European Commission
DG for Energy (ENER/B2)

Study on Synergies between Electricity and Gas Balancing Markets (EGEBS)

Final Report

Under the Framework Service Contract for Technical Assistance TREN/R1/350-2008 Lot 3

Specific contract No. ENER/B2/2011-251/SI2.602231

October 2012

In collaboration with DNV KEMA

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Glossary

Term	Explanation
Balancing energy	Active energy activated by the TSOs to maintain the balance between injections and withdrawals.
Frequency containment reserves	Frequency containment reserves are operational reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. Activation of these reserves results in a restored power balance at a frequency deviating from nominal value. This category includes operational reserves with a typical activation time of 30 s.
Frequency Restoration Reserves	Frequency restoration reserves are operational reserves necessary to restore frequency to the nominal value and power balance to the scheduled value after sudden system imbalance occurrence. This category includes operational reserves with an activation time typically up to 15 minutes. Operational reserves of this category are typically activated centrally and can be activated automatically or manually.
Inter-zonal exchange	An exchange (of energy and/or capacity) between two different market areas, bidding areas or balancing zones, including both cross-border exchanges as well as exchanges between different areas and/or zones in a single country.
Manually-instructed reserves	Services that are not automatically delivered when required, but are instead instructed by the SO. They are generally utilised to cater for plant loss and significant demand forecast error.
Operational reserves	Active power reserves located in the generation units or loads to maintain balance between generation and demand and restore the frequency to its set point value in the synchronous system. Operational reserves are classified as Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves.
Primary control	Automatic reaction of the primary controller of generating sets, involved in primary control, to a frequency deviation caused by a system disturbance or small variations in production and consumption.
Replacement Reserves	Replacement reserves are operational reserves used to restore the required level of operational reserves to be prepared for a further system imbalance. This category includes operational reserves with activation time from 15 minutes up to hours.
Secondary control	Instructed action of particular generating sets linked to a control loop in a control area, to move the overall system (frequency and interchange) deviation of the control area towards zero following the delivery of primary control in response to a sudden variation in production or consumption.

Foreword

The present report has been prepared by COWI Belgium, in collaboration with COWI A/S and DNV KEMA, under the existing COWI Service Framework Contract with DG TREN (ENER and MOVE) covering Technical Assistance Activities (Ref. TREN/R1/350-2008 Lot 3) and in response to the Terms of Reference included under the Specific Contract No ENER/B2/2011-251/SI2.602231.

Readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the Commission.

Executive Summary

This study has analysed the need and scope for exploiting synergies between gas and electricity balancing in light of the evolving balancing arrangements in both sectors, on the one hand, and the expected increase in the contribution of variable power generation sources, such as wind and solar power, to electricity production in the time horizon up until 2030.

In line with the political ambitions of the European Union, the penetration of variable renewable energy sources (RES) in the electricity sector is expected to increase significantly over the next two decades. Apart from the need for the provision of sufficient 'firm capacity' (back-up power), the volatile production of renewable energy sources creates particular challenges for the daily balancing process, i.e. for balancing any deviations between the planned or forecast production and demand, on the one side, and the actual outturn in real time, on the other side. Although a comparison of different scenarios in this study has revealed considerable differences in the expected developments until the year 2030, most studies assume a strongly increased contribution from wind and/or solar power.

Against this background, it is widely expected that gas-fired power plants will become even more important and, probably, even the main source of balancing power in many countries. In addition, the increasing dependency of the electricity market of gas-fired power plants will also increase the inter-dependency between the electricity and gas sector. Consequently, more volatile power prices may lead to more volatile gas consumption and may therefore contribute to more volatile prices in the gas market as well. Overall, the gas markets may thus also be faced with an increasing need for flexibility.

Despite this, the gas and electricity markets have been developing target models in a rather separate and non-coordinated way. It is therefore uncertain whether the evolving target models for the gas and electricity markets provide the right framework for making optimal use of available flexibility in both sectors.

On behalf of the European Commission, the current study has had the aim of assessing the compatibility of balancing arrangements in both sectors, in order to identify potential barriers as well as further synergies to be gained, with the ultimate objective of developing and proposing key design elements for electricity and gas balancing markets that may be used to exploit such synergies.

As illustrated in Table 1, the balancing arrangements in both sectors reflect important differences in the physical characteristics of power systems and natural gas networks. Most importantly, the need for immediate action in the power sector requires the use of a series of specific technical products, which can be commonly found in most of the European markets. Conversely, the inherent flexibility of natural gas networks facilitates the use of more commoditised products, whilst the European gas markets have so far failed to develop a comparable set of dedicated products for balancing purposes.

Although the evolving market and regulatory arrangements in both sectors clearly favour the use of market-based instruments of balancing, as well as regional integration, they do not yet address the interaction between both sectors.

Table 1: Key technical differences between electricity and gas balancing

Issue	Electricity Sector	Gas Sector
Balancing scope & range	Need to maintain system frequency within strict limits in real time	Inherent storage capability allows for certain range of operating pressures
Balancing process and time horizon	Focus on close to real time power balance	Focus on cumulative energy deviation
	Focus on immediate action in last hour before real time	Focus on delayed actions (≥ 2 hours)
Products	Clear sequence of specific technical services over time	Primarily reliance on market-based products; lack of standardised dedicated products and services

Source: DNV KEMA

The increasing penetration of renewable energy sources will create new challenges for balancing in the electricity market. Among others, more flexible generation sources, such as gas-fired plants, will have to be able to cover an increasing spread between peak and trough load and deliver increased ramp rates (Table 2). In addition, their operation will be subject to additional forecast errors for the uncertain production of renewable energy sources.

Gas-fired plants are generally expected to develop into the major sources of balancing services in the electricity market. As a consequence, these effects will also have an impact on the gas markets. In turn, the gas markets will be faced with a growing diurnal swing and other developments, which will increase the need for an optimal use of available flexibility in the gas market, in order to minimise operating costs and the need for costly extensions of the existing infrastructure.

Table 2: Future challenges for gas and electricity balancing

Electricity (Residual load)	**Gas**
Increasing spread between peak and trough load	Increased diurnal swing
Increased ramp rates	‚Slope‘ of within-day variations
Increased forecast errors	Additional forecast errors

Source: DNV KEMA

Apart from further improvements in both sectors, an improved interaction between both sectors may therefore render significant technical and economic benefits (compare Table 3). To start with, they may primarily help to reduce the amount of infrastructure requirements, such as the amount of pipeline, generation, storage or network capacity required. Secondly, improved balancing arrangements may also help to reduce operating expenditure. Thirdly, changes and synergies in gas and electricity balancing may also have an influence on network integrity and reliability in both sectors.

Whilst it is difficult to quantify the potential benefits in terms of network integrity and reliability, a simplified welfare analysis reveals that the potential welfare gains of exploiting synergies between gas and electricity balancing may easily reach up to 300 million on an annual basis, even when considering a limited number (7) of Member States only. In addition, more efficient balancing may also cause a considerable shift of welfare from providers of balancing services to consumers. These numbers indicate that an improved coordination of the gas and electricity balancing arrangements may render significant economic benefits for European consumers.

Table 3: Main technical benefits for gas and electricity balancing

	Gas	**Electricity**
Physical infrastructure (CAPEX)	- Reduced pipeline capacity - Reduced line pack - Reduced storage (underground, LNG)	- Reduced generation capacity - Reduced transmission - Reduced dynamic requirements
Daily operations (OPEX)	- Reduced use of compressors (network + storage) - Improved reliability - Better information on current and expected balancing needs	- Improved generation efficiency - Reduced network losses - Reduction of variability - Improved reliability - Availability of increased reserve margins

In order to exploit these synergies, this study has identified and assessed a total of potential measures. As illustrated by Table 4, many of these measures are specifically focused on either the electricity or gas market, whereas only two are clearly based on direct interactions between both sectors. Moreover, it is worth noting that most of these measures focus on improving the day-to-day operation of the balancing process; with the notable exception of coordinated network planning, which concentrates on investments instead.

Table 4: Overview of potential regulatory and market-related measures for implementing potential synergies between gas and electricity balancing

Scope	Measure
Electricity Market	• Replacement of day-ahead market coupling by intra-day capacity allocation • Regional sharing of operational reserves • Coordination of energy and reserve markets
Gas Market	• Enforcement of firm exit capacities for system-critical power plants • Inter-zonal exchange of balancing services • Within-day products for inter-zonal capacities • Within-day 'flexibility products' • Improved line pack management
Common Issues	• Coordinated operational planning • Coordinated network planning

Source: DNV KEMA

Based on a structured assessment against a set of nine evaluation criteria, this study has identified eight different measures, which we propose to pursue with the aim of exploiting the synergies for gas and electricity balancing. Most important are four priority measures, which should be pursued in any case. Apart from the regional sharing of operational reserves in the electricity sector, these include the coordination of network and operational planning between gas and electricity TSOs, as well as improved line pack management in the gas sector. All of these measures can basically be implemented within the current target models for the gas and electricity market and the framework of the Framework Guidelines and Network Codes, which have already been developed to date. Nevertheless, it is important to note that the full benefits of coordinated network planning could only be exploited if this measure were to be supported by suitable locational signals, for instance through locational tariffs or connection charges, or similar instruments.

In addition to these priority measures, four other measures should be considered under certain conditions:

- In power systems with a high share of fluctuating RES and where the TSOs need to procure a certain share of operational reserves from inflexible plants, TSOs may consider an *intra-day adjustment of reserve allocations*. The application of this concept should be checked carefully. However, it should be checked against several other options, such as the contracting of operational reserves with a limited activation time or the contracting of dedicated 'slow reserves' outside the main market.

- Secondly, TSOs should not be prevented from *procuring gas balancing services from external balancing zones* where this leads to lower costs. However, such exchanges should ideally be based on a limited set of standardised (temporal) products that can be activated within normal timescales for re-nominations. Moreover, such exchanges should preferably be implemented via open platforms which are also open for bilateral trades between shippers.
- Thirdly, where the development has shown a considerable need for the use of temporal products in two neighbouring markets with within-day obligations, it might furthermore be beneficial to consider the introduction of *within-day products for inter-zonal capacity in the gas market*.
- Last but not least, our analysis highlights the importance of the *design of within-day obligations in the gas market*. From the perspective of this study, in particular, it would be important to avoid any undue penalties on gas-fired plants that are providing balancing services in the electricity market but cannot re-schedule their gas consumption within the framework of ordinary re-nominations.

In addition, we believe that the provision of firm exit capacities for system-critical power plants in the gas market deserves further attention. Although we principally support the intentions of this concept, our analysis has also revealed a series of potential risks of an ill-designed measure. Consequently, we recommend that this measure should be subject to further study. Moreover, it is worth noting that the concept of coordinated network planning in the gas and electricity sector may already remove most of the potential limitations of this measure.

Table 5: Overall assessment of proposed measures

Measure	Comments
Priority Measures	
Regional Sharing of Operational Reserves in the Electricity Sector	Highly promising measure (principally already foreseen by draft FG on Electricity Balancing)
Coordinated network planning	May potentially lead to major savings in overall investments in both gas and electricity networks (if supported by tariffs and connection charges)
Coordinated operational planning	Improves reliability and efficiency of daily balancing in both sectors
Improved line pack management	Facilitates optimal use of available flexibility in the gas network
Potentially Promising Measures	
Intra-day adjustment of reserves in the electricity market	To be considered in power systems with a high share of fluctuating RES and the need to procure operational reserves from inflexible plants
Inter-zonal exchange of gas balancing services by the TSOs	Based on the procurement of standardised temporal products via an open platform
Within-day products for inter-zonal capacities in the gas market	To be considered where temporal products play a tangible role in neighbouring markets
Design of within-day obligation (e.g. cumulative tolerance)	Avoid excessive risks for gas-fired plants by facilitating market-based balancing

This study has not identified any need for far-reaching changes of the target models for the gas and electricity markets. Similarly, our analysis has not revealed any fundamental conflicts with the currently evolving set of Framework Guidelines and Network Codes. Overall, this study does therefore confirm the current process towards the further development of the European gas and electricity markets.

In turn, this also implies that the measures proposed above can principally be implemented within the scope and framework of the evolving regulatory framework. Against this background, Table 6 finally proposes a tentative roadmap for the implementation of the proposed design elements.

With regard to the priority measures, these can basically be addressed without delay, although we expect that most of them will take the form of a continued process of improvements. Conversely, the regional sharing of operational reserves represents a fairly complex measure. Consequently, we propose that the initial emphasis should be on identifying and specifying potentially promising solutions, which should ideally first be tested in the form of 2 – 3 pilot projects, in order to take an optimal approach.

With regard to the remaining measures, their development and implementation will finally have to be synchronised with the emergence of the preconditions of each of these measures, as mentioned above.

Table 6: Tentative roadmap for implementation of proposed design elements

Measure	Recommended steps and timing
Priority Measures	
Regional Sharing of Operational Reserves in the Electricity Sector	– Generally synchronise with deadline for transition to regional balancing market under the FG on Electricity Balancing – Start 2 – 3 pilot projects within the next 2 – 4 years, in order to test suitable models
Coordinated network planning, Coordinated operational planning, Improved line pack management	– Start initial discussions and initiatives (2013/2014) – Require TSOs and regulators to regularly report on any progress made
Potentially Promising Measures	
Intra-day adjustment of reserves in the electricity market	– Define and monitor suitable criteria, to identify the need for implementation – Investigate potential design and potential benefits in more detail, develop more detailed concept (where deemed to be beneficial)
Inter-zonal exchange of gas balancing services by the TSOs	– Same as above
Within-day products for inter-zonal capacities in the gas market	– Same as above
Design of within-day obligation (e.g. cumulative tolerance)	– To be considered in the context of the introduction of within-day obligations

Measure	Recommended steps and timing
Other	
Firm Capacities for system-critical power plants	– Further investigate possible design options and their impact, in coordination with the parallel work on coordinated network planning

1 Introduction

Gas is an important fuel for electricity generation in many countries. With the rise of variable power generation sources, in particular wind and solar power, gas-fired power plants will become even more important and probably even the main source of balancing power. Although hydro power is and will remain an important balancing source in some countries, the potential to expand hydro power capacity is limited. At the same time, it is widely expected that an increasing penetration of wind and solar power will result in a more volatile production by conventional power plants, including gas-fired plants.

The increasing dependency of the electricity market on gas-fired power plants will also increase the inter-dependency between the electricity and gas sector. Despite this, gas and electricity markets are developing target models in a rather separate and non-coordinated way. It is therefore uncertain whether the evolving target models for the gas and electricity markets provide the right framework for making optimal use of the flexibility available in both sectors.

Against this background, this study aims at:

- Identifying options for exploring synergies between gas and power balancing;

- Analysing the potential technical and economic benefits from the implementation of the options identified;

- Proposing key design elements for power and gas markets (including balancing markets) to exploit synergies; and

- Proposing a tentative roadmap for exploiting synergies between gas and power balancing markets

In order to reach these goals, the study also analyses the present and future needs for balancing in the gas and power market up to 2030, based on the ambitious renewable growth targets envisaged in the EU and the considerable volatility which renewable energy sources will introduce in the power system.

In detail, this document is structured as follows:

- Chapter 2 contains a brief introduction to the physical need for and means of balancing in both the electricity and gas markets, in order to provide for the overall background of this study;

- Thereafter, chapter 3 describes the current (market) arrangements for balancing in both sectors, as well as the current developments towards the design and implementation of so-called target models and the related set of regulations for both electricity and gas;

- Chapter 4 then summarises the findings of several studies which project the possible development of the gas and electricity sector in the time horizon up to 2030, and identifies a number of relevant implications for gas and electricity balancing;

- Against this background, chapter 5 identifies a number of potential synergies between gas and electricity balancing;

- Chapter 6 estimates the potential welfare gains in the form of technical and economic benefits, which may be being exploited by the synergies identified in chapter 5;

- Chapter 7 assesses the potential measures identified in chapter 5 and proposes a set of key design elements for gas and electricity balancing markets; and

- Chapter 8 presents a tentative roadmap for implementing the proposed design elements.

2 Technical Means and Need for Gas and Electricity Balancing

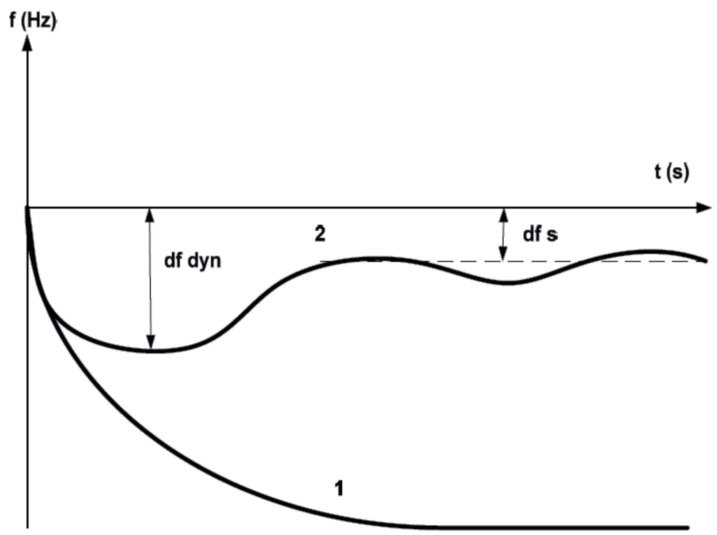
2.1 Balancing in the Electricity Sector

2.1.1 Need for Balancing in the Electricity Sector

For the power system to function there must be a real-time balance between production and demand. A mismatch between production and demand will immediately affect the system frequency. If the mismatch becomes too great, the whole power system risks a blackout. This might happen for example if there is an outage or a sudden positive or negative change in a large portion of production or demand. This will cause a marked discrepancy between production and load, which in real time will affect the frequency. If the discrepancy is too large, a partial or complete system blackout may occur.

In the short-term, a discrepancy between production and load results in a change in the system frequency as shown below in Figure 1, where *f* is the frequency [Hz], *t* is time [s] *df dyn* [Hz] is the dynamic change in frequency, and *df s* is the stationary change in frequency [Hz]. Line 1 illustrates the effect with no regulation with respect to the mismatch and line 2 illustrates the effect when a regulation scheme to compensate the mismatch is implemented.

Figure 1 - Effect of a discrepancy between load and production



The day-ahead and intra-day markets ensure a balance between production and demand and thus an energy balance. The day-ahead energy balancing is commonly handled by the physical market and normally has a time horizon of 12-36 hours. The intra-day market or intraday trade is the trade that takes place during the day of operation when the day-ahead market is closed. In the intra-day market imbalances due to incidents or unexpected events can be counter-balanced.

After the intra-day markets have closed, a Transmission System Operator (TSO) acts to ensure that demand and supply match in and near real time. To this end, the TSOs operate some form of balancing mechanisms which ensure that the power balance of the system is maintained (or restored) in real time at the lowest possible cost.

2.1.2 Different Types of Ancillary and Balancing Services

A significant aspect of balancing is the method to secure ancillary services. Ancillary services refer to a range of services which TSOs contract for so that they can ensure system security. These ancillary services include operational reserves, reactive power / voltage control as well as restoration services (such as black start).

For the purpose of this report, i.e. the daily balancing process, we are focusing on operational reserves. In accordance with recent documents prepared by ENTSO-E, these can be defined as active power reserves located in the generation units or loads that are used to maintain balance between generation and demand and restore the frequency to its set point value. From a functional perspective, operational reserves can be differentiated by the three main purposes they serve, i.e.:

- Frequency Containment Reserves (FCR), which are used to arrest frequency deviations;

- Frequency Restoration Reserves (FRR), which are used to restore system frequency to its nominal value and, where applicable, the power balance to the scheduled value; and

- Replacement Reserves (RR), which are used to restore the required level of frequency restoration reserves.

As further explained in chapter 3.1, this approach has recently been chosen for the classification of operational reserves in the context of the framework guidelines and network codes for the European electricity market. Alternatively, it is also possible to differentiate operational reserves by the technical means used for the provision of these services, which was earlier used by ETSO as predecessor of ENTSO-E[1]:

- Primary control[2], which is based on the automatic and immediate response of generating units to support frequency that is achieved through the automated governor control at each generating unit to frequency deviations;
- Secondary control[3], which is based on the instructed action of particular generating sets that are linked to a control loop in a control area, in order to move the overall system (frequency and interchange) deviation of the control area towards zero following the delivery of primary control in response to a sudden variation in production or consumption; and
- Manually-instructed reserves, which cover all operational reserves that are not automatically delivered when required, but are instead instructed by the TSO; in practice, this group is often further divided into tertiary control or fast reserves with an activation time of between 5 – 30 minutes and slow reserves with a delayed response time of one to several hours.

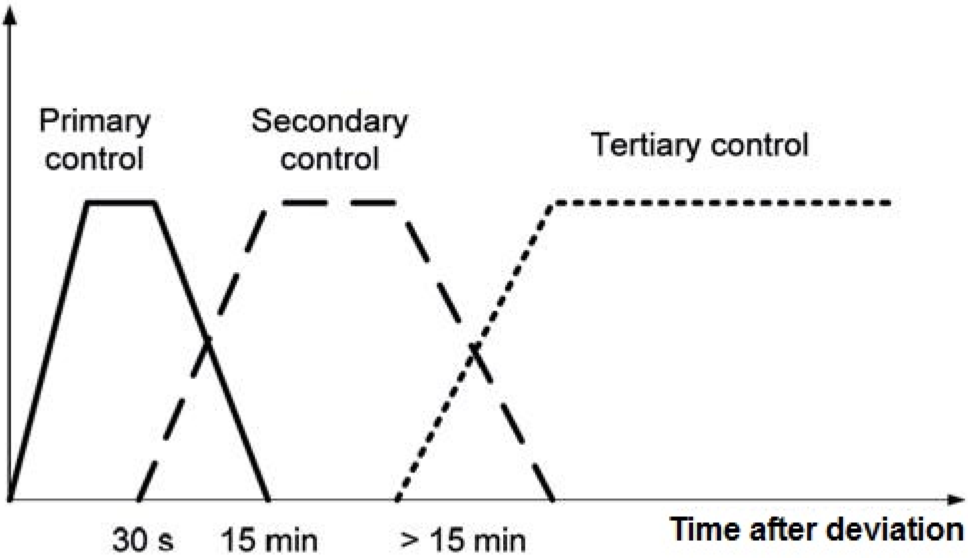
It is important to note that these two different approaches for classification do not fully correspond to each other. Whilst primary control is used for frequency containment and secondary control for frequency restoration, manually-instructed reserves (including tertiary control) may serve both for the purpose of frequency restoration and as a replacement reserve.

Access to a wide range of services from many different service providers enables TSOs to have flexible options allowing efficient decisions to be made. Important drivers for the aforementioned services are for example outages and forecast errors regarding RES and consumption.

An overview of the time horizon of the different control schemes are illustrated in Figure 6.

[1] European Transmission System Operators (ETSO). Current state of balance management in Europe. December 2003.
[2] Also known as frequency response
[3] Also known as automatic governor control (AGC) or regulation

Figure 2 - Primary, secondary and tertiary control



Source: UCTE

2.1.3 Main Sources of Different Generation and Balancing Technologies

Currently, the European power generation mix is mainly based on fossil fuels such as nuclear, hard and brown coal, gas, and oil[4]. Power generation from RES is steadily growing, and the main sources are wind and solar power. Another large renewable generation type is hydro power.

When available and using stored energy, pump storage, compressed air and large hydro power plants generally have fast regulation abilities and thus balancing capabilities. Inhibiting factors with respect to these plant types are geographical conditions and high construction costs. Most large hydro plant sites in Europe are already in utilisation and thus the potential for constructing new plants is limited.

Pump storage and compressed air/gas

Pump storage and compressed air/gas units have a low total efficiency as power is lost in the pumping or air/gas compressing processes. Pronounced balancing plants include pump storage and compressed air power plants as these units have short start-up times. The potential for new pump storage plant sites in Europe is somewhat limited since they, like hydro plants, require a usable height difference between two water reservoirs. Thus, there is little potential for constructing new plants, although the required reservoir size is smaller than for a hydro power plant.

Pump storage power plants have a start-up time of 60-90 seconds[5], and when already in operation, a ramp rate of up to 6.0 pu/min. The overall efficiency is

[4] http://www.energy.eu/country_overview
[5] http://brain2grid.org/documents/mypaper/EFRI_publication_1280258245.pdf

70-85 %. If in pump/storage mode, the plants need time to change into production mode.

Compressed air/gas power plants have a start-up time of 10-15 minutes[6], and when already in operation, a ramp rate of 0.20 pu/min. The overall efficiency of new plants can be 70-85 %.

Run-of-river hydro power

Hydro power plants have a fast start-up time which is in the range of 2-10 seconds. When already in operation, the plants have a fast ramp rate in the range of 5-10 pu/min. The overall efficiency is approx. 95 %[7]. Run-of-river hydro power plants are dependent on the water flow and do not have the same properties as conventional hydro power plants.

RES

In order for RES plants, like wind and solar power plants, to provide frequency response and fast reserve, they need to be operated below their possible power production, thus enabling a quick increase in power output. Thus, the plants are operated below their immediate actual power production capability allowing them to have very quick ramp rates in this operation mode. This type of operation can be used when large consumption increases are anticipated, e.g. during morning load increase. Generally, this operation scheme is not desired during longer periods, as energy and CO_2-free power production are lost. Thus, the price of this type of balancing is relatively high. However, if the RES plants have the possibility of operating, they can act as primary, secondary or even tertiary power production plants due to very short start-up times. Due to the nature, priority and low production cost of RES plants, this ability is often deemed irrelevant. The ramp rate and start-up time of RES are high if previously down-regulated or stopped completely.

Nuclear and coal

Nuclear and coal fired power plants are usually run as base load generators and have a limited ramp rate. The start-up time for nuclear power plants is a few to several days. However, when being synchronised with the system, nuclear plants are able to quickly change their output within certain limits. As such, nuclear plants are sometimes even used to provide secondary frequency control. Like RES plants, if available, nuclear power plants would normally be running their maximal capacity due to low production cost. This makes this production type a rather expensive source for balancing services that are used to increase production.

Coal power plants have a start-up time of 8-12 hours and, when already in operation, a ramp rate of 0.01-0.04 pu/min[8] [9]. Their start-up cost is high, and the overall efficiency is relatively low: 30-40 %.

Gas power plants

Gas power plants are able to vary their power production relatively quickly, making them a suitable fast reserve balancing provider to counterbalance the fluctuating RES plants. The start-up cost of gas power plants is usually limited.

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[6] http://www.dresser-rand.com/literature/general/85164-10-CAES.pdf

[7] http://www.mpoweruk.com/hydro_power.htm

[8] http://www.mech.kuleuven.be/en/tme/research/energy_environment/Pdf/WPEN2011-01

[9] http://www.repartners.org/pdf/coalwind.pdf

Gas turbines can be divided into two types: Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT). The OCGT are faster, more flexible, more compact and require lower investment costs than CCGTs.

The start-up time of a state-of-the-art CCGT can be as low as approx. 8 minutes, reaching nominal power in 30 minutes[10]. A CCGT has an electrical efficiency of up to 60 %. It is possible to reach an overall efficiency of up to 95 % when using the heat plant's condenser in community heating systems. CCGT power plants that are interlinked with local heat production, either district heating and/or industrial heating processes, have limited ability to vary their power production. The ramp rate of a CCGT is approx. 0.025-0.10 pu/min[11] [12].

The start-up time of a new fast starting OCGT is 3 minutes, reaching nominal power in 6 minutes[13]. An OCGT has an electrical efficiency of approx. 40 %[14]. OCGT are typically used as peak load plants due to their low construction cost but also lower efficiency and thus higher operations costs. The low efficiency results in large CO^2, NO_X and other emissions per produced MWh compared to CCGT plants. The ramp rate of an OCGT is 0.04 - 0.05 pu/min.

Demand side resources

The variation in consumer demand as a supplement to generator production adjustment is a relatively new concept in Europe. The most common implementation of demand side balancing is currently mostly based on a few large consumers. In the future, demand side balancing could be dispersed across many consumers as household machines, electric cars etc. could be included in the scheme. The ramp rate of variable demand is high, although the time constant is expected to be long.

A few ENTSO-E members[15] utilise the demand side balancing possibility in their primary and secondary control schemes, due to the challenge of fast activation and controllability. In the future, it may be expected that consumer demand response will have a greater role in the balancing market.

In Table 1, the properties of the different balancing sources are summarised.

[10] http://www.esat.kuleuven.be/electa/windbalance/docs/Deliverables/del5.pdf

[11] http://www.ridgeenergystorage.com/caes_benefits.htm

[12] http://www.technologyreview.com/energy/37635/

[13] http://www.esat.kuleuven.be/electa/windbalance/docs/Deliverables/del5.pdf

[14] http://files.asme.org/IGTI/101/13001.pdf

[15] https://www.entsoe.eu/fileadmin/user_upload/_library/position_papers/ENTSO_BalancingMaps_Final.pdf

Table 7 - Properties of different balancing sources

	Hydro	Pump storage	Com-pressed air/gas	Nuclear	Wind & solar	Variable demand	Natural gas (OCCT)	Natural gas (CCCT)	Coal
Ramp rate [pu/min.]	5-10	~6	0.2	Slow	High	High	0.04-0.05	0.25-0.10	0.01-0.04
Start-up time	2-10 sec.	1-1.5 min.	10-15 min.	2-5 days	2-30 sec.	Long	3-6 min.	8-30 min.	8-12 hours
Efficiency [%]	~95	70-85	70-85	-	-	-	~40	~60	30-40
Start up cost	Low	Low	Medium	High	Low	High	Low	Medium	High
Controllability	High	High	Medium	Low	High	Low	High	Medium	Low

Source: COWI

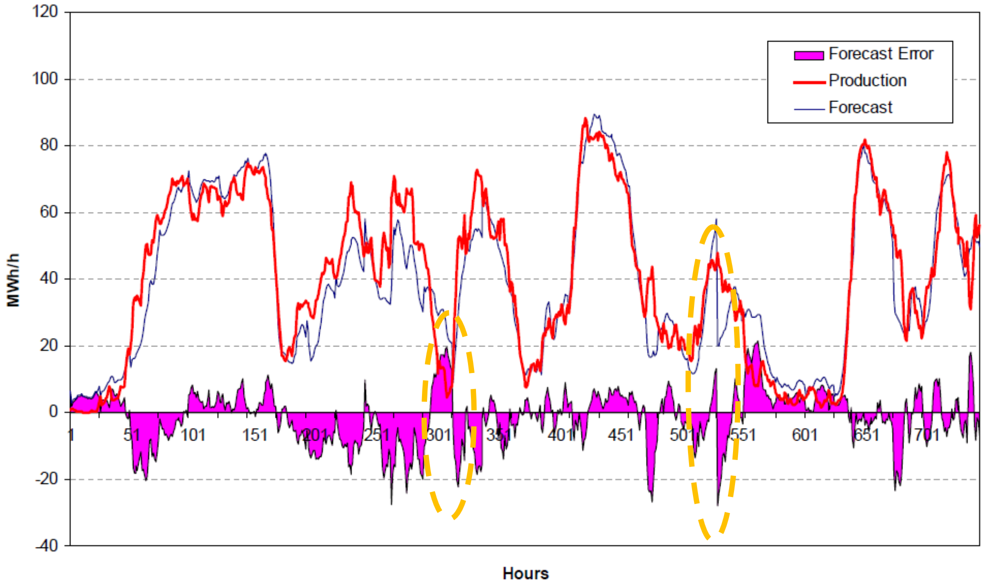
In practice, it is often recommended or anticipated that the majority of new balancing plants will be gas-fired power plants. Due to their relatively high efficiency, low operation cost and environmental impact and good ability to function as base load and balancing power plants, CCGT power plants could have a significant role in the future European production mix. Conversely, OCGT plants are best suited for peak load and contingency operation due to their fast start-up capabilities and low construction costs.

2.1.4 Specific Challenges Created by Renewable Energy Sources

The main drivers for short-term balancing are for example generation outages, load and production forecasting errors, load variations, grid availability and congestions. The increasing volume of generation with variable and less predictable levels of output (e.g. wind, solar generators etc.) is thus expected to have a notable impact on the need for system balancing requirements. In this context, the focus is on wind and solar power production.

In order for production to match consumption, the production forecast must be as accurate as possible. Naturally, the power production from wind power plants depends on the wind speed. Forecasting the exact wind speed and when the wind speed changes can be difficult. A small error in the expected wind speed and thus wind power production can result in a large mismatch between the expected and actual power production. Figure 2 illustrates this issue. The figure shows the expected wind power production, the actual production and the difference between these. The time series are from 24 different wind sites including 70 wind turbines covering a geographical area of 630 km in Finland. The forecasts are generated 12-36 hours before the hour of production. The installed capacity is 104 MW. The data covers one month in 2010.

Figure 3 – Example of wind power production forecasting error

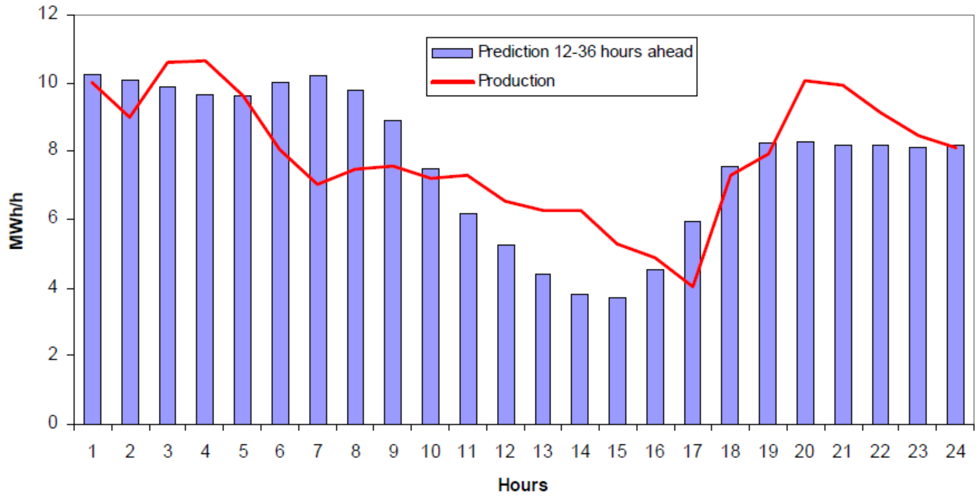


Source: EWEA. Wind Power Balancing Costs for Different size Actors in the Nordic Electricity Market, March, 2011

As seen in Figure 2, there is a large variation between the forecasted and actual wind power production. The first highlighted area illustrates a substantial and fast shift from an overestimate to an underestimate in the forecast. Within a few hours the deviations are approx. 40 MWh/h or close to 40 % of the installed analysed wind power capacity. In small systems forecasting errors of this magnitude would require comprehensive balancing abilities in order not to stress the system or risk a blackout.

