RESPONDING

Renewable Electricity Supply interactions with conventional POwer generation, Networks and Demand

Regulatory road maps for the optimal integration of intermittent RES-E/DG in electricity systems

Final Report of the RESPOND Project

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Acknowledgement

This document D8 is the final report of the RESPOND project and a result of the work undertaken in Work Package (WP) 5 of the RESPOND research project. The focus of the report is on developing for five different EU countries regulatory road maps and formulate on that basis per country sets of recommendations on policy and regulatory changes and timing of actions for pushing the optimal integration of large shares of intermittent RES-E/DG in the electricity system. The work has used the results from previous research conducted in the RESPOND project by partners, see referred reports D4, D5, D6 and D7 and discussions during the different presentations of results at the last RESPOND project workshop held in Berlin (February 3rd 2009) and the final RESPOND result presentations, i.e. at a conference in Leuven (May 27th 2009) and finally at DGTREN (July 22 2009). We highly appreciate the valuable suggestions and inputs of our project partners in preparing the regulatory road maps for their respective countries. Next to the principal authors, see front page, the authors thank Frits M. Andersen (Risoe-DTU), Norman Gerhardt (ISET), Poul Erik Grohnheit (Risoe-DTU), Enrique Lobato (Pontificia Comillas University), Pierluigi Mancarella (Imperial College), Luis Olmos (Pontificia Comillas University), Elena Poza (REE), Danny Pudjianto (Imperial College), Chanthira Srikandam (Dena) and Jakob Völker (Dena) for their contributions and comments.

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Project objectives

The RESPOND project aims at identifying efficient market response options that actively contribute to an efficient integration of (intermittent) RES-E and DG in the European electricity system. It recommends policy and regulation framework improvements that could effectively support the implementation of these market response options.

Other objectives are:

- Assess the impacts of an increasing penetration of (intermittent) RES-E and DG on all the segments of the integral electricity system;
- Identify and analyse feasible and efficient response options by market participants that can actively support an efficient integration of growing shares of (intermittent) RES-E and DG in the electricity system in the future;
- Identify barriers and failures in market competition and regulation that hinder the response options to be developed and implemented by market participants before 2020;
- Analyse and assess improvements and changes of the regulatory framework that facilitate the development and implementation of the recommended response options by market participants;

- Develop Regulatory road maps for five EU countries, i.e. Denmark, Germany, Spain, UK and the Netherlands. This to formulate recommendations and actions for proper timing of necessary regulatory changes and thereby facilitate the implementation of the response options and meeting of EU RES-E and DG targets in 2020.

Project partners:

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RISØ DTU, (RISO), Denmark

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Deutsche Energie-Agentur GmbH (DENA), Germany

Institute für Solare Energieversorgungstechnik eV (ISET) Germany

Red Eléctrica de España SA (REE), Spain

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Acronyms and abbreviations

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ANM	Active network management
APX	Amsterdam Power Exchange
AS	Ancillary services
BERR	Department for Business Enterprise & Regulatory Reform (UK)
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety)
BSC	Balancing and Settlement Code
CAPEX	Capital expenditures
CCL	Climate Change Levy
CCS	Carbon capture and storage
CEER	Council of European Energy Regulators
CUSC	Connection and Use of System Code
CWE	Central West European Electricity market
DA	Day-ahead
DG	Distributed generation

DN	Distribution network
DSO	Distribution system operator
DSM	Demand side management
DSR	Demand side response
E	Electricity
EC	European Commission
EU	European Union
ERGEG	Regulators' Group for Electricity and Gas
ERI	Electricity Regional Initiatives of ERGEG
FACTS	Flexible AC transmission systems
G	Generation
GUoS	Generation use of system (charges)
GW	Gigawatt
HAN	Home Area Networks
HHI	Herfindahl-Hirschman Index
HVDC	High voltage direct current (electricity lines)
ICT	Information and communication technology
IFI	Innovation funding incentive
kV	Kilovolt
kW	Kilowatt
L	Load
LRIC	Long Run Incremental Cost
MITYC	Ministerio de Industria, Turismo y Commercio
MO	Market operator
MVar	Mega Volt Ampere Reactive
MW	Megawatt
MS	Member state (of the European Union)
NMa	Nederlandse Mededingingsautoriteit (Dutch competition authority)
NTC	Net Transfer Capacity
nTPA	Negotiated third party access
NG	National Grid
Ofgem	Office of gas and electricity markets
OMEL	Operador del Mercado Ibérico de Energía (Spanish electricity market operator)
OPEX	Operational expenditures
PPA	Power purchase agreements
PV	Photo-voltaic
PRP	Programme responsible party
RES-E	Electricity generation from renewable energy sources
RO	Renewables Obligation
RPZ	Registered power zones
rTPA	Regulated third party access
SO	System operator
TN	Transmission network
ToU	Time of use
TOTEX	Total expenditures
TRM	Transmission Reliability Margin
TPA	Third party access
TSO	Transmission system operator
TTC	Total transfer capacity
TWh	Terrawatt-hour
UK	United Kingdom
UoS	Use of system
VPP	Virtual power plants

Executive summary

Background

The European Commission, in agreement with the member states, has formulated clear and ambitious targets for enhancing the energy market sustainability in 2020, i.e. 20% of final energy demand should be supplied by renewable energy, and both a reduction of 20% of CO_2 emission and 20% energy savings have to be achieved.
Particularly the first goal implies that electricity generation from renewable energy sources (RES-E) has to increase to about 35%. This is generally perceived as an ambitious target, especially in those member states with a limited availability of hydro and biomass. In the latter a large penetration of RES-E from wind, photovoltaics (PV) and heat-led combined heat and power (CHP) is essential for achieving the EU RES targets for each member state. These sources are considered to be of 'intermittent' nature, since they are either weather driven (wind and PV) which makes electricity output more variable and less predictable, or show a less controllable electricity output (heat-driven CHP) than other generation technologies.
This has also profound implications for the electricity system as a whole, for two reasons. Firstly, power flows in *networks* will become more variable as well as a result of the increase of generation variability. Besides, more power will be fed-in the grid at lower voltage levels ('distribution grid'), sometimes exceeding local demand and implying upward flows to higher voltage levels ('transmission grids') for transportation of electricity to other load centres. Secondly, when the penetration reaches substantial levels, the intermittent power supply implies also an increase in the balancing of supply and demand, and changes of *market* prices during times with and without wind energy[1]. Since intermittent RES increases strongly up to 2020 in countries such as Denmark, Germany, Spain, UK and the Netherlands and thereby adding more capacity than energy production to the system, the capacity credit decreases and renewable electricity needs to increase even more in production capacity terms to reach the target in 2020. Both effects are expected to result in much higher system costs, which in the next decades will impede the necessary integration of the large amounts of RES-E in the electricity system to meet the EU RES targets.

Consequently without profound changes in the electricity system the overall system costs will become much higher than the system benefits expected from increasing penetration of RES-E/DG in the electricity supply in 2020. At the end this will become a severe barrier to meet the EU 2020 targets for RES.

For this reason, this report analyses a wide range of cost reducing options. Since the RES-E share develops gradually, the number of available options is high and consequently some options are more required than others, a prioritisation of options is required to lower the system integration costs of intermittent renewables in the most cost-efficient way in time. However, countries electricity systems and their concomitant costs vary widely between different EU countries due to different system characteristics like generation mix, penetration level of RES, location of RES and demand, network topology and operation, and market design applied. Consequently for an optimal transition of the current EU electricity system towards a system that economically most efficiently can deal with large RES-E supply each country needs a country specific transformation path to facilitate and secure an efficient introduction of so called response options (enhancing flexibility and controllability). For that purpose it is necessary to design per country an optimal road map for implementing in time the required regulatory meas-

[1] Since electricity originating from wind generation is by far the most important intermittent production technology, we focus mainly on the description of the impacts of and solutions for the increase of wind generation.

ures. In this report we present regulatory road maps with recommendations for changes and actions for a electricity system transformation up to 2020 for the countries Denmark, Germany, Spain, UK and The Netherlands.

Methodology for building regulatory road maps

The goal of building road maps is securing an optimal timing of regulatory actions. Therefore, a regulatory road map presents possible routes of regulatory development and indicates important intermediate points in time ('milestones') for a smooth transformation of the electricity system of a country. The main building blocks of the road maps are:

1. Relate the response options to different RES impacts and system segments;
2. Relate the different stages of market integration to the RES impacts and response options;
3. Relate the different stages of network integration to the RES impacts and response options.

For realizing the socially optimal integration of intermittent technologies in electricity systems, a wide range of different technical and institutional options are available. We call them response options. Below in Figure E.1 we summarize these so called response options. The Figure is not exhaustive, but meant for illustrative purposes only.

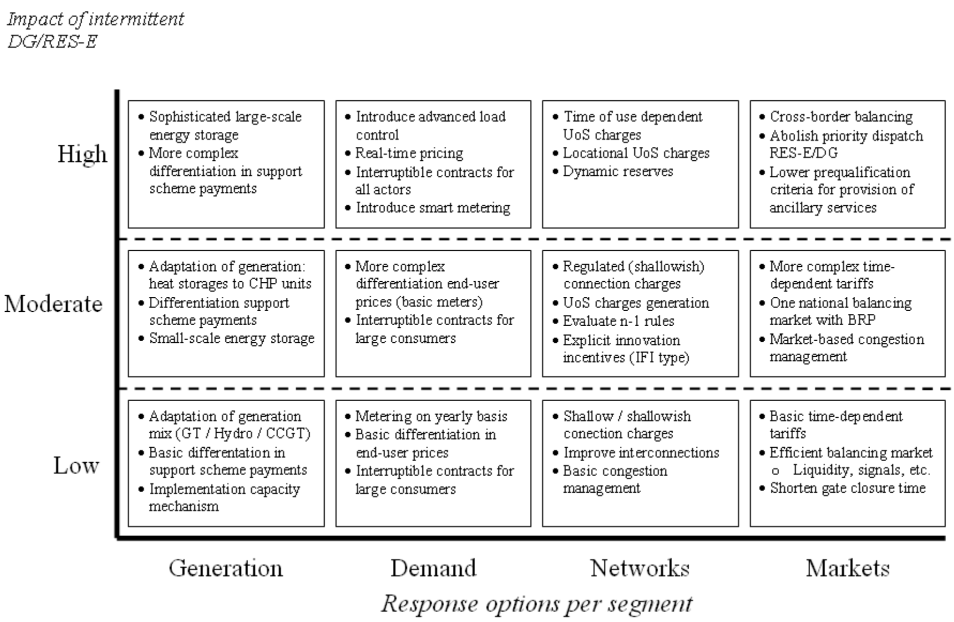


Figure E.1 *Indicative response options per segment*

The different electricity market value chain elements used throughout the RESPOND study are listed horizontally. On the vertical axis we depicted three qualitative degrees of intermittent RES-E/DG impacts within the electricity system. The impact of RES-E/DG on the electricity system, which results from either a high absolute level of intermittent RES-E/DG or a large relative share of RES-E/DG, is qualified as low, moderate or high. This classification should illustrate the principle that implementation of certain response options should be proportional to the problems created by more and more intermittent RES-E/DG.

The *system transformation process* of the electricity system consists of *two dimensions*. Firstly, *market integration* concerning the integration of new RES-E/DG in different markets: electricity wholesale market and the markets for system balancing and other ancillary services. Secondly, network integration concerning the integration of new RES/DG in both transmission and distribution networks. By combining the two dimensions of the system transformation process, i.e.

the process of technical and institutional changes for increasing market integration and network integration, we create the regulatory road maps for each country. The basic regulatory road map scheme is depicted in Figure E.2.

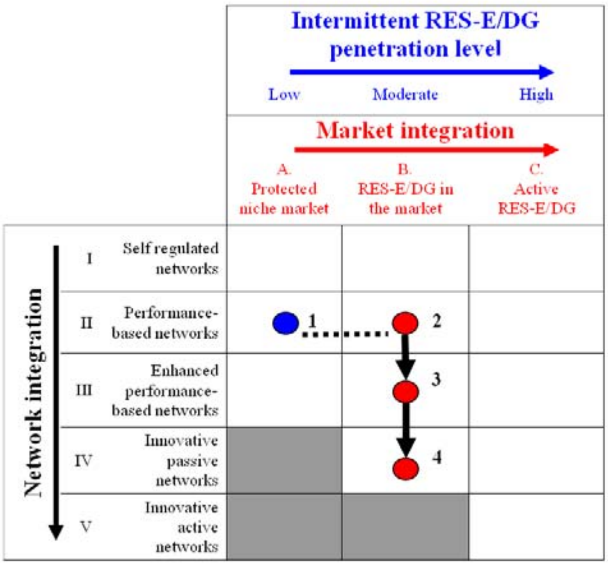


Figure E.2 *Generic scheme of a Regulatory road map*

The different stages of market integration are depicted on the horizontal axis. The horizontal axis at the same time also represents the impact of intermittent RES-E/DG on the electricity system. This can be interpreted as either an amount of RES-E/DG in the electricity system or the relative impact of existing RES-E/DG. The amount / impact of RES-E/DG is defined by the qualifications of 'low', 'moderate', and 'high' and related to the market integration stages. Likewise, the different stages of network integration are depicted on the vertical axis. Based on the two axis we can depict (1) the current situation with respect to the amount / impact of RES-E/DG in the current electricity system, (2) the current situation with respect to network integration in combination with the current level of market integration, and (3) the likely end-state (i.e. future point in time, say around 2020) of intermittent RES-E/DG integration. The latter identifies the required level of network and market integration and is dependent on the likely system impact at the end of the time horizon. The movement from the initial starting point to the envisioned end (state) point is referred to as the *regulatory road map*.

Recommended regulatory actions

The developed regulatory road maps for the five EU members Denmark, Germany, the Netherlands, Spain and the United Kingdom cover countries with varying levels of RES-E/DG penetration and intermittent technologies. Consequently some of the system impacts are different, giving rise to different recommended solutions (response options and regulatory actions) per country. In developing the regulatory road maps we have also resorted to available electricity system expertise within these countries, partners and stakeholders and other specific information resources. The most recommended key regulatory actions are presented for each of the countries in Table E.1 and briefly explained below.

Table E.1 *Overview of recommended regulatory actions per country*

Topic	Recommendation	Country				
		Den-mark	Ger-many	The Nether-lands	Spain	United Kingdom
Network integration						
Network charging	Implement shallow connection charges at all network levels			✓	✓	✓
	Implement cost-reflective use of system charges for generators	✓	✓	✓	✓	
Network planning	Implement dynamic reserve requirements in network planning standards	✓	✓	✓	✓	✓
	Introduce explicit innovation incentives in network regulation	✓	✓	✓	✓	
Congestion manage-ment	Implement market-based congestion management	✓	✓	✓	✓	✓
Market integration						
Demand re-sponse	Establish common standard for functionality of smart meters	✓	✓	✓	✓	✓
	Implement basic time-differentiated prices for all consumers	✓	✓	✓	✓	✓
Balancing market	Introduce balancing responsible parties		✓		✓	
	Implement shorter gate closure times of trade markets				✓	
Ancillary services	Increase possibilities for RES-E/DG to provide ancillary services	✓	✓	✓	✓	✓

Connection charges

The integration of increasing amounts of RES-E/DG gives rise to increasing costs in connecting and operating networks. These costs have to be borne by the users of the system, i.e. generators and consumers.

The costs of connection of network users and the operation of the network are paid by network users. These network costs are generally subdivided in costs of connecting users (generators and consumers) to the grid and costs for operation of the electricity system i.e. transport and complementary system services. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by use-of-system (UoS) charges.

Two distinct approaches of calculating connection charges can be distinguished: shallow and deep charges. Shallow connection charges include only the cost of connecting the customer to the nearest point in the distribution network. The costs of additional network reinforcements are not included in these charges. As opposed to shallow connection charges, deep connection charges contain the costs of network reinforcements both at the transmission and distribution level as well as the direct connection costs.

For providing fair and non-discriminatory network access to the network for different kinds of generators, including small RES-E/DG units, it is important to introduce shallow connection charges. This avoids large upfront costs for RES-E/DG, which would discriminate against DG as compared to centralised generation. Besides, this kind of connection charges lowers transaction costs to DG by keeping the calculation straightforward and transparent and avoiding negotiations about the "deep" connection cost component. Therefore, it is recommended to implement shallow connection charges in Spain, The Netherlands and Germany.[2]

Use of system charges
However, from the point of view of the system operators, the implementation of shallow connection charges is not a favourable option if the costs of network reinforcement due to DG are not covered in some way. Therefore, it is *recommended to socialize the incremental grid reinforcement cost among all network users by way of use of system (UoS) charges*. Currently, UoS charges are mainly levied upon consumers, with the exception of the United Kingdom. Consequently, generators do not receive an incentive to take into account the network costs that the system will incur as a result of their decision to install a new plant at a certain location. However, this is clearly inefficient from a system and welfare point of view and causes higher network integration costs. Therefore, the introduction of cost-reflective use of system charges for generators is recommended for Denmark, Germany, The Netherlands and Spain. Coordinated implementation of this measure, at least at regional level but preferably at European level, is highly recommended since an uneven implementation of UoS charges for generators might result in an uneven playing field across the EU.

Dynamic reserve requirements in network planning standards
In network planning a number of standards are used in order to guarantee security of supply (like the 'n-1' standard). The maximum capacity of networks circuits is nowadays calculated using static assumptions with standard load profiles among others. When network reserve requirements depend on actual (short-term) wind generation forecasts, additional network capacity may become available and network investments due to connection of additional renewable generation may be lowered without compromising security of supply. This recommendation applies to all five countries at hand.

Explicit innovation incentives in network regulation
Network planning is also influenced by network regulation, both at TSO and DSO level. Generally, within Europe *incentive regulation* with price or revenue caps is applied to network operators. Incentive regulation can be characterised by the strong focus on short-term cost-efficient network operation, which is necessary to decrease the monopoly profits of network operators but comes at the expense of more risky investments contributing to long term efficiency. As a result, already existing risk-averse behaviour of network operators is reinforced, which impedes investments in active network management technologies by DSOs. Therefore, it is recommended to add explicit innovation incentives to incentive regulation like the IFI type of incentives in the United Kingdom. These incentives effectively increase the scope for innovation by DSOs and therefore may speed up the implementation of active network management. This recommendation applies to Denmark, Germany, The Netherlands and Spain.

Market based congestion management
Installing new conventional and RES generators may require reinforcing the transmission and distribution grids, especially if new generation is either located far from load or production is exceeding consumption sometimes. Reinforcing the network usually takes more time than installing new plants, and starts only when generation consents have been provided. Consequently, existing network capacity falls short and congestion will emerge. For interconnections already implementation of market based congestion management is required by EC regulation

[2] Denmark and the United Kingdom have already implemented a shallow(ish) connection charges methodology.

1228/2003. Countries are increasingly using implicit and explicit auctions for cross-border congestion management. Also for national grids *implementation of market-based congestion management is recommended* in order to relieve congestion against lowest costs for all market actors including RES-E/DG as well as to diminish the occurrence of congestion. This recommendation applies to all countries.

Common standards for functionality of smart meters

Common standards for smart meters are required in order to ensure a certain standard of data quality and functionality within country. A *common standard is a basic requirement* for organising an increase of market-based demand response in the future and guarantees that the whole demand response potential can be utilised. An increase of demand response is valuable to increase the flexibility of the system to react to the higher variability of generation in systems with high penetrations of wind and PV. At present, common standards have not yet been defined. Therefore, it is recommended to *establish common standards* for smart meter functionality in Denmark, Germany, The Netherlands, Spain and UK, at least at national level.

Basic time-differentiated prices for all consumers

Smart meters are useful but not sufficient for an increase of demand response. Therefore, consumers need also to receive signals about the system status. In a liberalised market, this signal should be provided to consumers by making prices more variable. *As a first step, prices should be differentiated to peak, shoulder and off-peak periods.* In the medium term, i.e. before 2020, consumers should be facing hourly-based prices. It should be noted that the communication of hourly prices to final consumers itself might not always automatically induce price responsiveness. This might vary over the various types of electricity consumers. In order to fully use the demand response potential with for example household consumers automated response devices should be developed and implemented in parallel, since especially these consumers might be reluctant to make personal, real-time decisions on electricity consumption and responsiveness to electricity price changes.

Balancing responsible parties

The Scandinavian type of balancing market design with balancing responsibility for all connected parties (including RES-E/DG) provides an incentive to both generators and consumers to limit their imbalance as far as possible; connected parties have to pay imbalance payments in case their actual production deviates from their production forecast. Consequently, at a system level the amount of balancing power to be provided is reduced compared to a system without balancing responsibility. This allows for the integration of RES-E/DG production in the electricity system against lower costs. It is *recommended that a balancing system with balancing responsibility for all connected parties will be introduced* in both Germany and Spain. The other countries did already implement such a system in the past.

Gate closure times of trade markets

Generators can sell their production on markets with different time-frames. In a market environment wind and PV will mainly sell their production in markets for short time-frames, notably the day-ahead market due to the intermittent character of these sources. On a day-ahead basis production forecasts for wind do have a relatively high forecast error, but this error becomes smaller, the shorter the time frame; in order *to diminish their balancing cost exposure wind generators need the possibility to correct their production forecasts as close to real-time as possible* when the forecast error of production is much lower. In several countries intraday markets have been established for this purpose. Gate closure times of intraday markets (in the UK the spot market) range from a maximum of 8 hours ahead of real time (last intraday market for each day closes at 17:45 in Spain), via 1.5 hour (Germany) to 1 hour ahead of real time (UK, Netherlands, Denmark). For Spain, it is recommended to reduce the gate closure time to 1 hour ahead of real time.

Possibilities to provide ancillary services
Currently requirements of system operators as well as obliged provision of some ancillary services by conventional generation, prevent the delivery of ancillary services (including balancing services) by RES-E/DG. However, for both system (dramatic decrease of conventional generation in some regions) and level playing field considerations, it is deemed *useful that RES-E/DG will be enabled to provide ancillary services.* Therefore, requirements to RES-E/DG, including aggregators of a portfolio of small (distributed) generation assets, and all minimum size limits of the underlying individual installations or connections should be removed as far as economically and technically feasible. Furthermore, the ancillary services market design should allow for sufficient AS provision, efficient contracting of these services, as well as for a good trade-off for generators between either the provision of energy on the one hand or the provision of one of the different ancillary services on the other. Especially, services with a system-wide character (for example tertiary reserves) may be contracted through markets (i.e. auctions) instead of self-procurement by the TSO or bilateral contracts.[3] Consequently, RES-E/DG may diversify their revenue streams. Since today there is little experience with RES-E/DG providing ancillary services, *further field testing/research is required*. But the recommendation applies to all five countries; Denmark, Germany, The Netherlands, Spain, and United Kingdom.

Priority and critical regulatory actions per country

The most urgent and critical actions to improve the system flexibility of the electricity markets in the five countries are outlined below.

Denmark
The road map indicates that the main actions are required for improving network integration, as on the one hand major grid overloads and network congestion are expected, and on the other hand conventional hardware solutions are prevented by social acceptance issues and increasing cost burdens. First of all, generators should face the effects of their production and siting decisions on network investments; therefore *use-of-system charges for generators* should be set at a more substantial level. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Finally, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning in the longer term. Especially in a system with high and increasing shares of wind generation, dynamic planning criteria can lower network integration costs substantially.

Germany
For Germany actions are required for improving both network and market integration. Although network integration remains the main issue, during our analysis it became prevalent that the improvement of market flexibility delivers large quick wins for the German electricity system, potentially limiting required network integration actions. More market flexibility may limit the demand for network flexibility dramatically by stimulating generators to take into account the effects of their behaviour on the electricity system. First of all, when a *feed-in market premium scheme* is implemented instead of feed-in tariffs, RES-E/DG receives incentives to take into account the system demand for electricity in its production decisions. Secondly, difficult network situations can be dealt with more effective and efficiently when RES-E/DG disposes *no longer* of *priority access*, but is allowed to be curtailed against a cost-reflective payment. Finally, demand for system balancing can be decreased substantially if RES-E/DG becomes *balancing responsible* and a *rolling gate closure time* for the balancing market is introduced.

The Netherlands

3 For local services like the provision of reactive power, the number of service providers may be too small for a market in some cases.

For the Netherlands, the main actions are required for better network integration. First of all, network integration can be done against lower costs if generators have to take into account *use-of-system charges for generators* which influence generators' production and siting decisions. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Next, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning standards in the longer term. Last but not least, difficult network situations can be dealt with more effective and efficiently with congestion management when RES-E/DG will not dispose of the foreseen *priority access*, but remains to be allowed to be curtailed against a cost-reflective payment.

Spain
For the Spanish electricity system it is *vital that current flexibility provided by pumped-hydro and gas-based units is maintained.* Especially for gas-based electricity generation units there are concerns that the current capacity payment mechanism is not working satisfactorily. Without sufficient adaptation of this mechanism there will likely be insufficient incentives to expand flexible gas-based electricity generation in the near future. Furthermore, it is stressed that *interconnections with especially France need to be strengthened.* Current initiatives in this respect should receive continuing support. The above mentioned issues relate to the provision of system flexibility, but apart from that also the efficiency with which intermittent RES-E/DG operates needs to be substantially improved. Response options that should be highly valued in this respect are the adaptation of the use of system charges methodology (increasingly allocate costs to generation) and *balancing market rules (move gate closure closer to real-time).*

The United Kingdom
Network regulation in the UK seems quite robust when it comes to a further increase of intermittent RES-E/DG in the future, although possibly the implementation of more cost-reflective network charges should be given some attention in the medium-term. The more critical points in the future regulatory actions when it comes to the integration issue is to efficiently and effectively deal with (1) structural geographical imbalances in load and generation across the UK, and (2) the connection of large-scale off-shore wind parks.

Timing of regulatory actions

Since the current-day situation differs across the assessed EU member states, also the prioritisation of recommended regulatory actions that can increase system flexibility varies across these countries.

In the short-term, say until 2012, for most countries, relatively low cost response options include changes in the methodology of network tarification and the design of wholesale and balancing markets (i.e. change in gate-closure time). The major issue with the former type of response options is not the cost of implementation but the change in the allocation of costs over the different actors in the system, which could give rise to possible delays in implementation. It is recommended that discussions on the implementation of this response option are started as soon as possible. The latter type of response options should also be given high priority because it can substantially lower the costs of integrating intermittent RES-E/DG and hence improve overall system efficiency. In addition, high priority in the short-term should be given to the provision of innovation incentives to electricity market actors. This will benefit system capacity to create and adopt new innovations related to a successful integration of RES-E/DG in the medium and long-term.

In the medium to long-term, more fundamental and relatively more complex response options are recommended for the assessed EU member states. These include the implementation of more price responsive electricity demand. Whereas implementation of basic electricity price differentiation in base and peak is recommended in the very short term, even more differentiated electricity prices (e.g. hourly prices) are recommended in the medium term. Furthermore, more complex response options such as the implementation of cross-border balancing and the implementation of zonal pricing should be considered in the medium term. The former requires for many preparatory actions in describing and defining common balancing services characteristics and a common balancing market gate closure time. The latter type of response option enables efficient national market-based congestion management, but asks for a number of preparatory actions, for instance to establish different zones and to compute the constrained energy. Other options like provision of ancillary services by DG and implementation of active network management in distribution networks may be only partially possible before 2020, since these options require further technology development as well as adaptations of complex network criteria.

Responsibilities of different market actors

A large number of market actors bear responsibility in some way when it comes to the implementation of the response options that ensure a smooth integration of RES-E/DG units. Apart from the different actors involved in different stages of the electricity market value chain (i.e. electricity generation, transport, distribution, et cetera), there are also different jurisdictions involved (i.e. the national vs. the European level).

Regarding the implementation of response options related to efficient *network* integration at the distribution network level, the responsible market actors are mainly but not exclusively national. Response options in this field relate to the adaptation of distribution network charging methodologies, the provision of network planning and innovation incentives to DSOs and the method of network regulation. Here, the main responsible actors are the national DSOs and the regulatory authority. In joint cooperation with the DSOs, the regulatory authority should explore and finally adopt changes in existing distribution network regulation. For a number of the response options it holds that no changes in existing energy sector legislation are required at either the national or EU level. However, some response options will clearly benefit from common European legislation, for instance the planned European network codes probably will accelerate the implementation of active network management (smart grids), since technical manufacturers do only have to meet one set of technical specifications instead of several, often conflicting ones. Moreover, it goes without saying that during the process of drafting adaptations to existing regulation national market actors can, and need to, learn from experiences abroad. This could for example be done under the existing umbrella of the ERGEG Regional Initiatives.

For response that aim to deal with *network* integration issues at the transmission network level things are different. Here it is more important to coordinate the implementation of response options on EU or at least on a regional level, since changes in for example the allocation of scarce network capacity both nationally and at borders, transmission tarification for generators, and the design of network investments in national connections and interconnections immediately affect the electricity market across the border as well. Hence there is a much stronger need for coordination. However, the responsibility for implementation of many actions still rests with national market actors such as the operator(s) of the national transmission network (TSO) and the regulatory authority. Again, as was the case for response options at the distribution network level, it is expected that the role for government (for example in drafting new pieces of energy sector legislation) is not large since most response options in this field can already be implemented under existing laws.

For most of the response options aimed at an efficient *market* integration of intermittent RES-E/DG an additional legislative step is required before implementation. This is the case for substantive changes in support scheme mechanisms, regional wholesale and balancing market design related to export of electricity from renewable sources, differentiation of end-user electricity prices in time, and smart-metering and demand response. On the whole, given exceptions for some countries, implementation of these measures first requires a process of proposing, discussing and adopting new pieces of electricity market legislation at both the national and European level. After adoption in legislation, the actual implementation then still rests with a larger number of actors in the field. For example, DSOs and electricity retail suppliers will need to work together in successfully operating smart meters and communicating time-differentiated and/or locational electricity prices.

Conclusions

The increase in the amount of (intermittent) less controllable electricity generating units (i.e. wind, PV, heat-led CHP) presents both challenges and opportunities for the development of the electricity markets in Europe. For one, the increase in distributed or renewable-based generation units poses benefits with respect to energy efficiency and environmental impact. The challenges lie in the provision of more flexibility in current electricity systems. Therefore, the focus should be on providing this additionally required flexibility against the lowest possible cost, i.e. cost effective.

In the *short-term* this involves basic and relatively easier options such as improving balancing market design, increasing international and regional interconnection capacity and time-differentiated final electricity prices. In the *medium term* it involves the implementation of more differentiated cost-reflective network charges and renewable support schemes. In the *long-term*, beyond 2020, more innovative solutions related to for example the large-scale introduction of electrical vehicles should be considered.

Although the particular cost-effective measures for each EU member country may be different, depending on national electricity system characteristics, for each of the member states it holds that policy and *regulatory actions should on the one hand aim at improving the flexibility level* of the electricity system by the most-effective short term measures, and at the other hand aim at an optimal market environment where there is sufficient room for market actors to further develop more innovative technologies that are highly required in a post-2020 electricity system. Although the developed regulatory road map only looks until the 2020 mark, the underlying research on response options available for increasing electricity system flexibility together with the further developed road map methodology offers promising potential to further research this issue from a *longer-term perspective.*

1. Introduction

1.1 Background

The European Union (EU) has formulated ambitious long-term goals regarding the transition to a more sustainable EU energy system. In order to materialise this objective, country-specific targets have been set for (1) improvements in energy efficiency and (2) the amount of renewable electricity in the electricity supply system, both by the year 2020. Obviously, the specific EU RES targets for member states for 2020 are only an intermediate step in realising a fully sustainable energy system in the longer run.

Because some of the most promising RES-E generation technologies that will be deployed to meet these targets are also of a relative high intermittent nature this report addresses some of their impacts around 2020 for the electricity system as a whole. We focus on the different solutions to reduce the observed and expected system (costs of) impacts, i.e. on electricity markets, networks, demand and generation. The overall aim of the study is to integrate (intermittent) electricity generation in current electricity systems from a social perspective as efficient as possible. Consequently we concern ourselves with mitigating or removing the negative impacts that intermittent generation has on the electricity system; the options that could be implemented to reach these goals are called response options. These response options enable a socially efficient integration of more and more intermittent generation units in the electricity system.

1.2 Objectives

The report has the following objectives:

- Bring together and integrate the main findings of the RESPOND project;
- Develop for five countries regulatory road maps, for an optimal transition of the current electricity system towards a future electricity system that can optimally cope with larger shares of intermittent RES-E/DG;
- Develop country specific regulatory road maps for Denmark, Germany, the Netherlands, Spain and the United Kingdom (UK);
- Formulate both general and specific regulatory recommendations and actions per country to implement the road maps.

1.3 Methodology

The methodology for building a road map for regulatory changes and actions per country has been derived from other, earlier developed technology and regulatory road maps (Van Sambeek *et al.* 2003). Regulatory road maps present possible routes of regulatory development in time, taking into account specific country-specific conditions. Starting at today's situation, the road maps indicate important intermediate points in time for securing a smooth (optimal) transition of the electricity system in the period covered by the road map.

In the RESPOND project a road map identifies the required regulatory developments and changes for enabling integration of more and more (intermittent) RES-E/DG in electricity systems, given the availability of new technologies and their development. This means that a regulatory road map in this case does not include technological developments and improvements needed in a specific time span to enable a successful market introduction of e.g. small-scale energy storage facilities. We rather assume a certain generally expected availability of technologies in due time, and look at the required regulatory steps or changes required to implement this technology as a measure to reduce the observed or expected negative impacts of intermittent electricity generation.

Besides, each regulatory road map envisions a specific desired end-state. The desired end-state as presumed in the RESPOND project relates to the EU policy goals on sustainability. In the medium term these concern the sustainability targets for the EU electricity sector in the year 2020. The targets as laid down in the EU Renewables Directive (EC, 2009) require member states (MS) to significantly increase the share of renewable electricity generation in their respective electricity systems. The basic challenge is to reach these targets at the minimum cost for society as a whole. This for example means that increasing shares of electricity generation based on wind causing different types of intermittency problems should be accompanied with proper measures and actions as to mitigate, again at minimum social cost, the intermittency problems. In simpler words: in reaching the desired end-state, a smooth-as-possible transition path should be followed.[4] A road map systematically reveals and identifies the actions to be taken by different stakeholders in the transition path to reach the desired end-state and provides a clear set of recommendations that support such an optimal transition path.

Our road map contains a series of regulatory actions and developments. Furthermore, the road map indicates the timing of regulatory steps, where the timing of the steps depends on several key developments in the electricity sector and particularly the absolute level and the relative share of intermittently producing RES-E/DG in the electricity system. The level of detail in the description of the regulatory actions is higher for the short-term actions than for the long-term actions (Van Sambeek *et al.* 2003).

As EU electricity systems vary across MS due to geographical, technological and institutional differences, road maps are context dependent as well. Therefore this report provides not only one general framework of a regulatory road map concerning the optimal integration of intermittent RES-E/DG, but develops specific regulatory road maps for five different MS, namely; Denmark, Germany, the Netherlands, Spain and the United Kingdom.

1.4 Terminology

Distributed and centralised generation
Generally, we follow Ackermann (2001) in defining DG: "Distributed generation is an electric power source connected directly to the distribution network or on the customer site of the meter". It is difficult to provide a universal definition in a quantitative sense because this is country specific and relates to characteristics of the centralised electricity system. Co-generation (or Combined Heat and Power; CHP) and electricity generated from renewable energy sources (RES) are often considered as DG. However, as it is shown in Table 2.1, only a part of CHP and RES can be considered as DG.

Intermittent RES-E/DG
Within the report we will often use the term intermittent RES-E/DG. Here we refer to all electricity generating technologies of which generation is not primarily following electricity market developments: i.e. is not fully controllable to the degree that generation can not be fully adapted to electricity market needs. There are two reasons why controllability of these generation technologies is limited. First, generation can be driven by external sources such as wind and the sun for the case of wind or solar-based generation technologies. Second, generation can be driven by heat-demand, which is the case for CHP-based generation. The degree of intermittency (i.e. controllability) varies across the mentioned technologies. In this report, we focus on these less controllable production technologies i.e. wind power, PV and heat-demand driven CHP.

[4] In welfare economic terms one might even speak of 'optimal paths'.

Table 1.1 *Characterisation of generation units (Scheepers 2004)*

	Combined Heat and Power (CHP)	Renewable Energy Sources (RES)
Large scale generation	• Large district heating [a] • Large industrial CHP [a]	• Large hydro [b] • Offshore wind • Onshore wind (partly) • Co-firing biomass in coal power plants • Geothermal energy
Distributed Generation (DG)	• Medium district heating • Medium industrial CHP • Commercial CHP • Micro CHP	• Medium and small hydro • On-shore wind (partly) • Tidal energy • Biomass and waste incineration/gasification • Solar energy (PV)

[a] typically > 50 MW_e
[b] typically > 10 MW_e

Transmission and distribution networks
RES-E/DG generation units are connected to different network voltage levels. The responsibility of each network voltage level rests with either the transmission system operator (TSO) or the distribution system operator (DSO). Whether specific network voltage levels are operated by the TSO or the DSO is often based on historical developments and can largely differ across EU countries. In general, the following classification can assist when thinking about the relation between the size (capacity) of RES-E/DG generation units and the network voltage level to which the unit is connected.

Table 1.2 *Overview of controllable and non-controllable* RES-E/DG *technologies and network voltage levels*

	Network voltage level		
	Low	**Intermediate**	**High**
Controllable	**Small controllable** e.g. micro CHP, small-scale CHP. Units with a capacity smaller than 50 kW_e and small-scale CHP for units smaller than 1 MW_e	**Medium controllable** e.g. medium CHP unit (gas or biomass fired)	**Large controllable** e.g. large CHP unit (gas or biomass fired)**, large hydro (reservoir)** .
Non-controllable	**Small uncontrollable** e.g. PV. A typical residential PV-unit may have a capacity of 3-4 kWp.	**Medium uncontrollable** e.g. single wind turbine, small wind farm, small hydro, larger PV-units	**Large uncontrollable** e.g. large wind farm, medium hydro

Policy and regulation

Talking specifically about regulatory road maps we need to provide a clear definition of what we refer to as regulation. We specifically talk about regulatory road maps and not about policy road maps. This is explained by the two definitions provided below. *Policy* is referred to as the combination of basic principles by which a government is guided and the declared objectives that a government has defined and seeks to achieve and preserve in the interest of society[5]. *Regulation* can be considered as legal and institutional restrictions promulgated by government authority and can take various forms, such as self-regulation, social regulation (e.g. norms), co-regulation and market regulation[6]. In the RESPOND project thus far we have not addressed required changes in government principles or stated policy goals. Rather we have been looking at how regulation can contribute to efficiently meeting the declared general policy objectives regarding sustainability. Hence we will continue to speak of regulatory road maps. This off course does not mean that, at the end of the report, we do not have some general policy recommendations that result from preparing the regulatory road maps.

1.5 Report structure

In Section 2 the system impact of an increasing penetration of (intermittent) RES-E/DG is briefly described. Section 3 concerns the methodological approach used for developing the regulatory road maps. Herein we discuss and construct the different 'building blocks' that are required to construct the complete country specific road maps later on. The main two 'building blocks' are a generic road map framework and a scenario-background that needs to accompany the development of robust country-specific road maps. With 'generic' we refer to a for all countries applicable road map scheme that is not yet 'filled-in' with the country specific elements, such as the starting or end point conditions of the system. In Section 4 to 8 we present the actual construction of regulatory road maps for respectively Denmark, Germany, the Netherlands, Spain and the United Kingdom. Finally, in Section 9 the generally - from the country road maps derivable - recommended regulatory actions and their timing are summarised.

5 http://www.businessdictionary.com/definition/policy.html

6 http://en.wikipedia.org/wiki/Regulation

2. System impact and response options

2.1 Impact on electricity systems

In Ramsay et al. (2007) the impact of an increasing amount of intermittent RES-E/DG was extensively described by referring to various studies and different EU member states experiences. The main positive impacts ("key drivers of support policies") identified in that report are summarised in Table 2.1 while negative impacts on electricity systems are summarised in Table 2.2. For a more elaborate analysis we refer to Ramsay et al. (2007) and Zvingilaite et al. (2008) and the references mentioned therein.

Table 2.1 *Overview of positive impacts on the electricity system*

Segment	***Positive impact***	***Conditions***
Generation	Fuel savings Emissions savings	
Networks	Reduction of energy losses	Low to moderate levels of RES-E/DG, concentration / spread, match between load and generation
	Deferring investment	Low to moderate levels of RES-E/DG, concentration / spread, match between load and generation
Markets	Reduction in overall market prices	
	More efficient provision of (local) balancing (CHP, micro-CHP)	Controllability, electricity-demand driven production through heat storage or boiler
	More efficient provision of ancillary services	

Table 2.2 *Overview of negative impacts on the electricity system*

Segment	***Negative impact***	***Conditions***
Generation	Decreased profitability for conventional power plants at the margin Possible lack of incentives for investments in new flexible generation	
Networks	Increase of energy losses	Moderate to high levels of RES-E/DG, concentration / spread, RES-E/DG load factor
	Additional network investment	Moderate to high levels of RES-E/DG, concentration / spread, match between load and generation, RES-E/DG load factor
	Increase in costs for system reliability	Large share of very incontrollable RES-E/DG, geographical concentration, overall interconnection, match between load and generation, RES-E/DG load factor
Markets	Increase in system balancing costs	Large share of very incontrollable RES-E/DG, geographical concentration, overall interconnection, overall flexibility in existing system (generation)
	Increased market price volatility	

2.2 Response options

The previous Section restated the various observed and expected impacts caused by integrating more and more intermittent type of DG/RES generation in the electricity systems, whereby a distinction was made between potential negative and positive impacts. When striving for a socially optimal level of integration of intermittent technologies there are different options for either mitigating the negative impacts or enabling the positive impacts. Zvingilaite *et al.* (2008) provides an extensive list of options to do so: these are called response options. Below we summarise the main findings from the RESPOND study so far as we used it in this report. For an extensive overview of all response options we refer to RESPOND reports and their references therein. Note Figure 2.1 below is not exhaustive but is merely meant for illustrative purposes.

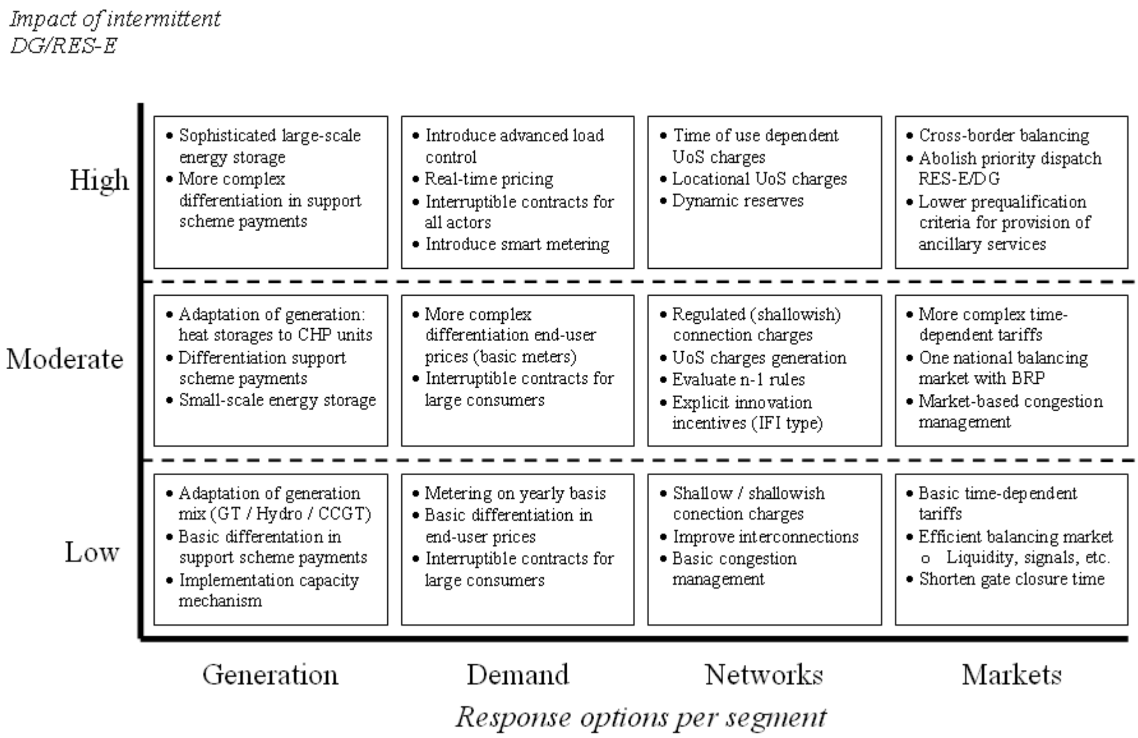


Figure 2.1 *Schematic overview of response options related to an indicative level of* RES-E/DG *penetration (based on Appendix in Zvingilaite et al., 2008)*

The above depicted figure basically shows that different response options exist for different elements in the electricity market value chain. For example, increasing flexibility could be introduced on the electricity demand side through implementation of demand side response whereas system flexibility could also be enhanced on the electricity generation side through (more) investment in flexible generation technologies or even storage technologies. The different electricity market value chain elements used throughout the RESPOND study are listed horizontally. On the vertical axis we depicted three qualitative degrees of intermittent RES-E/DG impacts within the electricity system. The impact of RES-E/DG on the electricity system, which results from either a high absolute level of intermittent RES-E/DG or a large relative share of RES-E/DG, can be qualified as low, moderate or high. This classification should illustrate the principle that implementation of certain response options should be proportional to the problems created by more and more intermittent RES-E/DG. At low levels of intermittent RES-E/DG, with relatively little problems caused in the electricity system, relatively simple response options should be implemented. When the share of intermittent RES-E/DG increases to very large levels, and problems are more severe, more complex and costly response options need to be implemented. More complex response options however should not be considered whenever there is still sufficient potential to implement less complex and less costly response options.

3. Approach and general framework for road maps

3.1 Introduction

The basic steps for the development of a regulatory road map for an optimal integration of intermittent RES-E/DG in the electricity system are threefold. Firstly, the particular desired end-state or goal that must be achieved by the regulatory roads map needs to be identified and defined. Secondly, the future ‘state of the world’ in which this desired end-state needs to operate has to be identified. This so called “system context” can be defined through the construction of background scenarios for defining the key elements of this context. Thirdly, the different stages of network and market integration of intermittent RES-E/DG units a country has to go through during the system transformation from the present situation till the desired end-state are to be identified and defined.

Section 3.2 deals with the identification of the desired end-state based on policy goals and available RES-E/DG background scenarios, i.e. how does the electricity system develop up to 2020. It also allows defining the current state of the system. Next in section 3.3 the different stages of network and market integration of RES-E/DG, connecting over time the system situation with the desired regulatory measures are identified.

3.2 RES-E/DG background scenarios and system end-state

The motivation for the RESPOND project in general and the most important factor in determining the sequence of regulatory steps to be identified later on in the regulatory country road maps are the expected and thus projected or expected increase in the share of intermittent RES-E/DG in the electricity system.

A large variety of studies have tried to develop projections on the future share of renewable electricity generation and/or some intermittent technologies such as wind turbines in the European electricity system. More specifically for assessing the impacts of *intermittent* generation in the RESPOND project (Ramsay *et al.* 2007) so-called ‘blue-prints’ for the EU MS of Denmark, Germany, the Netherlands, Spain and the UK were constructed. These blue-prints show the potentially expected penetration of intermittent RES-E/DG in the respective countries up to the year 2020. Table 3.1 and Table 3.2 provide the development in RES-E/DG in the assessed countries according to capacity and generation.

Table 3.1 *RES-E/DG development in five EU member states in electricity generation capacity (GW)*[7]

RES-E/DG technology	Country				
	Denmark	Germany	Nether-lands	Spain	UK
Onshore wind					
2005	2,75	18,40	1,15	8,26	1,14
2010	2,94	25,20	1,27	17,67	1,76
2015	n/a	27,20	1,52	n/a	5,68
2020	3,00	28,00	1,95	27,75	11,26
Off-shore wind					
2005	0,37	0,00	0,00	n/a	1,71
2010	0,77	0,50	0,70	n/a	2,63
2015	n/a	3,60	2,10	n/a	8,51
2020	2,50	10,00	3,50	n/a	16,89
PV in GW					
2005	0,00	1,90	0,06	0,02	n/a
2010	0,00	7,70	0,10	0,21	n/a
2015	n/a	13,00	0,13	n/a	n/a
2020	0,00	17,90	0,16	0,51	n/a
Total installed RES-E/DG					
2020	5,50	55,90	5,61	28,26	28,15
Total installed capacity					
2020	13,90	154,30	30,07	110,14	99,53
RES-E/DG share of total installed capacity					
2020	39,56%	36,23%	18,67%	25,66%	28,28%

As can be observed from both figures, both the current level as well as the projected the potential for intermittent RES-E/DG generation varies largely across the different MS. For example, the UK has only relatively little intermittent RES-E/DG generation at the moment, but has large potential when looking at 2015 projections. Denmark on the other hand already has a very high share of intermittent RES-E/DG generation.

In the road maps developed in this document we establish the year 2020 as a common reference point and end point. In reality, off course, the 2020 mark is only an intermediate point in the long-term transition to a sustainable energy system. The choice for 2020 instead of a later point in time is because facilitation of meeting the imposed 2020 RES targets have the highest priority. However, the transition of the electricity system should be in line with the more long-term transition of the system towards 2050 and beyond.

[7] For Denmark and Spain Eurelectric was used. Sources for data for Germany, the Netherlands and the UK are BMU (2008), ECN (2005) and BERR (2008) respectively.

Table 3.2 *RES-E/DG development in five EU member states in electricity generation (TWh)* [8]

RES-E/DG technology	Country				
	Denmark	**Germany**	**Netherlands**	**Spain**	**UK**
Onshore wind					
2005	5,40	27,20	2,44	16,10	2,84
2010	7,10	44,80	2,75	33,70	4,50
2015	n/a	49,60	3,44	n/a	15,62
2020	7,20	53,50	4,43	52,80	31,59
Off-shore wind					
2005	1,20	0,00	0,00	n/a	4,26
2010	2,80	12,20	2,16	n/a	6,76
2015	n/a	11,20	6,60	n/a	23,44
2020	7,00	33,70	11,14	n/a	47,38
PV					
2005	0,00	1,30	0,06	0,00	n/a
2010	0,00	6,20	0,10	0,20	n/a
2015	n/a	11,00	0,13	n/a	n/a
2020	0,00	15,50	0,16	0,40	n/a
Total generation by RES-E/DG					
2020	14,20	102,70	15,73	53,20	78,97
Total electricity generation					
2020	41,10	584,00	141,19	388,40	360,09
RES-E/DG share of total electricity generation					
2020	34,55%	17,59%	11,14%	13,70%	21,93%

For developing a regulatory road map for an increased penetration of intermittent RES-E/DG in the electricity system first one needs to define a perspective on possible expected developments in the EU electricity system up to 2020. In other words, a particular scenario should be assumed to secure consistent set of drivers for the EU electricity system and EU and member state developments and energy policy.

