ACER
Agency for the Cooperation of Energy Regulators

Council of European Energy Regulators

# ACER/CEER

# Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011

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## Foreword by the ACER Director and the Chair of ACER's Board of Regulators and CEER

We are pleased to present the first joint annual Market Monitoring Report by the Agency for the Cooperation of Energy Regulators ("the Agency") and the Council of European Energy Regulators (CEER).

This Report has a wider coverage than the aspects which are specifically mandated to the Agency by Article 11 of Regulation (EC) No 713/2009. It covers the retail prices of electricity and natural gas, access to the networks including access of electricity produced from renewable energy sources, and compliance with the consumer rights laid down in Directive 2009/72/EC and Directive 2009/73/EC. By producing a joint Report, we aim to provide as complete an assessment as possible of the progress towards the implementation of the Third Energy Legislative Package (3rd Package), including the completion of the wholesale internal energy market by 2014, the target recently set by the Heads of Government.

The 3rd Package has moved the European energy sector one important step closer to establishing a single energy market in Europe, not only by strengthening the provisions in areas already addressed by previous Packages – for example, on network unbundling, powers and independence of energy regulators, and consumer rights – but also by envisaging, for the first time, a more significant EU dimension in the planning of energy networks and the development of detailed EU-wide rules on network and market operation and by providing for the establishment of the Agency and the European Network of Transmission System Operators (ENTSOs) with their respective responsibilities.

European energy consumers and citizens must benefit still more from the single internal energy market. The 3rd Package must be transposed and implemented fully and effectively into national law and EU-wide network codes, and market rules must be developed and adopted. Monitoring is essential to indicate the way in which energy markets actually operate, both at the wholesale and retail level, and to highlight where possible improvements are needed. The report seeks to provide an indication of the real degree to which rules are implemented in practice. It also provides a level of transparency that should instil confidence in energy consumers throughout Europe. To ensure that market integration proceeds as smoothly as possible, the Agency is also tasked with identifying any barriers to the completion of the internal markets in electricity and natural gas. The Agency must propose to the European Parliament and the European Commission measures that could be taken to remove such barriers.

Overall, our findings show continuing internal market development and improvements in line with the Union's energy objectives. The report also points to persisting gaps and to the need for further progress in the real implementation of rules in practice in the full spirit of the law. This observation applies to consumer rights and to the need for further measures to tackle barriers to market integration and greater transparency. These conclusions have, to a significant extent, been reflected in the future Work Programmes of both CEER and ACER. However, effective transposition of the rules by Member States and concerted action from all stakeholders are needed to help exchange best practice.

Part of the Report's analysis is focused on how consumers are faring as a result of the changes in energy policy – is there a choice of supplier and are consumers switching? How have prices evolved during the year? Are prices regulated or subject to market pressures? How are consumer rights and consumer protection measures implemented in practice nationally? CEER's continuing commitment to address such issues, coupled with ACER's monitoring duties, should serve as a constructive input for further market improvements, in particular in the context of its initiative to build a 2020 vision for Europe's energy customers.

In this regard, the report assesses the presence of regulated retail prices and the implementation of a number of consumer rights provisions, including complaint handling procedures, supplier of last resort and the time needed to switch supplier. In particular we note that, in 2011, the majority of Member States (MS) still maintained regulated retail prices for electricity (17 MS) and gas (15 MS). Regulated prices may reduce the scope for effective competition. Meanwhile, our analysis of electricity wholesale markets shows that market coupling has facilitated price convergence. However, the growing phenomenon of "unplanned flows" in parts of Europe constitutes a barrier to the further integration of the internal market. In gas, although price correlation between European hubs was high, price differentials in parts of Europe still remain significant. With a few exceptions in North West Europe, the liquidity of gas hubs was found to be unsatisfactory, while contractual congestion remained a significant feature at a number of interconnection points, even if it was not always reflected in physical congestion. Further analysis of cross-border congestion and access charges is therefore required to identify any possible barriers to entry, and to ensure that interconnection capacity is used in the most efficient way.

The data used for compiling this Report have been collected and provided by National Regulatory Authorities for energy, the European Commission, and the ENTSOs for electricity and gas. We are grateful to them for their contribution. Our most sincere appreciation goes to our colleagues in the market monitoring team at the Agency for their sustained effort in continuously monitoring market developments and in producing this Report.

In the future, the Agency intends to work towards deepening the coverage of the Annual Market Monitoring Report. The timeliness and consistency of the available data is also an aspect on which the Agency wishes to focus to ensure that the quality and value of the results of its monitoring activities are continuously enhanced. For its part, CEER will dedicate significant resources to monitoring complimentary market issues, including LNG and gas storage transparency; implementation of the Gas Target Model; Transmission System Operators (TSO) and Distribution System Operators (DSO) unbundling; the roll-out of smart meters; the various approaches to smart grids; and consumer access to information on the cost (and sources) of their energy. Working nationally, regionally and at European level with policy makers (notably, with the European Commission and the European Parliament) and the industry, all energy regulators remain committed to putting the legal, regulatory and operational framework in place that will truly deliver an internal energy market for Europe's consumers.

**Lord Mogg**
Chair of ACER's Board of
Regulators and CEER

**Alberto Pototschnig**
ACER Director

# Executive Summary

## Introduction

*Structure of the report*

This is the first annual Monitoring Report by the Agency for the Cooperation of Energy Regulators ("the Agency") and the Council of European Energy Regulators (CEER) on the development of EU electricity and gas markets in 2011. It focuses on retail markets, consumer issues, the principal developments in gas and electricity wholesale market integration and network access issues which have an important impact on the degree of competition in retail markets and the prices that consumers pay for energy. The report also provides an analysis of the progress made in electricity and gas markets across the EU in 2011 and points to persisting barriers to market integration. A number of conclusions and recommendations are made to assist in achieving the Heads of Governments' objective of an Internal Energy Market (IEM) by 2014.

The report covers three main areas: the electricity market; the gas market; and consumer protection and empowerment. The electricity and gas chapters are further sub-divided into retail, wholesale and network access issues. The analysis in the chapters is complemented by detailed technical annexes.

## Electricity and gas retail markets

Drawing on CEER's experience in retail market monitoring, the Agency and CEER undertook extensive data gathering and analysis to assess the state of play of electricity and gas retail markets in the EU's Member States (MS). In a liberalised energy market, competition should bring benefits to customers, at least in terms of better services and cost-reflective prices. A variety of indicators can be used to understand how retail markets are functioning for consumers. The report focuses on the evolution of retail prices by component and on other relevant factors such as switching.

*Regulated prices*

The Agency and CEER are aware that different price setting rules and methodologies in place in the MS with regulated prices could have differing effects on retail market conditions. For end-user prices, the data reveal that regulated prices remained a central feature of EU gas and electricity retail markets in 2011. The majority of MS featured regulated prices for electricity (17 MS) and gas (15 MS).[1] Regulated prices should be set at levels which avoid stifling the development of a competitive retail market. They must be consistent with the provisions of the 3rd Package and should be removed where a sufficient level of retail competition is achieved. Indeed, regulated prices can suppress competition if they are set at a level which does not allow costs to be recovered. Conversely, where regulated prices are initially set at a level which exceeds underlying costs (assuming efficient costs are known to the regulator) by a

1 Northern Ireland also featured regulated prices for household customers in 2011, but is not referred to as a country as it is part of the United Kingdom.

guaranteed retail margin, they may set a reference starting point for competing suppliers. However, such a framework could prevent customers from reaping the full benefits of competition because, in an immature retail market, high regulated prices could be viewed as a focal point which competing suppliers can cluster around and – at least in markets featuring consumer inertia – slow the switching process down.

*Retail prices*

Gas and electricity retail prices rose for both households and industrial customers in the majority of MS in 2011. On average, electricity post-tax prices increased by 9% and gas post-tax prices rose by 10% between 2010 and 2011 in the EU-27 (EU-25 for gas, excluding Cyprus and Malta).

Coupled with this increase, large disparities in pre-tax price levels in both electricity and gas markets for households (and for industrial customers) persisted across the EU, and even between countries with similar retail market frameworks. These price differences are further amplified when taxes are included.

Gas retail prices followed wholesale price developments to some extent. There is preliminary evidence for some MS in 2011 that retail gas prices tended to follow wholesale price rises more quickly than wholesale price decreases. Although utilities can undertake hedging strategies to manage fuel price risk, retail prices should react to both wholesale price increases and decreases. For electricity, retail prices in countries without price regulation tended to adjust more quickly to changing wholesale prices. The degree to which wholesale prices impact retail prices will be monitored more closely in the future. Improved data and longer time series will allow for more robust conclusions. Progress will be assessed next year.

*Switching rates*

Switching rates, another retail market indicator, remained generally low in 2011, both in electricity and gas, irrespective of whether end-user prices were regulated. Low switching rates, when analysed in conjunction with price behaviour, and taking into account the lack of maturity of some retail markets, suggest that, in most MS, an improved level of competition would provide consumers with greater benefits.

An analysis of recent observed trends in a number of MS may signal a change in the nature of retail market operation and competition. Against a background of low economic growth and higher commodity prices, retail competition has started to take a different form. The relevance and effectiveness of non-price competition will require more monitoring in the future, along with the assessment of dual-fuel and web-only offers. In 2011, some regulators began (or resumed) probes into the effectiveness of retail competition. These actions will be further considered in next year's market monitoring report.

*Smart meters*

A further development which may impact future retail market monitoring is the expected roll-out of smart meters in many MS. Smart meters will provide more frequent and timely information on consumption patterns. In addition, the role of the entities collecting this information (in many – but not all – cases, distribution system operators) will be key. Therefore, retail market design must ensure that entities responsible for data collection and management make use of their status to foster active competition and act as market promoters and facilitators. Differences between some retail market designs in different MS could cause barriers to entry, which threaten to reduce the scope for retail competition.

### Consumer protection and empowerment issues

*Need for transparency*

The report identifies important gaps in a number of MS regarding consumer protection, empowerment and the fulfilment of specific requirements stipulated in the 3rd Package (e.g. maximum periods for switching supplier, treatment of vulnerable customers, and complaint handling and dispute settlement procedures).

Although supplier switching processes and information requirements have been incorporated into national legislation in most MS, inconsistencies remain between the transposition of EU law and its actual implementation. Greater transparency and clear, simple and understandable information are crucial to increase customer engagement.

*Customer complaint handling*

Protection schemes for vulnerable customers, along with supplier of last resort (SoLR) mechanisms, vary widely between MS. The concept of "vulnerable customer", as specified in the 3rd Package, is not always explicitly defined. Notwithstanding this divergence from EU legislation, MS typically protect their vulnerable customers through a combination of both energy-specific and general social security measures.

There are also many approaches to customer complaint handling and data collection, as well as out-of-court settlements – the latter often being handled by regulators, ombudsmen, or separate consumer bodies.

The collection of complaint data is often the responsibility of multiple actors and is generally not centralised. Detailed information on complaints and disputes is variously held by consumer organisations, ombudsmen, stakeholders and/or regulators. For reasons of effective consumer protection (and the overall efficiency of the process), the fullest cooperation between National Regulatory Authorities (NRAs) and these other organisations is needed.

The key areas for customer complaints are shown to be billing, metering, prices and, in many MS (despite five years of full retail market liberalisation), supplier switching. Greater transparency is therefore recommended in such areas, with price comparison websites being important tools in this respect. Working through CEER, regulators will continue to develop forward-looking recommendations to promote improvements in market processes and the implementation of consumer provisions. CEER's 2013 work programme includes a number of deliverables with this aim. In addition, the CEER and BEUC[2] Joint Statement on a 2020 vision for Europe's energy customers provides a broader set of principles to ensure that consumer needs are better understood and are placed at the heart of energy policy development, through a collective effort of market players, consumer organisations and policy makers. The Agency's continuous monitoring of retail markets provides an important test of whether markets are functioning in the interest of consumers.