Looking into the day-ahead market, Figure 3 illustrates the day-ahead prediction and the actual wind power production for the same set of wind power plants. Obviously, the prediction made 12-36 hours ahead can deviate significantly from the actual production as seen in Figure 3.

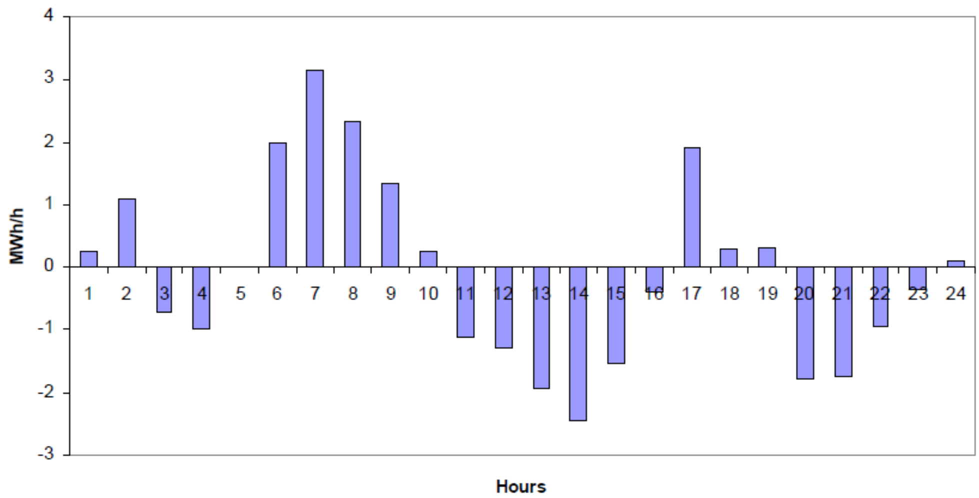
Figure 4 - Day-ahead prediction and actual production



Source: EWEA. Wind Power Balancing Costs for Different Sized Actors in the Nordic Electricity Market, March, 2011

Figure 4 shows the difference between the predicted and actual wind power production in Figure 3. This figure shows that the forecast error can be large and shifting.

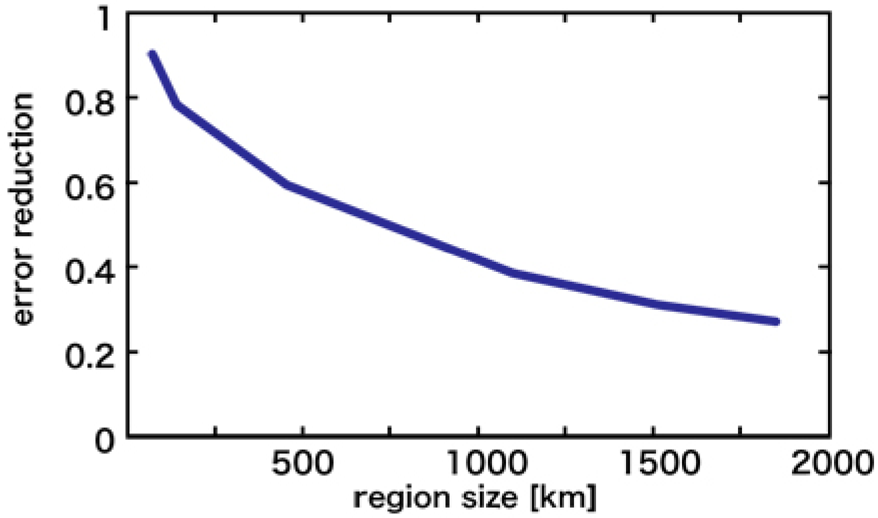
Figure 5 - Difference between day-ahead predicted and actual production



Source: EWEA. Wind Power Balancing Costs for Different Sized Actors in the Nordic Electricity Market, March, 2011

When distributed over a larger geographical area, variations and disturbances in load and production level out due to spatial smoothing effects. Thus, the larger the system and the area, the better the forecast becomes. Figure 5 below illustrates the reduction in forecast error with respect to the size of the considered region. The total forecast error on a European level is thus significantly less than the forecast error in a local area or region.

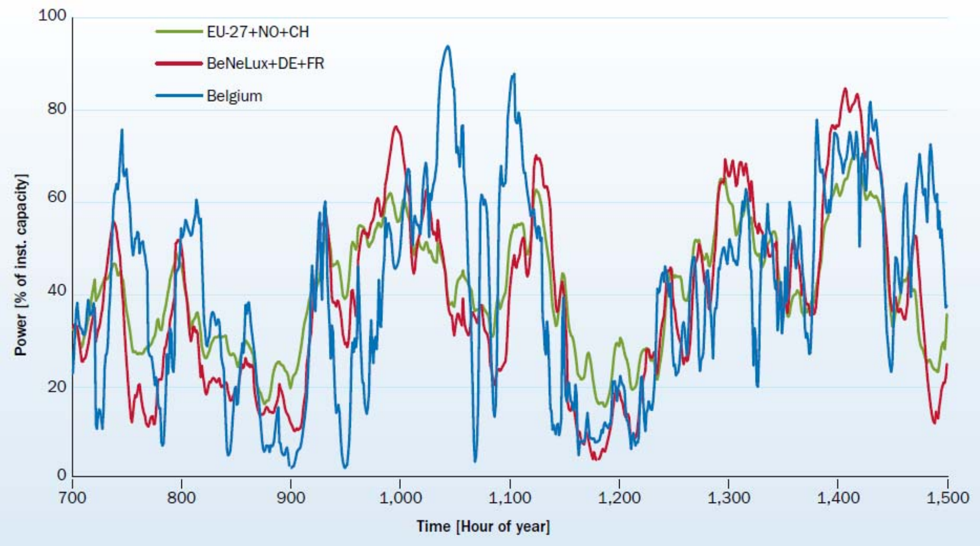
Figure 6 - Wind power forecast error reduction



Source: Energy and Meteo Systems

The same effect is also illustrated by Figure 7, which compares the hourly production for a single country, a larger region and the entire EU electricity market over one month. Whilst production in a smaller area (Belgium) varies between close to 0% and approx. 90% of installed capacity, the corresponding variation of the aggregate output on a European level decreases to between 20% and 70%. Nevertheless, one should bear in mind that the latter values refer to a much higher amount of capacity such that the resulting fluctuations are much bigger in absolute numbers.

Figure 7: Example of the smoothing effect of wind power by geographical dispersion



Source: EWEA. Powering Europe: wind energy and the electricity grid. November 2010

2.1.5 Relation of Renewable Energy Sources Forecast Accuracy Closer to Real-Time

Uncertainty in the forecasts (predicted forecast error) creates a need for balancing. Hourly, four-hourly and 12-hourly variations can mostly be predicted and thus taken into account when scheduling power units to match the demand. Extensive studies have been carried out in many countries on the extent of hourly variations of wind power and demand. The results are summarised in Table 8 as a percentage of installed wind power capacity.

Table 8 - Extreme short-term variations of large-scale regional wind power as % of installed wind power capacity for different time-scales

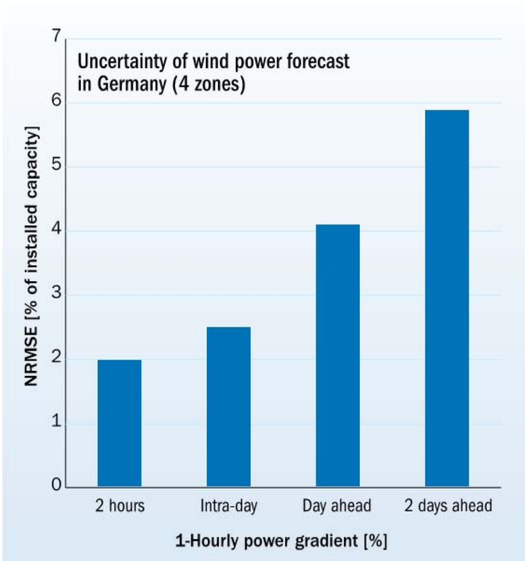
			10-15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Numbers of sites	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase
Denmark	300x300 km^2	> 100			-23%	+20%	-62%	+53%	-74%	+79%
West-Denmark	200x200 km^2	> 100			-26%	+20%	-70%	+57%	-74%	+84%
East-Denmark	200x200 km^2	> 100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km^2	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km^2	> 100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km^2	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km^2	56			-17%	+19%	-40%	+40%		

Source: EWEA. Powering Europe: wind energy and the electricity grid. November 2010

Logically the short-term variation becomes larger when observing a small geographical area in comparison to a larger area. E.g. the short-term variation for the Finish data covering a relatively large area is smaller across all time-scales compared to the Danish data. This corresponds to the results in Figure 6 and Figure 7. Correspondingly the variation becomes smaller the closer to real-time the forecast is made.

Figure 8 illustrates the uncertainty of wind power forecast in Germany as a function of the forecast horizon and shows a noticeable increase in the forecast accuracy when approaching real-time. As seen in Figure 8, the forecast accuracy becomes three times better two hours before real-time compared to two days before real-time.

Figure 8 - Average wind power forecast error as a function the forecast horizon in Germany



Source: EWEA. Powering Europe: wind energy and the electricity grid. November 2010

The forecasting accuracy with respect to geographical dispersion and time horizon is similar for wind and solar power.

Large RES prediction errors occur relatively frequently and affect system balancing and reserve planning. An effective way to address this is to use intra-day trading in combination with very short term forecasts (two to four hours) to reduce the forecast error.

2.2 Balancing in the Gas Sector

2.2.1 Main Determinants of Flexibility Needs

Natural gas is used in various applications such as power production, heating, cooking, feed stock and to some extent transport.

The three latter applications are rather stable in the short term and typically cause a limited diurnal swing only. Conversely, the gas utilisation devoted to heating and power generation remains largely impacted by large diurnal swings, forecast / planning errors and sudden changes during the day.

With regard to daily balancing, the following factors in particular play a role in the gas demand volatility:

1. Temperature variance depending on the season/day component i.e. on the specific weather conditions. This is especially the case in the residential sector where heating needs and subsequent fuel consumption are directly impacted by the outside temperature (and wind). It is also the

case in the power sector as part of the residential heating needs are covered by electricity but also as temperature impacts the efficiency of thermal power plants. In both sectors, temperature influences the diurnal swing as well as potential forecast errors.

2. Volatile and/or unexpected off take by power plants, reflecting the impact of balancing in the electricity market or more generally the volatility of electricity prices in the intra-day market. As a consequence, the production (and hence the gas consumption) of gas-fired plants may be subject to considerable fluctuations as well as unexpected changes during the day.
   In this context, we emphasise the impact of intermittent RES which provide the analytical framework of the present study through their impacts on gas-fired power generation capacities.

3. Unexpected outages of major consumers, such as power plants or large industrial consumers.

4. General variability of the consumption pattern of other consumers.

Apart from daily fluctuations, the temperature dependence of gas consumption also causes marked seasonal variations.

This is illustrated by Figure 7 which summarises the situation for both seasonal and daily components of gas demand. Each graph is built on the basis of the Standardised Load Profiles (SLP) corresponding to the Belgian gas market. Two reference days have been selected to illustrate the impact of seasonal variations, for two working days in June and December 2010. The two graphs comprise the observed consumption swings for three classes of consumers, i.e.:

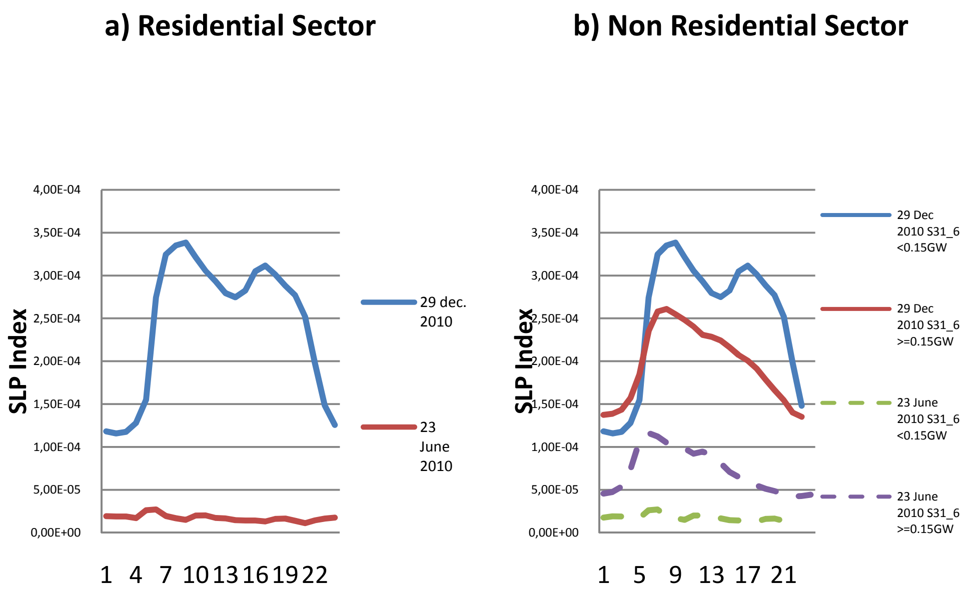
a) Residential consumers;

b) Small non residential consumers: <0,15 GW; and

c) Large non residential consumers: >=0,15 GW.

Please note that these profiles do not describe the consumption of gas-fired power plants used to cover base load.

Figure 9: Typical daily profiles for Belgian customers supplied on the basis of standard load profiles



Source: SYNERGRID

2.2.2 Physical Sources of Gas Balancing Services

An overview of the various products used in the gas balancing process is presented below. While some are widely used, others remain partially undeveloped to date. For clarification purposes, we emphasise that the discussion in this section is limited to physical products, whilst we deal with the applicable commercial arrangements in chapter 3.2 below.

The flexibility of the gas system is secured in practice through the mobilisation of various sources. The most important options are in turn:

1. *Line pack*, or the storage of gas in the transportation gas network within the pressure levels required for safely operating the system; line pack typically covers at least the very short term needs as it is available without delay, whilst the available volumes may be limited;

2. *Gas storage* in appropriate geological sites such as salt caverns, aquifers and/or depleted gas deposits; the available volumes usually are much larger than those available from line pack, although the diurnal flexibility may be limited in case of aquifers or depleted gas files.

3. The modulation of *gas production capacities*; this option is available in producing countries and within the limits of the flexibility offered by different gas fields;

4. The modulation of *LNG plants*, i.e. the possibility to delay/modulate the send-out process within the limits of the available storage volumes and the flexibility of the re-gasification operations;

5. The *quality conversion* through mixing gas of different natures; this option is exceptional and restricted to countries, such as the Netherlands, which operate gas networks with two different gas qualities (high and low calorific value) and which have installed technical means for physically converting high calorific gas into low calorific gas;

6. The *interruption of gas deliveries,* which addresses the option to reduce or even stop gas supplies in circumstances where demand exceeds the capacity of the local network and/or where insufficient supplies are available from production, import or storage; in practice, this option is usually restricted to specific categories of end-users such as power plants, large industrial clients or injections into storage; and

7. The *(cross-border) exchange* of gas between neighbouring countries or balancing zones, noting that some balancing zones do not have enough local flexibility and depend on the import of balancing services from neighbouring balancing zones.

It is important to note that all these options can be utilised in parallel within the limits of the transport capability of the local / regional network. Especially between different balancing zones or within larger balancing zones, the use of different sources of flexibility may thus be constrained by transport limitations, i.e. where the HP pipelines and compressor stations do not have sufficient capacities to absorb peak flows.

Secondly, it is worth noting that the use of many of the instruments is subject to the lead time required for changing the withdrawal and/or off-take at the corresponding sites, in particular where these require explicit (re-) nominations between different actors in the gas market.

2.3 Key Technical Differences between Gas and Power Balancing

When comparing the physical needs and resources for daily balancing, one can identify a number of key differences (see Table 9).

To start with, in the electricity sector, it is necessary to maintain the system frequency within very strict limits (50 ±0.1 Hz) at all times, as even minor variations will impair the stability of the system and may result in local, regional or even system-wide black out. For these reasons, the primary focus of electricity balancing is on the power balance of the system in real time. As a consequence, the balancing process in the electricity sector therefore generally focuses on immediate actions within the last hour before real time.

Due to the very short time scales, this furthermore requires the use of at least some fully automated balancing services, whilst other services can be manually activated. As a matter of principle, power systems in Europe (and elsewhere) therefore rely on a clear sequence of different products at least for the immediate balancing actions in the last 15 minutes before real time.

In contrast, gas networks benefit from the inherent storage capability of the network. More precisely, any physical imbalances between supply and demand will initially result in a variation of the pressure in the network. Since high pressure pipelines have generally been designed to accommodate considerable pressure fluctuations, any immediate fluctuations are thus absorbed by the so-called line pack in the network itself.

In contrast to the electricity sector, (physical) balancing actions in the gas network thus focus on the cumulative energy deviations rather than the second-by-second variation of the power balance. Consequently, most European gas networks rely on delayed actions, which can be taken within the time horizon for normal (re-) nominations in the market. This in turn also means that there has not been a need to develop and apply automated mechanisms. As a result, European gas networks have not developed a consistent set of standardised tools and services, which would be commonly applied across Europe.

Table 9: Key technical differences between electricity and gas balancing

Issue	Electricity Sector	Gas Sector
Balancing scope & range	Need to maintain system frequency within strict limits in real time	Inherent storage capability allows for certain range of operating pressures
Balancing process and time horizon	Focus on close to real time <u>power</u> balance	Focus on cumulative <u>energy</u> deviation
	Focus on immediate action in last hour before real time	Focus on delayed actions (≥ 2 hours)
Products	Clear sequence of different services over time	Lack of standardised products and services

Source: DNV KEMA

3 Status Quo and Ongoing Developments with Regard to Market Arrangements

3.1 Electricity Market

3.1.1 Current Arrangements for the Procurement and Activation of Operational Reserves

General Design Aspects

Besides the minimum technical requirements, there are also major differences with regard to the methods applied for the procurement of operational reserves[16]. In general, different mechanisms have been developed to allow for the **procurement** and **utilisation** of ancillary services by the TSO.

These can be roughly classified into two groups, namely:

- Non-market-based; and
- Market-based approaches.

Non-market-based methods comprise a compulsory provision (with / without remuneration), as well as bilateral or multilateral contracts based on standardised, regulated and/or negotiated agreement. In contrast, market-based methods make use of public tenders and (close to) real time markets.

Moreover, it is also important to note that operational reserves require a differentiation between the **availability** (of capacity**)** and the actual **utilisation** (of energy) in real time. The first dimension refers to the need for ensuring the availability of sufficient operational reserves when they are needed during the day. This is typically achieved through advance contracting of operational reserves for a certain period of time to keep them available and ready to use for whenever required during the reservation period. The second dimension refers to the actual activation and use of operational reserves in real-time which effectively results in an energy delivery.

[16] For the interaction with the gas market, frequency restoration and replacement reserves can be considered as most important, whilst frequency containment reserves can be regarded as less relevant. In the following, we therefore focus on the first two types of services, although we also comment on the procurement and use of primary control (i.e. frequency containment reserves).

This distinction provides the possibility to separate the procurement of capacity from the procurement of energy, as will be further explained below, and to differentiate between different payments. In general, three different payments may apply:

1. A payment may be made for the technical capability to provide a particular service;[17]

2. There may be a holding payment to remunerate the reserve provider for its obligation to ensure that the corresponding capability can be or is made available to the system; and

3. A utilisation payment is often made for the (active) energy delivered or received as a result of the activation of operational reserves by the TSO in or close to real time.

In practice, there are considerable differences with regard to the approaches used for procurement. This encompasses for example the basic mechanism for the selection of offers, the contract duration, the frequency of procurement, or the principles for the remuneration of capacity and energy. Such differences may exist for instance between countries, i.e. for the same service, or within a single country, either in the case of a different service or sometimes even for the same service[18].

Whilst we do not intend to provide a comprehensive summary of the corresponding arrangements, we briefly summarise the situation with regard to the three main types of ancillary services, which are related to balancing and which can be commonly found in many European countries, i.e. primary, secondary and tertiary control. The corresponding information is partially based on a recent overview from ENTSO-E[19], which can also be used as a reference for further details.

Primary Control

Primary frequency control represents a basic service, which is typically provided by generators. It has to be constantly available but requires only a relatively small regulation band. In most countries all generators above a certain size are required to have the capability of providing primary frequency control, although there sometimes are exceptions, for instance for nuclear power plants.

In most EU countries, the procurement of Primary Control is limited to the reservation of capacity, whilst there is no separate selection and/or remuneration of energy. Capacity is typically procured through organised markets or on a

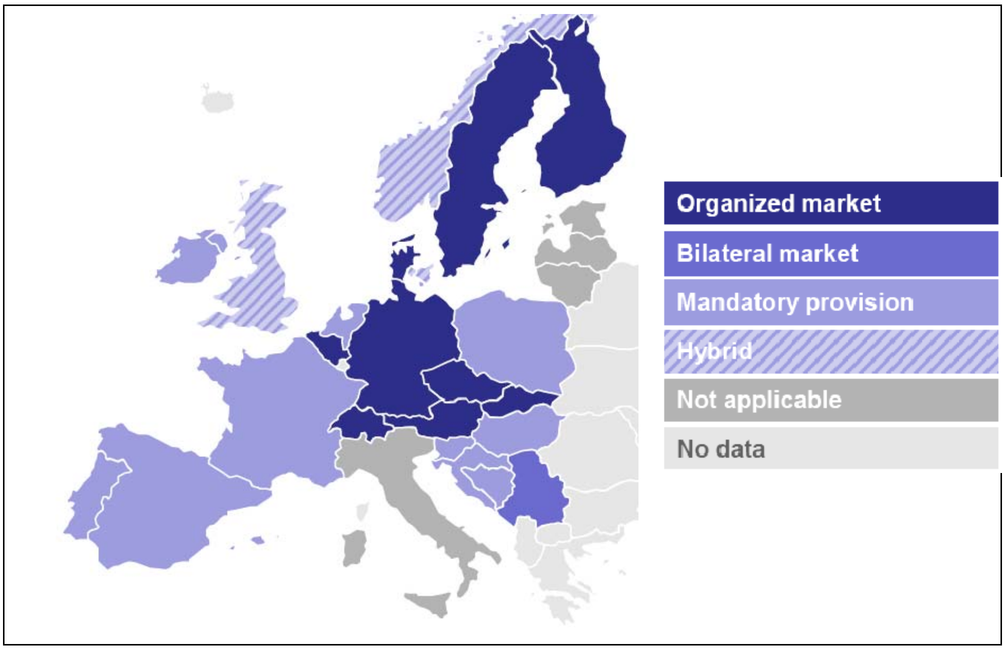
[17] Note that this payment is more relevant for services such as black start than for operational reserves.

[18] In the UK, for example, frequency response (defined as primary frequency control in chapter 2.1.2 above) is procured both on a mandatory basis and via tenders.

[19] ENTSO-E, WG Ancillary Services. Ancillary Services in Europe - Contractual aspects. Status: 6th of July 2011

mandatory provision. In case of a mandatory provision, all generation units have to make a certain amount of capacity available as primary frequency control whenever they are synchronised with the system (either with or without payment). For the option of an organised market, which may be based on either regular tenders or a separate market platform, is used mainly in Central and Northern Europe. Finally, some countries use a hybrid approach. For instance in Great Britain, primary frequency control is provided partly by all large (>100MW) generators on a mandatory basis and partly based on competitive tenders.

Figure 10: Procurement Schemes for Primary Control Capacity in Europe



Source: ENTSO-E, WG Ancillary Services. Ancillary Services in Europe - Contractual aspects. Status: 6th of July 2011. p. 12

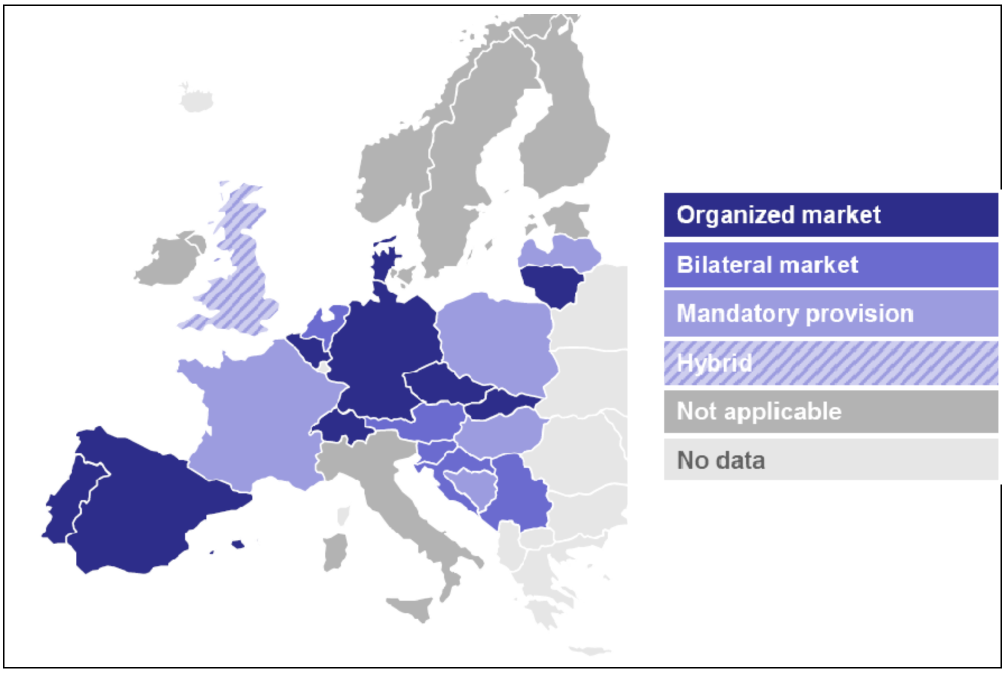
Relating to the timeframe, there is a diverse and heterogeneous picture across Europe. The time for which primary control power has to be kept available by the service providers ranges from minutes (GB) to an entire year or more (Poland, Balkan countries).

Secondary Control

Compared to primary frequency control, secondary frequency control represents a more specialised service that is subject to a number of specific requirements. The provision of secondary frequency control requires the ability to quickly adjust the output of generation unit in response to a signal from a centralised control system. Consequently, the provision of secondary frequency control is typically limited to more flexible units, such as hydropower or gas-fired plants, although it may also be provided by coal-fired units or less commonly, as in the case of France, by nuclear plants. These more demanding requirements are also reflected in the choice of arrangements for the procurement and remuneration of secondary frequency control in various European countries.

As shown in Figure 11, different approaches are used for the reservation of secondary control capacity, including the use of organised markets, bilateral contracts or a mandatory provision[20]. Similar to the case of primary control, there is much diversity in terms of the contract duration, which ranges from a single day to more than a year.

Figure 11: Procurement Schemes for Secondary Control Capacity in Europe

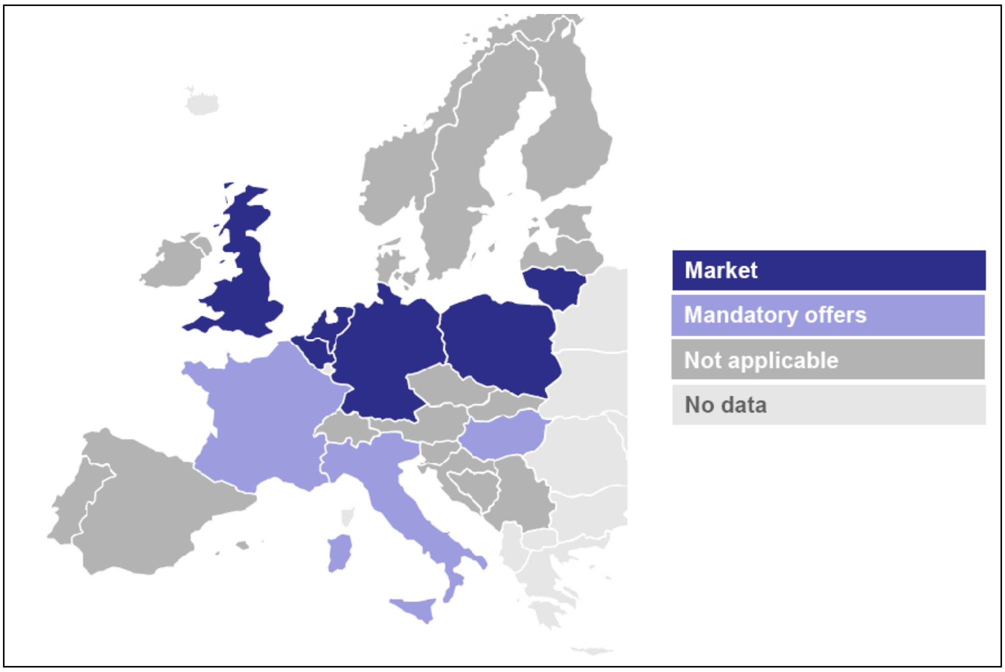


Source: ENTSO-E, WG Ancillary Services. Ancillary Services in Europe - Contractual aspects. Status: 6th of July 2011. p. 28

Depending on the operating policy of the local TSO and/or the pricing of balancing energy, the provision of secondary control may result in the delivery of potentially significant volumes of (balancing) energy. Consequently, several countries apply an additional market mechanism to dispatch available secondary control in real time (see Figure 12). Conversely, other countries remunerate service providers on the basis of a fixed price, whilst others do not pay an explicit remuneration for balancing energy delivered under secondary control at all.

[20] Please note that the use of secondary control is currently limited to the members of the former UCTE system.

Figure 12: Remuneration of Secondary Control Energy in Europe



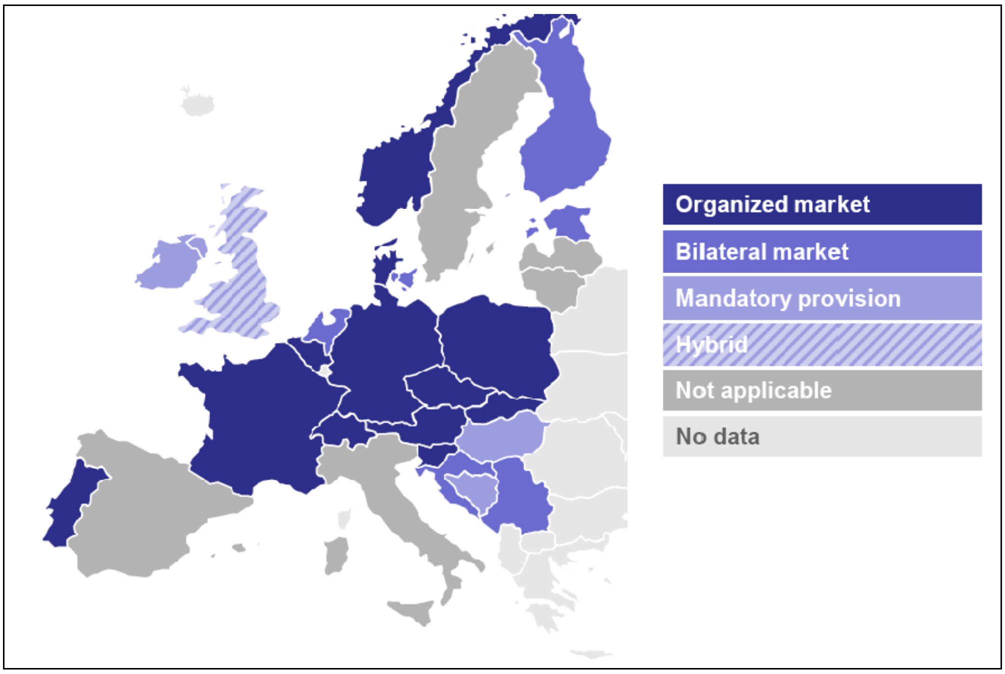
Source: ENTSO-E, WG Ancillary Services. Ancillary Services in Europe - Contractual aspects. Status: 6th of July 2011. p. 28

Manually-Instructed Reserves and Balancing Services

While frequency control is based on a fairly standard definition in each of the interconnected systems (e.g. UCTE, NORDEL, UK), the definition of manually-instructed reserves varies widely across Europe. For instance Austria, Belgium, Germany, the Netherlands and the Scandinavian countries apply a more standardised definition of so-called tertiary reserves (in the UCTE terminology), with a notice time of between 5 and 15 minutes for activation. In contrast, Great Britain uses a variety of different services, which are characterised by different activation times, which may vary between 2 minutes for fast reserves and a maximum value of 240 minutes for so-called Short Term Operating Reserve. Moreover, the balancing mechanisms of for instance France, Great Britain, Italy, Romania, and Spain do not consider any standardised notice time but are based on the flexibility that can be made available within any multiple of one minute. Moreover, besides the consideration of notice times, manually instructed services are sometimes also differentiated between spinning and non-spinning reserves or fast (hot) and slow (cold) reserves.

As illustrated by Figure 13, manually-instructed reserves are typically procured through market-based mechanisms in Europe. Among others, this can be explained by the limited technical complexity of these services compared to the other secondary control in particular. Similarly, manually-instructed reserves are typically procured for a limited time horizon of between a day and month ahead, although there are also examples of annual procurement. Moreover, participation in these services is often open to both generators and load.

Figure 13: Procurement of Tertiary Control Capacity in Europe

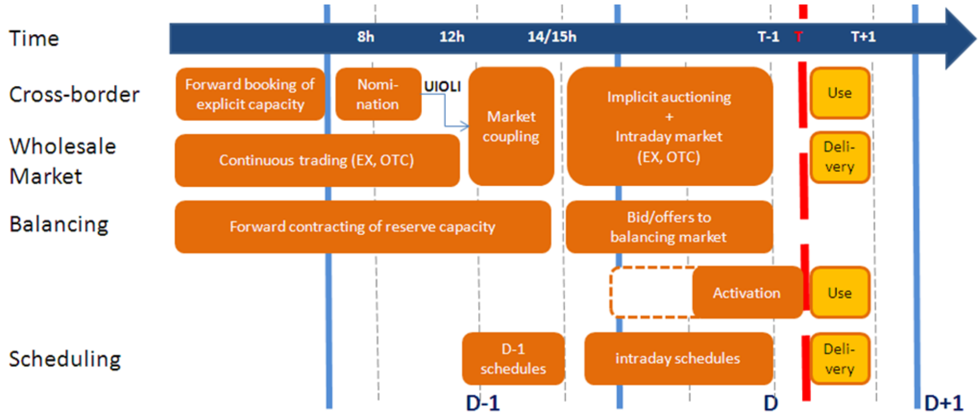


Source: ENTSO-E, WG Ancillary Services. Ancillary Services in Europe - Contractual aspects. Status: 6th of July 2011. p. 44

Whilst many TSOs contract for manually-instructed reserves in advance, the use of these services is typically integrated into the daily balancing mechanism. In many countries, contracted reserves are thus combined with additional offers for balancing energy on each day, which are only remunerated for the balancing energy actually delivered (or received) during the day. As mentioned above, these balancing mechanisms may either be based on standardised products, or consider the balancing energy effectively available within a given time at each point in time.