Given the clearly defined goal of this report, to provide a "regulatory road map for the efficient integration of intermittent RES-E/DG until 2020", our description of the underlying background scenario is straightforward. Firstly, it is assumed that the prime driver for the increased penetration of RES-E/DG is the EU 2020 renewable energy targets. A continuing awareness of the necessity of making current energy systems more sustainable will give rise to more ambitious sustainability targets and will provide strong incentives for RES-E/DG development. However, some policy support for a strong continuing transition to a more sustainable energy system might be (temporarily) interrupted by the current economic crisis or country performance (i.e. financial crises) and might lead to a reduction of ambitions and significantly weaker incentives for further RES-E/DG development. However for the purpose of our study we assume that the EU wide support for energy policy will continue to achieve the RES target for 2020. Note that in some EU member states the economic crisis has also been welcomed as an opportunity for extra governmental support of RES and emission reductions, a 'Green Deal', i.e. by large-scale

[8] For Denmark and Spain Eurelectric was used. Sources for data for Germany, the Netherlands and the UK are BMU (2008), ECN (2005) and BERR (2008) respectively.

investments in sustainable energy projects and energy efficiency measures as a way to counter the downturn of the economy. Secondly, the level of EU market integration and harmonization can be considered a key driver in any EU energy policy related scenario. More harmonized markets and interconnected markets will facilitate easier exchange of electricity flows, giving member state countries the opportunity to fully develop their natural advantages in electricity production (for example wind potential) and will at the same time make the system more robust for fluctuations in the supply of energy. We will assume that all governments, at both the EU and member state level, will actively continue to improve market integration and harmonization conditions within the EU. When constructing the regulatory road map we have to keep in mind the above described scenario assumptions as a background.

3.3 Integration of RES/DG in networks and markets

Building a regulatory road map for securing an economically efficient integration of intermittent electricity generation by RES-E/DG units concerns two different dimensions of system integration process to be considered simultaneously, because strongly related to each other and with the share/level of intermittent generation: (i) network operation and regulation and, (ii) RES-E/DG market presence and their access to the various electricity markets (i.e. wholesale market, balancing market, ancillary services market). Or in other words, the effective integration of intermittent RES-E/DG has two dimensions, *integration in networks* (transmission and distribution) and *integration in markets*.

Earlier research in the RESPOND project focussed on the possible response options to mitigate the impact of increasing penetration of intermittent RES-E/DG (Zvingilaite *et al.* 2008), analysing the barriers that prevent the implementation of response options (Lobato *et al.* 2009), and identifying general and country-specific recommendations (Grohnheit, *et al.* 2009). In the following Sections we discuss the two dimensions of market and network integration and present a framework that distinguishes different *stages* of market integration and network integration. The main driver in this framework will be the amount and share of intermittent RES-E/DG generation in the considered electricity system. At different degrees of penetration, different integration issues (might) prevail, each requiring the implementation of specific response options and regulatory actions. Furthermore with an (effective and efficient) integration of intermittent RES-E/DG we refer to the mitigation/reduction of negative impacts on the electricity system that is balancing the economic value gained by the possible overall positive impacts on the electricity system received by more RES-E/DG. Consequently identifying different stages and systematically linking particular RES-E/DG integration issues, response options and regulatory actions needed to the different stages that provide the complete path of transition of the system in time and is described by regulatory road maps per country.

Below we consecutively discuss the definition of the different stages of network (3.4.1) and market integration transformation process (3.4.2).

3.3.1 Stages of network integration

The two main questions to answer when identifying the possible different stages of the transition in the network integration of intermittent RES-E/DG are: what are the different network integration conditions and how do the elements evolve over time when the penetration of these intermittent types of generation units increases?

For network integration the following elements can be identified, which have also been dealt with in the RESPOND project earlier accordingly:

- Connecting intermittent RES-E/DG (cost allocation, tariffication, degree of differentiation in connection charges)
- Provision of services to the DSO
- Inclusion of RES-E/DG in DSO network planning

- Grid reinforcements
- Metering and information and communication technology (ICT) implementation (benefits)
- Institutional arrangements between DSO and DG operator (e.g. contracts, vertical integration, etc.)
- Incentives for active network management (ANM) by DSOs.

As mentioned earlier, the Sustelnet project developed an outline for the development of regulatory road maps (Van Sambeek *et al.* 2003). In addition herein a basic framework for different network *regulation* stages was also constructed. We have taken the basic structure of that framework and fully adapted it to the extensive needs of the RESPOND project, i.e. by incorporating additional elements and guidelines for a solution that were not covered in the Sustelnet project. This resulted under RESPOND in a extensive framework specifying the different stages of network integration transformation. The complete new framework for and definition of all the stages of network integration transformation is presented in Table 3.4.

In total, five different stages of network integration transformation have been identified. These vary from basic distribution networks with minor regulation that are operated very passively and configured towards centralized electricity generation (Stage I), to very complex and intelligent networks with substantial regulation that considers all short and long term costs and benefits and that are operated in a very active manner (Stage V). It should be noted that on a somewhat lower abstraction level even different ‘sub-stages’ can be identified for these 5 stages. For example, in Zvingilaite *et al.* (2008) three different phases of active network management were distinguished. These consecutively dealt with: (1) making the network more intelligent, (2) active participation of RES-E/DG units and consumers, and (3) local system balancing and microgrids. However, we will adopt the more general phase classification as presented in Table 3.4, since a more detailed approach than currently adopted would not give us more or improved insights on the issues at stake in our study.

Table 3.3 *Stages of network integration*

Stage		Description	Criteria: Network integration issues	General recommendation(s)[9]
I	**Self regulated networks**	Active TN, passive DN, negotiated access, no real unbundling required	- Negotiation about connection costs (also on distribution grid reinforcements)	- Negotiated TPA, negotiated connection charges (access possible?)
II	**Performance-based networks**	Active TN, passive DN, cost-driven, incentives for efficiency improvements, accounting/legal unbundling	- Negotiation about connection costs (also on distribution grid reinforcements) - Limited investments for network reinforcements needed - Limited congestion on some national and international interconnections due to renewables	- Implement shallow and regulated connection charges (Access mandatory) - Reinforce distribution grids to accommodate small share of RES-E/DG - Implement congestion management methods for all time frames on (inter)national connections
III	**Enhanced performance-based networks**	Active TN, passive DN, cost-driven, inclusion of quality and innovation aspects in regulatory framework, legal and management unbundling	- Additional network costs due to integration of renewables become substantial for DN, in some cases electricity feed-in at TN - Different DSOs face differential DG impact but network regulation does not take this into account - Increasing investments in some DN and TN impeded by efficiency considerations and social acceptance issues - Increasing congestion on both national and international interconnections	- Implement shallow and regulated connection charges plus UoS charges for G (and L) for covering remaining network costs - Account for differential DG impacts in network regulation - Improve coordination of network planning - Implement market-based congestion management methods on (inter)national connections

[9] This column only indicates the general guidelines with respect to optimal network integration of RES-E/DG. Country-specific recommendations are not mentioned and only drafted later on in the regulatory road maps.

IV	**Innovative networks**	Active TN with increasing steering and control possibilities (HVDC cables, phase shifters, high-temperature conductors), innovative DN with more network monitoring and control possibilities but still predominantly passive generators and loads, nearly full inclusion of benefits/costs of RES-E/DG in regulation, incentives for innovation, legal and management unbundling	- Additional network costs due to integration of renewables become high for DN, at many times upward flows from DN and TN and electricity feed-in at TN - Increasing investments in DN and TN impeded by efficiency considerations and social acceptance issues - Incentives for new DN management approaches limited due to difficulty of computing positive DG effect on quality of service and losses - Increasing congestion on both national and international interconnections	- Implement shallow and regulated connection charges, basic time and/or location differentiated GUoS charges - Implement smart metering - Integrate RES-E/DG in network planning by incentivising DSOs to optimize on grid reinforcements vs. active network management - Introduce network simulation tool to calculate effect of DG on reliability and losses and for trade-off between passive and active network management - Implement market-based congestion management methods on (inter)national connections
V	**Active networks**	Holistic approach, fully active TN (with all elements of FACTS), active DN with largely active generators and loads, RES-E/DG integrated part of regulatory model, legal, management and ownership unbundling	- Additional network costs due to integration of renewables become high for DN, highly fluctuating power flows at DN and TN - Increasing investments in DN and TN impeded by efficiency considerations and social acceptance issues - Limited incentives for DSOs to consider DG in provision of ancillary services - Increasing congestion on both national and international interconnections	- Implement shallow and regulated connection charges, real-time and/or locational differentiated GUoS charges - Implement genuinely smart metering - Integrate RES-E/DG fully in network planning by incentivising DSOs to optimize on grid reinforcements vs. active network management with full involvement of generators and loads (curtailment and demand response respectively) in all cases - Oblige DSOs to acknowledge potential contribution of RES-E/DG and loads to system services in grid codes - Implement better coordination of market-based congestion management methods on (inter)national connections

For each stage of network integration, criteria have been developed that can assist policy-makers or researcher in identifying the current state of network integration in a specific country. For example, observing the major issues in a specific country one can relate these, via the information in the table, to a particular stage of network integration. The next regulatory steps are presented in the last column labelled as so called ‘guidelines’. This column represents the different (regulatory) measures for every stage. They are derived from earlier mentioned RESPOND work.

3.3.2 Stages of market integration

Market integration involves the integration of new RES-E/DG generation units in different markets: electricity wholesale market, and the primary, secondary and tertiary reserve markets, and the market for ancillary services.

The market integration dimension of the increasing share of intermittent RES-E/DG encompasses several issues (see RESPOND reports), which are:

- General wholesale market access;
- Access to ancillary services markets;
- Access to primary, secondary and tertiary reserve markets;
- Gate closure times of day-ahead, intraday and balancing markets;
- Identification balancing zones;
- Congestion management / efficient operation of existing networks;
- Implementation of heat and/or energy storage, interconnection of heat markets;
- Variability of market prices;
- Design of support scheme;
- Optimal generation mix (flexibility) issues (for example positioning of energy storage in generation mix).

Based on earlier RESPOND research we have identified three different stages for market integration. These three stages are strongly related to the penetration level of intermittent RES-E/DG in the electricity system. The three stages respectively relate to low, moderate and high levels of RES-E/DG in the system and can be associated with various levels of problems experienced caused by this amount of RES-E/DG. In addition, the different stages specify the role that RES-E/DG plays, either actively or passively in electricity markets in each stage. With an increase in the share of intermittent RES-E/DG, RES-E/DG generation gets to an equal level as centralized (non-intermittent) generation on the various energy markets. This is called a level playing field. However, a level playing field should not be taken as a goal in itself. In the transition towards a situation with a high penetration level of RES-E/DG, providing RES-E/DG equal opportunities implies that additional incentives are realised that favour additional penetration. In the final end stage, RES-E/DG might be given an equal role to play in the different sub-markets of the electricity system (wholesale market, balancing market, ancillary services market, etc.), but this equal role should only be facilitated when deemed optimal from a social perspective. After all, there are particular differences between the inherent characteristics of conventional electricity generation technologies and RES-E/DG electricity generating technologies, and these differences might give rise to differential treatment of the two. Equal treatment could possibly lead to suboptimal electricity market outcomes from a society’s point of view.
For the purpose of constructing regulatory road maps each stage is again accompanied by specific criteria. We refer to Table 3.4 for an overview of the market integration stages we distinguish.

Table 3.4 *Stages of market integration*

Stage		Description	Criteria: market integration issues	General recommendation(s)[10]
A	**Protected niche market**	• Low penetration level of RES-E/DG • RES-E/DG outside the markets	• General wholesale market access • RES-E/DG impacts on balancing market negligible	Support schemes • Focus on economic viability RES-E/DG, support via priority dispatch, obligatory purchase regimes, feed in tariff
B	**RES-E/DG in the market**	• Moderate penetration level of RES-E/DG • RES-E/DG participates partly in supply side of ancillary services market. • RES-E/DG has little to moderate effect on market prices.	• Decreased profitability for conventional base-load power plants at the margin. Lack of flexible generators at critical hours. • No access to other markets than wholesale market (i.e. balancing and ancillary services) • Need for differentiated market prices which reflect system conditions • Not all ancillary services are remunerated (for instance primary regulation). • Moderate increase of system balancing costs	Generation flexibility • Guarantee the availability of enough flexible generation by capacity payments in or outside the market. • Add heat storages to CHP units • Increase flexibility of generation by one-stop shop approach for new flexible generation • Enable provision of services by DG to ancillary services markets (through VPPs) Support schemes • Implement feed-in market premium support scheme to stimulate RES-E/DG technologies and increase system efficiency Demand response • Introduce smart metering Balancing and ancillary services markets • Introduce balancing responsible parties • Enlarge balancing market to reduce market power of generators (one national market) • Shorten gate closure time of DA-market and/or intraday and/or balancing market to limit demand for balancing services • Introduce/extend the use of interruptible contracts • Lower prequalification criteria for offering ancillary services to technical and economic minimum • Establish ancillary services markets

[10] This column only indicates the general recommendations with respect to optimal market integration of RES-E/DG. Country-specific recommendations are not mentioned and only drafted later on in the regulatory road maps.

C	**Active RES-E/DG**	• High penetration share and level of RES-E/DG • RES-E/DG provides all kind of ancillary services when profitable • RES-E/DG has moderate to high effects on market prices	• Decreased profitability for conventional base-load power plants at the margin. Lack of flexible generators at critical system times. • DG does provide small amounts of energy to balancing and ancillary services markets • Need for more differentiated support scheme / market prices • Demand does provide small amounts of energy to balancing and ancillary services markets • Substantial increase of system balancing costs	Generation flexibility • Guarantee the availability of enough flexible generation by capacity payments in or outside the market. • Allow for RES-E/DG competition with large scale generation in *all* markets • Achieve economies of scale in district heating based on CHP / waste heat supply Support schemes • Separate commodity price, support mechanisms account only for externalities • Production subsidy level incentivises DG to offer energy not only to electricity markets Demand response • Improve utilisation of smart metering • Increase utilisation of demand response potential by VPPs Balancing and ancillary services markets • More responsive balancing market conditions: shorter gate closure times, (regional) congestion management, more flexible generation mix, ownership unbundling DSO/generation • Introduce cross-border balancing to reduce market power of generators providing balancing services • Introduce payments for the provision of all ancillary services

3.3.3 Generic regulatory road map scheme

In the previous two Sections we have presented two dimensions that define the different stages of network and market integration of (intermittent) RES-E/DG, i.e. the various issues characterising the integration process over time and related to the levels/shares of intermittent RES-E/DG penetrating for an optimal functioning of the electricity system from today till around 2020. This is an important building block for developing the regulatory road map for each country. In the next Section (Section 3.4) we will discuss the different methodological steps that need to be taken in developing the road maps. Herein we combine the two defined system transformation dimensions in one framework we call the generic road map scheme. The generic scheme is depicted in Figure 3.1. The properties of this scheme are as follows.

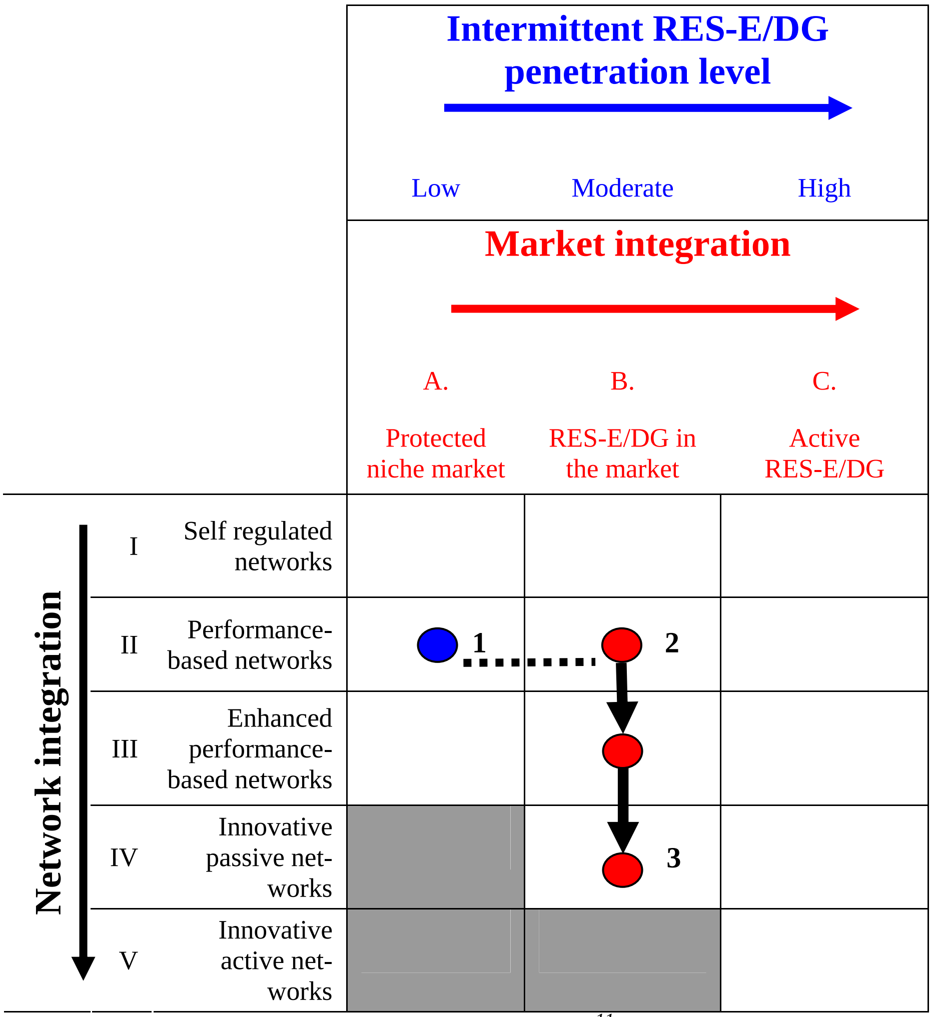


Figure 3.1 *Generic regulatory road map scheme*[11]

When defining the road map starting point and envisioned end state or point of the regulatory road map we need simultaneously determine the appropriate related stage of network integration and market integration. Hence, we need to combine the two integration dimensions (see Tables 3.3 and 3.4) defined in terms of the different stages. The combination of the two gives us the generic regulatory road map scheme, which is presented in Figure 3.1. The different stages of

[11] The depicted regulatory road map steps in this Figure are illustrative and do not represent a particular member state.

market integration are depicted on the horizontal axis. The horizontal axis at the same time also represents the impact of intermittent RES-E/DG on the electricity system. This can be interpreted as either an amount of RES-E/DG in the electricity system or the relative impact of existing RES-E/DG. The amount / impact of RES-E/DG is defined by the qualifications of ‘low’, ‘moderate’, and ‘high’ and related to the market integration stages. Based on the two axis we can depict (1) the current situation with respect to the amount / impact of RES-E/DG in the current electricity system, (2) the current situation with respect to network integration in combination with the current level of market integration, and (3) the likely end-state (i.e. future point in time, say around 2020) of intermittent RES-E/DG integration. Herein the latter identifies the required level of network and market integration and is dependent on the likely system impact at the end of the time horizon. Within this figure, horizontal shifts represent a shift in the stage of market integration, whereas vertical shifts represent a shift in the stage of network integration. At a given current level of network integration it is possible that two bullets are inserted one to reflect the level of market integration and the other the actual amount / impact of intermittent RES-E/DG on the other. Also in Figure 3.1 the current market integration level can successfully accommodate more intermittent RES-E/DG without a change being required in the level of market integration. When actual market integration is just sufficient to accommodate the associated level of intermittent RES-E/DG, then one bullet represents the starting point of the road map. The movement from the initial starting point to the envisioned end (state) point is referred to as the regulatory road map. A part of the cells in the Figure is marked grey, implying that at very low levels/hares of RES-E/DG there is no need for electricity systems to advance to the higher level market or network integration stages from a point of view of optimally efficiently integrating intermittent DG-RES-E. Or in other words it is not efficient to strive for these grey-marked combinations of market and network integration stages.

When applying this generic framework to specific countries it can be discussed what the optimal route concerning market and network regulatory actions is. For one country, the optimal route could mean a right-ward movement (step) initially, while in another country it is more efficient to take a downward movement first. This is dependent on country specific conditions, i.e. system conditions. For example, a country that is well-interconnected with the other electricity systems abroad might be able to significantly increase its RES-E/DG share in the country without having to alter existing network regulation (i.e. a move right-ward in the generic road map scheme). We present a listing of the possible important system conditions in the next Section.

3.4 Steps in developing the regulatory road maps

The general steps to be taken in developing regulatory road maps have been described in Van Sambeek *et al.* (2003). In the European Commission (EC) funded project Sustelnet an outline for developing regulatory road maps was prepared with as general conceptual example the case of technological road maps. The outline Sustelnet was applied for issues regarding the optimal integration of distributed generation (DG) in electricity networks, which represents a similar scope as that of the RESPOND project. In RESPOND the basic concept in Sustelnet was further elaborated and developed for building the regulatory road map.

The basic steps in developing the RESPOND based regulatory road maps are:

1. Define current state of system, i.e. starting point road map;
2. Defining route to end-state (2020) by scenarios and background story line;
3. Identify final status of market and network integration in 2020;
4. Back cast regulatory intermediate steps;
5. Describe actions and responsibilities for implementing the road map.

Firstly, a starting point of the road map needs to be identified,, which is of course system situation today and simultaneously the starting point of the scenarios for picturing the possible ‘system conditions towards and in the future year 2020’. When identifying this starting point it is important to have a complete overview of all the aspects and variables for the issue at stake, in our case the integration of intermittent RES-E/DG and called 'system conditions'. The list of system conditions can assist in describing the starting point of the regulatory road map, the final end point, and the intermediate path. For the country-specific regulatory road maps this implies that for each country the current (today's) level of market and network integration needs to be described. This involves a basic description of current market rules, market design, network regulation, tariff methodologies and the like. Based on the earlier RESPOND work undertaken we are able to present a complete overview of relevant system conditions, see Table 3.5. For clarity a categorization in technical, socio-economic or political, institutional and regulatory system conditions is used.

Table 3.5 *Overview of system conditions*

Category	System conditions

Technical	• share of RES-E/DG in the electricity supply system
	  o Dispersion / concentration?
	  o Type of technology?
	• share of natural gas in the electricity supply system
	• interconnection capacity with other countries
	• reliability of the electricity network
	• structure of district heating networks
	• ICT developments
	• investment plans for power plants
	• implementation of innovations
	• adoption of new technology

Socio-economic / political	• concentration in electricity (wholesale) market • EU / national energy policy • environmental policy • fuel price development • support schemes for RES-E/DG • cross-border trade • market opening
Institutional	• ownership of networks • degree of vertical/horizontal integration/ unbundling • regulator (presence & powers) • market design (electricity, heat)
Regulatory	• network regulation (role of RES-E/DG) • type of network access (nTPA/rTPA)

It should be noted that a number of system conditions will give rise to similar status quo descriptions (i.e. the current day situation), for example when it concerns EU policies and the state of technology. It goes without saying that some of the listed conditions are more relevant for the one country than the other, and will therefore have differential roles to play in the respective country road maps.

The most difficult part in developing regulatory road maps however is the identification and characterisation of the likely end state of a road map within a given time horizon (being 2020 in this study). For this purpose all available information on country-specific electricity system developments, today and expected, characterising the likely transition that a country electricity system will be experience is used. Next the Intermediate steps between the end state and the current state can then be derived. Specific recommendations regarding the development of market and network regulation for the intermediate points are again taken from the network and market integration stages presented in Tables 3.3 and 3.4. This added with many country specific regulatory actions constructs the road map per country.

4. Regulatory road map for Denmark[12]

4.1 Outlook RES-E/DG and the electricity system

Developing a country regulatory road map requires insight into the particular characteristics, i.e. RES-E/DG shares, system conditions, and the possible transition of that country's electricity system in the next decade. In this section several important factors are covered, such as developments in the generation mix, load growth, and connection and integration of RES-E and CHP under current system, market and network conditions. Finally, the impacts up to 2020 are shortly summarized in conclusions for network and market perspectives.

Electricity generation mix

The electricity generating system in Denmark is located at the border between the hydro power based systems in the North and the thermal system in Western Europe.

Figure 4.1 shows the development of electricity generation since 1975. The main characteristics are the steady increase in co-generation and wind power and the volatility of gross import and export.

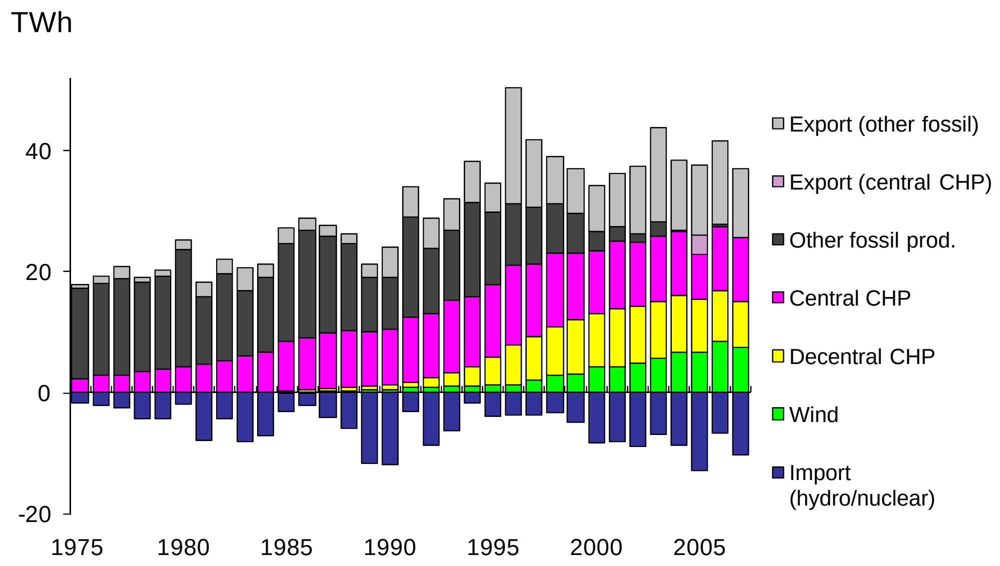


Figure 4.1 *Electricity production and import, Denmark 1975-2007- Source: Dansk Energi and own calculations*

From about 1980 all new power stations have systematically been located to supply district heating systems with co-generated heat. In the 1980s nearly all new capacity was medium-sized extraction-condensing units for large-scale CHP; in the 1990s a significant share was small-scale gas-fired CHP units for decentralised district heating systems. Wind power has grown constantly during the 1990s and covers now about 20% of the electricity demand on an annual basis. The trade pattern is mainly determined by the variations in hydro power in Norway and Sweden and wind energy in Denmark.

[12] This road map is mainly based on information provided by Risoe and the responsibility of both ECN and Risoe. We thank Risoe for their cooperation.

Table 4.1 below shows the *expected* development of production from different conventional and renewable (intermittent) resources in production as well as capacity terms, up to 2015. The current fuel mix of Denmark is characterized by high shares of hard coal and gas. The amount of coal-fired generation is expected to decrease. Biomass co-firing is used in several large-scale CHP power plants but plays a limited role in the generation mix. Hydro power will remain negligible.

Denmark has compared to relatively low energy demand a high amount of wind with 2.8 GW installed and 6.6 TWh of wind generation, which could potentially cover approximately 20% of the nation's demand (2005-2008). Denmark is also one of the first countries with a significant amount of offshore wind installed with 0.4 GW in 2005. After stagnation in installed capacity of wind power, when some 2000 small land-based wind turbines were replaced by wind farms and larger units, the government's new energy strategy supports the expansion of wind energy capacity both on- and offshore. Location of sites for up to 5000 MW offshore wind farms have been identified, all with a potential of about 4000 full load hours. The target is to achieve 4 GW onshore and 2.5 GW offshore wind capacity until 2025. PV has not played a major role in installations so far and will continue to play a minor role in the next decade. Prospects for micro-CHP seem to be limited due to the large role of district heating in heating of single-family houses. Although there is a potential market for micro CHP as replacement for gas-boilers that were installed in the 1980s and 1990s, micro CHP is not yet part of the statistics.

Table 4.1 *Danish* RES-E/DG *electricity production by fuel (TWh)*

Technology	**2000**	**2004**	**2010**	**2020**
Hydro	0	0	0	0
Renewables	4,5	9,9	9,9	14,2
Solar				
Geothermal				
Wind - onshore	-	*5,4*	*7,1*	*7,2*
Wind - offshore	-	*1,2*	*2,8*	*7*
Biogas				
Biomass	*0*	*1,9*	*0*	*0*
Waste	*0*	*1,4*	*0*	*0*
Other	*0*	*0*	*0*	*0*
Total	35,2	38,4	37,9	41,1

Source: Eurelectric (2006), p.169.

Table 4.2 *Danish* RES-E/DG *generation capacity by fuel (in GW)*

Technology	**2000**	**2004**	**2010**	**2020**
Hydro	0,009	0,011	0,011	0,011
Renewables	2,662	3,119	3,700	5,500
Solar				
Geothermal				
Wind - onshore	*2,377*	*2,753*	*2,943*	*3,000*
Wind - offshore	*0,040*	*0,366*	*0,766*	*2,500*
Biogas				
Biomass	*0,245*	*0,000*	*0,000*	*0,000*
Waste				
Other	*0,000*	*0,000*	*0,000*	*0,000*
Total	12,417	12,650	12,929	13,903

Source: Updated Dena blueprints, Eurelectric (2006), p.100

Electricity demand

Table 4.3 *Electricity balance of Denmark (in TWh)*

	1980	**1990**	**2000**	**2002**	**2003**	**2005**	**2010**	**2020**
Electricity Production	23.9	30.8	35.2	37.3	43.8	36.2	37.9	41.1
Pumping	0	0	0	0	0	-	-	-
Imports	2.0	12.0	8.3	8.9	7.0	-	-	-
Exports	1.6	4.9	7.7	11.0	15.6	-	-	-
Trade Balance	0.4	7.1	0.6	-2.1	-8.6	-2.3	-0.6	0
Demand (Including losses)	23.9	30.8	34.7	35.2	35.2	36.2	37.9	41.1

Source: Eurelectric

Based on these figures, demand including losses is expected to grow with 0.9% per year in the period up to 2010, and subsequently in the period 2010-2020 with 0.8% per year.

Connection of RES and DG

The majority of intermittent generation has been connected to the distribution networks (60 kV or lower) up to now, including all onshore wind and CHP that follows heat demand. The two offshore wind parks Horns Rev and Nysted which dispose of 10% of total wind production capacity are directly connected to the transmission networks. In 2020, 49%[13] of installed wind power capacity is directly connected to transmission networks, since most new wind turbines will be placed offshore. Based on a total estimated production of 14.2 TWh onshore and offshore wind for 2020, 7.2 TWh and 7 TWh of yearly wind production will be directly fed-in on distribution and transmission level respectively. The degree to which this increase of connection of intermittent generation influences the electricity system and its constituents will be elaborated upon below.

Integration of RES and DG

Impacts on networks and markets

An important variable shaping the impacts is the assumed RES-E/DG penetration in 2020. Based on the projected developments in electricity production, the 2020 sustainability targets

13 Based on information provided by Risoe and own calculations.

for Denmark and the Danish RES-E potential we conclude that the likely level of intermittent RES-E/DG in 2020 can be qualified as high; 35% of electricity may be produced from intermittent RES-E/DG sources. This percentage will be assumed as basis for the discussion of the likely impacts on networks and markets of intermittent RES-E/DG in 2020. Network impacts can be divided in impacts on distribution and transmission networks respectively, while market impacts can be distinguished in impacts on balancing market, and impacts on trade markets.

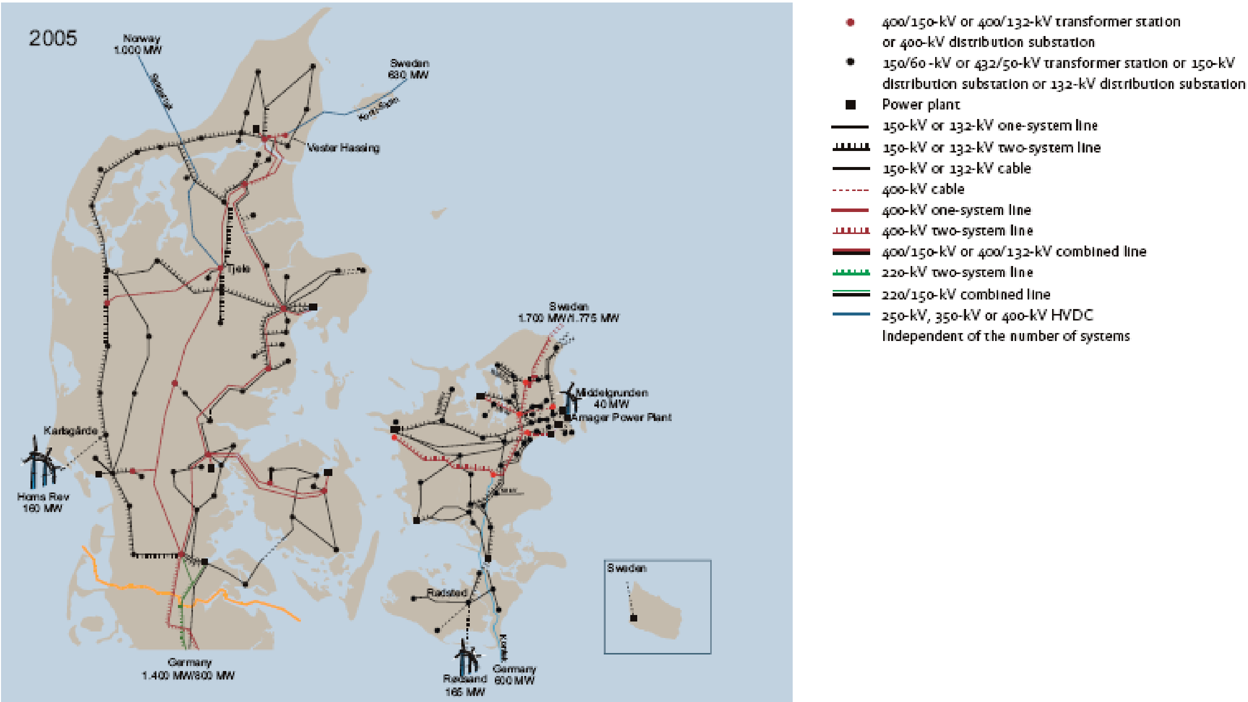


Figure 4.2 *Current national Danish transmission network (Danish Energy Agency, 2005)*

Impacts on *distribution networks* result mainly from increased connection of onshore wind and increasingly flexible CHP[14] to the medium voltage networks (60 kV) in rural areas. In recent years some 2000 onshore wind turbines (mostly 200-300 kW) have been scrapped and replaced by larger and more modern wind turbines which dispose of more favourable operational characteristics for network operation. Electricity production of PV and micro-CHP grow very slowly and will not have an impact on distribution networks before 2020.

Impacts on *transmission networks* originate from the instalment of several new offshore wind parks at Horns Rev and other locations (2.1 GW up to 2020), large-scale onshore wind parks as well as upward network flows in distribution networks during times of high intermittent production and low load.

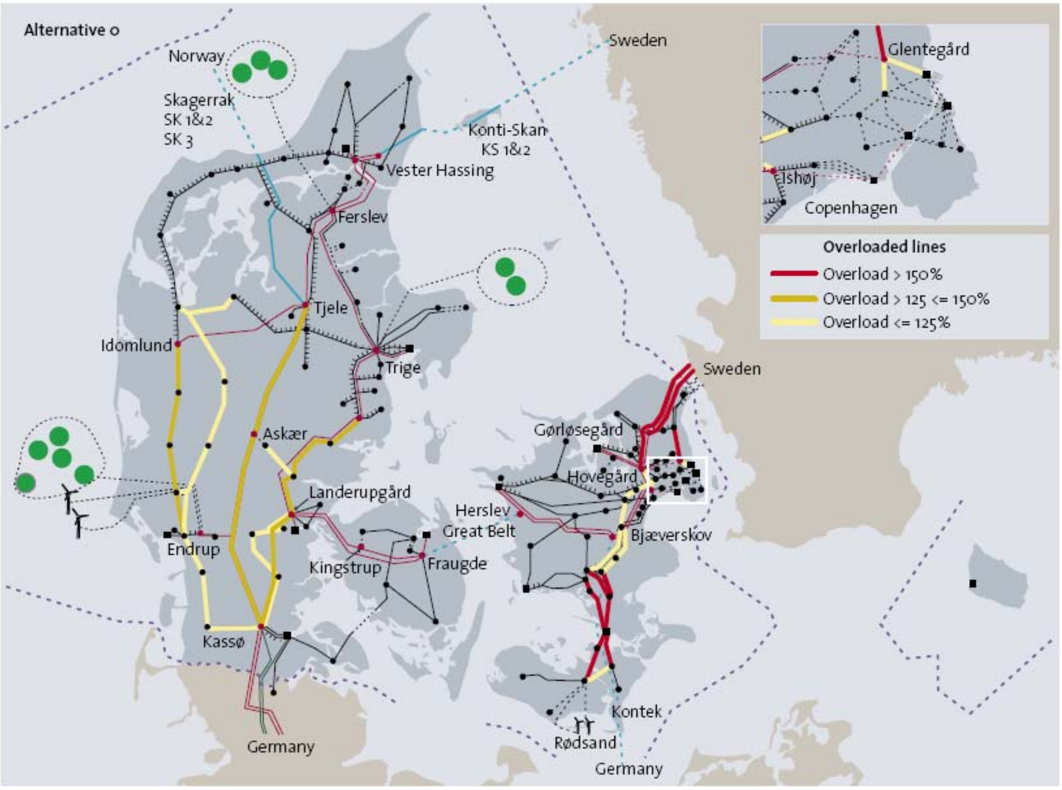
The System Plan 2007 of the Danish TSO Energinet.dk provides clear indications of the impacts of more wind energy on the grids. The plan contains a summary of the system consequences of the Danish government’s ambition to decrease its reliance on fossil fuels and instead use more renewable energy up to 2025. In this context, Energinet.dk has analysed two different alternatives for the transmission grid. Alternative 0 comprises the existing transmission grid, including present cross-border interconnections and the decided Great Belt Power Link 1. Alternative 2 comprehends additional interconnections. Load flow simulations show that in both scenarios

[14] CHP: In 2007 1,600 MW decentral CHP, expected amount in 2025 amounts to 2,300 MW.

major grids overloads will occur, illustrating the need for new infrastructure mainly due to the high share of new wind power.[15]

One of the expected key problems arises if all wind farms are connected in the Endrup grid connection point at Esbjerg (see figure below). Therefore, Energinet.dk is investigating the connection of 3 out of 5 new offshore wind farms in Landerupgaard at Kolding which will reduce the degree of overload of the 400 kV grid in Central Jutland and to some extent the 150 kV grid in Western Jutland. For connecting the offshore wind farms with Landerupgaard, the possibility of application of HVDC VSC (Voltage Source Converters) technology is considered. Besides, additional measures like the connection of the substation at Endrup to a 400 kV ring structure are required (Energinet.dk, 2007).

Figure 4.3 *Transmission network for Alternative 0 case*



Source: Energinet.dk (2007), p. 58

Other scheduled or considered network extensions which will favour the integration of wind power in the transmission network include:

- Great Belt link 600 MW (400kV) from 2010
- Skagerrak 600 MW (400kV) link between Jutland and Norway one of the grid extension projects prioritized by the EU and Nordel.
- Capacity upgrade of Jutland - Schleswig Holstein link by 200 MW under consideration, TEN-E priority project (Energinet.dk, 2007)
- Cobra link 600-700 MW between Denmark and The Netherlands is under consideration. May be in operation in 2016/2017.

In addition, in connection with the proposed large wind farm at Kriger's Flak on Danish, Swedish and German territories new HVDC connections between the three countries may be established, e.g. 600 MW.

[15] In the northbound/southbound direction the cross-border interconnections cause also grid overloading.

Impact on balancing
According to the updated blueprint for Denmark, in 2020 wind generation amounts to 5.5 GW, while in 2007 it was 3.1 GW. This means an increase of wind power generation of 2.4 GW. For Denmark only one study is available about the impact of wind generation on the future balancing market. According to Energinet.dk (2007) an increase of wind power by 3 GW (up to the year 2025) means an increase of required balancing power of at least 500 MW. In that case wind power will exceed demand in many hours.

Impact on trade markets
Impacts on energy markets for longer time frames (intraday, day-ahead, forward markets) are already visible in current price variability compared to price variability of some years ago (Zvingilaite *et al.*, 2008; Grohnheit *et al.*, 2009). The increase of intermittent generation will result in a further increase of the spread between off-peak and peak prices up to 2020.

Conclusions on future network impacts
Impacts on the distribution and transmission networks in 2020 are quite substantial in terms of required additional network capacity due to the connection of concentrated new offshore wind farms and new onshore wind. The former increases the distance electricity has to be transported (larger distance between generation and load), while the latter induces more upward network flows from distribution to transmission network levels. More specifically, Denmark faces the following network-related impacts of intermittent renewable generation (see Table 3.3):

- Network congestion in Western-Denmark in case of prolonged increase of wind power
- Significant unplanned electricity flows ('loop flows') occur on interconnections between Western-Denmark and Germany (Forbes, 2009)
- Conventional 'hardware' solutions (new lines and cables) for more network controllability are impeded by social acceptance issues, sometimes necessitating burying of lines. Besides, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.

Consequently, in the future Denmark seems to face a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit the cost impacts for both (distributed) generators and consumers to the efficient costs, an transition to a more active type of network management of both distribution and transmission networks is deemed necessary for Denmark at the end-point of the road map.

Conclusions on future market impacts
Based on the projected developments in electricity production, the 2020 sustainability targets for Denmark and the Danish RES-E potential we conclude that the likely level of intermittent RES-E/DG in 2020 can be qualified as high. However, impacts on the balancing market are assumed to be moderate. Concerning energy markets for longer time frames (intraday, day-ahead, forward markets); higher price variability is expected.

Denmark predominantly faces the impacts related to the 'Active RES-E/DG' stage of market integration in 2020 (see Table 3.4):

- High penetration level of RES-E/DG
- Substantial increase of system balancing costs
- Decreased profitability for conventional base-load power plants at the margin. Lack of generation capacity at critical system times.

Consequently, Active RES-E/DG is the assumed optimal market integration stage at the end-point of the road map i.e. in 2020.

4.2 Regulatory road map

4.2.1 End point road map

Against the background of the expected development of intermittent generation, network and market developments as described in the former section, and the general scenario assumed for the 2020 European electricity system as described in Section 3.2, the regulatory road map for Denmark will be developed.

The regulatory road map provides a *menu* of regulatory actions which are largely necessary to reach the desired future state of both market and network integration. The desired future states, i.e. the regulatory actions, are directly linked to the impacts described in the former section. The precise relationships are presented in the tables on the stages of market and network integration in Chapter 3. The desired future state in 2020, which was defined in the former section, is shown in Figure 4.4 below.

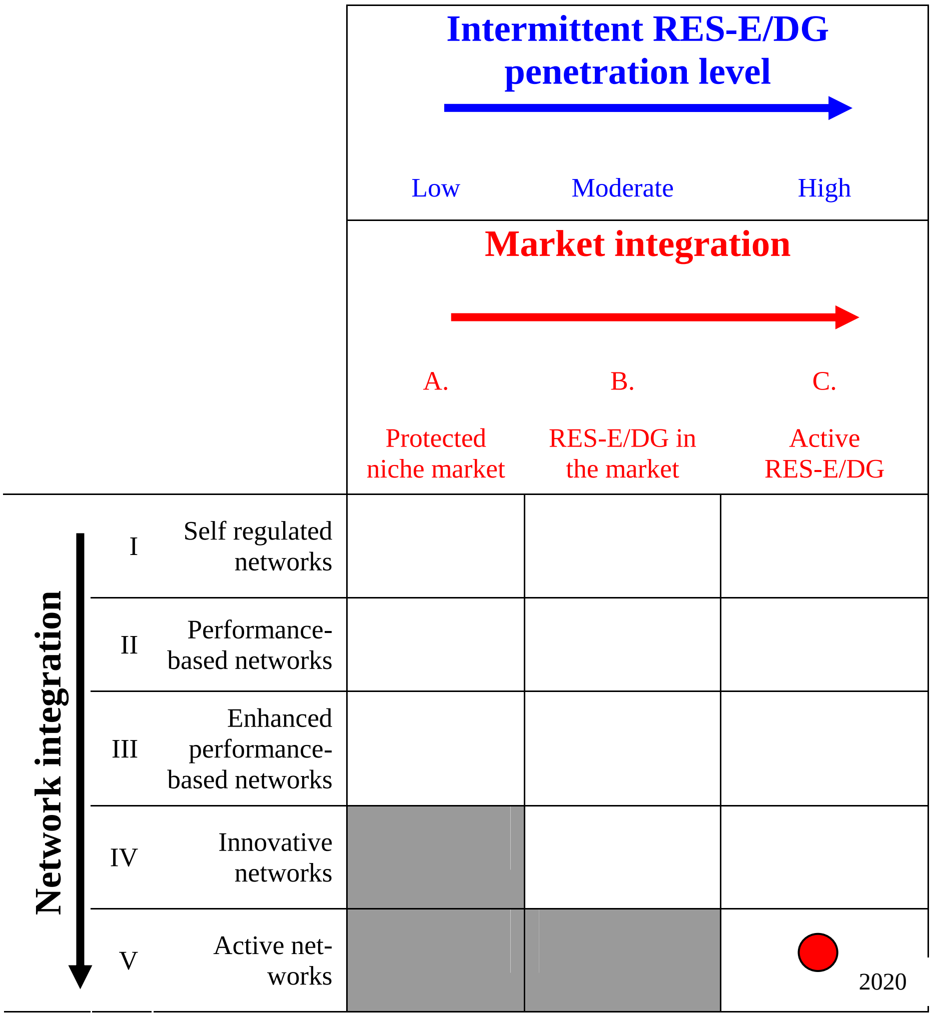


Figure 4.4 *Regulatory road map Denmark: end point*

The road map describes the path that stakeholders should take in order to reach stage IV-B in 2020, which is required to integrate optimally and efficiently the expected share of renewables in markets and networks at that year. The next sections describe the path towards this end point.

4.2.2 Starting point road map

Whereas the starting point of the regulatory road map with respect to the amount of intermittent RES-E/DG currently integrated in the electricity supply system is already defined, we need to define also the starting point from a regulatory perspective. In this respect, we distinguish between the following system segments:

1) Generation
2) Demand
3) Markets
4) Networks.

Below we explain briefly per system segment the current status of the regulatory framework, in order to define the starting point for the Danish regulatory road map.

Generation

Support schemes

The predominant type of support mechanism used for RES-E/DG in Denmark is a feed-in tariff scheme. Part of the support is not provided by feed-in tariffs, but feed-in premiums. Below the current subsidy schemes in place for different intermittent or less controllable technologies are discussed.

Feed in premiums are used for *wind power onshore*. In the last decade, for onshore wind the market premium for new turbines has been increased significantly. The premium includes a balancing compensation since wind turbine investors are responsible for their balancing costs. Old onshore wind turbines are financed by a flat feed-in tariff. For *offshore wind parks* a tendering procedure exists (Donkelaar *et al.*, 2008). Comparable with the development of market premiums for wind power onshore, during the last tender round higher tendering prices were paid than before. *PV* support is based on net-metering. Only limited support exists for solar heating in new dwellings (up to 20% subject to a number of criteria). For *CHP* the picture is mixed. Since 2007 all thermal generators above 5 MW has been part of the spot and balancing markets. Market participation for smaller generators is organised by commercial aggregators, who are financial entities that operate on both the spot and regulation power markets and aggregate production originating from DG and small scale CHP. Small CHP with capacity smaller than 5 MW, mostly built in the 1990s, has to choose between an annual production subsidy and a priority dispatch regime with fixed FIT. The advantage of the former is that small CHP is incentivised not to generate electricity when wind generation is abundant and prices are very low. Under the priority dispatch regime, CHP does not receive this incentive and consequently will not take into account the electricity demand in its production decisions; which is detrimental to market flexibility and system costs.

The change from FIT to feed-in premiums (fixed subsidy) for existing small and medium size CHP has improved the efficiency and functioning of the market as CHP units became exposed to market prices with a high time differentiation. The occurrence of falling prices at low demand and high wind was reduced, although it remains very significant. The previous combination of wind and decentralised CHP on FIT was inefficient in activating the flexibility of the CHP.

In addition, feed-in premiums can be differentiated to time and place to increase the incentive for RES-E/DG to behave in accordance with system needs. Support schemes in Denmark are neither temporal nor locational differentiated. In the future this may change when locational differentiation of support schemes may influence siting of micro-CHP units; these units may be excluded from district heating areas, which are already supplied by small or large-scale CHP, and they may be supported in areas zoned for natural gas. There is also no differentiation of support to voltage levels, but only a differentiation per type of DG/RES source (lowest subsidy for wind, higher for biomass, highest implicitly for PV). The costs for the support scheme remunerations are socialized via TSO tariffs.

Conventional generation

In Denmark conventional generation can be seen as residual to CHP generation and wind power. Conventional generation varies significant from year to year and depends also on hydro generation in Norway and Sweden. See Figure 4.4.

A higher share of intermittent generation in the electricity system implies that the total supply of electricity will become more variable, unpredictable and uncontrollable. Therefore the demand for flexible generation with fast start-up times and high ramping up and down capabilities will increase with the penetration of DG/RES in the system. This demand will come both from wholesale markets and balancing markets. As the market may fall short to provide enough upward balancing power due to two kinds of market failures (imperfect information and public good character of reserve capacity), additional policy incentives may be necessary in order to increase the quantity of flexible generation capacity available for producing energy during critical times on the balancing market.

Currently, policy incentives are limited to encouraging contingency units to take part in the market. However, there is not yet experience on their role in critical situations. Apart from this specific measure, there are currently no *general* policy incentives like extra capacity payments to all generators apart from market revenues in order to provide additional incentives to install new *flexible* generation capacity.

Storage

Concerning the availability of storage to decrease fluctuations of intermittent generation the picture is mixed. On the one hand heat storage capacity is available in district heating networks, among others, to allow flexible deployment of the CHP units for the electricity market while concurrently meeting the heat demand. On the other hand, Denmark does not dispose of pumped storage and –like in other countries- no storages in consumption facilities are installed. Traditionally, there were “pumped storage agreements” with Norwegian hydro reservoirs, therefore physical electricity storages in Denmark were not needed up to now.

Demand

Besides adding more flexible generation to the system as a response to more intermittent generation, alternatively higher variability can be managed by higher responsiveness of the demand side of the electricity system. Demand response can reduce or increase demand during specific time periods, shifting load to other points in time.

A crucial parameter in demand response is the time of notice. In the day-ahead market demand response may be driven by prices. With a very short time of notice automatic response is the preferred option. Requirements for effective demand response in the day-ahead market are hourly metering of consumption, billing according to hourly prices and the ability of customers to change/shift consumption in time.

Looking at metering, all large customers have hourly metering and the possibility to choose a rate reflecting hourly prices at Nord Pool. However, at present very few large customers have chosen an hourly varying rate. For households and other small customers a general roll-out of hourly meters has not been decided, but many (mainly municipal) DSOs have started to roll-out new meters to all customers in their area.[16]

[16] Traditionally (the co-operative or municipal) local DSOs were subject to a non-profit restriction, so new meters can be an attractive was to get rid of excess profit. This does not apply for the DSOs operated in urban areas.