### Electricity wholesale market integration and network access

*Wholesale prices*

One way to assess progress towards achieving an internal energy market is to consider the evolution of wholesale prices across the EU. In 2011, electricity wholesale prices significantly converged following market coupling. In the Central West Europe[3] (CWE) electricity region, for instance, the number of hours during which prices were identical across the German-Dutch border noticeably increased from 12% in 2010 to 87% in 2011. However, there remains significant scope for further market integration between regions across Europe; for example, between the Netherlands and Norway, the total number of hours during which market prices were identical was just 6% in 2011.

*Removing barriers to trade*

To ensure greater convergence of EU wholesale electricity prices and to remove barriers to trade, it is vital to implement the Electricity Target Model in terms of long-term, day-ahead, intraday and balancing markets, as well as flow-based capacity allocation and congestion management. This can be achieved by formal (Framework Guidelines and Network Codes) and informal processes (Regional Initiatives). Full implementation (and practical application) of the 3rd Package provisions is also important to achieve the IEM. Early implementation of the Target Model, even while the rules in the Network Codes are still being drafted, will ensure that the 2014 target for the completion of the internal electricity market is met and will also provide valuable input for the rule-making process. Promoting the early implementation of the Target Model has been a major part of the Agency's activity this year and features prominently in its work programme for next year.

A further example of progress towards market integration is provided by the introduction of bidding zones in the Swedish wholesale market in November 2011. It resulted in further market efficiency in the Nordic region and, to some extent, the Central West European region. Indeed, the most appropriate design of bidding areas might well include zones straddling multiple country borders.

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2 The European Consumer Organisation (Bureau Européen des Unions de Consommateurs), www.beuc.eu Note: All hyperlinks referred to in this document were correct and functioning at the time of going to press.

3 CWE includes Belgium, France, Germany, Luxembourg and the Netherlands.

*Unplanned flows*

However, barriers to market integration remain. The growing phenomenon of "unplanned flows" undermines the efficiency of the internal electricity market. Such flows are particularly pronounced in the Central East,[4] Central West and Central South[5] electricity regions. The report sets out a number of recommendations to tackle this problem: first, improved coordination between the relevant TSOs; second, the implementation of flow-based congestion management as an appropriate tool to make better use of existing network capacity; and third, the establishment of a sound incentive framework to ensure that TSOs are properly compensated if and when they apply efficient remedial actions to resolve network issues stemming from unplanned flows. Additional network investment (including phase-shifting transformers) should also be considered to increase (or better manage) available cross-border transmission capacity. However, such reinforcements come at a price and may take many years to be realised. They should therefore be considered only if their welfare benefits exceed the costs. A reconfiguration of bidding zones is a further remedial action which can be applied, subject to cost-benefit analysis.

*Renewable energy sources*

The key 2011 development in electricity generation was the progressive increase in the share of renewable energy, notably the increased contribution of solar energy to total generated electricity (from 7.4 TWh in 2008 to 41.5 TWh in 2011).

The growing penetration of electricity from renewable sources sets a number of challenges, in particular to ensure that the network is able to accommodate new renewable generators. In 2011, the timeliness of grid connection remained the main challenge to network access in several MS. Moreover, the increase in costs from network congestion resulting from faster connection of renewable-based generation (for instance, these included the compensation paid to generators when the use of the electricity they generated is restricted) was also challenging. The curtailment of renewable energy plants in 2011 was rare, albeit increasing.

The increase in renewables out of the total energy mix also serves as a reminder that energy sustainability and the achievement of EU renewable energy targets need to be better harmonised in an efficient and competitive European energy market. The Framework Guidelines on Balancing and on Capacity Allocation and Congestion Management (CACM) therefore set out requirements for renewable-based generators to become financially responsible for their imbalances. Gate closure should be nearer to real time in order to increase the efficiency of the whole system. In 2011, renewable-based generators were already financially responsible for their imbalances in 13 MS, and the remaining MS should also take this approach. These aspects form part of the urgent need to implement the Electricity Target Model and thus are reflected prominently in the Agency's work programme for 2013.

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4 Central East Europe (CEE) includes Austria, the Czech Republic, Germany, Hungary, Poland, Slovakia and Slovenia.

5 Central South Europe (CSE) includes Austria, France, Germany, Greece, Italy and Slovenia.

*Measuring gross welfare benefits*

The report also presents for the first time a new indicator that estimates the gross welfare benefits from the integration of electricity wholesale markets. This indicator is intended to measure benefits as the sum of consumer and producer surplus from cross-border market coupling, together with congestion rents. Among other things, the indicator shows in one case that, as a result of trade based on current interconnection capacity between Sweden and Finland, an annual welfare gain of 252 million euros is obtained. The Agency intends to develop this indicator as a monitoring tool to assess the efficient use of existing networks and to track the progress of market integration.

### Gas wholesale market integration and network access

Developments in gas wholesale markets have been dominated by sluggish demand reflecting the EU's economic downturn. In practice, this should facilitate gas-on-gas competition releasing supply and transportation capacity. However, low or even negative spark/dark spreads in power generation currently reduce the economic merit of gas as a generation fuel, thus limiting traded volumes on wholesale markets. On the other hand, in part due to the availability of short term gas volumes such as Liquefied Natural Gas (LNG), long-term oil-indexed contracts are being renegotiated to reflect cheaper prices in increasingly liquid and lower-priced gas hubs (especially, but not exclusively, in North West Europe[6]).

*Price convergence*

The report also signals that hub price convergence is increasing in North West Europe, although price decoupling still occurs in winter. Convergence was lower elsewhere in continental Europe in 2011. In Southern Europe, 2011 prices were still decoupled from North West European prices.[7] Nonetheless, hubs in Austria and Italy have experienced some price convergence since the first quarter of 2012 (not covered in this report).

*Availability of capacity*

As regards the availability of capacity in gas networks, utilisation issues are still present, especially where contracted capacity is not fully utilised and well-functioning secondary capacity markets or alternative mechanisms are not present. The Agency, the European Commission and European Network of Transmission System Operators for Gas (ENTSOG) are working, through Framework Guidelines and Network Codes, to ensure that capacity is allocated fairly and that any congestion is managed efficiently. This includes the creation of viable and functional secondary capacity allocation and trading mechanisms throughout the EU, whose design must ensure that any contracted but unused capacity is efficiently returned to the market.

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6 Relating to hubs based in Belgium, Great Britain, Germany, the Netherlands and Northern France.

7 Especially in Italy and the Balkan Peninsula, where the quantity and quality of interconnection to the North is not satisfactory.

*Cross-border interconnection*

The importance of ensuring cross-border interconnection, as well as its optimal use, which in turn should facilitate cross-border gas trade, are fully recognised in this report. A number of energy regulators are currently exploring measures, at either a regional or Europe-wide level, to improve the situation in line with the internal energy market's priorities. Subject to cost-benefit analysis, investment plans should be fulfilled when needed, in parallel with market-based (non-physical) mechanisms. The draft Energy Infrastructure Regulation, along with the 3rd Package provisions for EU-wide network planning, should contribute to the necessary prioritisation and coordination of infrastructure development. The Agency and national regulators are deeply involved in the implementation of these provisions, even though the Energy Infrastructure Regulation has not been finalised yet.

*Cross-border transportation tariffs*

Closely linked with developing interconnection is the issue of cross-border transportation tariffs. Analysis performed by the Agency shows that cross-border interconnection tariffs for gas are extremely heterogeneous and generally not transparent. In many cases, costing and pricing methodologies are not published. Some interconnections appear to be arbitrarily priced. In the absence of underlying cost data, tariff discrimination in an economic sense cannot be definitively diagnosed, but it can be hinted at, given the extreme differences in interconnection tariffs for the same or adjacent borders for gas flowing in opposite directions. Moreover, the way in which tariffs are calculated cannot always be replicated, given the absence, in many cases, of explicit methodologies. Indeed, in a separate analysis carried out in 2012, the Agency found that, in some instances, international gas transit is still treated and priced separately from domestic high-pressure transportation. Some of these issues are addressed in the Framework Guidelines on harmonised gas transmission tariff structures to be issued shortly, following consultation.

Interconnection efficiency (or lack thereof) and the extent to which gas moves in the appropriate direction are linked to the responsiveness of shippers to tariff and capacity design. Price responsiveness is hampered by the persistence of long-term contracts, which may give rise to inconsistent gas flows. Improved information on tariffs and auction designs/outcomes is needed to understand to what extent such factors constitute a barrier to the efficient functioning of interconnectors, irrespective of the presence of underlying technical constraints.

Consistent with its mandate to promote cross-border trade and EU market integration, the Agency is working on implementing the key principles of the Gas Target Model through its framework guidelines and the resultant binding network codes on capacity allocation mechanisms, balancing, cross-border tariffs and interoperability. Comitology Guidelines on congestion management procedures have recently been adopted. The timely adoption of these European rules, along with the full transposition of the 3rd Package, will ensure that consumers benefit from an integrated internal gas market.

*Transparency*

The availability of information is also a critical element of functioning competitive markets. Therefore, it is recommended that ENTSOG improve its Transparency Platform with respect to gas interconnection point capacity and price data, including the availability of storable time series on capacity and bookings. Data on capacity (bookings, prices, nominations, contracted values) should not only be projected into the future, but also permanently stored on the Platform for statistical analysis purposes.

The Transparency Platform should also contain up-to-date and unit-consistent, fully and readily comparable information on cross-border transportation tariffs and on the general terms and conditions of international gas transmission at each and every Interconnection Point (IP). This would make tariff evaluation possible to the maximum practical extent. Similarly, data formats should be user-friendly for download.

As a further step towards transparent and competitive gas markets, tariff methodologies should be published by all TSOs, and by ENTSOG as the information aggregator and verifier. Data and transparency improvements should take place by 1 October 2013 at the latest, in line with EU legislation on transparency requirements for transmission networks.

*New developments*

The report also outlines certain new developments in the gas sector, in particular the emergence of biogas and its future use as a renewable gas source, with certain caveats in terms of quality and safety and the need for a cost-benefit analysis. Biogas injection is prioritised in at least two MS. However, biogas generally does not enjoy preferential (subsidised/feed-in) tariffs, as do other renewable sources in electricity. For this and other reasons (mainly relating to quality standards and the cost of quality homogenisation, with national differences playing a role), biogas still accounts for a very limited share of total injected gas in the EU as a whole.

**Conclusions**

This report illustrates market developments in 2011 in the EU's electricity and gas sectors in view of the IEM target. The report further identifies those areas where additional measures (and monitoring) are needed to ensure that EU electricity and gas customers benefit from fully integrated markets.

Particular areas for further action include:

1. Transposition — Full transposition and implementation by Member States of 3rd Package provisions are essential. The European Commission should continue to monitor this closely and take action, where necessary, to pursue any infringements.

2. Consumer rights — Regulators will continue to promote the implementation of consumer provisions in the 3rd Package, taking advantage inter alia of CEER recommendations and advice, as well as the Agency's continuous monitoring activities. CEER's 2020 vision for Europe's energy customers will also promote dialogue and engagement with market players and policy makers to build an energy sector where the European consumer truly comes first.

3. Market rules and practical implementation — The EU-wide network codes provided for in the 3rd Package are key to achieving market integration. The Agency will continue to work with the ENTSOs, the European Commission and market players to deliver them. Voluntary (pilot) implementation and market integration efforts, based on multi-stakeholder regional cooperation, should continue and progress. Pilot projects help pave the way for, and test, future framework guidelines and network codes in order to achieve a truly competitive internal energy market.

Some measures require concerted action by all actors for the benefit of European consumers. The Agency and CEER will continue to support and promote the development of competitive, sustainable and secure electricity and gas markets in the public interest. Both the Agency and CEER are also committed to open dialogue with all parties, and to working with European institutions and Member States to deliver and apply the rules necessary to achieve Europe's energy goals.

# 1 Introduction

*(1)* The European energy markets for gas and electricity have been work in progress since the first Directives on the liberalisation of the internal market in 1996. The decision in February 2011 by the European Council to complete the market by 2014 is the ultimate step in this process. One essential pre-requisite for achieving the goal is to track the progress and report on achievements, as well as any remaining impediments to a fully functioning and satisfactory market. This report strives to provide such an analysis.