Finally, Figure 14 provides an overview of the role of daily balancing in the electricity market. The balancing process principally starts early in the after-noon on the day-ahead, i.e. once inter-zonal capacity has been allocated by means of market coupling, reserve commitments have established through re-serve markets and generators have submitted their initial day-ahead schedules. In most countries, the balancing markets start immediately afterwards, although market participants can often revise their initial bids and offers until the so-called 'gate closure', typically one hour before real time. In parallel, market par-ticipants may adjust their generation schedules or obtain and use additional in-ter-zonal capacity. Conversely, the physical balancing process mainly starts after gate closure as most balancing energy is activated shortly before or in real-time only.

Figure 14: Role of Daily Balancing in the Electricity Market



Source: DNV KEMA

3.1.2 Target Model for the Internal Electricity Market

The so-called Target Model for the Internal Electricity Market (Electricity Target Model) was developed by the so-called Project Coordination Group (PCG) of experts under the overall coordination and leadership of ERGEG and was presented to the Florence Forum in 2009. The Electricity Target Model specifies six areas, in which greater harmonisation across Europe should lead to an integrated power market, namely:

1. Capacity calculation;
2. Day-ahead market;
3. Forward market;
4. Intraday market;
5. Balancing market; and
6. Governance.

On the basis of this presentation, the Florence Forum asked ERGEG to work on the 'Framework Guidelines on Capacity Allocation and Congestion Management for Electricity'[21] (FG CACM). In 2011, the European Commission furthermore requested ACER to start working on the 'Framework Guidelines on Balancing Market Integration'[22] (FG Electricity Balancing), which were finalised in September 2012.

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[21] ERGEG. Framework Guidelines on Capacity Allocation and Congestion Management for Electricity, adopted by ACER (FG CACM), 29 July 2011

[22] ACER. Framework Guidelines on Electricity Balancing. FG-2012-E-009. 18 September 2012

In the following, we therefore briefly present some of the main provisions of FG CACM to the extent that they are relevant for the purpose of this study. In this context, we note that the FG CACM implicitly also cover the provisions of the Electricity Target Model on the development of day-ahead and intra-day markets. Based on this background, we then summarise the relevant provisions of the recently adopted FG Electricity Balancing.

Cross-Border Capacity Allocation and Use

For the purpose of adequate management of risks related to the forward electricity trading between interconnected network areas, the FG CACM propagate a forward allocation of cross-border capacities, in the form of either Financial Transmission Rights (FTR) or Physical Transmission Rights (PTR). The latter shall be subject to the so-called use-it-or-sell-it (UIOSI) principle.

Secondly, the FG CACM prefer implicit auctions with market coupling as primary mechanism for day-ahead cross-border transport capacity allocation. Implicit auctions shall be based on marginal pricing principle and shall set the price for cross-border capacity equal to the difference between the corresponding day-ahead power prices in the integrated network areas.

In addition to day-ahead market coupling, the FG CACM envisages the development of a pan-European intraday target model based on continuous implicit trading. In order to reach this goal, the FG CACM have defined the following elements of the target model:

- Harmonised gate closure time for intraday cross-zonal trade;
- Compatibility of generation schedules and related processes with the intra-day target model;
- Coordinated and frequent re-analysis of available cross-border transmission capacity by the TSOs; and
- Development of a pan-European shared order book, which includes all information submitted by power exchanges, or another organised intraday trading platform.

3.1.3 Framework Guidelines on Electricity Balancing

Cross-border exchanges of balancing energy

The FG Electricity Balancing require the Network Code on Electricity Balancing to set all necessary means to facilitate cross-border exchange of balancing energy on any border where possible. This includes the obligations on TSOs to coordinate and optimise the use of balancing energy by the following actions (in preferred time order):

- Avoidance of activating balancing energy in opposite directions and to net imbalances out in adjacent control areas, taking into account cross-border capacities

- Coordinated and optimal deployment of:

    - Replacement reserves; and

    - Restoration reserves

For this purpose, exchanges of balancing energy shall be based on a TSO-TSO model with a common merit order list, while technical constraints and the availability of transmission capacity must be taken into account at the time of activation. The inter-zonal exchange of balancing energy from replacement reserves and from frequency restoration reserves shall be carried out on the basis of a set of standard and coordinated features including products and activation process.

The FG Electricity Balancing specify that the TSOs shall implement a multilateral TSO-TSO model with a common merit order list for replacement reserves and manually-activated frequency restoration reserves no later than two and four years after the Network Code on Electricity Balancing enters into force, respectively. In this initial stage, TSOs may still reserve a certain volume of replacement reserves.

No later than seven years after the adoption of the Network Code on Electricity Balancing, a European-wide TSO-TSO model with common merit order list shall be implemented, unless the TSOs can show that this is not feasible and/or does not ensure positive net benefits. In the latter case, the TSOs shall propose modifications to these features and present a cost-benefit analysis no later than three years after the adoption of the Network Code on Electricity Balancing. Any corresponding proposal will have to be consulted with market participants.

For automatically activated frequency restoration reserves (secondary control), the TSOs have to coordinate the activation of balancing energy within four years after the Network Code on Electricity Balancing has come into force. In addition, the TSOs shall develop and present a target model for the exchange of balancing energy from automatically activated frequency restoration reserves within three years and implement it within six years after the adoption of the Network Code on Electricity Balancing, subject to consultation with market participants and approval by the NRAs.

Cross-border exchanges of contracted reserves

Although the Network Code on Electricity Balancing shall in principle allow for the exchange and sharing of reserves, such exchange shall be limited to cases where reservation of cross-border transmission capacity:

- Is not required (with the corresponding conditions to be defined in the Code(s)); or

- Is allowed according to section 4 on the "reservation and use of cross border capacity for balancing" of the FG (see below).

The exchange of reserves may be arranged:

- Bilaterally between two adjacent control areas in a non-harmonised procurement process; or

- Multilaterally including TSOs and BSPs of two or more control areas through a common procurement process.

The sharing of reserves shall be possible. This goes beyond exchange as it refers to a common and fully coordinated use and activation of reserves, enabling the participating TSOs to size their reserves and possibly procure them together in the most efficient manner. More precisely the Codes shall envisage the sharing of frequency restoration reserves, which may be further enforced by NRAs.

Reservation and use of cross-border capacity for balancing

The FG on Electricity Balancing specify that the mechanism for the allocation of cross-border capacity for balancing energy exchange must follow certain governance principles (market-based, fair, transparent, etc) and may not allow for charging for the use of cross-border capacity for balancing energy exchanges, provided that such capacity remains available after intraday cross-border gate closure.

Moreover, the TSOs shall take into account the physical capabilities of the network and make the most efficient use of these network capabilities when exchanging balancing energy. For this purpose, the TSOs shall use a cross-border capacity calculation method that is at least as precise as in previous timeframes and that provides the possibility to consider locational information on balancing resources.

As a general rule, the FG on Electricity Balancing have established fairly stringent limitations to the reservation of cross-border capacity for balancing. This is only:

- Where additional social welfare benefits from reservation may be proven via a comprehensive cost-benefit analysis;

- On a case-by-case basis;

- After market consultation;

- Upon approval by the NRAS;

- If optimally aligning the reservation for balancing purposes with other electricity market purposes is assured; and
- Subject to extensive ex-ante and ex-post transparency and reporting on capacity reservation (projected and actual use, benefit, cost).

With specific reference to frequency containment reserves, the FG on Electricity Balancing furthermore assume that these reserves can be exchanged within the reliability margin established in accordance with the Network Code on Capacity Allocation and Congestion Management[23]. Consequently, the conditions mentioned above apply only in case that the exchange of frequency containment reserves requires an increase of the reliability margin.

3.2 Gas Market

3.2.1 Overview of Gas Balancing Approaches and their Application across Europe

This section provides a brief overview of the situation with regard to balancing in the European gas markets[24]. In the first part, we focus on the procurement of balancing services by the TSOs. Thereafter, we summarise some of the main provisions with regard to imbalance settlement.

Procurement of balancing services by the TSOs

As already mentioned in chapter 2.2, European TSOs rely on a variety of different sources for physical balancing. In this context, they make use of diverse mechanisms, including market-based as well as non-market based instruments, such as direct bilateral contracts and other non-disclosed agreements.

With regard to market-based mechanisms, one can basically identify the following three approaches:

- Procurement of balancing gas in the wholesale market;
- Procurement of standardised balancing services via separate balancing platform; and
- Procurement of standardised balancing services via tenders.

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[23] ENTSO-E. Network Code on Capacity Allocation and Congestion Management. 27 September 2012

[24] This section mainly builds on a former study by KEMA and REKK fro DG-TREN from 2009 (KEMA / REKK. Gas Transmission and Balancing Models. December 2009). Although we have partially updated this information in line with the latest legal and regulatory changes, we acknowledge that we have ignored specific changes in recent years.

In the first case, TSOs sell and purchase balancing gas in the daily wholesale spot market (day-ahead and within-day) on a par with network users. This approach was originally developed in Great Britain but is now also applied in for instance France or Germany. This approach is also advocated by the ' Framework Guideline on Gas Balancing in Transmission Systems' (Gas Balancing FG, see section 3.2.2 below), as it is widely expected to reflect the true market value of balancing gas and supposed to improve the overall liquidity of the general wholesale market.

Secondly, various countries procure standardised balancing services via a separate balancing platform, also on a daily basis. This approach, which is broadly similar to the corresponding arrangements in most European electricity markets (compare section 3.1.1 above), has been successfully used in the Austrian gas market for more than 10 years. In addition, similar mechanisms are now used for instance in Germany, the Netherlands, Hungary or Sweden.

Thirdly, and partially in addition to one of the other approaches, several TSOs also contract for standardised balancing services in advance by means of public tenders. For instance, NCG in Germany contracts for different types of balancing services. Apart from the reservation of balancing gas, which is subsequently offered in the daily balancing platform, this also includes the contracting of a special flexibility product providing some form of 'virtual line pack'. Similar to the electricity market, tenders for balancing services are typically used for a medium term horizon, such as one or more months up to one year.

Apart from market-based mechanisms, some countries also rely on non-market-based approaches. These may instance include regulated access or direct contracts for underground storage, such as in Denmark, Green, Portugal or Spain.

In recent years, however, one can clearly observe a trend towards the application of market-based instruments. Hence, where feasible, non-market based approaches have often been replaced or at least complemented by market-based instruments. While some years ago most European TSOs primarily relied on non-market-based methods and there were few examples of market-based methods only, many TSOs have diversified their procurement strategy and incorporated more market-based elements.

The remuneration of balancing gas or balancing services is strongly linked to the actual procurement mechanism. Where balancing gas or balancing services are procured on a daily basis, i.e. either through the general wholesale market or via a separate balancing platform, the remuneration is solely based on the balancing gas bought or sold in the market. Conversely, where balancing services are reserved in advance, service providers typically receive a holding payment, whilst balancing gas may be remunerated based on the volumes actually delivered.

Imbalance Settlement

Today, European countries continue to use a variety of different balancing periods, ranging from hourly and within-day cumulative balancing, over daily and monthly balancing to evergreen imbalance accounts.

The majority of EU countries have a daily balancing system in place, i.e. imbalances are cashed out and cleared after each balancing day. In contrast, Austria is the only country with pure hourly balancing. Some countries also use monthly or even evergreen balancing accounts where imbalances are recorded until they are compensated in kind and/or financially settled at the end of each month. The Netherlands finally implemented a special system in 2011. Here, imbalance settlement is subject to cumulative balancing as long as the TSO does not need to intervene into the market. Conversely, the system changes to immediate hourly balancing of all imbalances, including any volumes accumulated before, whenever the TSO buys or sells balancing gas.

We furthermore note that some countries do not apply pure systems, but rather a mixture of daily or cumulative settlement with additional incentives, e.g. for exceeding hourly or cumulative tolerances. These tolerances and corresponding penalties may be limited to certain shippers or users. Apart from basic tolerance, network users are sometimes able to contract for additional flexibility and/or to trade their tolerances in a secondary market, such as in Belgium, France, Denmark, Luxembourg or the Czech Republic.

As already mentioned, some countries allow the compensation of imbalances in kind, including for instance the Czech Republic or Slovakia. Most countries, however, apply financial cash-out at the end of each balancing period. Depending partially on the approach for the procurement of balancing gas, cash-out charges may be:

- Market-based;
- Indexed; or
- Administrated.

Market-based prices can be found in those countries which procure balancing gas through a (daily) market mechanism, such as Austria, France, Great Britain or the Netherlands.

However, many countries (continue to) use imbalance prices which are charged to one or more reference prices. This approach is for instance applied in for instance in the Czech Republic, France[25] or Germany. In several cases, indexation is often also combined with a prescribed regulatory pricing model where

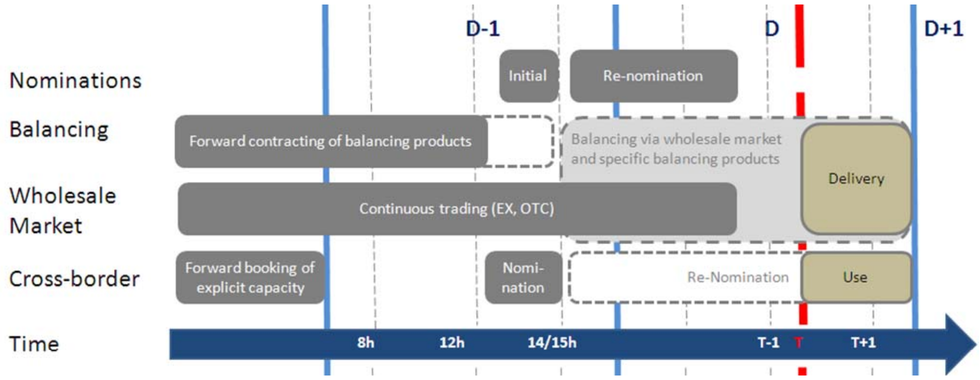
[25] Please note that France applies different charges for imbalances within or outside certain tolerances.

the regulator reserves the right to require the price or formula, or even adjust the price regularly.

Similarly, administrated charges are by definition set in advance either by the TSO or the regulator.

Last but not least, Figure 15 provides an overview of the role of daily balancing in the natural gas market. A comparison with Figure 14 on p. 39 reveals many similarities, with a few exceptions. For example, inter-zonal capacity is not allocated by market coupling but forward capacity rights can largely be used until the deadline for re-nominations, which typically is two hours before real time. In this context, it is worth noting that this deadline is similar to the notion of gate closure in the electricity market as network users are unable to change their nominations for the immediate hours after this deadline. In contrast to the principle of (sub-) hourly schedules in the electricity market, however, nominations ideally apply for the whole period until the end of the gas day. This also applies to market-based products use by gas TSOs for physical balancing, although some countries also use specific temporal products (see below).

Figure 15: Role of Daily Balancing in the Natural Gas Market



Source: DNV KEMA

3.2.2 Gas Target Model and FG Gas Balancing

Gas Target Model

In September 2010, the Madrid Forum invited the European Commission and the European regulators to start work on the establishment of a gas target model. After approximately half a year of internal preparations and four different stakeholder workshops, CEER presented its 'Vision for a European Gas Target Model' (the Gas Target Model) in July 2011. After further refinements, the Gas Target Model was finally endorsed by the Madrid Forum in August 2012.

Although various concepts have been considered in the context of the corresponding discussions, the Gas Target Model itself remains rather vague. In principle, it spells out three major objectives to be met:

- Enabling functioning wholesale markets;
- Connecting functioning wholesale markets; and
- Ensuring secure supply and economic investment.

With regard to the first objective, the Gas Target Model refers to the implementation of the entry-exit model. In addition, it mentions the need for the introduction and harmonisation of market-based balancing arrangements, which shall reduce the role of TSOs on the gas markets by ensuring that the bulk of balancing actions are carried out by shippers on the trading hubs. In addition, the Gas Target Model calls for the creation of larger market areas, either through the merger of individual entry-exit zones or the creation of so-called trading regions, whilst maintaining separate balancing zones.

Concerning the connection of markets, the Gas Target Model calls for the market-based allocation of cross-border capacity and the reservation of at least 10% of capacity for the short-term. In addition, the Gas Target Model explicitly refers to the potential merits of implicit auctions, but also points out certain differences between current trading practices in the European gas and electricity markets in this respect.

The third objective finally deals with arrangements for deciding on investments in new interconnection capacity.

Framework Guidelines on Gas Balancing in Transmission Systems (Gas Balancing FG)[26]

As mentioned, the Gas Target Model remains rather vague with regard to the detailed structure and functioning of the envisaged model. In contrast, the Gas Balancing FG, which were adopted by ACER on 18 October 2011, spell out a much clearer picture of the envisaged target model for gas balancing and provide for a set of detailed principles and conditions to be met.

The main stipulations of the Gas Balancing FG relate to the following six areas, which are addressed in more detail below:

- Principles for the distribution of responsibilities between network users and the TSOs;
- Procurement of balancing gas and related services by TSOs;
- Balancing period and (re-)nomination;

[26] ACER. Framework Guidelines on Gas Balancing in Transmission Systems. FGB-2011-G-002. 18 October 2011

- Imbalance charges;
- Information provision by the TSOs; and
- Cross-border cooperation.

For each topic, the Gas Balancing FG develop an idea of how gas balancing should be organised in the long run, and also outline different interim options. Network operators are obliged to put into practice the requirements set out in the Network Code for Balancing (see below) after its adoption. If TSOs decide to implement any of the interim options offered by Gas Balancing FG, they have to gain approval from their NRA and propose a roadmap for replacing them by measures specified under the framework guideline's target model of gas balancing. This roadmap has to be approved as it is by the NRA, unless further modifications are requested.

Principles for the distribution of responsibilities between network users and the TSOs

Following a number of general provisions, the first part of the Gas Balancing FG sets out some key **principles for the distribution of responsibilities between network users and the TSOs**. In this context, it is clearly stated that network users are primarily responsible for balancing their own portfolio, while the role of TSOs in balancing shall be reduced. Moreover, TSOs shall take account of the impact on adjacent balancing zones when developing their balancing rules and coordinate the development of their balancing regimes and balancing activities with other TSOs. In addition, the document explicitly allows for the allocation of line pack to individual network users, subject to approval by the national NRA.

Procurement of balancing gas and related services by TSOs

With regard to the **procurement of balancing gas and related services by TSOs**, the Gas Balancing FG stipulate that TSOs are required to procure such services through market-based approaches. In addition, TSOs shall preferably rely on standardised products. Where possible, such products shall be procured in the within-day market, although TSOs are entitled to contract for long(er)-term products. The latter may have a maximum duration of one year and may either be for balancing gas and/or an option to sell / buy a certain volume of balancing gas. Where wholesale markets are not yet sufficiently liquid, TSOs may also set up specific balancing platforms for the procurement of balancing gas and related services. The specification of balancing products as well as the set up of a separate balancing platform shall be coordinated with neighbouring TSOs.

Balancing period and (re-)nomination

Thirdly, the Gas Balancing FG establishes a standardised **balancing period** of 24 hours and stipulates that all imbalances shall be financially settled at the end of each balancing period. Nevertheless, TSOs may impose additional "within-day obligations" where the TSO needs to take balancing actions regarding the system's position during the day and where corresponding incentives are required to minimise the need for the TSO to take balancing actions. To the extent possible, such incentives shall be cost reflective whilst they must not represent unjustified barriers for network users. Similar to the general short-term procurement of balancing gas, recurrent balancing services for within-day balancing shall be procured in a market-based manner. Finally, this section also stipulates that rules for **(re-) nomination** have to be coordinated and harmonised among TSOs.

Imbalance charges

With regard to **imbalance charges**, these shall be dealt with separately from transmission and other charges and must reflect the cost (and potential revenue) of the TSO when balancing the system. Where balancing gas is procured from the wholesale market or balancing platforms, the TSO must apply marginal pricing for imbalance settlement. To provide adequate incentives for network users to avoid imbalances and to limit the TSO's balancing needs, imbalance charges may furthermore include a 'small adjustment'. Where TSOs are buying balancing services via a balancing platform, imbalance charges may furthermore be built on a market-based proxy (indexed price) or an administered price. Moreover, where network users do not have access to a liquid short-term wholesale gas market or to sources of flexible gas, tolerances may be used as an interim solution.

Cross-border cooperation

Following a number of conditions on the **provision of information by the TSOs**, the last part of the Gas Balancing FG deals with **cross-border cooperation** between TSOs. This section requires TSOs to foster regional integration of the European gas markets for instance by the merger of entry / exit zones or the formation of cross-border balancing zones. Apart from shipper-led cross-border portfolio balancing, the latter may in particular involve the direct exchange of balancing services between neighbouring TSOs (TSO-TSO concept) or the use of a joint balancing platform by multiple TSOs.

Draft Network Code on Gas Balancing (DNC Gas Balancing[27])

In order to implement the provisions of the Gas Balancing FG, ENTSOG[28] has been charged with preparing the 'Network Code on Balancing' in November 2011. Following the launch of the corresponding project in late 2011 and a series of public workshops, a draft version of the NC Gas Balancing (DNC) was published for consultation on 12 April 2012. It is accompanied by a Supporting Document for Public Consultation[29] to invite stakeholders to provide views on relevant issues, and a workshop was held at ENTSOG on 9 May 2012[30]. The final Network Code incorporating the outcome of the stakeholder consultation is to be submitted to ACER by 5 November 2012. The Agency's opinion will then be taken into consideration for the final document. The network operators will be given a period of another twelve months for implementation of the Network Code, such that the new regulations will be implemented as of January 2014.

[27] ENTSOG. Draft Network Code on Gas Balancing in Transmission Systems – An ENTSOG Draft Network Code for Public consultation. BAL300-12. Approved by the ENTSOG Board on 12 April 2012.

[28] ENTSOG: European Network of Transmission System Operators for Gas

[29] ENTSOG. Supporting Document for Public Consultation on the Draft Code on Balancing. BAL241-12. 13 April 2012.

[30] Presented materials available through ENTSOG website.

In accordance with the Gas Balancing FG, network users shall take primarily the responsibility to minimise the need for TSOs to actively balance its system (Article 7, Chapter II). However, if required, TSOs shall undertake balancing actions in order to maintain the transmission system within its operational limits and to achieve a given end of day line pack position (Article 12, Chapter IV). Whilst the Gas Balancing FG require a market-based approach and advocate the use of standardised short-term products, they leave the definition of these products to the NC Gas Balancing. In the following section we summarise three of the main propositions of the DNC Gas Balancing, insofar as these are relevant for the purpose of this study and go beyond the general provisions of the Gas Balancing FG in this respect:

- Balancing actions;
- Within Day Obligations (WDOs); and
- Trading Platforms.

Balancing actions

Undertaking **balancing actions** is limited to trading actions on the wholesale market by the TSO, aiming to change input into or off-take from the system.

These actions comprise of:

- The procurement of balancing gas: buying or selling '**Short Term Standardized Products**' (STSPs) on a trading platform; and/or
- The use of '**balancing services**' such as options to request network users to change flows or contracts with a storage operator.

The DNC Gas Balancing discerns four different standardised categories for STSPs. These are indicated in Table 10 below, including an indication of the priority (merit order) TSOs should apply per category (Article 13, Chapter IV). According to the DNC Gas Balancing, TSOs should firstly prioritise Title Market Products, and secondly consider Locational Market Products. These products provide for the exchange of a constant volume of gas for the (rest of the) day at respectively the virtual trading point or at specific locations. Temporal (Locational) Market Products are only to be used under defined circumstances for a specific time window within the gas day (i.e. only if for the given situation it is more efficient and economic compared to buying/selling of a combination of Title Market Products or Locational Market Products).

Table 10- Short Term Standardised Product Categories.

<table>
<tr><th colspan="2" rowspan="2">Short Term Standardised Product Categories</th><th colspan="2">Temporal</th></tr>
<tr><th>Balancing period (balance-of-day)</th><th>Specific time window (intra-day)</th></tr>
<tr><td rowspan="2">Locational</td><td>Virtual Trading Point</td><td>1
Title Market Products</td><td>3
Temporal Market Products</td></tr>
<tr><td>Entry or Exit Points</td><td>2
Locational Market Products</td><td>4
Temporal Locational Market Products</td></tr>
</table>

In addition to the STSPs, TSOs may procure balancing services. These services are often contracted through longer term contracts for recurrent use. Balancing services should be procured in a market-based manner. Again, the DNC Gas Balancing prefers standardised services, for instance with regard to available capacity and maximum volume, lead times, and/or contract duration. Non-standardised balancing services, characterised as tailor-made services with bespoke requirements in terms of quantity, location, urgency, etc., are to be used as last resort.

The DNC Gas Balancing provides several considerations for the choice between Short Term Standardised Products and Balancing Services, such as wholesale market liquidity, relevant lead times, operational issues and balancing costs. It also specifies a yearly review to assess if Short Term Standardised Products would better meet the TSO's operational needs (Article 16, Chapter IV). Generally, the use of balancing services should only be considered in situations where Standardised Products trade will (or is expected to) result in insufficient flow changes to keep the system within accepted operational limits.

Within Day Obligations (WDOs)

Furthermore, TSOs may impose **Within Day Obligations (WDOs)** to their network users in order to minimise their own need for action. WDOs refer to specific obligations the TSO imposes on its network users to behave in a certain manner with respect to its profiles of inputs and offtakes during the gas day. Although WDOs are referred to as obligations, the supporting document explicitly states that they may be executed as incentive mechanisms. WDO design may depend heavily on network topology and occurring flow patterns. The TSOs are therefore obliged to seek prior approval by the relevant NRA on the design of their WDOs.

The DNC Gas Balancing formulates a number of criteria which WDOs should meet concerning the effect on (cross-border) trade and daily balancing, the provision of information, the related costs and the financial settlement (for which it is prohibited to settle to zero during the gas day). It also outlines the procedures to be followed. Within day charges should constitute a small portion of any imbalance charges (Articles 32-35, Chapter VII).

As well as applying WDOs at a general system level, encouraging all network users to assist the TSO balancing its system, WDOs may be applied at portfolio level (this type of WDOs may be hourly or cumulative obligations, and may include tolerance levels) or at locational level (i.e. at entry or exit points, this type comprises of information provision and/or limitations to within day variations, and possibly flow variation instructions).

4 Expected Evolution of Balancing Needs in the Future

4.1 Projected Evolution and Trends in the Electricity Sector

4.1.1 Main Trends and Policies

The European Union has embarked on ambitious goals for the decarbonisation of the European economy. By 2050, domestic greenhouse gas emissions shall be reduced by 80% compared to 1990 levels, which is expected to require the almost complete decarbonisation of the European power sector.

The achievement of the 2050 targets will require the mobilisation of various complementary components detailed below. 2020 and 2030 will provide two important milestones on the way to longer term objectives. In the shorter term, the EU therefore strives to reach the so-called '20/20/20' targets, which require the following specific goals to be achieved by 2020[31]:

- 20% reduction in $C0_2$ emissions compared to 1990;
- 20% energy share from renewable sources; and
- 20% increase in energy efficiency.

In order to reach the targets for both 2020 and 2050, European policy makers and other stakeholders have already taken a number of steps. This involves inter alia various forecasting and planning exercises such as the recent Energy Roadmap 2050 by the European Commission (DG ENER), the development of the National Renewable Energy Action Plans (NREAP), the development of the so-called 10-Year Network Development Plans (10YNDP) by ENTSO-E and ENTSO-G as well as by a range of other stakeholders at a national, regional and European level.

In this chapter, we present a summary of the main trends and developments which have been identified or which are anticipated by various studies, in order

[31] Communication from the Commission, Energy efficiency: delivering 20% target, 13/11/2008, COM(2008) 772 final.

to provide the background for better understanding the implications for balancing in both the electricity and gas sectors in the future.

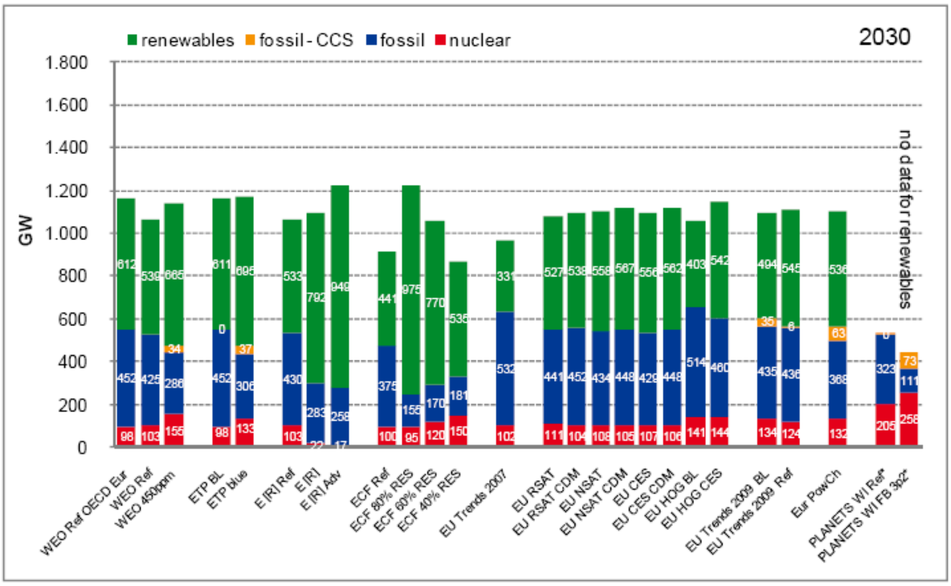
Development of RES

Renewable energy sources (RES) played a limited role until the end of the 90’s. The last decade was characterised by a growing concern about climate change, higher fossil energy prices and the wish to diversify energy sources at both EU and Member State level.

This has created a more favourable context for the development of RES, including in particular political, legal and regulatory measures to facilitate the integration of decentralised production units such as small cogeneration plants and wind turbines etc. For the reasons mentioned above, and especially due to the support from national governments and supranational institutions, the growth rates have increased considerably over the last decade.

Most available forecasts and studies suggest that the pace of development of RES will be maintained or even increase in the future, both in absolute and relative terms. Figure 8 compares the forecasts carried out by various institutions at horizon 2030 for all EU Member states. We can see that power generation capacities range between 800 and 1,200 GW. At the same time, the amount of RES varies between less than 400 and close to 1,000 GW, i.e. by a factor of three.

Figure 16: Installed power generation capacity in different scenarios in 2030 (GW)



* EU-25 plus Norway, Switzerland

Prognos 2011

EU Trends 2007, EU Trends 2009, EU ENV, Eur PowCh: net values – elsewhere gross values

Source: Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

Figure 17 summarises the anticipated evolution of the various types of RES over the present decade. In particular, it compares the present situation with the foreseeable situation in 2020 with regard to the installed capacity for each technology. In addition, 11 also indicates the total energy production from each technology in the same year.

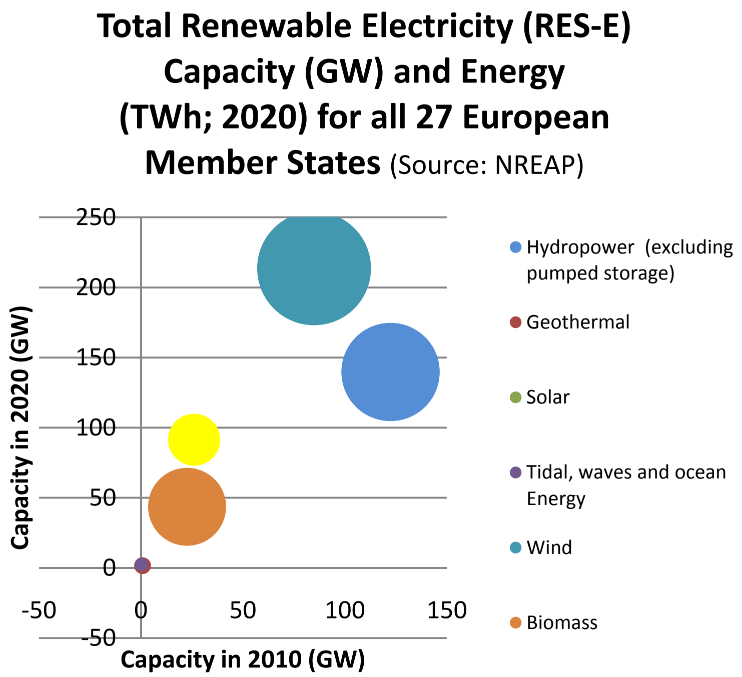
The analysis of these figures, which is driven by the national energy plans,[32] reveals that if forecasts and simulations are to be confirmed then:

a) Geothermal energy plays a negligible role and its marginal contribution is not expected to increase substantially by 2020;

b) Biomass and hydropower already provide a substantial input, whilst the anticipated evolution should remain relatively moderate; and

c) Solar and especially wind provide the most dynamic markets in terms of growth potential, both in terms of capacity and production.

Figure 17: Total capacity (GW) and energy production (TWh) from renewable electricity in the EU-27 in 2020



Source: COWI, based on data provided by Beurskens, L.W.M. and M. Hekkenberg. Renewable Energy Projections as Published in the National Renewable Energy Action

[32] Renewable Energy Projections as Published in the National Renewable Energy Action Plans of the European Member States, Covering all 27 EU Member states, L.W.M. Beurskens, M. Hekkenberg, Energy Research Centre of the Netherlands, European Environment Agency, 1/02/2011.