Concerning prices, as mentioned most large customers have chosen a flat rate over months or the year, for some very large customers this rate is negotiated reflecting their consumption profile. In general small customers have a flat rate over the year. Another important issue in Denmark is fixed components to the market price that vary between customer categories. For households the market price is about 20 to 25% of the bill customers have to pay for electricity. This gives household customers a limited incentive to react on variations in the market price. For small companies the fixed component is about 100% on the market price and for large industrial customers the fixed component is about 50% on the average market price.

Concerning the ability to change consumption in time, for most large customers costs of changing production plans are much higher than normal savings in the electricity bill by shifting consumption in time. However, a number of large customers have agreed to act as reserve capacity and be cut-off for shorter periods in critical periods. For this, they receive a payment that is considerably larger than normal variations in hourly prices. Even large consumers are unlikely to follow the market and bid to the spot and balancing markets. There are a few brokers, who work with the largest industrial consumers. They may also work as commercial aggregators and exploit future business opportunities like utilisation of storages in electrical vehicles that will be offered by the market.

For households, part of the consumption related to heating and cooling may be shifted in time, but at present incentives for doing this are extremely small. In addition, information costs of following hourly prices limits incentives, and some sort of automatic response seems to be required. In the future investments in automatic response technologies should be profitable due to savings in the electricity bill.

Markets

Efficient electricity markets for different time frames help in mitigating the effects of more variability and unpredictability of renewable electricity sources on the electricity system. Different market places for year-ahead up to real-time are necessary for generators and loads to diminish their business risks. An efficient market also allows for efficient cost allocation by remunerating or fining market participants for their actual contribution to the system over time, as shown in generation and demand patterns.

Wholesale markets

Since 2000 both parts of Denmark (east and west of the Great Belt) have been parts of the Norwegian based Nordic Power Exchange, Nord Pool, which operates a day-ahead spot market with regional hourly prices (Elspot), and continuous power trading up to one hour prior to delivery (Elbas). In addition, Nord Pool operates a financial market for the following days, weeks, months and annual contracts up to five years. The participants in the markets are power producers, distributors, industries and brokers. Nord Pool Spot AS acts as counterpart in all contracts and all trades are physically settled with respective TSOs (www.nordpool.com).

In Denmark, on the day-ahead or spot market (NordPool), bids are stated before noon for next day's operation (24 hours). The Elbas or intraday market makes it possible for actors to trade bilaterally until 1 hour before delivery in order to minimise their deviations from the production and consumption schedules determined in the day-ahead market. In Denmark this market has so far a fairly small turnover and consequently limited liquidity. Elbas was first introduced in Eastern Denmark as from 2004 and Western Denmark from 2007. It was also recently expanded to Germany, and it is planned to start in Norway from autumn 2009.

All markets are useful for selling electricity from RES-E/DG. The most electricity is sold on the forward and day-ahead markets. Intraday markets are especially useful for limiting the balancing costs exposure of wind generators by allowing corrections to their production projections since the forecast error of wind production decrease closer to real-time.

Balancing market
The regulating power market is run by the Nordic TSOs based on bids from the Nordic area. In general parties are penalised if they cannot fulfil their bids to the day-ahead market. It depends though on the need for balancing. If the system in a specific situation requires upward balancing and a producer is below his expected production, he will be penalised by the cost of balancing up. However, the power producer will not be penalised if he is above his expected production. In this case the spot price for the surplus production will be paid. This mechanism is applied vice-versa for balancing down (NordPool, 2007).

Denmark has a system of balancing responsible parties. A BRP is defined as: A player approved by and party to an agreement with Energinet.dk regarding balance responsibility. The player is financially liable for discrepancies between the submitted notifications and schedules and the actual consumption/production. A BRP can be balance responsible for production, consumption and/or trade.[17] Therefore, production forecasts are the responsibility of the generators.

Renewable and distributed generators are also responsible for their imbalances and have to pay accordingly; deviations from the traded volumes are subject to a tariff system set by the system operator and approved by the Regulator. DG/RES generators are compensated for the reasonable balancing costs they incur via the calculation of support-scheme subsidies. Wind receives an additional feed-in premium to compensate the balancing costs. If the RES operator is able to reduce his balancing costs by improved wind forecasts, he can also earn this additional feed-in premium instead of paying for balancing.

The key principle for this market (partly including West Denmark[18]) is that the balance responsible parties submit bids for upward or downward regulation to the local system operator stating the offered quantity energy payment. The system operators send the regulating power bids to a ‘coordinator’ (Statnett in Norway), who compiles a joint list of all regulating power bids in the Nordic countries, sorted by price. If regulation in the joint Nordic synchronic system is required, the most advantageous regulating power bids on the joint list are activated taking grid congestions into consideration.

This system also covers local East Denmark. All East Danish regulating power bids are activated and settled by Energinet.dk, rather than the balance responsible parties themselves. (Source: Energinet.dk website). Cross-border balancing takes already place.

The Scandinavian type of balancing seems at the moment the best way to guarantee efficient cost allocation and therefore has already been implemented or considered in a lot of European countries. As a result, it seems the most suitable market model to operate a balancing market in electricity systems with increasing high penetrations of DG/RES.

Networks
Network operators on both distribution and transmission levels face increasing penetrations of intermittent DG/RES connected to their grids. Currently, power is mainly transferred from the transmission level downwards in the chain to the end consumer (‘top-down’). However, increasing penetration of renewable sources imply that power from intermittent generation will some-

[17] http://www.energinet.dk/NR/rdonlyres/9AC19440-3D21-40BD-8234-16B1E05623D5/0/16591507_v3_RegulationAPrinciplesfortheelectricitymarketdoc.pdf
[18] “Energinet.dk West will exchange supportive power with the synchronous system after contacting Statnett.” Nordic Grid Code 2007, p. 75

times exceed local load[19] and needs to be exported to other regions. As a result, upward flows may occur as well and power flows alternate between top-down and bottom-up, in other words are bidirectional.

Accommodation of higher fluctuations of supply can be realised if physical available network capacity is not only extended, but even more important when existing capacity is exploited to a higher extent for integrating RES-E/DG in the grids. Network charging, network planning and congestion management are important topics for both transmission and distribution networks in this respect. Transmission networks are defined as networks with voltage levels of 132kV and above, distribution networks contain all voltage levels of 60 kV and below.

In Denmark there is 1 TSO, 10 operators of the regional transmissions networks (132/150 kV and some 60 kV) and 101 distribution network companies (by the end of 2007). The TSO owns and operates the 400 kV network as well as part of the 132/150 kV network and also operate all other networks of > 100 kV reimbursing the owners. The TSO has an obligation to acquire networks of 100-200 kV (in practice > 100 kV) put out for sale (DERA/ERGEG, 2008).

TSO Energinet.dk is state-owned. Ownership of network assets by DSOs is a requirement of the Electricity Supply Act. The 101 DSOs are legally and increasingly functional unbundled. Currently there is a movement to ownership unbundling visible; soon the majority of DSOs will have sold off their minority holdings in generation, although there is no ban on RES-E/DG ownership for DSOs as long as it is a minor activity.

Network charging

Transmission networks

Transmission network costs for network operation and planning (including new investments) have to be paid by network users. Network costs are generally subdivided in costs of connecting market parties (generators and consumers) to the grid and costs for operation of the electricity system. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by use-of-system (UoS) charges.

Next to connection charges and UoS charges, Denmark levies also PSO charges (public service obligations for stimulation of ‘environmental friendly’ energy) on consumers. Connection and UoS charges are levied on both generators and load, although the charges for generators are very limited. All generators - except those with priority access - pay the same network tariff, which is 0.0536 c€ per kWh in West and 0.0268 c€ per kWh in East (Q1 2009).[20] No network costs are allocated to generators with priority access (CHP units smaller than 5 MW which do not face market prices), which means that they do not pay any network charge at all. Charges for load are cascaded through the DSO to the loads (DERA/ERGEG, 2008).

Consequently, investment decisions by RES generators are not influenced by network costs in the choice of their production location and in their production profile. This may be deemed inefficient if penetration of RES generators rises further. Currently, transmission charges do not have temporal differentiation.

As a conclusion, network costs for transmission networks are almost entirely financed by consumers. TSOs are generally compensated for all network costs.

Distribution networks

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[19] For 2006-2008 wind production was larger than the regional demand in Western Denmark in 27, 50 and 43 hours respectively.

[20] The difference between east and west comes from the past division between two TSOs. Their relative values are hardly due to differences in structure between the two areas.

Costs for operating and investing in distribution networks by DSOs can be passed on to generators and consumers through two kind of network charges; connection charges and use-of-system charges.

Each distribution network company has its own network tariff. This means that there are around 100 different set of network tariffs. Only methodologies of tarification are approved ex-ante by DERA. Distribution network companies pay for transmission network tariffs to Energinet.dk and to regional transmission companies. Thus distribution network tariffs include these payments as a component in the distribution tariff.

Connection charges for RES-E/DG are shallow (Cossent *et al.*, 2008). No UoS charges for wind and local CHP. Low and fixed UoS charges for conventional generation (see part about transmission networks). Efficient integration of renewable sources can be improved by temporal and locational differentiation of network charges. Currently, no time and locational differentiation of network charges is applied.

Network planning

<u>Transmission networks</u>
Denmark is divided into two separate systems; West Denmark is connected to the UCTE synchronous system, East Denmark is connected to the Nordel system. The systems are connected by undersea cables already since 1915. Since 2005 a single TSO, Energinet.dk covers both systems. Both systems are small compared to the systems of other countries in the RESPOND project.

In general, both in Western and Eastern Denmark internal congestion problems are currently limited as the transmission lines are sufficiently strong to transport the requested power. Within each region countertrading is applied by the system operator in case of internal grid constraints in a bidding area. This means upward regulation on one side of the bottleneck and downward regulation on the other. The costs of countertrading are socialized in grid tariffs. The exercise of market power because of countertrading is an obvious concern in Denmark since there are only two major market players. Market power would be exacerbated if energy prices within congested areas are computed separately from those of the rest of the system.

Network operation and planning probably is influenced by priority dispatch of small scale CHP. This priority dispatch may increase congestion, since CHP under this scheme does not experience any incentive to take into account the effects of its behaviour on network operation and planning. Besides, inefficiencies may occur in removing congestion against lowest costs due to priority dispatch when small scale CHP generators cannot be deployed for removing congestion, while their ramping capabilities are often excellent and less costly than the ramping of conventional generators. However, since the part of production capacity under the priority dispatch regime seems to be limited to 2%, effects of priority dispatch may be limited.

<u>Distribution networks</u>
In current distribution network planning still a ‘fit-and-forget’ network philosophy is applied, which means that the network is dimensioned on all possible different network flow situations. All potential congestions are resolved through network reinforcements. In Denmark, revenue cap regulation will not be increased unless the network investment is related to RES-E/DG connection. Then authorities can allow for inclusion in the cap under specific terms. Increasing intermittent generation will make this traditional network planning philosophy very expensive. However, regulatory incentives for active network management are limited. So far there exist no incentives to induce efficient investments by DSOs. The Danish Cell Controller project is conducted by Energinet.dk to study possibilities for active network management at distribution

level in a part of the area covered by the distribution company Syd Energi during the period 2004-2011.

At a more general level, incentives for innovation at DSO level seem to be limited to revenue cap regulation without additional incentives. RES-E/DG is less willing to pay for equipment that is needed for efficient operation of the distribution grid, since it means additional costs without additional benefits in most cases (this holds especially for RES-E/DG that does not contribute to the balancing market). Quality of service is taken into account in network regulation. From 2008 the revenue regulation has included effect from quality performance in 2007. Revenue caps will be adjusted by benchmarking. RES-E/DG is expected to only marginally influence quality of service statistics. The revenue cap provides also an incentive to DSOs to reduce energy losses. The impact of DER to reduce losses is not considered (Cossent *et al.*, 2009).

Congestion management
Currently, in total nine interconnections with neighbouring countries are in place. The maximum commercial available capacity is determined by net transfer capacity (NTC) values. Net transfer capacity (NTC) is defined as the maximum exchange program between two areas compatible with security standards applicable in both and accounting for the technical uncertainties of the future network (Kristiansen, 2007). Table 4.4 provides the NTC values for interconnections of Denmark with its neighbours during the winter of 2008/2009 according to ETSO.

Table 4.4 *Danish interconnections with neighbouring electricity systems*

Denmark-West	Denmark-East
Germany: 950 MW (dependent on wind situation in Germany) Norway: 950 MW Sweden: 680 MW	Germany: 550 MW Sweden: 1300 MW

Source: ETSO - NTC Matrix and BTC map

The available interconnection capacity is quite high compared to other countries. Denmark is one of the countries, which has already achieved the European objective of developing transmission capacity with neighbouring countries to at least 10% of the production capacity at the national level. At the end of 2007 the net generating capacity amounted to 12.7 GW (DERA/ERGEG, 2008), consequently the interconnection capacity is about 35% of national generating capacity.

Nevertheless, demand for interconnection capacity is higher than available capacity; consequently congestion occurs and existing capacity needs to be allocated and traded for different time frames.

In the long term (year or month-ahead) no physical network capacity is traded in the Northern market, but the risks of volatility of price differentials between countries are hedged with financial forward markets and “contracts for differences”. On the interconnections with Germany explicit auctions are in place.

On the day-ahead market a ‘system price’ for both network capacity and traded energy is calculated covering the whole area of the NordPool spot market (Denmark, Finland, Norway and Sweden) assuming no network constraints. In hours when congestion occurs on interconnections between price areas (Finland, Sweden, Norway (divided in two or more areas), and Denmark (east and west) separate day-ahead market prices are calculated. Congestion is managed by price differences resulting from implicit auctions (market splitting) on the interconnectors to Norway, Sweden and between Eastern Denmark and Germany (KONTEK) and explicit auctions on the interconnector between Western Denmark and Germany. Remaining capacity or non-used capacity is allocated within the intraday time frame in the Elbas market, in which the Nordic countries and Germany participate.

This market-based maximisation of the usage of existing network capacity is valuable for the Danish electricity system, since it offers intermittent generators additional possibilities to sell their excess supply and offers possibilities to import power when wind speeds in Denmark are very low. Besides, it increases security of supply.

Some of the frequently occurring congestion on the interconnection from Sweden to East Denmark is caused by the process of solving internal congestion within Sweden, as available trading capacity (NTC) on the interconnectors is curtailed in order to reduce demand. This congestion seems to be reduced in the near future with the Swedish decision to reinforce internal north-south transmission lines.

Other cross-border congestions can be solved by investments in additional interconnection capacity, amongst other measures. A 600 MW DC cable is now under construction between East and West Denmark and to be commissioned in 2010. Furthermore, Denmark strives for additional interconnection capacity with Norway (600 MW in 2014) and a new DC cable with the Netherlands (see also DERA/ERGEG, 2008 report). Concerning the fairness of the method used to allocate investment costs, it has the opinion that compensation among TSOs within Europe by the inter-TSO compensation scheme (ITC) should be made compulsory and payments should be fixed.

Conclusion
Based on the description of the current situation on different issues relevant for the integration of RES-E/DG in markets and networks, the current stages of market and network integration can be established.

Market integration
The RES-E/DG production as fraction of total electricity production is already moderate in Denmark. Clear effects of intermittent production on day-ahead market prices have been identified. Electricity market rules have been explicitly acknowledged by the Danish TSO as of decisive importance to the utilisation of the electricity system in the context of the increasing share of wind generation.[21]

The attention for market rules is also proven by the fact that:
– For wind generation a feed-in market support scheme is already in place.
– RES-E/DG already provides some ancillary services through aggregators
– The current balancing market design is characterized by balancing responsible parties including RES-E/DG, short gate closure time of day-ahead market and deployment of contingency units for emergency situations.

Therefore one could conclude that the current stage of market integration in the road map is stage B (RES-E/DG in the market).

Network integration
The transmission network in Denmark is already deployed with several steering and control possibilities like HVDC cables connecting the Nordel and UCTE systems. Although some pilot projects for first phases of active network management of distribution networks are ongoing, in practice distribution networks are still managed by the ‘fit-and-forget’ philosophy, implying

[21] Energinet (2007), p.14.

monitoring and control possibilities of network (actors) are highly limited. Network regulation is characterized by revenue cap regulation with quality of service regulation but without explicit innovation incentives.

Therefore, we conclude that the current network integration stage is fitting best in stage II (performance-based networks). The figure below combines the identified current market and network integration phases to fix the starting point in the road map framework.

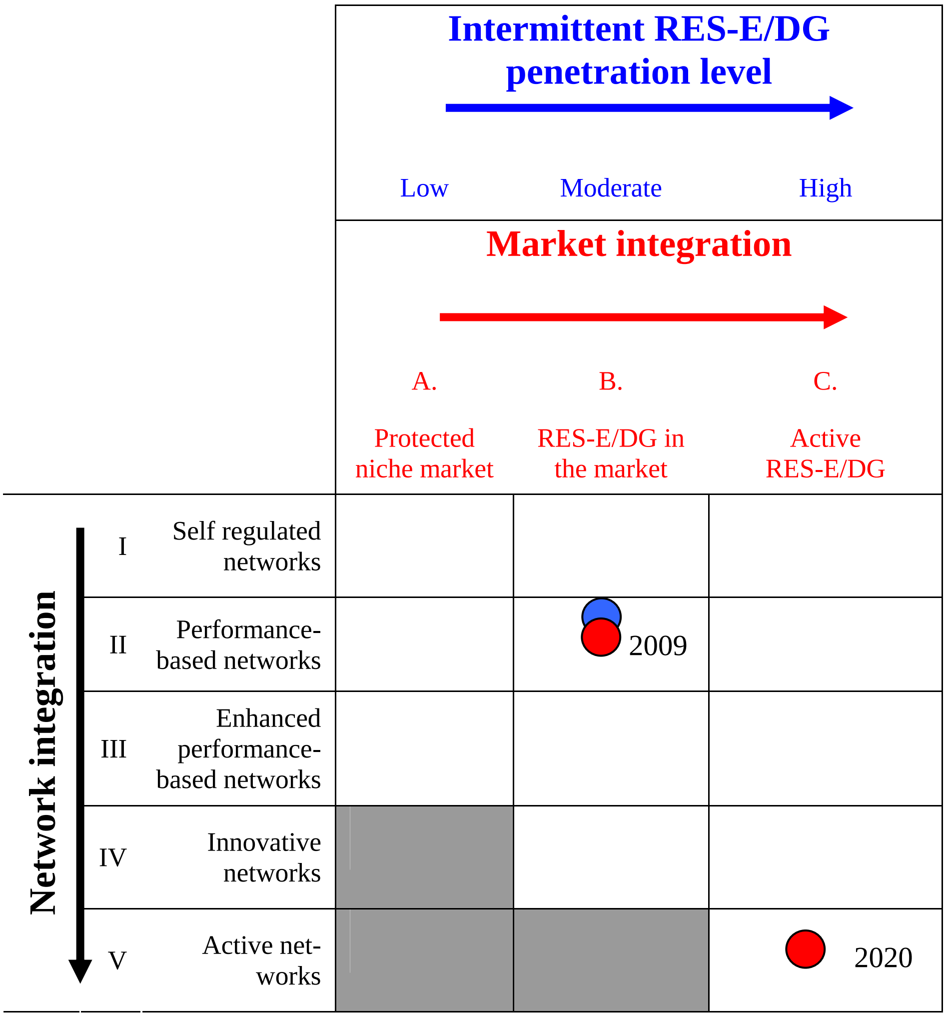

Figure 4.5 *Regulatory road map scheme Denmark: starting and end point*

4.2.3 Steps in regulatory road map

In order to reach the end-point of the road map in 2020, starting from the current situation (see Figure 4.5) an optimal system transformation route concerning market and network regulatory actions towards the end-point has to be determined. Since the route crosses different market and network integration stages, and every market and network integration stage is defined by a different set of consistent measures, intermediate regulatory steps have to be defined accordingly. These intermediate stages are useful to know for securing an optimal timing and progress of regulatory transformation process, i.e. which measures should be directly implemented and which a few years later before 2020. Besides, it prevents that cost-efficient and optimal measures of earlier integration phases are ignored and also the size of the package of required measures is effective as it offers stakeholders the opportunity for a timely planning and implementation of recommended regulatory measures.

4.2.3.1 First step

The first step towards a next stage (RES-E/DG in the market and enhanced performance based networks) is a vertical shift to the next stage of network integration while concurrently some preparatory actions can be taken for a horizontal shift to a more advanced stage of market integration in one of the next steps. The recommended actions are largely presented in the guidelines connected to the network and market integration stages, as defined in Table 3.3 and Table 3.4 respectively. In addition some country-specific measures are provided, which are tailored to the system conditions of Denmark.

For *RES-E/DG in the market* the following general recommendations are made:

– Increase *generation flexibility*
– Implement feed-in market premium *support scheme*
– Increase *demand response*
– Implement measures to increase *balancing market efficiency*
– Enable *provision of ancillary services by DG*

For *Enhanced performance-based networks* the following regulatory recommendations are made:

– Implement shallow and regulated *connection charges* plus GUoS charges
– Integrate RES-E/DG in *network planning*
– Implement market-based *congestion management methods*

Below we explain briefly these recommended actions per system segment.

RES-E/DG in the market

Generation flexibility
The flexibility of the generation market can be further improved by introducing *the possibility of negative prices* at the power exchange to stimulate RES-E/DG operators to control their production and to act in accordance with market prices which reflect system conditions. Without negative prices, the lower price floor of zero limits the reflection of system conditions in market prices. Consequently, wind generation probably will not react to low or even zero market prices since the market premium for wind generation exceeds the very low marginal costs of wind. The introduction of a negative price floor at -200 €/MWh is foreseen for October 2009.

Support schemes
A *feed-in market premium scheme* for subsidizing RES-E/DG has already been introduced. Marginal changes to the premium level are required to account for the decrease of RES-E/DG production technology costs and changes in market prices.

It is recommended to make the existing feed-in market premium system obligatory for all subsidized production technologies including all CHP with less than 5 MW capacity. If all RES-E/DG receives price incentives, they will adapt their behaviour to these prices, increasing overall system efficiency.

Demand response
Concerning meters, there is no *common standard for the functionality of smart meters* currently in place. Such a standard is deemed useful to ensure a certain standard of functionality within a country, which in turn prepares for market-based demand response by small consumers in the future. Also *common communication standards* have not yet been defined and need to be developed.

Concerning prices, small consumers[22] should be prepared for future demand response possibilities with concomitant variable pricing as a result of the introduction of smart meters. Therefore, suppliers should *implement simple time-differentiated (peak, off-peak and shoulder) prices* for small customers.

Furthermore, the *functioning of smart home area networks (HAN) at households* to control load automatically in response to price signals *has to be demonstrated* at a larger scale. These systems will be connected to the smart meters in order to lower transaction costs of consumers in reacting to variable prices.

Balancing market efficiency
The Scandinavian type of balancing market is maintained. This system is characterized by *balancing responsibility* for all connected parties (including RES-E/DG) and *gate closure time* of trade markets, which is the time period between scheduling generation and its physical delivery, of one hour before real-time. The commissioning of the Great Belt link will improve the integration of Western-Denmark in the Nordic balancing market. Furthermore, the Nordic countries plan to apply harmonised imbalance settlement rules in the autumn of 2009, which avoids market distortion between markets and prevents undue market behaviour.

Provision of ancillary services by DG
Introduce possibilities for provision of ancillary services by RES-E/DG by removing too restrictive technical requirements for the provision of these services. Too restrictive technical requirements include minimum size limits to either aggregators of a portfolio of small distributed generation assets as well as limits to the size of the underlying individual installations or connections. In this respect minimum size limits to participation of VPPs in the provision of ancillary services may be modified from 10 MW to 5 MW. Consequently, RES-E/DG has better opportunities to participate in these markets.

Enhanced performance-based networks

Network charging
Both on transmission and distribution level it is advised to implement *regulated* shallow *connection charges*. Regulated charges remove possible adverse locational investment incentives for generators caused by different charges for generators applying for a connection.

Costs of network reinforcements which are not covered by connection charges should be covered by *use-of-system charges* levied more proportionally on both generators and consumers. This will guarantee a more efficient allocation of costs between generators and consumers. Currently, although generators do have clear benefits from network reinforcements in transporting their produced energy, they pay only 2-5% of the transmission tariffs (ETSO, 2007). In order to avoid opposition of inland generators which face competition from generators originating from other countries, the implementation of higher use-of-system charges should probably be accompanied by the introduction of comparable use-of-system charges in neighbouring countries. Therefore, coordination of this topic on multi-country level, i.e. within the Northern region is required.

Network planning
A national coordination procedure for obtaining building permits may be useful to overcome social objections at a local or regional level against important network reinforcements. This will limit both the construction time of new lines or cables as well as burying of new extra high voltage lines which is very costly.

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22 Large customers already dispose of smart metering since hourly metering is required for consumers with a consumption of 100,000 kWh or more per year (ERGEG/DERA, 2008).

It is suggested to *evaluate current network security standards* with respect to their position to economic optimal security standards. Up to now security standards are quite stringent (n-1 and additional requirements) and probably at a higher level than necessary from an economic point of view; the marginal costs of security standards are in general perceived to be much higher than marginal costs of disturbances (see among others Ajodhia, 2006). For implementation of more optimal network security standards surveys need to be done and support from the system operators need to be guaranteed.

For distribution network planning it is important to take into account the additional costs and benefits of RES-E/DG in the determination of the allowable yearly costs (incentive regulation) of each DSO. Since DG has become an important factor determining network costs, *DG should be included as cost factor in the productivity benchmark analysis* in order to account for differences in RES-E/DG production between different distribution networks (Jansen *et al.*, 2007). Cost differences due to integrating RES-E/DG are then no longer neglected in benchmarking DSOs for new regulatory periods in revenue cap regulation. As a result, network costs faced by DSOs no longer have to be financed out of their own pockets as has been the case in the past (Abildgaard *et al.*, 2004). Consequently, potential disagreement between DSOs and DG about the remuneration of network reinforcement costs probably will not longer be an issue, which will speed up the network integration of increasing shares of RES-E/DG.

Furthermore, incentives for investments by DSOs in new distribution network management approaches are limited, potentially limiting RES-E/DG integration in the near future. In order to change the focus of DSOs more to the long term, *explicit positive incentives for innovation* like IFI (Innovation Funding Incentive) in the UK and demonstration projects need to be implemented in network regulation. An (IFI) type of scheme permits DSOs to spend up to 0.5% of its allowed revenues on eligible IFI projects related to any distribution system asset management aspect. DSOs can be given a special allowance in the RAB to stimulate network innovation (Jansen *et al.*, 2007). Demonstration projects like the Cell Controller Pilot Project stimulate DSOs to integrate new DG in their systems by using innovative network management. The network management possibilities include cut-off and reconnection to the synchronous grid as well as black start. Preferably, both public and private institutions should participate in such demonstration projects in order to attain sector-wide demonstrations and knowledge exchange. Both measures will reduce risks for network operators to integrate RES-E/DG in an innovative ('smart grids') way.

Congestion management

Congestion is expected to occur more often due to more fluctuating power flows and increasing use of interconnection capacity. At a national level congestion may be exacerbated by the priority access regime in place which gives a small fraction of CHP (about 2% of Danish electricity generation capacity) legal priority in the transport of their electricity, regardless of system and local demand for electricity. Although this policy is not efficient from a system point of view, actual consequences for cost-efficient relief of congestion are deemed to be small.

Concerning cross-border interconnections, the introduction of implicit auctions for the day-ahead time frame on interconnections with Germany will help to increase the utilisation of interconnection capacity implying higher revenues of RES-E/DG during times of high wind power supply.

4.2.3.2 Second step

The second step is again a vertical shift to the next stage of network integration ('innovative networks'), while concurrently some additional preparatory measures are taken for a horizontal shift to a more advanced stage of market integration in one of the next steps. The recommended actions are largely given in the guidelines connected to the network and market integration phase at hand, see Table 3.3 and Table 3.4 respectively. Moreover, some country-specific measures are provided, which are tailored to the system conditions of Denmark.

For *RES-E/DG in the market* the following general recommendations are made:
- Increase *generation flexibility*
- Implement feed-in market premium *support scheme*
- Increase *demand response*
- Implement measures to increase *balancing market efficiency*
- Enable *provision of ancillary services by DG.*

For *Innovative networks* the following regulatory recommendations are made:
- Implement shallow and regulated *connection charges*, basic time and/or location differentiated *GUoS charges*
- Integrate RES-E/DG in *network planning*
- Implement market-based *congestion management methods.*

Below we explain briefly these recommended actions per system segment.

RES-E/DG in the market

Generation flexibility
The generation market is characterized by two kinds of market failures i.e. free-riding on reserve capacity and imperfect information during peak demand. Currently in Denmark no additional non-market based incentives are in place to guarantee sufficient investments in new flexible power plants. Combined with the substantial increase in demand for balancing power, the market failures may require *implementation of additional incentives for the provision of balancing power during extreme system conditions*.

Whether the implementation of these incentives is necessary depends also on the other policy incentives and place as well as the characteristics of the Danish electricity system. On the one hand, the flexibility of the electricity system may be limited by the relatively high share of coal-fired power plants which are scheduled up to a week in advance and dispose of limited ramping rates. In the long term the problem may be limited to some extent, since additional gas-fired power plants are planned to replace old coal-fired plants, which will be decommissioned. On the other hand, existing contingency units (e.g. in hospitals) have been encouraged to participate in system security after a black-out in 2003. They may be used for the reserve and balancing market, although the operation of some units is restricted to 500 h/year due to NO_x emission regulation. Besides, demand for balancing may be provided by production units in Sweden or Norway due to the implementation of cross-border balancing. As a conclusion, although the combination of spot and regulation markets might prove sufficient, it is advised to consider additional policy incentives as back-up measures.

Another issue is the increasing spot market price variability. To account for this price variability, *CHP generators* that are still heat-led probably may *add heat storages, heat pumps, or electric boilers for down regulation* to either their plants or heat distributing networks in order to obtain the possibility to decouple heat and electricity production for achieving more flexibility for operation on the electricity market.

Support schemes
The *feed-in market premium level* may be decreased in order to stimulate RES-E/DG to consider provision of ancillary services through auctions or bilateral contracts instead of producing for energy markets only.

Demand response
Concerning metering a *general roll-out of genuinely smart meters to all customers* should be encouraged/obliged. Concerning prices, given hourly metering the default rate should be *hourly market prices*, and customers should not be allowed to choose a fixed rate. A fixed rate implies a cross-subsidy to customers with a relative large consumption in expensive hours. Fixed price components, especially for households, should be reduced or changed to a percentage type of component. However, it should be considered that annual revenues (and bills) become more volatile than with fixed components. Furthermore, *automated smart home area networks (HANs)* need to be introduced to offer opportunities for consumers to react to variable market prices and network charges at low transaction costs. Finally, *pilot projects* have to be conducted for testing the communication infrastructure required *for smart metering with an even higher frequency* (every PTU i.e. 30 minutes) for enabling a wider range of applications of meters (e.g. steering network flows).

Balancing market efficiency
A few large customers with consumption for heating, cooling, and pumping act as reserve capacity and this possibility should be explored further. Refine the system for *cross-border balancing* applied in the Nordic area.

Provision of ancillary services by DG
The ancillary services market design may allow for a better trade-off for RES-E/DG between either the provision of energy or the provision of one of the different ancillary services. In this respect, ancillary services markets or auctions are more efficient than self procurement by TSOs, compulsory provision of services by RES-E/DG or bilateral contracts (the latter are less transparent). Currently, a number of services are already contracted through auctions. The *establishment of more ancillary services markets (for example in the form of auctions) or the possibility for generators to close bilateral contracts* enables RES-E/DG production technologies to provide a wider variety of ancillary services when they dispose of the required technical capability. For instance, wind turbines will be able to provide primary control services in the near future. These new market opportunities may be valuable for RES-E/DG producers in diversifying their revenue streams.

Innovative networks

Network charging
It is assumed that on both transmission and distribution level all *connection charges* are shallow and regulated.

Since the network cost impacts of RES-E/DG differ highly to time and location in Denmark due to the high penetration of wind power in 2020, *time differentiated GUoS charges s*hould be implemented as a first step. In this way, (RES-E/DG) generators receive an incentive to behave more in accordance with network needs when deploying their units.

In regions with a large share of wind power and transmission network constraints to neighbouring regions congestion management should be applied. One of the possibilities for congestion management is implicit auctioning of the scarce network capacity and accompanying electricity. Consequently, in hours with congestion two different price areas evolve; while in hours without congestion prices in both areas will be equal (see section about congestion management below).

Network planning
Following the surveys towards more optimal security standards from a socio-economic point of view, it is recommended to *introduce dynamic reserve requirements* dependent on the actual

wind forecasts with its embedded variance in network planning standards. Consequently, reserve requirements and concomitant system costs could be reduced for most of the time without compromising security of supply (Zvingilaite *et al.*, 2008).

Besides, *advanced network simulations tools* are required to provide insight in the most efficient way of network reinforcement, either by conventional investment in new cables and lines or by adding intelligent network monitoring and controlling devices to the grids. These simulation tools will make it easier to measure and monetise benefits and costs of active network management (ANM) and the potential contribution of RES-E/DG to ANM. Both TSO and regulator can use such a tool for better coordination and optimization of network planning. Among others, it enables a better review of network investments by DERA or experts on behalf the regulator before they apply for remuneration.

Demonstration projects about active network management like the Cell project should be extended to increase the experience of DSOs with new network management approaches, and lower risks for investments in ANM.

Congestion management
If congestion evolves in the West Danish electricity transmission grid, this area can be divided in two or more price areas to solve internal overload problems following the existing method within Nordpool for market splitting among the Nordic countries and within Norway. When congestion is absent the applied implicit auction mechanism will provide one price for entire West-Denmark.

This *market-based congestion management* method is favourable to countertrading since it allocates the costs to individual market participants like generators which caused the network congestion and therefore fulfils the cost causality principle. It is advised to replace countertrading as far as possible with implicit auctions and/or other market-based congestion management methods, since countertrading is characterized by a lower efficiency due to the socialization of congestion management costs to all market participants.

Congestion on cross-border connections is envisaged to be fully dealt with by implicit auctions for allocation of network capacity in the intraday and day-ahead time frames on borders with the Nordic countries as well as Germany. *Auctions are coordinated regionally* within the Nordic region, in order to make available as much network capacity to the market as possible.

Conclusion
Figure 4.6 below summarizes the intermediary steps in the road map scheme and indicates when these steps need to be taken for reaching the required market and network integration stages in time.

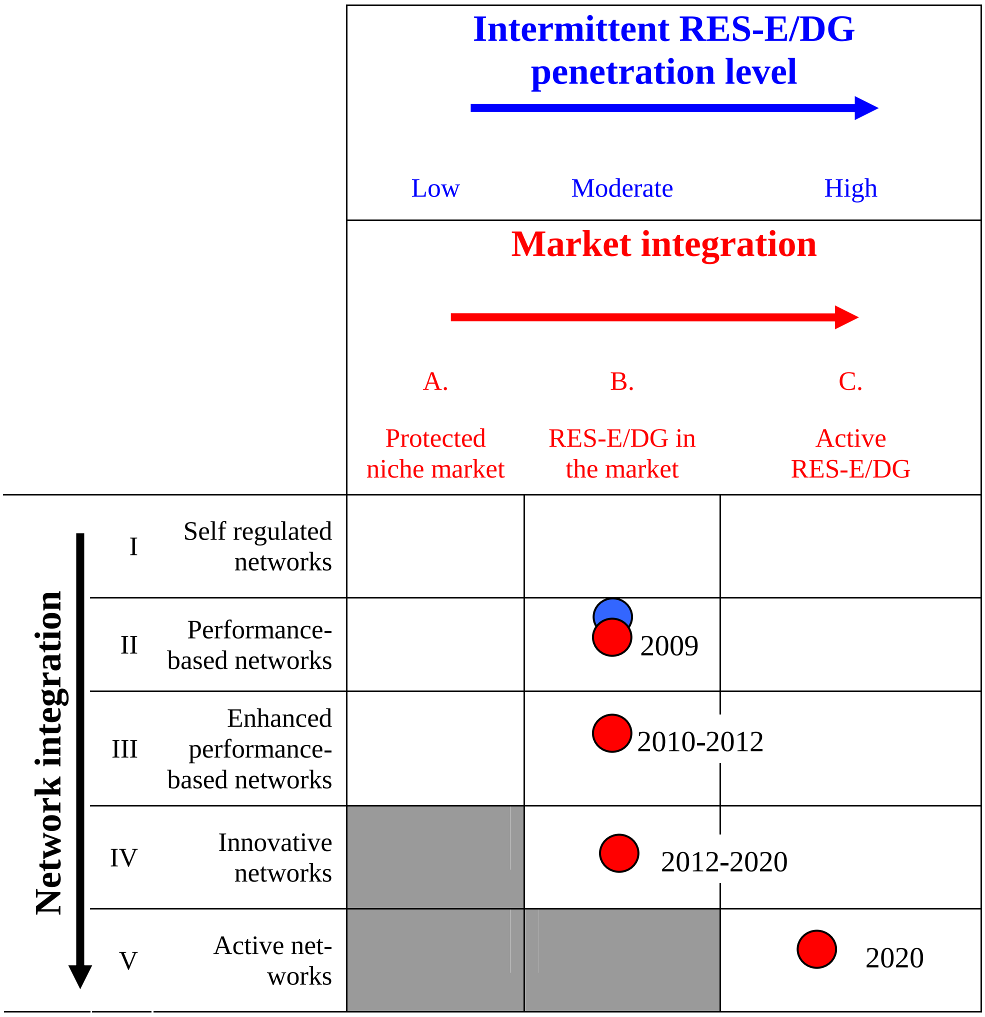

Figure 4.6 *Regulatory road map scheme Denmark: including intermediate steps*

4.2.3.3 Last step towards the end point

Based on the expected market and network impacts in 2020, the end point has already been defined in Section 4.1 (Active RES-E/DG and active networks). Together with the description of the starting point as well as intermediate steps between starting point and end point, the last step is clear and the complete road map can be constructed (see Figure 4.7 below). The last step consists of both a vertical and horizontal shift to the next stages of network integration and market integration respectively. With help of Table 3.3 and Table 3.4, recommended sets of regulatory measures are again coupled with the regulatory market and network stages selected for the end point. Besides, some country-specific measures are provided, which are tailored to the specific system conditions of Denmark:

For *Active RES-E/DG* the following general recommendations are made:

- Increase *generation flexibility*
- Implement efficient feed-in market premium *support scheme*
- Increase utilisation of *demand response*
- Implement measures to further increase *balancing market efficiency*
- Enable wide-scale *provision of services by DG to ancillary services markets*

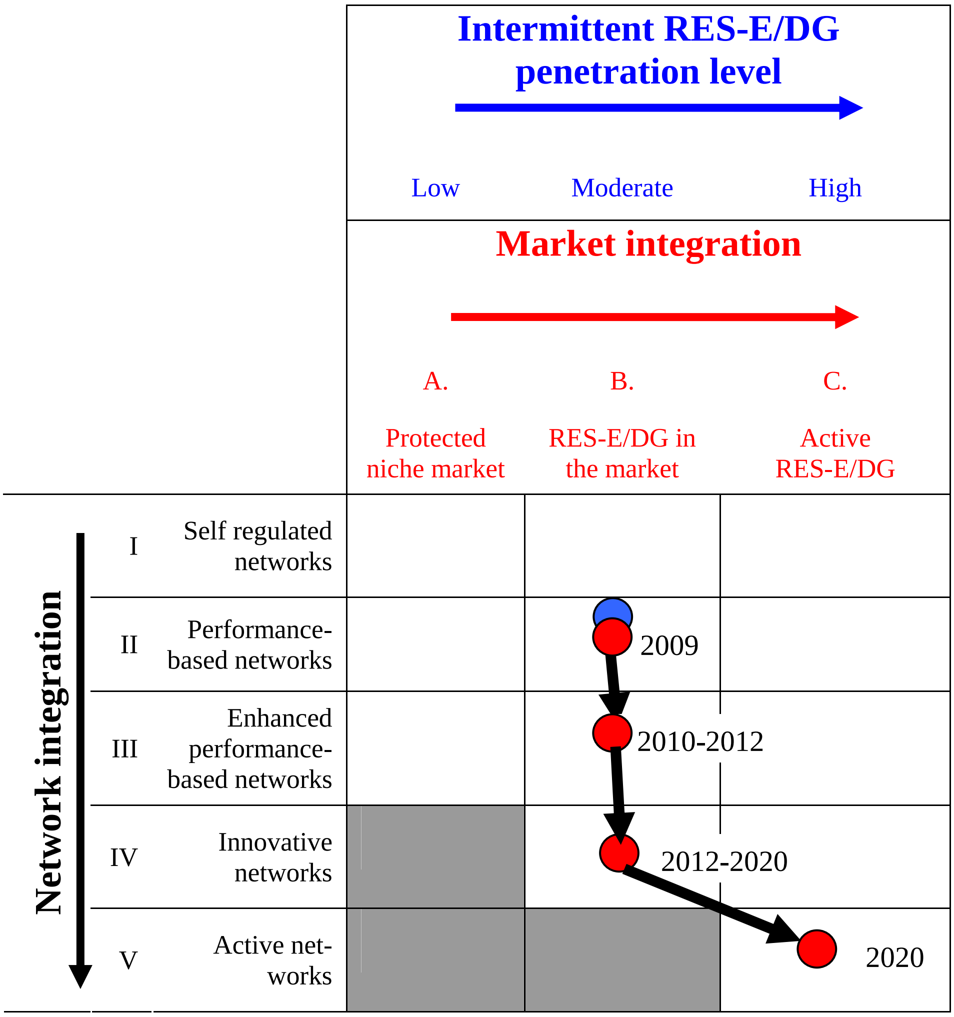

Figure 4.7 *Regulatory road map scheme Denmark: complete route 2009-2020*

For *Active networks* the following regulatory recommendations are made:

- Implement shallow and regulated *connection charges*, real-time and/or locational differentiated *GUoS charges*
- Encourage more active role of RES-E/DG and demand in *network planning*
- Introduce arrangements for using smart metering in distribution network management
- Improve market-based *congestion management methods.*

All recommendations are discussed below per system segment.

Active RES-E/DG

Generation flexibility

The generation market is characterized by two kinds of market failures i.e. free-riding on reserve capacity and imperfect information during peak demand. If additional non-market based incentives are not yet in place, they should be considered in order to guarantee sufficient investments in new flexible power plants. Combined with the substantial increase in demand for balancing power, the market failures may require *implementation of additional incentives for the provision of balancing power during extreme system conditions.*

Storage technologies like heat pumps, batteries, supermagnetic energy storage (SMES), supercapacitors, flywheels and compressed air energy systems (CAES) may become profitable due to the high price variability between situations with abundant wind and no wind. Also storages of electrical vehicles may be deployed to increase market flexibility.

Support schemes
Market premiums probably can be adapted downwards according to the higher efficiency of new technologies and concomitant lower costs, but at the same time may be corrected upwards due to higher expected market prices. Market premiums for CHP production will decline compared to current premiums or tariffs, since avoided CO_2 emissions by deployment of CHP generation will decrease in time due to emission reductions of conventional production technologies.

Moreover, market prices for different technologies may be calculated on weekly or monthly basis instead of a yearly basis. An increasing calculation frequency of market prices provides stronger incentives to RES-E/DG to take into account system conditions.

Demand response
Meters should be increasingly used for energy savings and mitigation of critical network flows. *Consumers* are gradually deployed for network and balancing purposes through *virtual power plants*. Therefore, demonstration projects with the combination of smart metering, advanced load control and virtual power plants aggregating high number of small customers are carried out.

For enabling TSO and DSOs to deploy small customers for balancing and network purposes a start is made with *real-time pricing*, both in energy supply and network charging. As a result, some consumers' appliances (including storages of electrical vehicles) are switched on and off if necessary either to balance electricity supply and demand or to stabilize grids.

Balancing market efficiency
One regional Nordic balancing market serving both Denmark (both West and East), Sweden, Finland and Norway will be put in place.

Interruptible contracts are not longer limited to large loads only, but increasingly used by the TSO to contract medium and small size loads (through virtual power plants) as well for balancing purposes.

Provision of ancillary services by DG
The increase of intermittent generation will increase the demand for balancing and other ancillary services in 2020. At the same time, the increase of monitoring and control of networks, generation and loads offers opportunities to meet this increase of demand through the provision of system services by DG. Therefore it is expected that *VPPs* with a mixed portfolio of wind turbines, (micro-) CHPs units and loads will operate in ancillary services market such as the provision of reserves. The *minimum size requirement for VPPs* to participate in these markets may be further limited to 1 MW (currently 10 MW) if the system benefits of this measure compensate for the additional transaction costs for the TSO. Nowadays, some ancillary services are procured bilaterally since the current demand for these services is limited. In order to accommodate the expected increase of demand for ancillary services and stimulate DSOs to manage their networks actively, possibilities need to be created for the provision of voltage control, black-start and primary response by RES-E/DG. Besides, this provides DG the possibility to arbitrage between a wider range of markets in order to obtain higher revenues. The scope of these markets may depend on the nature of the specific ancillary service; for instance auctions for system-wide services and bilateral contracts for local services.

Active networks

Network charging
Both on transmission as well as distribution network levels, all *connection charges* will be shallow and regulated. Since the network cost impacts of RES-E/DG will differ highly to time and location in Denmark due to the high penetration of wind power in 2020, simple time-differentiated GUoS charges and implicit auctioning of scarce transmission network capacity may be not enough for an efficient integration of renewables in the electricity system. Therefore, stronger incentives are required to limit network congestion and influence the siting of new generators. More differentiation in network cost allocation methodologies implies stronger adherence to the cost causality principle and less socialization of costs. Through introducing *real-time and/or locational differentiated* UoS charges for both generators and consumers, more network costs are attributed to network actors which require network services at critical system times and places (high local demand and low supply or the other way around), and less network costs are attributed to network actors which require network services during non-critical system times at non-critical places. In this way, all generators (including RES-E/DG) and consumers receive a strong incentive to behave in accordance with system needs when deploying their units.

Implementation of locational differentiated GUoS charges may be hindered by the volatility of these type of network charges due to high volatility of network reinforcement costs. Consequently, in Grohnheit *et al.* (2009) the implementation of zonal network charges is advised. Network charges need to be computed for each type of profile in advance of actual operation. Given the complexity of implementation of locational GUoS charges, demonstration projects on the applicability and net benefits of this type of initiatives should be launched.

Network planning

Transmission networks
For an optimal network planning, it is advised to implement new possibilities to increase steering and control possibilities of network flows (HVDC Voltage Source Converter technology, phase shifters, high-temperature conductors, FACTS) on a wider scale in practise.
Additional transmission lines (for instance Great Belt link 2, Skagerrak line 4, Cobra line) are assumed to be ready in 2020. For additional required transmission lines, it may be necessary to bury them in order to gain social acceptance for their construction in densely populated areas.

Distribution networks
Active network management is increasingly applied in some distribution networks with a lot of wind and CHP production, which exceed often local load. An example is the (wide scale) application of the Cell controller concept. The latter embraces a decentralised system control architecture at 60 kV network level for enabling black-start of the system with deployment of distributed generation only (Lund, 2007). This enables the part of the system under control to operate in islanding mode when a severe disturbance takes place and the system nearly breaks down. In this way, islanding helps to increase security of supply in system parts that are vulnerable to grid disturbances. Consequently, *DSOs are becoming entrepreneurs*, looking to the most efficient possibilities to resolve congestion in network planning and operation, either by contracting services from (distributed) generators and load or by network reinforcement measures. For this aim, additional monitoring and control devices are installed in networks and at grid connection points. Network simulation tools help to prevent and accommodate upcoming network congestion and to calculate their effects (both positive and negative) on quality of supply and losses both from a technical and economic point of view. Demonstration projects for utilising load for

network purposes, requiring deployment of smart metering and advanced load control, are carried out.

Congestion management
Capacity is already calculated on a common basis; optimisation and the use of existing cross-border transmission capacity is therefore the focus. This will help to increase the utilisation of the technical available network capacity. The envisaged new interconnections with Norway, Germany and The Netherlands will increase the available network capacity with about 2000 MW and open possibilities for capacity allocation in a wider region. Integration of the Northern and CWE region with respect to capacity allocation auctions is foreseen.

4.3 Action plan for road map implementation

The implementation of the identified recommendations should be supported by an effective set of actions by system actors or stakeholders. All these actions can also be seen as recommendations from the regulatory road map for Denmark, and are summarized in Table 4.5 below. The Table indicates the market parties or organisations that are first responsible for preparing and approving these recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020.

Based on the Danish road map description we select the most urgent and critical actions to improve the system flexibility **in the short term**. The road map indicates that the main actions are required for improving network integration, as on the one hand major grid overloads and network congestion are expected, and on the other hand conventional hardware solutions are prevented by social acceptance issues and increasing cost burdens.

First of all, generators should face the effects of their production and siting decisions on network investments; therefore *use-of-system charges for generators* should be set at a more substantial level. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Finally, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning in the longer term. Especially in a system with high and increasing shares of wind generation, dynamic planning criteria can lower network integration costs substantially.