*(2)* Indeed, the process so far has seen the development of a set of more specific common rules for energy markets across the EU. The first EU Directives began liberalising the wholesale energy market and specifying rules on unbundling and regulation in general terms. The 2nd Package in 2003 foresaw more specific regulatory rules such as on tariff setting and the unbundling of network operators (to be enforced by independent energy regulators). It also extended liberalisation to include retail markets, foreseeing full market opening by June 2007.

*(3)* However, the European Commission's 2006 inquiry into the European gas and electricity sectors[8] identified several persisting insufficiencies relating, predominantly, to structural market issues. High concentration and foreclosure of markets underpinned by insufficiently unbundled transmission system operators (TSOs) were found to be the main causes of the still low level of competition in most markets. Already in early 2006, national energy regulators promoted and set up the Regional Initiatives as an interim step towards creating a single energy market in the EU. The main goal of the process was to work together to develop common, standardised practices which would enable market participants to enter cross-border markets and thereby help overcome the structural problems of national markets. Progress achieved in that area also increased support for market integration overall, as it illustrated the potential cost to the industry of continuing with the status quo.

*(4)* In addition, the discussions in the Regional Initiatives made it possible to identify the main barriers to entry at an early stage, such as insufficient levels of transparency, the potential for discrimination in capacity allocation, non-existent transport capacity markets for short-term physical energy supply etc.

*(5)* The 3rd Package[9] addresses the aforementioned structural deficiencies, requiring a high level of independence for TSOs and regulators, as well as better cross-border coordination. The European process towards market integration laid down in EU legislation is a combination of top-down and bottom-up procedures where regulators set the initial framework guidelines and TSOs have to provide detailed technical and market rules. The success of this process depends to a large extent on guaranteeing the independence of these main actors. Close monitoring of the functioning of the internal market can therefore also provide an indication of whether these two actors are sufficiently empowered (and independent) to fulfil their tasks.

8 European Commission, "Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)" 10 January 2007, COM(2006) 851 final, see: http://eur-lex.Europa.eu/LexUriServ/LexUriServ.do?uri=COM:2006:0851:FIN:EN:PDF

9 Set of 5 EU legislative acts on energy liberalisation adopted in 2009: Electricity: 2009/72/EC, EC/714/2009; Gas: 2009/73/EC, EC/715/2009; ACER: EC/713/2009, see: http://eur-lex.europa.eu/JOHtml.do?uri=OJ:L:2009:211:SOM:EN:HTML

*(6)* The initial draft Directives in the 3rd Package foresaw a structural separation of TSOs from vertically integrated suppliers and of national regulators (NRAs) from governments. Whereas the strict separation of NRAs was supported by Member States (MS), with respect to TSO unbundling, alternative models were included in the final Directives. One of the salient questions in that respect is whether the unbundling requirements (i.e. the model for an independent transmission operator) in Chapters V and IV of the electricity and gas Directives (respectively), enable a track record of independent investment decisions and non-discrimination with regard to network access and dispatch.

*(7)* When comparing the European process with the former situation of TSO decision making, it is clear that structural separation implies several ramifications which must be taken into account. In a world of mostly vertically integrated companies, the rationale for investment was mainly the economic consequences for the company as a whole. In some cases, vertical integration supported investment, for instance for companies with export interests; it possibly even led to excessive levels of investment in some cases. Separating transmission from production and/or supply takes away restrictive as well as supportive external interests, making TSOs "neutral" in terms of investment. The solution provided by the 3rd Package in this respect is to foresee a process of coordinated and, if necessary, enforced development of network plans. These serve as the basis for future network investment decisions.

*(8)* Such aspects of independence are a prerequisite for successful market integration and reliable energy supply. However, in order to meet the overall objectives of the present legislation, the EU must a) integrate markets; b) achieve efficient investment in production, transport and dispatch of capacity; and c) guarantee adequate and affordable prices for small and industrial customers. The 3rd Package tasks the Agency with monitoring electricity and gas markets, and in particular retail markets, which are the final element in the value chain. By assessing the functioning of markets as a whole, this market monitoring report will provide useful feedback for the ongoing process of setting and updating EU-wide market rules. With this joint report with CEER, the Agency meets its monitoring obligations as laid down in Regulation (EC) No 713/2009[10].

*(9)* The ultimate goal of market integration is to improve efficiency in the system by enabling functioning competition. This entails efficient price formation, which in itself requires a high level of transparency in a structurally competitive environment. Assessing the economic benefits of current market integration is therefore highly relevant. The report provides a first assessment for the electricity and gas sectors. Contrary to the situation in natural gas, in many regions wholesale electricity markets exist, indicating the social value of the commodity.

10 Pursuant to Article 11 of Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009, establishing an Agency for the Cooperation of Energy Regulators (OJ 2009 L 211, 14.8.2009).

*(10)* A second pillar of the 3rd Package is centred on guaranteeing that markets deliver benefits for final customers, especially households and small business customers. The report therefore places a special focus on issues of consumer satisfaction and protection of specific customers (as laid down in Annex I of the electricity and gas Directives).

*(11)* Finally, this monitoring report should also be seen in the context of the EU's 20-20-20 targets.[11] Priority network access and dispatch of renewable energy, as well as combined heat and power (when appropriate), are also monitored by the Agency.

*(12)* In its 8th recital, the Agency Regulation clarifies that there should be no duplication of monitoring work. In order to best integrate the results of monitoring at national level into the Agency's monitoring activities, this report is being prepared jointly by the Agency and CEER, the Council of European Energy Regulators. As a consequence, in addition to analysis undertaken especially for this report, the document sources information from specific reports produced by the Agency and NRAs, as well as the national reports and data provided by national regulators.

*(13)* It is worth pointing out that the new regime conceived in the 3rd Package is, in many respects, only starting to be implemented. In many MS, full transposition is still ongoing, meaning that the analysis of market results necessarily has had to take into account the early stages of this process. For this reason, and especially in areas where measures have been taken which probably have longer term effects, this first report presents such measures without drawing in-depth conclusions.

*(14)* This transitional context implies that data are quite often not available or cannot yet be compared in a meaningful way. It should also be mentioned that the 3rd Package foresees quite an extensive list of areas to be monitored by national regulators where the details are to be developed on a national basis. It is even foreseen that competent authorities other than NRAs may perform monitoring tasks. For an EU-wide report on energy markets, this means that there will be some reliance on available data which are collected under potentially 27 different monitoring regimes. Further harmonisation in this area would certainly facilitate future EU-wide monitoring.

*(15)* The present report is based on publicly available information and information provided by National Regulatory Authorities on a voluntary basis. The activities foreseen by Article 11 of Regulation (EC) No 713/2009 (the Agency Regulation) are not complemented with data collection powers.

11 These EU targets, known as the "20-20-20" targets, set three key objectives for 2020: a 20% reduction in EU greenhouse gas emissions from 1990 levels; raising the share of EU energy consumption produced from renewable resources to 20%; and a 20% improvement in the EU's energy efficiency.

# Part I: The electricity sector

## 2 Electricity retail markets

### 2.1 Introduction

(16) Electricity retail market monitoring has notably gained importance over the last few years. Both CEER and (formerly) ERGEG have addressed this issue by providing Guidelines of Good Practice and analyses of retail market design, retail market indicators, smart metering, and price regulation etc. With this work, CEER and ERGEG have paved the way for the development of both the Agency's and CEER's retail market monitoring.

(17) According to Directive 2009/72/EC, Article 37 (j), NRAs should monitor retail markets thoroughly, namely the "level and effectiveness of market opening and competition at…retail levels…" whereas Article 11 of Regulation (EC) No 713/2009/EC describes the Agency's monitoring tasks as focusing mainly on retail prices.

(18) The components making up final (end-user) electricity prices usually include the commodity price, transportation, distribution and retail supply costs (metering, billing, customer service, additional services) and margins plus levies, surcharges and taxes, as applicable. These components can fluctuate widely between MS due to different regulatory regimes and market developments.

(19) In principle, retail price monitoring should concentrate on the commodity component of the final price and on the retail mark-up[12], as these are the elements in the end-user price which retail market participants can directly influence (the other components being regulated network charges and government-imposed taxes and levies).

(20) It is important to note that retail prices alone generally do not tell the whole story about whether markets are working well or not, for instance in relation to barriers to entry or any other non-competitive conditions. Therefore, it is important to know the dynamics of supply and demand in order to fully understand price movements and entry barriers.

(21) Competition in retail electricity markets is a key element in cost-reflective pricing and fair and transparent procedures. Cost-reflective prices do not necessarily mean low prices, since a variety of factors can impact on prices. Input costs can be directly influenced by suppliers through the choice of their purchasing strategy. There are, however, a number of input costs for suppliers that are not determined by suppliers themselves, such as network charges and taxes. Nevertheless, retail suppliers compete on the margin, which is the mark-up on their incurred costs.

12 Retail market monitoring encompasses a variety of indicators including (but not limited to) retail price levels, switching rates, differences between wholesale and retail prices and concentration rates.

*(22)* The aim of retail market monitoring is to: detect barriers to competition; detect and measure inefficiencies in European electricity retail markets from a qualitative as well as a quantitative perspective; to establish pre-requisites for customers to benefit from a transparent market model in which suppliers compete on merit and prices are competitive up to the level of the efficient costs of supply. Differentiation is required between indicators that intend to measure the potential of a market and those measuring the dynamics of a market. The main categories of economic indicators used in this chapter to assess the development of competition in electricity retail markets are the evolution of prices and switching rates.[13] In order to ensure an in-depth analysis, and due to data constraints, this report will focus on prices and switching rates, although the Agency and CEER do recognise the importance of other retail monitoring indicators (for example, concentration ratios and market entry). The indicators tackled in this report are analysed in isolation and, where appropriate, set in relation to each other. In addition, smart metering and retail market design will be addressed in a descriptive way, with the inclusion of case studies where appropriate.

*(23)* This report distinguishes between regulated and non-regulated consumer prices. The Agency and CEER are aware that the very different price setting rules and methodologies in place in countries with regulated prices could have a different impact on retail market conditions. For the purpose of this report, the distinction between countries with regulated and non-regulated retail prices has been kept for reasons of data availability and continuity. In addition, a split between the EU-15[14] and non EU-15 MS will be made for the same reason, where appropriate.[15] As Norway is a member of CEER and contributes to the implementation of a single European energy market, it will also be included in the appropriate sections of this chapter.

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13 The categories will be analysed in detail in this chapter, e.g. the section on prices includes price developments, price indices and the relationship between wholesale and retail prices.

14 The EU-15 countries are the member countries of the European Union prior to 1 May 2004. They are Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom.

15 In all figures and tables, when UK and Ireland data occur, the following definitions apply: UK means the United Kingdom (England, Wales, Scotland, and Northern Ireland); Ireland means the Republic of Ireland; and Northern Ireland is the constituent country within the UK which shares a land border with the Republic of Ireland. In terms of consistency, data relating to different subsets of the UK are separately reported, depending on availability and source, using the name of the relevant constituent country or subset, for instance Great Britain (GB) or Northern Ireland (NI). In some but not all cases, data are available for the UK as a whole.

## 2.2 Electricity prices for final customers

*(24)* Several components influence the total electricity price charged to a customer. These components include the commodity price, transport, distribution and supply costs, levies and taxes. These components can differ widely between EU MS (and Norway) due to the various regulatory schemes and market developments. Most market surveys are interested in the commodity component, as this is the only component over which the customer can exert some discipline by switching supplier.