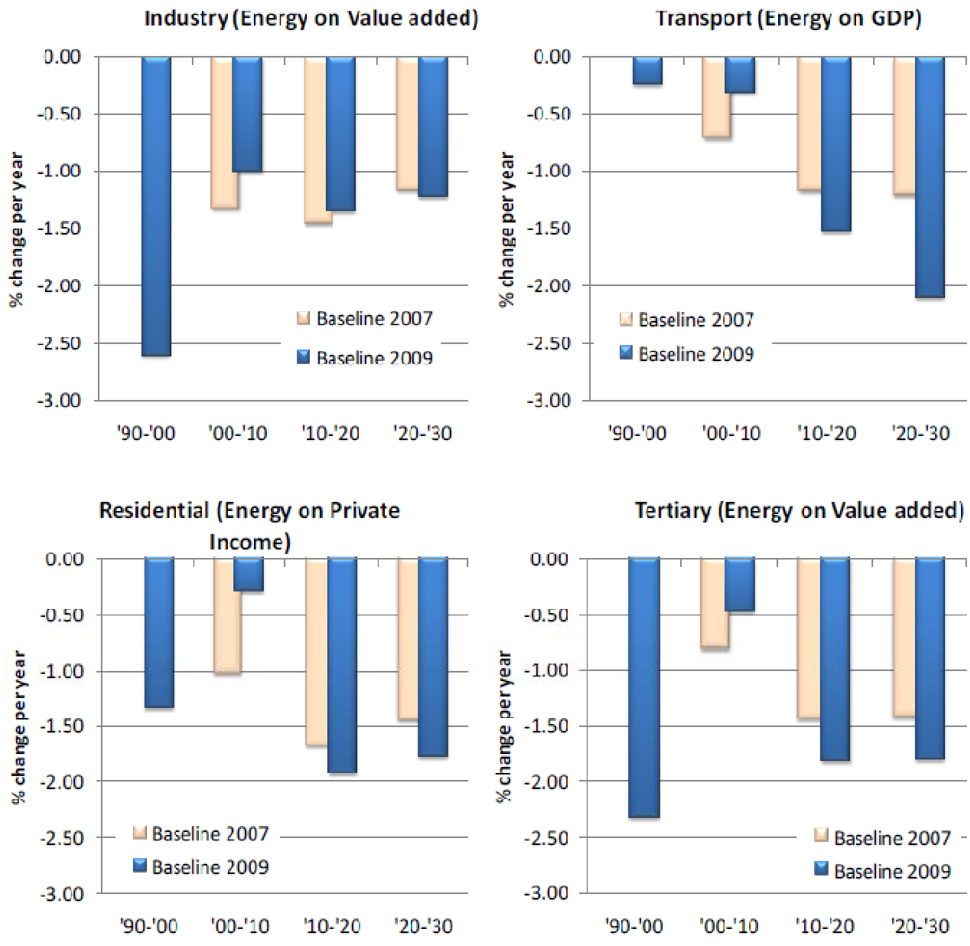
Plans of the European Member States, covering all 27 EU Member States. Energy Research Centre of the Netherlands, European Environment Agency, 1/02/2011

RES, wind and solar energy thus deserve specific attention, not only due to their expected growth but also due to their intermittent nature. As already mentioned in chapter 2.1.4, the output of wind power plants may fluctuate between 0% and 100% of installed capacity on a local basis, and still be significant on a European level. Similarly, major variations can also be experienced with regard to solar PV.

Expected Achievements in Energy Efficiency

A second emerging trend is the growing pressure and the anticipated impact of energy efficiency measures. Figure 10 illustrates this trend on the basis of several energy intensity indicators, as reported by one of the earlier PRIMES studies published in the last few years. In most consumption segments, i.e. the transport, residential and tertiary sectors, energy intensity shows a marked reduction till 2030, indicating a significant increase in energy efficiency. This follows a similar trend which was already seen during the 1990's.

Figure 18: Development of energy intensity in four main consumption segments between 1990 and 2030

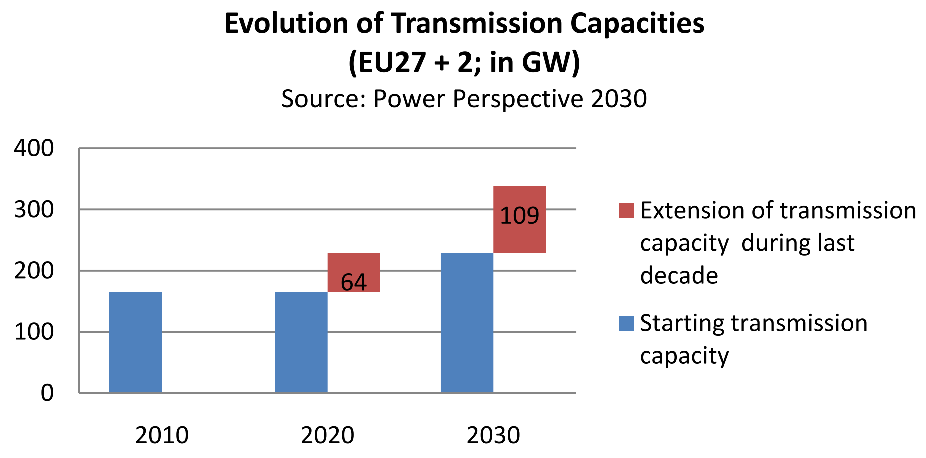


Source: PRIMES. EU Energy trends to 2030, update 2009

Network Expansion

The last ongoing trend addresses the planned and/or desired expansion of the European transmission grids, both of the different Member States as well as on a national level. For illustration, Figure 19 shows the anticipated evolution of the EU grid between 2010 and 2030 as derived by a recent study from the European Climate Foundation. These values show that the planned investments from the European TSOs would already result in a significant increase of available capacities. Nevertheless, Figure 19 also suggests that even larger extensions may be required after 2020.

Figure 19: Evolution of transmission capacities in EU27+2



Source: European Climate Foundation (ECF). Power Perspectives 2030: On the Road to a Decarbonised Power Sector, A contribution study to Roadmap 2050: A practical Guide to Prosperous Low-Carbon Europe. Brussels. November 2011

4.1.2 Summary of Current Plans and Forecasts

Various forecasts and simulations have already been carried out to study the possible evolution of the European electricity sector up until 2050. In a recent report by Prognos[33], a number of different scenarios have been compared with regard to their methodology, assumptions and results. Based on this report, this section provides an overview of the main assumptions and results of the different studies and scenarios.

The scenarios are rather convergent with regard to the time scale (which always equals or exceeds 2030). But they differ from a variable extent regarding the types and characteristics. For example, some studies are only based on a bot-

[33] Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

tom-up approach, while others combine both a top-down and bottom-up approach. In some cases, the forecasts correspond to an econometric modelling supported by partial market equilibriums. In other cases, scenarios are a pure simulation which are based on the boundary conditions of achieving certain policy targets (e.g. energy mix or GHG emissions). All this indicates that the limits of the comparison have been carried out on the basis of available studies.

Table 11: Selection of future scenarios

Source	Study	Main target	Regional Coverage	Time horizon
IEA World Energy Outlook	WTO Ref	20-20-20 target		2030
IEA World Energy Technology Perspectives	ETP BL	20-20-20 target	EU-27	2050
Greenpeace/EREC Energy [R]evolution	E[R] Ref		Global (long term)	2050
Greenpeace/EREC Energy [R]evolution	E[R] Adv	-95% GHG (2050)	Global (long term)	2050
ECF Roadmap 2050	ECF 80% RES	-80% GHG (2050)	OECD (2020)	2050
ECF Roadmap 2050	ECF 40% RES	-80% GHG (2050)	OECD (2020)	2050
Eurelectric Power Choices	Eur PowCH	-75% GHG (2050)		2050
EU Energy Trends up until 2030 - Update 2007 Baseline	EU Trends 2009 Ref		EU-27	2030
European Commission	EU NSAT	20-20-20 target	EU-27	2030

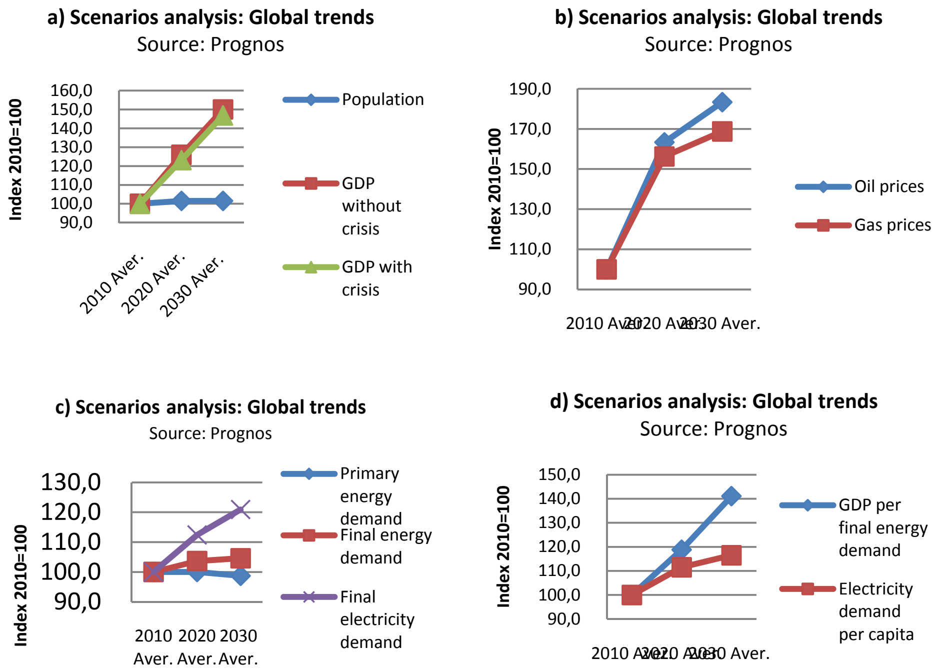
Source: COWI, based on Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

Underlying Macroeconomic Hypothesis

Before analysing the results available, it is worth concentrating on the main working hypothesis. Figure 20 below summarises the evolution of the main indicators for the time scale up until 2030. For the purpose of facilitating comparisons, all indicators are shown as indexes (2010=100). In general, all values focus on the European evolution, although slight differences may occur at the level of the geographical coverage[34].

[34] In some cases, the analysis concentrates on the EU 27, while in others on EU OECD.

Figure 20: Scenarios Analysis: Global Trends for Selected Indicators



Source: COWI, based on Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for the EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

The main observations from Figure 20 can be summarised as follows:

a) The demography is expected to remain rather stable over the two decades, despite a slight increase. During this period, GDP increases by at least 45% even when taking the 2008 crisis into consideration.

b) Primary energy prices, especially oil and gas, are expected to grow at a higher pace than GDP, with a slight comparative advantage for gas.

c) Primary energy demand is expected to remain stable, despite a possible growth in final electricity demand. However, the latter's growth remains lower than GDP forecasts.

d) This finding is confirmed by the evolutions of the GDP per final energy demand which shows decreasing energy intensity. Similarly, energy demand per capita tends to deteriorate over the period under review.

Figure 21 summarises the evolution up until 2020 and 2030 respectively with emphasis on the variance range characterising each of the variables. We can see that:

1. Population and GDP growth reveal a high consensus, for both 2020 and 2030. Conversely, a large variance characterises the assumptions with regard to fuel prices, primary and final energy demand.

2. As expected the relative inaccuracy of forecasts particularly characterises a longer time scale. In most cases, the variance exceeds by far the average growth figures in 2030, which makes the outcome rather speculative.

Figure 21: Scenarios analysis - global trends up until 2020 and 2030

Source: COWI, based on Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

RES Production Capacities Forecasts

Above we presented a comparison of generation capacities up until 2030 driven by various available studies (Figure 16). Figure 22 and Figure 23 below summarise the variance of wind and solar energy generation forecasts developed by the corresponding studies. The two figures combine the studies considered by the Prognos report[35] as well as other specific scenarios, such as PRIMES Ref-

[35] Prognos. Analysis and comparison of relevant mid-and long-term energy scenarios for EU and their key underlying assumptions. ENER/10/NUCL/SI2.561687. Final report. April 2011

erence, EURELECTRIC, EWEA and NREAP, for which comparable data was available. In particular, the graph highlights the last forecasts developed by the DG ENER Energy Roadmap 2050 which is represented in dashed lines.

Two reference periods are taken into consideration. They address respectively i) the reference point of 2020 and ii) the projected evolution by 2030.

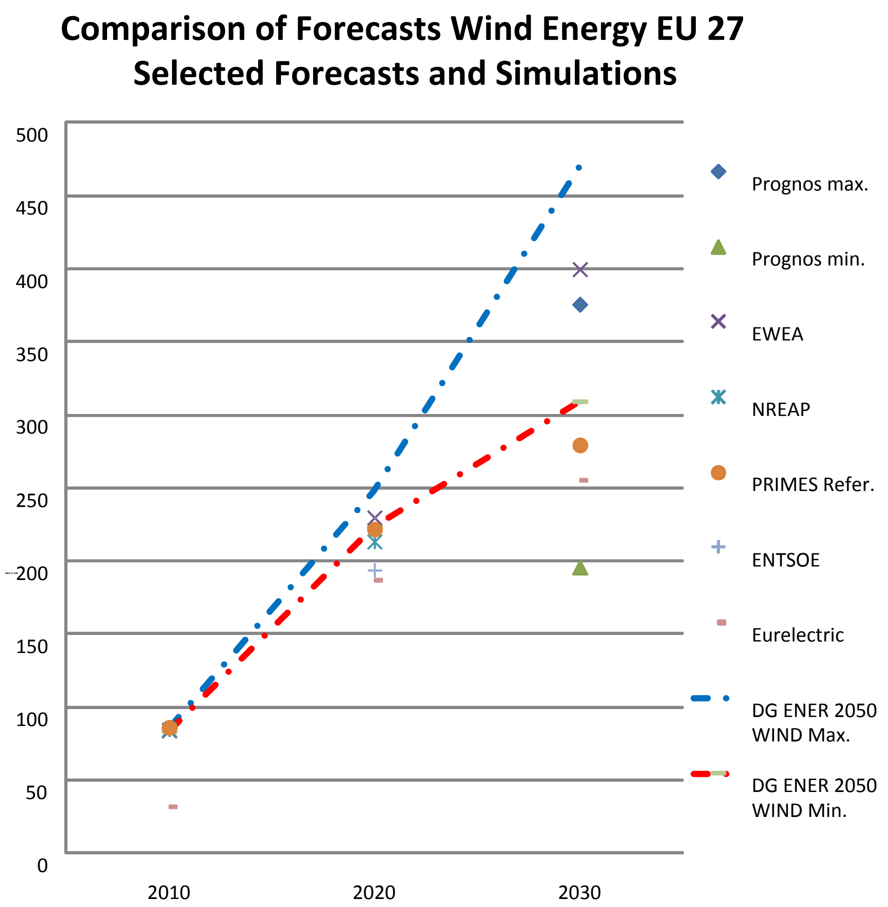
In the case of wind energy (Figure 22), forecasts converge at the date of the reference point (2020), based on the common use of the NREAP in most of these studies. We can see that the DG ENER Energy Roadmap 2050 forecasts provide the top of that range, while EURELECTRIC is slightly less optimistic.

The variance increases largely in the longer term forecasts (2030).Two sets of data deserve particular attention.

First, PRIMES has inspired many of the other scenarios through its underlying macroeconomic forecasts and energy market trends. The latter stays slightly below the middle of the range and can be regarded as a conservative forecast, even if this concerns the reference scenario which is a priori more optimistic in terms of RES deployment. The older PRIMES forecasts are also less optimistic than the lowest DG ENER Energy Roadmap 2050 scenario.

Secondly, the EWEA forecast, which is even above the maximum estimates reported by Prognos, can be considered as optimistic while still being in the range of the upper limits of the DG ENER Energy Roadmap 2050.

Figure 22: Comparison of selected forecasts for wind energy in the EU-27 till 2030



Source: COWI

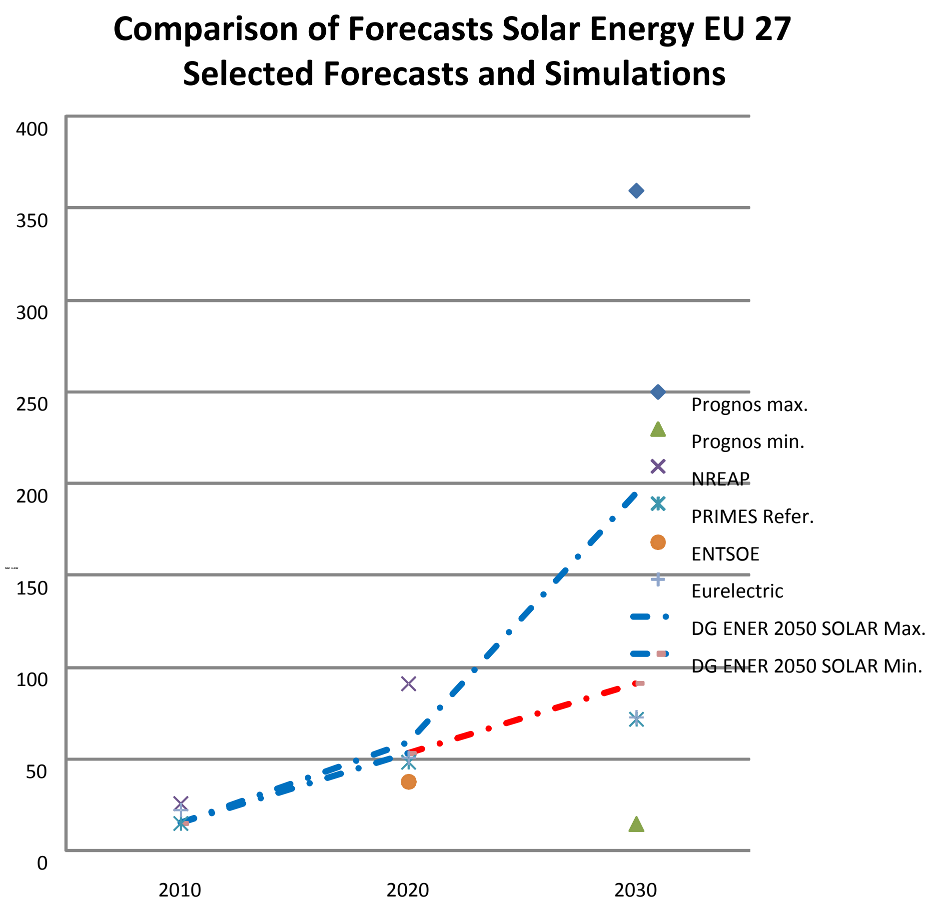
The range characterising the evolution of solar energy is by far more important, whether we consider the absolute or relative values. The divergence already appears at the reference point (2020) but literally explodes at the end of the forecast period (2030). A closer analysis of the underlying data shows that the very high upper bound of the values reported by Prognos is explained by the very optimistic data driven by the ECF simulations which combine ambitious RES targets with a massive shift from other fuels to electricity as a result of energy efficiency measures.

As in the case of wind forecasts, solar forecasts confirm the conservative approaches of the PRIMES Reference and the EURELECTRIC scenarios, whilst the NREAP are more ambitious for the time scale 2020.

Another aspect is the regional allocation of these developments. In particular, most of the growth of solar energy is expected in the Southern part of Europe, whilst North-Western Europe is dominated by the growth of wind power.

In contrast to the wind capacity forecasts, the various scenarios of the DG ENER Energy Roadmap 2050 occupy the medium part of the range, with a variance substantially lower than that of the other analysed scenarios.

Figure 23: Comparison of selected forecasts for solar energy in the EU-27 till 2030



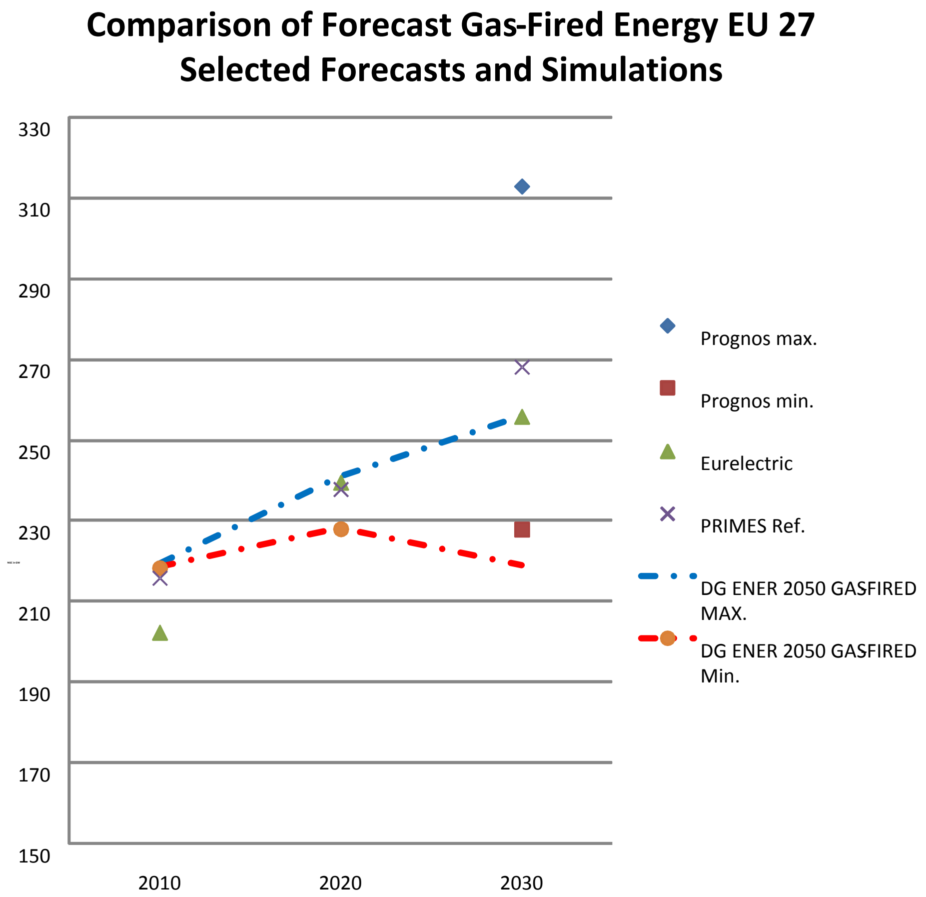
Source: COWI

4.2 Projected Evolution and Trends in the Gas Sector

4.2.1 Gas-Fired Power Capacities

Figure 24 shows the possible evolution of gas-fired capacity between 2010 and 2030, based on the same studies as considered above. As above, the differences increase by the end of the forecast period (2030). Again PRIMES is close to the average of the range. EURELECTRIC data is close to the latter but a bit less optimistic. The most conservative data is provided by the DG ENER Energy Roadmap 2050 which stretches over the lower part of the range, especially for 2030 forecasts.

Figure 24: Projected development of gas-fired capacity until 2030



Source: COWI

This prospective evolution must be considered in line with available gas production and import capabilities within the same time frame. The future depletion of gas deposits will have an increasing impact but are generally expected to be compensated by the scope for increased imports.

From the perspective of daily balancing, it is also interesting to consider the future development of storage capacities. As mentioned above, flexibility from line pack can be supplemented by four types of natural gas storage facilities with different performance characteristics:

1. Depleted gas and oil fields;
2. Aquifers;
3. Salt caverns; and
4. LNG storage facilities (whether they are fully dedicated to storage or used as a temporary storage in the LNG chain)[36].

The development of gas storage capacities has been increasing since 1990. The largest development took place in the Northern EU region in the form of salt caverns, while in the South-West region it focused on depleted fields.

In 2008, the EU storage capacity amounted to approximately 78 bcm in terms of working volume. This figure can be broken down as follows: 42.6% in the Northern region, 19.6% in the South-West region and 37.8% in the South-East region.

Forecasts[37] carried out by the end of the last decade, on the basis of the PRIMES 2007 Baseline scenario, estimated that the demand for gas storage would grow from 82 bcm in 2005, to 86 bcm in 2015, 91 bcm in 2020 and 100 bcm in 2030.

In 2008, there were 111 underground storages that were distributed in the EU as follows:

1. 63 depleted fields (totaling 54 bcm of gas working volume);
2. 26 salt caverns (7.9 bcm);
3. 22 aquifers (15 bcm);
4. 12 LNG peak shaving facilities (1.6 bcm).

Salt caverns and LNG peak-shaving facilities are the most flexible types of storage. By the end of the last decade, there were about 9.5 bcm of highly gas flexible storage available.

Out of the 58 bcm investments planned in gas storage on that date, around 15 bcm were in salt caverns and 1.3 bcm in peak shaving facilities. Hence, the flexibility of gas storage should increase in the long run.

Table 12 below illustrates the foreseeable evolution of storage capacities up until 2015, as well as the expected demand till 2030[38]. The corresponding demand forecasts are driven by an analysis conducted by PRIMES in 2007 which are based on the 'High Renewable/High Efficiency Scenario'. Conversely, the expected development of storage supply is based on the expected development of investments in storage, according to the GSE storage data base of February

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[36] Gas Directive, Article 2 (11).

[37] Ramboll. Study on natural gas storage in the EU, DFR for DG TREN C1, October 2008.

[38] Source: ibidem.

and updated investment data base of June 2008. More specifically, two scenarios have been considered:

a) The *long-term scenario* takes into consideration all investment listed by GSE; and
b) The *short-term scenario* takes only into consideration the already commenced (under construction) or committed investments in storage.

When all investments are taken into account, an increase of storage capacity of more than 50 bcm is expected in the period until 2015. The gas storage capacity already exceeds the expected demand already in the short-term storage scenario. The long-term storage scenario shows that if all planned investments were implemented then the supply of gas storage would increase significantly and much more than the demand.

Table 12: Available vs. required gas storage (bcm)

	Available Storage			**Expected Demand**			
	Current	**Short Term**	**Long Term**	**High Renewable/High Efficiency Scenario**			
	2008	**2015**	**2015**	**2005**	**2015**	**2020**	**2030**
North	34	40	68	29	33	39	34
South-West	15	22	23	15	14	15	13
South-East	30	36	46	28	30	33	29
Total	79	98	137	72	77	87	76

Source: COWI, based on: Ramboll. Study on natural gas storage in the EU. DFR for DG TREN C1. October 2008

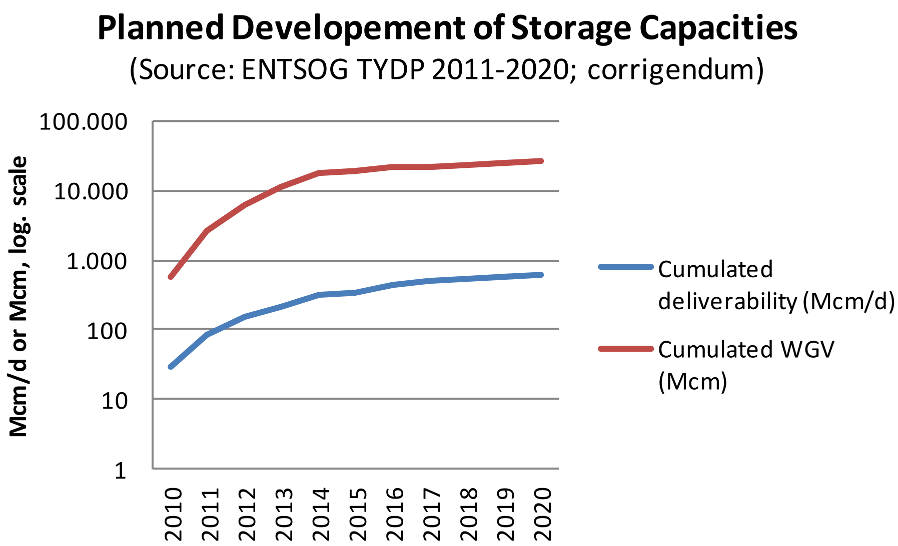
We emphasise that the numbers presented in Table 12 are based on the seasonal (winter) demand for natural gas but do not consider the peak demand on individual days.[39] In contrast to the numbers presented in Table 12, it is thus quite possible that the demand for flexibility will continue to increase considerably even after 2025, despite a potential stagnation in overall demand.

When considering the figures provided by the ENTSO-G 10YNDP (Figure 25), it appears that the planned expansion of underground storage is expected to

[39] The corresponding study carried out a similar analysis as well but only for the year 2015. As a consequence, the potential increase in peak daily demand, resulting from the expected growth of gas-fired electricity generation capacity in the 15 years between 2015 and 2030, was not considered by this study.

reach the ceiling by the middle of the decade, both in terms of deliverability and working gas volume. However, the numbers shown in Figure 25 are limited to projects for which a firm investment decision (FID) has already been taken. Conversely, when also considering known projects, which have not yet been decided (non-FID), storage deliverability may increase by another 22% between 2015 and 2020 alone.

Figure 25: Planned developement of storage capacities (FID projects only)



Source: COWI, based on ENTSO-G 10YNDP

4.3 Projected Distribution of Fluctuating RES and Gas-Fired Plants in 2030

The two preceding sections have analysed the possible development in the electricity and gas sector, based on a number of different studies and scenarios. This analysis has clearly revealed a significant growth in fluctuating RES, as well as gas-fired generation in general, but has so far been kept at an aggregate level. But in practice, the uneven geographical distribution of fluctuating RES may create challenges for gas and electricity balancing, even where the overall penetration of fluctuating RES remains limited.

For this purpose, this section compares the growth of fluctuating RES as an important driver for the demand for flexibility in the electricity sector, on the one hand, with the development of hydro power and gas-fired generation as important sources of flexibility, on the other hand. More specifically, the following analysis compares three different scenarios from two recent studies:

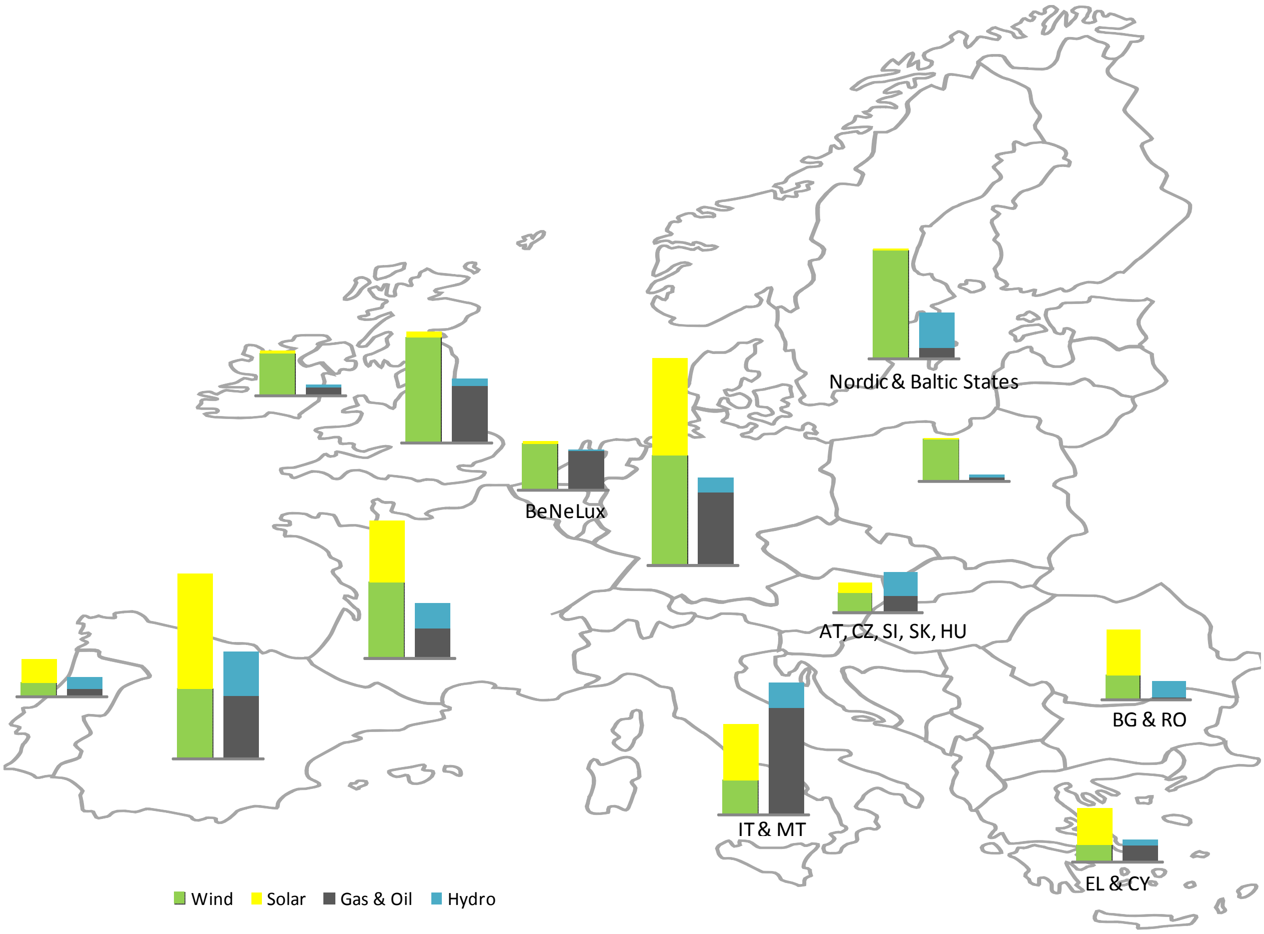
- ECF Power Perspective 2030, 'On-track' scenario;
- ECF Power Perspective 2030, 'High-RES' scenario; and
- EWI / Energynautics 'Roadmap 2050 – a closer look', scenario A.

For each of the three scenarios, we subsequently illustrate the development in the EU-27. To facilitate this comparison, we have aggregated smaller countries in some regions, such as in Central Eastern Europe[40] or the Nordic countries and the Baltic States. Furthermore, the comparison is limited to the main sources of fluctuating RES, such as onshore and offshore wind as well as solar power, whereas we do no consider other types of RES.

To start with, Figure 26 shows the regional distribution of generation capacities in the 'On-track' scenario from ECF. It is clearly visible that most of the capacity from fluctuating RES is located in Western Europe, while the penetration is much lower in Eastern Europe, at least in nominal terms. Secondly, some countries face a (considerable) gap between the aggregate volume of fluctuating RES, on the one side, and the capacity of hydro power and gas-fired plants, on the other hand. This particularly applies to Bulgaria and Romania, Germany, France, Ireland and Spain, but to a certain extent also to Great Britain, Greece, and Portugal.