Table 4.5 *Action plan for implementation of the Danish Regulatory road map*

	Action	Responsibility		
		Prepare & implement	Approve	Term
Market integration	***Generation flexibility***			
	Introduce possibility of negative prices at power exchange	PX	Regulator	short
	Contract regulating and reserve power outside the market to guarantee balancing power availability (optional)	TSO	Regulator	medium
	Add (larger) heat storages, heat pumps or electric boilers to CHP units	RES-E/DG operators	-	medium
	Invest in new heat or electric storage facilities	Generators/Traders	-	medium
	Support schemes			
	Oblige market premium system for CHP generation < 5 MW	Ministry	-	short
	Decrease market premium to stimulate RES-E/DG to consider provision of system services	Ministry	-	medium
	Demand response			
	Establish common standard for the functionality of smart meters	Whole sector	Ministry	short
	Define and develop common communication standards	Whole sector	Ministry	short
	Introduce time-differentiated prices for all customers	Suppliers	Regulator	short
	Pilot projects for testing communication infrastructure for smart metering with high frequency	DSOs	-	medium
	Demonstrate functioning of smart home area networks for automatic load control	DSOs	-	short
	Introduce smart metering at premises of low voltage customers	DSOs	Ministry	medium
	Implement smart home area networks for automatic load control	DSOs	-	medium
	Introduce real-time pricing for all customers	Suppliers	Regulator	medium
	Balancing and ancillary services markets			
	Introduce possibilities for provision of ancillary services by RES-E/DG and lower minimum size requirement for VPPs to participate in ancillary services markets to 5 MW.	TSO	Regulator	short
	Refine cross-border balancing within Nordel	Nordic TSOs	Nordic regulators	short/medium
	Extend the use of interruptible contracts to medium and small sized loads and generation	TSO	Regulator	medium
	Establish more ancillary services markets or the possibility for DG to close bilateral contracts with network operators (for instance for reactive power)	TSO/DSOs	Regulator	medium
	Modify minimum size requirement for VPPs to participate in balancing and ancillary services markets to 1 MW	TSO	Regulator	medium

Table 4.6 *Action plan for implementation of the Danish Regulatory road map (continued)*

	Action	Responsibility		
		Prepare & implement	**Approve**	**Term**
Network integration	***Network charging***			
	Increase UoS charges for all generators for covering remaining network costs	Nordic TSOs	Nordic regulators	short
	Implement basic time differentiated UoS charges for generators	Nordic TSOs	Nordic regulators	medium
	Implement real-time differentiated and locational differentiated UoS charges	Nordic TSOS	Nordic regulators	medium
	Network planning			
	Coordination procedure to overcome local or regional objections against new lines	Government	-	short
	Account for differential DG impacts in network regulation	Regulator	-	short
	Introduce explicit innovation incentives in regulation (IFI and RPZ type)	Regulator	-	short
	Evaluate current network security standards (a.o. N-1 regulation)	Regulator	-	short
	Implement dynamic reserve requirements in network planning standards	TSO	Regulator	medium
	Implement network simulation tool for better coordination of network planning and better evaluation of network investments	TSO & Regulator	-	medium
	Increase number of demonstration projects about active network management (like the Cell project), smart metering and advanced load control for network purposes	TSO & DSOs	-	medium
	Congestion management methods			
	Introduce implicit auctions for day-ahead time frame on interconnections with Germany	Northern region	Nordic regulators	short
	Introduce possibility of two or more price areas in West-Denmark in implicit auctions	Nordic TSOs	Nordic regulators	medium
	Concerning national congestion management, replace countertrading as far as possible with more market-based CM methods like implicit auctions	Nordic TSOs	Nordic regulators	medium
	Optimize common transmission models for capacity calculation	Nordic TSOs	Nordic regulators	medium
	Coordinate capacity allocation through regional auction office	Nordic TSOs	Nordic regulators	medium

5. Regulatory road map for Germany[23]

5.1 Outlook RES-E/DG and the electricity system

Developing a country regulatory road map requires insight into the particular characteristics, i.e. RES-E/DG shares, system conditions, and the possible transition of that country's electricity supply system in the next decade. In this section several important factors are covered, such as developments in the generation mix, demand growth, and connection and integration of RES-E and CHP under current system, market and network conditions. Finally, the impacts up to 2020 are shortly summarized for road map perspectives.

Electricity generation mix

The Tables below show the expected development of production from different conventional and renewable (intermittent) resources in production as well as capacity terms, up to 2020. The fuel mix of Germany is currently characterized by a high share of coal (both hard coal and brown coal) and nuclear power plants. The amount of coal-fired generation is expected to increase marginally, while nuclear generation will diminish due to the phase-out of nuclear. The high share of coal-fired generators is due to the abundant availability of brown coal in Germany. Besides, more flexible generation like gas-fired power plants and hydro will be available. Biomass may attain a higher production level than nuclear production in 2020. Renewable production from intermittent resources like wind and to lesser extent PV has already reached substantial shares in the German generation mix and is deemed to increase further.[24]

Germany is one of the countries with the highest penetration of onshore wind worldwide, with 20.6 GW installed in 2006. This is due to favourable feed-in tariffs which stimulate investments. There is still potential for the installation of onshore wind so that a total amount of 28 GW installed capacity is possible until 2020 (equivalent production: 53.5 TWh). The government has the ambitious target of approximately 20 to 25 GW of offshore wind till 2025/ 2030. At the end of 2009, two offshore wind turbine parks will be installed. The installation of future offshore wind farms will most likely be delayed due to factors like delay in the development of multi-megawatt turbines, limited experience with 5 MW technology and the high risk in offshore projects. Other obstacles are lower water depths and greater distances to the shore than in other North Sea countries. Also, investments in onshore parks are still more attractive than in offshore projects. It is assumed that about 10 GW of offshore wind power will be installed in 2020, producing 33.7 TWh of electricity on an average yearly basis. Wind is mainly installed in the most wind-rich Northern part of the country.

Germany has already a high production of PV with 1.8 GW installed in 2005. This development is largely due to the good investment conditions with favourable feed-in tariffs for PV. If these favourable conditions remain, the future expansion of PV is projected to reach 18 GW of installed capacity in 2020, with an equivalent electricity production of 15.5 TWh (BMU, 2008).

[23] This road map is mainly based on information provided by dena and ISET and the joint responsibility of ECN, dena and ISET. We thank dena and ISET for their cooperation.

[24] The significance of RES-E in the German electricity system can already be illustrated by the amount of vertical load i.e. the total amount of the power flowing out of the transmission networks into the distribution and large consumer networks. For example, on 5 October 2008 the vertical load amounted to 24 GW and the feed-in from RES-E amounted to 16 GW. Thus, the RES-E feed-in amounted already to 67% of vertical load in Germany.

In the past micro CHP has not played a major role in the political agenda. Since 2009 Germany promotes and subsidizes micro CHPs. No credible scenarios are available for the development of this technology in the next decade.

Table 5.1 *Total installed electricity generation capacity in Germany, by fuel in GW*

Technology	2010	2015	2020
Wind	25,7	30,8	38,1
- offshore	0,5	3,6	10
- onshore	25,2	27,2	28
Natural Gas & Oil, Other Gases	30	33	36,9
Hard Coal and Other Solid Fuels	29,3	26,5	25,2
Brown Coal	21,2	19,2	18,3
Nuclear energy	17,4	12,6	4,5
Geothermals	0	0,1	0,3
Photovoltaics	7,7	13	17,9
Hydro	4,8	5	5,1
Biomass	4,6	6,1	7,2
Misc			
Total (without Pumped Storage)	140,6	146,4	154,2

Biomass: aggregate RES (inclusive Biomass) - RES (except Biomass)
Misc: not stated explicitly in the BMU-Leitstudie 2008[25]

Table 5.2 *Total electricity generation in Germany, by fuel in TWh*

	2010	2015	2020
Wind	46	60,8	87,2
- offshore	1,2	11,2	33,7
- onshore	44,8	49,6	53,5
Natural Gas & Oil, Other Gases	104	123	145
Hard Coal and Other Solid Fuels	137	118	109
Brown Coal	142	127	119
Nuclear energy	130	94	34
Geothermals	0,1	0,6	1,8
Photovoltaics	6,2	11	15,5
Hydro	22,5	23,9	24,3
Biomass	29,2	39,7	46,2
Misc			
Import (just RES)			3
Total (without Pumped Storage)	617	598	585

Biomass: aggregate RES (inclusive Biomass) - RES (except Biomass)
Misc: not stated explicitly in the BMU-Leitstudie 2008

Electricity demand

In the period 2005-2020 final electricity demand is expected to grow with 0.3% per year (calculated on basis of figures of Eurelectric) due to a rising GDP, rising living space, increasing freight traffic and increase of the residential population in Germany until 2020. Whether or not

25 This study does not represent the official government position.

the electricity demand increases after 2020 is unclear. On the one hand, a reduction of electricity consumption can be expected initial after 2020 when energy policy measures to increase power efficiency on the consumer side will become effective. On the other hand, new electricity consumers from traffic and heat sectors may enter the market – like electric cars and heat pump or cooling systems. Latest statistics show a decreasing electricity demand for 2008. Due to the economic crisis ongoing decreasing electricity demand can also be expected for 2009 and 2010. However, it remains to be seen whether this development has implications for the long term electricity demand.

Connection of RES and DG

In Germany the transmission networks are the network levels of 220 kV and higher, distribution networks are 150 kV networks and lower. Transmission networks and the majority of distribution networks are owned by private parties. The large part of all wind generation, 85-90%, is connected to distribution networks, while the remainder is connected directly to transmission networks. Nearly all PV generation (99.9%) is directly connected to one of the distribution networks. All non-industrial CHP are mainly connected to the distribution networks as well. As a conclusion, in Germany intermittent generation needs to be mainly integrated in distribution networks. The degree to which this increase of connection of intermittent generation influences the electricity system and its constituents will be elaborated upon below.

Integration of RES and DG

An important variable shaping the impacts is the assumed RES-E/DG penetration in 2020. Based on the projected developments in electricity production, the 2020 sustainability targets for Germany and the German RES-E potential we conclude that the likely share of intermittent RES-E/DG in 2020 can be qualified as moderate; 18% of electricity probably will be produced from intermittent RES-E/DG sources. This percentage will be assumed as basis for the discussion of the likely impacts on networks and markets of intermittent RES-E/DG in 2020. Network impacts can be divided in impacts on distribution and transmission networks respectively, while market impacts can be distinguished in impacts on balancing market, and impacts on trade markets.

Impacts on distribution networks

Currently, power is mainly transferred from the transmission level downwards in the chain to the end consumer (‘top-down’). However, increasing penetration of renewable sources imply that power from intermittent generation will increasingly exceed local load and needs to be exported to other regions. As a result, upward flows may occur as well and power flows alternate between top-down and bottom-up, in other words are bidirectional. Most severely influenced areas lie in the northern and eastern part of Germany (Saxony-Anhalt, Mecklenburg-Western Pomerania, Schleswig-Holstein, Lower Saxony and Brandenburg).

Impacts on transmission networks

The transmission network will face more variable upward flows from the distribution networks as well as more exchange of energy through the interconnections. Besides, changes in locations of load and generation will change the electricity flows in the networks. The main load centres are in the South and West of Germany. Conventional generators are more or less equally divided over Germany. In the North and South are more nuclear and in the West and East more coal plants. The first nuclear plants to close (if there is no political change) are in the South. The largest amount of new generation is planned in the North; offshore wind in the North and Baltic Sea as well as new hard coal plants. Besides, the most onshore wind power capacity is installed in the Northern part. Therefore in the future there will be even a higher need for power transmission from the North to the South, requiring more reinforcements of North-South transmission connections. The figure below shows the current *transmission* network in Germany and already planned network extensions.

Unfortunately, the implementation of some of the planned network extensions is delayed (especially the extensions planned for 2010), which may lead to additional congestion in 2010 or close thereafter. Especially, it may hinder the achievement of the Federal Government's goal of a share of at least 20 percent of renewable energy in power generation in Germany between 2015 and 2020. Up to 2015, there will be a need for approximately 850 km of 380-kV-transmission routes in order to transport wind power to the load centres. This corresponds to a share of 5% of the currently existing extra voltage line tracks. Reinforcement of 390 km of existing power lines will also be needed. In addition, numerous 380-kV-installations will need to be fitted with new components for active power flow control and reactive power compensation (approximately 7350 Mvar till 2015). The total costs for the transmission system extension necessary up to the time horizon 2015 are approximately €1.1 billion (Dena, 2005). Additional network reinforcements for the period 2015-2020 and beyond are subject of a new study which has to be published in 2010.

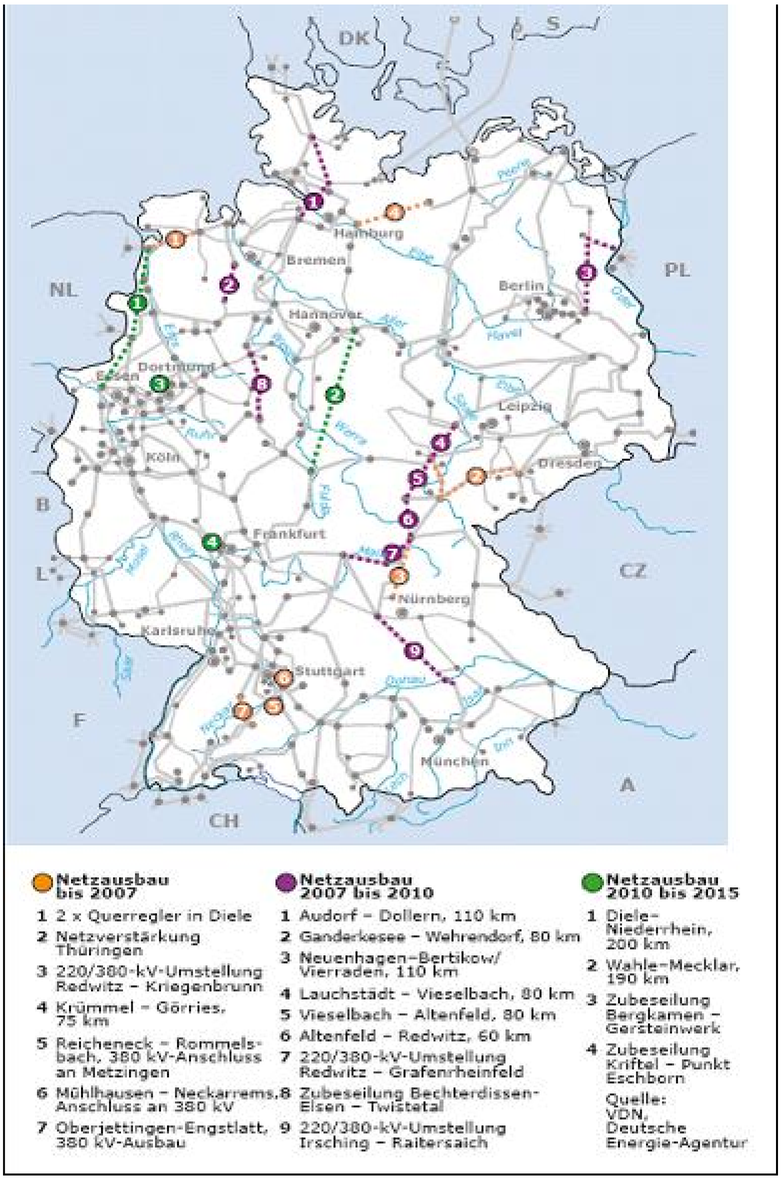

Figure 5.1 *Overview of German transmission network, including planned upgrades*

Impacts on balancing markets
It is expected that the need for regulation services will increase, mainly due to the increase of intermittent generation. Both the demand for secondary and tertiary regulation is expected to increase. Additional required positive secondary and tertiary reserve will increase from 1.7 GW in 2007 to 3.24 GW in 2015 on a day-ahead basis. Additional required negative secondary and tertiary reserve will increase from 2007 -1.4 GW to -2.88 GW on a day-ahead basis. The improvement of wind power forecasting cannot compensate for this tendency (Dena, 2005). Besides, there are some uncertainties concerning the consideration of other RES and improvements of forecast systems. Up to now, positive secondary reserve has increased from 200 MW to 400 MW from 2004-2006, while negative secondary reserve has decreased. Minute reserve quantity and utilisation has stayed stable (Bundesnetzagentur, 2007).

Impact on trade markets
Impacts on energy markets for longer time frames (intraday, day-ahead, forward markets) are already visible in current price variability compared to price variability of some years ago (Zvingilaite *et al.*, 2008). The increase of intermittent generation will result in a further increase of the spread between off-peak and peak prices up to 2020.

Conclusions on future network impacts
Impacts on the distribution and transmission networks in 2020 are quite substantial in terms of required additional network capacity due to the connection of concentrated new offshore wind farms and new onshore wind. The former increases the distance the electricity produced has to be transported, while the latter induces more fluctuating network flows on the distribution level and upward network flows from distribution to transmission network levels. More specifically, Germany faces the following network-related impacts of intermittent renewable generation (see Table 3.3):

- Network congestion in Germany seems to be substantial in 2015; according to EWIS (2009) up to 5000 MW of re-dispatch of conventional generation is required by that date since RES-E/DG has priority dispatch.
- Although Germany imports renewable power from Denmark, there is a net export of renewable power. Unplanned electricity flows (‘loop flows’) occur mainly on international interconnections with The Netherlands and Poland.
- Conventional ‘hardware’ solutions (new lines and cables) for more network controllability are impeded by social acceptance issues, sometimes necessitating burying of lines. Besides, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.

Consequently, in the future Germany seems to face a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit the cost impacts for both (distributed) generators and consumers to the efficient costs, a transition to a *more active type of network management of both distribution and transmission networks is deemed necessary* for Germany at the end-point of the road map.

Conclusions on future market impacts
Based on the projected developments in electricity production and the 2020 sustainability targets for Germany we conclude that the likely share of intermittent RES-E/DG in 2020 can be qualified as moderate. Impacts on the balancing market are assumed to be high. Concerning energy markets for longer time frames (intraday, day-ahead, forward markets); a higher price variability is expected. Although impacts of intermittent generation on the balancing market are high, Germany predominantly faces the impacts related to the ‘RES-E/DG in the market’ stage of market integration in 2020 (see Table 3.4):

- Moderate penetration level of RES-E/DG in relation to the RES-E potential
- Need for differentiated prices which reflect system conditions

– Decreased profitability for conventional base-load power plants at the margin. Possible lack of flexible generators at critical system times.

Consequently, *RES-E/DG in the market* is the assumed market integration stage at the end-point.

5.2 Regulatory road map

5.2.1 End point road map

Against the background of the expected development of intermittent generation, network and market developments as described in the former section, and the general scenario assumed for the 2020 European electricity system as described in Section 3.2, the regulatory road map for Germany will be developed.

The regulatory road map provides a *menu* of regulatory actions which are largely necessary to reach the desired future state of both market and network integration. The desired future states, i.e. the regulatory actions, are directly linked to the impacts described in the former section. The precise relationships are presented in the tables on the stages of market and network integration in Chapter 3. The desired future state in 2020, which was defined in the former section, is shown in Figure 5.2 below.

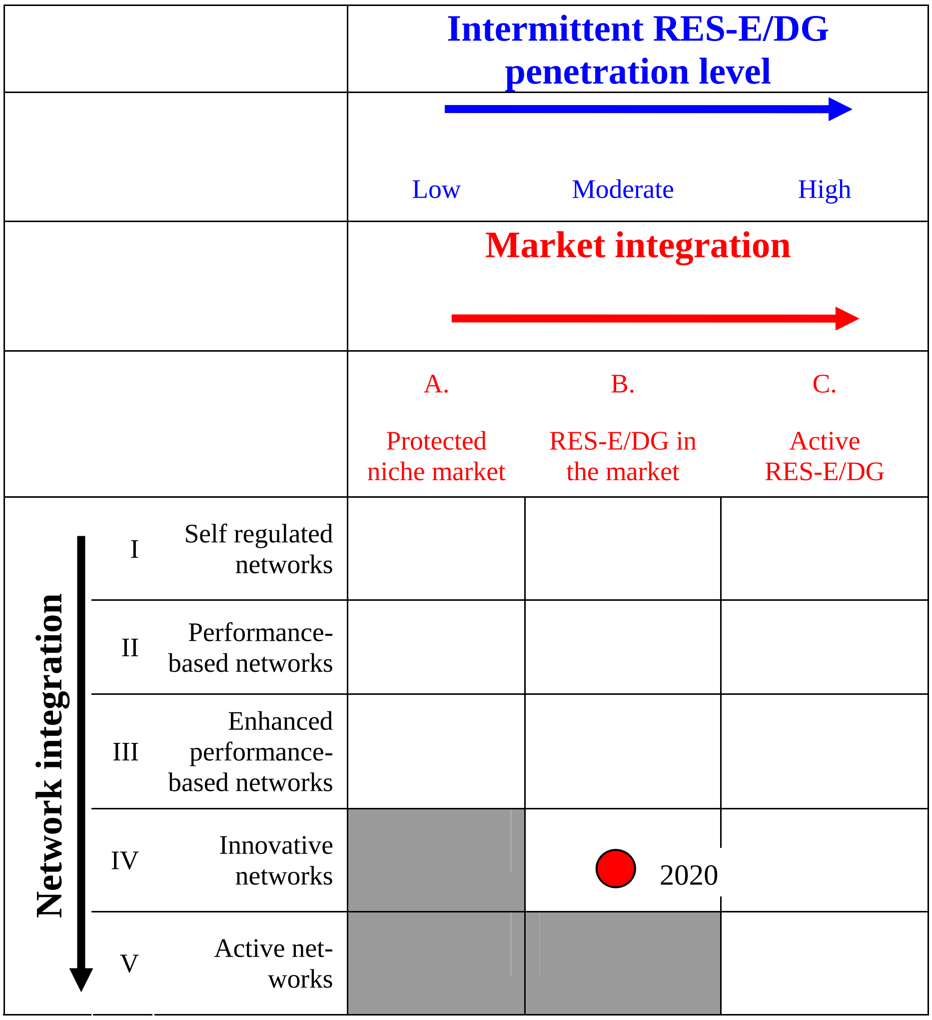

Figure 5.2 *Regulatory road map scheme Germany: end point*

The road map will describe the path that stakeholders should take in order to reach stage IV-B in 2020, which is required to integrate optimally and efficiently the expected share of renewables in markets and networks at that year. The next sections describe the path towards this end point.

5.2.2 Starting point road map

Whereas the starting point of the regulatory road map with respect to the amount of intermittent RES-E/DG currently integrated in the electricity supply system is known, we need to define the starting point from a regulatory perspective. In this section we describe the regulatory starting point for Germany. In this respect, we distinguish between the following segments:

1) Generation
2) Demand
3) Markets
4) Networks.

Below we explain briefly per system segment the current status of the regulatory framework, in order to define the starting point for the German regulatory road map.

Generation

Support schemes

The predominant support mechanism for renewable electricity generation (RES-E and CHP, the latter only for biomass) is the feed-in tariff laid down in the Renewable Energy Sources Act (EEG). The EEG guarantees RES operators fixed tariffs for electricity fed into the grid for a period of 20 years. The fee paid depends on defined tariff in the year the equipment was installed. The current EEG includes a digression rate for the FIT paid, i.e. an annual percentage reduction. The digression for the various technologies is adjusted in each case to the technical learning curve. The amended EEG (2004) sets out the digression rate for all technologies. The Feed-in tariff is a flat price differentiated by technology.

In the future, producers might be able to choose monthly between producing for the market or to remain under the fixed feed-in tariff. To this effect, an amendment on the Renewable Energy Sources Act (EEG) of June 2008 has entered into force on 1 January 2009, but it is still unsure whether concomitant secondary legislation will be implemented. Besides, according to some market parties, the envisaged choice for producers between producing for the market or to remain under the FIT seems to be balanced to remaining under the FIT support scheme.

Furthermore, currently there exists some locational signal which favours an evenly distribution of wind farms onshore and supports offshore wind farms for different water depths. Although this is less efficient from a production point of view, at the same time the geographical distribution of wind power plants is improved which seems efficient from a balancing and network point of view (if there is one balancing market and transmission network operator).

The last amendment of the Renewable Energy Sources Act (EEG) also contained the introduction of some bonuses which may be preferable to the system. Two kind of bonuses are considered; integration bonus and system services bonus.

The introduction of an *integration* bonus attempts to optimize network capacity utilisation (lesser peak feed-ins, lesser grid congestions) with generation management of controllable RES like biogas, shifting intermittent RES (wind, PV) by accumulators (storages and batteries), deployment of virtual power plants, and in the future possible demand side management by electric cars. Both the composition (three part design?) and introduction date of the integration bonus are right now under discussion; the bonus might be enacted in the next governmental term.

A legislation that is already enacted is the *system services* bonus for wind turbines. The system services bonus gives incentives for: (1) behaviour of plants in failure situations; (2) voltage control and reactive power; (3) frequency control; (4) verification procedure[26]; (5) behaviour in black start situations.

Conventional generation
A higher share of intermittent generation in the electricity system implies that the total supply of electricity will become more variable, unpredictable and uncontrollable. Therefore the demand for flexible generation with fast start-up times and high ramping up and down capabilities will increase with the penetration of intermittent RES-E/DG in the system. This demand will come both from wholesale markets and balancing markets. As the market may fall short to provide enough balancing power due to two kinds of market failures (imperfect information and public good character of reserve capacity[27]), additional policy incentives are necessary in order to encourage instalment of additional flexible conventional generators to produce energy during critical times on the balancing market. Nowadays, in Germany no additional policy incentives are given. This might cause a problem in the light of the high ambitions for renewable energy in 2020. Besides, the flexibility of the electricity system may be limited by the relatively high share of coal-fired power plants with limited ramping rates. On the other hand, CHP-engines with favourable ramping capabilities and loads already provide balancing power (minutes reserves) through virtual power plants like Evonik (Steag) in Saarland. Renewable generators are not included in the virtual power plant since the Renewable Energy Sources Act (EEG) does not allow renewable generators to receive fixed incentives and to participate in balancing markets at the same time (double commercialisation ban).

Finally, today much more conventional capacity (mainly hard coal-fired), is planned or is in the licensing procedure than could be run economically in wholesale markets. On the positive side, this new generation capacity may be beneficial for the flexibility of the electricity system since new power plants dispose of higher flexibility and may force decommissioning of old less flexible coal-fired power plants, which are already completely depreciated.

Storage
In 2020 it is expected that 4% of the power produced is provided by hydro. Pumped storage capacity will remain equal (in 2007: 2.5% of total power production). Cold and heat storage do not play a major role, yet. The buffer storages of existing CHP-units are still too small for a decoupling of heat and electricity generation. Electricity storage options mainly investigated are pumped hydro storage, batteries for mobility and fuel cells. Also the possibility of adiabatic compressed air storage is investigated.

Demand
Besides adding more flexible generation to the system as a response to more intermittent generation, alternatively higher variability can be managed by higher responsiveness of the demand side of the electricity system. Demand response can lower demand during specific time periods, shifting load to other time periods in three steps.

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26 Upon request of the system operator, generation units have to prove compliance with some network requirements.

27 For technical and economic reasons it is not possible to curtail all customers individually from using reserve capacity, even when they are not paying for the services delivered by that reserve capacity. This follows from the non-excludable nature of reserve capacity. We call a good non-excludable if it is either physically impossible or prohibitively expensive to prevent users from consuming it. Devices to curtail customers at a distance from consuming electricity are still quite costly to apply on households. Therefore, during extreme demand there is free-riding of electricity consumers on reserve capacity, consequently reserve capacity can be considered as a public good.

As a first step, consumer electricity prices can be differentiated in time. Large customers face hourly wholesale market prices directly (if they are contracting energy directly on the market) or indirectly through the supplier. Small consumers do experience limited time-differentiation since the standard tariff usually covers all price fluctuations of the wholesale market price. Sometimes the suppliers offer a special night tariff. Therefore, most consumers are shielded from the fluctuations in real-time prices and current price elasticity of demand seems to be limited.

As a related second step, smart metering can be implemented to bill consumers according to their actual use instead of their assumed consumption profile. For small customers no large-scale roll-out of smart metering is envisaged as the metering market is liberalised. Customers are free to choose a smart meter. Nowadays, consumers face a lack of opportunities to react on variable electricity prices, even when they face differentiated prices, since there are only a few opportunities where load can be shifted.

Alternatively, in case of large short-term unevenness between supply and demand interruptible contracts can be used. These interruptible contracts specify the conditions for interruption of consumers and the compensation payment they will receive in return. Industrial consumers (steel producers etc.) have sometimes special interruptible contracts with power traders or TSOs (provision of positive minute reserves). In some cases, the provision of positive minute reserves by industrial consumers is directly controlled by TSOs.

Markets

Efficient electricity markets for different time frames (forward, day-ahead, intraday and balancing) support the mitigation of the effects of more variability and unpredictability of renewable electricity sources on the electricity system. Different market places for year-ahead up to real-time are necessary for generators and loads to diminish their business risks. An efficient market also allows for efficient cost allocation by remunerating or fining market participants for their actual contribution to the system over time, as shown in generation and demand patterns.

Wholesale markets

In Germany future, day-ahead and intraday markets exist for energy trading. On the day-ahead market of the EEX, hourly contracts for every hour of the following day are tradable. Apart from contracts for single hours contracts for contiguous blocks of hours can be obtained. Bids can be placed until noon for next day’s operation. The intraday market allows both anonymous trading and registration of option trading up to 75 minutes ahead of delivery on the same and the next day. Contrary to the day-ahead market, in the intraday market only whole hours, equivalent to the hours of the day, are tradable. The trade is possible until 3 p.m. of the current day. Until then all hours of the following day can be traded (EEX, 2007a and EEX, 2007b). The day-ahead market is regarded as liquid, while the liquidity of the intraday market is still limited.

Balancing markets

The four German transmission system operators (TSOs) are required to maintain a permanent balance between power generation and demand in their control area, through keeping the system frequency within narrow borders (primary control) and provide balancing energy to the balancing groups (electricity producers and consumers) from the secondary control power and minutes reserve (tertiary control) kept available. Minutes reserve can be contracted until 19:00 on day-ahead basis (VDN, 2005). Beyond the traditional balancing markets (primary, secondary, tertiary) there is a market for wind reserve. Wind reserve is used by each TSO to balance the RES forecast within the EEG-balance-circle (activated within 45 minutes for at least 1 hour).

Balancing power is tendered centrally for all four balancing zones in Germany. In these balancing zones there is no locational differentiation. If a balancing zone is short on balancing power and another one is long there will be an exchange. However, until a few years ago this has not been the case and costs were higher than they could have been.

Participation in the balancing market is voluntary. Required balancing power in 2007 amounted to 600 MW primary reserves, 3,000 MW (2,400 MW) upward (downward) secondary reserves, and 3,300 MW (2,000 MW) upward (downward) tertiary reserves. The costs for procurement of balancing power have increased to €360 million in 2006 (Bundesnetzagentur, 2007).[28] The largest part of the balancing cost is capacity payments, payments for produced power are less important. Liquidity in the balancing market is a problem. Therefore, prices might be higher than anticipated. The prequalification criteria are very complex, only a small amount of providers can qualify for these services. Among others, secondary and tertiary control power has to be partly within the same control area and partly beyond the control area.

The balancing responsible parties are the interfaces of the grid operators and the network users. They have the economic responsibility for the balancing areas. The network users (electricity producers and consumers) in this balancing area are the balancing group. The balance responsible parties showing a surplus get paid the price for and the balance responsible parties showing a deficit have to pay for balancing group deviations. Conventional generators are held responsible for the balancing costs of their own deviations of the scheduled production. Instead, balancing caused by deviations of RES production from their prediction has to be paid by the TSO and not by the owner of the installation. The costs for procurement of balancing services for RES generators are included in the grid tariffs paid by end-users. Since RES-plants do not have to predict or schedule their production, the TSO is also obliged to make production forecasts for RES generators.

From a system point of view, this lack of incentive for RES generators to limit their imbalance for the operation of the system as a whole is not efficient and induces higher fluctuations of supply and therefore higher system costs than necessary. Furthermore, the fact that RES-plants have no obligation to predict or schedule their production diminishes the incentive to develop better production forecasts or to improve the controllability of their plants as far as possible in order to limit their imbalance cost exposure. Besides, it causes unnecessarily higher uncertainty for network operators and consequently makes network operation more difficult.

Networks

Network operators on both distribution and transmission levels face increasing penetrations of intermittent DG/RES connected to their grids. Currently, power is mainly transferred from the transmission level downwards in the supply chain to the end consumer ('top-down'). However, increasing penetration of renewable sources imply that power from intermittent generation will sometimes exceed local load and needs to be exported to other regions. As a result, upward flows may occur as well and power flows alternate between top-down and bottom-up, in other words are bidirectional.

Accommodation of higher fluctuations of supply can be realised if physical available network capacity is not only extended, but even more important when existing capacity is exploited to a higher extent for integrating more RES-E/DG in the grids. Network charging, network planning and congestion management are important instruments for both transmission and distribution networks to achieve this objective.

Transmission networks are defined as networks with voltage levels of 220 kV and above, distribution networks contain all voltage levels below 220 kV. In Germany there are 4 TSOs and

[28] In 2007, 6865 MW of positive and 4930 MW of negative balancing power was required (primary, secondary and tertiary power). Total gross power capacity in 2007: 124 GW. As a maximum, 5.5% of system load has to be balanced.

about 855 DSOs (by June 2008). Transmission system operators are owned by private companies, while distribution system operators are often owned by public authorities. All TSOs are legally unbundled. Of the 855 DSOs, of the DSOs with 100,000 customers or more the majority is legal unbundled from production and supply activities or currently is in the implementation phase (ERGEG/Bundesnetzagentur, 2008). Clear separation of network activities from commercial production and supply activities is important for guaranteeing network access to independent generators and suppliers as well as for ensuring sufficient network investments.

Network charging

Transmission networks

Transmission network costs for network operation and planning (including new investments) have to be paid by network users. Network costs are generally subdivided in costs of connecting market parties (generators and consumers) to the grid and costs for operation of the electricity system. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by use-of-system (UoS) charges.

Connection charges can be shallow (costs account for the connection to the next connection point only) or deep (if they include investment costs behind the connection point). In Germany, both generators and consumers have to pay connection charges. All generators connected to the transmission networks, including RES generators, pay a one-off shallow connection charge for the new connection between their facility and the network (source: questionnaire and ETSO, 2007). Use-of-system charges are only in place for consumers, not for generators. All other network costs, including costs for reinforcement of networks are incorporated into the network tariffs for loads by the TSOs. Consequently, investment decisions by RES generators are not at all influenced by network costs. Finally, like in many other countries, transmission charges do not exhibit temporal differentiation.

As a conclusion, transmission network costs are largely passed on to consumers. TSOs are generally compensated for all network costs. RES-generators, like other generators, do not pay UoS charges, and therefore do not face investment incentives to behave in accordance with network needs.

Distribution networks

In Germany, DSOs levy shallow connection charges on network users. Since connection charges are shallow, these charges form only a small portion of total investment costs and the effect of these charges on generation investments is limited.

DG operators do not have to pay UoS charges, UoS charges are fully levied on load customers. In contrast, DG operators are remunerated for avoided DSO Use of System charges at higher network levels. Connection charges as well as use-of-system charges do not contain any temporal differentiation.

Like transmission network costs, also the distribution network costs are largely financed by consumers. Consequently, incentives for generators to behave in accordance with the network costs they cause are very limited. This impedes efficient integration of renewable source in the distribution network i.e. network costs are higher than necessary due to inefficient cost allocation.

Network planning

<u>Transmission networks</u>
Concerning network planning and operation, there are some practical experiences in showing inefficient behaviour and system operational problems due to RES production which may be caused by the non-optimal design of the support mechanism and lacking incentives for network extension. At the end of 2007 the following congestion was found to exist in the domestic German distribution system (number in brackets): Substation level extra high/high voltage (1), medium voltage (1) and low voltage (5) (ERGEG/Bundesnetzagentur 2008). From an official point of view, there are no congestions in the transmission grid. Other congestions have been resolved by congestion management in the form of countertrading; TSOs manage congestion by individual contracts with power plant operators, costs are socialized in the grid tariffs. There seems to be a discussion about the current (informal) congestion management scheme and possible more efficient alternatives. The Bundesnetzagentur stated that in case of congestion, the law requires the implementation of a market based and non-discriminatory congestion management mechanism.

<u>Distribution networks</u>
Some network congestions on the distribution network levels have already been mentioned in the transmission networks part above. In current distribution network planning still a 'fit-and-forget' network philosophy is applied, which means that the network is dimensioned on all possible different network flow situations. All potential congestions are resolved through network reinforcements. Increasing intermittent generation will make this traditional network planning philosophy very expensive. Regulatory incentives for active network management are limited. However, there are some incentives for innovation like the integration bonus within the context of EEG and the explicit acknowledgement of DG in incentive regulation. Furthermore, a quality factor will be introduced in incentive regulation as from 2010. Besides, the system services incentive may improve quality of supply. Reduction of energy losses is only indirectly incentivised (as part of the revenue cap).

The incentive regulation scheme includes incentives for DSOs to carry out efficient investments. Investments are assessed beforehand on their efficiency by the Bundesnetzagentur. Active network management seems not explicitly acknowledged within the current investment assessment scheme.

Congestion management
In the winter of 2006/2007 Net transfer capacity interconnections with the following countries amounted to:

– Austria	1600 MW
– Czech Republic	700 MW
– Denmark (East)	550 MW
– Denmark (West)	800 MW
– France	3300 MW
– Netherlands	3800 MW
– Poland	1200 MW
– Sweden	600 MW
– Switzerland	2400 MW

Source: ETSO - NTC Matrix and BTC map
Online: [http://www.etso-net.org/file/pdf/NTC_Matrix_W0607_Version20061211.pdf]

The average import capacity in 2007 was 17 GW; the installed generating capacity according to the German Association of Energy and Water Industry (BDEW) amounted to 129.2 GW. While the import capacity remained unchanged, the generating capacity continued to increase. This means that the degree of interconnection in Germany decreased to around 13 percent in 2007. Export figures amounted to 56 TWh in 2007, while import totalled 39 TWh. Total production in TWh in 2007 amounted to 513.5 TWh (excluding own consumption and losses) (ERGEG/Bundesnetzagentur, 2008).

New interconnections are planned with Denmark, Belgium and The Netherlands. In cases that demand for interconnection capacity is higher than available capacity congestion will occur and consequently existing capacity needs to be allocated and traded for different time frames. Germany is considered as a central country in maximizing utilisation of interconnection capacity with neighbouring countries through the implementation of explicit auctions for the long term and implicit auctions for shorter time frames (day-ahead and intraday).

Before the end of this year, Germany will be coupled on a day-ahead basis with the Nordpool market. For next year, day-ahead market coupling with Benelux and France in the so-called "Pentalateral market" of the CWE region is envisaged. This maximisation of the usage of existing network capacity is valuable for the electricity system, since it offers intermittent generators additional possibilities to sell their excess supply and offers possibilities to import cheap power when wind speeds in Germany are very low. Security of supply is also deemed to increase with the extension of interconnections.

For the allocation of interconnection capacity in the intraday time frame, trading possibilities have been put in place as well with the Czech Republic, Denmark, France, and The Netherlands (ERGEG, 2008b and additional information).

Besides congestion on interconnections, also congestion on national connections is prevalent. Congestion is exacerbated by the RES priority access regime in place which gives RES-E/DG generators legal priority in the transport of their electricity, regardless of system and local demand for electricity. Although this policy may be preferable for maximum utilisation of RES-E/DG resources, from a system point of view this policy is clearly inefficient for three reasons.

First of all, priority access may impede cost-efficient relieving of severe congestion by RES-E/DG generators when other flexible local conventional generation has already been utilised, particularly since TSOs are forced to deploy more expensive options to manage congestion. From a social welfare point of view, it is questionable whether the benefit of priority access i.e. higher RES-E production including its positive externalities, compensates for the increase of congestion management costs.

Secondly, since priority access prevents deployment of RES-E/DG for congestion management, revenues of diversification and increase of profits for RES-E/DG are impeded as well, limiting the market integration of RES-E/DG.

Apart from that, since wind comes first in the merit order of generation units, wind has the lowest marginal costs and in a market-based congestion management scheme therefore will be only curtailed after conventional generators with higher marginal costs have already been curtailed. Wind generators will only offer to curtail their production if the revenues for relieving of congestion are higher than the opportunity costs i.e. the RES production subsidy. As a result, wind generators are a more expensive option for market-based congestion management by TSOs than other generation and load options. Consequently, wind generators will probably only be deployed for congestion management during extreme system conditions.

Conclusions

Based on the description of the current situation on different issues relevant for the integration of RES-E/DG in markets and networks, the current stages of market and network integration can be established.

Market integration

The RES-E/DG production as fraction of total electricity production is already moderate in Germany and high in absolute terms. Clear effects of intermittent production on day-ahead market price variability have been identified. Therefore one could conclude that the current stage of market integration is stage B (RES-E/DG in the market).

However, when looking at the current market design and the actual opportunities of RES-E/DG this corresponds more with a less advanced stage of market integration (stage A) since:

- The predominant support scheme is the feed-in tariff scheme. Producers may choose for producing for the market, but most producers are under the feed-in tariff scheme since this is more profitable.
- The current balancing market design is characterized by a central balancing mechanism without balancing responsibility for RES/DG. Furthermore, RES/DG has priority access to the grid and is not considered as an option for congestion management.
- Gate closure time of the balancing market is long, since the gate closure time is fixed (i.e. not rolling on hourly basis like in several other European countries).
- At the positive side: CHP already takes part in the provision of balancing services through virtual power plants, system service bonus is in place.

Combining our observations on the current level of network and market integration for the case of Germany we state that the starting point is *protected niche market* / *RES-E/DG in the market*.

Network integration

The German transmission networks will be deployed with steering and control possibilities like HVDC cables and phase shifters. However, distribution networks are still managed by the 'fit-and-forget' philosophy, implying monitoring and control possibilities of network (actors) are highly limited. Concerning network regulation, (distributed) generators do not have to pay Use of System charges; therefore network incentives to generators to behave in line with system demand are negligible. Recently incentive regulation became in force; within this framework quality of service regulation will be implemented next year. DG is considered as a cost driver within network regulation and a system services bonus is provided to wind turbines, which may force them to innovate. Therefore, Germany is currently on the *intersection of performance based networks and enhanced performance-based networks.* Probably without additional measures in the near future enhanced performance-based networks will be in place. The figure below combines the identified current market and network integration phases to fix the starting point in the road map framework.

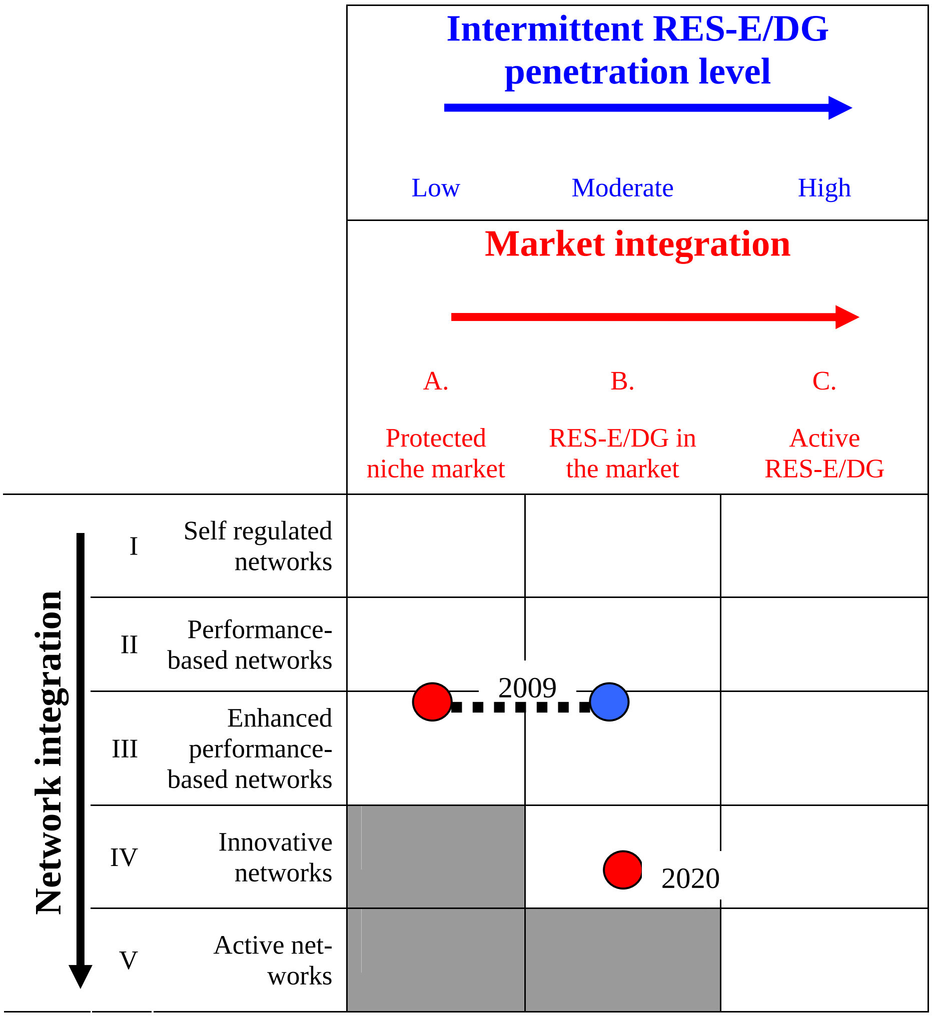

Figure 5.3 *Regulatory road map scheme Germany: starting and end point*

5.2.3 Steps in regulatory road map

5.2.3.1 First step

In order to reach the end-point of the road map in 2020, starting from the current situation (see Figure 5.3) an optimal route concerning market and network regulatory actions towards the end-point has to be determined. Since the route crosses market and network integration phases, and every market and network integration phase requires a different set of measures, an intermediate regulatory step has to be defined accordingly. This step is useful in the timing of regulatory actions i.e. which actions may be directly implemented and which actions may be implemented a few years before 2020, for two reasons. First of all, it prevents that cost-efficient and optimal measures of intermediate integration phases are ignored. Secondly, the step restricts the size of the package of required measures, offering stakeholders the opportunity for conscious choices concerning the implementation of measures.

The step is both a vertical and horizontal shift to more advanced stages of network and market integration respectively (RES-E/DG in the market and enhanced performance-based networks). The recommended actions are largely given in the guidelines connected to the network and market integration phase at hand, see Table 3.3 and Table 3.4 respectively. In addition some country-specific recommendations are provided, which are tailored to the system conditions of Germany.

For *RES-E/DG in the market* the following recommendations are made:
– Increase *generation flexibility*
– Implement market-based *support scheme*
– Increase *demand response*
– Implement measures to *increase balancing market efficiency*
– Enable *provision of ancillary services by DG*

For *Enhanced performance based networks* the following regulatory recommendations are made:
– Implement shallow and regulated *connection charges* plus GUoS charges
– Integrate RES-E/DG in *network planning*
– Implement market-based *congestion management methods*

Below the additional recommended measures per system segment are discussed extensively.

RES-E/DG in the market

Generation flexibility
One-stop shop approaches for investors planning new wind generation are already quite common in several countries. In order to promote the extension of flexible generation capacity in the same place, it is advised to introduce also an *one-stop shop approach for investors planning new flexible generation* like gas-fired power plants and hydro power. This is deemed useful to decrease the average time required for the construction of new lines (10 years).

Support schemes
Since secondary legislation has not yet been agreed upon, a market-based subsidy scheme like a *feed-in market premium (FIP) scheme* has not been implemented besides the existing feed-in tariff (FIT) scheme. However, since the feed-in market premium scheme ('self-marketing') stimulates RES-E/DG to take into account the state of the system as reflected in the market price and therefore increases market integration of RES-E/DG, the FIP scheme is advised to be implemented. Combined with the possibility of *negative market prices* (which already has been introduced at power exchange EEX) the feed-in market premium scheme stimulates RES-E/DG operators to control their production and to act in accordance with market prices which reflect system conditions. Therefore the FIP scheme deserves preference to the FIT scheme.

During extreme system conditions if system demand is very low, but supply is considerable, marginal revenues may not longer be sufficient to produce. For instance, for wind during these circumstances the total of market premium plus market price may become negative, below marginal costs. As a result, producing electricity is not longer profitable for wind turbines, and wind will shut down and actively contribute to keep the electricity system in balance. However, since wind comes first in the merit order as all other producers have higher marginal costs, the latter receive earlier market incentives to shut down their production (besides the market premium shields wind generators for curtailment). As a consequence, wind generation will be only incentivised to shut down if no other possibilities are available.

Therefore, in the short term RES-E/DG should be enabled to choose for the FIP scheme and the revenues balance between choosing for FIP or FIT is advised to be tilted to FIP.

Demand response
Concerning meters, it is advised to introduce *minimum functional requirements to smart meters* in order to ensure a certain standard of data quality and meter functionality within whole Germany. The regulator is already involved in establishing standards for business processes be-

tween supplier, DSO and customers. Also *common communication standards* have not yet been defined and need to be developed to guarantee interoperability. Besides it is important to *require more frequent meter readings or bills based on actual consumption*. This approach puts an obligation on the meter responsible to ensure frequent (daily, monthly) data retrieval and access. As frequent meter readings cannot be carried out manually in an economic way, it indirectly forces the meter responsible to install at least AMR (automated meter reading) systems (ERGEG, 2007).

Concerning prices, small consumers should be prepared by suppliers for future demand response possibilities with accompanying variable pricing as a result of the introduction of smart meters. Therefore, suppliers should *implement simple time-differentiated (peak, off-peak and shoulder) prices* on a wider scale to prepare consumers for variable pricing. This problem has been acknowledged in Germany; as from 2010 suppliers have the obligation to introduce time and load variable prices with limited differentiation for all customers, except if this is not technical and economic feasible for the supplier.

Furthermore, the *functioning of smart home area networks (HAN)* to control load automatically in response to price signals *has to be demonstrated* at larger scale with pilot projects. These systems will be connected to smart meters in order to lower the transaction costs of consumers in reacting to variable prices.

Balancing market efficiency
In the balancing market important changes are required to increase its efficiency and lower the costs of increasing RES-E and CHP.

An important step is changing the balancing market design. Currently, only conventional generators are balancing responsible, while costs for balancing of RES-E/DG are socialized in grid tariffs. It is recommended to *introduce a Scandinavian type of balancing market with balancing responsibility for all connected parties* (including RES-E/DG). This balancing market design is increasingly favoured within Europe (DG-TREN, 2009) and allows for the integration of RES-E/DG production against lower system costs. Balancing responsibility gives connected parties an incentive to limit their imbalance as far as possible and therefore lowers balancing costs for the system as a whole considerably.[29]

The *introduction of cross-border balancing* should be considered as it is part of the CWE and Northern regional regulatory market initiatives in which Germany participates.

Provision of ancillary services by DG
The *system services bonus* already provides incentives to wind turbines for: (1) behaviour of plants in failure situations; (2) voltage control and reactive power; (3) frequency control; (4) verification procedure; (5) behaviour in black start situations. It is advised to fine-tune these incentives with regard to the market prices that conventional generators obtain for the provision of these services. Consequently, a market-based level playing field for the provision of system-wide ancillary services by both conventional and renewable generators can be established in the future.

Enhanced performance based networks

Network charging

[29] At the same time RES-E/DG, especially wind, is usually compensated for additional efficient balancing costs through the support scheme. This compensation limits the comparative disadvantages for wind due to its production technology compared to conventional production technologies.

Costs of network reinforcements which are not covered by connection charges need to be covered by *use-of-system charges* levied on both generators and consumers. This will guarantee a more efficient allocation of costs between generators and consumers. Currently, although generators do have clear benefits from network reinforcements in transporting their produced energy, they are not obliged to pay part of the network reinforcement costs. In order to avoid opposition of inland generators which face competition from generators originating from other countries, the introduction of use-of-system charges in Germany should be accompanied by introduction of comparable use-of-system charges in neighbouring countries. Therefore, coordination of this topic within the Northern, Central-West, Central East, and Central-South region is required.[30]

Network planning
In order to overcome social objections at a local or regional level against important network reinforcements, a *national coordination procedure* may be put in place to reduce the construction time of new lines or cables.

It is suggested to *evaluate network current security standards* with respect to their position to economic optimal security standards. Up to now security standards are quite stringent (n-1 and additional requirements) and probably at higher level than necessary from an economic point of view; the marginal costs of security standards are in general perceived to be higher than marginal costs of disturbances (see among others Ajodhia, 2006). For implementation of more optimal network security standards surveys need to be done and support from the system operators need to be guaranteed.