*(25)* The literature defines some of the main determinants of retail prices, which include:[16]

- Wholesale electricity prices:[17] there exists a strong relation between wholesale and retail prices in some countries, in particular the Scandinavian retail markets, where customers also have the possibility to take advantage of spot-priced products[18]; and
- Consumer protection regulation: implementation of measures such as the reduction of switching costs[19], fair contractual terms and transparent customer information.[20]

*(26)* Consumers with lower consumption profiles usually experience a higher average per kWh price due to standing charges applied by the majority of suppliers. A standing charge is a fixed amount consumers pay to be connected to an electricity network, irrespective of the amount of electricity actually consumed. Standing charges within the network price also lead to higher per kWh prices for low consumption profiles.[21] This chapter will primarily deal with an analysis of electricity prices for household customers.[22]

*(27)* At this stage, most NRAs monitor electricity end-user prices for household customers, either as price offers, or as actual prices paid by customers. Moreover, the majority of NRAs also monitors related indicators, such as the price spread vis-à-vis comparable products, the number of available offers and the retail margin.[23]

16 "The functioning of retail electricity markets for consumers in the European Union", European Consumer Markets Evaluation Consortium, 2010, see: http://ec.europa.eu/consumers/consumer_research/market_studies/docs/retail_electricity_full_study_en.pdf

17 Note that wholesale prices are affected by generation and consumption characteristics, including fuel mix, prices for fuels, consumption patterns, the structure of the generation sector (that is concentration of generation) and network topology.

18 The relationship between wholesale and retail prices will be addressed in more detail in section 2.3

19 In this context, the term "switching costs" relates to the non-monetary, psychological switching costs experienced by the consumer.

20 Bellantuono, G. and Boffa, F. (2008) "Residential energy markets in Europe: Designing effective institutions". February 2008, available at SSRN, see: http://ssrn.com/abstract=1121272

21 Some countries have decided not to introduce standing charge prices.

22 Household customers are a core topic of the 2009 Electricity Directive, as they are covered by Annex 1 when implementing the 3rd Package.

23 CEER Status Review of the Implementation of the ERGEG GGP on Retail Market Monitoring as of 1 January 2012.

### 2.2.1 The development of electricity prices

*(28)* In 2011, the retail market was, once again, held back by price regulation in a number of countries. The Agency and CEER are aware that the very different price setting rules and methodologies in place in countries with regulated prices could have a different impact on retail market conditions. In this report, those differences are not further analysed.

*(29)* Regulation of prices can take different forms.[24] Price regulation can be ex-ante or ex-post, can be focused in some categories of consumers (e.g. social tariffs) or comprehensive and can impose specific prices or set price caps. In the majority of cases, the regulatory authority is the price-setting authority. In some MS, NRAs reported that retail prices for small-scale users are not regulated, even though there might be an ex-post regime where NRAs review the reasonableness of prices and may intervene. Table 1 shows that in 2011, 100% of household customers were supplied under regulated prices in seven countries (Bulgaria, Cyprus, Estonia, Lithuania, Malta, Romania and Slovakia). In Greece, Hungary and Poland almost 100% of household customers still featured regulated prices, varying between 98.7% in Greece to 99.9% in Poland.

*(30)* Regulated end-user prices for households existed in 17 countries in 2011.[25] These were the same countries as in 2010. For non-household consumers, regulated prices were still applied in 12 countries, demonstrating that regulated end-user prices are continuing to be applied in a significant proportion of the countries analysed.[26] In Ireland, price regulation for electricity household customers was abandoned in April 2011.

*(31)* If necessary at all, regulated prices should be set at levels which avoid stifling the development of a competitive retail market, must be consistent with the provisions of the 3rd Package, and should be removed where a sufficient level of retail competition is achieved. Indeed, regulated prices can suppress competition if they are set at a level which does not allow costs to be recovered.

*(32)* If regulated prices are initially set at a level which exceeds underlying costs (assuming efficient costs are known to the regulator) by a guaranteed retail margin, this may not hinder competition, at least initially and under the condition of no entry barriers, because it may serve as a reference point. If the perceived switching benefits for consumers are negligible, any incentive to switch will be weak. Moreover, efficient entrants might make excessive profits for a period of time (i.e., until such profits are competed away) if the initial competition benchmark was set by the regulator at too high a level in comparison with efficient entry costs. As a consequence, consumers would be prevented from reaping the full benefits of competition.

*(33)* Where regulated end-user prices exist, the share of households supplied at regulated prices in 2011 is in five countries below 90%, in five countries between 90% and 100%, and in seven countries this share is 100%.

24 The Agency and CEER are aware of these differences in price-setting regimes and consider addressing these differences in the future. In particular, it is relevant to assess how these regimes affect the market.

25 Northern Ireland also featured regulated prices for household customers in 2011, but is not referred to as a country as it is part of the United Kingdom.

26 The example of Romania is described in detail in Annex 3.1.4 on regulated prices.

(34) The share of households supplied at regulated electricity prices (approx. 127 million households) out of the total households (approx. 247 million) supplied with electricity in the analysed countries (the EU-27 and Norway) was higher than 50% in 2011.

(35) The share of non-household customers (by volume) supplied at regulated prices varied widely in 2011, ranging from 2% to 100% in countries that still regulate non-household prices. The share of non-household consumers with regulated prices as a percentage of the total consumption of non-household consumers in the EU-27 group (and Norway) is around 14%.

**Table 1: Retail electricity price regulation across Europe – 2011**

| Country | Household regulated prices | % of household customers under regulated prices |
|---|---|---|
| Austria | No | |
| Belgium | Yes | 7.7% |
| Bulgaria | Yes | 100.0% |
| Cyprus | Yes | 100.0% |
| Czech Republic | No | |
| Denmark | Yes | 85.0% |
| Estonia | Yes | 100.0% |
| Finland | No | |
| France | Yes | 94.0% |
| Germany | No | |
| Great Britain | No | |
| Greece | Yes | 98.7% |
| Hungary | Yes | 99.6% |
| Ireland | Yes (until April 2011) | 63.3% |
| Italy | Yes | 83.3% |
| Latvia | No | |
| Lithuania | Yes | 100.0% |
| Luxembourg | No | |
| Malta | Yes | 100.0% |
| Netherlands | No | |
| Northern Ireland | Yes | 89.9% |
| Norway | No | |
| Poland | Yes | 99.9% |
| Portugal | Yes | 94.5% |
| Romania | Yes | 100.0% |
| Slovakia | Yes | 100.0% |
| Slovenia | No | |
| Spain | Yes | 74.4% |
| Sweden | No | |

*Source: CEER National Indicators (2012)*

*(36)* Low levels of consumer switching are not necessarily an indicator of ineffective competition, for example in mature markets where prices have converged and consumers hardly find it attractive to switch any longer.

*(37)* Post-tax total prices (POTP) are defined as the sum of the commodity price, regulated transmission and distribution charges, and retail components (billing, metering, customer services, and a fair margin on such services) plus VAT, levies (as applicable: local, national, environmental) and any surcharges (as applicable).

*(38)* Table 2 shows that Germany records the highest POTP of all those countries without any price regulation in place.[27] The total price for German household consumers was 25.3 euro cent/kWh in 2011, which is e.g. 100%, 70% and 63% higher than the price charged to households in respectively Latvia, Czech Republic and Finland. This can be explained by the fact that energy taxes are twice (see Figure 5) as high in Germany as for example in Finland. Generally speaking, and as is expected, the highest retail prices can be observed in countries with higher taxes and those having limited or even non-existent interconnections to neighbouring countries (so-called “electricity islands” such as the Baltic region, Malta and Cyprus).

*(39)* In countries with price regulation in place, the picture is even clearer. Danish household customers pay the highest prices in the EU (29.42 euro cent/kWh). Again, this is mainly due to high taxation, which accounts for up to 55% of total energy prices in Denmark, whereas the energy component makes up less than 25% of total prices overall.[28] Prices in Bulgaria were the lowest among the group of EU-27 countries, with a total price of 8.5 euro cent/kWh in 2011. The average price for EU-27 countries in 2011 was 18.1 euro cent/kWh. For EU-15 countries, the average price was 19 euro cent/kWh.

27 Annual non-weighted average per country, based on half-yearly data, using Eurostat consumption band DC (2500-5000 kWh) for households and consumption band ID (2000-20000MWh) for non-households.

28 Detailed analysis for EU-15 MS can be found in section 2.2.2.

**Table 2: Electricity post-tax total prices in EU-27 plus Norway – 2010 and 2011 (euro cent/kWh)**

| Country | Household regulated prices | Household prices (euro cent/kWh) | | Industrial prices (euro cent/kWh) | |
|---|---|---|---|---|---|
| | | 2010 | 2011 | 2010 | 2011 |
| Austria | No | 19.49 | 19.76 | NA | NA |
| Belgium | Yes | 19.67 | 21.28 | 11.37 | 12.03 |
| Bulgaria | Yes | 8.22 | 8.50 | 7.05 | 7.05 |
| Cyprus | Yes | 19.40 | 22.32 | 17.32 | 19.99 |
| Czech Republic | No | 13.69 | 14.81 | 11.46 | 11.78 |
| Denmark | Yes | 26.89 | 29.42 | 19.06 | 23.77 |
| Estonia | Yes | 9.87 | 10.08 | 8.34 | 8.68 |
| Finland | No | 13.48 | 15.57 | 8.25 | 8.95 |
| France | Yes | 13.17 | 14.03 | 7.82 | 8.60 |
| Germany | No | 24.07 | 25.30 | 13.76 | 15.28 |
| Greece | Yes | 11.96 | 12.44 | 9.48 | 10.20 |
| Hungary | Yes | 16.38 | 16.18 | 11.72 | 12.19 |
| Ireland | Yes (Until April 2011) | 18.40 | 19.94 | 9.51 | 10.26 |
| Italy | Yes | 19.43 | 20.26 | 14.04 | 15.03 |
| Latvia | No | 10.49 | 12.55 | 10.14 | 11.55 |
| Lithuania | Yes | 11.86 | 12.18 | 11.74 | 12.39 |
| Luxembourg | No | 17.37 | 16.70 | 8.35 | 7.75 |
| Malta | Yes | 17.00 | 17.00 | 16.80 | 16.80 |
| Netherlands | No | 17.00 | 17.91 | 11.06 | 10.31 |
| Norway | No | 19.67 | 20.02 | 10.48 | 10.77 |
| Poland | Yes | 13.62 | 14.11 | 10.44 | 10.15 |
| Portugal | Yes | 16.25 | 17.68 | 8.41 | 10.05 |
| Romania | Yes | 10.42 | 10.84 | 8.62 | 9.16 |
| Slovakia | Yes | 15.79 | 16.96 | 12.76 | 13.99 |
| Slovenia | No | 14.14 | 14.67 | 10.27 | 10.16 |
| Spain | Yes | 17.90 | 20.35 | 10.67 | 10.94 |
| Sweden | No | 18.99 | 20.68 | 9.08 | 9.35 |
| United Kingdom | No for GB, Yes for NI | 14.18 | 15.09 | 10.33 | 10.94 |

*Source: Eurostat (2012), CEER National Indicators (2012)*

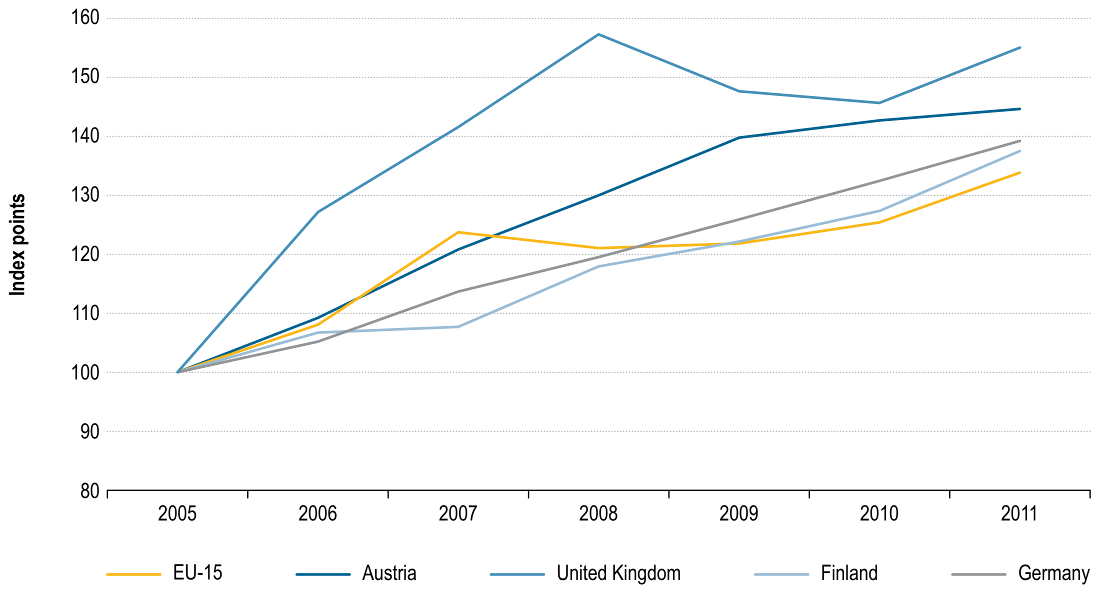
*Note: The vast majority of the United Kingdom has non-regulated electricity prices, with Northern Ireland still featuring regulated prices in 2011.*