[40] Austria, Czech Republic, Hungary, Slovakia and Slovenia

Figure 26: Regional distribution of fluctuating RES, hydro power and gas-fired generation in the 'High RES' scenario (Energy Roadmap 2050)

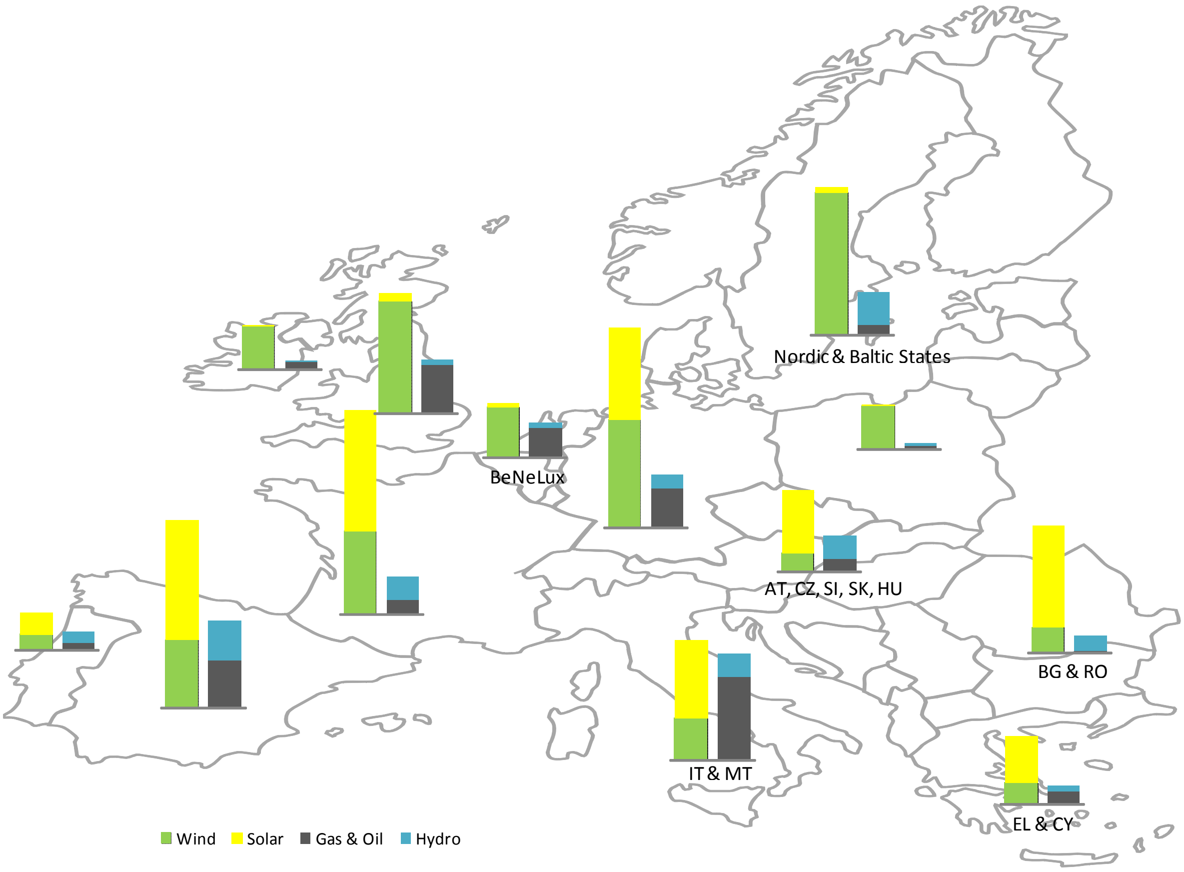


Source: DNV KEMA, based on European Climate Foundation (ECF). Power Perspectives 2030: On the Road to a Decarbonised Power Sector, A Contribution Study to Roadmap 2050: A practical Guide to Prosperous Low-Carbon Europe. Brussels. November 2011

For instance in Spain, a total installed RES capacity of approx. 100 GW corresponds to a total flexibility of less than 60 GW. Simultaneously, the share of gas-fired plants remains very limited in France as most flexible capacity is provided by hydro power. Conversely in Germany, gas-fired plants represent the major source of flexibility. Similarly, flexibility will mainly be provided by gas-fired power plants in Ireland and Great Britain. In these countries, a high penetration of fluctuating RES, in combination with limited flexibility and a high dependency on gas-fired plants, can be expected to have a considerable impact on the volatility of demand in the gas network as well.

The 'High RES' scenario from ECF, which is shown in Figure 27, shows a similar pattern, but with significantly larger differences between the volume of fluctuating RES, on the one side, and the level of available flexibility, on the other side. Most importantly, one can observe the combination of a very high level of fluctuating RES and a considerable but much smaller volume of gas-fired plants in France, Germany, Ireland, and Spain. Consequently, it seems reasonable to assume that the gas consumption of gas-fired plants in these countries may be subject to considerable volatility.

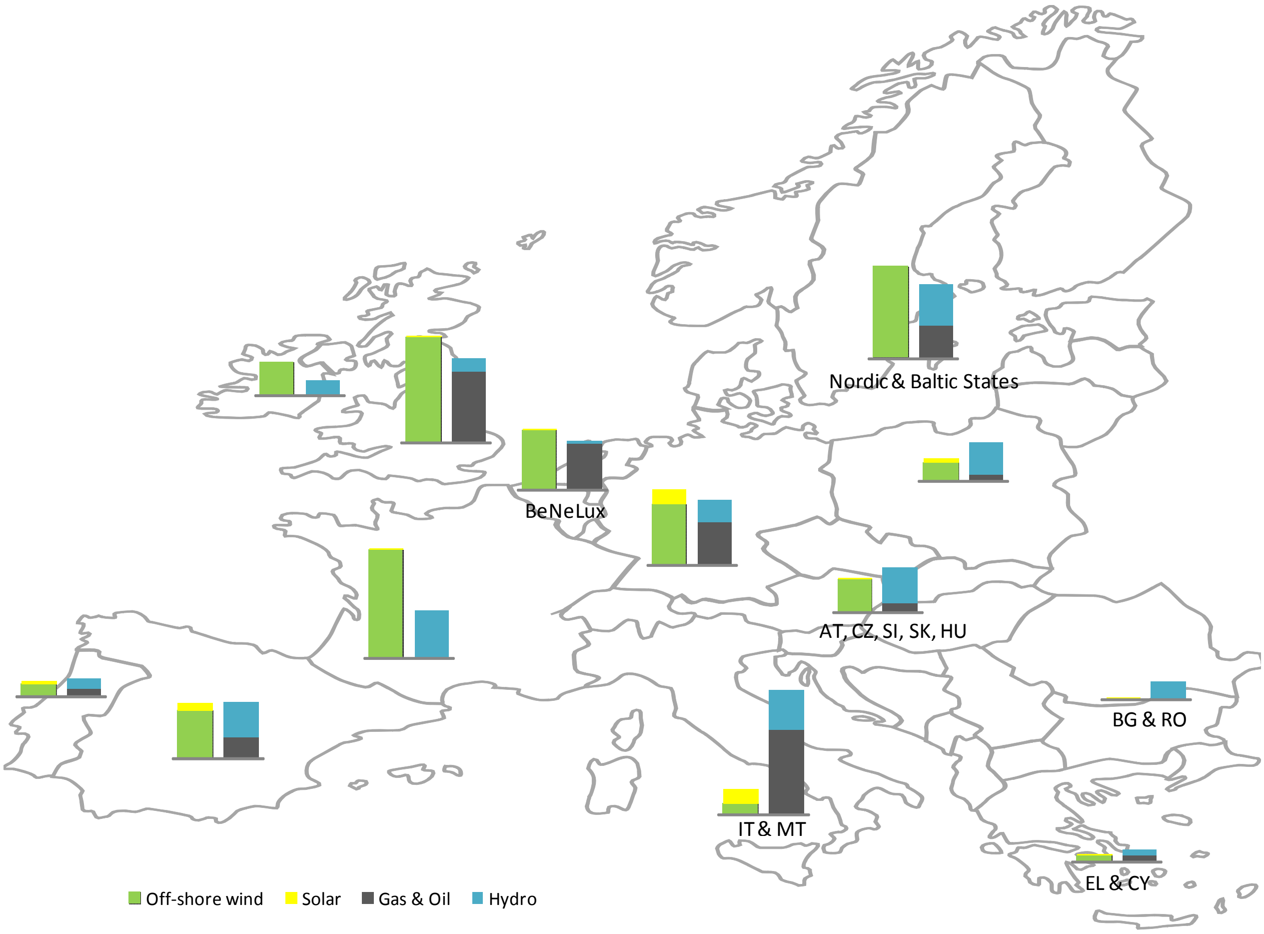
Figure 27: Regional Distribution of Fluctuating RES, hydro power and gas-fired generation in the 'High RES ' scenario (ECF)



Source: DNV KEMA, based on European Climate Foundation (ECF). Power Perspectives 2030: On the Road to a Decarbonised Power Sector, A contribution study to Roadmap 2050: A practical Guide to Prosperous Low-Carbon Europe. Brussels. November 2011

Finally, Figure 28 provides an overview of fluctuating RES, gas-fired plants and hydro power in another study by EWI and Energynautics from October 2012. In contrast to the ECF scenarios, this scenario is characterised by an almost negligible share of solar power as well as a much lower capacity of wind power plants. With the exception of France, this scenario furthermore shows a much more balanced capacity between fluctuating RES and flexible plants. Overall, this scenario should thus lead to much less challenging situations in terms of daily balancing than the previous two cases.

Figure 28: Regional Distribution of Fluctuating RES, hydro power and gas-fired generation in the EWI/Energynautics study (scenario A)

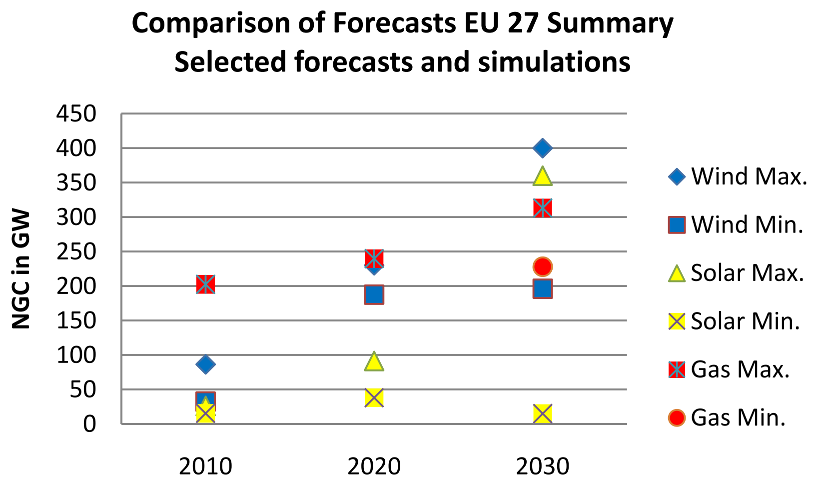


Source: DNV KEMA, based on Institute of Energy Economics - University of Cologne (EWI) and EnergyNautics: "Roadmap 2050 – a closer look" (October 2011)

4.4 Implications on Electricity and Gas Balancing

Based on the background of EU energy policy, the summary of different studies in this chapter has shown that the capacity of wind and solar power in the EU electricity markets is widely expected to increase significantly over the next two decades. Although the expectations of individual studies or scenarios vary widely (see Figure 29), in particular after 2020, they generally show a strong increase of wind power and, in most cases, also solar power. In parallel, most studies also anticipate the need for the construction of additional gas-fired power plants, although the latter may not necessarily result in a simultaneous growth of gas consumption.

Figure 29: Range of expected evolution of wind, solar and gas-fired electricity generation capacity between 2010 and 2030.



Source: COWI

Taking these overall trends into account, we can draw the following general conclusions with regard to the expected impact and requirements on daily balancing within the electricity and gas sector:

- Wind and solar power will replace production with other generation technologies, thus replacing the residual load to be provided by other gas-fired plants. However, due to the uncertain availability of wind and solar power, in particular during peak winter conditions, the peak load to be supplied by non-renewable energy sources will not decrease by a similar amount. As a result, electricity generation from non-renewable energy sources will need to be able to cover an increasing spread between peak and trough loads[41], including on a daily basis.

- Due to declining load factors for non-renewable energy sources, it is widely expected that an increasing share of the capacity required for covering residual load will need to be supplied by gas-fired plants. Assuming that gas-fired electricity generation will often represent the marginal generation technology, the effect of large daily variations in electricity production, and hence fuel consumption, can be expected to be especially pronounced for gas-fired plants.

- The output of wind and solar power plants may be subject to fast changes during the day[42], even when taking into account the fact that corresponding deviations will partially compensate each other in an enlarged region. As a consequence, an increased penetration of RES

[41] I.e. the times of the daily maximum and minimum load, respectively.

[42] Whilst solar power can be expected to be mainly subject to a structural daily pattern in a larger region, the variability of wind power is more related to the prevailing weather conditions on individual days.

may require increased ramp rates to be provided by other generation technologies, in particular in the case of wind power. Again, it seems reasonable to expect that a considerable share of the corresponding flexibility will have to be provided by gas-fired plants.

- Thirdly, it is important to note that electricity production from wind and solar power will remain subject to considerable forecast errors. These forecast errors will be reflected in the production that is to be supplied by electricity generation from non-renewable energy sources, including gas-fired plants. As such, the production by gas-fired plants can be expected to become unpredictable on the day ahead or even a few hours ahead of real time in comparison to today.

- Although various studies have shown that these effects may be mitigated by transmission expansion, demand response or an increased use of electricity storage, the same studies have also shown that it would not be economical (if at all feasible) to fully compensate the corresponding impacts.

In summary, these considerations imply that the electricity sector will require significant additional flexibility to be available for daily balancing in the future. Moreover, this flexibility will be characterised by three main dimensions, i.e.:

1. The ability to cover an increasing spread between peak and trough load on a daily basis;

2. The need for supplying increased ramp rates; and

3. The ability to deal with increased forecast errors and hence a decreasing predictability of the (residual) load to be supplied during the day.

Based on the expectation that gas-fired plants will represent one of the main sources for dealing with these issues, the corresponding need for flexibility thus equally applies to the gas market. Assuming that a considerable share of the remaining base load in the electricity sector will be provided by other generation technologies (e.g. nuclear, lignite or coal fired plants), it furthermore seems reasonable to assume that the corresponding effects may be even greater for gas-fired plants in relative terms.

Depending on the future evolution of energy efficiency measures, these developments may coincide with a decline in gas demand for heating purposes, for instance due to better building insulation and, potentially, a partial shift from space heating from natural gas (and other fuels) to electricity (e.g. heat pumps). These developments could principally reduce the need for diurnal flexibility in the gas sector. However, these developments are difficult to predict, such that the (positive) impact on the demand for flexibility in the gas sector remains highly uncertain.

5 Potential Synergies between Electricity and Gas Balancing

5.1 Introduction

In chapter 3 above, we have argued that the electricity sector will be faced with the need for significant additional flexibility to be available for balancing the system on a daily basis in the future.

More specifically, this flexibility involves three main dimensions:

1. The ability to cover an increasing spread between peak and trough load on a daily basis;

2. The need for supplying increased ramp rates; and

3. The ability to deal with increased forecast errors and hence a decreasing predictability of the (residual) load to be supplied during the day.

In addition, we have also explained why we believe that this will have a similar effect on the gas market as a considerable amount of the additional flexibility in the electricity sector is expected to be provided by gas-fired power plants. As a result, we observe an increasing need for diurnal flexibility in both markets.

Moreover, it is important to note that the corresponding effects are closely linked to each other. To start with, the incremental need for flexibility in the gas sector directly depends on the daily need for flexibility within the power sector. However, it may not always be economical (or even feasible) to provide the corresponding flexibility from the gas sector. Hence, the flexibility of the gas sector equally influences the availability of flexible resources in the electricity sector, and hence the need to rely on other sources of flexibility in the power market.

Given that the provision of flexibility in both sectors will incur certain costs, it is thus important to strive for an optimal allocation and use of flexibility in the electricity and gas market. Simultaneously, this also implies that it will become increasingly important to use any synergies, which may exist with regard to provision and use of flexibility for balancing the two systems on a daily basis.

Therefore, in this chapter we present some preliminary thoughts on potential measures, which may be considered in this respect. In this context, we acknowledge that it may become necessary to invest additional flexibility into both sectors. However, in line with the task specifications, we understand that this study shall not aim to identify the optimal infrastructure requirements. Below we briefly comment on some corresponding options below and therefore we focus on possible measures, which may be taken in the areas of regulation and market design.

In Table 13, we present an overview of potential measures which could potentially be considered. For a better understanding, the individual measures have been grouped along two dimensions. Firstly, we differentiate between measures aimed at investment planning, as opposed to the daily system and market operation. In addition, we also indicate to which extent each measure would influence the electricity sector, the gas market or both.

Table 13: Overview of potential regulatory and market-related measures for implementing potential synergies between gas and electricity balancing

Scope of Potential Measures	Measures focusing on: Daily Operations	Measures focusing on: Investments
Electricity Market	• Replacement of day-ahead market coupling by intra-day capacity allocation • Regional sharing of operational reserves • Coordination of energy and reserve markets • *Increased use of demand response*	
Common or Combined Issues	• *Market-based balancing* • *Harmonised 'gate closure'* • *Harmonisation of trading days* • Coordinated operational planning	• Coordinated network planning • *Locational tariffs* • *Locational pricing*
Gas Market	• Enforcement of firm exit capacities for system-critical power plants • Inter-zonal exchange of balancing services • Within-day products for inter-zonal capacities • Within-day 'flexibility products' • Improved line pack management	

Source: DNV KEMA

We emphasise that the list of measures in Table 13 presents a long list of potential approaches, which are subsequently analysed in more detail in chapter 7 below. In this context, however, we emphasise that a number of potential measures are not further considered below. The reasons to exclude these measures, which are highlighted in Table 13 in italics, can be summarised as follows:

- An increased use of *demand response* in the electricity sector as well as the transition to *market-based balancing* in the gas market are already targeted by the currently evolving regulatory framework. Consequently, we assume that these measures will be implemented in any case.

- With regard to a *harmonised gate closure*, an initial analysis showed that this measure would be unlikely to generate any tangible benefits for the perspective of this study. More specifically, a significant reduction of the deadlines for re-nomination in the gas network appears infeasible as physical flows in the gas network can be changed with a certain delay of one to several hours only[43]. Conversely, any increase of gate closure times in the electricity sector would contradict the current ambitions of the electricity target model and increase the share of physical deviations to be covered by the balancing process rather than through the intra-day market.

- Similarly, we believe that the *harmonisation of trading days* would not generate any tangible benefits. Although it may help to avoid transition issues from one gas day to the following, the scope of the corresponding problems can generally be expected to remain limited.

- *Locational tariffs and locational pricing* finally are beyond the scope of this study.

[43] Depending on the geographical area concerned, the volume of such changes etc.

6 Analysis of Potential Technical and Economic Benefits

6.1 Main Dimensions of Balancing

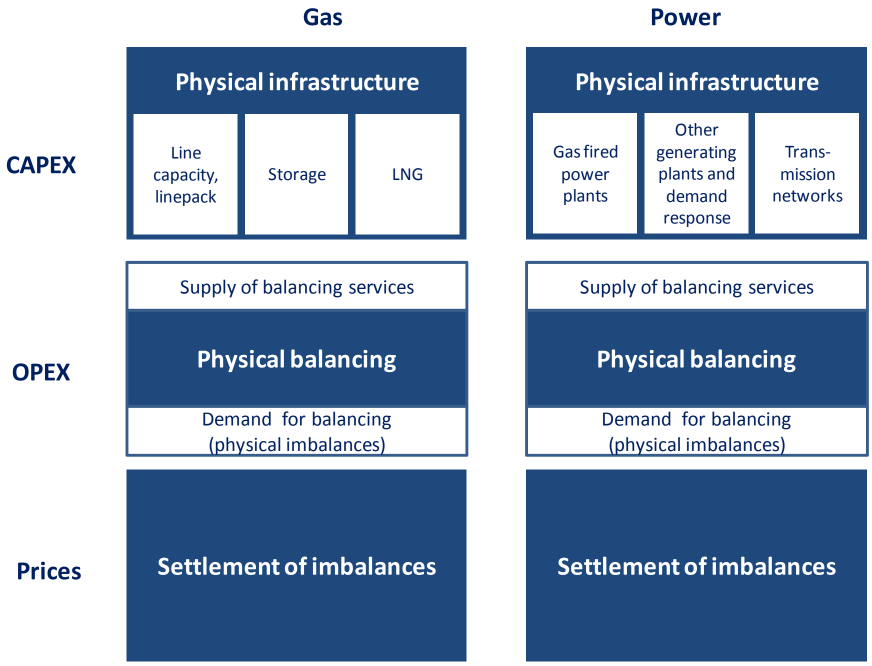
In order to assess potential technical and economic benefits, it is useful to consider that gas and electricity balancing makes use of different types of 'instruments' or mechanisms. As illustrated by Figure 30 this effectively involves the following three dimensions, which can be found both in the gas and the electricity market:

- Physical infrastructure;
- Physical balancing; and
- Settlement of imbalances.

First, balancing makes use of the physical infrastructure and assets, such as pipelines (incl. line pack), underground storage and LNG terminals in the gas sector, or gas-fired power plants (e.g. CCGT, OCGT), other power plants, demand response and transmission lines in the power sector. This infrastructure basically provides the 'supply side' of physical balancing actions, whilst the demand side of the physical balancing mechanism is determined by the physical imbalances of network users. Thirdly, balancing in the gas and electricity market also involves the ex-post settlement of each network user's imbalances.

These three dimensions also correspond to three different types of costs or economic impacts. The physical infrastructure is obviously related to investments and hence CAPEX. Secondly, physical balancing builds upon operational decisions and actions in response to arising balancing needs. As such, physical balancing influences the operating cost (OPEX) of using the available balancing means (i.e. infrastructure). Finally, the settlement of imbalances is based on imbalance (and other) charges. Although these charges should ideally reflect the cost of physical balancing, they also represent an additional element which has an impact on market participants.

Figure 30: Main dimensions of balancing in the gas and electricity market



Source: DNV KEMA

6.2 Interdependencies between Gas and Electricity Balancing

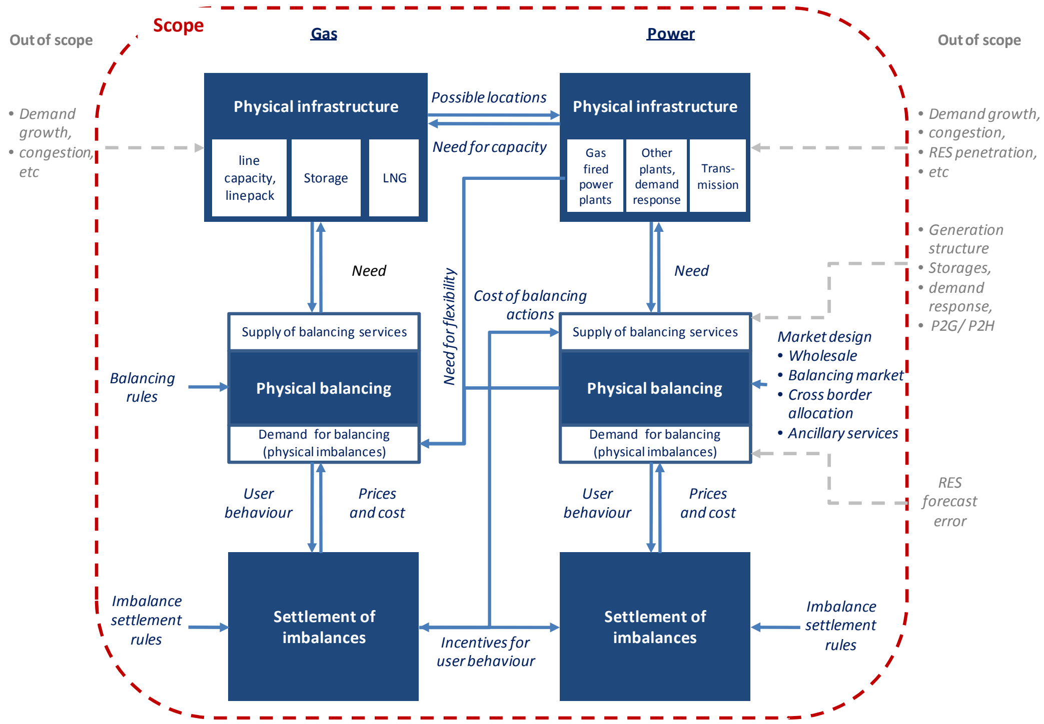
In chapter 5 above, we have identified a number of potential measures, which may help to implement synergies between gas and electricity balancing. Before analysing the potential technical and economic benefits, it therefore seems useful to consider the interactions between the different dimensions of balancing, as identified in Figure 30 above. Indeed, multiple and partially reciprocal relationships between do exist:

- The gas and electricity sector;
- The different dimensions of balancing in each sector; and
- Other, external influence factors.

These effects are illustrated by Figure 31, which provides a more detailed overview of the different elements and their interplay, which we comment on hereafter.

Within each sector, the **interdependencies between infrastructure, physical balancing and settlement** are similar for gas and power. As already mentioned, the infrastructure corresponds to the supply side of physical balancing (means). In fact, this relationship is bidirectional. For instance the demand for physical balancing determines the need for (additional) infrastructure and hence for investments into new infrastructure. In turn, the available infrastructure influences the flexibility of the corresponding system and hence the ability for physical balancing. Similarly, the need for physical balancing originates from the behaviour of network users and their imbalances. Simultaneously, imbalance settlement arrangements and the price of imbalances influence the behaviour of network users with regard to the 'acceptance' of imbalance and incentives for self-balancing.

Figure 31: Interactions between different parts of the balancing process



Source: DNV KEMA

Secondly, balancing in the gas and power sector is also influenced by some **external influence factors**, which are quite similar in both sectors. For instance the demand for new infrastructure is influenced by changes in demand, the need for the replacement of ageing assets and congestion etc. Likewise, the general wholesale market design and the applicable rules for the procurement and activation of balancing services clearly influence the physical balancing process, whilst the settlement of imbalances depends on the corresponding imbalance settlement rules.

In the power market, the supply of balancing services is also influenced by other external factors, such as the generation structure, the availability of storage and demand response or the potential emergence of new technologies, like Power-to-Gas (P2G) or Power-to-Hydrogen (P2H). Conversely, the penetration of fluctuating RES and RES forecast errors are among the main drivers for the need of balancing services in the power sector.

Please note that a considerable number of these external factors is not related to the design of wholesale market and balancing arrangements in the gas and electricity sectors. Consequently, the corresponding aspects are beyond the scope of this study and are not considered any further below.

Thirdly, Figure 31 also reveals important **interrelations between the gas and electricity sector**. We note that, in particular, the power sector has an influence on the gas sector, due to the importance of gas-fired power plants for electricity balancing. Equally, potential within-day obligations and imbalance charges influence the price or cost of balancing actions or services of gas-fired plants.

On the infrastructure level, the operation of gas-fired power plants requires the availability of sufficient gas infrastructure, including peak capacity as well as diurnal flexibility. Conversely, the available gas infrastructure plays an important role with regard to the location of a new gas-fired power plant.

Secondly, the operation of gas-fired power plants also influences the need for daily flexibility and balancing actions in the gas network. In practice, this influence depends both on the underlying operating mode of a power plant in the wholesale market and the potential contribution of balancing services in the electricity market. Conversely, the price (and hence cost) of corresponding balancing actions are influenced by the arrangements and charges for imbalance settlement in the gas sector, as already mentioned above.

Likewise, operators of gas-fired power plants are partially able to trade off imbalances, in both sectors, against one another. For instance they may decide to accept a higher imbalance in the gas network, in order to reduce an imbalance in the electricity market, or vice versa.

6.3 Estimation of Technical and Economic Benefits

This section serves to provide an overview and estimation of relevant technical and economic benefits that could be reached by exploiting synergies between gas and electricity balancing.

As a starting point, Table 9 lists the main technical benefits in the area of gas and electricity balancing. In accordance with the general structure presented above, these can generally be split into benefits for the physical infrastructure, on the one side, and the daily operations of the balancing process, on the other side. In the former case, synergies between gas and electricity balancing may primarily help to reduce infrastructure requirements, such as the amount of pipeline, generation, storage or network capacity required. Apart from a reduction of the overall requirement for capacity and/or energy, further benefits may be gained with regard to the type and capability of the corresponding assets, such as the dynamic requirements on power plants.

With regard to daily operations, technical benefits mainly relate to the use of the available infrastructure, both within and outside the network. Examples include a reduced use of compressors in the gas network, for instance as the result of less variations in pressure and/or transport speed, or variations in the use of production and storage facilities. Likewise, electricity balancing may influence the efficiency and variability of electricity production and the volume of network losses.

As further analysed below, all of these benefits correspond to the economic costs of benefits. In addition, however, changes and synergies in gas and electricity balancing may also influence network integrity and reliability in both sectors. These may, for instance, be a result of better information (or less uncertainty) on current expected balancing needs in the gas network, or an increase in the available reserve margins in the power market. In the latter case, this may also involve other issues such as possible reaction times etc.

Table 14: Main technical benefits for gas and electricity balancing

	Gas	Electricity
Physical infrastructure (CAPEX)	- Reduced pipeline capacity - Reduced line pack - Reduced storage (underground, LNG)	- Reduced generation capacity - Reduced transmission - Reduced dynamic requirements
Daily operations (OPEX)	- Reduced use of compressors (network + storage) - Improved reliability - Better information on current and expected balancing needs	- Improved generation efficiency - Reduced network losses - Reduction of variability - Improved reliability - Availability of increased reserve margins

Based on the initial summary in Table 9, we now present a quantitative estimate of relevant technical and economic benefits. However, it must be noted that it is extremely difficult to quantify the impact on reliability in a more general sense. For this reason, we subsequently focus on those benefits which can be directly linked to variations in economic terms.

As a starting point, Table 15 provides an estimate of the specific costs for 1 kW of pipeline capacity, assuming that an average of 250 km of pipeline would need to be built in order to supply the corresponding demand. Based on these assumptions, the specific costs for different types of pipelines range between approx. 30 and 45 €/kW.

Table 15: Estimation of specific costs for pipeline capacity (MW peak)

Diameter	in	**30**	**36**	**42**	**30**	**36**	**42**
Pressure	bar	60	60	60	80	80	80
Pipeline unit costs[44]	M€/km	1,024	1,312	1,760	1,024	1,312	1,760
Cross-sectional area	m^3	0,44	0,64	0,87	0,44	0,64	0,87
Gas volume[(a)]	Mcm/km	26,51	38,17	51,95	35,34	50,89	69,27
Cost of pipeline capacity [(b)]	€/kW	44,71	39,78	39,21	33,53	29,84	29,41

[(a)] – Ideal gas law approximation; [(b)] – for 250 km, incl. 10% premium for compressor stations
Calculations based on a design transport speed of 6 m/s

Next, Table 16 presents a similar set of estimates for the cost of additional line pack. These estimates are based on the assumption that line pack will be provided by increasing the diameter of a (planned) pipeline and a useful pressure variation of 20 bar[45]. Finally, we assume that the volume of line pack should be sufficient to cope for two hours of full consumption of the corresponding off-take point. Based on these assumptions, the specific costs of line pack vary between approx. 13 and 17 €/kW, which is less than 50% of the cost of pipeline capacity. Please note that the assumptions for line pack refer to the provision of within-day flexibility, whereas the cost of pipeline capacity can be considered as a proxy for peak capacity.

As an alternative for the provision of within-day flexibility, we also consider the cost of cavern storage. This is based on a recent study[46] with one cubic meter of working gas capacity between 0.5 and 1 €. When assuming that each MW of withdrawal capacity corresponds to between 400 and 1,000 MWh of working gas capacity, this results in specific costs for withdrawal capacity of approx. 18 to 90 €/kW[47]. Even when accepting a 50% reduction of the hourly capacity, i.e. when partially relying on line pack, this still corresponds to specific costs of some 10 – 45 €/kW. By direct comparison, cavern storage is thus significantly

[44] Source: Mott MacDonald. Supplying the EU Natural Gas Market. Final Report. Nov 10
[45] Alternatively, line pack could also be provided by the installation of additional compressors.
[46] Stefan Lochner. The Economics of Natural Gas Infrastructure Investments, Theory and Model-based Analysis for Europe. Inaugural dissertation. Universität zu Köln. 2011
[47] Based on a calorific value of 11 kWh/m^3

more expensive than line pack for the purpose of providing within-day flexibility alone.

Table 16: Estimation of specific costs for additional line pack

Increase of pipeline diameter	in	30 => 36	36 => 42	42 => 48
Incremental line pack [(a)]	Mcm/km	3,89	4,59	5,30
Incremental unit costs (see Table 15)	M€/km	0,29	0,45	0,40
Required pipeline extension [(b)]	km	46	39	33
Resulting costs	€/kW	13,11	17,26	13,35

[(a)] – Assuming a pressure variation of 20 bar; [(b)] – to cover 2 hours full consumption of a 1,000 MW offtake

For the power sector, we consider 250 km of a 380 kV line with a current of 4 kA per circuit. Based on estimates by the German TSOs[48], a corresponding line would cost some 1.15 M€/km in the case of single circuit line but 1.4 M€/km for a double circuit line. In addition, one has to take into account that the additional transport capability will be less than the nominal capacity of the line since it is necessary to account for possible line outages. We therefore assume that the incremental transport capability amounts to 2/3 of the nominal capacity. When again assuming an average line length of 250 km, this corresponds to specific costs of between 100 and 164 €/kW.

Finally, we also consider an open-cycle gas turbine (OCGT). In accordance with a recent study by the European Climate Foundation[49], the specific investment costs of this plant are estimated at 350 €/kW.

In order to derive an estimate for the overall savings, which might be achieved through the exploitation of synergies between gas and electricity balancing, it is furthermore necessary to estimate the quantity of the technical benefits, which have been identified in Table 9 above. Unfortunately, it is hardly possible to derive a robust estimate without any more detailed analysis.

As an alternative, we therefore consider the seven countries[50] which have been identified as potentially critical, with regard to gas and electricity balancing in

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[48] dena. dena-Netzstudie II. Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 – 2020 mit Ausblick auf 2025. Berlin. November 2010

[49] ECF. Power Perspectives 2030. Brussels. November 2011

chapter 4.3 above. In summary, the installed capacity of gas-fired plants in these countries in 2030 amounts to some 130 GW in the three scenarios considered. For simplification, we assume that synergies between gas and electricity balancing might allow for a saving between 2.5% and 10% of this capacity (i.e. 3 – 13 GW), either in the power system or in the gas market.

Based on these assumptions, Table 17 presents an estimate of the potential economic benefit in terms of reduced investments. The corresponding numbers reveal a fairly large range of estimates, which vary between a few million and almost half a billion Euro per year. However, the results are clearly in line with common perceptions for the transport of energy, i.e. that the cost of flexibility in the power sector is considerably higher than in the gas sector.

Consequently, it generally appears desirable to optimise the use of available flexibility in the gas network, in order to minimise investment requirements in the power sector. In this case, the incremental investment cost for additional within-day flexibility in the gas network ranges between Euro 100 million and 1.5 billion, or some € 10 – 150 million on an annual basis.

Table 17: Estimation of potential savings for a 2.5% to 10% reduction in infrastructure requirements for gas-fired power plants in 2030

	€ billion	**M€/a [c]**
Power plant [a]	1.1 – 4.6	114 – 455
Electricity Transmission line [a]	0.3 – 2.1	32 – 213
Gas transmission pipeline [b]	0.2 – 1.5	24 – 145
Line pack [b]	0.1 – 0.6	11 – 56
Underground storage [b]	0.1 – 2.9	14 – 288

[a] – Based on 130 GW of installed capacity; [b] – Based on 325 GW maximum off-take (assuming an OCGT with an efficiency of 40%); [c] – 10% annuity

Furthermore, apart from investment cost, it is also necessary to consider potential savings in operating expenditure. When neglecting transmission losses in the power sector and the cost of compression cost in the gas network, the potential economic benefits are largely equivalent to a potential reduction in the volume or price of balancing energy to be purchased by the TSOs.