For distribution network planning it is important that additional costs and benefits of RES-E/DG are already taken into account in the determination of the allowed costs of each DSO. Since DG has became an important factor determining network costs, DG has been included as cost factor in the productivity benchmark analysis in order to account for differences in RES-E/DG production between different distribution networks

Furthermore, sector-specific incentives for investments by DSOs in new distribution network management approaches are limited, potentially limiting RES-E/DG integration in the near future. In order to change the focus of DSOs more to the long term, *explicit sector-specific positive incentives for innovation like IFI or RPZ schemes in the UK need to be implemented*. An Innovation Funding Incentive (IFI) type of scheme permits DSOs to spend up to 0.5% of its allowed revenues on eligible IFI projects related to any distribution system asset management aspect. DSOs can be given an special allowance in the RAB to stimulate network innovation (Jansen *et al.*, 2007). Demonstration projects like Regulatory Power Zones (RPZ) stimulate DSOs to connect new DG to their systems by using innovative and more cost efficient ways. Preferably, both public and private institutions should participate in such demonstration projects in order to attain sector-wide demonstrations and knowledge exchange. Both measures will reduce risks for network operators to integrate RES-E/DG in an innovative way.

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[30] All project participants except for dena accepted this recommendation to allocate network costs by network charges to consumers as well as generators, which both cause these costs (in line with the 'cost causality principle'). So *no* locational differentiation of network charges is proposed. Although *locational differentiated* network charges for generators thus are not advised in the German roadmap (with the envisaged intermittent RES-E penetration for 2020 this is not required), dena has a different opinion for two reasons. Firstly, according to dena market parties seem to have insufficient possibilities to react to monetary signals due to the lack of adequate locations where permits are possible outside Northern-Germany. Secondly, the volatility of G-charges might create additional uncertainty for investors in (renewable) generation.

Congestion management
Congestion is expected to occur more often due to (renewable) generation growing faster than transmission capacity. For relieving the congestion at lower total system costs, *RES-E and DG should no longer have priority dispatch* (see former section), but allowed to be curtailed against a payment. As a result, possibilities for congestion management are increased which will lower the system costs.

The introduction of market-based congestion management methods on international connections will help to increase the use of interconnection capacity implying higher revenues of RES-E/DG during times of high wind power supply. For the year-ahead and month-ahead time frames, explicit auctions already have been implemented on all borders. For the day-ahead time frame, implicit auctions (market coupling) will be introduced in this period with Denmark and in 2010 within the CWE region with France, Belgium and The Netherlands. On the remaining borders (except on the border with Austria), explicit auctions will be introduced. Furthermore, existing non market-based intra-day auctions will be upgraded to market-based implicit auctions.

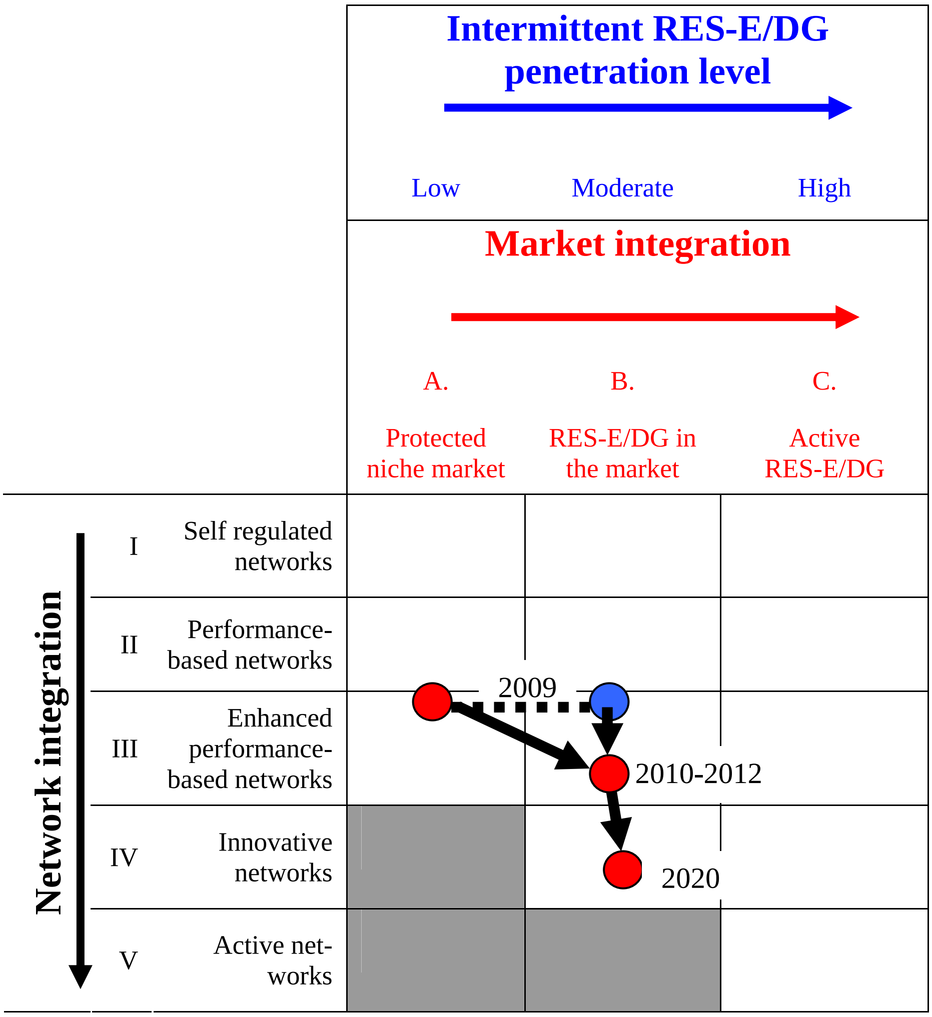

Figure 5.4 *Regulatory road map scheme Germany: complete route 2009-2020*

5.2.3.2 Last step towards the end-point

Based on the expected market and network impacts in 2020, Section 5.1 has already identified the required market and network integration phases for the end point (RES-E/DG in the market and innovative networks). Together with the description of the starting point as well as the intermediate step between starting point and intermediate point, the whole road map can be described (see Figure 5.4).

The last step consists of a vertical shift to the next stage of network integration as well as further reinforcement of market integration within the current market integration phase. With help of Table 3.3 and Table 3.4, recommendations are again coupled with the regulatory market and network phases selected as end points. Besides, some country-specific measures are provided, which are again tailored to the specific system conditions of Germany.

For *RES-E/DG in the market* the following recommendations are made:
- Increase *generation flexibility*
- Implement market-based *support scheme*
- Increase *demand response*
- Implement measures to *increase balancing market efficiency*
- Enable *provision of ancillary services by DG*

For *innovative networks* the following regulatory recommendations are made:
- Implement shallow and regulated *connection charges*, basic time and/or location differentiated *GUoS charges*
- Integrate RES-E/DG in *network planning*
- Implement market-based *congestion management methods*

The recommendations are discussed extensively below per system segment.

RES-E/DG in the market

Generation flexibility
Generation markets are generally characterized by two kinds of market failures i.e. free-riding on reserve capacity and imperfect information during peak demand. Currently in Germany no additional non-market based incentives are in place to guarantee sufficient investments in new flexible power plants. Besides, the flexibility of the electricity system may be limited by the relatively high share of coal-fired and nuclear power plants with limited ramping rates. In the long term the problem may be limited to some extent, since both nuclear and coal-fired power plants will be put out of operation and additional gas-fired power plants are planned.

However, in the medium term the substantial increase in demand for balancing power, the market failures and generation market structure together may require *implementation of additional incentives for the provision of balancing power during extreme system conditions*.
CHP generators without storage facilities probably will *add heat storages* to their plants in order to obtain the possibility to decouple heat and electricity production for achieving more generation flexibility.

Support schemes
It is recommended to *make the feed-in market premium system obligatory* for all subsidized production technologies. If all generators including RES-E/DG receive price incentives, they will adapt their behaviour to these prices, increasing overall system efficiency.[31] Marginal changes to the premium level are justified to account for the decrease of RES-E/DG production technology costs and changes in market prices. Furthermore, the market premium level may be decreased in order to stimulate RES-E/DG to consider provision of services to ancillary services

[31] All project participants except for dena accepted this general recommendation to implement a feed-in market premium. Dena recommends another type of incentive to prevent excess RES production during low demand conditions, e.g. an incentive for storages.

markets instead of producing for energy markets only. This market incentive may make the system services bonus superfluous.

Demand response
The requirement for more frequent meter readings or bills based on actual consumption (see former section) is assumed to have led to instalment of smart meters in the premises of the majority of customers in 2020. As a next step, it is important to *stimulate usage of additional functionalities of smart meters* such as transferring price signals to the customer.

Since the majority of customers face hourly metering, concerning prices the default rate should be *hourly market prices* and customers should not be allowed to choose a fixed rate. A fixed rate implies a cross-subsidy to customers with a large consumption in expensive hours. Fixed price components, especially for households, should be reduced or changed to a %-type of component. However, in doing this it should be considered that annual revenues (and bills) become more volatile than with fixed components. Furthermore, *automated smart home area networks (HANs)* need to be introduced to offer opportunities for consumers to react to variable market prices and network charges at low transaction costs. Finally, *pilot projects* have to be conducted for testing the communication infrastructure required *for smart metering with an even higher frequency* (every PTU i.e. 30 minutes) for enabling a wider range of applications of meters (e.g. steering network flows).

Balancing market efficiency
For increasing the participation of RES-E/DG in balancing markets, the *gate closure time of the balancing market* should not longer be at fixed windows, but rolling at least every hour during the operation day. Consequently, costs of provision of balancing services diminish considerably for RES-E/DG, since their production forecast error decreases shorter to real-time. Besides, balancing market access can be improved if prequalification criteria for the provision of balancing power are lowered; currently, secondary and tertiary control power has to be partly within the same control area and partly beyond the control area which is detrimental to RES-E/DG involvement in the balancing market. *Interruptible contracts* are not longer limited to large loads only, but increasingly used by the TSO to contract medium size loads (through virtual power plants). This seems likely since the technology for TSOs to sign interruptability contracts with small customers is already tested within E-energy programme. Finally, a refined system for *cross-border balancing* has to be put in place to resolve large system disturbances due to wind generation.

Provision of ancillary services by DG
More possibilities for provision of other ancillary services by RES-E/DG like (downward) secondary and tertiary reserves may be valuable for RES-DG producers in diversifying their revenue streams. For this aim too restrictive technical requirements for the provision of these services need to be removed. These requirements may include minimum size limits to either aggregators of a portfolio of small distributed generation assets as well as limits to the size of the underlying individual installations or connections. In this respect *minimum size requirement for participation* in ancillary services markets of 15 MW *should be diminished* to 5 MW to enable RES-E/DG to participate in the provision of these services.

Besides, *the design of ancillary services markets* may be changed to allow for a better trade-off for RES-E/DG between either the provision of energy or the provision of one of the different ancillary services. In this respect, ancillary services markets or auctions are often more efficient than self procurement by TSOs, compulsory provision of services by RES-E/DG or bilateral contracts (the latter are less transparent). Currently, a number of services are already contracted through auctions.

Innovative networks

Network charging

Since the network cost impacts of RES-E/DG differ highly to time and location due to the high penetration of wind power in 2020, *time differentiated GUoS charges* should be implemented as a first step. In this way, (RES-E/DG) generators receive an incentive to behave more in accordance with network needs when deploying their units.

In regions with a large share of wind power and transmission network constraints to neighbouring regions congestion management should be applied. One of the possibilities for congestion management is implicit auctioning of the scarce network capacity and accompanying electricity. Consequently, two different price areas evolve in hours with congestion; while in hours without congestion prices in both areas will be equal (see section about congestion management below).

Network planning

New transmission lines both national and international will enable a higher transport of electricity originating from renewable sources. The new national transmission lines envisaged in the Dena Grid studies are assumed to be in operation. Concerning cross-border interconnections, planned additional interconnections with Denmark, Poland and The Netherlands are expected to be in operation. For some additional required transmission lines, it might be necessary to bury them in order to gain social acceptance for their construction.

Following the surveys towards more optimal security standards from a socio-economic point of view, it is recommended to *introduce dynamic reserve requirements* dependent on the actual wind forecasts with its embedded variance in network planning standards. Consequently, reserve requirements and concomitant system costs could be reduced for most of the time without compromising security of supply (Zvingilaite *et al.*, 2008).

To increase network planning efficiency more close collaboration between the four TSOs is envisaged. Besides, *advanced network simulations tools* are required to provide insight in the most efficient way of network reinforcement, either by conventional investment in new cables and lines or by adding intelligent network monitoring and controlling devices to the grids. These simulation tools will make it easier to measure and monetise benefits and costs of active network management (ANM) and the potential contribution of RES-E/DG to ANM. Both TSOs and regulator can use such a tool for better coordination and optimization of network planning. Among others, it enables a better review of network investments by Bundesnetzagentur or experts on its behalf when investors apply for remuneration (Jansen *et al.*, 2007).

Demonstration projects about active network management should be introduced to increase the experience of DSOs with new network management approaches, and lower risks for investments in ANM.

Congestion management

Because of the assumed high congestion, already occurring in 2015 (5,000 MW at some times), application of a *market-based congestion management method* like implicit auctions is recommended. Currently, all congestion is resolved by countertrading which is characterized by a lower efficiency due to the socialization of congestion management costs to all market participants. However, implementation of a market-based congestion management method will resolve network congestion in a more efficient way. Such a method allocates the costs to individual market participants like generators which caused the network congestion and therefore fulfils the cost causality principle. Consequently, congestion is resolved against lower system costs.

Congestion on cross-border connections is assumed to be fully dealt with by implicit auctions for allocation of network capacity in the intraday and day-ahead time frames on borders with Denmark, France and the Netherlands. *Auctions are coordinated at least regionally*, in order to make available as much network capacity to the market as possible while guaranteeing system security.

Network capacity on interconnections is calculated with help of *common transmission models for capacity calculation*, both nationally and regionally. As a result, loop flows on interconnections are reduced and available interconnection capacity for trading purposes and abundant production from intermittent generation will increase.

5.3 Action plan for implementation

The implementation of identified recommendations should be supported by an effective set of actions by identified system actors or stakeholders. All these actions can also be seen as recommendations from the regulatory road map for Germany, and are summarized in Table 5.3 below. The Table also indicates the market parties or organisations that are first responsible for preparing and approving these recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020.

Based on the road map description above we select the most urgent and critical actions to improve the system flexibility **in the short term**. The road map indicates that the main actions are required for improving both network and market integration. Although network integration remains the main issue, during our analysis it became prevalent that the improvement of market flexibility may deliver the largest quick wins for the German electricity system in the short term, limiting required network integration actions. More market flexibility may limit the demand for network flexibility dramatically by stimulating generators to take into account the effects of their behaviour on the electricity system. First of all, when a *feed-in market premium scheme* is implemented instead of feed-in tariffs, RES-E/DG receives incentives to take into account the system demand for electricity in its production decisions. Secondly, difficult network situations can be dealt with more effective and efficiently when RES-E/DG disposes *no longer* of *priority access*, but is allowed to be curtailed against a cost-reflective payment. Finally, demand for system balancing can be decreased substantially if RES-E/DG becomes *balancing responsible* and a *rolling gate closure time* for the balancing market is introduced in Germany.

Table 5.3 *Action plan for implementation of the German regulatory road map*

	Action	Responsibility		Term
		Prepare & implement	**Approve**	
Market integration	***Generation flexibility***			
	Increase investments in new flexible generation by introducing one-stop shop approach for licensing/permits	Ministry	-	short
	Contract regulating and reserve power outside the market to guarantee balancing power availability	TSO	Regulator	medium
	Add (larger) heat storages or back-up boilers to CHP units	RES-E/DG operators	-	medium
	Support schemes		-	
	Introduce Feed-in Premium scheme besides Feed-in Tariffs	Ministry	-	short
	Oblige feed-in market premium system[32]	Ministry	-	medium
	Instead of system services bonus, stimulate RES-E/DG to consider provision of system services through efficient market premium level	Ministry	-	medium
	Demand response			
	Introduce minimum functional requirements to smart meters	Ministry	Regulator	short
	Define and develop common communication standards	Whole sector	Ministry	short
	Require more frequent meter readings or bills based on actual consumption	Ministry	Regulator	short
	Introduce time-variable pricing on a wider scale	Suppliers	-	short
	Demonstrate functioning of smart home area networks for automatic load control	DSOs / suppliers	Regulator	short
	Pilot projects for testing communication infrastructure for smart metering with high frequency	DSOs	-	medium
	Introduce time-differentiated prices for all customers	Suppliers	-	medium
	Balancing and ancillary services markets			
	Make all generators including RES-E and CHP balancing responsible	TSOs & regulator	-	short
	Introduce rolling gate closure time for balancing market	TSOs	Regulator	short/medium
	Fine-tune existing system services bonus to existing payments for provision of these services by conventional generators	TSOs	Regulator	short
	Introduce cross-border balancing within North, Central West and other regions	ERI-TSOs	ERI regulators	short/medium
	Extend the use of interruptible contracts to medium size loads	TSOs	Regulator	medium
	Lower prequalification criteria for offering balancing services to technical and economic minimum	TSOs	Regulator	medium
	Limit minimum size requirement for VPPs to participate in ancillary services markets to 5 MW	TSOs	Regulator	medium
	Enable wider possibilities for provision of other ancillary services by RES-E/DG	TSOs	Regulator	medium

[32] All project participants except Dena agreed with this recommendation, see the explanation in the main text.

Network integration	***Network charging***			
	Introduce UoS charges for all generators[33]	ERI TSOs & German DSOs	ERI regulators	short
	Implement basic time differentiated UoS charges for generators	ERI TSOs & German DSOs	ERI regulators	medium
	Network planning			
	Coordination procedure to overcome local or regional objections against new lines	Government	-	short
	Introduce explicit innovation incentives in regulation (IFI and RPZ type)	Regulator	-	short
	Evaluate current network security standards (a.o. N-1 regulation)	Regulator	-	short
	Implement dynamic reserve requirements in network planning standards	TSOs	Regulator	medium
	Introduce network simulation tool for better coordination of network planning and better evaluation of network investments	Regulator	-	medium
	Increase number of demonstration projects about active network management, smart metering and advanced load control (like E-energy) for network purposes	TSOs & DSOs	-	short/medium
	Congestion management methods			
	Allow for paid curtailment of RES-E and CHP by abolishing priority dispatch of RES-E and CHP	Ministry/regulator	-	short
	Introduce implicit auctions for day-ahead time frame on interconnections with Denmark, The Netherlands, France	ERI TSOs	ERI regulators	short
	Introduce market-based national congestion management method	TSOs/regulator	Regulator	medium
	Introduce common transmission models for capacity calculation	ERI TSOs	ERI regulators	medium
	Coordinate capacity allocation through regional auction office	ERI TSOs	ERI regulators	medium

[33] All project participants except Dena agreed with this recommendation, see the explanation in the main text.

6. Regulatory road map for the Netherlands

6.1 Outlook for RES-E/DG and the electricity system

Developing a country regulatory road map requires insight into the particular characteristics, i.e. RES-E shares, system conditions, and the possible transition of that country's electricity system up to 2020. This first section aims to provide this information. Several important factors are covered, such as developments in the generation mix, demand growth, import and export, and connection and integration of RES-E and CHP under current system conditions. Finally, the impacts up to 2020 are shortly summarized for constructing the road map.

Electricity generation mix

The figures below show the expected development of production from different conventional and renewable (intermittent) resources up to 2020. From a European perspective, the electricity generation mix in the Netherlands is made up of a relatively high share of gas-fuelled generators. This high share of gas-fuelled generators is due to the wide availability of own gas sources, currently 75% of the gas production is from inland resources. Before 2020 it is not likely that the Netherlands will change from a net gas exporting country into a net importing one. The high gas share in the generation mix is expected to increase further in the period 2005-2020 due to relatively low investment costs of gas-fired plants and short construction period. Of course this depends highly on assumptions about fuel price developments. Of the other conventional generation technologies, hard coal has a substantial share in the fuel mix while the share of nuclear generation is quite small. Pumped storage is absent due to unsuitable geographical conditions for this type of storage.

Concerning the renewable resources, obviously *wind* has the highest potential amounting to 17.7 TWh of production in 2020, split in 11.1 TWh offshore and 6.6 TWh onshore wind production. It seems reasonable that 2.9 GW offshore and 3.5 GW of onshore wind capacity can be installed up to 2020. Of this amount 1.2 GW of onshore wind already was installed in 2005. So far 2 offshore wind parks are in operation with 96 turbines, totally 228 MW, installed. Especially, offshore wind is assumed to reach considerable amounts by 2020 due to limited water depths of the North Sea. Currently the amount of onshore wind production is still higher than offshore wind, but the situation will reverse due to limited space and public objections concerning onshore wind which slow down its development (although these arguments also hold for offshore wind to some extent).

PV has played a minor role in the Netherlands so far with 0.1 GW installed and is not expected to reach a significant share in generation before 2020.

Micro CHP has a good potential in the Netherlands with an optimistic industry prediction of up to 0.4 GW installed until 2015. Factors that could negatively influence the introduction of this technology are the spread between the gas and electricity price (i.e. spark spread) and insufficient environmental achievement of micro-CHP units based on gas motors or Stirling engines. Furthermore, production of high numbers is necessary to lower costs by economies of scale in order to make micro-CHP units more attractive for customers (COGEN *et al.*, 2006). Market introduction is delayed until 2011 at least.

Biomass may form a substantial part of the generation mix in 2020, mainly due to co-firing in coal-fired power plants and waste incineration. The potential of hydro is fairly limited as most feasible locations are already in use.

Table 6.1 *Overview of electricity generation mix, by fuel in TWh (Source: ECN, 2005)*

Technology	2000	2005	2010	2015	2020
Wind	0,85	2,44	5,64	11,55	17,76
offshore	0,0	0,0	2,2	6,6	11,1
onshore	0,9	2,4	3,5	5,0	6,6
Pumped Storage					
Natural Gas & Oil	54,7	58,2	61,6	73,9	86,2
Hard Coal	25,0	27,0	28,9	24,9	20,9
Brown Coal					
Nuclear energy	3,7	3,7	3,7	3,7	0,0
Geothermals					
Photovoltaics	0,0	0,1	0,1	0,1	0,2
Hydro	0,2	0,2	0,2	0,2	0,2
Biomass+Waste	3,6	5,0	8,3	8,9	9,5
Misc*	1,3	1,4	1,6	1,6	1,6
Import	19,0	17,1	15,3	11,2	7,2
Total	108,2	115,1	125,4	136,1	143,4

Table 6.2 *Overview of installed electricity generation capacity, by fuel in GW (Source: ECN, 2005)*

Technology	2000	2005	2010	2015	2020
Wind	0,4	1,2	2,3	4,3	6,4
offshore	0,0	0,0	0,7	2,1	3,5
onshore	0,4	1,2	1,6	2,2	2,9
Pumped Storage					
Natural Gas & Oil	14,6	15,3	16,0	17,7	19,5
Hard Coal	4,5	4,3	4,2	3,5	2,9
Brown Coal					
Nuclear energy	0,4	0,4	0,4	0,4	0,0
Geothermals					
Photovoltaics	0,01	0,06	0,10	0,13	0,16
Hydro	0,0	0,0	0,0	0,0	0,0
Hydro Power >10MW		0,04	0,04	0,04	0,04
Biomass+Waste	0,6	0,8	1,3	1,6	2,0
Misc					
Total	20,6	22,2	24,4	27,8	31,0

Electricity demand

The final electricity demand is expected to grow with 1.4% per year in the period up to 2010 and in the period 2010-2020 with 1.3% per year.

Import and export
The share of electricity import is high in the Netherlands, compared to surrounding countries. In 2008, 25.0 TWh of electricity was imported while only 9.1 TWh was exported, so the net import amounted to 15.9 TWh (TenneT, 2009). The volume of electricity import is determined by the difference between the electricity price inland and abroad and by the available cross-border capacity for electricity transport. As a result of the relatively large share of gas-fired plants in the Dutch electricity production and the accompanying higher prices, import occurs most, while at some other times electricity is also exported. However, based on scenarios of ECN and TenneT, imports will decrease substantially in the coming years due to decreasing price differences, more interconnection capacity coming in place (the interconnection with United Kingdom is expected to become in place around 2011), and massive investments in new generation capacity (30 GW of new production capacity has applied for a connection). Consequently, the Netherlands may become a net exporter around 2020. Besides, the large electricity supply from wind energy will result in large import/export fluctuations on the cross border connections.

Connection of RES and DG
The table below shows the estimated amount of RES-E/DG capacity (in shares of total capacity) to be connected to either the distribution networks or the transmission network in the Netherlands.

Table 6.3 *Overview of estimated amount of future* RES-E/DG *capacity connected to the distribution networks and transmission network in the Netherlands (Source: ECN)*

Technology	Distribution network	Transmission network
Biogas	100%	-
Solid biomass	25%	75%
Biowaste	80%	20%
Geothermal	-	100%
Hydro large-scale	100%	-
Hydro small-scale	100%	-
Photovoltaics	100%	-
Solar thermal	-	-
Tide	100%	-
Wind onshore	80%	20%
Wind off-shore	0%	100%

Based on the production estimates of the blueprints, 5.3 TWh and 12.4 TWh of yearly wind production will be directly fed-in on distribution and transmission level respectively. Consequently, about 22% of *all* wind production is delivered to the distribution networks and 78% to transmission networks. This highlights the increasing importance of the transmission network in transporting electricity from intermittent sources to demand in the near future. The degree to which this increase of connection of intermittent generation influences the electricity system and its constituents will be elaborated upon below.

Integration of RES and DG
An important variable shaping the impacts is the assumed RES-E/DG penetration in 2020. Based on the projected developments in electricity production, the 2020 sustainability targets for the Netherlands and the Dutch RES-E potential we conclude that the likely level of intermittent RES-E/DG in 2020 can be qualified as moderate; 11% of electricity will be produced from intermittent RES-E/DG sources. This percentage will be assumed as basis for the discussion of the likely impacts on networks and markets of intermittent RES-E/DG in 2020. Network impacts can be divided in impacts on distribution and transmission networks respectively, while market impacts can be distinguished in impacts on balancing market, and impacts on trade markets.

Impacts on *distribution networks* result mainly from increases of CHP and onshore wind to the medium voltage networks. Currently, transformer capacity at distribution-transmission network boundaries in Westland falls short due to the fast increase of horticulture CHP units with heat buffer, which are mainly electricity-led. In the Northern part of the Netherlands, onshore wind and biomass digestion require extension of both distribution and transmission networks since these production facilities are placed within regions with low load. Electricity production of PV and micro-CHP grows relatively slow and probably will not have an impact on distribution networks before 2020. The latter are generally located nearby load, making network reinforcements less necessary.

Impacts on *transmission networks* will originate from the instalment of new offshore wind parks in the North Sea (800 MW up to 2011), large-scale onshore wind parks as well as upward network flows in distribution networks during times of high intermittent production and low load. It is not yet clear whether offshore wind parks will be connected to the 380 kV connection points Beverwijk, Maasvlakte or Borssele. In any case network reinforcements are necessary (TenneT, 2007). One major ongoing project by TenneT is to expand the transmission capacity of the electricity grid in the Randstad region in the Western part of the Netherlands (see Figure 6.1 below). This is deemed necessary because of the increasing demand for electricity in this area and the increasing energy flows because of energy trading. At the same time, it will make it easier to connect additional offshore wind parks to the transmission grid (although the Randstad 380+ project is not enough to this latter aim). The first part of the project has been finished in 2005, the whole project has to be finalized in 2015 (TenneT, 2005b). For transporting the excess electricity from the Northern part of the Netherlands the 220 kV connection Zwolle-Eemshaven will be upgraded with high temperature conductors. In the medium term an additional (North-West) 380 kV interconnection between Diemen and Eemshaven (length: 200 km) is considered to be necessary due to the extension of a high amount (5 GW) of additional production capacity (coal, gas, CHP and wind) nearby the coast (planned to be in operation in 2016).

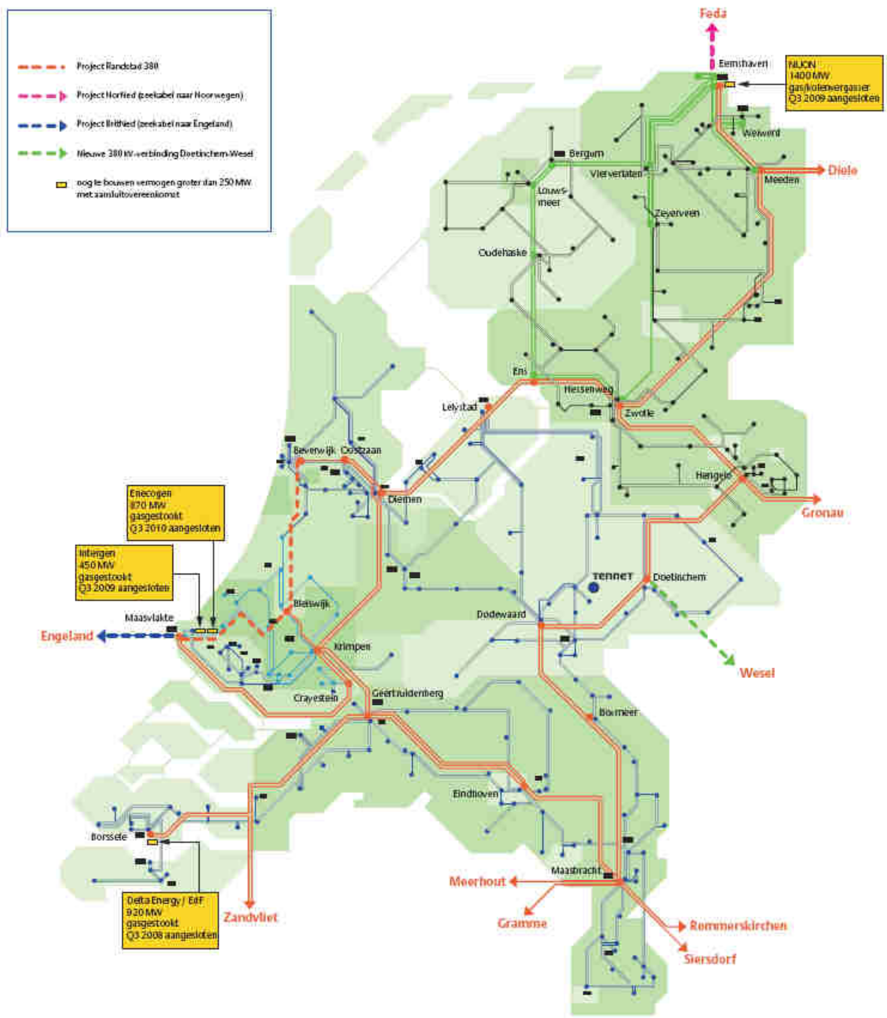

Figure 6.1 *Grid map for the Netherlands*
Source: TenneT (2007)

Networks of 110 kV and higher (150, 220, 380 kV) are operated by the transmission system operator, who owns also most networks. High voltage networks which are not yet owned by the TSO have to be sold to the TSO by the DSOs in the medium term according to recent legislation.

Impacts on *balancing markets* will come from the increasing share of intermittent RES-E/DG in the Netherlands. Based on a simulation study by KEMA/TUD, TSO TenneT expects that 6,000 MW of wind capacity can probably be managed adequately within the present system. Based on current technological and institutional/regulatory characteristics, additional spinning reserves may be necessary to compensate for the larger wind production fluctuations if wind capacity exceeds 6,000 MW.

However, blueprints indicate that 1.95 GW of onshore and 3.5 GW of offshore wind power will be installed in 2020, implying that no drastic system changes are required before 2020. For estimating the required balancing power for amounts of wind power as indicated in the blueprints, some scenario studies are available. Out of these scenarios the 2 GW onshore, 4 GW offshore scenario mentioned in TenneT (2005) and Ummels *et al.* (2007) is most in line with the blueprint. This scenario indicates that as a maximum approximately 1550 MW (1725 MW) of downward (upward) regulating and reserve power is required. This is the case when the prediction error is at maximum i.e. maximum wind power deviations from forecasts (prediction is 0

MW).[34] In practice, wind power forecasts are better and consequently this amount of regulating and reserve power can be clearly considered as a maximum estimation of the actually required balancing power.

Impacts on energy markets for longer time frames (intraday, day-ahead, forward markets) i.e. *trade markets*, imply higher price variability in 2020, with a higher spread between off-peak and peak prices due to the increase of intermittent generation. The demand for flexible generation will increase, while the demand for base-load generation will decrease.

Conclusions on future network impacts

Impacts on the distribution and transmission networks in 2020 are substantial in terms of required additional network capacity due to more upward network flows from distribution to transmission network level and the generally larger distance between generation and load. More specifically, the Netherlands faces the following network-related impacts of intermittent renewable generation (see Table 3.3):

- In some regions, high wind and CHP shares in Westland, the Northern region and North-Holland North will increase further, exceeding load at many times and causing network congestion at distribution and transmission lines. Therefore, additional network reinforcements in transformers and new distribution and transmission lines are necessary, requiring high investments
- Increasing unplanned electricity flows (‘loop flows’) at international interconnections with Germany diminish the availability of interconnection capacity for trading purposes, increase congestion and consequently decrease RES-E/DG power prices during low national load situations
- Conventional ‘hardware’ solutions (new lines and cables) for more network capacity are impeded by social acceptance issues, sometimes necessitating burying of lines (Randstad 380+) or side-payments to regional government (maintaining and upgrading of 220 kV connection Zwolle-Eemshaven). Besides, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.

Consequently, the Netherlands seems to face a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit the cost impacts for both (distributed) generators and consumers to the efficient costs, a transition to a more active and innovative type of network management is deemed necessary for the Netherlands (‘more software instead of hardware’) at the end-point of the road map.

Conclusions on future market impacts

Based on the projected developments in electricity production and the 2020 sustainability targets for The Netherlands we conclude that the likely level of intermittent RES-E/DG in 2020 can be qualified as moderate.

Based on the available studies, impacts on the balancing market seem relatively limited when reasonable assumptions for the forecast error are taken, given the moderate amount of intermittent resources expected for 2020 in the Netherlands. Clearly, more sophisticated balancing integration studies would allow to substantiate this conclusion about balancing impacts further. Concerning electricity markets for longer time frames (intraday, day-ahead, forward markets); a higher price variability is expected.

The Netherlands predominantly faces the impacts related to the ‘RES-E/DG in the market’ stage of market integration in 2020 (see Table 3.4):

[34] Instead of using a certain forecast error, it is assumed that wind power variates between perfect prediction and a prediction of 0 MW wind power. The latter shows the maximum forecast error, which probably is reflected in the maximum required regulating power.

- Moderate penetration level of RES-E/DG
- Moderate increase of system balancing costs
- RES-E/DG is expected to have little to moderate effect on wholesale market prices and their variability
- RES-E/DG has access to the balancing market and to the market for emergency power through VPPs. No access to other ancillary markets
- Presumably no lack of flexible generators at critical system times since the share of gas-fired generation is high.

Consequently, RES-E/DG in the market is the assumed market integration stage at the end-point.

6.2 Regulatory road map

6.2.1 End point road map

Against the background of the expected development of intermittent generation, network and market developments as described in the former section, and the general scenario assumed for the 2020 European electricity system as described in Section 3.2, the regulatory road map for The Netherlands will be developed.

The regulatory road map provides a *menu* of regulatory actions which are largely necessary to reach the desired future state of both market and network integration. The desired future states, i.e. the regulatory actions, are directly linked to the impacts described in the former section. The precise links are presented in the tables on the stages of market and network integration in chapter 3. The desired future state, which was derived in the former section, is shown in Figure 6.2 below.

Furthermore the road map describes the path that stakeholders should take in order to reach stage IV-B in 2020, which is required to integrate optimally and efficiently the expected share of renewables in markets and networks at that year. The next sections describe the path towards this point.

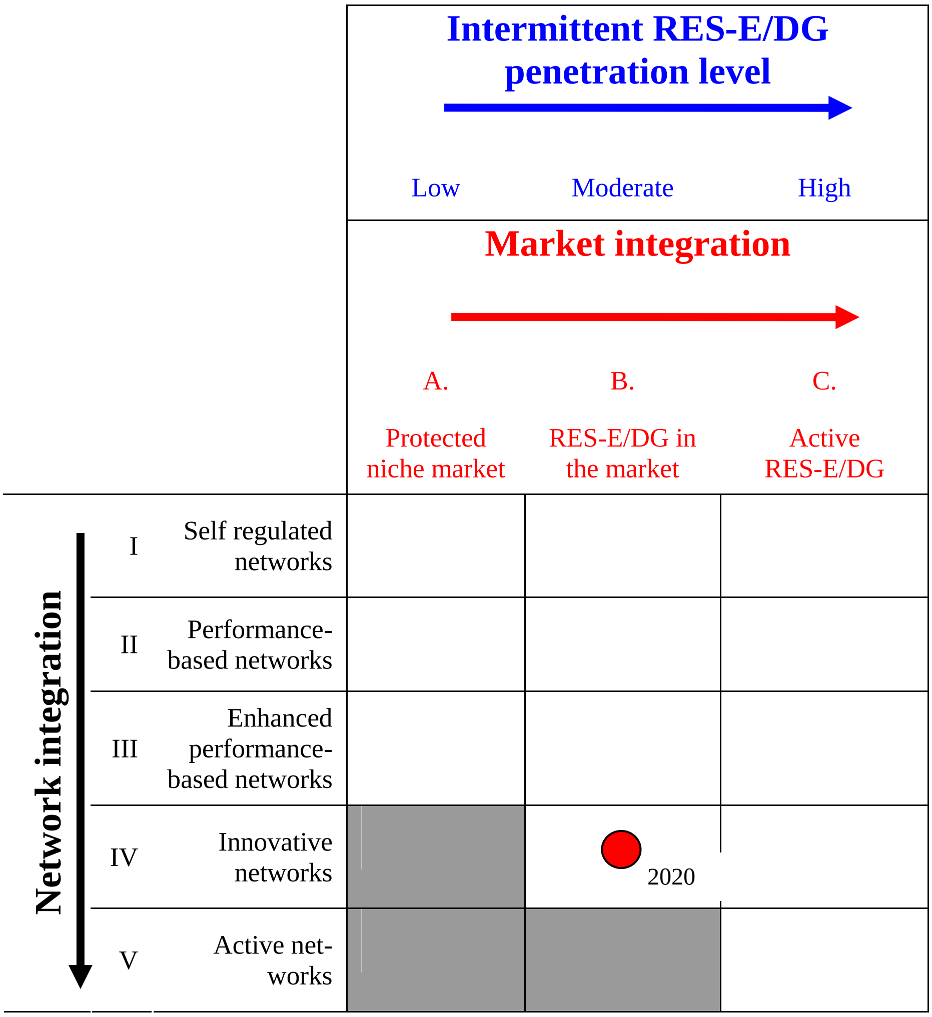

Figure 6.2 *Regulatory road map scheme The Netherlands: end point*

6.2.2 Starting point road map

Whereas the starting point of the regulatory road map with respect to the amount of intermittent RES-E/DG currently integrated in the electricity supply system is known, we need to define the starting point from a regulatory perspective. In this section we describe the regulatory starting point for the Netherlands. In this respect we distinguish between the following segments:

1) Generation
2) Demand
3) Markets
4) Networks.

Below we explain briefly per system segment the current status of the regulatory framework, in order to define the starting point for the Dutch regulatory road map.

Generation

Support schemes

Predominant support mechanism for renewable electricity generation (RES-E and CHP[35]) is a feed-in premium. This premium varies with the realisation of electricity revenues in order to

[35] Currently, feed-in premia for CHP generators are set at zero.

guarantee sufficient revenues to RES/DG operators while concurrently limiting the budget requirements for the government. The choice for a feed-in premium system is favourable to system operation and society since it forces DG operators to take into account market prices which reflect system conditions and incentivise to behave more to system needs.

Since a system-wide production surplus or shortage on the production market may not reflect (local) conditions for other system segments, especially networks and balancing, from the viewpoint of the system as a whole some additional incentives are needed. These incentives are discussed in the network section below.

Conventional generation

The increase of intermittent RES-E/DG may drive the need for more balancing power, as outlined in Section 6.1. As the market may fall short to provide enough balancing power due to two kinds of market failures (imperfect information and public good character of reserve capacity), additional policy incentives are in place to encourage conventional generators to produce energy whenever the system needs them to cover demand. The system operator has contracted a certain amount of Regulating and reserve power (275 MW) and emergency power (300 MW). Both are contracted outside the market, to prevent balancing power is competing with power in trade markets and therefore is not available for securing supply during times of peak demand. The system seems to work well. Furthermore, the balancing system with balancing responsible parties encourages market parties to decrease the demand for balancing power as far as possible.

Besides, a higher share of intermittent generation in the system implies that supply of electricity may become more variable and unpredictable in other markets (day-ahead, forward) as well. Consequently, the demand for flexible generators with fast start-up times and high ramping up and down capabilities will increase with the penetration of intermittent RES-E/DG in the system. Since the Netherlands has a high share of gas-fired power plants in its generation mix, additional incentives to increase the share of flexible generation seem not directly necessary. Apart from that, the aforementioned mechanism to ensure enough balancing power with capacity payments also increases the prices for generation on spot and forward markets, and therefore provides an incentive to increase flexible generation capacity or to import more electricity. Alternatively, also small distributed generation may offer flexible power either to markets or by means of bilateral contracts through aggregators, both for ramping up (for instance, CHPs with gas motors) and down (CHP and wind).

Storage

Different type of generators can be operated more flexible through deployment of electric or heat storages. Many CHPs in horticulture are already deployed with heat storages. The Netherlands does not have any potential for pumped hydro storage due to unfavourable geographical conditions. There are some plans for large-scale storage (CAES, underground pump accumulation power plant, energy island with pump accumulation), which are deemed not very likely. In the future also micro-CHPs may be deployed with heat storage facilities, to decouple electricity and heat production.

Demand

Besides adding more flexible generation to the system as a response to more intermittent generation, alternatively higher variability can be managed by higher responsiveness of the demand side of the electricity system. Demand response can lower demand during specific time periods, shifting load to other time periods in three steps.

As a first step, consumer electricity prices can be differentiated in time. Large customers with a network connection of 0.1 MW or more already face hourly wholesale market prices, directly (if they are contracting energy directly on the market) or indirectly through the supplier. Low voltage customers do experience limited time-differentiation since consumers may choose for simple time-of-use tariffs differentiated to peak hours (working days, 7.00-23.00 h) and off-peak hours. However, they are not obliged to pay differentiated tariffs. Therefore, most consumers are wholly shielded from the fluctuations in real-time prices. So, demand flexibility for low voltage consumers seems to be limited in the Netherlands.

As a related second step, smart metering can be implemented to bill consumers according to their actual use instead of their assumed consumption profile. Currently, network connections with a contracted transport power of 0.1 MW or more are obliged to dispose of a telemetric-meter/daily remote readable meter. The application of smart metering to the premises of small customers is limited to newly constructed houses with a network connection up to 3*80A. Currently, DSOs are conducting a lot of experiments and have placed up to 220,000 'smart' meters. Probably, these meters are not yet suitable for future network purposes. The planned large-scale roll-out of smart metering scheduled for the period 2009-2015 recently was suspended for at least 2 years for fine-tuning the functional requirements of the meter to be well prepared for the future use of the meters.[36]

However, the implementation of smart metering probably will be not enough to drive consumers' behaviour since consumers face a lack of opportunities to react on variable electricity prices as there are currently only a few opportunities where load can be shifted. Small consumers cannot be expected to follow market prices and their consumption continuously due to prohibitive high transaction costs. Automated smart home area networks (HAN) may overcome this problem. Besides transaction costs, experiments indicate some other preconditions for small consumers to take part in demand response actions; they want not to lose comfort, the DR action has to be simple and orderly and they want to remain an active actor with decisive power concerning their own demand.

Alternatively, in case of large unevenness between supply and demand interruptible contracts can be used. These interruptible contracts specify the conditions for interruption of electricity consumers and the compensation payment (availability and utilisation) they will receive in return.
Currently, mainly the industrial and horticulture sectors (switching-off assimilation lighting) are involved in interruptible contracts. Large industrial interruptible demand participates in the market for reserve power. The TSO is currently contracting 300 MW of wholesale demand response reserves as so-called emergency reserves. The minimum desirable contract size for emergency power is 20-25 MW. Also aggregators/pools can provide emergency power when, a pool participant should have at least 5 MW interruptible load available. Households and small businesses cannot participate in the emergency reserves due to lack of technological infrastructure (e.g. smart metering) and communication infrastructure to deal with the large amounts of data resulting from smart metering. Suppliers of emergency power are remunerated according to the measured energy supplied. As a rule the remuneration is set on Imbalance settlement price for positive power + 10% (or minimum contract price) for each programme time unit (PTU) during the disconnection period (TenneT, 2008). Furthermore, business customers can sell interruptible demand to the supplier in exchange for a compensation payment. As a supplier is part of a Program Responsible Party (PRP) in that way the imbalance of the PRP is reduced. Consequently, the TSO has to deal with smaller imbalances, and system security is promoted (Deloitte, 2004).

Markets

Efficient electricity markets for different time frames help in mitigating the effects of more variability and unpredictability of renewable electricity sources on the electricity system for two reasons. Firstly, different market places for year-ahead up to real-time are necessary for genera-

[36] Recently, due to privacy considerations consumers have been exempted of the obligation to let install a smart meter at their premises.

tors and loads to diminish their risk exposure by enabling hedging of positions. Secondly, an efficient market allows for efficient allocation of system costs according to the cost causality principle by remunerating or fining market participants for their actual contribution to the system over time, as shown in generation and demand patterns.

Wholesale markets

Several commodity markets are available for hedging of market positions: for instance yearly, monthly and weekly forward OTC markets operated by ENDEX[37] and the day-ahead and intraday power exchanges operated by APX.

At the day-ahead market all registered market participants are able to buy and sell electricity on a day-ahead basis at the APX (Amsterdam Power Exchange). On the day prior to the day of delivery, the market participants issue their respective offers and bids for the next day, before 11:00h in the morning when the market closes. The Intraday market offers market participants opportunities to list power products in 15 minute intervals until one hour prior to delivery.

According to some indicators the supply-side of the wholesale market is concentrated. First of all, the Herfindahl-Hirschmann Index (HHI)[38] based on realized production has an average of 1828 in 2007. Furthermore, during 34% of total hours in 2007 the production capacity of one electricity producer was required to meet market demand i.e. the producer was pivotal. Besides, the extent to which capacity of a producer was essential increased (NMa, 2008).

Balancing markets

The electricity sold bilaterally or at power exchanges has to be physical delivered on the electricity grid of TenneT. Market parties are obliged to keep their own energy balance within each settlement period, i.e. provide energy programs (E-programs) to the TSO and act accordingly (APX, 2007). This program responsibility is a main characteristic of the balancing market and comparable with balancing responsibility in a Scandinavian type of balancing market. Deviations on energy programs are settled by the imbalance pricing system. To get an open market for the price setting of imbalance, the regulation market was introduced. The System Code foresees in the obligation to all market parties (with connection capacity > 60 MW) to offer all available Regulating and Reserve Power (RRP) capacity to TenneT by bids at a chosen price, while other connected parties are allowed to do so (NMa, 2007). There is a bid ladder which contains bids of Regulating and Reserve Power with a dispatch time smaller than or equal to 15 minutes. The bids are ordered per direction, from the cheapest bid to the most expensive bid. Bids for regulating down (negative power) can be found on the left hand side of the ladder, while bids for regulating up (positive power) are on the right side. The dispatch price per direction (positive or negative) is the bid price of the marginal bid in that direction. Bids of positive power are deployed by TenneT in order of increasing bid price, and bids of negative power in order of decreasing bid price (the latter is due to the fact that the generation unit has to pay). Positive bids are settled at the price of the highest bid deployed and negative bids at the price of the lowest bid deployed, for each PTU (each 15 minutes). These two regulation prices constitute the basis for valuation of the contribution of market participants (programme responsible parties) to the system imbalance (Beune and Nobel, 2001).

Also RES/DG operators are balancing responsible or can transmit this responsibility (like all other market parties) to a balancing responsible party in exchange for a payment. Balancing responsibility incentivises RES/DG investors to submit more realistic energy programmes and to use and develop more accurate prediction tools; in this way RES/DG developers decrease their costs and subsequently the overall system costs. Therefore the major advantage is that RES/DG producers take into account negative external effects of production on system operation. Since

[37] In December 2008 ENDEX and APX merged, ENDEX being part of APX.

[38] Defined as the sum of the squared values of the market shares in %.

the average balancing costs per MWh for wind turbine investors are higher compared to the balancing costs for conventional producers the costs for imbalance and program responsibility are (partly) compensated through government subsidies; the *efficient* balancing costs for wind onshore are part of the correction values for the base feed-in premium. These costs are set on 11% of the baseload day-ahead (APX) market price and correct the base feed-in premium upwards. Since this compensation is more or less fixed, companies have an incentive to reduce imbalance as remaining means accrue to them.

Within the system of balancing responsibility, E-programs can be delivered up to 13.00 pm before the day of execution of the contracts. Until 16.00 p.m. transport restrictions can be solved by the TSO and then authorization of the bids takes place. Alterations of E-programs can be made from the moment of authorisation until closure of the intraday market (1 hour before hour of execution). This means that the gate closure time is rolling (so no fixed window). Although the PTU is 15 minutes, alterations can only take effect every whole hour and therefore should at least be submitted one hour before each whole hour. The intraday market offers renewable generators an important opportunity to limit their imbalance exposure, since it enables PRPs taking advantage of the decrease of forecast errors of production of intermittent resources closer to real-time.

The current Dutch balancing market design can be said to be successfully embedded in the liberalized electricity market, since market parties including RES generators are driven to prevent and resolve system imbalances. Furthermore, less than 3.5% of the system load has to be balanced in the RRP market. However, balancing market prices can be considered as relatively high due to the small market size of the Netherlands and the resulting market power for generators.

Networks

Network operators on both distribution and transmission levels face increasing penetrations of intermittent RES-E/DG connected to their grids. Currently, power is mainly transferred from the transmission level downwards in the chain to the end consumer ('top-down'). However, increasing penetration of renewable sources imply that power from intermittent generation will sometimes exceed local load and needs to be exported to other regions (currently already the case in four regions; South-Holland, North-Holland, Groningen region, Zeeland). As a result, upward flows may occur as well and power flows alternate between top-down and bottom-up, in other words are bidirectional.

Accommodation of higher fluctuations of supply can be realised either by extension of physical available network capacity or by exploiting existing capacity to a higher extent for integrating intermittent RES-E/DG in the grids. Network charging, network planning and congestion management are important topics for both transmission and distribution networks in this respect. Transmission networks are defined as networks with voltage levels of 110 kV and above, distribution networks contain all voltage levels below 110 kV. Currently, there are one TSO and 11 DSOs. Both transmission and distribution system operators are state-owned and are not allowed to be sold to private companies. The TSO is legally, functional and ownership unbundled, the DSOs are legally and functional unbundled and are obliged to implement ownership unbundling. In this way, network access of independent generators is guaranteed.

Network charging

<u>Transmission networks</u>

Transmission network costs for network operation and planning (including new investments) have to be paid by network users. Network costs are generally subdivided in costs of connecting market parties (generators and consumers) to the grid and costs for operation of the electricity system. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by Use-of-System (UoS) charges.