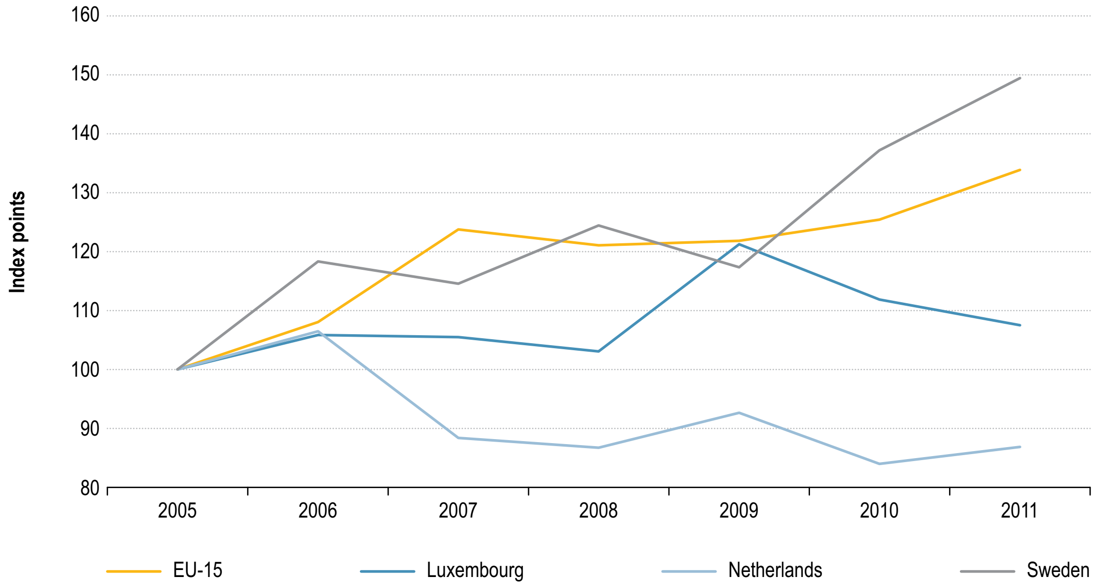
*(40)* The statistics show a strong variation in both household and industrial prices. For regulated prices, the highest 2010 value (Denmark) was 3.3 times higher than the lowest value (Bulgaria). In 2011, this ratio increased to 3.5. The ratio was lower for industrial customers: prices in Denmark were 2.7 times higher than in Bulgaria. In 2011, this ratio increased significantly to 3.4.

*(41)* Figure 1 describes price developments over time as an index, where January 2005 is taken as the base value of 100.[29] It shows that prices for household customers increased in nearly all EU-15 countries without regulated prices. The highest increase of 55% between 2005 and 2011 occurred in the United Kingdom. Over the same period, the lowest increase can be observed in Luxembourg, which was 10%. Only in the Netherlands did the total price reach a 14% lower level in 2011 compared to 2005.

29 Consumption band DC, 2500-5000 kWh, Eurostat, new methodology from 2007 on.

**Figure 1: Indexed post-tax total prices for households across EU-15 without regulated prices – 2005 to 2011 (2005 = 100 index points)**



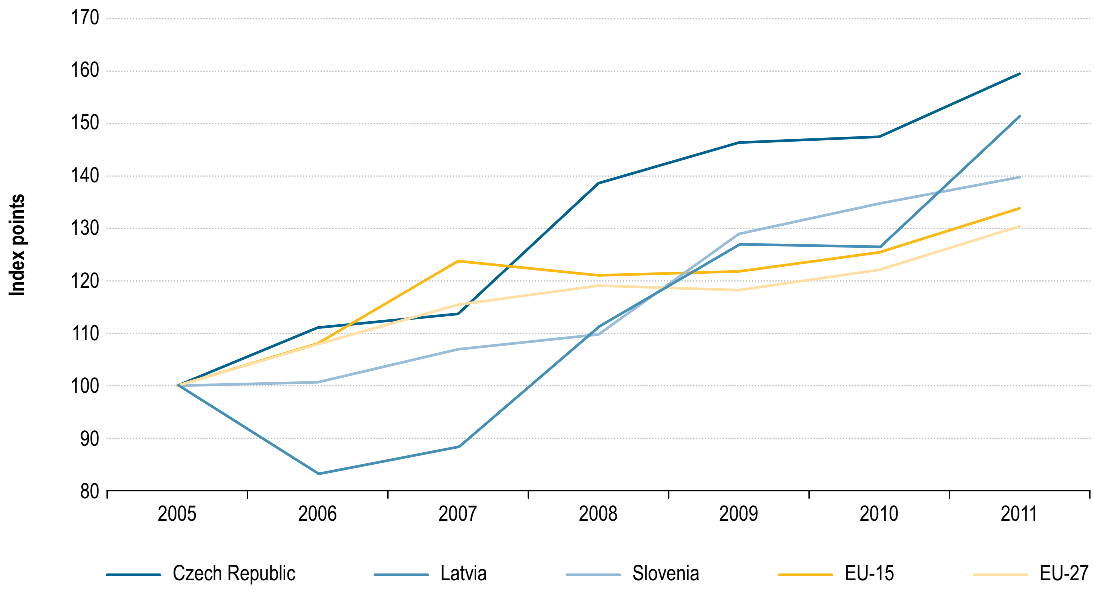




*Source: Eurostat (2012)*

*Note: Consumption band DC, 2500-5000 kWh. The vast majority of the United Kingdom features non-regulated electricity prices, with Northern Ireland still featuring regulated prices in 2011.*

*(42)* The Czech Republic, Latvia and Slovenia are the only non EU-15 countries without regulated prices for household customers. Following a significant decrease in 2006 and 2007, prices in Latvia increased by 50% in 2011 compared to 2005. Figure 2 shows that the overall price differences between 2005 and 2011 in these MS have been much higher than the EU-15 average, varying between 40% and 60%. This can be partially explained by initially low prices (also due to the exogenous macroeconomic targets of the respective governments) compared to other countries in 2005. On average, post-tax prices in the EU-27 countries increased by 30% from 2005 and by 9.4% between 2010 and 2011.

**Figure 2: Indexed post-tax total prices for households across non EU-15 without regulated prices – 2005 to 2011 (2005 = 100 index points)**



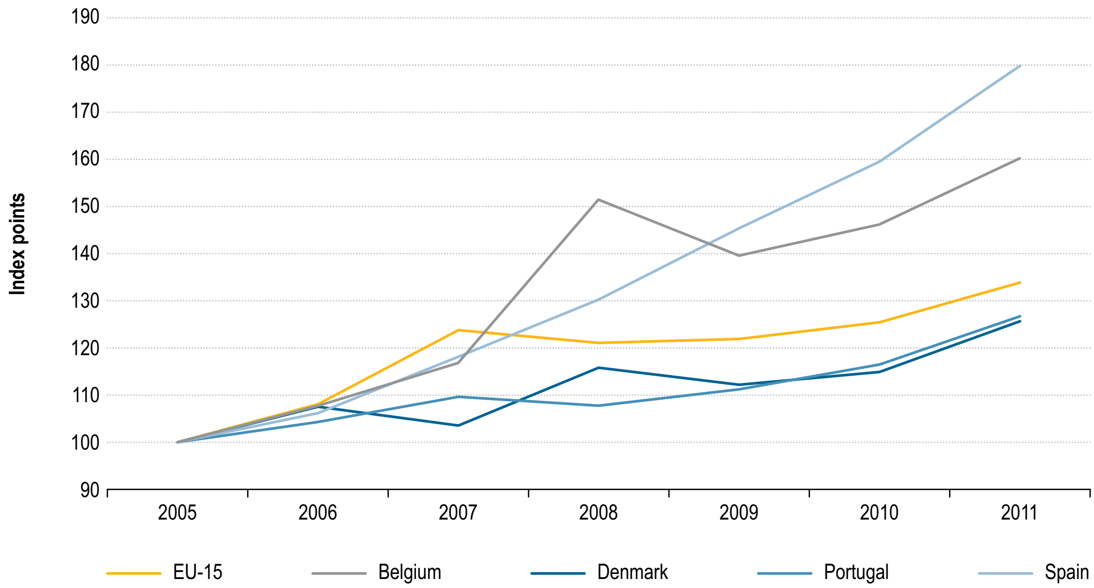

*Source: Eurostat (2012)*

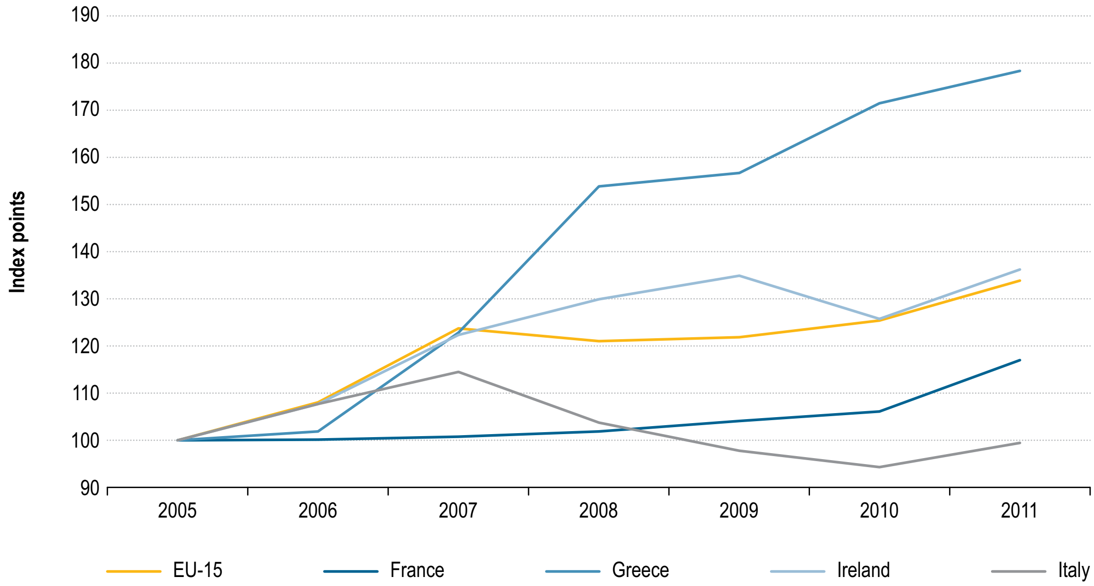
*Note: Consumption band DC, 2500-5000 kWh.*

*(43)* Among the EU-15 countries, regulated prices for household customers are still in place in Belgium, Denmark, France, Greece, Ireland,[30] Italy, Portugal and Spain. As shown in Figure 3, regulated prices have mostly been increasing since 2005. The highest increases, up to 80%, can be observed in Spain and Greece, while in 2011, Italian prices were at the same level as in 2005.