Experience shows that balancing energy typically represents between 2% and 5% of total consumption in both the gas and electricity market. For our analysis, we therefore assume that synergies between gas and electricity balancing

[50] France, Germany, Greece, Ireland, Poland, Spain, United Kingdom

may allow saving about 10% of the total volume of balancing energy instructed by the TSOs, or between 0.25% and 0.5% of total consumption[51] in the seven countries considered. In addition, we assume that the incremental cost[52] of balancing energy is approx. 5 – 10 €/MWh in the power market and 2.5 – 5 €/MWh in the gas market, respectively.[53] When using these assumptions, one can derive the estimates presented in Table 18. Overall savings range between slightly less than 50 and some 175 million Euro, and are thus in a similar range as potential savings in CAPEX. Depending on the competitiveness of the balancing markets, some share of this may actually represent additional producer surplus and thus a re-distribution of welfare.

Table 18: Estimation of potential savings in the costs of balancing energy

	Electricity	Gas	Total
Annual consumption (TWh) [(a)]	2,000*[(b)]*	3,000*[(c)]*	
Assumed reduction in balancing energy	0.25% – 0.5%	0.25% – 0.5%	
Equivalent volume of energy (TWh)	5 - 10	7.5 - 15	
Assumed savings (€/MWh)	5 - 10	2.5 - 5	
Potential savings (M€/a)	25 - 100	19 - 75	44 – 175

[(a)] – France, Germany, Greece, Ireland, Poland, Spain, United Kingdom; [(b)] – 2030, based on DG ENER Energy Roadmap 2050; [(c)] – 2020, based on ENTSO-G 10-Year Network Development Plan

Finally, more efficient gas and electricity balancing may also influence the distribution of welfare with regard to the settlement of imbalances. Although the rules for the pricing of imbalances vary, it seems reasonable to assume that the price for balancing energy, and hence the price for imbalances, will on average be close to the marginal price for balancing energy. Similarly, one may reasonably expect that a reduced activation of balancing energy will also result in decreasing prices. Whilst direct savings will remain limited, this effect will influence the imbalance charges to be paid by network users. Although this variation does not change the overall economic benefits, it results in a different distribution of welfare between the providers of balancing services, on the one hand, and the sum of all network users, on the other hand.

[51] Corresponding to potential savings of some 10% of total energy

[52] I.e. the spread between the price of balancing energy and the prevailing wholesale market price.

[53] Alternatively, these numbers can also be interpreted as the premium requested by balancing service providers.

In order to estimate the corresponding impact, we assume that balancing energy represents 2.5% of total consumption on average, which corresponds to some 125 TWh for the seven countries considered (compare Table 18). Furthermore, when assuming that the average incremental price of balancing energy and imbalances decreases by about 10%, or between 0.5 and 1 €/MWh based on the assumptions presented above, this results in a redistribution of welfare of between Euro 50 and 125 million.

Table 19 finally summarises the results of our different estimates. Overall, these estimates suggest that the potential welfare gains of exploiting synergies between gas and electricity balancing may range between Euro 60 and 300 million on an annual basis, even when only considering seven countries. In addition, more efficient balancing may also cause a considerable shift of welfare from providers of balancing services to consumers.

Table 19: Summary of estimated welfare gains (M€/a)

	Potential welfare gains
Reduction of CAPEX	10 - 150
Reduction of OPEX	50 - 175
Total savings	60 - 325
Redistribution of welfare from balancing service providers to aggregate of all network users	50 - 125

Last but not least, we note that actual welfare gains may be significantly higher than indicated by these numbers. For instance a recent study by ECF[54] has estimated that the regional sharing of reserves (compare with chapter 7.3) may result in annual savings of more than Euro 2 billion in the EU-27 in 2030. This number, which is about 10 times larger than the estimates presented below, effectively reflects savings in costs for fuel and CO_2, i.e. a reduction in the total cost of electricity supply to the European economies. These savings are made possible by a more efficient generation dispatch in the power sector in case of reduced reserve requirements, i.e. an effect which has not been considered in our analysis. In summary, a comparison with these numbers therefore suggests that the estimates presented in this chapter may be considered as conservative.

[54] ECF. Power Perspectives 2030. Brussels. November 2011

7 Assessment of Key Design Elements for Electricity and Gas Balancing Markets

7.1 Overview of Measures and Assessment Criteria

Based on our initial analysis in chapter 5, we have selected a number of market-related measures, which may help to exploit potential synergies between gas and electricity balancing. In total, this selection covers the following 10 measures, which are further explained and analysed below:

1. Replacement of day-ahead market coupling by intra-day capacity allocation in the Electricity Sector;
2. Regional Sharing of Operational Reserves in the Electricity Sector;
3. Coordination of Wholesale and Reserve Markets in the Electricity Sector;
4. Enforcement of firm exit capacities for system-critical power plants in the gas market;
5. Inter-zonal exchange of gas balancing services by the TSOs;
6. Tradeable within-day products for inter-zonal capacities in the gas market;
7. Within-Day Flexibility Products in the Gas Market;
8. Coordinated network planning;
9. Coordinated operational planning; and
10. Improved line pack management

In the remainder of this chapter, we present and discuss each of these potential measures in more detail. In each case, firstly we present the underlying rationale, which suggests that the corresponding measure might provide some potential benefits to the electricity and/or gas markets. Where necessary, we also describe each measure as well as our assumptions in more detail, in order to facilitate the understanding of the corresponding concept.

For each measure, we then discuss its feasibility and impact on balancing in the gas and/or electricity markets, with the ultimate aim of identifying the (most) promising options. In this context, we identify and discuss a number of key aspects, which we believe to be the most relevant for each measure. In order to facilitate a structured approach, this discussion is supplemented by a structured evaluation against nine different assessment criteria, which are listed in Table 20 below.

As indicated by Table 20, we consider the first four criteria to be the key objectives, whilst the remaining aspects refer to a number of supplementary targets. The key objectives cover the principal feasibility of each measures as well as its ability to implement potential synergies in gas and/or electricity balancing, both in terms of increasing efficiency and improving reliability. Conversely, the supplementary targets consider other issues, such as the cost of each measure, speed of implementation, distribution of welfare, promotion of competition and transparency. Implicitly, we have also considered the sustainability of each measure in the long term, although this aspect is not shown as a separate category in Table 20.

Table 20: Assessment criteria for evaluation of potential measures for further development of the electricity and gas balancing markets

	Criterion	Explanation
Key Objectives	**Feasibility**	Overall feasibility and complexity of the mechanism; compatibility with market arrangements
	Ensure reliability	Ability to ensure / improve the reliability (security) of electricity and/or gas network operations
	Efficiency (long term)	Impact on productive (and allocative) efficiency in the long term (investments)
	Efficiency (short term)	Impact on productive (and allocative) efficiency in the short term (daily operations)
Supplementary target	**Cost**	(Limited) Cost for implementation and operation
	Speed of implementation	Time and complexity of implementation, taking compatibility into account with current / planned market arrangements
	Welfare distribution	Impact on the distribution of welfare between different stakeholders and/or countries
	Competition	Potential to increase the scope for competition in the electricity and gas balancing markets
	Transparency	Promotion of more transparent market mechanisms and outcomes

In section 7.10, we summarise the findings of our assessment and identify those measures and key design elements, which we proposed to consider for the further development of the market arrangements for gas and electricity balancing.

7.2 Replacement of Day-Ahead Market Coupling with Intra-Day Capacity Allocation in the Electricity Sector

7.2.1 Rationale and Basic Description

As explained in chapter 3.1, the so-called Target Model for the electricity market is based on day-ahead market coupling, which provides for the allocation of inter-zonal capacities on the day-ahead. This choice corresponds to traditional operating practices in the electricity sector, where the unit commitment of less flexible plants with long start-up times has to be decided well in advance of real time, against the background of relatively accurate load forecasts.

In contrast, it is widely expected that most European power markets will be characterised by a strongly increasing penetration of RES-E, including in particular wind and solar power. Electricity production from these sources is subject to considerable forecast errors, which shows a significant reduction in the last 3 – 4 h before real time only. Consequently, it appears reasonable to assume that the initial generation scheduling, as decided under day-ahead market coupling, may often turn out to be inefficient in power systems with significant amounts of wind and solar power. To cope with this issue, the Target Model for the electricity market additionally foresees an increasing use of the intra-day market, which serves to adjust the initial day-ahead scheduling to the evolving situation during the day.

As an alternative, it has been suggested to us that it might be more appropriate to move towards a fundamental revision of the market model for the electricity sector, based on an exclusive intra-day allocation of inter-zonal capacities. Conceptually, this alternative approach could be described as follows:

- Where forward capacity was still allocated in the form of physical transmission rights, the deadline for the exercise of forward capacity rights would be shifted from the morning of that day-ahead to several intra-day gates; and market participants would be obliged to firmly nominate the use of inter-zonal capacity rights for a certain period at each intra-day gate, starting one or several hours after the current intra-day gate;
- Any unused capacity (including capacities reserved for short-term allocation) would be allocated by means of market coupling after the corresponding intra-day gate[55];
- Where applicable, any remaining capacity could still be allocated by means of subsequent intra-day allocation, in the same manner as currently foreseen under the Target Model for the electricity market.

[55] Assuming that the current use of physical transmission rights will be replaced by financial instruments, the volume of 'unused capacity' would become equivalent to total available capacity.

7.2.2 Impact Assessment

As outlined above, the replacement of day-ahead market coupling by intra-day capacity allocation would obviously reduce the frequency and size of potential deviations between the initial scheduling of generation and inter-zonal exchanges on the day-ahead, on the one side, and the optimal generation schedule close to real time, on the other hand. In an ideal form, this option would therefore allow one to determine the 'optimal' generation schedule in a single iteration, without or at least with a strongly decreased need for additional corrective actions in the intra-day market.

Obviously, the same observations would apply from the perspective of the gas market, which might equally benefit from a similar reduction of corrective actions. Indirectly, this measure might thus also improve the combined functioning of the gas and electricity markets. More specifically, it might decrease potential fluctuations of the planned production of gas-fired plants. Since gas-fired plants may have a tangible impact on total demand and hence prices in the gas market, this measure may therefore also help to decrease the volatility of the gas market during the operating day.

These potential benefits would, however, come at the expense of several disadvantages and would probably be smaller than they appear at first sight. In particular, we note the following potential issues:

- Risk of sub-optimal dispatch of less flexible power plants;
- Adverse impacts on liquidity and competition in the power market;
- Additional operational risks for power system operation; and
- Limited benefits or even negative impacts for/on the gas market.

Risk of Sub-Optimal Dispatch of Less Flexible Power Plants

We have already noted above that the traditional concept of day-ahead generation scheduling stems from the need to decide on the unit commitment of less flexible plants (such as nuclear, lignite, coal, CCS or CHP plants) over a sufficiently long period, mainly due to long start-up times and/or high start-up costs. For the same reason, the corresponding plants may either have to remain committed or be kept offline even when this is no longer justified, for instance as a result of a different production by wind and solar plants than originally estimated.

Under the current market arrangements, these risks are potentially increased by the risk that the day-ahead market provides inflexible plants with a certain income for their planned production. For instance, in a situation where the wind and/or solar power forecast underestimates the actual production from these sources and inflexible power plants sell more energy on the day-ahead market than what would have been optimal / required in the intraday market. The latter may be reluctant to shut down in response to a sudden decline of market prices. Instead they may remain synchronised with the system even though their variable costs of production are higher than prices in the intra-day market. Besides other reasons, it is possible that the opportunity cost of additional start-ups, increased risks for break down in the start-up phase or uncertainty about the optimal time of re-connection under volatile market prices may outweigh the benefits of short-term changes to their initial schedule.

Although these issues appear to be particularly relevant for the current market model, they would equally apply in the case of a market with an exclusive intra-day allocation of inter-zonal capacities. Indeed, we note that the corresponding issues represent a fundamental challenge which is related to the technical inability or the high costs of such plants for responding to changing circumstances. As such, these issues hold true irrespective of the concrete market arrangements.

Indeed, if the allocation of inter-zonal capacities were to be shifted into the intra-day market then less flexible plants might be forced to decide on the unit commitment under considerable uncertainty on market prices. In principle, this risk might be mitigated through participation in the OTC market. However, due to uncertainty of the market outcome in an enlarged regional market with (flow-based) market coupling, it is possible that inter-zonal spreads in the OTC market are higher before the initial market coupling, in particular in a situation where a PTDF-based capacity model is used. Moreover, wind and solar plants could be expected to remain cautious on the volumes they can offer into the market, in order to minimise their imbalance risks. Knowing that additional volumes may become available relatively shortly before real time, buyers may similarly face an incentive to delay their purchases in the market.

As a result, less flexible plants may find it more difficult to find trading partners or, alternatively, demand higher prices in order to compensate for the additional risks. Both effects create a risk of a sub-optimal dispatch as the production from less flexible plants may be below the economic optimum. This effect is likely to be the larger the shorter the time scale of intra-day gates is. Moreover, it will generally to increase for plants with longer start-up times or higher start-up costs.

Overall, these considerations highlight that the underlying issues simply reflect a fundamental conflict between renewable energies, on the one side, and inflexible conventional power plants, on the other side. While the former benefit came from the possibility of trading as close to real-time as possible (i.e. in order to reduce imbalance risks and cost from corrective trade activities), the latter favoured an earlier conclusion of commercial transactions due to the long lead times for unit commitment.

Overall, we are thus not convinced that a transition to an exclusive intra-day allocation of inter-zonal capacities would offer any tangible benefits in terms of economic efficiency, provided that a functioning intra-day market exists.

On a side note, it is worth noting that the decision on the timing of the short-term allocation of inter-zonal capacities primarily affects the distribution of risks and welfare between different types of generators. Indeed, the current market arrangements are beneficial for conventional plants with limited flexibility, whilst they create significant commercial risks for wind and solar plants that are subject to substantial forecast errors. Conversely, a transition to intra-day capacity allocation would shift a considerable share of the risk of forecast errors from fluctuating renewable sources to less flexible plants.

Adverse Impacts on Liquidity and Competition in the Power Market

One of the major advantages of day-ahead market coupling is the concentration of liquidity in the day-ahead spot market. This includes both the uniform price auction (market coupling) itself, as well as the continuous trading in the organised and OTC markets before and after this time. As experience of the Nordic and continental European markets has shown that this feature has been an important element in the development of liquid wholesale electricity markets. In contrast, the British electricity market, which has largely focused on continuous trading, is still characterised by significantly lower trading volumes.

Abolishing day-ahead market coupling in exchange for intra-day trading would naturally spread total market liquidity over various market sessions, with the total volume in each session likely being significantly smaller than in the combined day-ahead market. Consequently, the level of liquidity and the degree of competition would likely be lower than under the current market arrangements. In addition, some market sessions and hence part of the trading activities would be shifted from normal business to evening and night hours. Due to the cost of 24/7 operations, this would probably represent a significant barrier to smaller market participants, thereby further decreasing liquidity and competition in the spot market.

Overall, the transition from day-ahead to intra-day market coupling would therefore bear a considerable risk of reducing liquidity and could thus negatively affect the level of competition in the electricity spot market.

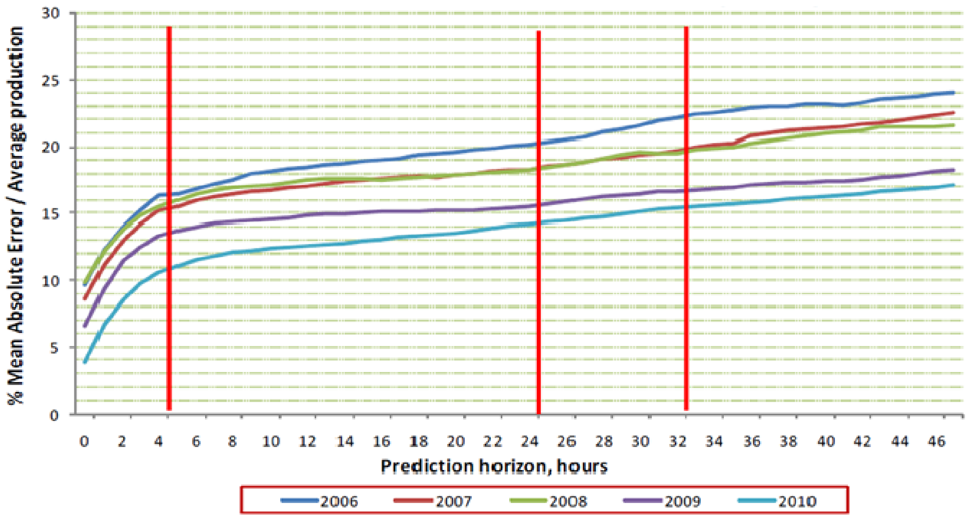
Additional Operational Risks for Power System Operation

In most countries that rely on decentralised scheduling, the day-ahead spot market provides the basis for generation scheduling. This process requires some time as generators need to know their market position before deciding on the unit commitment and planned dispatch of their plants. Thereafter, the TSOs need further time to validate scheduled cross-border exchanges and carry out a detailed congestion forecast, which is particularly important in the strongly meshed regional grids in Central Europe. Furthermore, where necessary, this may require additional remedial actions by the TSOs, in order to deal with physical congestion.

The current time line for the corresponding processes provides for a period of approx. 7 - 8 h between the time of day-ahead market coupling at 12 pm and the finalisation of the day-ahead congestion forecast by the TSOs early in the evening on the day ahead. When moving towards an intra-day allocation of inter-zonal capacities, this time would obviously need to be shortened, in order to benefit from improved forecast accuracy for renewable energies. In this context, it is important to consider that the quality of wind (and solar) forecasts improves in the last few hours before real time only, see Figure 32. Conversely, the reduction of the forecast error from the day-ahead horizon until a few hours ahead of real time remains limited. Consequently, inter-zonal capacities would need to be allocated very shortly before delivery, i.e. some 2 – 3 h before real time, in order for the abolishment of day-ahead market coupling to provide any tangible benefits.

Under these circumstances, the TSOs would have very little time for the harmonisation of cross-border schedules, the short-term security assessment and potential remedial actions. Although these processes may benefit from the transition to a PTDF-based allocation of inter-zonal capacities as well as from further harmonisation and automation, this might create serious operational risks for power system operation. Moreover, the corresponding actions would occur beyond the timeline for the activation of inflexible plants (see discussion above), such that the TSOs might be forced to take precautionary measures even before the allocation of inter-zonal capacities. Rather than minimising the intervention of TSOs into the market, this might therefore result in an increased role of TSO actions outside the general wholesale market.

Figure 32: Development of the aggregate wind power forecast error in the Spanish power system



Source: REE, "The wind in Spain: past, present and future challenges for a TSO", Juan Ma. Rodríguez, DS3 AG Dublin 2nd Feb 2011.

Limited Benefits or even Negative Impacts for the Gas Market

The main benefit of an exclusive intra-day allocation of inter-zonal capacities would be that it would no longer be necessary correct for the deviations between the planned wind and solar power production and the actual outturn in real time. However, except for the effects discussed above, the current target model, with its combination of the day-ahead and intra-day markets, will principally lead to the same final dispatch as intra-day market prices will incentivise (flexible) plants to adjust their output to changing circumstances during the day.

As such, the proposed change would thus not reduce the flexibility to be physically provided by the gas network. Instead, it might merely serve to reduce the need for re-nominations in comparison to the current market arrangements. Moreover, this effect would come at the expense of a general delay in the availability of robust initial nominations in case of an exclusive intra-day allocation of inter-zonal capacities. Rather than improving the situation, it may therefore create further uncertainty for the gas market and hence even increase the demand for flexibility in the gas market.

We emphasise again that (flow-based) market coupling in a meshed regional grid may substantially impact local prices, and hence the generation dispatch, in specific market areas. Assuming that gas-fired power generation will represent an increasing share of total consumption in the gas market, this would imply similar changes in market prices and exchanges in the gas market. Moreover, as mentioned before, the allocation of inter-zonal capacities in the electricity market would need to be delayed until a few hours before real time, in order to provide any fundamental gains compared to the current market model.

Consequently, the gas TSOs would receive robust nominations some 2 – 3 h before real time only, i.e. within the current time frame for final re-nominations. Similar to the case of the power system, this may actually create increased operational risks rather than improving the situation, in particular where this involved sudden and significant changes in the expected inter-zonal exchanges in the gas market.

Overall, we thus believe that the abolishment of day-ahead market coupling would offer very little, if any, fundamental benefits for the gas market. Moreover, these advantages would come at the expense of additional uncertainty for the daily gas market and increased operational risks for the operation of the gas networks, such that the overall impact on the gas market may even be negative.

7.2.3 Summary Assessment

The following table summarises our evaluation of the abovementioned instrument against the assessment criteria defined in section 7.1. To start with, we principally believe that a corresponding change would be feasible, although it would be necessary to deal with the complexity of short-term operational processes. In the same context, we have explained above why we believe that the shortening of the market timeframe may create additional risks for the reliable operation of the power system.

As explained above, the transition towards the intra-day allocation of inter-zonal capacity would be unable to resolve the fundamental problem of uncertain wind and solar forecasts. Consequently, we would not expect any tangible gains in efficiency. In contrast, the fragmentation of the electricity spot market over time might reduce the level of competition, which would be detrimental to the overall efficiency of the electricity market. Moreover, significant investments would be required, in order to enable the required degree of automation of operational (and market) processes. For similar reasons, we assume that this measure would require a long time for implementation.

In our view, the disadvantages and risks of this measure therefore clearly outweigh the potential gains, which we assume to be strictly limited.

Table 21: Evaluation - Intra-day allocation of inter-zonal capacities (electricity market)

Criterion	Evaluation[(a)] / Comments	
Feasibility	**0**	Note complexity of short-term processes
Ensure reliability	**(-)**	Additional operational risks (E and G)
Efficiency (long term)	**0**	No tangible changes to status quo
Efficiency (short term)	**0**	No tangible changes to status quo
Cost	**(-)**	Costs for full automation of operational processes (+ limited costs for adaptation of market systems)
Speed of implementation	**-**	Requires major revision of target model and operational processes in electricity market
Welfare distribution	?	Limited to distribution of welfare between RES-E and inflexible conventional plants
Competition	**(-)**	Fragmentation of electricity markets
Transparency	**0**	No tangible changes to status quo

[(a)] – Compared to status quo / current target arrangements

7.3 Regional Sharing of Operational Reserves in the Electricity Sector

7.3.1 Rationale and Basic Description

With few exceptions, operational reserves in the electricity market are currently procured on a national level. Recent developments and several studies have shown that a regional approach for the dimensioning and procurement of reserves can lead to substantial cost savings.[56] Moreover, with an increasing share of electricity from renewable sources, the need for operational reserves is commonly expected to grow (despite improvements in forecast quality), whilst the availability of reserves from conventional plants may decline. Consequently, the potential savings from sharing operational reserves between different TSOs are likely to further increase in the future.

[56] See, for instance, the reduction of total reserve requirements in Germany after introduction of the Grid Control Cooperation, or results of the ECF Power Perspectives 2030 study from 2011.

The basic idea of this measure would be to determine and procure operational reserves[57] at a regional (or even European) level by or on behalf of multiple TSOs. In addition to the common procurement of operational reserves through a single mechanism, this would also entail a partial sharing of operational reserves by several TSOs or control areas. Instead of a 1:1 relation between operational reserves and control areas, at least some operational reserves would serve two (or more) control areas at the same time. In other words, at least some control areas or TSOs would be able to deal with local incidents only by relying on operational reserves from other control areas, whilst the same operational reserves would also serve to ensure security in the other control area(s).[58]

7.3.2 Impact assessment

Overall Technical and Economic Benefits

The need for operational reserves is primarily driven by stochastic events, such as unplanned outages of large (conventional) plants and the uncertain production by fluctuating RES, i.e. wind and solar power. The size of the largest unit is generally driven by constraints in generation technology, such that there is no correlation between the size of a control area and the size of the largest unit. As a result, larger control areas generally benefit from a relative level of reserve requirements. Likewise, it is principally possible to share the risk of generation outages between several control areas as the risk of the largest units simultaneously tripping in "n" control areas each is the same as the risk of "n" corresponding units failing in a large control area at the same time.

Similar observations also apply with regard to the forecast error of fluctuating RES. Despite a certain degree of spatial correlation, the aggregate forecast error in a larger geographical area principally decreases in relative terms compared to smaller areas. Consequently, larger geographical regions with a high penetration of fluctuating RES need relatively less operational reserves than smaller control areas with the same relative share of fluctuating RES.

Regional sharing of operational reserves thus offers significant economic benefits. First of all, it can generally be expected to allow for a tangible reduction in overall reserve requirements and OPEX, as illustrated by the example in Text Box 1. Although the corresponding numbers will be different for other scenarios, such as those considered by the EC Energy Roadmap 2050, they clearly illustrate that this measure may render major economic benefits. Moreover, although the ECF study did not report any tangible savings in capital investments, it seems reasonable to assume that a regional approach would also allow

[57] It should be noted that this concept can also be extended to back-up capacity.

[58] In the easiest case, a given amount of reserve might for instance serve to cover the loss of the largest unit in two neighbouring control areas, assuming that the probability of both units failing at the same time is negligible. In reality, however, the corresponding relations will generally be much more complex.

for a possible reduction in overall capacity requirements, in particular when also considering the potential need for back-up capacity[59].

Text Box 1: Potential savings due to regional sharing of operational reserves

> The 'Power Perspectives 2030' study by the ECF from 2011 has analysed several scenarios for the further development of the European power system until 2030, with different levels of decarbonisation and (fluctuating) RES. Among others, the study has also analysed the potential benefits of sharing operational reserves on a regional level instead of a purely national dimensioning and provision.
>
> The study found that regional sharing of operational reserves might allow for a potential reduction of operational reserves by approx. 35 GW in 2030, which is equivalent to more than 25% of the total reserve requirement at a European level. This reduction corresponds to cumulative annual savings of € 2.4 billion in operating expenditure. In contrast, the ECF study did not report any reduction in capital expenditure as the latter was driven by the need for sufficient back-up capacity. In this context, it is worth noting that the ECF study assumed a massive expansion of the European transmission grids, which principally facilitates the exchange of energy and reserves between different regions.

In addition to the positive impact on the electricity market, we also expect clear benefits for the gas market. First, it seems reasonable to assume that a more balanced use of the electricity generation infrastructure, as reflected by decreasing OPEX, will also help to limit the fluctuating use of the gas infrastructure. This in turn should help to reduce the need for balancing services in the gas sector as well as to reduce the costs of daily gas supply overall. Most importantly, however, reducing the total power reserve requirement is likely to decrease the need for transport capacity and flexibility requirements in the gas market. Although we are unable to quantify these savings in the current study, we do assume them to be potentially significant as well.

On top of these fundamental effects, the regional integration of the operational reserve markets can also be expected to increase competition in this market segment, which would further increase the economic benefits of this measure.

Need for Reservation of Inter-Zonal Capacity

In order to enable a regional exchange of operational reserves, it would be necessary to ensure that the corresponding volumes could actually be made physically available when required. At least in certain cases, it may therefore be necessary to reserve a part of inter-zonal capacity for this purpose, which would thus no longer be available for commercial exchanges of energy in the wholesale market.

From an overall economic perspective, a corresponding reduction in the volume of inter-zonal capacity used in the wholesale market would nevertheless still be

[59] In contrast to operational reserves, both of the scenarios referred to in Text Box 1 were assuming the regional (or even European-wide) sharing of back-up capacities.

efficient, provided that the economic benefits of the exchange of operational reserves exceed the economic costs of reduced exchanges in the wholesale market. This perspective is also supported by draft FG on Electricity Balancing, which explicitly allow for the reservation of inter-zonal capacity for balancing, provided that it is supported by a cost-benefit analysis (see chapter 3.1).

Overall, we therefore do not consider the need for reservation of inter-zonal capacity to be a principal disadvantage of this measure. However, it would certainly add to the complexity of implementation as discussed next.

Complexity and Costs of Implementation

In our view, the concept is fully compatible with the current target model for the electricity market in general and the FG on Electricity Balancing in particular. Still, it would require major efforts by the TSOs in terms of improving coordination and cooperation on a regional or potentially even European basis. Among others, it would be necessary to agree on a harmonised set of reserve products and to develop, agree on and implement common approaches, processes and IT systems as well as to amend the existing contractual and regulatory framework accordingly.

We note that many of these issues overlap with similar efforts, which will be required for implementing the regional exchange of balancing energy as required under the draft FG on Electricity Balancing. To a large extent, the corresponding complexity and costs will thus need to be dealt with anyhow, thus reducing the (incremental) cost of this measure. Nevertheless, due for instance to the diversity of the reserve and balancing products currently used by the European TSOs, we assume that implementing this measure would require considerable time.

Furthermore, one particular issue in this respect is that the European TSOs do not have a proven methodology for the regional dimensioning of operational reserves. Consequently, it would be necessary to develop, validate and agree on a corresponding methodology. Although we principally believe in the feasibility of a corresponding approach, this would require a very high level of coordination between the participating TSOs and countries, including agreement on actions and consequences in those cases where the use of operational reserves is unable to avoid system incidents. For these reasons, and due to the critical importance of sufficient operational reserves for system security, we assume that the corresponding discussions would be highly complex and hence time consuming.

7.3.3 Summary Assessment

As shown in Table 22 we believe that the regional sharing of operational reserves is feasible, as also illustrated for instance by the operation of corresponding schemes in the German and Nordic electricity markets today. We also assume that system reliability would remain stable (or even improve), provided that sufficient inter-zonal capacity is available. In addition, we have explained above why we believe that this measure would potentially render major economic benefits, both in terms of increased efficiency (CAPEX and OPEX) and increasing competition in the market for operational reserves. Finally, a fully integrated, or even European market, for operational reserves may promote transparency by providing clear price signals on the value and offering of operational reserves.

Naturally, these effects will also influence the distribution of welfare between different stakeholders in the market. More specifically, we would expect a redistribution of welfare from producers to consumers, due to decreasing costs of reserves, as well as between different countries, which may benefit from the overall savings to different degrees.

The main disadvantage of this approach would obviously be its complexity and the need to harmonise existing and/or develop new products, planning and operating philosophies as well as the associated market mechanisms, IT systems and regulations. Consequently, we would expect this measure to take significant time to implement. Similarly, this will also create additional costs for the adaption of market and operational processes, although we would expect these to be far smaller than the potential benefits mentioned above. Moreover, it is important to note that much of the associated complexity and costs will already arise in the context of the regional integration of the European balancing mechanisms, as mandated by the draft FG on Electricity Balancing.

Overall, we clearly regard this measure as both feasible and beneficial.

Table 22: Evaluation - Regional exchange of operational reserves

Criterion	**Evaluation[a] / Comments**	
Feasibility	**(+)**	Fully compatible with target model; Proven concept (e.g. Germany, Nordic countries)
Ensure reliability	**0**	No tangible changes compared to status quo
Efficiency (long term)	++	Potentially significant savings in both markets
Efficiency (short term)	++	Potential for substantial reduction of OPEX (cost-wise and due to increased competition)
Cost	**(-)**	Costs for adaption of market and operational processes (already required for exchange of balancing services)
Speed of implementation	-	Requires new operational and planning concepts, plus regulatory and commercial framework
Welfare distribution	**0**	No negative effects foreseen
Promotion of competition	+	Regional integration of reserve markets
Transparency	+	More transparent price signals on value and offering of operational reserves (at different locations)

[a] – Compared to status quo / current target arrangements

7.4 Coordination of Wholesale and Reserve Markets in the Electricity Sector

7.4.1 Rationale and Basic Description

In line with traditional practices for system operation, operational reserves in liberalised electricity markets are commonly procured on or even before the day-ahead. However, where operational reserves are procured in the short term, one can identify different approaches with regard to the relative timing of wholesale and reserve markets. In markets with decentralised scheduling, reserves are typically procured before the day-ahead spot market[60]. Conversely, in markets with centralised scheduling, operational reserves are often procured through (a sequence of) subsequent bidding rounds in the day-ahead (and intra-day) market, like for instance in Italy or Spain. Alternatively, markets with centralised scheduling may also apply a simultaneous clearing (co-optimisation) of energy and reserve markets like in the All-Ireland market.

As already discussed in several instances before, a strongly increasing penetration of fluctuating RES will lead to additional uncertainty due to forecast errors, which will require higher volumes of operational reserves to be held. Due to the forecast error, the production schedule of electricity from renewable sources and, hence, also from conventional generation may change substantially after the day-ahead market. Simultaneously, an improving RES forecast during the operating day will allow decreasing the volume of operational reserves to be held. In addition, the changing (planned) production by fluctuating RES will also influence the scheduled operation of other plants. Consequently, additional sources of operational reserves may become available during the day. As a result, the original volume and allocation of reserves, as decided on the day ahead, may no longer be optimally closer to real time.

These considerations suggest that the efficiency of power system operation, and indirectly also the gas market, may be improved by either deciding on the allocation of reserves at a later stage, or by allowing a revision of the original reserve schedule during the operating day. Assuming that a considerable share of reserves will be provided by gas-fired plants, any corresponding changes will also influence the gas market and may either increase or decrease the challenge of providing sufficient flexibility.

In the following section, we therefore discuss two different options with regard to the coordination of the reserve and wholesale markets:

- Option A: Intra-day procurement of reserves; or
- Option B: Intra-day 'adjustment market' for reserves.

Under Option 1, current practices would be replaced by the procurement of reserves at several intra-day gates. Similar to the concept of a pure intra-day mar-

[60] Since we are focusing on the daily balancing process, we do not consider the timing of advance contracting of operational reserves in this context, i.e. whether such reserves are procured on or before the day ahead.

ket discussed in section 7.2 above, each intra-day gate would effectively represent a separate short-term market for reserves that are limited to the time horizon of, for instance, the next one or more hours.

Under option 2, today's practice of contracting reserves in advance (e.g. on the day ahead[61]) would principally remain in place. In addition, several intra-day gates would be introduced where reserve providers would be invited to submit additional bids and offers. Offers would refer to the price at which service providers would be willing to make additional reserves available to the TSO, whilst bids would specify the price service providers would be willing to pay for cancelling their existing reserve commitments. The TSOs could then use these additional markets to revise and optimise the original allocation of reserve requirements to individual plants or portfolios for the remainder of the day or at least the next hours ahead. In addition, the TSO would also be able to release excess reserves, which are no longer required, as well as to procure additional reserves where necessary.

7.4.2 Impact assessment

General Benefits and Constraints

The main benefits of this approach are related to the reduction of the RES forecast error closer to real time. As indicated in Figure 32 (see page 93), the forecast error may decrease by some 75% between the day ahead and the last hour before real time. This reduction of forecast errors is often associated with a simultaneous variation in the expected production by fluctuating RES. In return, this will influence the planned production schedule of conventional generators. As a result, previously committed plants may now be able to provide operational reserves (at lower costs). Conversely, it is also possible that plants that are currently providing operational reserves may now represent the most efficient source of energy in the wholesale market. This would suggest shifting their current reserve obligations to other (more expensive) plants. With an increasing share of fluctuating RES, the original allocation of operational reserves on the day ahead may thus become increasingly 'inefficient' when approaching real time.