Connection charges can be shallow (costs for the connection only) or deep (if they include investment costs behind the connection point). Both generators and consumers have to pay connection charges. All generators connected to the 220-380 kV networks, including DG/RES generators, pay a one-off shallow connection charge for the new connection between their facility and the network. All generators, including DG/RES, connected to the 110-150 kV networks require a connection larger than 10 MVA for which connection charges are not regulated and deep. This differentiation of network charges between voltage levels is not deemed efficient and consistent and therefore may pose a barrier for the connection of renewable sources.

Use-of-system charges may be levied on both generators and consumers. In the Netherlands, generators do not pay use of system charges ("G-charges") for the electricity fed into the grid due to level playing field considerations. Therefore, G-charges have been removed in the past. Consequently, investment decisions by RES promoters are not influenced by network costs.

Furthermore, efficient integration of renewable sources can be improved by temporal and locational differentiation of network charges. Currently, these charges are neither temporal nor locational differentiated. However, at the same time the current system provides an implicit locational signal through the waiting time for new connections in certain areas. Furthermore, the congestion management scheme might stimulate flexible generators to apply for a connection in a non-congested area since profit possibilities for generators in congested areas are likely to be reduced.

No regulatory principle is in place preventing differentiation between generators to their type/operation profile. The Ministry is just planning to implement priority access for renewables in the future and will issue a legal proposal to this end (see part about congestion management below).

<u>Distribution networks</u>
Costs for operating and investing in distribution networks by DSOs can be passed on to generators and consumers through two kind of network charges; connection charges and use-of-system charges.

Connection charges are levied upon both generators and consumers. Connection charges for generation and consumers with a connection below 10 MVA are shallow, regulated and averaged. Charges include (i) a periodical connection payment (fixed, dependent on voltage level), (ii) a onetime connection charge (fixed, differentiated to units within and beyond 25 meter, dependent on connection capacity). These connection charges differ between DSOs since the price cap regulation is aimed at the weighted average tariff basket, implying separate tariffs differ for each DSO to a certain extent. Connection charges beyond 10 MVA are deep and unregulated and thus negotiable between DSO and DG. DSOs could pass through the necessary reinforcement costs (deep connection charges) to customers (like DG operators). UoS charges are fully levied upon consumers.

Furthermore, efficient integration of renewable sources can be improved by temporal and locational differentiation of network charges. Currently, no time differentiation of network charges is currently applied.

Network charges for generation and load requiring connections larger than 10 MVA are deep and therefore differ to location. These charges differ widely since sometimes no investments are necessary, while in other cases large investments are needed in new cables, transformers and other devices. Therefore, wind farm project developers typically have to negotiate hard and over longer periods before reaching final agreement with DSOs on connection charges at their preferred project site.

The distance component in connection charges for connections smaller than 10 MVA is regulated. For these connections, the regulated distance component beyond 25 meter provides a small locational incentive to install the generator at short distance of the grid.

Network planning

Transmission networks
Concerning network operation and planning, there are some practical experiences showing inefficient behaviour and system operational problems mainly because of the investment boom in new (conventional) generation capacity and lagging extension of concomitant network capacity due to long lasting procedures for network extension. The fast increasing amount of RES production in some regions as well as loop flows from Germany contributes to these problems.

Both new wind and CHP production is experiencing some limitations in providing energy to the grid due to restrictions in transformer capacity from distribution networks to transmission networks (Westland) and lacking transmission capacity to transport abundant power from the North-East region to the 380 kV ring. This is strongly linked to the simultaneous connection of several large power plants to the grid in the coming years too, the difficulties of extending transmission network capacity in the short term due to long lasting procedures (obtaining permits may last up to 10 years) and political and social opposition against new overhead lines (necessitating burying part of the transmission lines).

These difficulties stimulated the national government both to change laws for planning procedures and to add a new law about congestion management. Concerning the former, a new procedure has became in force recently (national state coordination regulation), which gives more competences to the national government and less to the local governments in case of large projects concerning the infrastructure, including new electricity lines. The new law about congestion management is currently in preparation and probably will contain an exemption for renewable generators to participate during normal system conditions (‘priority access’).

The network investments in new overhead lines and cables are financed out of the depreciation of the asset base (the TSO is subject to revenue cap regulation). Besides, there exists a regulatory system to remunerate exceptional, large-scale investments of the TSO. Up to now, these exceptional investments are approved afterwards by the regulator and compensated for in the transmission tariffs (mainly levied upon consumers). In the near future, these investments will be approved before investment takes place. In that way, TenneT is not only compensated fully for all extra costs but also network investments are not delayed by uncertainty about their remuneration.

Distribution networks
In current distribution network planning still a ‘fit-and-forget’ network philosophy is applied, which means that the network is dimensioned on all possible different network flow situations. All potential congestions are resolved beforehand through investments in network reinforcements. Increasing intermittent generation results in an increase of possible network congestion situations and therefore will make this traditional network planning philosophy very expensive.

Alternatively, active network management can be applied. However, active network management is not yet explicitly considered as a solution in the most recent capacity and quality documents of DSOs dealing with network planning and quality of transport (covering the period

2008-2014). This is probably partly due to a number of implicit disincentives for efficient investments of DSOs. First of all, DSOs are subject to incentive regulation, which emphasis is on short-term benefits at the expense of more risky measures contributing to long term efficiency like innovation. This tendency is reinforced by the TOTEX type of cost regulation applied, which incentivises DSOs to efficient network planning but at the same time probably impedes more risky investments in active network management since the regulator is usually not involved in investment selection processes. With an alternative type of regulation, building blocks regulation which considers OPEX and CAPEX separately instead of jointly, the regulator may be forced to pay more attention to optimal network management and investment selection. Secondly, yardstick competition turned out to result in a first mover disadvantage for DSOs to conduct new investments. Besides, DG penetration differs between regions, but is not yet acknowledged as regional difference that needs to be compensated by the regulator.

The Ministry responsible for energy issues recently announced to establish cooperation between network operators, research institutions, regulator and government, which is deemed necessary for implementing smart grid innovations and applications in the networks. Furthermore, it was announced that incentives for network innovation like already in place in the United Kingdom will be considered. Finally, some incentives for guaranteeing an optimal level of quality of supply are in place. Reduction of energy losses, which may prevent building certain lines, is only indirectly incentivised since energy losses are part of OPEX costs (reduction of energy losses saves costs, which translate into higher profits if the cost reduction is not sector-wide).

Congestion management
In order to be able to connect all generators and divide the limited available network capacity on a non-discriminatory basis, a *national congestion management* scheme will be implemented. Until recently, the TSO TenneT in principle did not connect new generators until the network has sufficient capacity to accommodate their production in all circumstances, so the TSO does not have to rely to any considerable extent on re-dispatch. The re-dispatch situations were infrequent and unpredictable. Therefore, congestion was dealt with by instructions of the TSO to generators to increase/reduce their output or turn on/off their units in case of emergency and if previously taken measures did not have the desired result. This measure still applies to all generation units with an installed capacity of more than 5 MW and with available capacity at their disposal. Generators are compensated through the balancing market.

Since the number of potential congestion situations increases highly in several regions, new legislation is prepared in order to establish a legal basis for a country wide introduction of congestion management in the framework of the balancing market. In one region (Westland), congestion management has already been implemented recently to ensure connection of new (mostly controllable) CHP units. Besides, new generators applying for a connection to the transmission grid had to agree with a runback scenario: in case of network difficulties the system operator may oblige the generator to decline its production. These ‘runback scenarios’ are intended to be temporarily until network reinforcements are finished. This quantity restrictions (‘last-in, first-out’) are not very efficient and discriminatory between new and existing generators, and therefore runback scenarios are deemed unacceptable by the regulator NMa. The costs of congestion management are currently socialized in the UoS charges, but alternative more efficient cost allocation methods including auctioning are subject of scrutiny.

Renewable generators (including high-efficiency CHP generators) most likely will be exempted from the new congestion management system in order to guarantee priority access of renewable generators. In the draft of the proposed law, wind and other renewables are not allowed to be curtailed for market reasons. However, proposed law will also contain a provision for network operators to curtail renewable generators if necessary during critical system conditions. Consequently, the priority access scheme does not seem useful since access during normal circumstances already is certain without the scheme due to the low marginal costs of renewable generators. Moreover, depending on its implementation, the scheme may prevent wind generators from diversifying their revenues by operating on the balancing market.

Interconnection capacity
Currently, three interconnections with Germany, two with Belgium, and one with Norway are in place. The maximum commercial available capacity is determined by net transfer capacity (NTC) values. NTC is defined as the maximum exchange program between two areas compatible with security standards applicable in both and accounting for the technical uncertainties of the future network (Kristiansen, 2007). According to ETSO, during the winter 2008/2009 period NTC values for interconnections to Belgium, Germany and Norway amounted to 2,400 MW, 3,000 MW and 700 MW respectively.

The available interconnection capacity is quite high compared to other countries, which implies a relatively high potential to integrate additional intermittent RES-E/DG in the grid. The interconnection capacity in NTC terms is 38% of the installed production capacity at national level.[39] Moreover, a 1000 MW DC-interconnection with Great Britain will come in operation in 2011, an additional 1500 MW AC-interconnection with Germany is planned to be available from 2013 onwards and an interconnector with Denmark (Cobra) may be in operation as from 2016/2017.

However, the interconnection capacity for trading purposes (including selling wind generation), is limited by the TSO for being able to cope with the way the German system is designed. If there is RES production in the North of Germany, the inverse load is transferred through German/Dutch interconnectors.

This issue has been resolved partly by installing phase shifters nearby the German-Netherlands border to control the direction and amount of power flow over the transformer, albeit to a limited extent. Therefore, the existence of loop flows, uncertainties of generation and network outages implies that under normal circumstances approximately 3,600 MW of cross-border network capacity with Germany and Belgium (in total) is available for the market, under favourable circumstances 3,850 MW (NMa, 2008)[40]. This is only about two-third of the total Net Transfer Capacity. Sometimes, the import capacity is even further reduced because of the high wind expectations in Germany, especially in the first and fourth quarter of the year (TenneT, 2009). The role of intermittent renewable production is well visible here; changing wind speeds result in highly variable wind production in North-Germany and production surpluses in the northern German grid. These surpluses result in large import/export fluctuations on the cross-border connections due to lacking national network capacity in Germany. This requires more reservation of interconnector capacity by TSOs and as a result (increasingly) less net transfer capacity on the interconnectors with Germany and Belgium can be regarded as reliable import capacity (TenneT, 2007 and 2009).

Given the limited cross-border network capacity, congestion management is also necessary for cross-border connections. Therefore, TenneT, the Dutch TSO, organizes auctions with the grid managers of the neighbouring countries, for the allocation of the cross-border capacity. There are four different auction categories: year-ahead, month-ahead, day-ahead and intraday auctions. Year-ahead and month-ahead capacity is traded on explicit auctions. Day-ahead capacity is traded on explicit auctions with Germany and Norway and on an implicit auction by market coupling with Belgium and France. The latter means that in the absence of shortage of interconnection capacity, day-ahead market prices are equal between these three countries for commonly traded products; in 2008 prices were equal for 70% of the hours. The average difference

39 Installed production capacity: 15.976 MW (first quarter 2009) => 6100/15976*100%= 38%.
40 As a rule the interconnection capacity with Norway is full available under normal circumstances.

between electricity spot prices in Belgium, France and the Netherlands was 1.04 per MWh during 2007 (source APX, 9 January 2008). An extension of market coupling with Germany and Luxemburg is envisaged for the first quarter of 2010 (Pentalateral forum). Because of existing agreements with Norway a separate implicit auction between the Netherlands and Norway has to be put in place before the end of 2009. This auction cannot be combined with the trilateral market coupling in the Benelux since gate closure times between Norway and Benelux still differ.

Recently, allocation of intraday capacity started on the border of Germany/The Netherlands (method: first-come first-served) as well as on the border of The Netherlands/Belgium on basis of improved pro rata allocation. Both intraday trading mechanisms are intended to be temporarily until more market-based methods are ready for implementation.[41] The allocation of remaining interconnection capacity on an intraday basis is useful since it increases available interconnection capacity to mitigate peaks and off-peaks of intermittent generation. In this way also security of supply in the Netherlands is deemed to increase.

Conclusion

Based on the description of the current situation on different issues relevant for the integration of RES-E/DG in markets and networks, the current stages of market and network integration can be established.

Market integration

Since the actual market penetration of intermittent RES-E/DG in the Netherlands is small one could conclude that the current stage of market integration is stage A (protected niche market). However, when looking at the current market design and the actual opportunities of RES-E/DG this corresponds more with an advanced stage of market integration (stage B) since:

- A feed-in market support scheme already is in place
- RES-E/DG already provides some ancillary services through aggregators
- Balancing market design is characterized by balancing responsible parties including RES-E/DG, short gate closure time of day-ahead market, deployment of load for emergency situations through interruptible contracts and a national organisation.
- This could indicate that the Dutch electricity markets should be well capable to integrate moderate levels of RES-E/DG penetration without significantly altering current market design.

Combining our observations on the current level of network and market integration for the case of the Netherlands we state that the starting point is *protected niche market* / *RES-E/DG in the market*.

Network integration

The transmission network in the Netherlands is increasingly deployed with steering and control possibilities like HVDC cables and phase shifters. However, the distribution networks are still managed by the ‘fit-and-forget’ philosophy, implying monitoring and control possibilities of network (actors) are highly limited. Network regulation is characterized by emphasis on achieving of short-term benefits, although incentives for quality regulation are implemented. However, explicit incentives for innovation are missing and implicit incentives probably discourage DSOs to invest in projects with higher risks due to the first mover disadvantage resulting from yardstick competition.

[41] CWE regulators recently consulted market parties about the market-based method to be implemented.

Consequently we conclude that the current network integration stage is *performance-based networks.* The figure below combines the identified current market and network integration stages thereby fixing the starting point in the road map framework, see Figure 6.3 below.

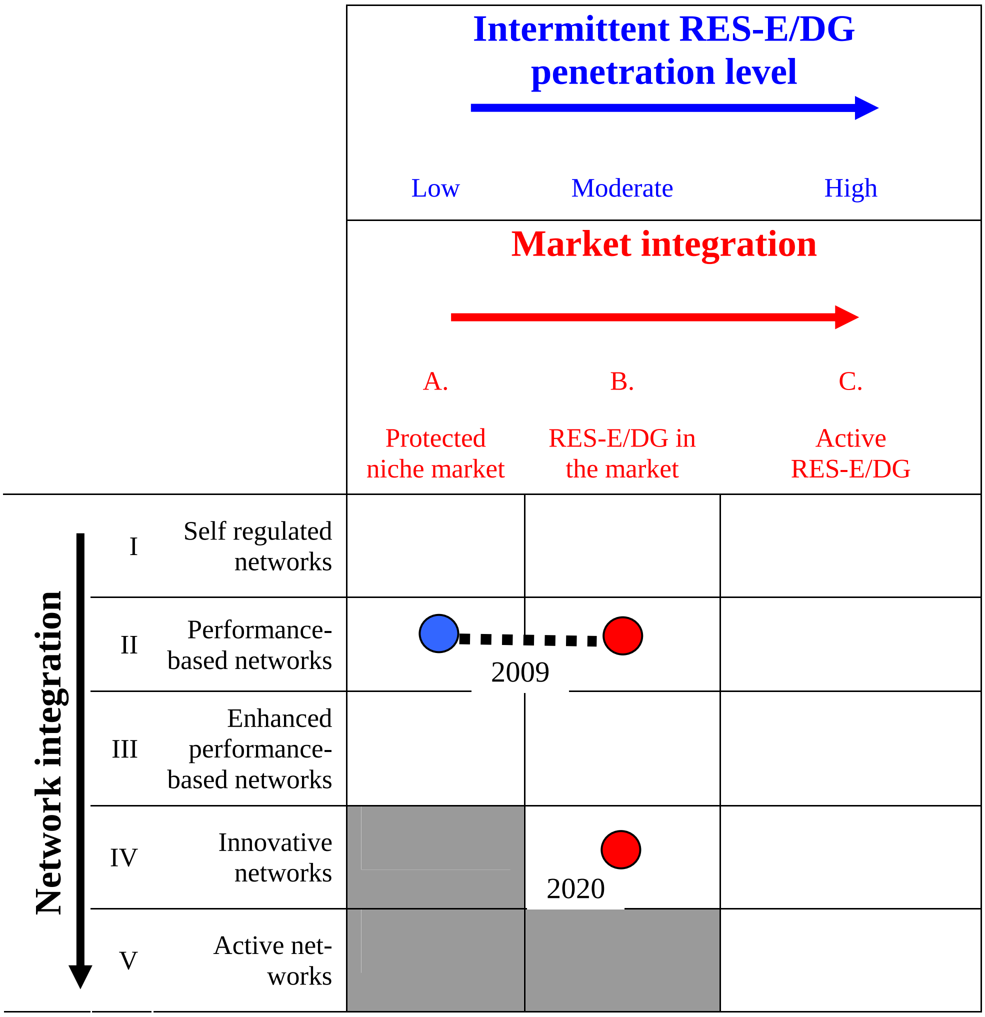

Figure 6.3 *Regulatory road map scheme The Netherlands: starting and end point*

6.2.3 Steps in regulatory road map

In order to reach the end-point of the road map in 2020, starting from the current situation (see Figure 6.3) an optimal route concerning market and network regulatory actions towards the end-point has to be determined. Since the route crosses one network integration stage that requires a different set of measures, an intermediate regulatory stage (RES-E/DG in the market and enhanced performance based networks) has to be defined. This step is useful in the timing of regulatory actions, i.e. which actions may be directly implemented and which actions may be implemented a few years before 2020, for two reasons. First of all, it prevents that cost-efficient and optimal measures of intermediate integration phases are ignored. Secondly, the step restricts the size of the package of required measures, offering stakeholders the opportunity for conscious choices concerning the implementation of measures.

The regulatory step is a vertical shift to the next stage of network integration, while concurrently some actions can be taken to improve the market integration further within its current stage. The recommended actions are largely given in the guidelines connected to the network and market integration phase at hand, see Table 3.3 and Table 3.4 respectively. In addition some country-specific measures are provided, which are tailored to the specific system conditions of The Netherlands.

For *RES-E/DG in the market* the following recommendations are made:
– Increase *generation flexibility*
– Implement feed-in market premium *support scheme*
– Increase *demand response*
– Implement measures to *increase balancing market efficiency*
– Enable *provision of ancillary services by DG.*

For *Enhanced performance based networks* the following regulatory recommendations are made:
– Implement shallow and regulated *connection charges* plus GUoS charges for covering remaining network costs
– Integrate RES-E/DG in *network planning*
– Implement market-based *congestion management methods.*

All recommended regulatory measures are discussed extensively below per system segment.

RES-E/DG in the market

Generation flexibility
Since investment decisions regarding generation are left to the market, new investments cannot be directly influenced by the government, although the government still is able to change institutional boundary conditions for the promotion of RES-E/DG integration like the subsidy level for RES-E/DG. Especially, issuing of building permits for generation can be organised more efficiently in The Netherlands, not only for RES-E/DG but also for flexible conventional generation. A fast construction of new flexible generation probably will limit the system integration costs of renewable generation to a high extent. Therefore, an *one-stop shop approach* may be introduced *for* investors planning *new flexible generation* like gas-fired power plants.

The flexibility of the generation market can be further improved by introducing *the possibility of negative prices at power exchange APX* to stimulate wind power to control their production and to act in accordance with market prices which fully reflect system conditions. Without negative market prices, the lower price floor of zero limits the reflection of system conditions in market prices. Consequently, wind generation probably will not react to low or even zero market prices since the market premium for wind generation exceeds the very low marginal costs of wind. The introduction of a negative price floor is currently under discussion. It is recommended to introduce a negative price floor in order to resolve large unevenness between supply and demand at lower costs, to the benefit of the power system as a whole.

Support schemes
A *feed-in market premium scheme* already has been introduced in 2008. Marginal changes to the premium level are required to account for the decrease of RES-E/DG production technology costs and changes in market prices. Furthermore, the premium level may be decreased in order to stimulate RES-E/DG to consider provision of services to ancillary services markets instead of producing for energy markets only.

Demand response
Concerning meters, *standardisation efforts* for the roll-out of *smart metering* have to be finalised. Among others, meters have to be able to measure and bill consumption in real-time and need to offer possibilities for advanced load control and communication with neighbouring meters. Besides, it has to be decided how to deal with the non-obligatory character of the large

scale metering roll-out. Finally, *common communication standards* have not yet been defined and need to be developed.

Concerning prices, suppliers should prepare customers connected to the low voltage level for the introduction of smart meters by *introducing simple time-differentiated* (peak, off-peak and shoulder) *prices* for these customers.

Furthermore, the functioning of *smart HAN to control load automatically* in response to price signals has to be demonstrated at larger scale. These systems will be connected to the smart meters in order to lower transaction costs of consumers in reacting to variable prices.

Balancing market efficiency
The Scandinavian type of balancing market in the Netherlands is maintained. This system is characterized by program responsibility for all connected parties (including RES-E/DG), gate closure time of one hour before real-time, and one national market for the whole country.

Surveys will be executed for the introduction of *cross-border balancing*. Due to the complexity and interests of different parties, introduction cannot take place earlier than in the medium term.

The current *restriction of changing initial energy programs (E-programs)* only 1500 times a year without payment to the TSO is assumed to be abolished to allow for more frequent changes of E-programs and therefore lower system cost for generators. Especially wind power producers may need more costless possibilities to change their E-programs in accordance with changes in wind power expectations (the forecast error of wind diminishes considerably in the time span between the day-ahead expectation and one hour before real-time).

Provision of ancillary services by DG
Introduce possibilities for provision of ancillary services by RES-E/DG by removing both too restrictive technical requirements for the provision of these services and compulsory provision of ancillary services by conventional generation only (like the provision of primary control which is currently not paid for). Too restrictive technical requirements may include minimum size limits to either aggregators of a portfolio of small distributed generation assets as well as limits to the size of the underlying individual installations or connections. Removal of these requirements, increases opportunities of RES-E/DG to participate in these markets.

Enhanced performance-based networks

Network charging
All *connection charges* will be shallow. Therefore, distribution network connections higher than 10 MVA will move from covering deep costs to covering shallow costs. This removes different treatment of generators connected to different voltage levels.

Costs of network reinforcements which are not covered by connection charges will be covered by *use-of-system charges* levied on both generators and consumers instead of consumers only. This will guarantee a more efficient allocation of costs between generators and consumers. Currently, although generators do have clear benefits from network reinforcements in transporting their produced energy, they are not obliged to pay part of the network reinforcement costs.

In order to avoid opposition of inland generators which face competition from generators originating from other countries, the reintroduction of use-of-system charges in the Netherlands should be accompanied by the introduction of comparable use-of-system charges in neighbouring countries. Therefore, coordination of this topic within the CWE region is required.

Network planning
The *new coordination procedure* to overcome social objections at a local or regional level against important network reinforcements helps to reduce the construction time of new lines or cables. Better coordination of network planning is guaranteed through the shift of operation and ownership of networks of 110 and 150 kV from the DSOs to the TSO.

It is suggested to *align network security standards with economic optimal security standards*. Up to now network security standards are quite stringent (n-1 and additional requirements) and probably at higher level than necessary from an economic point of view; the marginal costs of security standards are in general perceived to be higher than marginal costs of disturbances (see among others Ajodhia, 2006). For implementation of more optimal network security standards surveys need to be done and support from the system operators need to be guaranteed. Recently, it has been decided that N-2 network security regulation will be abolished and that N-1 regulation should be relaxed *temporally* in areas with congestion, before new network reinforcements are in place, in order to be able to transport energy produced by intermittent sources.

Furthermore, *incentives for investments by DSOs in new distribution network management approaches* are limited in regulation. The limitation of these incentives seems to be strengthened by the application of yardstick competition on top of price-cap regulation of DSOs which provides a first mover disadvantage with respect to risky investments to DSOs. In order to change the focus of DSOs more to the long term, *explicit positive incentives for innovation like IFI or RPZ in the UK need to be implemented*. An Innovation Funding Incentive (IFI) type of scheme permits DSOs to spend up to 0.5% of its allowed revenues on eligible IFI projects related to any distribution system asset management aspect. DSOs can be given a special allowance in the RAB to stimulate network innovation (Jansen *et al.*, 2007). Demonstration projects like Regulatory Power Zones (RPZ) stimulate DSOs to connect new DG to their systems by using innovative and more cost efficient ways. Preferably, both public and private institutions should participate in such demonstration projects in order to attain sector-wide demonstrations and knowledge exchange. Both measures will reduce the risks for the network operators to integrate RES-E/DG in an innovative way.

Congestion management
In 2011 probably a new law will become in force, allowing *market-based management of congestion throughout all areas of The Netherlands* by TSO TenneT. Non-market based congestion management will be phased out after 2011. Possible adverse effects of the envisaged congestion management scheme like exercise of local market power should be mitigated by alternative system design. Nodal pricing is generally acknowledged as the most efficient way of congestion management and should therefore be considered.

This law probably will be accompanied by an *exemption for renewable generators* to participate in this scheme ('priority dispatch'). The scheme is yet under design, and some choices still need to be made. As argued before, the priority dispatch regime does not have added value and should therefore not be implemented.

Concerning *congestion management on cross-border interconnections*, market coupling in the day-ahead time frame within the Pentalateral Forum has been realised, implicit auctions are expected to be in place on interconnections with Belgium, France and Germany. As a result, an implicit auction for the *day-ahead* time frame with Norway has been introduced and an implicit auction with the United Kingdom is in preparation. Implicit auctions for the *intra-day* time frame with Belgium and Germany are in preparation as well. For time frames longer than day-ahead, energy is traded separately from capacity in explicit auctions with Belgium and Germany.

6.2.4 Last step towards the end point

Based on the expected market and network impacts in 2020, Section 6.1 has already identified the end point and so the required market and network integration stages (RES-E/DG market and innovative networks). Together with the description of the starting point as well as intermediate steps between starting and end point, the whole road map can now be defined, see Figure 6.4.

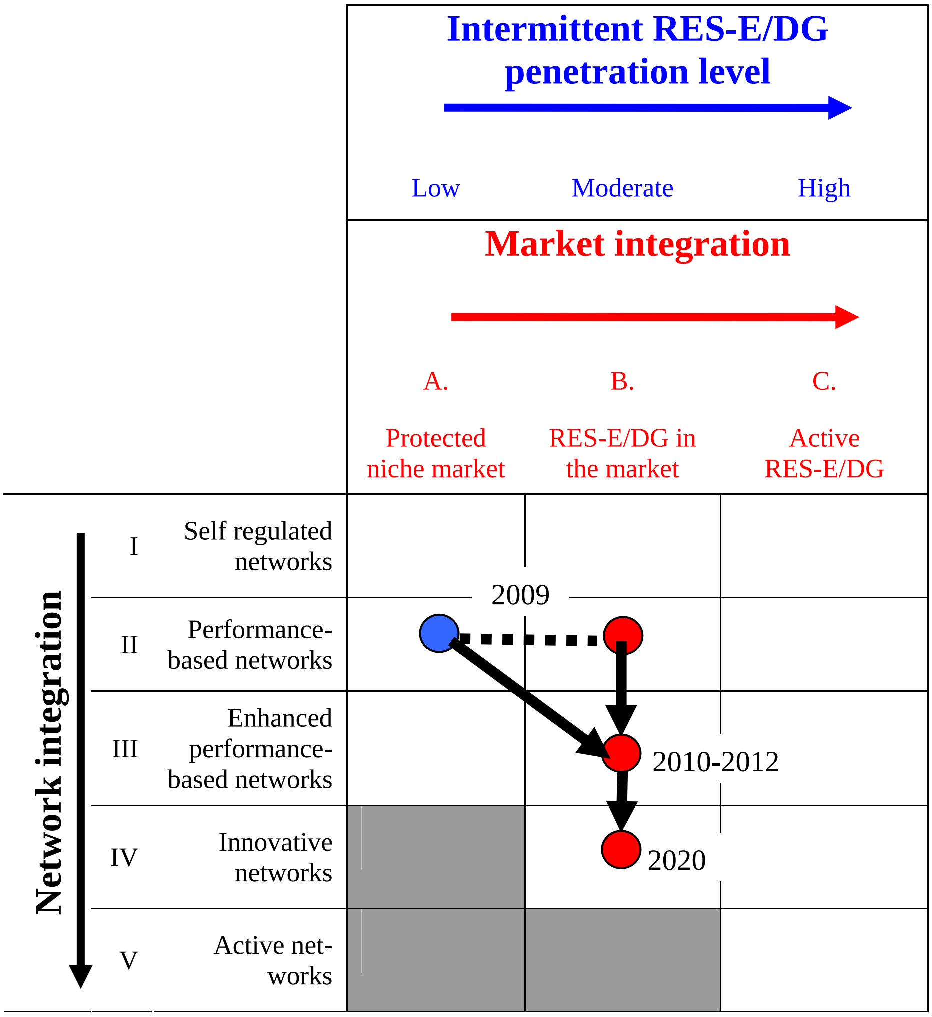

Figure 6.4 *Regulatory road map scheme The Netherlands: complete route 2009-2020*

The last step consists of a vertical shift to the next stage of network integration as well as further reinforcement of market integration within the current market integration phase. With help of Table 3.3 and Table 3.4, recommendations are again coupled with the regulatory market and network phases selected as end points. Besides, some country-specific measures are provided, which are tailored to the specific system conditions of The Netherlands.

For *RES-E/DG in the market* the following recommendations are made:

– Increase *generation flexibility*
– Implement feed-in market premium *support scheme*
– Increase *demand response*
– Implement measures to *increase balancing market efficiency*
– Enable *provision of ancillary services by DG*

For *innovative networks* the following regulatory recommendations are made:

– Implement shallow and regulated *connection charges*, basic time and/or location differentiated *GUoS charges*
– Integrate RES-E/DG in *network planning*
– Implement market-based *congestion management methods*

All recommended regulatory measures are discussed extensively below per system segment.

RES-E/DG in the market

Generation flexibility

A high share of gas-fired power plants in the generation mix will be still in place in 2020. Therefore, *additional incentives to guarantee investments in new flexible power plants* seem not necessary to mitigate the increase in volatility of the residual load (after subtracting intermittent generation). If necessary, the contracting of a certain amount of regulating and reserve power and emergency power outside the market can be extended to account for the additional demand for flexible generation in order to balance supply and demand during extreme system conditions.

CHP generators increasingly add heat storages or back-up boilers to their plants in order to obtain the possibility to decouple heat and electricity production for gaining (additional) generation flexibility.

Support schemes

For RES-E/DG the *feed-in market premium system* is assumed to be still in place. Market premiums are adapted downwards according to the higher efficiency of new technologies and concomitant lower costs, but at the same time are corrected upwards due to higher expected market prices. Market premiums for CHP production will decline more strongly, since avoided CO_2 emissions by deployment of CHP generation will decrease in time due to emission reductions of conventional production technologies.

Moreover, feed-in market premiums for different technologies will be calculated on weekly or monthly basis instead of a yearly basis. An increasing calculation frequency of market premiums provides stronger incentives to RES-E/DG to take into account system conditions.

Demand response

Concerning meters, the *large scale roll-out of smart metering* is assumed to be finalised. Concerning prices, given hourly metering the default rate should be hourly market prices, and customers should be discouraged to choose a fixed rate. A fixed rate implies a cross-subsidy to customers with a large consumption in expensive hours. Fixed price components, especially for households, should be reduced or changed to a %-type of components. However, in doing this it should be considered that annual revenues (and bills) become more volatile than with fixed components.
Furthermore, *automated smart HAN* need to be introduced to offer opportunities for consumers to react to variable market prices and network charges at low transaction costs.
Finally, smart meters are mainly used for detecting of fraud and billing, but increasingly new applications are introduced. Therefore, *pilot projects* have to be conducted for testing the communication infrastructure *required for smart metering with an even higher frequency* (every PTU i.e. 15 minutes) for enabling a wider range of applications of meters (e.g. steering network flows).

Balancing market efficiency

Interruptible contracts are not longer limited to large loads only, but increasingly used by the TSO to contract medium and small sized generation and loads (through VPPs) as well.

Cross-border balancing will be introduced within the CWE region in order to lower balancing costs for system participants through larger balancing markets as well as to increase security of supply during tight system conditions.

Relaxation of prequalification criteria for provision of secondary reserves is considered because current requirements are directed to central capacity. Alteration of the requirements for the offering of regulating and reserve power could facilitate the bidding of DG as regulating and reserve power (Van der Veen, 2007).

Provision of ancillary services by DG
Not only virtual power plants consisting of horticulture CHPs only, but also VPPs with a mixed portfolio of wind turbines, (micro-) CHPs units and loads are assumed to operate in ancillary services market such as the provision of tertiary reserves and emergency power.

The design of ancillary services markets may be changed to allow for a better trade-off for RES-E/DG between either the provision of energy or the provision of one of the different ancillary services. In this respect, ancillary services markets or auctions are more efficient than self procurement by TSOs, compulsory provision of services by RES-E/DG or bilateral contracts (the latter are less transparent). Currently, a number of services are already contracted through auctions. The *establishment of more ancillary services markets or the possibility for generators to close bilateral contracts* enables RES-E/DG production technologies to provide a wider variety of ancillary services when they dispose of the required technical capability. For instance, wind turbines will be able to provide primary control services in the near future. These new market opportunities may be valuable for RES-E/DG producers in diversifying their revenue streams.

Innovative networks

Network charging[42]
All *connection charges* will be shallow. Therefore, distribution network connections higher than 10 MVA will move from covering deep costs to covering shallow costs. This removes different treatment of generators connected to different voltage levels.

Costs of network reinforcements which are not covered by connection charges will be covered by *use-of-system charges* levied on both generators and consumers instead of consumers only. This will guarantee a more efficient allocation of costs between generators and consumers. Currently, although generators do have clear benefits from network reinforcements in transporting their produced energy, they are not obliged to pay part of the network reinforcement costs.

In order to avoid opposition of inland generators which face competition from generators originating from other countries, the reintroduction of use-of-system charges in the Netherlands should be accompanied by introduction of comparable use-of-system charges in neighbouring countries. Therefore, coordination of this topic within the CWE region is required.

Since the network impacts of RES-E/DG differ to time and location, *basic time and/or locational differentiated* GUoS charges should be implemented. In this way, generators receive an incentive to behave in accordance with system needs when deploying their units. Many small generators already dispose of smart metering since telemetering for every 15 minutes is required in the metering code for network connections of 0.1 MW and larger. In order to offer possibilities to consumers to react to changing network charges, smart metering need to be introduced in

[42] In the Netherlands, network charges are an important part of total electricity costs for consumers. Excluding energy taxes and rebates, an average Dutch consumer paid €162 network charges and €277 for electricity supply (2007 figures, based on ERGEG, 2008a). As a result, roughly one third of total costs excluding taxes concerns network costs.

the medium time frame. Before the large scale roll-out of smart meters, standardisation efforts need to be finalized in the short-term. Large scale roll-out of meters with more functionalities is favoured due to the lower costs of a large scale roll-out versus a more individual consumer approach. Existing regulation of metering enables such a roll-out. Furthermore, automated smart HAN need to be introduced in the medium term for lowering transaction costs of reacting to variable network charges by households.

Implementation of locational differentiated GUoS charges may be hindered by the volatility of these types of network charges due to high volatility of network reinforcement costs. Consequently, in Grohnheit *et al.* (2009) the implementation of zonal network charges is advised. Tariffs need to be computed for each type of profile in advance of actual operation. Besides, discrimination between new generators which have to pay UoS charges and generators under the old regime which did not have this obligation is perceived as unfair. Before introduction of locational tariffs, therefore demonstration projects on the applicability and benefits of this type of initiatives need to be launched. As a result, locational charges probably can be introduced only in the long term after the introduction of time-dependent charges in the medium term.

Network planning
New transmission lines both national and international will enable a higher transport of electricity originating from renewable sources. The new transmission lines for projects Randstad 380+, North-West and South-West of The Netherlands are assumed to be ready in 2020. With respect to cross-border interconnections, planned interconnections with the UK, Germany and Denmark are assumed to be in operation at this date. For some additional required transmission lines, it might be necessary to bury them in order to gain social acceptance for their construction in densely populated areas.

Following the surveys towards more optimal security standards from a socio-economic point of view, it is recommended to *introduce dynamic reserve requirements* dependent on the actual wind forecasts with its embedded variance in network planning standards. Consequently, reserve requirements and concomitant system costs could be reduced for most of the time without compromising security of supply (Zvingilaite *et al.*, 2008).

Besides, *advanced network simulations tools* are required to provide insight in the most efficient way of network reinforcement, either by conventional investment in new cables and lines or by adding intelligent network monitoring and controlling devices to the grids. These simulation tools will make it easier to measure and monetise benefits and costs of active network management (ANM) and the potential contribution of RES-E/DG to ANM. For instance, potential benefits of new network approaches like higher quality of service and lower energy losses are currently difficult to monetise due to the absence of a public available and commonly agreed upon network simulation tool or reference model within the Netherlands. Both TSO and regulator can use such a tool for better coordination and optimization of network planning. Among others this seems a useful tool for evaluation of (exceptional) network investments by the NMa or experts on behalf the regulator before they apply for remuneration (Jansen *et al.*, 2007). Nowadays, the regulator has to evaluate investments partly by using simple indicators, since network planning models are not directly available.

Supervision of network investments should be increased in order to stimulate network reinforcements and the consideration of new, innovative network management approaches. Consequently, instead of exceptional network investments only, all investments above a certain threshold have to be reviewed by the regulator or experts on behalf of the latter (implying a move from the TOTEX approach which considers capital and operational costs in an integrated way, to the building blocks approach which considers capital and operational costs separately).

Demonstration projects about active network management should be put in place to increase the experience of DSOs with new network management approaches, and lower risks for investments in ANM.

Congestion management
The complexity of the national congestion management scheme may be limited by *predetermined nodal/zonal factors for systematic predictable congestion*. These factors could vary depending on time of day, week and year to compute the constrained energy dispatched, and therefore generators to be curtailed, in a less complex way. Congestion on cross-border connections is envisaged to be dealt with by *implicit auctions for allocation of network capacity in the intraday and day-ahead time frames* on borders with Belgium, Denmark, Germany, Norway and United Kingdom. At the same borders, explicit auctions are expected to remain in place for allocation of network capacity in longer time frames. *Auctions are coordinated* at least *regionally within the CWE region*, in order to make available as much network capacity to the market as possible. Therefore, *common transmission models are introduced for capacity calculation* as well as for preventing unexpected load flows. This will help to increase the current available network capacity to market parties of approximately 3,600 MW to the net transfer capacity of current interconnections of 6,100 MW. The envisaged new interconnections with the UK, Germany and Denmark will probably add 3,000 MW[43] to this figure.

6.3 Action plan for implementation

The implementation of the identified recommendations should be supported by an effective set of actions of system actors or stakeholders. All these actions can also be seen as recommendations from the regulatory road map for The Netherlands, which is summarized in Table 6.4 below. The Table indicates the market parties or organisations who are first responsible for preparing and approving these recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020.

Based on the road map description we select the most urgent and critical actions to improve the system flexibility **in the short term**. The road map indicates that the main actions are required for better network integration. First of all, network integration can be done against lower costs if generators have to take into account *use-of-system charges for generators* which influence generators' production and siting decisions. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Finally, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning standards in the longer term.

[43] Interconnections with these countries extend interconnection capacity with 1000, 1500 and 700 MW respectively. The additional total transfer capacity (TTC) of 3200 MW is reduced to a net transfer capacity of 3000 MW to account for the expected transmission reliability margin (TRM).

Table 6.4 *Action plan for implementation of the Regulatory road map of The Netherlands*

	Action	Responsibility		Term
		Prepare & implement	**Approve**	
Market integration	***Generation flexibility***			
	Diminish lead times for investments in new flexible generation by introducing one-stop shop approach for licensing/permits	Ministry of Economic Affairs	-	short
	If necessary contract higher amount of regulating and reserve power outside the market	TSO	Regulator	medium
	Add heat storages or back-up boilers to CHP units	RES-E/DG operators	-	medium
	Support schemes			
	Introduce possibility of negative prices at APX	APX	Ministry of Economic Affairs	short
	Decrease market premium to stimulate RES-E/DG to consider provision of system services	Ministry of Economic Affairs	-	medium
	Demand response			
	Finalize standardisation efforts for roll-out of smart metering	Whole sector	Ministry of Economic Affairs	short
	Define and develop common communication standard	Whole sector	Ministry of Economic Affairs	short
	Introduce time-differentiated prices for small customers	Suppliers	Regulator	short
	Demonstrate functioning of smart home area networks for automatic load control	Suppliers	-	short
	Introduce smart metering at premises of low voltage customers	DSOs	Regulator	medium
	Implement smart home area networks for automatic load control	Suppliers	-	medium
	Pilot projects for testing communication infrastructure for smart metering with high frequency	DSOs	-	medium
	Balancing and ancillary services markets			
	Introduce possibilities for provision of ancillary services by RES-E/DG	TSO	Regulator	short
	Remove restriction for changing of initial energy programs max 1500 times a year	TSO	Regulator	short
	Introduce cross-border balancing within CWE region	CWE TSOs	CWE Regulators	short/medium
	Extend the use of interruptible contracts to loads and small generation	TSO	Regulator	medium
	Lower prequalification criteria for offering secondary reserves to technical and economic minimum	TSO	Regulator	medium
	Establish ancillary services markets (primary control) or the possibility to close bilateral contracts (reactive power)	TSO	Regulator	medium

Network integration	***Network charging***			
	Reintroduce UoS charges for G for covering remaining network costs	TSOs in CWE region	Regulators CWE	short
	Implement basic time differentiated UoS charges for generators	TSOs in CWE region	Regulators CWE	medium
	Network planning			
	Account for differential DG impacts in network regulation	Regulator	-	short
	Introduce explicit innovation incentives in regulation (IFI and RPZ type)	Regulator	-	short
	Evaluate current network security standards (a.o. N-2 and N-1 regulation)	Regulator	-	short
	Implement dynamic reserve requirements in network planning standards	TSO	Regulator	medium
	Implement network simulation tool for better coordination of network planning and better evaluation of network investments	Regulator	-	medium
	Congestion management methods			
	Do not implement planned priority dispatch for renewables during congestion	Ministry of Economic Affairs	-	short
	Introduce implicit auctions for day-ahead time frame on interconnections with Germany and Norway	CWE & Northern region	Regulators CWE	short
	Implement market-based national congestion management method	Whole sector	Regulator	short/medium
	Use predetermined nodal/ zonal factors for systematic predictable congestion	Whole sector	Regulator	medium
	Introduce implicit auctions for the intra-day time frame within CWE region	CWE	Regulators CWE	medium
	Use common transmission models for capacity calculation	TSOs CWE	Regulators CWE	medium
	Coordinate capacity allocation through regional auction offices	TSOs CWE	Regulators CWE	medium

7. Regulatory road map for Spain[44]

7.1 Outlook of RES-E/DG and the electricity system

Developing a country regulatory road map requires insight into the particular characteristics, i.e. development RES-E, regulation, other system conditions, and the possible transition of that country's electricity system until 2020. Several aspects are covered, such as the generation mix and generation mix developments, current network conditions (interconnection and quality) and institutional characteristics to provide sufficient background information to assess the different stages of the road map.

Demand and generation

Spanish electricity demand is expected to increase by about 2% per annum in the period 2010-2020 (Eurelectric 2005), with relatively larger growth in the transport and services sectors (about 3% growth). Table 7.1 and Table 7.2 show future intermittent RES-E/DG capacity in Spain.

Table 7.1 *Overview of projections of installed* RES-E/DG *capacity in the Spanish electricity mix (in GW)*

RES-E/DG technology		Scenario		
		Eurelectric	Primes	MITYC[45]
Onshore wind				
	2005	8,26	9,93	11,23
	2010	17,67	16,36	22,00
	2015	n/a	25,71	29,00
	2020	27,75	33,69	-
Offshore wind				
	2005	n/a	n/a	n/a
	2010	n/a	n/a	n/a
	2015	n/a	n/a	n/a
	2020	n/a	n/a	n/a
PV				
	2005	0,02	0,05	0,06
	2010	0,21	0,43	1,50
	2015	n/a	0,86	4,00
	2020	0,51	1,83	-
Total generation by RES-E/DG				
	2020	28,26	35,52	-
Total installed capacity				
	2020	110,14	109,13	-
RES-E/DG share of total installed capacity				
	2020	25,66%	32,55%	-

[44] This road map is mainly based on information provided by IIT University Comillas and REE and the joint responsibility of ECN, IIT University Comillas and REE. We thank IIT University Comillas and REE for their co-operation.

[45] Source for these figures is Ministerio de Industria, Turismo y Commercio (MITYC) (2008). Cited figures are for the years 2006, 2011, and 2016 respectively.

Table 7.2 *Overview of projections of* RES-E/DG-*based electricity generation in the Spanish electricity mix (in TWh)*

RES-E/DG technology		Scenario Eurelectric	Primes	MITYC[46]
Onshore wind				
	2005	16,10	21,22	23,40
	2010	33,70	35,26	47,00
	2015	n/a	60,29	62,00
	2020	52,80	78,19	
Offshore Wind				
	2005	n/a	n/a	n/a
	2010	n/a	n/a	n/a
	2015	n/a	n/a	n/a
	2020	n/a	n/a	n/a
PV				
	2005	0,00	0,79	n/a
	2010	0,20	3,21	n/a
	2015	n/a	5,69	n/a
	2020	0,40	9,06	n/a
Total installed RES-E/DG				
	2020	53,20	87,25	-
Total electricity generation				
	2020	388,40	386,82	-
RES-E/DG share of total electricity generation				
	2020	13,70%	22,56%	-

Recent estimates for intermittent RES-E/DG capacity are taken from data provided by the regulatory commission (CNE)[47]. At the beginning of 2009 installed generation capacity of wind (solely onshore) is 15.2 GW. Total PV capacity in 2009 was 3.2 GW.

The potential for Spain to increase the share of RES in electricity generation is mainly in onshore wind and PV. Offshore wind is a very limited option due to deep water conditions. Apart from this geological disadvantage the public acceptance for creating large offshore wind projects is negatively influenced by the large dependence on tourism in a large number of coastal areas. In contrast with offshore wind, the potential realization of onshore wind projects amounts to about 16-17 GW in 2010, and 28-34 GW in 2020. This potential seems to be realised; according to the planning for network investments the total amount of wind-based electricity capacity will already be 29 GW in 2016 (MITYC 2008).

Current installed CHP capacity[48] is about 6.2 GW. This is primarily installed in the industrial and refinery sector. The residential sector in Spain does not provide the heat load to operate CHP in a district heating scheme profitably, owing to the climate in Spain (IEA 2005). Over the last few years, CHP plants have had to change their operating conditions, introducing running criteria that are driven by the market rather than by the desire to achieve the highest overall efficiency. This means that generation is switched off during off-peak hours and loads are reduced in medium-load periods (IEA 2005). The network planning report for the period 2008-2016 projects that CHP (cogeneration) will slowly increase to about 8 GW in 2016 (MITYC 2008). Micro-CHP is not deemed to be a viable option, mainly because of a lack of substantial heat demand for a large part of the year.

[46] Source for these figures is Ministerio de Industria, Turismo y Commercio (MITYC) (2008). Cited figures are for the years 2006, 2011, and 2016 respectively.

[47] Data is available from the website of CNE: www.cne.es.

[48] Also referred to as co-generation.

Scenario projections for PV vary between 0.5 and 1.8 GW of installed PV capacity in 2020. Even the most positive estimation of PV capacity is clearly surpassed by reality; as said before the total PV capacity in 2009 amounted already to 3.2 GW. Spanish electricity production based on PV closely follows the electricity demand pattern throughout the year and therefore causes relatively less network integration problems than the PV installed in countries in the north of Europe.

The above described developments imply an increase in intermittent RES-E/DG penetration in the Spanish electricity market in capacity terms to about 26-32% (excluding CHP). The degree to which this increase in intermittent generation can give rise to different types of intermittency problems is dependent on for example the dispersion and predictability of intermittent generation and the potential for making the generation mix more flexible.

The Spanish electricity system is considered to have good potential at the generation side to accommodate any negative intermittent RES-E/DG penetration. This is based on the observed pumped-hydro capacity and potential and the presence of flexibly gas-based peaking units. Total hydro-based capacity at the beginning of 2009 amounted to about 16 GW. This capacity is expected to increase to about 20 GW in 2016 (MITYC 2008). Spanish electricity system planning assumes an increase in the amount of gas-based electricity peaking generation to a total of 3 GW in 2016 (MITYC 2008).[49]

On the other hand, current interconnection capacity with Portugal and France is relatively limited compared to total available generation capacity at national level. According to ETSO, during the winter 2008/2009 period NTC values for interconnections to France and Portugal amounted to 1400 MW and 1200 MW respectively. As a result, the interconnection capacity in NTC terms is only 3% of the installed production capacity at national level.[50]

The transition of the electricity supply system described above has consequences for the electricity system as a whole: it has an impact on the distribution network, the transmission network, and the balancing market.

Networks
For the impact of future RES-E/DG capacity integrated in the electricity system it matters whether new units are connected at distribution or at transmission level. From detailed data from CNE we derive which share of current RES-E/DG capacity is connected at transmission and distribution level. These shares are presented in Table 7.3. We observe that only 11 and 2 % of respectively CHP and PV generation capacity is connected to transmission networks. However, 49% of total wind capacity is connected to transmission networks.

Table 7.3 *Allocation of* RES-E/DG *units over transmission and distribution networks*

	Unit	CHP	PV	Wind
Transmission level	[MW]	699	64	7474
	[%]	11	2	49
Distribution level	[MW]	5509	3142	7713
	[%]	89	98	51

[49] However, there is currently strong uncertainty about the profitability of recently installed CCGT plants due to the reduced capacity factors for these units resulting from the already high penetration of DG/RES, and the economic downturn. See discussion in Section 7.4.
[50] Installed production capacity: 75.300 MW (2004/2005, blueprint) => 2600/75300*100%= 3%.

The main impact on *distribution network* operations and management will be caused by PV and small-scale wind parks / turbines. The impact of PV in 2010 on networks is expected to be largely positive: in 2010 it is envisaged that installed PV capacity will become about 1% of peak load, and will therefore contribute to 0.75% and 0.25% network loss reduction in rural and urban distribution networks respectively (Ramsay *et al.* 2007, p. 103). In general, PV is able to closely match electricity demand geographically and in time (over seasons). In addition, a substantial share of new wind capacity will be connected to the distribution networks. This ‘local’ feed-in may give rise to high to very high intermittent RES-E/DG penetration rates in a large number of areas.[51] Consequently, this may give rise to local distribution network integration problems. As mentioned before, micro-CHP will not be a viable option and is therefore neither a potential source for intermittency problems, nor part of a possible solution for intermittency problems through virtual power plants for example.

The *transmission network* will be mainly impacted by new large-scale wind parks. Large-scale wind parks are mainly located in the western Andalusia area, the areas of Aragon, Catalonia and the Region of Valencia. In order to smoothen the possible negative impact of this concentration effect, a sufficient network design and balancing zone regime will be necessary. Currently there are a substantial number of plans to reinforce the Spanish transmission network. On the one hand it concerns internal network reinforcements to accommodate wind-based generation in earlier mentioned specific parts of Spain, and on the other it concerns new interconnection capacity with Portugal and France. There is a large amount of new transmission lines and devices planned and to be commissioned until 2015 (UCTE 2007). Studies for two new interconnections of 400 kV between Spain and Portugal for reaching a commercial exchange capacity of 3,000 MW have already started.