30 Ireland abandoned price regulation for household customers in April 2011.

**Figure 3: Indexed electricity post-tax total prices for households across EU-15 with regulated prices – 2005 to 2011 (2005 = 100 index points)**



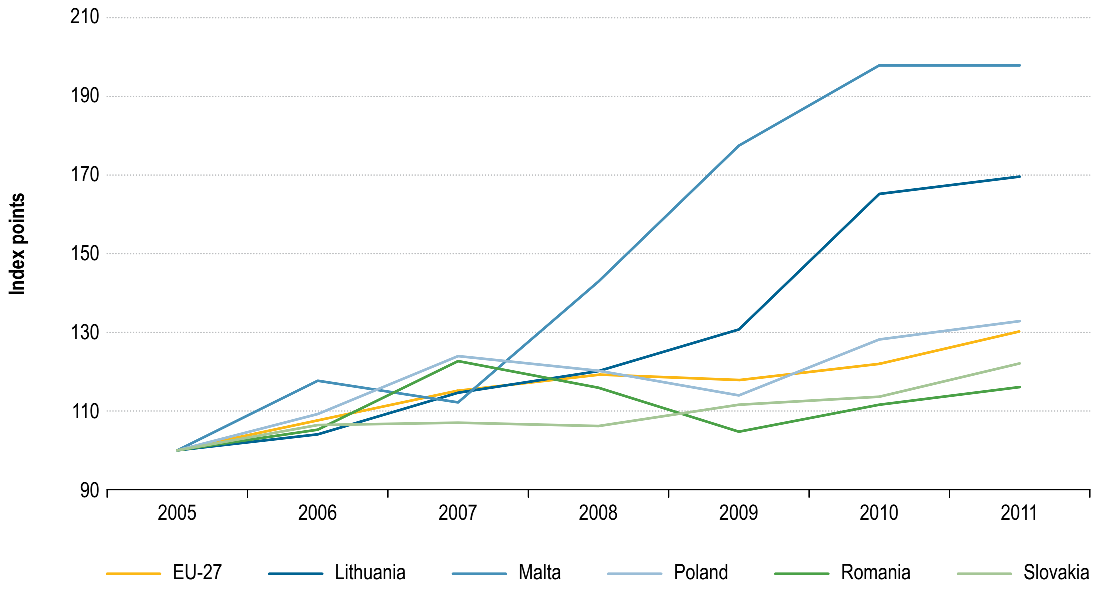



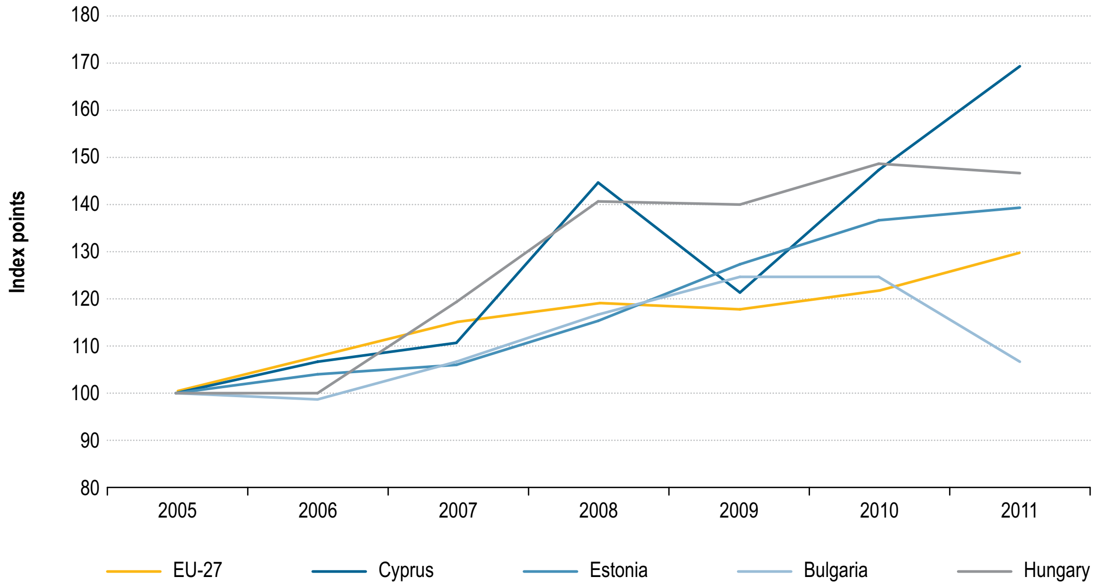

*Source: Eurostat (2012)*

*Note: Consumption band DC, 2500-5000 kWh.*

(44) For non EU-15 countries, the pattern of price developments since 2005 is more complex. Figure 4 shows an overall upward trend. It should be remembered that most of the countries included in the figure experienced relatively low price levels prior to 2005, as opposed to, for example, countries without regulated prices. An increase of almost 100% within seven years can be seen in Malta. Bulgaria is the only country where prices in 2011 were only moderately higher than in 2005 (6%).

**Figure 4: Indexed post-tax total prices for households across non EU-15 with regulated prices – 2005 to 2011 (2005 = 100 index points)**




*Source: Eurostat (2012)*

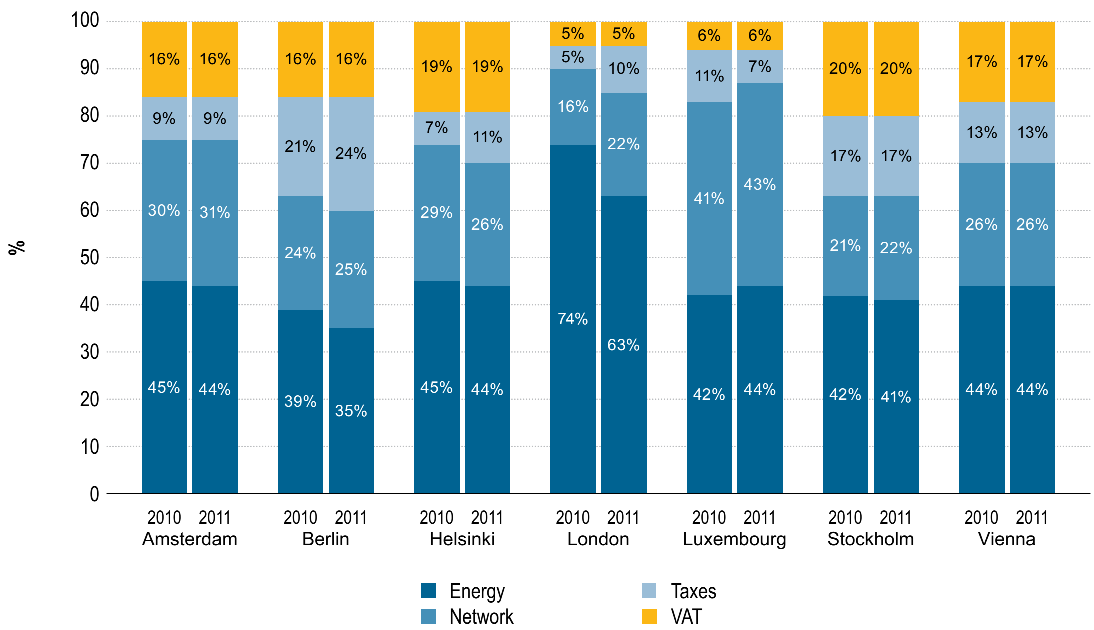
*Note: Consumption band DC, 2500-5000 kWh.*

### 2.2.2. Retail price breakdown

*(45)* This section provides an analysis of the structure of retail prices which are charged to consumers in several capital cities of EU MS. The data includes information on regulated and non-regulated prices covering December in both 2010 and 2011.

*(46)* Significant variations in the structure of prices charged to household customers apply to capital cities without regulated prices (see Figure 5). It is striking that the energy component has decreased or remained at the same share of the total price in all capital cities except Luxembourg. The increase in levies and taxes is mainly due to the increasing support for renewables in a selection of European capital cities, for instance in Berlin, Helsinki and London. For capital cities of the EU-15 countries, the electricity price component (including retail margins) represents about 45% of the total cost; transmission and distribution accounts for 30%; energy taxes for 12%; and VAT for 14%,[31] with some rounding error.

**Figure 5: Breakdown of post-tax total price for a selection of capital cities without regulated prices – December 2010 and December 2011**

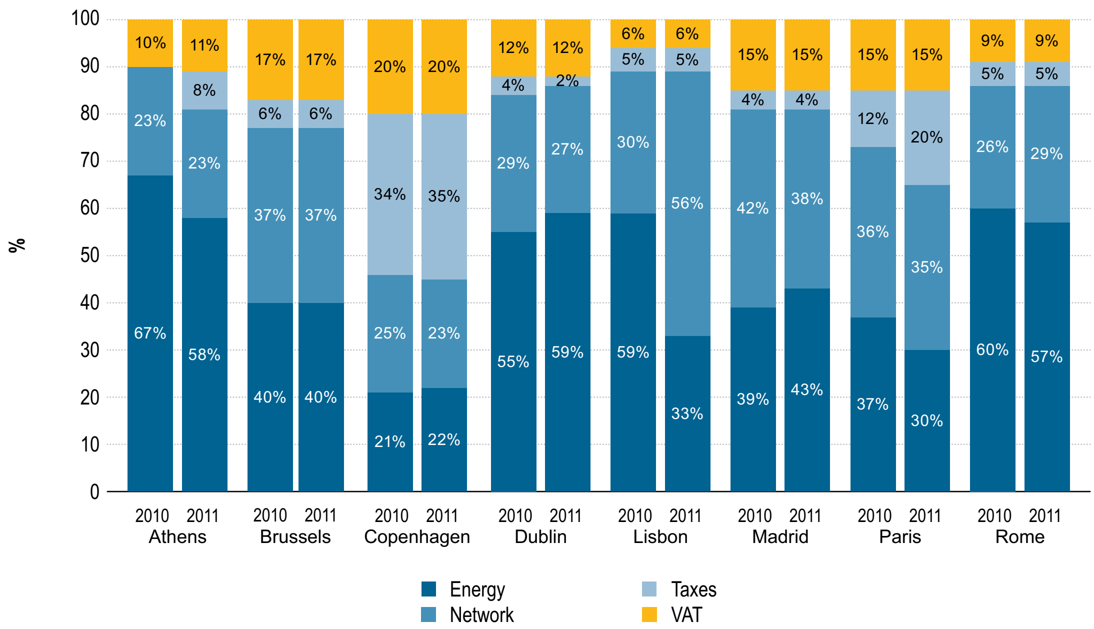



*Source: E-Control/VaasaETT (2012)*

31 E-Control/VaasaETT (2012).

(47) Figure 6 shows the variations in the structure of prices charged to household customers in the capital cities of the EU-15 countries in which price regulation applies. The highest taxes can be found in Copenhagen, where the sum of all energy taxes, levies and VAT accounts for more than 50% of the total price.