In addition, the RES forecast error may become the dominating factor for the dimensioning of operational reserves in power systems with a large share of fluctuating RES. This aspect is of limited relevance as long as a TSO limits itself to the procurement of operational reserves for the last minute and/or hour(s) before real time. Consequently, one could argue that it will be sufficient to restrict the provision of operational reserves accordingly, but to fully rely on the intra-day market otherwise. However, reserve requirements are not only influenced by the (residual) forecast error, but also by the planned production

[61] For the purpose of the analysis below, it is not relevant whether the advance contracting of reserves takes place on the day ahead or even earlier. For the sake of simplicity, we therefore consider the case of a day-ahead reserve market below.

of fluctuating RES[62]. Consequently, the TSOs might still remain with reserves that are no longer required, or be forced to procure excess reserves on the day ahead.

Moreover, in power systems with tight reserves and a substantial share of inflexible plants, it may be necessary to use plants with long start-up times (≥8 h) to ensure the availability of sufficient reserves in real time.[63] In these cases, generators may have no (or insufficient) incentives to start their corresponding plants for the potential provision of operational reserves in real time. For example, an independent power producer that has not sold any power in the day-ahead or intra-day market will have no incentives to start-up its plant.

In certain cases, this may lead to a fundamental conflict with regard to the deployment of less flexible generators. To benefit from improved forecast errors, reserves should ideally be procured as close to real time as possible, such as one hour before real time. Conversely, to ensure security, TSOs must have access to balancing services from plants that have to be started several hours in advance of real time. Apart from conventional coal and lignite fired plants, this also applies to less flexible CCGTs, which may have a start up time of between 2 and 4 hours. Similar to the case of an exclusive intra-day allocation of interzonal capacity, these observations represent a fundamental conflict between the desire to (re-) optimise the allocation of operational reserves as close to real time as possible, on the one hand, and the possible need to accommodate less flexible plants, on the other hand.

In the particular case of an exclusive intra-day contracting of reserves (Option A), this furthermore implies that reserves may have to be procured several hours before real time or, alternatively, that reserves from less flexible plants would have to be procured through a separate mechanism. In the former case, the potential benefits of this measure may be strongly reduced as the forecast errors does reduce in the last few hours before real time only. Conversely, a fragmentation of the reserve market into several parallel sessions could reduce the scope for competition.

Market Distortions Caused by Exclusive Intra-Day Contracting

Not all plants are equally suited for the provision of operational reserves. Furthermore, certain reserves can only be provided by plants that are synchronised with the power system and operate above their minimum stable level. As a consequence, reserve requirements lead to a different generation dispatch than in the theoretical cases of a market without reserves. For example, units with low variable costs may be forced to produce below their optimal output, in order to enable an increase of production. The loss of production will be compensated

[62] For instance when fluctuating RES are expected to produce at (or close) to their minimum output, it is no longer necessary to provide for the full volume of (positive) reserves as the potential shortfall of generation is limited to the current estimate of production. Similarly, the volume of negative reserves can be reduced where fluctuating RES are expected to produce at or close to their maximum output.

[63] See the example of warming reserves in the GB market.

by more expensive resources and prices in exporting zones and/or during peak hours will increase. Conversely, units with high variable costs may have to be started up and/or be required to increase their output, for instance in order to enable the provision of negative reserves (reduction of production) in real time. Again, resources with lower variable costs are replaced and prices in importing zones or during off-peak hours may further decrease.

As explained, these effects do not influence the generation dispatch as well, but they do also have an impact on prices in the wholesale market. As a general rule, operational reserves will generally increase prices especially during peak hours, whilst they may further depress prices during off-peak hours. Similarly, the provision of reserves will also influence the price differential between different market areas.

The case of an exclusive intra-day contracting of reserves (Option A) would thus create a structural mismatch between the day-ahead market, on the one hand, and the intra-day market, on the other hand. More precisely, prices in the intra-day market would be constrained by the provision of operational reserves, whilst the day-ahead spot market would be cleared without any corresponding constraints. As a result, both generation schedules and prices in the two markets would structurally differ from one another. Most importantly, prices in the day-spot market could be expected to be principally lower and subject to lower variations (over space and time) than in the intra-day market.[64]

Instead of fostering the link between the day-ahead and the intra-day market, Option A would thus create a structural distortion. This in turn would result in additional uncertainty for market participants, also for the use of gas-fired power plants and hence for the gas market. Moreover, it would effectively make it impossible to use the day-ahead market as a reference price for the intra-day and balancing markets, and vice versa.

Apart from these fundamental concerns, market players as well as the TSOs would also be confronted with the need to accommodate potentially significant changes in inter-zonal exchanges during the operating day. Depending on the timing of the intra-day reserve market(s), these may conflict with the scope of corresponding changes and applicable time limits. Moreover, they would in any case create additional complexity for intra-day congestion management (at a regional level). Finally, these effects would be further aggravated in the case of regional procurement of reserves (compare section 7.3 above).

[64] In theory, one might argue that generators will anticipate higher prices in the intra-day market and will hence withhold a certain volume of capacity from the day-ahead market, such that day-ahead and intra-day market prices would converge. This assumption would require generators to be able to estimate the volume and price of reserves they will sell to the TSO in the intra-day market with sufficient certainty. Especially in a market with a high share of fluctuating RES, however, both parameters will be subject to considerable uncertainty. Consequently, it appears reasonable to assume that generators would nevertheless try to optimise their generation schedule on the day-ahead market first, and then gain from additional opportunities in the day-ahead intra-day later on.

In our view, an exclusive intra-day contracting of reserves does therefore not represent an acceptable option. For the remainder of this section, we therefore discard this option and limit the discussion to Option B.

Feasibility and Value of an Intra-Day Adjustment Market for Reserves

In contrast to the exclusive intra-day contracting of operational reserves, the option of an 'intra-day adjustment market' for operational reserves (Option B) maintains the link between generation scheduling and prices in the day-ahead and intra-day market. We also believe that any resulting changes could be handled within the scope of the normal intra-day capacity allocation, although the variation of inter-zonal exchanges may increase. Similarly, we assume that this option is fully compatible with the draft FG on Electricity Balancing.

As a result, we believe that this option does not create any disadvantages for any stakeholders compared to the status quo. At the same time, this measure should make it possible to increase social welfare by allowing for the optimisation of reserve commitments against changing circumstances during the operating day.

However, it is clear that this option would not remove the potential inefficiencies of the initial day-ahead allocation of reserve commitments to different reserve providers. In this context, it is not clear whether there would be sufficient scope for competition in the additional intra-day market(s). As a consequence, it is possible that the economic benefits would be largely reaped by reserve providers, whilst the remaining benefits for the overall market would be minimal.

Moreover, we also acknowledge that the scope of the corresponding benefits depends on the choice between a unit- or portfolio-based reserve market, as well as on the distribution of available reserves between different market participants. We believe that the corresponding benefits would generally be larger in a unit-based reserve market as market participants were unable to adjust the allocation of reserve commitments to changing circumstances during the day. . Conversely, in a market with portfolio-based reserve commitments, reserve providers would be able to re-distribute their obligations to different plants or technologies as the situation evolves during the day. Consequently, the potential benefits of this measure can be expected to be considerably smaller in a market with portfolio-based reserve commitments.

Impact on Gas Market

For both options considered in this section, we would not expect any significant benefits for the gas market. In fact, the adjustment of reserve commitments during the day may create additional variations in the planned production schedule of gas-fired plants, although this is already possible in the case of portfolio-based reserve commitments today.

Similarly, we note that neither of the two options reduces the remaining uncertainty, with regard to real-time operation. In both cases, the dispatch of gas-fired plants remains subject to uncertainty on the possible activation of balancing energy, both from the two committed reserves and uncommitted capacity in the real-time balancing mechanism. Especially in decentralised markets, this uncertainty is further increased by the potential effects of self-scheduling.

7.4.3 Summary Assessment

Whilst we believe that, in principle, it would be possible to implement both options considered in this section 7.4, we consider that they would have a fundamentally different impact on economic efficiency. However, as explained above Option A, this may cause fundamental distortions between the day-ahead and intra-day markets. In our view, this effect can be expected to outweigh the potential benefits of deciding on the allocation of reserves closer to real time. As a consequence, we expect Option A to have a negative effect on economic efficiency, at least on the daily operation of the electricity (and gas) market. Depending on the timing of the intra-day reserve market and the treatment of less flexible plants with longer start-up times, this option may also create serious risks for system operation and hence impede reliability.

For these reasons, we do not believe that Option A represents a viable option.

Table 23: Evaluation - Coordination of electricity wholesale and reserve markets

Criterion	Option A	Option B	Evaluation[(a)] / Comments
Feasibility	(0)	+	No issues foreseen (Option B); need to tackle complexity for Option A
Ensure reliability	(-)	**0**	Increased uncertainty under Option A; no tangible changes under Option B
Efficiency (long term)	-	**0**	Market distortions in Option A; no tangible changes under Option B
Efficiency (short term)	--	**(+)**	Market distortions in Option A; potential cost reductions under option B
Cost	N/A	**(-)**	Cost for adaptation of market systems
Speed of implementation	N/A	**0**	Requires supplementing existing reserve markets by additional intra-day sessions
Welfare distribution	N/A	**?**	Distribution of benefits remains questionable
Promotion of competition	N/A	**0**	No tangible changes to status quo

Transparency	N/A	**0**	No tangible changes to status quo

[(a)] *– Compared to status quo / current target arrangements*

Conversely, Option B allows one to adjust the initial reserve allocation during the day and thereby offers the opportunity of optimising the generation dispatch to changing circumstances. As illustrated by Table 23 this may promote the efficiency of daily system and market operation, which may potentially result in significant savings for the overall electricity market. These benefits would, however, be reduced by the cost of introducing a sequence of intra-day sessions where market participants can both 'sell' and 'buy' reserve commitments. Moreover, the scope to which the overall economic impact of this measure will be positive therefore also depends on the need to consider less flexible plants with longer start-up times for the provision of operational reserves. Finally, it seems questionable to which extent consumers would be able to benefit from the associated savings, or whether these would be fully captured by producers.

On balance, we suggest that Option B deserves further attention as it may offer significant benefits in areas with a large share of fluctuating RES and a limited (or heterogeneous) supply of flexibility from conventional plants. Conversely, the scope for this option seems less convincing in other cases, i.e. in areas with a limited share of fluctuating RES and sufficient flexibility being available from other plants. Consequently, implementation of Option B may not be generally justified but would have to be assessed on a case-by-case basis for different regions.

7.5 Enforcement of Firm Exit Capacities for System-Critical Power Plants in the Gas Market

7.5.1 Rationale and Basic Description

One of the key responsibilities of TSOs in the gas and electricity and gas markets is to ensure the reliable operation of the network and power system, respectively. This aspect is especially important for the power sector as the reliable supply of electric power is commonly regarded as an essential good, which is critical for the entire economy.

In order to achieve this goal, the electricity sector often depends on an uninterrupted supply of natural gas to gas-fired power plants which provide energy and ancillary services to the power system. Any interruptions of gas supply may therefore endanger the security of the power system. In this context, it is important to note that supply interruptions in the gas market may not only result from unforeseen incidents. In addition, interruptible exit capacities may have a similar effect, i.e. where the offtake of gas-fired power plants that are supplied via interruptible exit capacities is interrupted.

These risks have been highlighted in recent cases in Germany during the last winter (see Text Box 2). Although the electricity TSOs were eventually able to maintain the reliability of the power system, the interruption of several gas-fired power plants aggravated an already critical situation. Moreover, similar cases have also been apparent in other regions. For instance in the United States, ERCOT had to instruct rolling back outs to residential customers on 2 February 2011[65]. Again, the problems were primarily caused by exogenous factors, i.e. extremely cold weather which caused a sudden increase in electricity demand, as well as wide-spread generator outages. Moreover, the situation became worse due to simultaneous problems in the gas market, which additionally resulted in the supply of natural gas to several power plants. Overall, a report conducted by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) found that "*Gas shortages were not a significant cause of the electric generator outages [...] [but] contributed to the problem*"[66].

Text Box 2: Contribution of gas supply interruptions to operational risks to the German power system in February 2012

In early February 2012, low temperatures led to a very high electricity demand, which forced the power system to rely on all available capacity in particular in the South of Germany. Similarly, the gas market experienced supply shortfalls in the South of the country as the very high demand coincided with an unexpected interruption of deliveries from Russia. As a result, the gas TSOs decided to either reduce or stop deliveries to several gas-fired plants, which had booked interruptible exit capacities only. Although the electricity TSOs were able to avoid black outs, the curtailment of generators by the gas TSOs further reduced reserve margins in the power system during this critical period.

These examples clearly show the importance of a secure delivery of gas to power plants for the power system. This is especially relevant for 'system-critical' plants that are vital for system and network operation in certain areas or during shortage situations, i.e. where the power system cannot rely on sufficient alternatives for these system-critical plants.

In a report investigating the events from February 2012[67], the Bundesnetzagentur has since suggested that so-called system-critical plants should be entitled (and obliged) to contract for firm exit capacities. In broad terms, this concept can be explained as follows:

- Electricity TSOs, or a similar neutral institution, are entitled to identify ‘system-critical’ power generation plants; and
- Gas network operators are obliged to make firm exit capacities available to system-critical plants.

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[65] See e.g. http://www.reuters.com/article/2011/02/02/us-ercot-rollingblackots-idUKTRE7116ZH20110202.

[66] Federal Energy Regulatory Commission and North American Electric Reliability Corporation. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - Causes and Recommendations. August 2011. p. 11

[67] Bundesnetzagentur. Bericht zum Zustand der leitungsgebundenen Energieversorgung im Winter 2011/12. Bonn. 03. Mai 2012

This concept builds upon the notion of system-critical plants. It would thus be necessary for the electricity TSOs to develop clear and transparent criteria for identifying corresponding plants. In practice, these may be related to a variety of different requirements, such as the provision of energy or reserves in congested areas, or the provision of reactive power control capabilities at specific locations. For the purpose of this study, however, it is suffice to simply define such plants as generating units that are critical for system and/or network operation in certain areas or during shortage situations.

The obligation on gas network operators to offer firm exit capacity to system-critical plants may potentially be combined with an obligation on the latter to also contract for firm capacity. Finally, a third and more radical approach would be to allow for new power plants connecting to the gas network only if they have contracted firm capacity at the gas TSO. In the following section, we therefore consider these different options.

7.5.2 Impact Assessment

Provided that sufficient firm exit capacities can be made available to system-critical plants, this measure will clearly improve the reliability of the power system. Most importantly, the power system would be protected from the risks of interruptible capacities in the gas market. Hence, the corresponding production capacities could be considered as truly stable, otherwise they would effectively have to be de-rated for the purpose of the TSO's security assessment.

The operation of gas-fired plants requires sufficient exit capacities to the plant's site, as well as access to sufficient volumes of commodity gas. In principle, it might therefore be necessary to make sure that system-critical plants are either able to buy, or have perhaps already bought, sufficient volumes of natural gas to withstand a sustained critical period[68]. From the isolated perspective of daily balancing, i.e. for the direct scope of this study, this issue can be largely considered as irrelevant. Namely, even if a generator was unable to buy the required amounts on the market, it might still be possible to accept the resulting shortfall of energy and have it financially settled as imbalances[69].

Risk of Inefficient Gas Network Extensions and Shift in Welfare from the Gas to the Electricity Market

In order to provide firm exit capacities to system-critical plants, network operators may be forced to invest into new capacity and expand the gas networks.

[68] Some of the gas shortages in Texas in February 2011 referred to above were caused by insufficient stocks of natural gas in local storage rather than insufficient transport capacities. Similarly, the developments in Germany in February 2012 also led to significant extractions out of the German underground storages.

[69] Nevertheless, this issue may be important in certain downstream parts of the gas network, which have to rely on local storage (potentially including in LNG terminals) to supply local demand during peak load situations. However, we consider this aspect to be beyond the scope of this study.

Depending on the location of the corresponding plants, this may potentially require substantial investments. Especially where the corresponding costs are not taken into account in the investment decision for a new plant, this may then result in considerable inefficiency. This will, for instance, be the case where users do not have to pay the full cost of network extensions when connecting a new plant to the gas network. Moreover, in the absence of effective coordination between the gas and electricity sector (compare section 0), neither the new connectee nor the gas and electricity TSOs are to be expected to consider the full costs of the new connection to both sectors. With the knowledge that the new plant can rely on firm capacity if necessary, the investor may further have limited incentives to investigate alternative locations.

In addition, it is important to note that existing plants may also be identified as system-critical plants. This creates additional uncertainty and complexity as it may be difficult to forecast corresponding future decisions, especially in the light of the expected far-ranging changes caused by the massive penetration of fluctuating RES. As a result, gas network operators may face an incentive to generally invest in the provision of firm capacity for all new power plants, which could create further inefficiencies.

Further issues arise where such investments are made only once the corresponding plants have been newly defined as system-critical by the electricity TSOs. Namely, unless gas network operators are able to make firm capacities available from other network users (see below), this may trigger additional investments without a new connection application from the generator. In this case, the corresponding cost would likely have to be socialised across all users of the gas network.

Overall, these considerations highlight that the gain in reliability for the electricity sector may come at the expense of significant inefficiencies in investment decisions. Moreover, the last argument also reveals that this measure may shift welfare from the gas market to the electricity market.

Potential Distortions in Gas (and Electricity) Markets

Apart from the potential shift of welfare between the gas and electricity sector, this measure also has several other potential draw-backs. To start with, a unilateral priority for power plants effectively represents a positive discrimination of electricity generators over other users in the gas market who may not enjoy a similar right to request firm capacity.

Secondly, in the case of existing power plants, it may become necessary to restrict the quality of existing capacity rights of other users, for instance by converting firm capacity to interruptible capacity or by imposing locational restrictions. In this case, it would furthermore be questionable to which extent such interventions into existing capacity contracts are feasible, or how the incumbent capacity holders would be compensated. Similarly, where system-critical plants are being supplied, based on interruptible capacities, this may effectively create different levels of interruptible consumers as the gas TSOs may be obliged to give priority to the former one in critical situations.

Further issues may arise with regard to the option of either allowing or obliging system-critical plants to contract for firm capacities. Firm capacity is generally sold at a premium to interruptible capacity. In the U.S. gas markets, it is thus often claimed that some power plants contract for interruptible capacity, in order to reduce costs. The lack of any obligation on system-critical plants to contract for firm capacity could thus create a potential moral hazard as they may expect that gas network operators will refrain from interruption in critical situations. Conversely, system-critical plants may face a disadvantage when being forced to contract for more expensive firm capacity, whilst other generators are able to use interruptible capacity at lower costs.

In practice, these issues may be less relevant as it seems reasonable to expect that most generators will generally have a preference for firm capacities. Moreover, the additional costs for firm capacity will usually be small in proportion to the overall costs of a gas-fired power plant. Nevertheless, these considerations do highlight potential implications, which would need to be taken into account when implementing a corresponding scheme.

Finally, another question requiring attention may be related to the treatment of existing plants. For example, newly defined system-critical plants may request a compensation for the additional costs of contracting for firm capacity. Likewise, it may be necessary to arrange for the case of a plant that is no longer identified as system-critical by the electricity TSO, as it could equally be argued that it would otherwise not have booked firm capacity.

7.5.3 Summary Assessment

As discussed in the previous section, this measure creates a fundamental conflict between the desire to increase the reliability of the electricity sector, on the one hand, and the risk of excess investments into the gas network, on the other hand. In the absence of any well functioning mechanism for the coordination of investments into both sectors (compare section 0 below), this measure may therefore cause potentially significant inefficiencies and high costs for the gas sector. Moreover, we have also noted the risk of a general shift of welfare from the electricity sector to the gas sector, which may induce further inefficiencies.

Despite these reservations, the nature of electricity as an essential good for developed economies implies that it may be beneficial to address the risks caused by system-critical power plants being supplied, on the basis of interruptible exit capacities. However, the discussion in this section indicates that any corresponding steps will require careful analysis, and that appropriate measures would be required to mitigate the risk of major inefficiencies.

Table 24: Evaluation - Firm exit capacities for system-critical power plants

Criterion	Evaluation[a] / Comments	
Feasibility	(+)	Principally yes, but detailed implementation unclear and difficult to extend to existing plants
Ensure reliability	++ (-)	Maximum reliability for power system but may create risks for new interruptible gas consumers
Efficiency (long term)	-	Risk of excess investments into gas network; Reduced incentives on electricity TSOs to expand electricity grid
Efficiency (short term)	0	No major impact expected
Cost	-	Low transaction costs, but risk of excessive investments
Speed of implementation	-	Requires potentially fundamental changes to existing contractual arrangements
Welfare distribution	?	Highly sensitive to actual design
Competition	?	Potential distortions between system-critical and other plants; shift of welfare from the gas to the electricity sector
Transparency	-	Determination of system-critical plants?

[a] – Compared to status quo / current target arrangements

7.6 Inter-Zonal Exchange of Gas Balancing Services by the TSOs

7.6.1 Rationale and Basic Description

Both the Framework Guidelines and the draft Network Code on Gas Balancing give priority to the use of standardised market products for balancing. Nevertheless, it seems reasonable to assume that TSOs may also need to use temporal products in order to deal with (increasing) fluctuations in the network.

The extent to which these products are traded outside the general wholesale market, there may be no direct arbitrage through the market. Furthermore, in certain cases, the time scale for some of these products may be shorter than the deadline for re-nominations. In both cases, it may therefore be beneficial or even necessary for the TSOs to engage in a direct exchange of balancing services between themselves, for instance in a similar way as envisaged for the regional integration of the balancing markets in the electricity sector (compare with section 3.1).

In short, the outline of a corresponding approach could be described as follows:

- Each TSO procures balancing services on the local market[70], i.e. in the local balancing zone;
- Each TSO makes all (or a part) of these balancing services available to other TSOs;
- If necessary, one TSO can 'buy' balancing services from another TSO who will purchase these balancing services in the local market, subject to the availability of sufficient inter-zonal capacity.

7.6.2 Impact Assessment

Regional Optimisation and Increased Competition

This measure principally supports the integration and optimisation of balancing mechanisms and resources at a regional level. Compared to the isolated optimisation of local systems of markets, it should thus principally promote economic efficiency. In addition, it could facilitate daily balancing for some TSOs as they may have gained access to additional volumes of balancing services, which they would not have without the inter-zonal exchange of balancing services.

This advantage has to be balanced against the risk of local flexibility being used elsewhere. Similar to the electricity market, certain safeguards might therefore be required, in order to ensure that each balancing zone still maintains sufficient flexibility locally. However, we do not consider this to be a substantial problem and believe that it would only require a limited reduction in the economic benefits, which could be implemented by regional optimisation.

A second advantage of this concept would be that the exchange of within-day products between TSOs increases the scope for competition as service providers cannot unduly differentiate their prices in different markets. This is particularly relevant where certain balancing services are not offered on a market basis or where they have to be procured in tight markets, noting that most of the European gas markets still suffer from limited competition. In this context, this measure could also create an important instrument for actually opening these markets and foster their integration with the overall wholesale market.

Need for Standardised Balancing Services

A regional exchange of balancing services essentially requires the definition and use of a (limited) set of standardised temporal products. This issue has been identified as one of the major challenges in the electricity sector. Nevertheless, in chapter 2 we have already argued that the dynamic requirements for different balancing services are far more important in the power sector, where even mi-

[70] With or without the participation of external service providers

nor differences may be relevant. Conversely, we assume that it would be considerably easier to agree on a set of standardised services in the gas sector, for instance in the form of (multi-) hourly products with an agreed activation (i.e. nomination) time. Furthermore, such standardisation is already required under the draft Network Code on Gas Balancing.

Separation between Balancing and Wholesale Market

Although the use of tailored balancing services has already been foreseen by the draft Network Code on Gas Balancing, it effectively creates two separate markets; i.e. the daily wholesale market which is based on daily or end-of-day products as well as a balancing market with temporal market products. Promoting the exchange of balancing services between TSOs might further strengthen this effect as it could reduce the incentives for TSOs to engage into the general wholesale market for within-day balancing.

In this sense, this measure potentially conflicts with the aim and intentions of the target model for gas, which opts for harmonised market-based balancing arrangements that reduce the role of TSOs on the gas market and where the bulk of the balancing actions are taken over by the network users on the hubs[71].

Potential Conflict with Re-Nomination Rights

The possibility for the bilateral exchange of balancing services between the TSOs would be subject to the availability of sufficient inter-zonal capacity as gas would need to be physically transported from one zone into the other. This in turn would imply that the TSOs would need to have access to firm inter-zonal capacity. Unless the inter-zonal exchange of balancing services was limited to the last one or two hours after the deadline for re-nominations, this concept would therefore conflict with the current set-up of unlimited re-nomination rights. As such, this concept might require major changes to the current regulatory framework, including the Network Code on Capacity Allocation Mechanisms.

Alternatively, the use of unused transmission capacity by the TSOs could be limited to an interruptible basis only. This would, however, limit the value of external balancing services because the TSOs had to weigh potential savings and/or additional flexibility against the risk of necessary counteractions to neutralise the use of balancing services if capacity was interrupted. Moreover, it might even create additional operational risks if the TSOs did not have access to equally 'fast' services locally.

Limited Benefits for Short-Term Balancing Actions

As mentioned above, the inter-zonal exchange of balancing services might conflict with the overall aim of integrating balancing actions into the wholesale market. One possible counter-measure might therefore be to limit correspond-

[71] Council European Energy Regulators, "CEER Vision for a European Gas Target Model - Conclusions Paper", Ref: C11-GWG-82-03, 1 December 2011.

ing transactions to very short-term products, e.g. with a nomination time of a maximum of one to three hours. In this case, the TSOs might furthermore be able to use inter-zonal capacity which has not been used by the market within the deadline for normal re-nominations.

Due to the short duration, the physical impact of corresponding actions would remain limited, however. In addition, the short activation time may conflict with the time required to physically adjust inter-zonal flows, in particular in case of larger volumes.

7.6.3 Summary Assessment

The exchange of balancing services by the TSOs would offer potential savings for the daily operation of the gas networks. In addition, it would also generally promote reliability by providing local TSOs with access to external sources of flexibility. Moreover, we would expect that implantation of this concept would be far simpler than in the electricity market as it should be possible to rely on a simple set of standardised products to a large degree.

At the same time, however, this measure would represent a clear diversion from the principal aim of integrating residual balancing with the overall gas market as far as possible. As such, the separation between the balancing and wholesale markets may also be detrimental to competition and transparency, although it equally promotes competition in otherwise tight markets.

On balance, this results in a mixed assessment such that we do not see a clear justification for this measure without any additional changes having to be made.

Table 25: Evaluation - Inter-zonal exchange of gas balancing services by TSOs

Criterion	Evaluation[a] / Comments	
Feasibility	+	No issues foreseen
Ensure reliability	+	TSOs gain access to additional flexibility
Efficiency (long term)	**0**	No major changes to status quo
Efficiency (short term)	**(+)**	Facilitates regional integration of temporal products, but expect limited benefits
Cost	+/-	Depending on complexity of chosen solution
Speed of implementation	+/-	Depending on complexity of chosen solution
Welfare distribution	**0**	No issues foreseen
Competition	-/+	Separates balancing and wholesale market; but may promote competition in tight markets
Transparency	-	Separate mechanism from general market

[a] – Compared to status quo / current target arrangements

7.7 Within-Day Products for Inter-Zonal Capacities in the Gas Market

7.7.1 Rationale and Basic Description

In the gas market, inter-zonal capacity rights are currently allocated in the form of constant daily capacity bands. This means that these capacity rights follow a flat structure until the end of the corresponding gas day, irrespective of any within-day obligations or the length of the balancing period. In accordance with the Network Code on Capacity Allocation Mechanisms, this principle also applied to within-day capacity products, which shall "from a start time within a particular Gas Day until the end of the same Gas Day"[72].

In contrast, actual exchanges at various borders have to be nominated on an hourly basis, allowing for the transfer of diurnal profiles. With an increasing share of electricity generated by fluctuating RES and an increasing share of

[72] ENTSOG: Network Code on Capacity Allocation Mechanisms – An ENTSOG Network Code for ACER review and Comitology Procedure. CAP0210-12. Art. 4.2. 6 March 2012

gas-fired power plants, the need for and the benefits of profiled inter-zonal exchanges can be expected to increase. Moreover, the need for such profiled exchanges may also grow due to potential within-day obligations, which would increase incentives for shippers to follow their offtake profile exactly. Similarly, the use of temporal balancing products, as foreseen by the draft Network Code on Gas Balancing, may also increase the demand for profiled exchanges.

In order to facilitate profiled exchanges, one option might be to proceed from simple capacity rights for (remainder of) the gas day to a series of within-day capacity rights, which can be independently booked and used. In broad terms, this concept would be based on splitting day-ahead and within-day capacities into a number (‘m’) blocks of (‘n’) consecutive hours. In an extreme form, this change might lead to the approach currently being used in the electricity sector where day-ahead and intra-day capacities can be booked for each individual hour.

Within this set-up, both individual capacity blocks and combined multiple capacity blocks could still be allocated simultaneously, subject to the objective of maximising the value of capacity. This way it would still be possible for shippers to book combined capacity products, up to a full daily band as today.

7.7.2 Impact Assessment

Benefits of Within-Day Capacity Products

Assuming that shippers are subject to within-day obligations[73], the use of within-day inter-zonal capacity products offers a number of advantages. Firstly, it facilitates self-balancing by shippers across multiple balancing zones who may find it easier to obtain capacity for individual blocks of hours even if the same capacity is fully used in other hours.

In those areas where TSOs (have to) use temporal products for within-day balancing, this concept furthermore facilitates the inter-zonal exchange of temporal balancing products. Moreover, and even more importantly, it supports an optimal use of external balancing services as shippers are able to differentiate prices by time blocks, thereby reflecting potential differences in (opportunity) cost during the day.

In parallel, a change towards within-day capacity products may increase the price elasticity of the market to variations of the supply-demand balance during the day as market prices can differ between different time blocks. This may also contribute to the reduction of cross-subsidies from consumers with a 'flat' offtake to consumers with 'high' diurnal profile. Differentiated price profiles may provide a premium to more flexible sources and hence reward those who contribute to supply of the diurnal profile. In combination with the use of temporal products by the TSOs, it may thus potentially also support the market-based pricing of within-day obligations where those apply.

[73] In the context of imbalance settlement

In this context, we finally note that this concept is fully compatible with the procurement of balancing gas through the wholesale market. Moreover, it does not create any fundamental conflicts with current arrangements as daily capacity can always be construed as combination of multiple block products.

Limitations and Requirements

As mentioned before, the potential advantages described above basically apply to balancing zones where shippers are subject to within-day obligations and/or where TSOs rely on the use of temporal products for within-day balancing. Conversely, the application of within-day capacity products does not seem to offer any tangible value between markets with full daily balancing and without a tangible need for the use of temporal products for balancing. In other words, within-day products for inter-zonal capacity do only add value in balancing zones that face difficulties in enabling full daily balancing for all users.

Secondly, this measure obviously requires nominations with at least the same time resolution as the underlying capacity products, most likely in the form of separate values for each individual hour. Although corresponding arrangements are already in place in many gas markets today, this measure would therefore require a fundamental change of the current regulations and systems for daily nominations in other markets. This would be the case, however, in those balancing zones which may need to switch to within-day obligations. This observation therefore reinforces the earlier comment that this measure is compatible with markets with within-day obligations, whilst it seems less suited for balancing zones with 'unlimited' daily balancing.

7.7.3 Summary Assessment

As already discussed, the use of within-day products for inter-zonal capacities potentially offers significant benefits. However, this clear positive assessment is subject to the condition that shippers in the corresponding balancing zones are subject to within-day obligations and/or that TSOs have to rely on temporal products for within-day balancing. Conversely, there seems to be little scope for this measure in other markets. Consequently, it appears that the value of this concept strongly depends on the market(s) in question.

Table 26: Evaluation - Within-day products for inter-zonal capacities in the gas market

Criterion	Evaluation[(a)] / Comments	
Feasibility	(+)	No issues (provided that hourly nominations are used)
Ensure reliability	+	Facilitates exchange of temporal products
Efficiency (long term)	0	No major changes to status quo
Efficiency (short term)	++	Facilitates regional integration with regard to self balancing and exchange of temporal products; Potentially supports market-based pricing of within-day obligations
Cost	(-)	Requires adjustment of systems for day-ahead/within-day capacity allocation and use as well as use of hourly nominations
Speed of implementation	+	Minor adjustments to evolving arrangements for capacity allocation, provided that hourly nominations are used already
Welfare distribution	+	No negative impact but increase of overall welfare
Competition	+	Promotes competition through regional integration
Transparency	+	Improves visibility of relevant system constraints

[(a)] – Compared to status quo / current target arrangements

7.8 Tradeable Within-Day Flexibility Products in the Gas Market

7.8.1 Rationale and Basic Description

As explained in chapter 3.2, the currently proposed Framework Guidelines on Gas Balancing and the Network Code generally focus on the use of daily balancing in the gas market. At the same time, an increasing role of gas-fired power plants for within-day balancing in the power sector are likely to increase the within-day variations in the gas sector. Against this background, it may become necessary to introduce within-day obligations at least for volatile gas consumers in different parts of the European gas market.

Secondly, a significant share of balancing actions in the electricity market takes place within the last 15 to 60 minutes before real-time only. Conversely, most gas TSOs apply re-nomination lead times of around two hours. This discrepancy creates a clear commercial risk for operators of gas-fired power plants. Since they are unable to change their nominations in the gas market when being called to provide balancing energy in the electricity market, they are exposed to an increasing risk of their imbalances violating the permitted variations in a system with within-day obligations.

Since it is impossible for shippers to hedge themselves against the corresponding risks in the market, the provision of reserves and balancing energy in the electricity market may therefore create significant commercial risks for the corresponding plants. Operators of gas-fired power plants will have to factor these risks into their bids and offer them to the balancing market in the electricity sector. Unless potential penalties for the violation of within-day obligations represented the underlying cost exactly, the current arrangements therefore create a considerable risk of excess costs for the electricity market. Depending on the design of within-day obligations, such restrictions may even reduce incentives for timely shipper balancing, i.e. once the corresponding deviations are subject to corresponding penalties.

One possible counter-measure might be to simply reduce the deadline for re-nominations in the gas market. However, the current deadlines are not only the result of administrative processes, but equally, and more importantly, reflect the need for the gas network operators to prepare or align the operation of the gas transmission system[74]. Although some TSOs are allowing network users to apply shorter re-nomination lead times, such as GTS from the Netherlands, such exceptions are limited to specific cross-border points under certain conditions. Also taking into account the inherent inertia of the gas network, it therefore seems reasonable to assume that it will generally take more time to physically implement re-nominations in the gas market than the balancing actions in the electricity markets.