Balancing market

The large additional volumes of wind-based electricity in the Spanish electricity system increase the importance of a well-designed and functioning balancing market. Balancing the system in an effective and efficient manner will become increasingly difficult and possibly more costly. This means that further improvements of wind prediction tools are needed. The existing and remaining potential for pumped hydro units and the planned gas-fired peaking plants will be increasingly put to use in order to keep the system intact. Another viable option to accommodate the increasing need for balancing power is the use of demand side response. DSOs can contribute to this option through increasing use of smart metering and ICT and through active network management.

7.2 End point road map

Based on the projected developments in electricity production, the 2020 sustainability targets for Spain and the Spanish RES-E potential we conclude that the likely level of intermittent RES-E/DG in 2020, estimated at about 26% of total installed capacity, can be qualified as moderate. However, this does not immediately gives us the desired end state in the generic road map scheme. To answer this question we need to discuss the likely type of problems that Spain will experience with the integration of intermittent RES-E/DG in 2020. For this assessment the identified criteria in Table 3.3 and Table 3.4 are instructive.

In general we observe that in the period until 2020, penetration of wind-based electricity generation is strongly increasing over the whole time span, while solar-based electricity generation is mainly taking a flight in the period from 2015 to 2020. This has implications for the type of problems that Spain might experience with respect to intermittent RES-E/DG.

[51] This could for example become the case in distribution areas in Castilla La Mancha, Andalucia and the eastern coast, among others.

Large penetration of wind will require increasing investments in (inter)national network connections and balancing capabilities through flexible gas-based units and (large) hydro-based units. The move towards more and more PV will mainly translate into the need for improved network operations (and possible investments) and enhanced network regulation that acknowledges the large differences in the impact on DSOs across Spain. So far, these developments could give rise to network integration issues associated with network integration stage III: Enhanced performance-based networks. However, especially the possible concentration of both a large amount of wind and PV based electricity generating units within particular distribution areas could require the development of network regulation towards innovative networks.

In Figure 7.1 we have depicted the above described envisioned 2020 end-point concerning the market and network integration stages required in Spain.

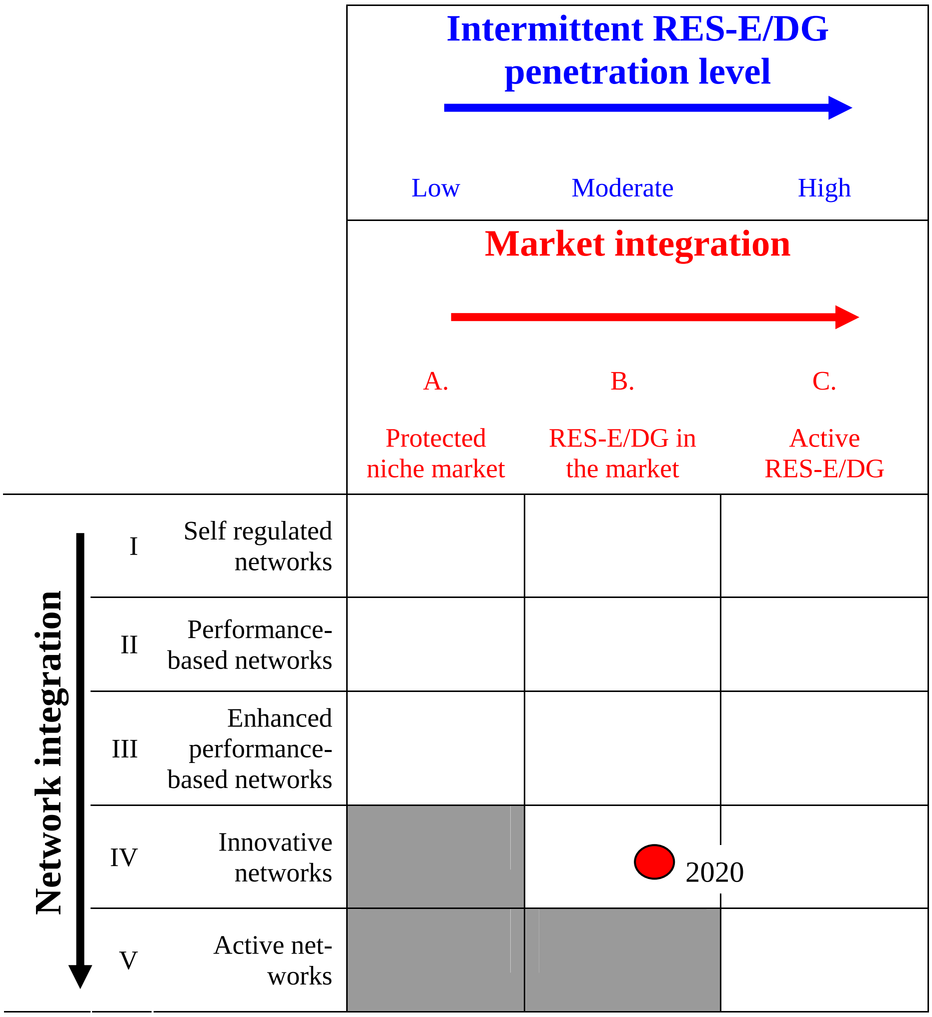

Figure 7.1 *Regulatory road map scheme for Spain: end-point*

7.3 Starting point road map

In the previous section the possible transition towards the 2020 end-point of the regulatory road map for Spain was described. It included a perspective on the possible developments with regard to the penetration of intermittent RES-E/DG in the system. Whereas the end-point of the regulatory road map with respect to the amount of intermittent RES-E/DG currently integrated in the electricity supply system is known, we need to define the starting point from a regulatory perspective. That is to say: we need to know to what degree current market and network regulation facilitates the integration of RES-E/DG in the Spanish electricity system. In our description we distinguish between the following electricity system segments:

1) Generation
2) Demand
3) Markets
4) Networks.

At the end of this analysis on the current regulatory status quo we will be able to define the starting point for Spain in the generic regulatory road map scheme.

7.3.1 Generation

One of the regulatory options that contributes to a more flexible electricity supply system is the use of time of use (ToU) differentiated tariffs, or premiums in the support scheme mechanism. Spain's support scheme for intermittent RES-E/DG encompasses feed-in tariffs for PV and feed-in tariffs and feed-in premiums for wind and CHP. Too a limited degree, Spain is currently applying such a time of use (ToU) differentiated feed-in tariffs for specific technologies between peak and off-peak hours and summer and winter. This ToU differentiated tariff is only available for co-generation, hydro units (if not larger than 50 MW) and bio-mass units.

Although the Spanish electricity market is liberalised the government has implemented various regulatory measures to ensure sufficient capacity and generation during super-peak hours. These are the so-called capacity and availability payments. Generators with a rated power equal or above larger than 50 MW receive a capacity payment per installed MW per year during their first 10 years of operation. As an additional pre-requisite, units need to belong to the 'ordinary regime' in order to receive those payments.

The level of the capacity payment is dependent on overall Spanish electricity system reserve margin in electricity generation and determined by the system operator (SO). Availability payments are implemented to guarantee the availability of generating units during peak hours. Availability is agreed upon in bilateral contracts (maximum duration one year) between the SO and the operator of the generating unit with negotiated compensation payments.

7.3.2 Demand

Accommodating fluctuations in demand and supply (for example caused by increasing generation shares from RES-E/DG) can be done by making the demand side of the electricity system more responsive.

A next step in making demand more responsive is the implementation of smart metering. Spain has in fact planned for the replacement of old electricity meters with smart electricity meters before December 2018. Each DSO is obliged to replace 30% of its old electricity meters before December 2010, in 2012 an additional 20% should be replaced, and an additional 20% in 2015. The final 30% of old electricity meters should be replaced before December 2018. In addition, demand response mechanisms should be fully operational by January 2014 (Lobato *et al.*2008).

A more extreme demand response option are interruptible contracts specifying the conditions under which electricity consumers are interrupted in their electricity supply in return for some pre-specified compensation payment. Currently, large Spanish electricity consumers connected to the high voltage networks with a contracted capacity of over 5 MW can sign interruptability contracts. Since July 1st a new type of interruptability service was introduced for especially large consumers. Five different interruptability contracts are offered with different interruption and warning time. The compensation that can be received for providing interruptability services is related to the total interruptible load to which consumers commit. Compensation fees are independent of time or geographical location. However, discounts are not geographically or time differentiated, and market mechanism to assign interruptability contracts may be useful.

7.3.3 Markets

As a general rule, a more flexible and efficient electricity system is realised when the actual consequences of differences in electricity generation and demand patterns across regions and over time are passed-through to the electricity actors. Therefore, pricing structures that enable differentiation are recommended. Furthermore, demand and generation fluctuations can be more efficiently accommodated when market rules are efficient (i.e. no market entry barriers for example). Here we briefly sketch the current room for differentiation of electricity prices on the one hand, and the functioning of the different electricity markets.

Electricity price differentiation

In principle the Spanish electricity market is currently fully liberalised. However consumers connected to the 15 kV network may choose to continue paying regulated integrated tariffs until July 2009. Differentiation in regulated electricity prices is achieved through different structures and tariff levels depending on the overall consumption level and the voltage level consumers are connected to. The commodity price of electricity is mainly determined in the Iberian electricity market OMEL. Currently, Spanish electricity legislation does not allow for geographically differentiation of electricity tariffs.

Electricity wholesale market

Spanish regulation does not contain any unit size limitations that might prevent (intermittent) RES-E/DG from participating in the electricity wholesale market.

Balancing market

Spanish regulation assumes full responsibility for electricity generation deviations for intermittent RES-E/DG operators. Hence, they pay imbalance penalties proportional to their contribution to overall system imbalance. In order to reduce their imbalance in the time between programme submission and realisation electricity generators trade on the intraday market. This market functions reasonably well. Related to the relatively high level of liquidity on the intraday market is the fact that gate closure time of the Spanish intraday market is between 2 and 6 hours approximately ahead of realisation. Only those controllable units that sell their energy in the wholesale energy market will be allowed to participate in the balancing markets by means of RD 661/2007 (the new operation procedures adapted to this RD were approved by the Spanish Industry Ministry in May 2009. Now, the SO will define the tests that the units have to pass to be considered as controllable). Thus, RES units are currently not participating in the balancing markets. Smaller generation units wishing to participate in the wholesale and balancing market may be aggregated into one entity. An additional requirement is then the installation of a so-called generation control centre that directly communicates with the TSO control centre. From the TSO control centre for RES units (CECRE), the maximum wind energy output that the system can allow under safety conditions is calculated in real time. If the actual production is higher than this value any unit connected to it can be curtailed. Wind generators, as any conventional generator, are given 15% of the spot price in case of real-time curtailment. To participate in the TSO balancing markets, the control centre has to be connected with the TSO. Besides this, new DSO operating procedures are currently being developed that enable the provision of certain ancillary services at the DSO level. In this case the DSO should be able to meter at the local RES-E/DG unit level. The costs of setting up the generation control centre are incurred by the RES-E/DG operator(s). However, RES-E/DG units that receive a constant feed-in tariff are explicitly not allowed to participate in the balancing market.

Secondary reserve market
The provision of secondary reserve is not compulsory but designed as a competitive spot market. Services can be offered by regulation zones that encompass different sets of generating units belonging to a generating company. Actual dispatch is based on signals from the SO and upward or downward regulation is rewarded symmetrically. Compensation is received based on the submitted band of regulating capacity (MW) and delivered energy (MWh). Intermittent RES-E/DG is currently not participating in the secondary regulation market in Spain. This is explained on technical and economic grounds: technical adaptations regarding load-following services are not yet sufficiently developed to warrant actual implementation and current support scheme design based on both feed-in tariffs and feed-in premiums does not encourage participation in the regulation power market over the wholesale market. Actually, 91% of the onshore wind units sell their energy in the wholesale energy market.

Tertiary reserve market
The market for *tertiary* reserve power (manually activated reserve power that is usually called upon by the TSO after utilization of secondary control to free up the secondary reserve after 15 minutes) has a similar designed to the secondary regulating market and is only active when the secondary market is exhausted. When looking at historical data on the price for regulating power one can observe that prices on average have been quite constant throughout the years, despite a considerable increase in wind-based generation capacity. This can possibly be explained by continuously improved wind forecast tools and the like.

Voltage control
Currently all generating units smaller than 50 MW (including RES-E/DG based ones), are encouraged to maintain voltage control through a *bonus/malus* scheme. The particular bonus or penalty is dependent on the degree of voltage control violation and the time of day (peak vs. off-peak hours). However, the scheme does not take into account the location of voltage control violation and therefore the incentive is not deemed optimal by DSOs. On the electricity demand-side, only large consumers with contracted capacity of over 15 MW can provide voltage control at the transmission level.
Currently, there are no organized markets for ancillary services at the DSO level. They are currently run by the Spanish TSO with neither TSO nor DSO entering contracts with RES-E/DG operators for the provision of ancillary services. However, new DSO operating procedures are currently under development, which may be the basis for direct provision of ancillary services by RES-E/DG units to the DSO in the future.

7.3.4 Networks

Electricity networks can help to achieve an efficient integration of more and more intermittent RES-E/DG units in the electricity system in various ways. On the distribution network level, actively managed networks can reduce the overall network costs incurred when connecting intermittent RES-E/DG when compared to passively managed networks. Moreover, RES-E/DG may impact the level of distribution losses in the system. When connecting new RES-E/DG capacity the DSO ideally needs to balance the costs and benefits of two options: expanding existing deep network capacity or postpone this investment and incur higher congestion costs resulting from the bottlenecks deep in the network. On the transmission level there is the issue of optimally connecting new RES-E/DG units. This can for example be done by providing locational signals to RES-E/DG operators: i.e. passing-through costs *and benefits* of connecting the RES-E/DG unit with the network to the RES-E/DG operator. Here we briefly review the current role of RES-E/DG in network operations and investment planning, on both distribution and transmission level.

Distribution networks

DSOs have an obligation to connect all generation units, including RES-E/DG, to their network. RES-E/DG operators are charged negotiated deep connection charges. In case of non-agreement a case might be taken to the National Energy Commission. However, in cases where DSOs are in fact benefiting from new RES-E/DG connections, for example through investment postponements or reductions in energy losses, there is no compensation paid out to RES-E/DG operators. At the beginning of 2008, legislation for a new regulatory framework was implemented. The new framework is performance-based and involves a revenue cap approach and regulatory periods of 4 years. The new framework doesn't only assess economic efficiency but also quality performance. One of the cost elements included, and affected by RES-E/DG, is the costs of energy losses. Particularly energy losses can be impacted in very different manner depending on network configuration and level of RES-E/DG penetration. However, the standard (target) setting procedure for energy losses performance is not explicitly considering the role of RES-E/DG penetration levels in the various distribution networks.

The new regulatory framework contains a specific mechanism to encourage efficient investment by DSOs in the face of increasing RES-E/DG units in their network. Every year within the regulatory period, incremental allowed revenue for each DSO is calculated based on increment demand and RES-E/DG penetration. This is calculated with the help of a network reference model resembling the actual DSO distribution network.

In addition, the new Spanish regulation explicitly considers RES-E/DG as a cost driver in the DSO benchmarking exercise. This should ensure that the differential impact of RES-E/DG on DSO operations across Spain is recognised in determining the individual efficiency factors.

In the current regulatory design under which DSOs operate there is no incentive for innovation. This fact is actually one of the reasons why the current revision of the regulatory design takes place. No Spanish DSO has currently implemented elements of active network management. However, there is a national program where demonstration projects are funded by the Ministry of Industry together with private companies, and research in this field is also contemplated as a European research priority line known as Smart Grids under the 7th Framework Programme (Andersen *et al.* 2009).

Transmission network

In Spain, electricity generators whether connected to the transmission or distribution network in general do not pay use of system charges. Changing this feature would require an adaptation of the current energy law. Connection charges for generating units connecting to the transmission network are based on a shallow connection charge philosophy. The development of the transmission grid (construction of new lines) faces significant obstacles that have to do with the perception by the public and authorities of the effect that lines may have on human health and the environment. This may result in construction times for some lines being as long as 10 years or more.

Congestion management

Currently re-dispatching of generators is applied when congestion occurs. Thus, no locational signal in the form of locationally differentiated energy prices is being sent to generators. Besides, given that the re-dispatch mechanism presently applied has some design flaws, use of scarce transmission capacity of the network may not be efficient. Wind-based electricity can be curtailed by the system operator with limited payment to wind generators when overall system safety rules are under threat. Moreover, the TSO can curtail the production of any RES, but only as last resource. The priority rules to curtail the production due to technical constrains are: (1) 'ordinary regime', (2) special regime (units no larger than 50 MW), of which first non-RES units, and second RES units.

Unbundling
Spanish legislation has implemented legal unbundling of electricity generating and electricity distribution and transmission activities. This implies that DSOs can only indirectly own generating units. However, an exemption exists for very small DSOs, which is conform EU legislation. Both in the cases of legal unbundling and the cases where the exemption holds, a limited number of possible discriminatory practices and conflicts of interests have arisen when 'third party' RES-E/DG units applied for network connections. These cases were taken up by the Spanish energy regulator CNE.

Conclusion
Having described the current Spanish electricity system and the current state of intermittent RES-E/DG developments we observe the following. The current (2006) penetration rate of intermittent RES-E/DG, when measured as percentage of total generation capacity, is about 14%. This can be deemed as a considerable, but still relatively low, penetration rate. Almost 99% of this is related to wind-based generation of which about half is connected to the transmission network. This means that when based on the penetration level only, the required stage of market integration should be stage A. However, due to the large concentration on wind-based generation, there are reasons to believe that the actual current stage of market integration could be stage B, mainly because of the impact of wind generation on balancing markets. This has for example resulted in RES-E/DG paying for imbalance penalties, the development of an intraday electricity market, and the implementation of so-called control centres.

The current stage of network integration, see section 7.3, is derived from confronting the described network regulation aspects with the criteria in the table on network integration in chapter 3. It seems that Spain is currently at stage II of network integration. This is mainly based on the observation that current network regulation is not so much taking into account differential impacts of RES-E/DG on different network operators: the network regulatory regime is very generic. On the other hand, regarding network investments and investment planning on a more national and international level it seems that stage III is approached. Therefore, we have identified the starting point of the regulatory road map for Spain at the borders of II.A and II.B. Figure 7.1 presents the start and end point of the regulatory road map for Spain.

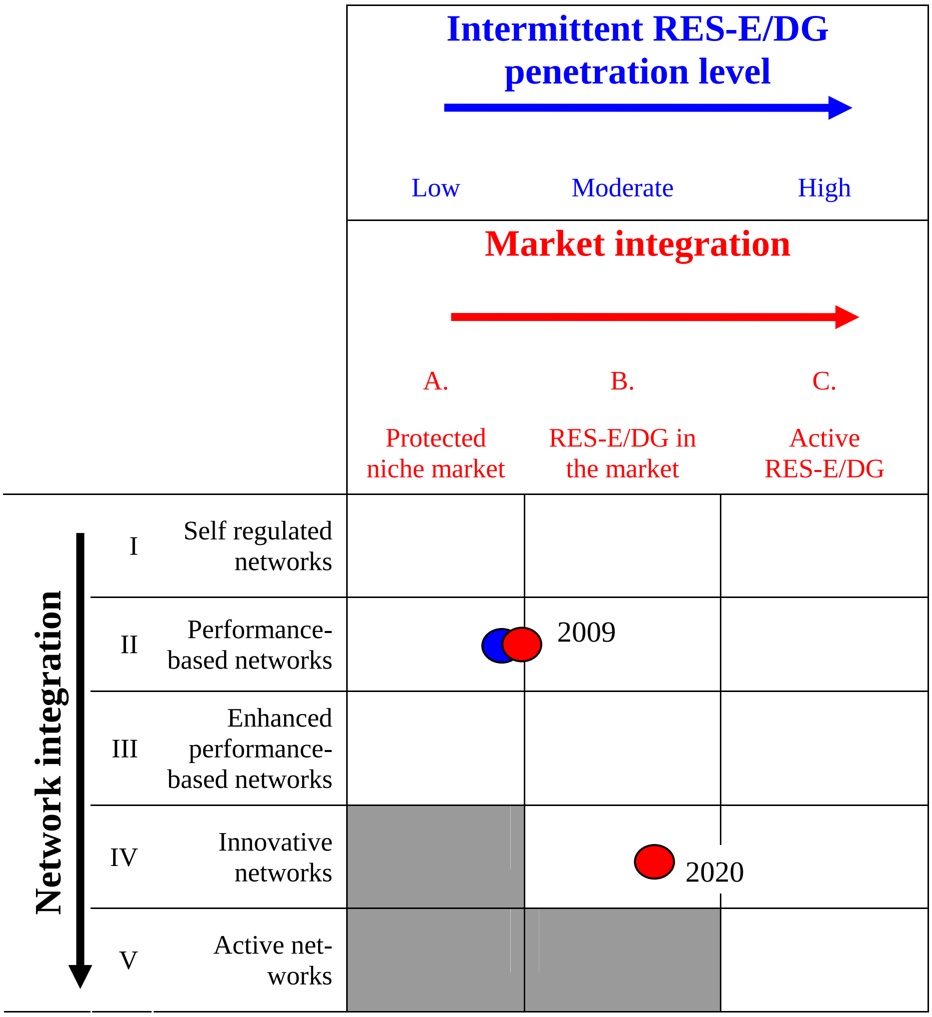

Figure 7.2 *Regulatory road map scheme for Spain: start point and end point*

7.4 Steps in regulatory road map

Based on the identified start and end points of market and network integration of intermittent RES-E/DG we can start the discussion on the required intermediate steps in the regulatory road map. Here we discuss the current regulatory initiatives in Spain, whereas the next subsection discusses the recommended regulatory actions in the near to medium future. Figure 7.3 presents the integral regulatory road map for Spain.

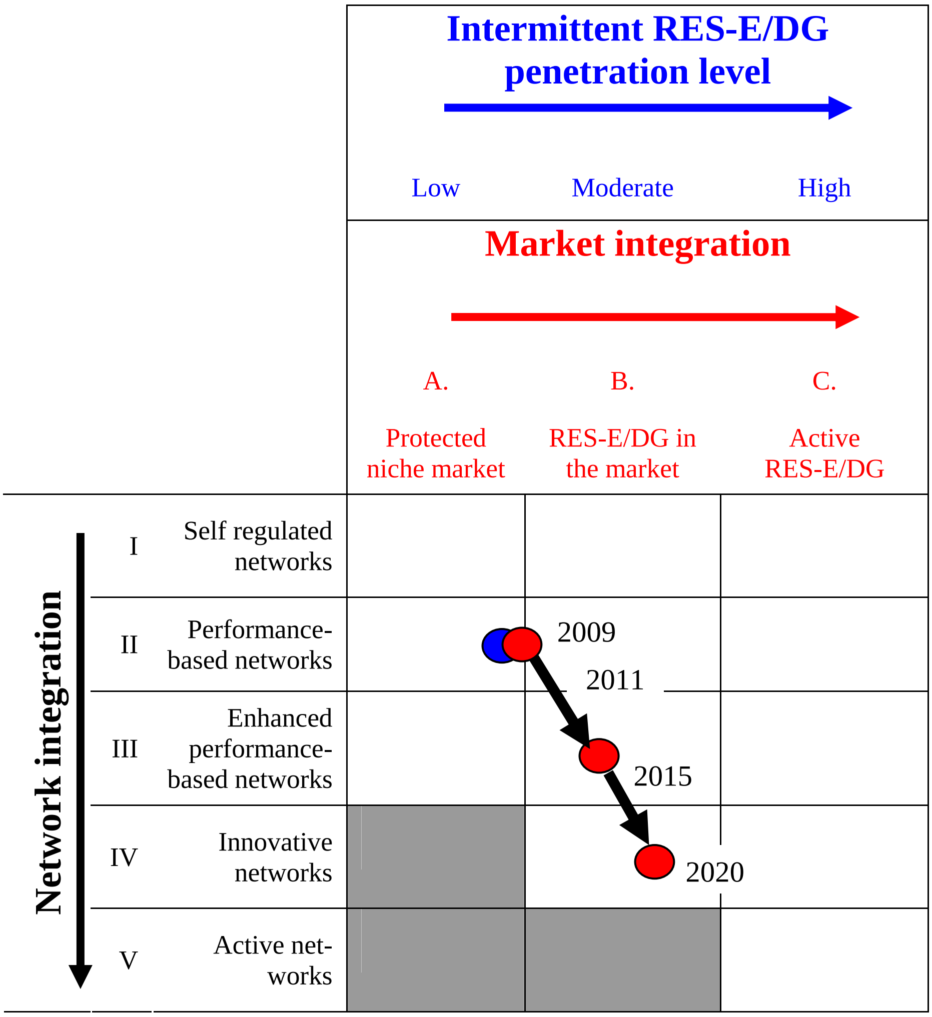

Figure 7.3 *Regulatory road map scheme for Spain: the integral road map*

7.5 Current regulatory initiatives

With respect to RES-E/DG, there is currently an ongoing discussion in Spain on the participation of controllable RES-E/DG units in the balancing market. Controllable units should be allowed to participate in balancing markets in order for the system to cope with high DG/RES penetration levels.

There currently is strong uncertainty about the profitability of recently installed CCGT plants due to the reduced capacity factors for these units resulting from the already high penetration of DG/RES and the economic downturn. This may lead to the conclusion that either the current generation mix is not well adapted or capacity payments received by these units should be changed to better reflect the value their capacity has for the system. This may result in an adaptation of the current capacity payment mechanism. From the point of view of RES-E/DG integration, the direction of adaptation of this mechanism can only be advantageous. In other words, a more lenient generation capacity mechanism increases viability of newly installed gas-based peaking units and gas-based peaking units yet to be build. If the current mechanism remains unchanged, there is the risk that the overall electricity system will become less flexible and less capable of integrating large amounts of RES-E/DG.

Another important aspect related to the integration of DG/RES that is in debate is the economic sustainability of the whole system. Currently, support payments to DG/RES have resulted in an economic deficit for the system. This is due to the fact that the cost of these payments is not fully considered when computing electricity tariffs paid by consumers, nor is it recovered from other type of charges/taxes. Consequently, tariffs only manage to recover a fraction of the whole supply cost of electricity. This issue should be satisfactorily dealt with if the future development and integration of DG/RES is to be ensured. The question remains which mechanism should be implemented to recover the cost of the DG/RES support payment mechanism for the system. According to authorities, the current deficit resulting from the application of this mechanism must be reduced to zero in 2-3 years time. In order to do so, electric utilities may have to pay part of the deficit and the regulated part of electricity tariffs will have to increase to more accurately reflect the electricity supply costs.

7.6 Action plan for implementation

Based on the above identified road map specific regulatory actions can be recommended. Again we use of the tables on stages of network and market integration related to RES-E/DG impacts and with each other in time in Section 3. Each stage of integration is linked to a specific number of guidelines, i.e. regulatory recommendations. However in formulating the recommended action points for implementation of the system transformation process (road map) we have also take into account the country specific characteristics and future RES-E/DG developments as described earlier in this chapter 7. This means that the guidelines listed with the different stages of integration need to be coherent with the specific country characteristics before they materialise in a concrete recommendation in the action plan, see table below.

Table 7.4 *Action plan for implementation Regulatory road map Spain*

Category	Action	Responsibility		Term
		Prepare	Approve	
Network integration	Encourage further international coordination in regulation and network operations, for example through increasing cooperation with French TSO and regulator.	Regulator/ TSO	-	Short
	Implement additional measures for increased interconnections. E.g. allow merchant investment, improve coordination with respect to regulatory processes.	Regulator/Government	Government	Short-medium
	Implementing innovation incentives in network regulation.	Regulator/Government	Government	2012
	Include RES-E/DG as factor in performance-based distribution network regulation.	Regulator/Government	Government	2012
	Implement use of system (UoS) charges for generation.	Regulator	Government	Medium
	Implement shallow connection charges.	Regulator	Government	Medium
	Implement market-based congestion management methods on national network connections.	Regulator	Government	Medium

Market integration	Encourage the creation of aggregators with balancing responsibility (BRP).	Regulator/Government	Government	Short
	Implement more market conform levels for the compensation of RES-E/DG curtailment.	Market operator / TSO	Government	Short
	Adapt support scheme for RES-E/DG so that participation of RES-E/DG units in various electricity markets is encouraged (or at least not prevented).	Government	Government	Short-medium
	Implement higher level of time-based differentiation in final electricity prices for end-consumers for demand response purposes (i.e. change from base and peak electricity prices to hourly electricity prices). Pre-condition: instalment of smart meters.	Electricity companies	Government / regulator	Medium
	Move gate closure time of intraday markets closer to real-time so as to achieve a reduction in wind output prediction error and, therefore, in the amount of reserves and regulating energy required	Market operator	Market operator	Short-medium
	Implement dynamic reserve requirements in network planning standards	TSO	Regulator	medium
	Implement market-based congestion management, possibly with final end-consumer compensation.	Government	Government	Medium
	Adapt support schemes for RES-E/DG to allow for more time- and /or location dependent support payments. Optimal design (from social perspective) needs to be assessed in further research.	Government	Government	Long
	Implement supporting measures for flexible electricity generation units (gas) and (large) hydro-storage units (for example via capacity mechanism) when investments are lacking / not materialising (for example via capacity mechanism) or in order to ensure the profitability of already existing plants so as to avoid their exiting the market.	Government	Government	Continuous

Network regulation methodology
Since the distribution of (intermittent) RES-E/DG is unequal, not all DSOs will be equally affected by increasing penetration of RES-E/DG in the period until 2020. In order to maintain network efficiency incentives (through performance-based regulation) for all DSOs while at the same time not obstructing further increase in the amount of RES-E/DG to be connected by DSOs, the methodology used to set individual DSO regulation (i.e. revenue cap) should be taking into account the differential RES-E/DG developments. This means that the specific network regulation regime to be adopted in the next regulatory period (starting in 2012) needs to be

amended to include these aspects. It is the responsibility of the regulator to propose a new methodology. In doing this, lessons can be learnt from regulation abroad (for example the UK).

Incentives for innovation
Current network regulation does not provide sufficient incentives for innovation. Although there are funding possibilities outside the revenue cap regulation for performing innovation activities, including this aspect in network regulation is advised.

Use of system charges
Spanish electricity generators are not paying UoS charges, irrespective of the voltage level connected to. For an efficient integration of more and more intermittent RES-E/DG units it would be advisable to provide stronger incentives to these units so that they will increasingly take into account the impact of their operations on the network. Implementing this feature would require an amendment of the Electricity Law. When implemented, a common approach is recommended with respect to the type of generation, so that a level playing field for all generators is obtained.

Congestion management and zonal prices
The uneven distribution of RES-E/DG across the country may give rise to increasingly large electricity flows from the one region to the other and on borders of the system. As a result, congestion within the system could take place in a larger number of hours during the year. To counter this effect efficiently allocating the scarce transmission capacity becomes more urgent. Therefore, creating different price zones and implementing market-based auctioning between regions and on borders could increase overall efficiency and make the system more responsive to congestion due to large penetration rates of intermittent RES-E/DG units.

Applying different energy prices to generators (zonal prices) would be possible in Spain and is recommend in the case where very significant congestion arises between different regions in the Spanish electricity market. One of the main objections against such measure is the possible difference in final end-consumer prices. When it is deemed politically desirable that for example small-end consumers should not pay different prices due to their location, compensation of such could be undertaken by the government. Note that price differences in electricity prices paid by end-consumers can also vary across retail companies (due to type of contract, quality of supply, etc) but this is a different issue from the issue of differences due to regional differences caused by location of load and generation. Any compensation policy can (and maybe should) distinguish between the different type of consumers. For example, industrial consumers might be more responsive to regionally differentiated electricity tariffs than households.

Tariff setting methodology and RES-E/DG support schemes
The regulated part of the electricity tariff should be computed by adding up the costs incurred related to the different regulated aspects of the functioning of the system in order to guarantee the recovery of the reasonably incurred costs. Otherwise, the future development of RES-E/DG based generation may be put at risk.

Furthermore, the current support scheme for RES-E/DG should be adapted so that also RES-E/DG based units are allowed to provide services to other than the electricity wholesale market (i.e. balancing markets, ancillary services markets). This is not allowed under the current regime, which creates an uneven playing field and hinders efficient working of the various energy markets.

Capacity market
Continuing implementation of support measures for flexible electricity generation units (gas) and (large) hydro-storage units, for example via the capacity mechanism), remains necessary for the overall flexibility of the system. Although there is a need for additional flexible electricity

generation, investment in new generation capacity might not come about due to a too large (private) risk of not being able to remunerate investment costs. Therefore, the capacity mechanism is needed when investments are lacking, i.e. not materialising, and can ensure the continuing profitability of already existing units so as to avoid their market exit. The current mechanism of capacity and availability payments is probably not working properly due to the wrong incentives it provides. Subject to this mechanism, promoters of new generation are encouraged to wait until capacity in the system is already scarce, instead of investing ex ante in order to prevent this situation. Besides, these payments together with energy prices in a context of an economic downturn like the present one are unable to provide enough revenues to some generators recently installed, such as CCGT plants, so that they are able to recover their investments. This could prevent the installation of more generators or even cause the shutdown of some of the already existing ones if the current economic situation worsens.

Curtailment of RES-E/DG

Currently, last resort electricity curtailments by the TSO are compensated to the level of 15% of the day-ahead electricity price. This is deemed not to be efficient for two reasons. On the one hand this does not do justice to the foregone electricity market revenues for the (RES-E/DG) operator, while on the other hand it does not provide strong incentives for the TSO to implement structural measures that can prevent these type of curtailments in the future, It is recommended that the level of compensation is raised to a more market-reflective level in the short-term.

Balancing market

To improve upon (balancing) market efficiency and increase the role of smaller generation entities and demand in the market the creation of aggregators with balancing responsibility should be encouraged. These Balancing Responsible Parties (BRP) would be in charge of keeping the balance between the generation and demand by re-scheduling their generators output and demand entities consumption either at internal level, or by participating in the intraday market or, closer to real-time, by participating in the balancing market established.

Dynamic reserve requirements in network planning standards

Following the surveys towards more optimal security standards from a socio-economic point of view, it is recommended to *introduce dynamic reserve requirements* dependent on the actual wind forecasts with its embedded variance in network planning standards. Consequently, reserve requirements and concomitant system costs could be reduced for most of the time without compromising security of supply (Zvingilaite *et al.*, 2008).

Electricity price differentiation and demand response

In the medium term, when the current plans for the instalment of smart meters have been implemented, it is recommended to implement a high level of differentiation in final electricity prices over time (i.e. day, week). This would allow for more demand response from the side of the final electricity consumer. Currently, only a basic differentiation in day and night electricity tariffs is implemented.

Gate closure time

The need for balancing energy could decrease if the closure time of current intraday markets where also reduced. Currently there are several intraday markets, where generators seeking to balance their positions can trade energy after the celebration of the day-ahead market. However, these markets close up to 6 hours ahead of the real time operation for some hours of the day, when the knowledge about the actual output of intermittent generation is still not accurate enough. By reducing the time span between the closure time of intraday markets and actual system operation, the need for extra reserves and regulating energy to balance deviations between actual production by intermittent generation and the predicted level could be significantly reduced. Similar experiences have been successfully implemented in other systems like Australia, where real time or close to real time markets already exist. However, the division of responsibilities between the market operator (which is responsible of intraday markets) and the system operator (which is responsible for the deviation management market) is regarded as a major obstacle to implement this measure.

8. Regulatory road map for the United Kingdom[52]

8.1 Outlook for RES-E/DG and the electricity system

In this Section we provide a description of the particular UK electricity system conditions and the likely transition of the system in the period until 2020. Several aspects are covered, such as the generation mix and generation mix developments, current network conditions (interconnection and quality) and institutional characteristics.

Demand and generation

According to Eurelectric (2005) UK electricity consumption is expected to grow with 1.8% per year in the period 2005-2020, with growth unevenly spread of different sectors. The transport and services sectors for example are expected to grow twice as fast on a yearly basis. The tables below provide an overview of what developments are expected regarding intermittent RES-E/DG in the UK electricity market.

Table 8.1 *Overview of projections of installed* RES-E/DG *capacity in the UK electricity mix (in GW)*

RES-E/DG technology		**Scenario**	
	BERR2008	**Eurelectric**	**Primes**
Onshore wind			
2005	1,1	0,8	1,6
2010	1,8	6,8	4,2
2015	5,7	n/a	5,5
2020	11,3	11,1	10,3
Offshore wind			
2005	1,7	0,1	*
2010	2,6	1,1	*
2015	8,5	n/a	*
2020	16,9	5,5	*
PV			
2005	n/a	0,0	0,0
2010	n/a	0,0	0,0
2015	n/a	n/a	0,1
2020	n/a	0,0	0,1
Total installed RES-E/DG			
2020	28,2	16,6	10,4
Total installed capacity			
2020	99,5	108,1	96,2
RES-E/DG share of total installed capacity			
2020	28,3%	15,4%	10,8%

52 This road map is mainly based on information provided by Imperial College and the joint responsibility of ECN and Imperial College. We thank Imperial College for their cooperation.

Table 8.2 *Overview of projections of* RES-E/DG-*based electricity generation in the UK electricity system (in TWh)*

RES-E/DG technology	Scenario		
	BERR2008	**Eurelectric**	**Primes**
Onshore Wind			
2005	2,8	1,8	2,9
2010	4,5	16,8	11,7
2015	15,6	n/a	15,8
2020	31,6	27,3	28,9
Offshore wind			
2005	4,3	0,0	
2010	6,8	3,4	
2015	23,4	n/a	
2020	47,4	16,9	
PV			
2005	n/a	0,0	0,3
2010	n/a	0,0	1,8
2015	n/a	n/a	4,4
2020	n/a	0,0	7,4
Total generation by RES-E/DG			
2020	79,0	44,2	36,3
Total electricity generation			
2020	360,1	472,7	451,5
RES-E/DG share of total electricity generation			
2020	21,9%	9,4%	8,0%

The current level of intermittent RES-E/DG is at 4.4% of total installed capacity. Notably, the UK has a substantial nuclear capacity, which is known to be quite inflexible.[53] On the other hand, the UK also has relatively more flexible brown coal fired generation capacity and CCGT generating units. Currently, there is a total of about 2.8 GW of wind in the UK. The estimated capacity credit of wind in the future varies from 25-35% for low penetration rates to 5-15% for high penetration rates. The total amount of PV in the UK electricity system is negligible.

Projections for the development of future UK electricity supply shows that the UK will extensively use its large potential in wind-based electricity generation, both on shore and off shore. Onshore wind capacity is projected to largely increase until 2020, although estimates for this increase vary from scenario to scenario. BERR (2008) projects an increase from 2.8 GW in 2005 to 4.5, 15.6, and 31.6 GW in respectively 2010, 2015 and 2020. Offshore capacity is expected to increase from 4.3 to 6.8, 23.4 and 47.4 GW in respectively 2010, 2015, and 2020. High average wind speeds in combination with favourable compensation for wind generation makes investment in the north of the British Isles very attractive for wind developers. But also in the South there is ample opportunity for new wind projects. The penetration of PV in the UK is very limited and according to projections it will not play a significant role in the future. Installed CHP capacity has doubled since 1990 and accounted for about 7% of electricity genera-

53 If there is 40% or more installed nuclear capacity in the system, wind power can only be added if the cost of constraining wind or nuclear is covered by the consumer. With 20% of nuclear in a electricity system, only 10% wind power can be accommodated without an economic downside (Milborrow, 2006a).

tion in 2007 (IEA, 2008). 90% of CHP came from industrial CHP, while less than 6% is related to district heating. The government has a target to reach 10 GW of installed CHP capacity by 2010 (IEA, 2008). In 2007, only 5.5 GW was actually installed. Micro-CHP seems a viable option in the UK, also due to the favourable match of heat and electricity demand a large time of the year. The industry forecasts that micro-CHP can realistically take up to a 30% share of the boiler replacement market until 2015 which would mean that 5.6 million homes could have micro CHP installed by 2020 (SBGI, 2006). This is equivalent to 6.2 GW of winter peak generating capacity. Taken all technology developments together we observe that total RES-E/DG capacity could possibly total 18% of total electricity generating capacity, or 11% of total electricity consumption (National Grid 2006).

Networks

The overall penetration of intermittent RES-E/DG is projected to be moderate in 2020 and the dominant share of this is likely to be a large share of intermittent RES-E/DG. Regarding the penetration of wind-based electricity in particular distribution networks, Cao *et al.* (2006) noted that the concentration of intermittent RES-E/DG in the UK is unlikely to bring about particular concerns. Bottlenecks in the transmission network mainly exist on the north-south axis connecting the fuel-based electricity generation units in the north to large demand centres in the south. Given significant developments in wind-based electricity generation in Scotland and off the coast in the North West and North East of England, and off the North Wales coast it is likely that this axis will remain important in future transmission capacity investment plans. But this is also dependent on the location of new-scheduled power plants and the location of decommissioned plants. Connecting the large amount of off shore wind parks will involve substantial investment in the transmission network anyhow (Strbac *et al.*, 2007).

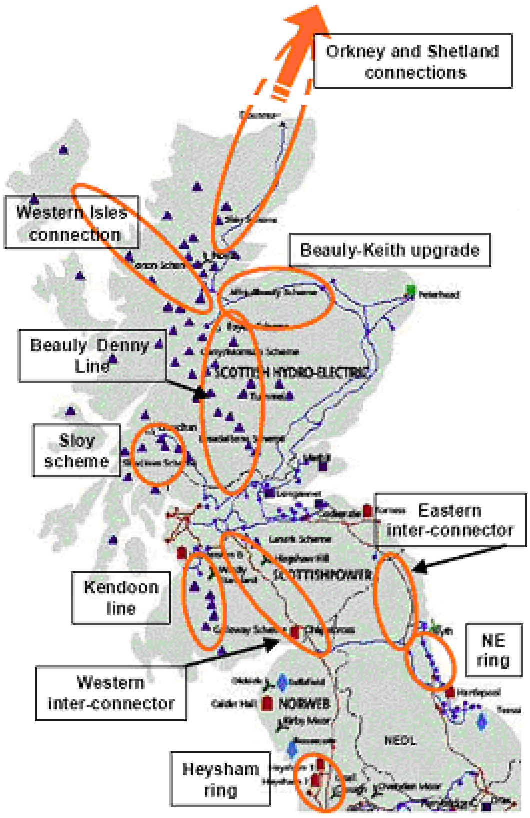

Figure 8.1 *Transmission licensee's investment proposal (SKM 2004)*

Given that these developments are similar to off shore wind developments in for example Germany and the Netherlands it could be viable to strive for the realisation of a North Sea super grid to which all off shore wind parks are connected. There are ongoing discussions on the development of offshore transmission grids. Offshore transmission of wind-generated electricity is seen as one of the viable options to solve network bottleneck problems caused by the lengthy process of getting planning permission to build transmission on shore. Currently, the UK has electricity interconnections with France and Northern-Ireland. In the short-term new interconnections with the Netherlands (by the end of 2010) and Ireland (2012) will be realised. Figure 8.1 below illustrates the proposed transmission reinforcement in Scotland to deal with the increasing number of wind power connection applications (SKM, 2004). For a comprehensive overview of planned infrastructure upgrades at the transmission level we refer to the GB seven year statement published by National Grid (2008).

8.2 End point road map

In describing the likely transition of the UK electricity system over the period until 2020 we noted that the projected total level of RES-E/DG penetration in 2020 varies quite largely across different scenarios. While BERR (2008) projects a penetration rate of 28%, Primes (2008) and Eurelectric (2005) project a penetration rate of 11% and 15% respectively. Given these figures we conclude that it is likely that the envisioned end-state of UK RES-E/DG market integration in 2020 can best be described by stage B.

Given that the further development of the level of RES-E/DG penetration is predominantly caused by large-scale on and off-shore wind generation connected to transmission networks, and probably to much lesser extension caused at distribution network level we hypothesize that the UK electricity system transition (at least until 2020) will not require implementation of network integration stage V and that implementation of stage IV is likely to suffice. This envisioned end-state is depicted in Figure 8.2. Combining the starting point and the envisioned end point gives the regulatory road map for the UK. In the next Section we will assess the starting point of the UK regulatory road map.

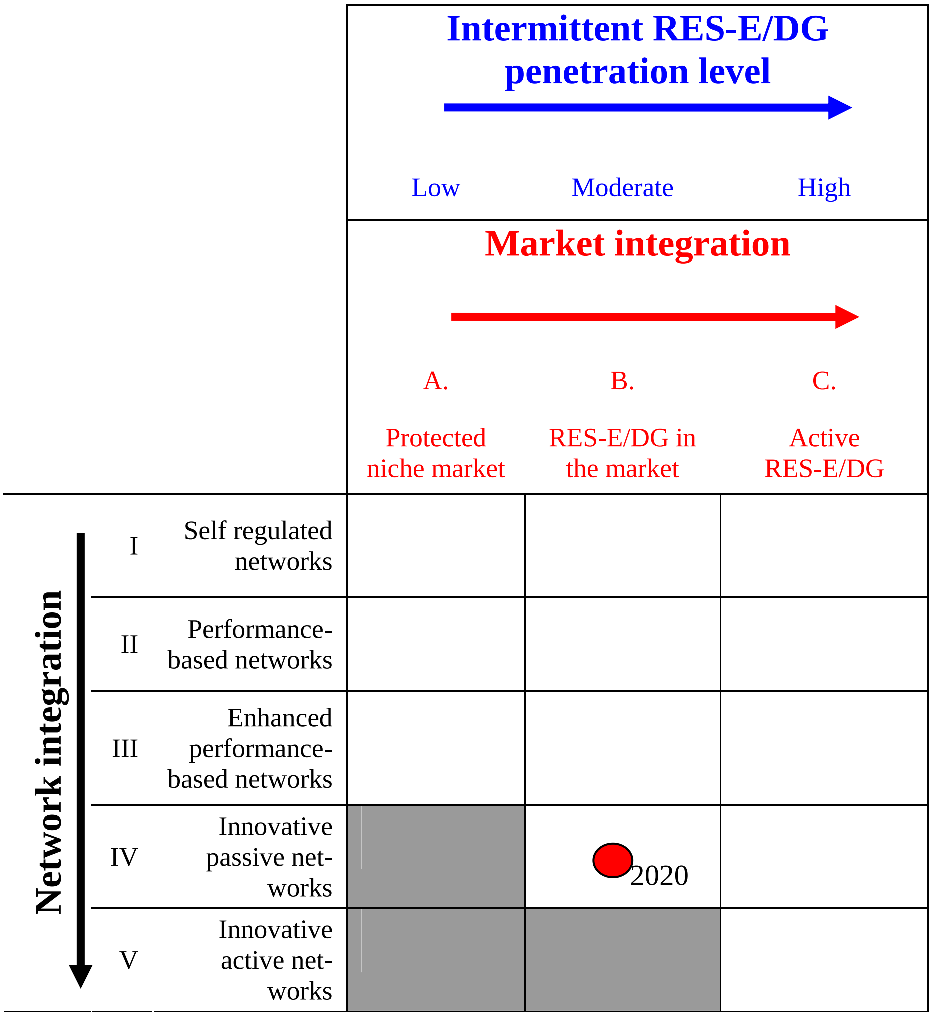

Figure 8.2 *Regulatory road map scheme for the UK: the end point*

8.3 Starting point road map

8.3.1 Generation

As was discussed earlier the UK generation mix has limited flexibility based on projected generation capacity projections. Current UK legislation has a small number of options to influence the development of the generation mix over time. For example, the UK does not allow for additional payments to particular generation technologies outside the market. However, there are some other government instruments that are able to influence the generation mix. For example, energy policy with regard to the conditions under which nuclear electricity generation is allowed influences the share of nuclear energy in the short and long-term. Furthermore, the specific targets of the Renewables Obligation (RO) determine the balance of demand and supply for electricity generated from renewable sources and thus influences new investments in the generation mix. Nuclear generation is likely to keep playing a key role in providing electricity in the UK in the future. In addition, there is also a policy of not building conventional coal plants further except for coal plants that are CCS ready. A number of pilot projects have been approved.

With an increase in the amount of intermittent capacity the risk of insufficient generation capacity being available at a particular moment in time is considered an issue. The UK has not implemented a capacity mechanism to cover this risk. In this respect, the market principle that additional investment in generation capacity is automatically encouraged through price formation in the electricity wholesale market and the balancing market is followed. However, the SO does periodically publish an outlook containing electricity demand and supply projections on the basis of which market actors decide on possible new generation capacity investment.

The current UK support scheme for RES-E based on RO, a green certificate-based system, does not contain provisions regarding a differentiation in time of production. The system can provide an incentive for RES-E producers to produce according to actual market needs since revenues from the certificate trade are additional to basic electricity market sales. However, this assumes that electricity is actually sold in the spot wholesale market where prices fluctuate over the day and week. In reality, electricity is sold through various institutional arrangements (i.e. long-term contracts) that exhibit less price differentiation over time. CHP units on the other hand are supported by an exemption from the Climate Change Levy (CCL) – an additional charge on fossil fuelled generation sources, but its level is not differentiated over time or location and is only dependent on the CHP scheme meeting certain minimum standards in operating efficiency.

8.3.2 Demand

Heat or electricity storage facilities are capable of making the demand side of the market more flexible and, hence, can enable a smoother accommodation to any potential intermittency problems. However, the use of district heating has very low popularity among the UK population, which hinders its implementation despite its potential for cost reduction and increasing system flexibility. Energy storage facilities are being explored as part of the IFI / RPZ programme[54]. The primary aim of these programmes is to encourage the DSOs[55] to apply technical innovation in the way they pursue investment in and the operation of their networks.[56]

There are currently no specific plans for a large-scale realisation of heat or electricity storage facilities. However, recently the government did address this issue in a consultation document and a prominent Greenpeace campaign highlighted the potential for CHP and heat networks in the UK. [57] The major barrier for implementation of electricity storage seems to be related to its cost. Interest for heat networks is limited: traditionally community heating schemes reliant on CHP and heat networks have had very bad public approval rating). Further studies are in progress to address the environmental and economic efficiency of district heating schemes coupled to more or less distributed CHP systems, also in comparison to alternative scenarios such as widespread use of electric heat pumps.

Large UK consumers connected to the transmission network can enter interruptible contracts and participate in the balancing market. This requires compliance with the Balancing and Settlement Code (BSC) though. In practice however only few large consumers are active on the balancing market. They rather prefer to enter a bilateral interruptible contract with the SO. On the balancing market the interruptible service is valued with the marginal bid (or offer) whereas a bilateral contract already specifies the level of compensation ex ante, i.e. before the service is called upon. Participation in either way by smaller electricity consumers would require advanced metering infrastructure that is not currently available in the UK. In Britain and Finland examples where industrial technologies are used as frequency controlled demand response in-

[54] IFI stands for Innovation Funding Incentive, while RPZ stands for Registered Power Zones. For initiatives under IF we refer to http://www.ofgem.gov.uk/Networks/Techn/NetwrkSupp/Innovat/ifi/Pages/ifi.aspx.

