemination activities are required.

Active integration of DG into distribution networks is also strongly related to Demand Side Management (DSM) and Demand Response (DR). Therefore a stronger cooperation between IEA DSM and IEA ENARD is suggested by Annex II. Another important aspect concerning DER integration is the expected integration of a high share of e-vehicles in distribution networks. In the future the operation of e-vehicles should also be actively integrated as a DER in distribution network operation and considered in related research and development.

Grid policy and regulatory aspects were identified as the most challenging issues concerning massive DER integration in distribution systems. Therefore in the future activities dealing with DER and network related grid policy issues should be intensified.

8. List of abbreviations

BRP	Balancing Responsible Partie
CHP	Combinded Heat and Power
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
DR	Demand Response
DSM	Demand Side Management
ENARD	Electricity Networks, Research and Development
ENTSOE	European Network of Transmission System Operators for Electricity
ICT	Information and Communication Technologies
R&D	Research and Development
RES	Renewable Energy Sources
TSO	Transmission System Operator