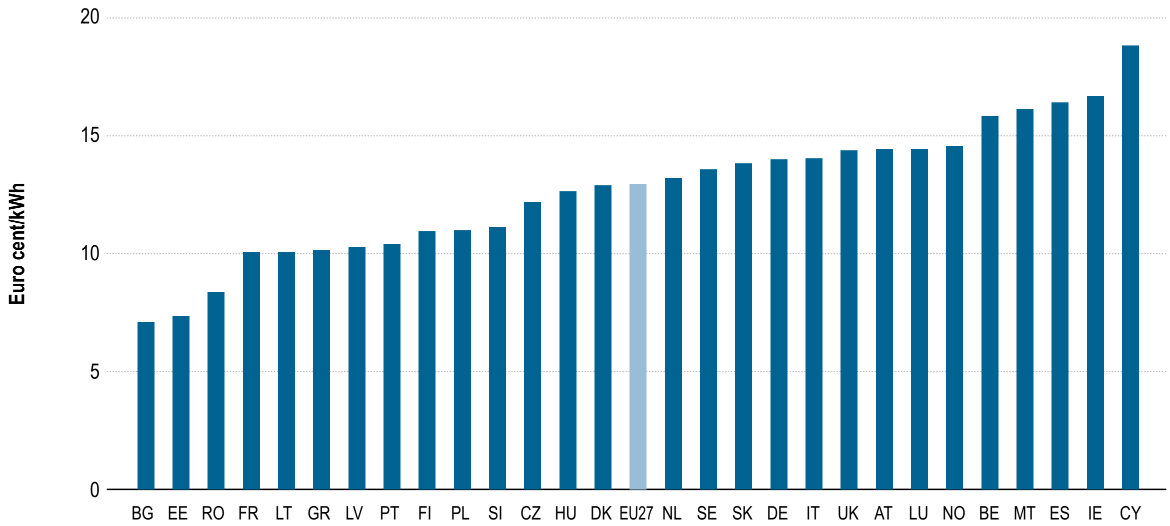
**Figure 6: Breakdown of post-tax total price for a selection of capital cities with regulated prices – December 2010 and December 2011**




*Source: E-Control/VaasaETT (2012)*

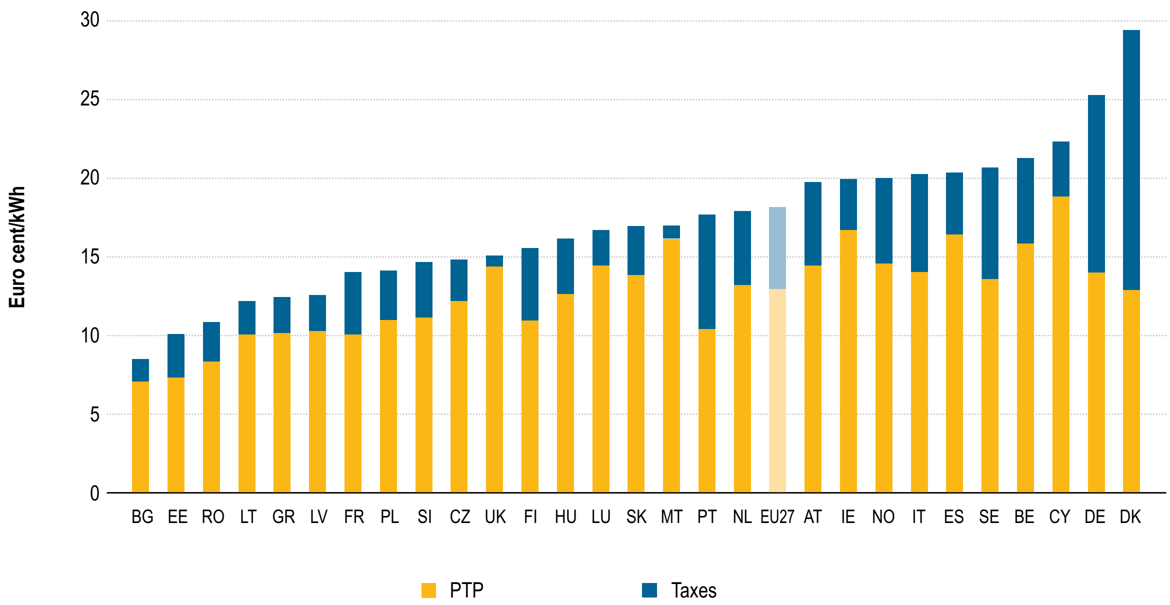
*(48)* Figure 7 and Figure 8 provide evidence of the impact of taxes on the relative prices of electricity to households across the EU. Price disparities exist even pre-tax; they do, however, become more significant when comparing them post-tax. In this context, it is important to mention that surcharges for supporting renewables and other price add-ons can be represented in different price components across countries depending on support mechanisms. Some countries add them to the energy price, whereas others include them in the distribution or taxes component.

**Figure 7: Electricity pre-tax total price in the EU-27 plus Norway – 2011 (euro cent/kWh)**




*Source: Eurostat (2012)*

**Figure 8: Electricity post-tax total price in the EU-27 plus Norway – 2011 (euro cent/kWh)**




*Source: Eurostat (2012)*

*Note: Consumption band DC, 2500-5000 kWh.*

*(49)* Some countries (Bulgaria, Estonia and Romania) recorded the lowest Pre-Tax Total Price (PTP)[32] and the lowest POTP[33]. There are countries such as Luxembourg and Malta that rank above EU-27 average prices in terms of PTP and below in terms of POTP. Cyprus records the highest PTP and the third highest POTP, with Spain also placed at the higher end in both sets of rankings. Germany shows the second highest POTP but ranks lower in terms of PTP. This is mainly due to support for renewables, which is reflected in higher taxes. The highest taxation regime applies to Denmark, where the PTP is even lower than the EU-27-average.

### 2.2.3 Price variations using the PPS methodology

*(50)* The "Purchasing Power Standard" (PPS), is an artificial currency unit which allows for price comparisons of goods or services across Europe. One PPS buys the same volume of goods and services in all MS, based on a standard basket of representative goods and services as determined by Eurostat. This unit allows for meaningful volume comparisons of economic indicators. Aggregates expressed in PPS are derived by dividing aggregates in current prices and national currency by the respective purchasing power parity (PPP).[34]

*(51)* Using the PPS methodology is one possible way to determine by how much end-user prices converge or diverge once they are adjusted for different purchasing powers. PPS would typically correct prices upwards in those MS whose cost of living is below the European average, and downwards otherwise.

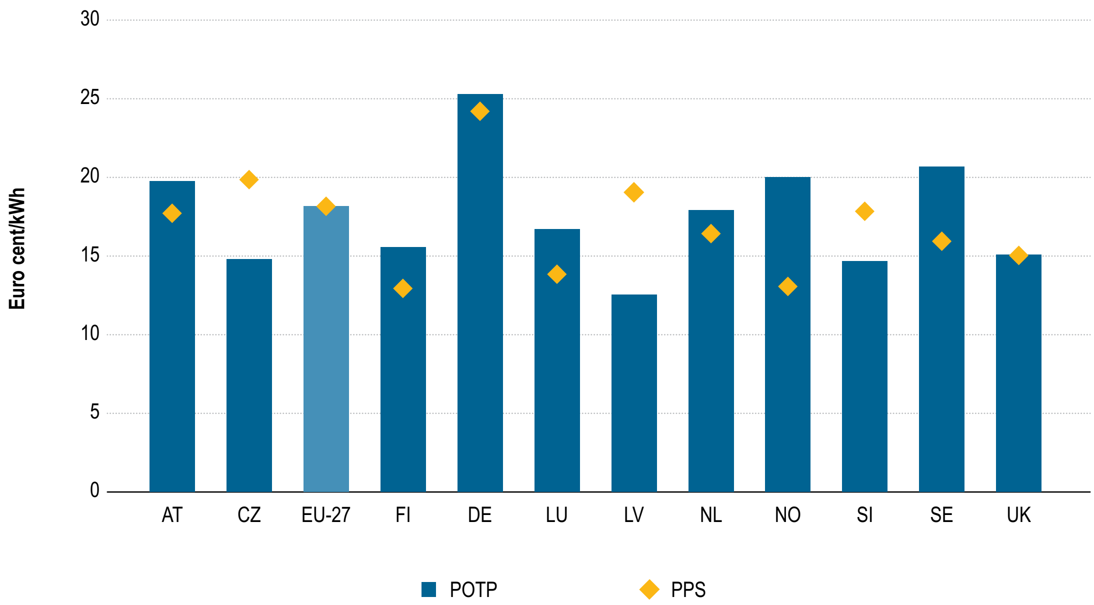
*(52)* Price dispersion throughout the EU is lower when energy prices (excluding network tariffs, levies and taxes) are compared using PPS; however, it remains significant. The highest PPS price is 2.1 times higher than the lowest price (see Figure 9 and Figure 10). Obviously, countries such as the Czech Republic, Latvia and Slovenia, which on the face of it appear to have low prices, become much more expensive when prices are normalised to adjust for purchasing powers.

32 The Pre-Tax Total Price (PTP) is defined as the sum of the commodity price, regulated transmission and distribution charges, and retail components (billing, metering, customer services and a fair margin on such services).

33 The Post-Tax Total Price (POTP) is the final price to consumers, including the commodity price, regulated transmission and distribution charges, and retail components (billing, metering, customer service, and a fair margin on such services), any tax or levy (as applicable: local, national, environmental) and any surcharges (as applicable).

34 PPS is a measure developed by Eurostat and adopted by the European Commission. Together with related indicators, it is described at: http://epp.Eurostat.ec.Europa.eu/statistics_explained/index.php/Glossary:Purchasing_power_standard_(PPS)

**Figure 9: Electricity post-tax total price versus PPS for MS without regulated prices – 2011 (euro cent/kWh)**

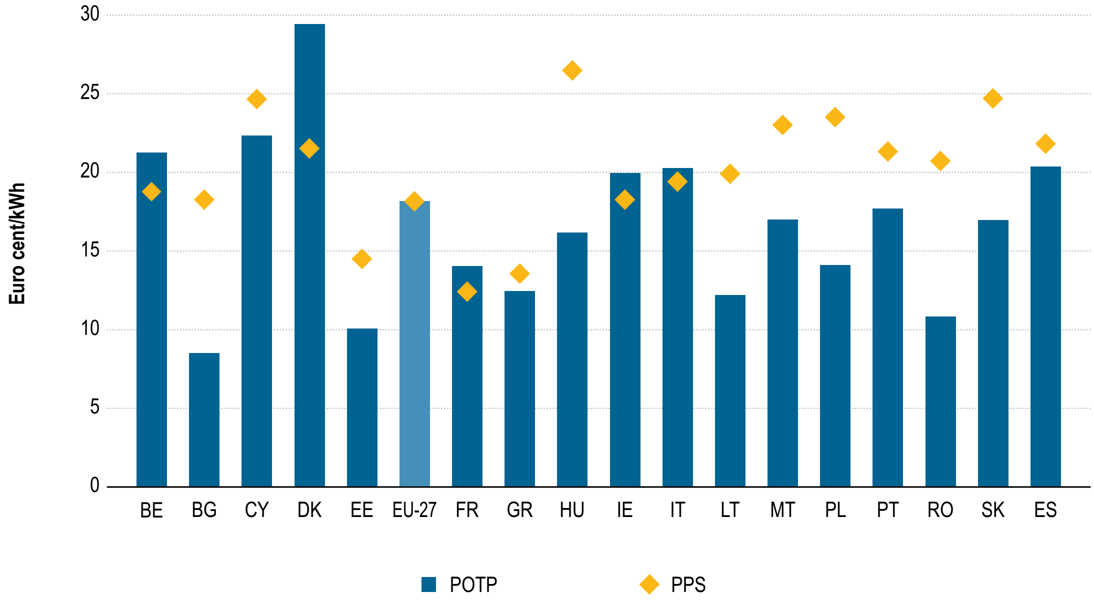



*Source: Eurostat (2012)*

*Note: Consumption band DC, 2500-5000 kWh.*

*(53)* Figure 9 and Figure 10 show that when normalising prices to adjust for purchasing powers, prices for most of the "newer" MS (that is to say non EU-15 countries) especially become much more "expensive". Nominal prices in these countries seem to be particularly low, leading to the conclusion that electricity in these countries is more affordable. In fact, the PPS in countries such as Lithuania, Romania and Bulgaria imply that the average price is set at a comparatively high level in terms of actual affordability.

**Figure 10: Electricity post-tax total price versus PPS for MS with regulated prices – 2011 (euro cent/kWh)**




*Source: Eurostat (2012)*

*Note: Consumption band DC, 2500-5000 kWh.*

### 2.2.4 Other retail monitoring indicators

*(54)* The Household Energy Price Index (HEPI) is a volume weighted end user price index (for electricity and gas) that assesses the overall price development in the capital cities of the EU-15, excluding taxes.[35] It is based on the *monthly* electricity and natural gas prices collected for both incumbents and competitor companies from January 2009 to December 2011. The advantage of the HEPI index vis-à-vis the retail prices which have been presented above is that it illustrates the prices paid (in kWh) by households for a typical average national consumption profile. In other words, these are the prices charged to the common household in the group of EU-15 capitals cities.[36]

*(55)* The ACER Price Index is similar to the HEPI index and also covers the period from January 2009 to December 2011. However, it describes price development, excluding taxes, for the EU-27 countries on a *half-yearly* basis.[37] It provides information on the overall development of prices for household consumers, excluding taxes, with a typical average national consumption profile and is based on the Eurostat half-yearly price and annual consumption data. The ACER Price Index shows how much the average European consumer pays per kWh. In contrast to the HEPI, the ACER Price Index includes the average national prices and the average national consumption profiles of all EU-27 countries.