In order to deal with this issue and avoid undue risks for gas-fired power plants, it may therefore be necessary to introduce an instrument, which allows shippers to hedge themselves against the corresponding risks. Indeed, offering a well-designed within-day flexibility product might alleviate some of these risks for network users supplying gas-fired power plants.

In the following section, we therefore consider two different approaches, in both cases assuming that shippers are generally subject to within-day obligations:

- Option A:Offering of within-day flexibility at a fixed price; and
- Option B: Market-based offering of within-day flexibility as a tradable product.

[74] For example, large deviations between the originally nominated volumes and the re-nominated volumes could require the TSO to quickly ramp-up compressor stations as gas needs to move physically from the entry point to the exit point even if the network user is in perfect balance.

In both cases, the TSOs would market a separate within-day flexibility product, which could for instance take the form of a cumulative (within-day) ance[75]. This product could either be sold for a fixed fee (Option A) or by means of a market-based mechanism (Option B), i.e. an auction. In the latter case, we furthermore assume that shippers would be allowed trading of this product in a secondary market.

Under both options, the TSO would first determine the basic volume of additional within-day flexibility that can be made available to network users on a firm basis. This volume would then be sold to shippers either at fixed tariffs (Option A) or by means of a market mechanism (Option B). In addition, the TSO might make further volumes of this flexibility product available on, for instance, a daily basis based on the expected state of the network. To facilitate secondary trading under Option B, these volumes could for instance be offered on an open platform, which also provides for the offering of flexibility by network users. This would allow network users with excess flexibility to sell the corresponding flexibility to other network users.

We note that these approaches are partially similar to some products, which have been offered by some European TSOs, such as the flexibility product offered by GRTgaz in France (compare Text Box 3). In the following, however, we refrain analysing any specific examples, but focus on the three generic models listed above.

[75] Please note that this product is conceptually different from the 'Linepack Flexibility Service' as specified by the draft Network Code on Gas Balancing. Indeed, the product described in the draft Network Code is an "end-of-day" service, which mainly allows network users to shift their cumulative imbalance from one day to the next.

Text Box 3: Flexibility products offered by French TSO GRTgaz

The French TSO GRTgaz offers a flexibility product for highly modulated end consumers. By definition, highly modulated sites show large fluctuations during the gas day. A highly modulated site is defined as a site that shows a daily modulated volume greater than 0.8 GWh/day, where the daily modulated volume is defined as half of the sum of the absolute hourly differences between the recorded hourly consumption and the average daily consumption. In France, this currently applies to all power plants, but may also cover other sectors, such as district heating and chemical industry.

The price of the intraday flexibility service is broken down into two elements: i) the total modulated daily volume, and ii) the maximum hourly flow rate amplitude recorded during the gas day (i.e. the difference between the maximum and minimum hourly consumption).

The flexibility service is accompanied by intensive communication between a highly-modulated site and GRTgaz. The operational procedures are primarily applied to deal with short-term uncertainties in the gas demand. For example, the highly-modulated site has to declare three days ahead its expected hourly consumption schedule. GRTgaz will process these schedules and assess their feasibility. GRTgaz will communicate the results of this assessment for each highly-modulated site and inform the shipper whether or not the site should apply a schedule reduction factor. The schedule reduction factor is set in such a way that the network can accommodate the eventual gas off take. Where necessary, highly-modulated sites have to provide a modified hourly schedule. Also, in case the hourly consumption is likely to vary by more than +/- 10% of its subscribed hourly capacity, the site is obliged to notify GRTgaz of its new hourly consumption profile.

7.8.2 Impact Assessment

Potential Promotion of Economic Efficiency and Market-Based Balancing in Gas and Electricity

Both options provide network users with an instrument to balance diurnal variations and/or temporary imbalances in their portfolio. From the perspective of gas-fired power plants, this would principally allow network users hedging themselves against the risk of providing balancing energy to the power system. Operators of gas-fired power plants would thus no longer be exposed to risks reflecting administrative penalties[76] rather than the true (opportunity) cost of diurnal flexibility when offering balancing energy to the electricity market.

In principle, this effect could also be reached by simply granting all network users some additional flexibility, for instance in the form of a cumulative tolerance. The provision of free flexibility may result in cross-subsidies between different network users, however, i.e. where such network users have a different demand for flexibility and where this flexibility represents a scarce product. Although some gas networks have sufficient diurnal flexibility today, the provision of line pack (and other sources of flexibility) principally causes additional costs to the network (compare chapter 6). When providing this flexibility to all users as part of the overall transport service, network users who do not need this flexibility are effectively cross-subsidising other network users who depend

[76] On the violation of within-day obligations in the gas market

on this flexibility[77]. In this respect, network users with a flat off-take cross-subsidise network users that have more volatile off-take patterns. Implicitly, this issue also relates to the interaction between the gas and electricity markets as a low price for within-day flexibility may result in a cross-subsidisation of the electricity market by the gas market, and vice versa.

By separating within-day flexibility as a separate product, it is principally possible to avoid or at least mitigate this problem. Namely network users without the need for additional flexibility would pay less than other network users who require additional flexibility. Moreover, this approach can also be expected to result in a more efficient allocation of available line pack to individual network users as shippers will additionally purchase this product only to the extent that the value of within-day flexibility exceeds their own (opportunity) cost.

Ideally, the price for the additional within-day flexibility should therefore reflect the true economic costs of this product. However, at least in the case of line pack, this service effectively represents part of a bundled product (i.e. peak capacity and flexibility) such that the distribution of total cost to both sub-products will always remain arbitrary to some extent. Instead of relying on the cost of this service, it may thus be economically more efficient to base the allocation of this product on its market value, i.e. by selling it through a market-based mechanism (Option B). Although this approach may not necessarily ensure full cost recovery, it would at least theoretically result in an optimal allocation of available flexibility to individual network users.

This process would obviously be facilitated if within-day flexibility was organised as a tradable product that can be freely traded between different parties in a secondary market. Assuming that operators of gas-fired plants will factor in the value of within-day flexibility in their offers for ancillary and balancing services to the electricity market, Option B would furthermore increase the scope for an optimal allocation of available flexibility in the gas network between the electricity sector and other users. Indirectly, this option would thus also promote market-based balancing in both sectors in general.

Operational Benefits for Gas TSOs

Besides the apparent advantages for network users and economic efficiency, the concept of a within-day flexibility product also offers advantages for the gas TSOs. Firstly, the daily demand or price for flexibility can provide an indication of the diurnal variations to be expected. In addition, a within-day flexibility product could principally be designed as a locational product which better reflects the network constraints in certain areas or subsystems of the gas trans-

[77] See also Keyaerts, N., Hallack, M., Glachant, J.M., and W. D'haeseleer. Gas market distorting effects of imbalanced gas balancing rules: Inefficient regulation of pipeline flexibility. TME WORKING PAPER - Energy and Environment. WP EN2010-10. KULeuven Energy Institute. Last update: December 10

mission system, such as in the case of the flexibility product developed by GRTgaz in France (see Text Box 3 above)[78].

Risk of Artificial Congestion and Dysfunctional Markets

Unfortunately, there are reasons to believe that the effectiveness and efficiency of both options may be less than they appear at first sight. Assuming that within-day flexibility represents a scarce product and that it is allocated for longer periods (i.e. not only on a day-ahead basis), risk aversion of network users may create artificial scarcity.[79] Introduction of a corresponding product could thus result in incentives for an inefficient extension of the network.

Obviously, this risk would be particularly relevant if this product was allocated under a fixed tariff and if the tariff was lower than the market value of within-day flexibility. The option (B) of a market-based mechanism would ideally avoid this problem, although it might still occur due to different risk perceptions and uncertainty. Moreover, the efficiency of this measure might also suffer from a lack of liquidity in potential the secondary market as illustrated by experiences to date with the secondary trading of transmission capacity in both the gas and electricity markets.

Indeed, liquidity in this market might be limited by the fact that the market value of within-day flexibility will be different from zero only cases of shortages. Conversely, and as also illustrated for instance by the recent experiences with the day-ahead auctioning of inter-zonal capacity in the German gas market, the price could be expected to be (close to) zero whenever there were sufficient volumes of flexibility available in the system.

In this context, we furthermore note that a corresponding situation would appear to be relatively likely as the volume of line pack is negatively correlated with the transport volume in a given grid. For this reason, the volume of flexibility in most North-Western European countries strongly depends on outside temperatures since a large part of gas is used for heating purposes. In cases of high demand, the amount of line pack in the system this is small, even if demand matches supply perfectly. As a consequence, one can often identify a typical relationship between the amount of line pack in the system and outside temperatures as shown in Figure 33 below.

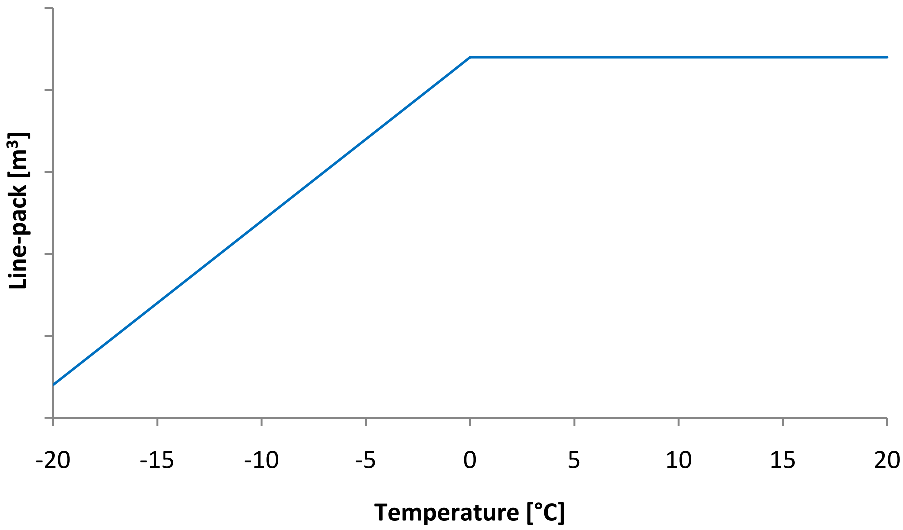
Apart from temperature dependence, similar effects may also be expected with regard to the impact of fluctuating RES on the production from gas-fired plants. Despite the generally volatile production by fluctuating RES, daily variations will usually be much smaller, whilst the extremes will only occur on a rela-

[78] Each day, GRTgaz specifies the minimum re-nomination lead time for the next day for nine different subzones in the network. This re-nomination lead time, referred to as notice period, is calculated by computer simulations on a day-ahead basis and is applied to each site in a specific subzone of the network. This lead time effectively represents a measure of the within-day flexibility provided to different parts of the network.

[79] Please note this aspect is very similar to the issue of contractual congestion for transmission capacity.

tively small amount of days. Simultaneously, it would probably still be necessary to ensure the sufficient supplies to gas-fired plants during such extremes as alternative means of flexibility will often be significantly more expensive.

Figure 33: Stylised relationship between available line pack and outside temperatures in a gas network with substantial heating demand



Overall, the market value of within-day flexibility might thus remain very low (or constant) for most of the time. Under these circumstances, a liquid market would appear less likely to develop, which in turn would undermine the scope for the efficient functioning of this mechanism.

Finally, the efficient functioning of this instrument may also be limited by the locational nature of line pack, or other means of within-day flexibility. Due to the physics of gas transport, any immediate variations of the supply-demand balance in a certain part of a gas network will necessarily have to be balanced by 'local' sources, such as line pack or external sources (production, storage) that are located within a limited distance. Consequently, it would either be necessary to provide for a considerable share of (excess) flexibility in the network, or to construe within-day flexibility as a locational product. In the latter case, however, this product could only be traded in a relatively small local market where liquidity is likely to remain even more limited.

Fundamental Conflict between Long-Term and Short-Term Impact of Within-Day Flexibility Products

The within-day flexibility products suffer from a fundamental conflict between long-term and short-term commitments to the products. One could argue that there is an inherent incompatibility between the long-term and short-term commitments that gas-fired power plant operators need to make as they are either forced to purchase the full flexibility on a long-term basis, or take the risks and accept the potential constraints on individual days. Both of these approaches seem to suffer from several concerns.

In case within-day flexibility products are offered on a long-term basis, generators would be forced to pay for flexibility they may only need for specific days. One might argue that the contracting of within-day flexibility represents an 'insurance' against restrictions on specific days. However, due to the current lack of long-term arrangements for rewarding flexibility in the electricity sector, it would be difficult for generators to properly reflect the corresponding 'insurance premium' in their offers for ancillary services. Moreover, generators that have bought within-day flexibility in the long term would be neutralised against daily variations of physically available flexibility. As such, they would appear less likely to reflect the true daily market value in their offers to the power system.

Alternatively, one could promote the opposite concept of offering flexibility products on a short-term basis. As mentioned before, when flexibility is only offered as a short-term product, generators face the risk of potential constraints on individual days. These constraints might lead to a situation where the power system does not have enough flexibility available, resulting in additional risks for power system planning and operations. Such a situation would be similar to the case of interruptible capacities and lead to the issues already discussed in the context of section 7.5 above.

7.8.3 Summary Assessment

As indicated by Table 27 below, we believe that Option A could be implemented fairly easily and at limited costs and complexity. Nevertheless, it seems uncertain whether the offering of within-day flexibility at a fixed price would have a tangible impact on efficiency and the distribution of welfare, or whether its positive effects would be undermined by artificial scarcity. To some extent, the performance of this measure furthermore depends on the 'base flexibility' available to shippers, either explicitly or in the form of less stringent within-day obligations. On balance, the case for this measure appears to be questionable.

Similarly, we perceive a mixed assessment with regard to the second option of a tradable product for within-day flexibility (Option B). Theoretically, this option may substantially contribute to the optimal allocation of available flexibility to individual network users and the efficiency of daily network operations. Moreover, the market value for flexibility may provide gas and electricity TSOs with an indication of critical situations caused by a shortage of flexibility in the gas network. At the same time, however, this may also cause additional risks for power system operation, i.e. where power plants are unable to obtain sufficient within-day flexibility. Conversely, if gas-fired power plants were still allowed to violate within-day obligations, this scheme might be subject to gaming.

The potential benefits of Option B are based on the assumption of a sufficiently liquid market for within-day flexibility. As explained above, however, there are several reasons as to why this assumption may not hold in practice, or as to why the market may not work as efficiently as desired. Conversely, a dysfunctional market may even have adverse effects on efficiency, welfare distribution and competition. In any case, this concept would require a new set of products, market mechanisms, rules and IT systems, which will take some time and cost to for development and implementation.

Table 27: Evaluation - Within-Day Flexibility Products in the Gas Market

Criterion	Option A	Option B	Evaluation[(a)] / Comments
Feasibility	+	(-)	Scope for sufficiently liquid market unclear
Ensure reliability	(-)	+/-	Market-based product may signal system risks to TSOs (Option B) Additional risks for electricity balancing if gas-fired plants are unable to obtain sufficient flexibility
Efficiency (long term)	0	(+)	Market price for flexibility may signal need for network extension
Efficiency (short term)	(+)	(++)	Supports optimal allocation and use of available flexibility; Benefits may be limited by complexity and practical issues (Option B); May cause artificial scarcity
Cost	0	(-)	Option B requires new products, regulatory and commercial framework
Speed of implementation	0	(-)	Option B requires new products, regulatory and commercial framework
Welfare distribution	(-)	+	Avoids / Reduces cross-subsidies
Promotion of competition	0	+/-	hanges expected
Transparency	0	+/-	Benefits of improved transparency on actual system status vs. additional complexity (Option B)

(a) – Compared to status quo / current target arrangements

Despite its theoretical advantages, we are therefore not fully convinced of Option B, in particular with regard to the specific objectives of this Study. Indeed, we note that the main potential benefit of this concept, i.e. the market-based allocation and pricing of within-day flexibility, is in an inherent conflict with the aim of ensuring sufficient flexibility for power system operation (compare with section 7.5). For these reasons, we have not included this option in the list of recommended measures presented in chapter 7.10 below.

7.9 Network Planning and Operations

7.9.1 Coordinated Network Planning

Gas-fired plants are expected to become one of the primary drivers for demand in the gas market and at the same time a critical source of back-up capacity and/or flexibility for the electricity market. This development will increase the mutual dependence between both sectors with regard to the location of new power generation sources and/or gas consumers as well as requirements for transport capacity and the provision of flexibility.

The location of new gas-fired power plants will have a substantial impact on the requirements for network expansion in both sectors. Conversely, any decisions on the location of new plants should ideally also take into account the capabilities and constraints of both the electricity and gas networks. Consequently, the coordinated planning of network extensions (and user connections) may potentially allow for significant savings by avoiding and/or optimising investments. In order to reach these goals, electricity and gas network operators should ideally plan the re-design and expansion of the gas and electricity networks in a coordinated manner, in order to best adapt the network infrastructure to future challenges caused by an increasing penetration from fluctuating RES.

Ideally, this would involve an integrated approach whereby all possible options for the gas and electricity infrastructure were assessed and optimised though a single integrated mechanism. However, this ideal solution might be difficult to implement in practice, also with regard to the parallel need for regional coordination within both sectors. At a minimum, however, gas and electricity TSOs should strive to:

- Mutually provide relevant information to each other, for instance on expected demand, potential constraints for the supply/demand of specific sites or regions, the timing of investments etc.;
- Coordinate the timing of network investments.

Apart from the network infrastructure itself, this process should also ideally cover the location of new generation / production, LNG and storage capacities etc. Nevertheless, due to the principle of unbundling, the corresponding plans are beyond the authority of the TSOs and are thus difficult to enforce in the current regulatory framework, in particular in those markets where network tariffs do not provide for any direct restrictions and/or locational signals.

As illustrated by Table 28 we believe that coordinated network planning may potentially render major economic benefits in terms of improved investments. In addition, coordinated network planning is likely to improve reliability, whilst the cost of this measure would be largely limited to additional information exchange. However, we also acknowledge that implementation of this concept may be a very time-consuming process, not the least due to the need for agreement on relevant methods, assessment criteria and decisions on a regional or even European level. Nevertheless, this concept clearly appears to be a highly promising option.

In principle, network investments should ideally be coordinated and optimised at a European level. However, a pan-European approach might result in excessive complexity. Conversely, many of the key questions, like the local siting of new generations, will have a limited impact on a regional or even the European level. Consequently, we do only see limited benefits for a centralised approach. Instead, it appears that most of the synergies could also be implemented through a regional approach by different network operators involved.

Table 28: Evaluation - Coordinated network planning

Criterion	**Evaluation[a] / Comments**	
Feasibility	+	No issues foreseen
Ensure reliability	+	Improves planning process in both sectors
Efficiency (long term)	++	May provide major savings
Efficiency (short term)	**N/A**	Minor impacts
Cost	+	Efforts largely limited to information exchange
Speed of implementation	**(-)**	Implementation expected to be time consuming
Welfare distribution	**N/A**	No tangible impact
Competition	**N/A**	No tangible impact
Transparency	**N/A**	No tangible impact

[a] – Compared to status quo / current target arrangements

7.9.2 Coordinated Operational Planning

As mentioned above, the mutual impacts between the gas and electricity sector are expected to grow in the future. Moreover, recent events in Germany and the U.S. (compare section 7.5) have clearly shown that incidents in one sector may have a serious effect on the other sector. In addition, gas and electricity operators do not commonly 'understand each other', in particular when it comes to the physical background, technical restrictions (network operation, energy flows, and infrastructure), market rules and the interplay between these different elements.

Similar to the case of network planning discussed above, it appears highly desirable to provide for (improved) coordination between gas and electricity TSOs with regard to operational planning and real time operations. Apart from an increased efficiency of the combined operation of both systems, this concept would, in particular, promote reliability as it would allow one to identify them with potential risks and incidents at an early stage and dealing with them in a coordinated manner. Indeed, potential risks to the reliability of gas pipeline and power system operations were the primary reasons why the North American Electric Reliability Council (NERC) set up a dedicated task force in 2002, which ultimately proposed a total of 7 different recommendations mainly aimed at the coordination of operational planning (see Text Box 4).

In our view, the key aspect of coordinated operational planning would be the mutual information exchange across different time horizons, ranging from at least a few days ahead to real time. Among others, this information exchange may cover expected supply / demand at system and local level, maintenance schedules, production schedules, local constraints, and the establishment of operational communication routines. It may also be extended to mutual security / impact assessment of relevant outages. Ideally, this process should also cover earlier processes, such as maintenance scheduling, and should comprise also other preventive measures, including the establishment of emergency protocols.

With regard to the particular scope of this study, one very important aspect would probably be the exchange of RES forecasts and their expected impact on production and reserve levels (and the associated geographical distribution) in the power system. Based on this information, the gas TSOs would be able to better assess the potential need for short-term flexibility and optimise the line pack of the gas network in anticipation of possible developments during the day (compare also section 7.9.3 below). In turn, the gas TSOs should then be able to inform their partners on the electricity side about potential constraints to the gas supply for individual power plants.

As also identified by the GEITF study in the U.S., these processes would probably benefit from cross-sectoral training of operators and/or planners, in order to provide them with a minimum understanding of the other sector.

Text Box 4: Gas and electricity interdependencies in the US

In October 2002, the North American Electric Reliability Council (NERC) decided that interdependencies between gas pipeline operations and planning and electric generation operations and planning could be a reliability issue. In order to address these reliability concerns associated with the dependence of electricity generation on natural gas, the Gas/Electricity Interdependency Task Force (GEITF) was formed. The primary goal of the Gas/Electricity Interdependency Task Force was to determine the relationship between gas pipeline system operations and planning and electric generation operations and planning. In addition to this, the task force was also envisaged to recommend possible measures to mitigate any negative reliability impacts for any such interdependency between the two industries.

After the process, the GEITF devised a list of seven recommendations which the NERC could consider to mitigate any reliability impacts from the interdependency between the gas industry and the electric industry. These seven recommendations were:

1. NERC Regions should include in their regional assessment program a review of the impact of any fuel transportation infrastructure / interruption that could adversely impact electric system reliability.
2. NERC reliability coordinators or their delegates, subject to appropriate treatment of commercially sensitive information, should develop regular, real time communications with pipeline operators about disturbances that could adversely impact the reliability of either the electric systems or the gas pipeline.
3. For planning purposes, gas pipeline outages that could have an adverse impact on the reliability of the electric systems must be coordinated with the electric industry so that plans to mitigate any impacts to the electric systems may be developed.
4. NERC should develop a reliability standard relating fuel infrastructure reliability to resource adequacy.
5. NERC should include analysis of fuel infrastructure contingencies that could adversely impact the reliability of the electric systems in the NERC planning standards.
6. NERC should establish a monitoring system that tracks fuel infrastructure contingencies that have, or could have, an adverse impact on electric system reliability.
7. NERC should, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

The outcomes of the GEITF study lead to FERC Order 698, which was issued on June 25, 2007. Order No. 698 includes new standards defined by the Wholesale Gas Quadrant (WGQ) and the Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Boards (NAESB). These standards require interstate pipelines and power plant operators, TSOs and independent balancing authorities and regional reliability coordinators to establish communication procedures aimed at improving the communications for the coordination of gas transportation scheduling and the operations of gas-fired generators.

Source: Gas/Electricity Interdependencies and Recommendations - Gas/Electricity Interdependency Task Force of the NERC Planning Committee, June 15, 2004

Since this measure is mainly based on communication and information exchange between different TSOs, we expect that significant improvements could already be achieved quite quickly and at limited cost. Conversely, coordinated operational planning may not only render economic benefits but, most importantly, would furthermore contribute to reliability in both sectors. As such, we clearly regard this as a potential priority measure.

Although the scope for coordination basically applies on a universal scale, we assume that much of the relevant information will be of a more local nature, or at least require sufficient knowledge of the local situation and constraints. Examples include limitations to within-day flexibility in the gas network or stability issues in the power system. For these reasons, we believe that the emphasis should be on improving the coordination between TSOs on a national or regional level, whilst we see limited benefits in a centralised approach on a European level.

Table 29: Evaluation - Coordinated operational planning

Criterion	Evaluation[(a)] / Comments	
Feasibility	+	No issues foreseen
Ensure reliability	++	Improves planning process in both sectors
Efficiency (long term)	**0**	Minor impacts
Efficiency (short term)	+	May provide major savings
Cost	+	Efforts largely limited to information exchange
Speed of implementation	+	Improved communication and training
Welfare distribution	**N/A**	No tangible impact
Competition	**N/A**	No tangible impact
Transparency	**N/A**	No tangible impact

[(a)] *– Compared to status quo / current target arrangements*

7.9.3 Improved Line Pack Management

The extent to which gas network operators actively manage available line pack varies considerable across different European countries. At the same time, an optimal use of available line pack will become increasingly important in a gas network with limited flexibility. Among others, this may be the case in regions with a combination of an increasing penetration of fluctuating RES and a high share of gas-fired power plants. In such systems, an optimal use of line pack may be essential for maximising available flexibility whilst limiting the overall costs to the network. Consequently, we expect that further synergies between gas and electricity balancing could be implemented by improving line pack management.

As mentioned before, the availability and use of line pack competes with the use of a pipeline for transport purposes. We therefore assume that potential improvements would need to focus on improved forecasts on the current and expected need for both services, in order to enable an informed decision on the optimal use of available flexibility. In this sense, this measure therefore is also closely related to the previous one (coordinated operational planning) as the expected need for line pack may for instance be influenced by RES forecasts. Due to the locational nature of line pack, such information may also be required at a sufficiently high level of geographical resolution, similar to the determination of within-day flexibility in France (compare Text Box 3 on p. 121).

In practice, this option would probably be a combination of improved information on the current and expected status of the network and relevant injections and offtakes, as well as tools for determining available line pack in different parts of the network under different assumptions.

Table 30: Evaluation – Improved line pack management

Criterion	Evaluation[a] / Comments	
Feasibility	+	No issues foreseen
Ensure reliability	+	Enables more optimal use of available flexibility in the gas network
Efficiency (long term)	(+)	May avoid investments into additional flexibility
Efficiency (short term)	+	Enables more optimal use of available flexibility in the gas network
Cost	+	Efforts largely limited to information exchange
Speed of implementation	(+)	Need to develop required tools
Welfare distribution	**N/A**	No tangible impact
Competition	**N/A**	No tangible impact
Transparency	(+)	Provides network users within better understanding of critical situations (provided that information is published)

[a] – *Compared to status quo / current target arrangements*

7.10 Summary of Proposed Design Elements

Based on the assessment of each individual measure above, Table 31 presents a summary of those measures, which we propose to pursue with the aim of exploiting the synergies for gas and electricity balancing as identified above. To start with, there are four different priority measures, which in our view should be pursued in any case. Apart from the regional sharing of operational reserves in the electricity sector, these include the coordination of network and operational planning between gas and electricity TSOs as well as improved line pack management in the gas sector. With the exception of network planning, these measures are therefore mainly related to the daily balancing process, whilst they would not directly influence the need for investments. However, we also note that one would be able to exploit the full benefits of coordinated network planning only if this measure was supported by suitable locational signals to market participants, for instance through locational tariffs or connection charges, or similar instruments.

Table 31: Overall assessment of proposed measures

Measure	Comments
Priority Measures	
Regional Sharing of Operational Reserves in the Electricity Sector	Highly promising measure (principally already foreseen by draft FG on Electricity Balancing)
Coordinated network planning	May potentially lead to major savings in overall investments in both gas and electricity networks (if supported by tariffs and connection charges)
Coordinated operational planning	Improves reliability and efficiency of daily balancing in both sectors
Improved line pack management	Facilitates optimal use of available flexibility in the gas network
Potentially Promising Measures	
Intra-day adjustment of reserves in the electricity market	To be considered in power systems with a high share of fluctuating RES and the need to procure operational reserves from inflexible plants
Inter-zonal exchange of gas balancing services by the TSOs	Based on the procurement of standardised temporal products via an open platform
Within-day products for inter-zonal capacities in the gas market	To be considered where temporal products play a tangible role in neighbouring markets
Design of within-day obligation (e.g. cumulative tolerance)	Avoid excessive risks for gas-fired plants by facilitating market-based balancing

In addition, Table 31 also contains four other measures, which we believe should be considered under certain conditions. First, we suggest that there may be benefits for the intra-day adjustment of reserve allocations in the electricity market, but only in power systems with a high share of fluctuating RES and where the TSOs need to procure a certain share of operational reserves from inflexible plants. However, the scope for this concept should be carefully checked against the potential to limit the advance contracting of operational reserves to those with a very short activation time. Similarly, it may be more efficient to procure a limited amount of 'slow reserves' from inflexible plants outside the main market for operational reserves.

Secondly, we believe that one should consider direct inter-zonal exchanges of gas balancing services by the TSOs, in order to promote the scope for competition and grant TSOs the access to a maximum of efficiency. However, to promote integration with the general wholesale market, we would suggest that such exchanges should be based on a limited set of standardised (temporal) products that can be activated within normal timescales for re-nominations. Moreover, such exchanges should preferably be implemented via open platforms which are also open for bilateral trades between shippers.

Where the development shows a considerable need for the use of temporal products in two neighbouring markets, it may furthermore be beneficial to consider the introduction of within-day products for inter-zonal capacity in the gas market. This would in particular be the case if one observed a considerable demand for the bilateral trading of temporal products between shippers.

As discussed in section 7.8 we are not convinced of the scope for tradable products for within-day flexibility in the gas market. Simultaneously, the relatively long deadlines for re-nominations in the gas market may create significant risks for gas-fired power plants if within-day obligations are applied. In order to mitigate the corresponding risks and to avoid distorted prices for bids and offers to the balancing market in the electricity sector, it may be desirable to account for this risk in the design of potential within-day obligations. As discussed above, one option could be, for instance, the introduction of a cumulative tolerance which would allow shippers to, themselves, compensate their imbalances in the within-day market, whilst the immediate physical balancing would be carried out by the TSO.

Last but not least, we believe that the provision of firm exit capacities for system-critical power plants in the gas market deserves further attention. Although we principally support the intentions of this concept, we have highlighted the potential risks of an ill-designed measure. Consequently, we recommend that this measure should be subject to further study. Among others, the concept of coordinated network planning in the gas and electricity sector may already remove most of the potential limitations of this measure.

8 Tentative Roadmap for Implementation of the Proposed Design Elements

In the previous chapter, we have proposed eight different measures, which we propose to implement or at least to consider for gas and electricity balancing. In the following section, we briefly discuss the best timing of each of these measures and present an overall roadmap, which summarises our findings.

The regional sharing of operational reserves in the electricity sector represents the first priority measure identified in chapter 7.10 above. Due to its major potential benefits, it might appear useful to also pursue this model with high priority. Nevertheless, we note that it is closely related to the intended efforts towards the regional integration of the electricity balancing and reserve markets, as stipulated by the draft FG on Electricity Balancing. More specifically, the draft FG demand that the European TSOs implement a TSO-TSO model with a common merit order and margins for replacement reserves within than three years after the Electricity Balancing Network Code(s) enters into force, whilst a final model (without margins) shall be implemented within seven years after the adoption of the Network Code(s). Likewise, the TSOs shall also develop and implement a similar model for restoration reserves, within seven years.

Against this background, it appears useful to synchronise the transition to the regional sharing of operational reserves with the efforts for the integration of the balancing markets. In this context, great attention should be paid, however, to avoid a dilution of resources, which might complicate or even stall one or both processes. Moreover, it is also important to note that the draft FG set rather stringent conditions on the reservation of inter-zonal capacity for the procurement of operational reserves. Given that such reservation may be required to enable a regional exchange of operational reserves, this also suggests that this measure can only be implemented in the medium to long term.

Simultaneously though, the large potential benefits of this measure imply that any undue delays should be avoided. An alternative could therefore be to first promote one or several pilot projects in regions where this concept can be implemented relatively easily or where it can be expected to deliver significant benefits. This would furthermore identifying, testing, validating and refining a suitable model, before starting a large-scale 'roll out' on a European scale.

From the perspective of the regulatory framework, we finally note that this concept is fully compatible with the draft FG on Electricity Balancing. In our view, the focus could thus be on actual implementation, whilst no major changes to the current and evolving framework would be required.

The remaining three priority measures, i.e. coordinated network planning, coordinated operational planning and improved line pack management, are all related to the internal operations of the gas and electricity TSOs. Consequently, implementation of these measures would not require any additional rules or regulations, although it might be beneficial if these objectives were reflected in one or more of the Network Codes. On the other hand, we are aware that actual implementation of these three concepts will partially be a complex and time-consuming process.

In general, we would recommend starting first discussions in this respect without significant delays. However, the initial focus should probably be on the identification of the main objectives to be pursued and the identification of possible 'quick wins'. Moreover, any corresponding efforts should probably concentrate on those regions with the highest level of interdependency between the gas and electricity market. In line with our argumentation above, this also implies that these three measures should be pursued mainly on a national or regional level.

The only exception might be the coordination of network planning, which is implicitly linked with the initiatives within the context of the long-term network development plants developed by both ENTSO's. But again, the complexity of the existing process means that it will probably be necessary to consider these three measures as a medium- to long-term goal.

For each of the next three measures, we have identified above specific conditions, which should be fulfilled before the corresponding measures are implemented. Apart from the intra-day adjustment of reserves in the electricity market, this also refers to the inter-zonal exchange of gas balancing services and the introduction of within-day products for inter-zonal capacities in the gas market. Consequently, we believe that the focus should initially be on defining more specific criteria for each of the three measures and then to monitor the further development. In parallel, it may make sense to further investigate the scope, impact, and design of each concept, in order to be prepared once so required.

Last but not least, the design of within-day obligation may have to be addressed by each TSO when implementing the requirements of the FG and draft NC on Gas Balancing. Consequently, the timing of this measure obviously depends on the need for within-day obligations such that it is not possible to define a single time line for all countries or markets.

Based on these considerations, Table 32 finally presents a tentative roadmap for implementation of proposed design elements.

Table 32: Tentative roadmap for implementation of proposed design elements

Measure	Recommended steps and timing
Priority Measures	
Regional Sharing of Operational Reserves in the Electricity Sector	– Generally synchronise with deadline for transition to regional balancing market under the FG on Electricity Balancing – Start 2 – 3 pilot projects within the next 2 – 4 years, in order to test suitable models
Coordinated network planning, Coordinated operational planning, Improved line pack management	– Start initial discussions and initiatives (2013/2014) – Require TSOs and regulators to regularly report on any progress made
Potentially Promising Measures	
Intra-day adjustment of reserves in the electricity market	– Define and monitor suitable criteria, to identify the need for implementation – Investigate potential design and potential benefits in more detail, develop more detailed concept (where deemed to be beneficial)
Inter-zonal exchange of gas balancing services by the TSOs	– Same as above
Within-day products for inter-zonal capacities in the gas market	– Same as above
Design of within-day obligation (e.g. cumulative tolerance)	– To be considered in the context of the introduction of within-day obligations
Other	
Firm Capacities for system-critical power plants	– Further investigate possible design options and their impact, in coordination with the parallel work on coordinated network planning