[55] The operators and owners of distribution networks are referred to as 'distribution network operators' (DNOs) in the UK. In this report we use the common EU terminology of DSOs.

[56] http://www.ofgem.gov.uk/Networks/Techn/NetwrkSupp/Innovat/Pages/Innvtion.aspx

[57] The summary of the report is available at www.greenpeace.org.uk/files/pdfs/climate/industrialCHP_summary.pdf

clude industrial ovens, pumping systems and metal works. There is a mechanism to allow large industrial customers to sell demand response services. There are a number of on-going research projects such as CEU-Smart A and UK Dynamic Demand that investigate the possibility of using residential appliances to support frequency regulation. This can be facilitated by the application of smart metering.

8.3.3 Markets

Wholesale market

Large amounts of intermittent RES-E/DG based electricity entering the market can influence wholesale market price formation. Varying energy demand throughout the day and over seasons generally gives rise to consequential price fluctuations which in turn incentivizes electricity generators to produce at that hour of the day at which the need for additional electricity supply is the largest. However, in the UK, most RES and CHP are not exposed to these varying market prices because they are engaged in PPA (power purchase agreements) with larger market participants (typically energy suppliers) who pay a fixed rate for all energy produced regardless of time of output or location.

Electricity end-use prices are to some degree differentiated over time, although mainly for large consumers. Large consumers can enter a large variety of different contracts that for example can vary with respect to the exposure to wholesale price fluctuations or the degree to which peak period usage is used as a cost driver. A limited number of electricity consumers with electrical storage water heating have at their disposal specific time of use meters that are linked to a particular tariff category. For the large majority of electricity consumers there is no time differentiated tariff. However, it is possible to opt for a day-night tariff suitable to deploy electric heating with heat storage by switching them on during the night. Retail consumers are allowed to commit to contracts based on fixed electricity tariffs over a longer period of time (i.e. years) instead of being exposed to wholesale market price fluctuations.

All generators, including RES-E/DG operators can sign the Balancing and Settlement Code (BSC) and participate in the wholesale and balancing market directly. However, operators of units below 100 MW are not obliged to sign the code. Not signing the code implies that operators will enter into Power Purchase Agreements (PPA) with larger electricity producers in order to sell their electricity. Operators of small generation units connected to distribution networks will enter contractual arrangements with an energy supplier and see their total output be netted with electricity demand. Entering into a contract with a larger electricity producing or trading entity is also advantageous from the perspective of imbalance risks. Generators below 1 MW cannot sell their energy output at the energy markets directly. SOs treat small generation units as negative load that are not centrally dispatched.

The UK has adopted a 1 hour gate closure, which is different from gate closure time in neighbouring countries Ireland and France. The same goes for balancing activities: there is no strong interaction between these countries.

Market for ancillary services

UK electricity generators can offer different type of AS in return for a basic availability payment plus an additional payment if the contracted service is indeed called upon. Depending on the system service, the payment will be related to location and time. RES-E/DG can provide some system services through an aggregator. Whether they are remunerated exactly by time of output and location will be dependent on the contractual agreement with the aggregator and the profit sharing arrangement.

Operators of RES-E/DG units smaller than 100 MW are to limited degree allowed to provide ancillary services. For example, they are allowed to offer reserve/response services as part of a larger aggregator, with an additional minimum size limit of 3 MW applying. Aggregation of smaller units can be realized by setting up a commercial (or virtual) generation unit or via a larger energy trader / producer that manages the different units via an established control centre. The control centre then acts as the interface between the smaller RES-E/DG units and the market place.[58]

Small consumers are allowed to participate in the provision of secondary reserve. Typically they would participate through an aggregator. Several such commercial aggregation companies exist in the UK. The conditions that they must fulfil to participate are the same as for generators wishing to provide these services. There seems to be little interest from the part of medium to larger scale demand in offering these services (aside from those that are already offering high value interruptability services). The SO has initiated a number of schemes to try and make offering AS more attractive to demand with little success despite good engagement with demand customer through working groups. On the domestic customer side the lack of widespread half hourly metering or AMI (advanced metering infrastructure) makes this activity impossible at present. In general, the main obstacle is the investment for the AGC control system that is required between the system operator and the consumer plants and processes. It would also imply technical challenges of the remotely controlled disconnection-reconnection devices. Thus, consumers can provide negative reserve to the ancillary service market. However, participation by consumers is not prepared from a technical point of view, lack of communication infrastructure.

Regulation power market
In the UK, generation units below 100 MW are not obliged to participate in the market for regulating power but units larger than 50 MW are obliged to meet the (transmission and distribution) grid codes.

Primary regulation is a mandatory service as part of the Connection and Use of System Code (CUSC) – the grid code that all eligible generators must comply with. Exempt generators are typically those under 100MW. Generators complying with the CUSC must have primary regulation services installed at every generating unit. There is no remuneration for this activity. Tertiary and Secondary regulation are established as a voluntary competitive market. Services are tendered on an annual basis. Depending on the service provided, payment will be on the basis of a call-out charge (£/MWh) and in some instances will include a standing payment for availability (£/MW). The SO has developed a number of reserve products to allow a range of reserve service providers to participate in these markets.

Conditions for provision of secondary and tertiary services vary with the service. Some allow aggregated provision, others do not. Most have a minimum response capacity allowable and a time conditions for sustaining response, this varies according to the service. The SO sends signals to each company central dispatch and it sends signals to its own units.

Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from TO. Providers of the Optional Service will receive an Enhanced Rate Availability Fee (£/h) payment for periods of time where they provide TO (following despatch) with enhanced MW run-up and run-down rates. The Enhanced Rate Availability Fee is defined by the provider in the framework agreement. Providers of the Firm Service will receive an Availability Fee (£/h) for each hour in a Tendered Service Period where the service is available. TO will notify ‘windows’ during which it requires the service to be provided: in return a Window Initiation Payment is received. During a window, Providers may also specify a Positional Fee (the cost of putting plant in a position where fast reserve may be provided).

58 Examples of organizations are Gaz de France, Flexitricity and npower Cogen.

All fees for the Firm Service are submitted by the provider as part of the tender. An utilisation fee (£/MW/h) is payable for the energy delivered in both services (for Balancing Market Unit participants via a bid/offer acceptance). For the firm service this utilisation fee will be capped by the tender parameter submitted.

Balancing market
In the UK system all generating units, including RES-E/DG units are responsible for deviations from earlier submitted energy programmes. This encourages intermittent RES-E/DG operators to improve upon prediction tools used for assessing for example the expected amount of wind entering the electricity system at certain point.

Furthermore, gate closure time in the UK market is only one hour ahead, which implies that compared with some other countries with much longer gate closure times (up to 8 hours), UK operators of RES-E/DG are better capable of predicting the amount of intermittent electricity expected to be produced. This consequently puts less strain on the balancing market and pushes down overall balancing costs. Large RES-E/DG participating in the balancing market pay for balancing costs according to the balancing market rules. Small RES-E/DG however is treated as negative demand and not seen by the TSO.

The UK has not implemented an explicit mechanism to incentivise electricity generators to provide sufficient generation capacity in critical periods. Implementing this type of mechanism should be considered when market incentives alone are not sufficient. Whether the UK market is providing sufficient incentives on its own is an open discussion. However, the accurate information provided in the Seven Year Statement periodically published by National Grid (2008) so far has proven to yield a significant contribution to plan future generation development.

8.3.4 Networks

Distribution network
Active network management is acknowledged to be an effective measure when striving for an improvement of RES-E/DG integration conditions. In current UK distribution network regulation there are two particular incentives that influence RES-E/DG integration, the earlier mentioned IFI and RPZ regulation. These incentives *de facto* act as a 'cost-adder' to the revenue cap of every DSO. This piece of regulation explicitly links RES-E/DG penetration to network performance. However, there is the difficulty of setting these incentives at adequate (or even optimal) levels. UK distribution network regulation does not contain explicit incentives for DSOs to consider RES-E/DG in their (long-term) network planning, since it is assumed that this is already achieved though: (i) existing targets with respect to energy losses and (ii) regulation with respect to quality of network services.

Use-of-the-system charges paid by distributed generators in some systems may be locationally and temporally differentiated. This is the case of the UK, where Long Run Incremental Charging (LRIC) is applied to compute the charges to be paid by those generators connected to the EHV network, while distribution use of the system charges paid by generators connected to the HV/MV/LV levels are computed according to a Distribution Reinforcement Model (DRM). Connection charges for generators to be connected to the distribution network are based on negotiations, with Ofgem passively urging DSOs to implement cost-reflective charges. In this respect, charges are likely to exhibit some differentiation over locations (but not over time). However, this current type of regulation is taken to be an interim policy; discussions on this issue are still on going with the objective to have more coherent and consistent approaches across DSOs in the UK.

Transmission network
In the UK, electricity generators connected to the transmission network and electricity generators larger than 100 MW connected to the distribution network are required to pay transmission use of system charges.[59] UK transmission use of system charges are to some degree differentiated over time, through use of peak day pricing. NG uses a TRIAD period where the charges are based on the use of the system by users during that peak periods. This could be described as a pseudo time-specific charging methodology. In addition, a location-specific differentiation is adopted through the so-called Long Run Incremental Cost (LRIC) methodology. Connection charging of UK electricity generators connected to the transmission network is based on shallow connection charging principles.

The construction of new network connections in general is hindered by existing concerns about new transmission lines affecting the environment and the lack of fairness of the method employed to determine which countries should pay the cost of these lines. Moreover, especially for international network connections the processes associated with project initiation (e.g. permit procedures) are deemed to be severely delaying project realization. In addition, a general lack of harmonization of market rules and regulatory frameworks is also considered to be a barrier.
Transmission capacity on the electricity interconnectors between the UK and surrounding countries is allocated through explicit auctioning (UK-France). Capacity of the planned interconnector between the UK and the Netherlands will be allocated based on implicit auctioning.

Conclusions
Using the information on the current state of the different electricity system elements we can assess the regulatory starting point for the UK by linking this information to the tables on the stages of market and network integration presented in chapter 3.

The current issues regarding the integration of RES-E/DG in the UK mainly relate to the increasing costs of accommodating new RES-E/DG in some distribution networks and some parts of the transmission network. Furthermore, there is the increasingly important issue of internal congestion due to the geographically varying potential of large-scale RES-E. This holds for both onshore wind generation that is increasingly developed in the north of the UK, and the increasing number of wind parks at sea that requires connection to the transmission network. The two described issues are exemplary for stage 3 in network integration. Hence, we conclude that stage 3 is best associated with the current level of network integration in the UK.

Since the actual market penetration of RES-E/DG in the UK is currently quite small one could conclude that the current stage of market integration is stage A (protected niche market). However, when looking at the actual market design and the actual opportunities of RES-E/DG in the current UK electricity system this corresponds more with an advanced stage of market integration (stage B). This could indicate that initially, the UK electricity system should be quite well capable to move forward when it comes to the level of RES-E/DG penetration without significantly altering current market design.

Combining our observations on the current level of network and market integration for the case of the UK we state that the UK starting point is III.A / III.B. Figure 8.3 presents the starting and earlier defined end-point for integration of RES-E/DG in the UK electricity system.

[59] Small electricity generators connected to the transmission network may be able to negotiate a ‘discount’.

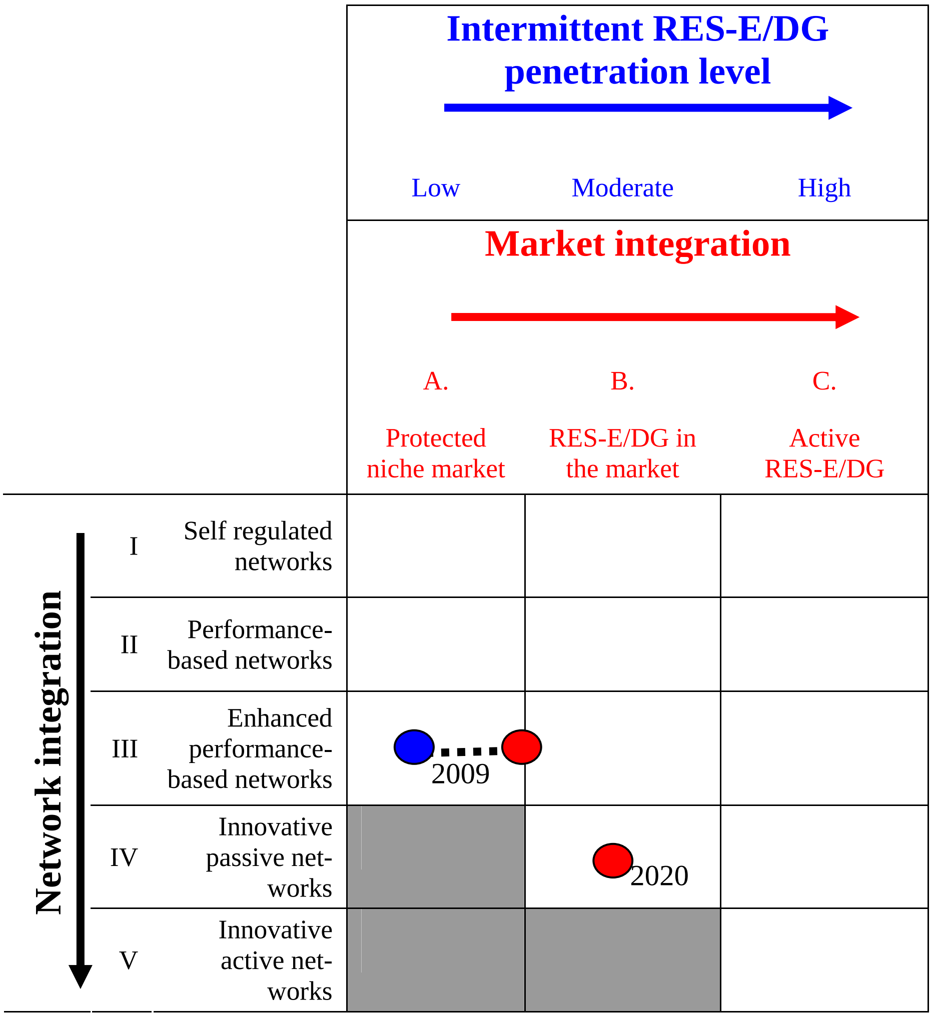

Figure 8.3 *Regulatory road map scheme for the UK: start and end point*

8.4 Steps in regulatory road map

Combining the identified start and end point of the regulatory road map for the UK provides us the integral road map, see Figure 8.4 below.

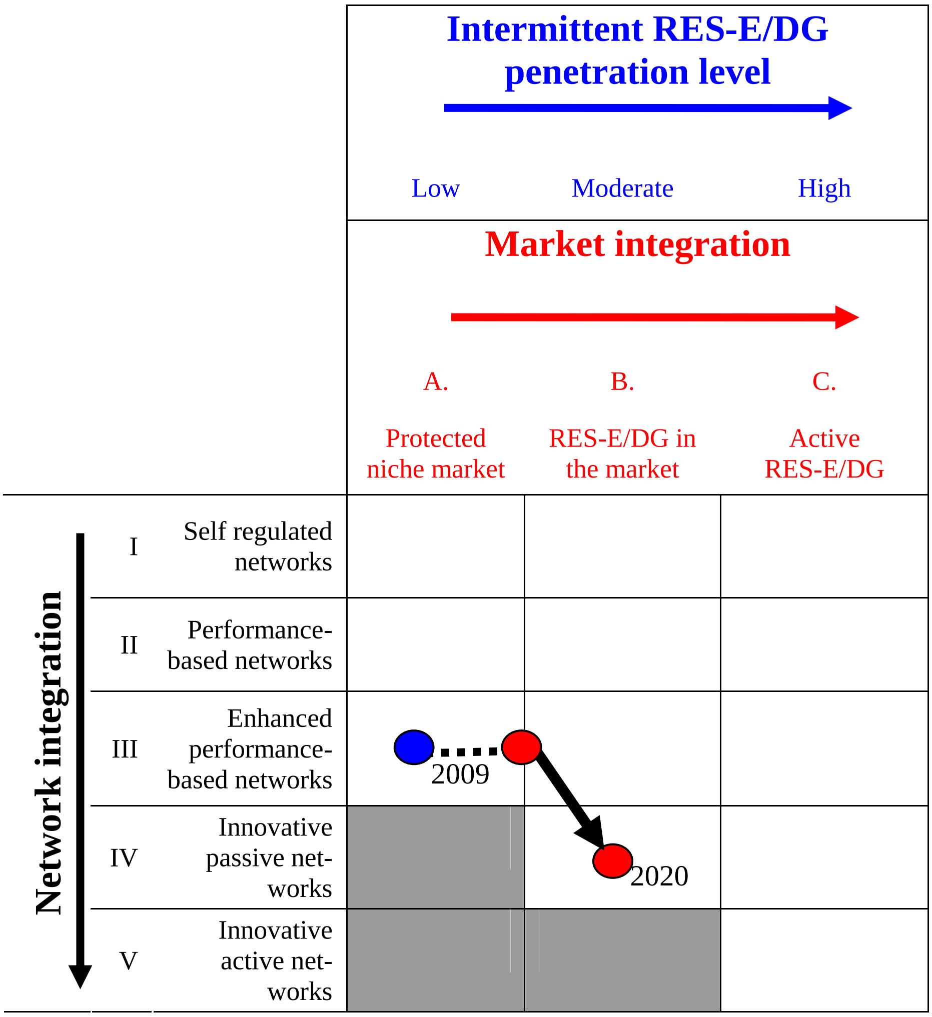

Figure 8.4 *Regulatory road map for the UK: the integral regulatory road map*

In the next sections we discuss the current regulatory initiatives and the additional recommended regulatory actions required when implementing the regulatory road map of the UK.

8.5 Current regulatory initiatives

Below we list the current regulatory initiatives that are under discussion as intermediate stages for the optimal integration of (intermittent) RES-E/DG in the UK electricity system.

Distribution network charging methodology
On March 20, 2009 an Ofgem project team published a decision document on future structure of distribution charges (Ofgem, 2009). It seeks to "achieve a common, cost reflective charging methodology with open governance arrangements across all 14 Distribution Network Operators in Great Britain by April 2010. The document proposes the implementation of a common methodology and governance at the lower voltage levels for April 2010. For the highest voltage levels it is decided to allow DSOs to choose between two different charging models from 2011 onwards.

Energy Act 2008
The Energy Act 2008 provides broad enabling powers for the introduction of feed-in tariffs (FITs) for small-scale low-carbon electricity generation, up to a maximum limit of 5 megawatts (MW) capacity - 50 kilowatts (kW) in the case of fossil fuelled CHP. The FITs will be introduced through changes to electricity distribution and supply licences. These provisions are in-

tended to encourage the uptake of small-scale low-carbon energy technologies while the Renewable Obligation (RO) continues to be the main support mechanism for large scale intermittent RES-E/DG deployment. Small-scale low-carbon electricity technologies include:

- Solar photovoltaic (PV);
- Wind turbines (including micro wind turbines);
- Micro-hydro;
- Combined heat and power (CHP) – this also includes micro CHP; the technology is not always renewable.

FITs will guarantee a price for a fixed period for electricity generated using small-scale low carbon technologies. This will remove uncertainty for investors, reduce the pay back period and increase the return on their investment. It is believed that the increased certainty that feed-in tariffs provide will encourage individual households, communities, businesses, schools, hospitals, universities and a host of other organisations to consider installing small-scale low carbon electricity generation technologies. The government is currently working to expand and develop evidence in order to form recommendations on the design of the mechanism, including the tariff levels and the period during which they will apply, the detail of which we will consult on in summer 2009. Government is committed to having FITs in place in April 2010.

Transmission system study for 2020

In the final report of the Transmission Access Review (Ofgem/BERR 2008) it is acknowledged that reaching the 2020 sustainable electricity goals require large infrastructure investments. *"The three transmission companies, led by the GBSO, will undertake studies to look at investment scenarios/requirements to meet the 2020 target. The companies are committed to carrying out these studies and delivering a report in six months. The Electricity Networks Strategy Group, which is jointly chaired by Ofgem and BERR and with senior industry representation, will have oversight of this process, in particular supporting the development of credible network scenarios. These scenarios will include proposals for the development of up to 25GW of additional offshore wind capacity, and the possible requirement for further interconnection with other European countries"*.

Energy Demand Research Project

Four major energy suppliers, EDF Energy, E.ON, Scottish Power and Scottish and Southern Energy, are leading trials examining how customers respond to better information about their energy consumption. The project is funded by £10m from the Government, matched by equivalent funding from the companies. The trials are being managed by Ofgem on behalf of the Government. Several different ways of making customers more aware of their energy usage are being tested through the trials including:

- Smart electricity and gas meters;
- Real-time display devices, which show energy use in pounds and pence;
- Additional billing information;
- Monthly billing;
- Energy efficiency information;
- Community engagement.

The trials are made up of different combinations of these actions and are exploring the responses of around 50,000 different households. There will be smart meters in around 18,000 houses and real-time display devices in about 8,000 homes. The results should provide information on which of these actions help customers reduce energy consumption and over what timescales this is achieved. The trial will also look at how these reductions have been achieved (e.g. in heating, lighting or other energy efficiency measures). It will also assess the impacts on different households, including the disadvantaged. The trials were announced in July 2007 and suppliers began recruitment and set-up later that year. The trials will last two years, but as different trial elements began at different times and most will cover at least two summers and two winters, final reporting will not be complete until autumn 2010. In the meantime, reports will become available approximately every six months.

Concluding observations
We observe that currently a large number of initiatives taken up by the different stakeholders in the UK electricity system are actually addressing the issue of making the system more flexible in response to increased penetration of intermittent RES-E/DG. The above initiatives further develop cost-reflectivity of network charges (initiated by Ofgem), stimulate further penetration of both non-intermittent and intermittent RES-E/DG (Energy Act 2008), strengthen the transmission network for increasing amounts of wind power (Ofgem / BERR), and increase demand response in the long-term (research projects). Apart from these very positive developments we propose some additional regulatory actions in the next session.

8.6 Action plan for implementation

Based on the above identified road map for the UK a number of additional regulatory actions and those responsible for implementation are identified to secure timely introduction of the regulatory measures recommended. Here we again make use of the developed tables on network and market integration in Section 3, linking each stage of integration to a specific number of guidelines, i.e. regulatory recommendations. When drafting the recommended action points we have taken into account the country specific characteristics and future RES-E/DG developments as described earlier in this chapter. This means that the guidelines listed with the different stages of integration need to be coherent with the specific country characteristics before they materialise in a concrete recommendation in the action plan below.

For specifically the UK case we note that the current implemented stages of network and market integration already quite extensively deal with (intermittent) RES-E/DG issues. This for example refers to the highly advanced network regulation regime for DSOs and TSO and the incentives for innovative activities. Furthermore, large efforts have been undertaken to improve the position of RES-E/DG on the various markets (wholesale, balancing, ancillary, et cetera). However, we identify a limited number of specific measures that could significantly contribute to a more flexible electricity system that efficiently deals with the increased penetration of RES-E/DG in the period until 2020.

Zonal transmission tariff system
The installation of intermittent RES-E/DG generation in remote areas can give rise to increasing congestion in the system. Since a relatively high concentration of intermittent RES-E/DG is expected (e.g. onshore and offshore wind in the north of the UK), congestion on large north-south network connections is to be expected. In the UK the TNUoS charges are currently to some degree location specific. Obviously, this increases the cost of connecting more and more RES-E/DG based generation in high transmission cost areas. This will be an incentive to search for other solutions. Overall, the goal should be to achieve 2020 sustainability targets cost-efficiently. This might involve the discouragement of the realisation of more RES-E/DG in high potential areas with very high cost network costs, and the stimulation of RES-E/DG in areas with somewhat less potential but more favourable network costs. Introducing more location and time specific incentives, for example in transmission charging, will lead to more efficient RES-E/DG integration. However, before implementation of more location specific charges, further investigations will be needed to conform that the added benefits in efficiency are not exceeded by the costs related to the increased complexity of the tariff system and its regulation.

Table 8.3 *Action plan for implementation of regulatory road map UK*

Category	Action	Responsibility Prepare	Responsibility Approve	Term
Network integration	Reform of Transmission Access Arrangements (introducing non-firm access rights)	Regulator	Government	2009
	Implementation of more location specific transmission charges	Regulator	Regulator	2009-2010
	Implementation of more cost-reflective network charging methodologies	Regulator/DSOs/ TSO	Regulator	2011
	Implementation of market-based congestion management on borders.	Regulator	Regulator	2011
	Investigation of medium-term opportunities for interconnections with Norwegian electricity system	TSO / Ofgem	Ofgem	Medium
	Investigation of opportunities for long-term development of supergrid at sea, cooperation within the Northwestern European electricity market region.	TSO / Ofgem		Long
Market integration	Implementation of FIT tariffs for certain RES-E			2010
	Continuing support for smart metering initiatives that can enable more flexible, price responsive load	Regulator / government	Regulator / government	Medium
	Implement higher level of time-based differentiation in final electricity prices for end-consumers for demand response purposes (i.e. change from base and peak electricity prices to hourly electricity prices). Pre-condition: instalment of smart meters.	Electricity companies	Government / regulator	Medium
	Support for (flexible) CHP technologies	Government	Government	Medium
	Implementation of dynamic reserve requirements in network planning standards	Ofgem	Ofgem	Medium

Another alternative, currently being developed by Ofgem, is reform of current transmission access arrangements. This includes the enabling of non-firm access in addition to firm access rights. Although the introduction of non-firm access rights will provide some relief in the short- to medium term, it will not be the long-term solution to deal with increased system flexibility requirements.

Dynamic reserve requirements in network planning standards

Another part of the reform of current transmission access arrangements is the adaptation of network security standards. The maximum capacity of networks circuits is nowadays calculated using static assumptions with standard load profiles among others. When network reserve requirements depend on actual (short-term) wind generation forecasts, additional network capacity may become available and network investments due to connection of additional renewable generation may be lowered without compromising security of supply. Furthermore, it is considered to increase short-term network capacity with data collection of specific network circuit items, aiming at a better utilisation without unacceptable reductions in operating life of network assets.

Flexibility through individual CHP units

It seems that there are relatively little studies available on the potential of CHP units to provide additional flexibility to the system. Given the large potential heat demand one can hypothesize on increasing potential in this field. When sufficient investigation acknowledges this potential, there might be a case to increase the availability of this type of flexibility through particular support schemes, with support schemes aiming at flexible CHP units in industry, but in the further future also micro-CHP units in the residential sector.

Super grid at sea

Given the large geographical concentration of intermittent RES-E/DG in the UK when it comes to offshore wind, the already much about hypothesized research option of creating a (international) super grid at sea must be addressed in the context of this study as well. In order to avoid large-scale integration issues arising from singular connections to offshore wind parks, a super grid might be most efficient when network integration is concerned. For the UK, and its ‘neighbouring’ countries of the Netherlands, Germany, Belgium and France this could be a very important development. For such a large investment project to come off the ground in an efficient and effective way international cooperation is absolutely necessary. It is therefore recommended to further investigate this particular option (as is currently been done).

Interconnection with Norway

Another possibly interesting option for responding to an increasing share of non-controllable RES-E/DG in especially the north of the UK (Scotland) is an electricity interconnection with Norway. This would give access to large-scale hydro-based storage facilities in this country that can assist in reducing the impact of wind variability in the UK. This could reduce the negative impact (i.e. costs) of integrating non-controllable RES-E/DG within the UK. Apart from that, this option could prove to have synergy effects with connecting off-shore wind parks to the north of Scotland. As such, it could be become part of a super grid at sea in the more distant future.

Electricity price differentiation and demand response

Current end-user prices are differentiated over time for a limited number of consumers and if so, in a very basic manner. In the medium term, it is recommended that basic differentiation in end-user prices, in for example day and night tariffs, and is implemented for all consumers. In the longer term, with the instalment of smart meters a further differentiation in end-user prices on for example an hourly basis should be foreseen.

Smart metering

Currently, UK industrial and large consumers typically have half hourly meters and are billed by their energy suppliers accordingly. These meters are not explicitly smart but could be linked to an Energy Management System of some sort. This would benefit the UK electricity system since it could assist in stimulating the use of electricity when it is cheap (and possibly ‘green’), i.e. when system conditions for an increase in electricity consumption are good. Reversely, electricity consumption can be limited when electricity is expensive (and not ‘green’). Further initiatives in this field should be continued, for example through the support of demonstration projects and innovative projects. Another aspect that needs to be addressed in this respect is the institutional structure: a particular obstacle to adoption of this type of measures is the separation of meter ownership away from the network operator. Energy suppliers have responsibility for the metering system and mandating suppliers (operating in a liberalised competitive marketplace) to undertake wholesale replacement of all metering technologies against some kind of prescribed scheme is likely to be a long and complex process. In general, the main barriers for smart metering are associated with the lack of experience in large scale deployment of these equipments. Moreover, some technological difficulties still exist regarding equipment and communication protocol standardization and solutions to manage such large volumes of information. These would need to be addressed in currently ongoing research and demonstration projects.

9. Conclusions and recommendations

9.1 Why building regulatory road maps

For the planning of the implementation of the transition of the European electricity system to optimally cope with the expected strong increase in the share of RES-E/DG generation, in particular of the less controllable type (e.g. wind, PV, and heat-led CHP) in 2020, it is necessary to develop road maps to secure an optimal electricity system transformation. A road map identifies an optimal and feasible path towards the realisation of a pre-specified goal for a later year or/and situation per country system. In the RESPOND project the key objective of developing a regulatory road map (as tool for system change) is to anticipate on the effects of the expected growth of intermittent RES-E/DG for the electricity system. The reasons for using the instrument of regulatory road maps for this purpose are twofold:

- **First** of all, the issue at hand is very complex, and requires the involvement of a large number of disciplines (points of view) in decision-making. An overarching view that brings together this variety gives additional insights in the way forward, to the most cost-efficient and effective realisation of targets for sustainability. Therefore, this report identifies the different challenges and opportunities that can be created by RES-E/DG, the measures available to tackle challenges and seize the available opportunities, but also the potential barriers that need to be removed to realize these opportunities.
- **Second** there is no single and uniform way forward for each of the EU member states when it comes to realizing an optimal integration of intermittent RES-E/DG in their electricity markets. Each individual country might encounter different specific problems when it comes to increasing intermittent RES-E/DG penetration due to for example different RES-E/DG potentials, electricity market structures, network configurations, and electricity demand characteristics.

The developed regulatory road maps encompasses two different type of challenges i.e. variability and less predictability, not to say problems, which intermittent RES-E/DG can cause and the type of measures that can be implemented. For optimally integrating intermittent RES-E/DG measures need to be implemented in order to enhance the flexibility within the electricity system. Different segments in the electricity system offer different opportunities for increasing system flexibility. These opportunities can be technical or economic in nature and vary from an improved design of balancing markets to the deployment of large-scale energy storage. In the implementation of measures aimed at increasing system flexibility important observations are that not all measures are available to individual countries in the same degree, and that, from the perspective of efficiency, countries should successfully aim at implementing these measures according to their relative cost-efficiency, with least-cost measures implemented first.

The developed country-specific regulatory road maps for an optimal integration of intermittent RES-E/DG, is necessary for facilitate regulatory decision-making on RES-E/DG integration in the five analysed member states Denmark, Germany, The Netherlands, Spain and UK, but also in other EU member states that find themselves in quite similar situations (system conditions, RES-E/DG shares et cetera). They might use the road map methodology for there own country as it offers a systematic approach for a more economic efficient implementation of the many technical, institutional and regulatory options in the different segments of the electricity system to reduce the negative (cost) impacts posed by intermittent RES-E/DG. In that way, the road map methodology assists in removing barriers for meeting the EU RES targets for 2020.

9.2 Recommended regulatory actions per country

Based on the developed five regulatory road maps the following regulatory actions can be formulated for these countries. The five EU members Denmark, Germany, the Netherlands, Spain and the United Kingdom cover countries with varying levels of RES-E/DG penetration and intermittent generation technologies. Consequently some of the system impacts are different and so are the solutions (response options and regulatory actions) per country and road map. In developing the regulatory road maps we have also resorted to available electricity system expertise within these countries, partners and stakeholders and other specific information resources. The most recommendable key regulatory actions are presented in Table 9.1 and further explained below.

Table 9.1 *Overview of recommended actions per country*

Topic	Recommendation	Country				
		Denmark	Germany	The Netherlands	Spain	United Kingdom
Network integration						
Network charging	Implement shallow connection charges at all network levels			✓	✓	✓
	Implement cost-reflective use of system charges for generators	✓	✓	✓	✓	
Network planning	Implement dynamic reserve requirements in network planning standards	✓	✓	✓	✓	✓
	Introduce explicit innovation incentives in network regulation	✓	✓	✓	✓	
Congestion management	Implement market-based congestion management	✓	✓	✓	✓	✓
Market integration						
Demand response	Establish common standard for functionality of smart meters	✓	✓	✓	✓	✓
	Implement basic time-differentiated prices for all consumers	✓	✓	✓	✓	✓
Balancing market	Introduce balancing responsible parties		✓		✓	
	Implement shorter gate closure times of trade markets				✓	
Ancillary services	Increase possibilities for RES-E/DG to provide ancillary services	✓	✓	✓	✓	✓

Connection charges

The integration of increasing amounts of RES-E/DG gives rise to increasing costs in connecting and operating networks. These costs have to be borne by the users of the system, i.e. generators and consumers.

The costs of connection of network users and the operation of the network are paid by network users. These network costs are generally subdivided in costs of connecting users (generators and consumers) to the grid and costs for operation of the electricity system i.e. transport and complementary system services. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by use-of-system (UoS) charges.

Two distinct approaches of calculating connection charges can be distinguished: shallow and deep charges. Shallow connection charges include only the cost of connecting the customer to the nearest point in the distribution network. The costs of additional network reinforcements are not included in these charges. As opposed to shallow connection charges, deep connection charges contain the costs of network reinforcements both at the transmission and distribution level as well as the direct connection costs.

For providing fair and non-discriminatory network access to the network for different kinds of generators, including small RES-E/DG units, it is important to introduce shallow connection charges. This avoids large upfront costs for RES-E/DG, which would discriminate against DG as compared to centralised generation. Besides, this kind of connection charges lowers transaction costs to DG by keeping the calculation straightforward and transparent and avoiding negotiations about the “deep” connection cost component. Therefore, it is recommended to implement shallow connection charges in Spain, The Netherlands and Germany.[60]

Use of system charges

However, from the point of view of the system operators, the implementation of shallow connection charges is not a favourable option if the costs of network reinforcement due to DG are not covered in some way. Therefore, it is *recommended to socialize the incremental grid reinforcement cost among all network users by way of use of system (UoS) charges*. Currently, UoS charges are mainly levied upon consumers, with the exception of the United Kingdom. Consequently, generators do not receive an incentive to take into account the network costs that the system will incur as a result of their decision to install a new plant at a certain location. However, this is clearly inefficient from a system and welfare point of view and causes higher network integration costs. Therefore, the introduction of cost-reflective use of system charges for generators is recommended for Denmark, Germany, The Netherlands and Spain. Coordinated implementation of this measure, at least at regional level but preferably at European level, is highly recommended since an uneven implementation of UoS charges for generators might result in an uneven playing field across the EU.

Dynamic reserve requirements in network planning standards

In network planning a number of standards are used in order to guarantee security of supply (like the ‘n-1’ standard). The maximum capacity of networks circuits is nowadays calculated using static assumptions with standard load profiles among others. When network reserve requirements depend on actual (short-term) wind generation forecasts, additional network capacity may become available and network investments due to connection of additional renewable generation may be lowered without compromising security of supply. This recommendation applies to all five countries at hand.

Explicit innovation incentives in network regulation

Network planning is also influenced by network regulation, both at TSO and DSO level. Generally, within Europe *incentive regulation* with price or revenue caps is applied to network operators. Incentive regulation can be characterised by the strong focus on short-term cost-efficient network operation, which is necessary to decrease the monopoly profits of network operators but comes at the expense of more risky investments contributing to long term efficiency. As a result, already existing risk-averse behaviour of network operators is reinforced, which impedes investments in active network management technologies by DSOs. Therefore, it is *recommended to add explicit innovation incentives to incentive regulation like the IFI type* of incentives in the United Kingdom. These incentives effectively increase the scope for innovation by

[60] Denmark and the United Kingdom have already implemented a shallow(ish) connection charges methodology.

DSOs and therefore may speed up the implementation of active network management. This recommendation applies to Denmark, Germany, The Netherlands and Spain.

Market based congestion management

Installing new conventional and RES generators may require reinforcing the transmission and distribution grids, especially if new generation is either located far from load or production is exceeding consumption sometimes. Reinforcing the network usually takes more time than installing new plants, and starts only when generation consents have been provided. Consequently, existing network capacity falls short and congestion will emerge. For interconnections already implementation of market based congestion management is required by EC regulation 1228/2003. Countries are increasingly using implicit and explicit auctions for cross-border congestion management. Also for *national grids implementation of market-based congestion management is recommended* in order to relieve congestion against lowest costs for all market actors including RES-E/DG as well as to diminish the occurrence of congestion. This recommendation applies to all countries.

Common standards for functionality of smart meters

Common standards for smart meters are required in order to ensure a certain standard of data quality and functionality within country. *A common standard prepares for an increase of market-based demand response in the future* and guarantees that the whole demand response potential can be utilised. An increase of demand response is valuable to increase the flexibility of the system to react to the higher variability of generation in systems with high penetrations of wind and PV. At present, common standards have not yet been defined. Therefore, it is recommended to establish common standards for smart meter functionality in Denmark, Germany, The Netherlands, Spain and UK

Basic time-differentiated prices for all consumers

Smart meters are useful but not sufficient for an increase of demand response. Therefore, consumers need also to receive signals about the system status. In a liberalised market, this signal should be provided to consumers by making prices more variable. As a *first step, prices should be differentiated to peak, shoulder and off-peak periods.* In the medium term, i.e. before 2020, consumers should be facing hourly-based prices. It should be noted that the communication of hourly prices to final consumers itself might not always automatically induce price responsiveness. This might vary over the various types of electricity consumers. In order to fully use the demand response potential with for example household consumers automated response devices should be developed and implemented in parallel, since especially these consumers might be reluctant to make personal, real-time decisions on electricity consumption and responsiveness to electricity price changes.

Balancing responsible parties

The Scandinavian type of balancing market design with balancing responsibility for all connected parties (including RES-E/DG) provides an incentive to both generators and consumers to limit their imbalance as far as possible; connected parties have to pay imbalance payments in case their actual production deviates from their production forecast. Consequently, at a system level the amount of balancing power to be provided is reduced compared to a system without balancing responsibility. This allows for the integration of RES-E/DG production in the electricity system against lower costs. It is *recommended that a balancing system with balancing responsibility for all connected parties will be introduced* in both Germany and Spain. The other countries did already implement such a system in the past.

Gate closure times of trade markets

Generators can sell their production on markets with different time-frames. In a market environment wind and PV will mainly sell their production in markets for short time-frames, notably the day-ahead market due to the intermittent character of these sources. On a day-ahead basis production forecasts for wind do have a relatively high forecast error; in order *to diminish their balancing cost exposure wind generators need the possibility to correct their production forecasts as close to real-time as possible* when the forecast error of production is much lower. In several countries intraday markets have been established for this purpose. Gate closure times of intraday markets (in the UK the spot market) range from a maximum of 8 hours ahead of real time (last intraday market for each day closes at 17:45 in Spain), via 1.5 hour (Germany) to 1 hour ahead of real time (UK, Netherlands, Denmark). For Spain, it is recommended to reduce the gate closure time to 1 hour ahead of real time.

Possibilities to provide ancillary services
Currently requirements of system operators as well as obliged provision of some ancillary services by conventional generation, prevent the delivery of ancillary services (including balancing services) by RES-E/DG. However, for both system (dramatic decrease of conventional generation in some regions) and level playing field considerations, it is deemed *useful that RES-E/DG will be enabled to provide ancillary services*. Therefore, requirements to RES-E/DG, including aggregators of a portfolio of small (distributed) generation assets, and all minimum size limits of the underlying individual installations or connections should be removed as far as economically and technically feasible. Furthermore, the ancillary services market design should allow for sufficient AS provision, efficient contracting of these services, as well as for a good trade-off for generators between either the provision of energy on the one hand or the provision of one of the different ancillary services on the other. Especially, services with a system-wide character (for example tertiary reserves) may be contracted through markets (i.e. auctions) instead of self-procurement by the TSO or bilateral contracts.[61] Consequently, RES-E/DG may diversify their revenue streams. Since today there is little experience with RES-E/DG providing ancillary services, *further field testing/research is required*. But the recommendation applies to all five countries; Denmark, Germany, The Netherlands, Spain, and United Kingdom.

9.3 Priority and critical regulatory actions per country

From the developed road maps we select the most urgent and critical actions to improve the system flexibility of the five countries in the short term.

Denmark
The road map indicates that the main actions are required for improving network integration, as on the one hand major grid overloads and network congestion are expected, and on the other hand conventional hardware solutions are prevented by social acceptance issues and increasing cost burdens. First of all, generators should face the effects of their production and siting decisions on network investments; therefore *use-of-system charges for generators* should be set at a more substantial level. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Finally, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning standards in the longer term. Especially in a system with high and increasing shares of wind generation, dynamic planning criteria can lower network integration costs substantially.

Germany
For Germany actions are required for improving both network and market integration. Although network integration remains the main issue, during our analysis it became prevalent that the improvement of market flexibility delivers large quick wins for the German electricity system, po-

[61] For local services like the provision of reactive power, the number of service providers may be too small for a market in some cases.

tentially limiting required network integration actions. More market flexibility may limit the demand for network flexibility dramatically by stimulating generators to take into account the effects of their behaviour on the electricity system. First of all, when a *feed-in market premium scheme* is implemented instead of feed-in tariffs, RES-E/DG receives incentives to take into account the system demand for electricity in its production decisions. Secondly, difficult network situations can be dealt with more effective and efficiently when RES-E/DG disposes *no longer* of *priority access*, but is allowed to be curtailed against a cost-reflective payment. Finally, demand for system balancing can be decreased substantially if RES-E/DG becomes *balancing responsible* and a *rolling gate closure time* for the balancing market is introduced.

The Netherlands
For the Netherlands, the main actions are required for better network integration. First of all, network integration can be done against lower costs if generators have to take into account *use-of-system charges for generators* which influence generators' production and siting decisions. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Next, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning standards in the longer term. Last but not least, difficult network situations can be dealt with more effective and efficiently with *congestion management if* RES-E/DG will not dispose of the foreseen *priority access*, but remains to be allowed to be curtailed against a cost-reflective payment.

Spain
For the Spanish electricity system it is vital that *current flexibility provided by pumped-hydro and gas-based units is maintained.* Especially for gas-based electricity generation units there are concerns that the current capacity payment mechanism is not working satisfactorily. Without sufficient adaptation of this mechanism there will likely be insufficient incentives to expand flexible gas-based electricity generation in the near future. Furthermore, it is stressed that *interconnections with especially France need to be strengthened*. Current initiatives in this respect should receive continuing support. The above mentioned issues relate to the provision of system flexibility, but apart from that also the efficiency with which intermittent RES-E/DG operates needs to be substantially improved. Response options that should be highly valued in this respect are the adaptation of the use of system charges methodology (increasingly allocate costs to generation) and *balancing market rules (move gate closure closer to real-time).*

The United Kingdom
Network regulation in the UK seems quite robust when it comes to a further increase of intermittent RES-E/DG in the future, although possibly the implementation of more cost-reflective network charges should be given some attention in the medium-term. The more critical points in the future regulatory actions when it comes to the integration issue is to efficiently and effectively deal with (1) structural geographical imbalances in load and generation across the UK, and (2) the connection of large-scale off-shore wind parks.

9.4 Importance of timing of regulatory actions

All recommended regulatory actions derived in the RESPOND project, and highlighted above, can successfully increase the flexibility in the electricity system that is needed to continue successful integration of intermittent RES-E/DG in that system. However, within the country-based road maps we have also identified a prioritisation of these regulatory actions when it comes to the implementation within the 2020 timeframe. In general, implementation of relatively easy and less costly response options should precede the implementation of more complex and more costly response options. Since the current-day situation differs across the assessed EU member states, also the prioritisation of recommended regulatory actions that can increase system flexibility varies across these countries.

In the short-term, say until 2012, for most countries, relatively low cost response options include changes in the methodology of network tarification and the design of wholesale and balancing markets (i.e. change in gate-closure time). The major issue with the former type of response options is not the cost of implementation but the change in the allocation of costs over the different actors in the system, which could give rise to possible delays in implementation. It is recommended that discussions on the implementation of this response option are started as soon as possible. The latter type of response options should also be given high priority because it can substantially lower the costs of integrating intermittent RES-E/DG and hence improve overall system efficiency. In addition, high priority in the short-term should be given to the provision of innovation incentives to electricity market actors. This will benefit system capacity to create and adopt new innovations related to a successful integration of RES-E/DG in the medium and long-term.

In the medium to long-term, more fundamental and relatively more complex response options are recommended for the assessed EU member states. These include the implementation of more price responsive electricity demand. Whereas implementation of basic electricity price differentiation in base and peak is recommended in the very short term, even more differentiated electricity prices (e.g. hourly prices) are recommended in the medium term. Furthermore, more complex response options such as the implementation of cross-border balancing and the implementation of zonal pricing should be considered in the medium term. The former requires for many preparatory actions in describing and defining common balancing services characteristics and a common balancing market gate closure time. The latter type of response option enables efficient national market-based congestion management, but asks for a number of preparatory actions, for instance to establish different zones and to compute the constrained energy. Other options like provision of ancillary services by DG and implementation of active network management in distribution networks may be only partially possible before 2020, since these options require further technology development as well as adaptations of complex network criteria.

9.5 Responsibilities of different market actors

A large number of market actors bear responsibility in some way when it comes to the implementation of response options that can ensure a smooth integration of RES-E/DG units. Apart from the different actors involved in different stages of the electricity market value chain (i.e. electricity generation, transport, distribution, et cetera), there are also different jurisdictions involved (i.e. the national vs. the European level).

Regarding the implementation of response options related to efficient *network* integration at the distribution network level, the responsible market actors are mainly but not exclusively national. Response options in this field relate to the adaptation of distribution network charging methodologies, the provision of network planning and innovation incentives to DSOs and the method of network regulation. Here, the main responsible actors are the national DSOs and the regulatory authority. In joint cooperation with the DSOs, the regulatory authority should explore and finally adopt changes in existing distribution network regulation. For a number of the response options it holds that no changes in existing energy sector legislation are required at either the national or EU level. However, some response options will clearly benefit from common European legislation, for instance the planned European network codes probably will accelerate the implementation of active network management (smart grids), since technical manufacturers do only have to meet one set of technical specifications instead of several, often conflicting ones. Moreover, it goes without saying that during the process of drafting adaptations to existing regulation national market-actors can, and need to, learn from experiences abroad. This could for example be done under the existing umbrella of the ERGEG Regional Initiatives.

For response that aim to deal with *network* integration issues at the transmission network level things are different. Here it is more important to coordinate the implementation of response options on EU or at least on a regional level, since changes in for example the allocation of scarce network capacity both nationally and at borders, transmission tarification for generators, and the design of network investments in national connections and interconnections immediately affect the electricity market across the border as well. Hence there is a much stronger need for coordination. However, the responsibility for implementation of many actions still rests with national market actors such as the operator(s) of the national transmission network (TSO) and the regulatory authority. Again, as was the case for response options at the distribution network level, it is expected that the role for government (for example in drafting new pieces of energy sector legislation) is not large since most response options in this field can already be implemented under existing laws.

For most of the response options aimed at an efficient *market* integration of intermittent RES-E/DG an additional legislative step is required before implementation. This is the case for substantive changes in support scheme mechanisms, regional wholesale and balancing market design related to export of electricity from renewable sources, differentiation of end-user electricity prices in time, and smart-metering and demand response. On the whole, given exceptions for some countries, implementation of these measures first requires a process of proposing, discussing and adopting new pieces of electricity market legislation at both the national and European level. After adoption in legislation, the actual implementation then still rests with a larger number of actors in the field. For example, DSOs and electricity retail suppliers will need to work together in successfully operating smart meters and communicating time-differentiated and/or locational electricity prices.

9.6 Validity of findings for other European countries

The recommendations derived in this study are not only relevant for improving the integration of intermittent RES-E/DG in the electricity systems of the five considered countries, but also for the EU-27 as a whole, for at least three reasons.

First of all, the group of countries in the RESPOND project concern several countries (Denmark, Germany and Spain) which can be considered as being forerunners within Europe with respect to the penetration of wind and/or photovoltaics in their respective electricity systems. Other European countries are expected to face the same impacts in the coming decades when striving for attaining the EU renewable energy goals of 2020.

Secondly, since interdependencies between countries increase due to efforts aimed at achieving common European electricity and gas markets, a lot of recommendations will have also effects on other countries and therefore require regional coordination. For instance, the introduction of cost-reflective UoS charges for generators in one country will be to the detriment of these generators when at the same time GUoS charges are not introduced in other countries.

Thirdly, many recommendations are not only useful for countries with high amounts of renewables, but also for countries which look for opportunities to accomplish higher security of supply and lower energy price levels. The recommendations derived from this study can also significantly contribute to more resilient electricity systems with higher security of supply, and to a more efficiently operating electricity system by enhancement of market functioning. In this study regulatory actions were assessed from the perspective of efficient and effective RES-E/DG integration, but the energy policy goals of security of supply (reliability) and overall efficiency are addressed by a large share of the derived actions as well.

9.7 Final reflections

The increase in the amount of (intermittent) less controllable electricity generating units (i.e. Wind, PV, heat-led CHP) presents both challenges and opportunities for the development of the electricity markets in Europe. For one, the increase in distributed or renewable-based generation units poses benefits with respect to energy efficiency and environmental impact. The challenges lie in the provision of more flexibility in current electricity systems. Therefore, the focus should be on providing this additionally required flexibility against the lowest possible cost, i.e. cost effective.

In the *short-term* this involves basic and relatively easier options such as improving balancing market design, increasing international and regional interconnection capacity and time-differentiated final electricity prices. In the *medium term* it involves the implementation of more differentiated cost-reflective network charges and renewable support schemes. In the *long-term*, beyond 2020, more innovative solutions related to for example the large-scale introduction of electrical vehicles should be considered.

Although the particular cost-effective measures for each EU member country may be different, depending on national electricity system characteristics, for each of the member states it holds that policy and regulatory actions should on the one hand aim at improving the flexibility level of the electricity system by the most-effective short term measures, and at the other hand aim at an optimal market environment where there is sufficient room for market actors to further develop more innovative technologies that are highly required in a post-2020 electricity system. Although the developed regulatory road map only looks until the 2020 mark, the underlying research on response options available for increasing electricity system flexibility together with the further developed road map methodology offers promising potential to further research this issue from a *longer-term perspective*.

Finally, on an EU or national level this analysis could be followed by a more *detailed and quantitative approach of the different measures proposed and their net benefit for the country* at hand. The actual added benefits are dependent on many country-specific conditions such as market structure, geographical conditions, and prevailing regulation. Such analysis would give much better insight in the prioritisation of regulatory actions over time. Whereas the prioritisation and timing of regulatory actions in this study could only be highlighted indicatively, quantification-based recommended actions could give rise to more definite priorities and timing. This remains a challenge for future research.

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