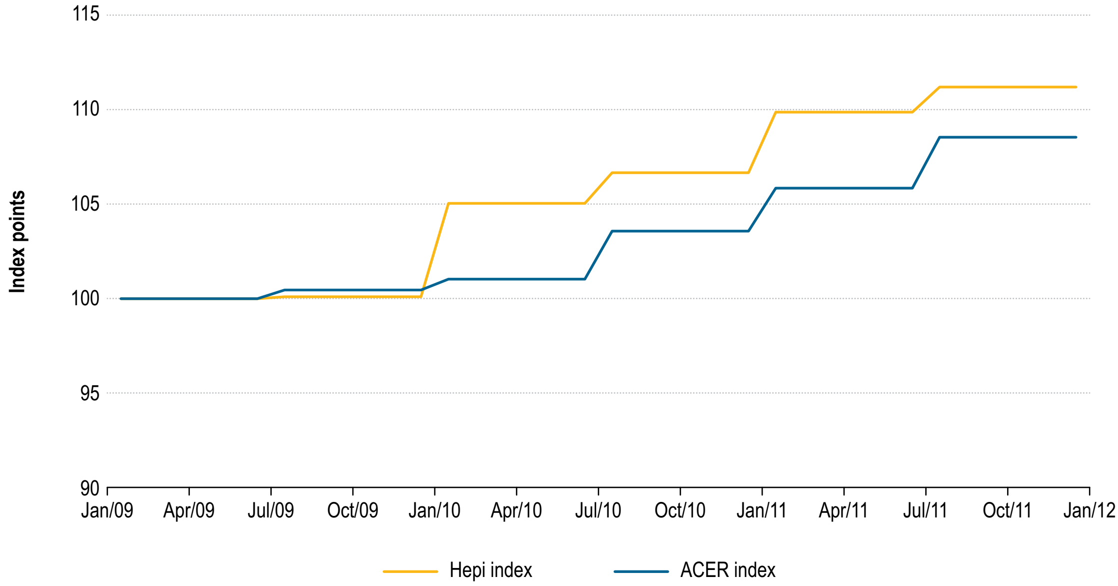
*(56)* Figure 11 plots the HEPI and ACER Price Index from January 2009 to December 2011. Both confirm the general increase in retail prices, as presented in the previous sections. The HEPI and the ACER Price Index show similar developments in time. It is remarkable that from January 2010 onwards, the HEPI index is consistently around 3 index points higher than the ACER Price Index. However, this does not imply that the general price level is necessarily higher in the EU-15 capital cities compared to the EU-27 country averages, as neither the HEPI nor the ACER Price Index show absolute values, but instead show the variation in prices over time.

35 E-Control Austria – in cooperation with VaasaETT – compiled HEPI in January 2009, see: http://www.e-control.at/portal/page/portal/medienbibliothek/presse/dokumente/pdfs/HEPI_Juni_englisch_Final.pdf

36 A six-month average of the HEPI monthly values is used to make data compatible with the data for the ACER Price Index, which is only available on a half-yearly basis.

37 Household consumption bands DB (1000-2000 kWh), DC (2500-5000 kWh) and DD (5000-15000 kWh) of Eurostat were used for the ACER Price Index, according to the average national annual consumption of households.

**Figure 11: HEPI versus ACER price Index – first semester (2009 = 100 index points)**




*Source: Eurostat, E-Control/VaasaETT (2012)*

*(57)* The price spread is an important indicator measuring retail market outcomes by analysing the difference between the cheapest and the most expensive offer.[38] A low price spread can be taken as a sign of a mature competitive market, although this may not necessarily be the case. The price spread is defined as the difference between the most expensive and the cheapest comparable offer available to a household customer at the same point in time. Comparable offers are defined as equivalent contract types.

*(58)* When comparing price spreads in capital cities[39] with switching rates, no strong relation can be observed.[40] This can be explained by the fact that prices are not the only driver of switching, but that other non-price competition elements also play an important role. The lack of switching can be explained by, for example, customer loyalty, good quality of service, lack of awareness/information and pure inertia.

*(59)* In countries with low regulated prices, the lowest price tends to settle near the regulated price. For example, given the regulated price in Spain the cheapest (non-regulated) offer available is only 3% cheaper, and in France the price difference is between 4% and 5%.[41] As this price spread is stable, it seems that the lowest price is generally set in line with the regulated price, give or take a negligible amount. This could affect the development of effective competition.

38 See previous work of ERGEG; ERGEG "Final GGPs on Indicators for Retail Market Monitoring" (Ref:E10-RMF-27-03).

39 Price Comparison Tools; NRAs; the information is available only for a limited number of countries.

40 Switching rates are only available at the national level; CEER National Indicators (2012).

41 CNE, CRE, Price Comparison Tools.

## 2.3 The relationship between retail and wholesale prices

(60) In countries with less competitive energy retail markets, typically characterised by limited choice for consumers, switching rates are likely to be rather low. In these countries, market entry of new suppliers is often limited. One of the main factors influencing the competitive character of a country is the relationship between retail and wholesale prices.

(61) In this section, an analysis of the relationship between retail and wholesale prices for a number of MS is provided.[42] Only retail prices in capital cities have been taken into account as a retail price reference, which can be indicative of retail market trends in the country. Due to data constraints, only spot prices are taken into account as wholesale price references. The Agency and CEER are aware that this might not be totally accurate for all countries (especially in those where the day-ahead market is less relevant and its prices diverge from forward prices) and that purchasing strategies of suppliers might differ from the scenario described in this section. Margins will not be assessed, as the purchasing strategies (costs) of suppliers in the different countries are unknown. All countries with or without regulated prices with liquid spot markets are examined.[43] The spot prices will be compared to the energy component of retail prices, excluding network charges, taxes and levies.

(62) The data is compiled in the following way:

- The monthly average of power exchange prices;
- The average spot prices during the last three months; and
- The monthly average of the energy component of the retail price in capital cities (excluding network charges, taxes, levies).[44]

(63) In principle, the commodity price should, at least to a certain extent, influence the retail price. As shown in the figures in Annex 3.1.2 on the correlation between wholesale and retail electricity prices, this is not always confirmed by the data.

(64) In general, it can be noticed that the energy component of retail prices in countries without regulated prices correlate better with wholesale prices than in countries with regulated prices. This is intuitive, as the retail commodity element in countries with regulated prices in place is not exposed to the full dynamics of the market. However, different retail market designs and different price setting mechanisms in countries with regulated prices lead to completely different results. The Swedish market without regulated prices and the Belgian market with a share of 92% of customers supplied at non-regulated prices seems to react significantly to wholesale prices. In Sweden, a huge variety of retail products are linked to the spot price, which explains the link between the retail and wholesale prices. Finland shows moderate correlation. In summary, all countries except Sweden, Belgium and Finland show a very low or, in exceptional cases, even a negative correlation. In Austria and Germany, extremely stable retail prices hardly reflect any change in the wholesale prices. Finally, huge differences in retail prices are apparent between Sweden and Finland where almost the same wholesale prices exist; this is due to completely different approaches to retail competition.

42 Detailed figures for all countries can be found in Annex 3.1.2 on the correlation between wholesale and electricity retail prices.

43 Even though some countries, e.g. Spain, have a dynamic component taking care of the development of wholesale market prices indirectly, regulated prices cannot be assumed to fully capture market dynamics due to the intervention of price-setting authorities.

44 Monthly energy price of the incumbent and the biggest competitive supplier in capital cities weighted by market shares. E-Control/ VaasaETT (2012).

(65) Appropriate national monitoring tools are needed to analyse and understand market behaviour. Therefore, an in-depth analysis of the relationship and the influence of wholesale prices on retail prices is a useful exercise that should be undertaken at national level. The case study of Austria (below) offers an example of how NRAs analyse the relationship between retail and wholesale prices. The main message of the case study is that wholesale prices for different purchasing strategies have converged constantly over the last few years. Since the results for Austria may prove illustrative for some other countries, an analysis of the relationship between spot prices and retail prices seems to be a useful starting point.

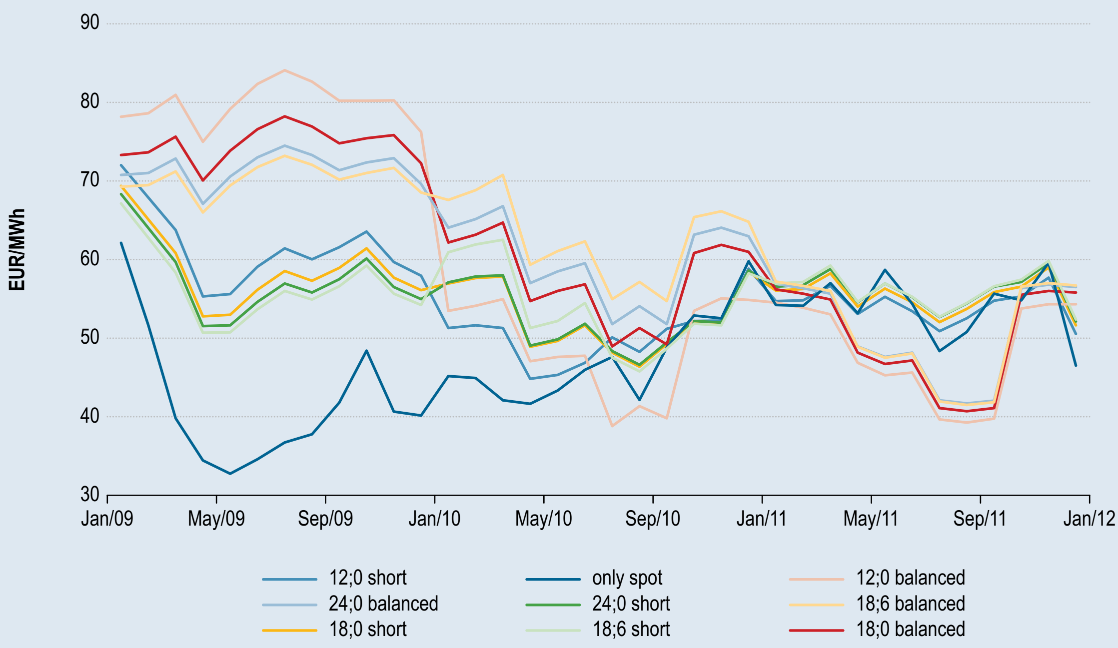
## Estimation of retail margins in Austria

The Austrian NRA, E-Control, has developed a model which allows for a simulation of nine supplier purchasing strategies. Strategies differ in terms of wholesale (spot) electricity purchases by Austrian retailers as well as purchasing intervals. The strategy "18;6 balanced" assumes for instance that purchasing starts 18 months in advance and ends 6 months prior to delivery. A balanced strategy implies that additional electricity has to be bought on the spot market half of the time, while during the other months, the retailer needs to sell excess electricity on the spot market. On the other hand, there exists a "short" strategy whereby 100% of the energy sold to customers is bought on the spot market.

It becomes obvious that, in 2011, the mark-ups which suppliers obtain from different purchasing strategies converged. Furthermore, a purchasing strategy longer than 2-3 years on EEX is not feasible, due to the lack of liquidity of long-term products.

Cost related to purchasing strategies varied between 4 and 6 euro cent/kWh in 2011. If one takes into account the most expensive Austrian electricity suppliers, this leads to a mark-up of more than 40%. Mark-ups could be even higher when suppliers were able to buy electricity more profitably by taking advantage of price developments in the wholesale market.

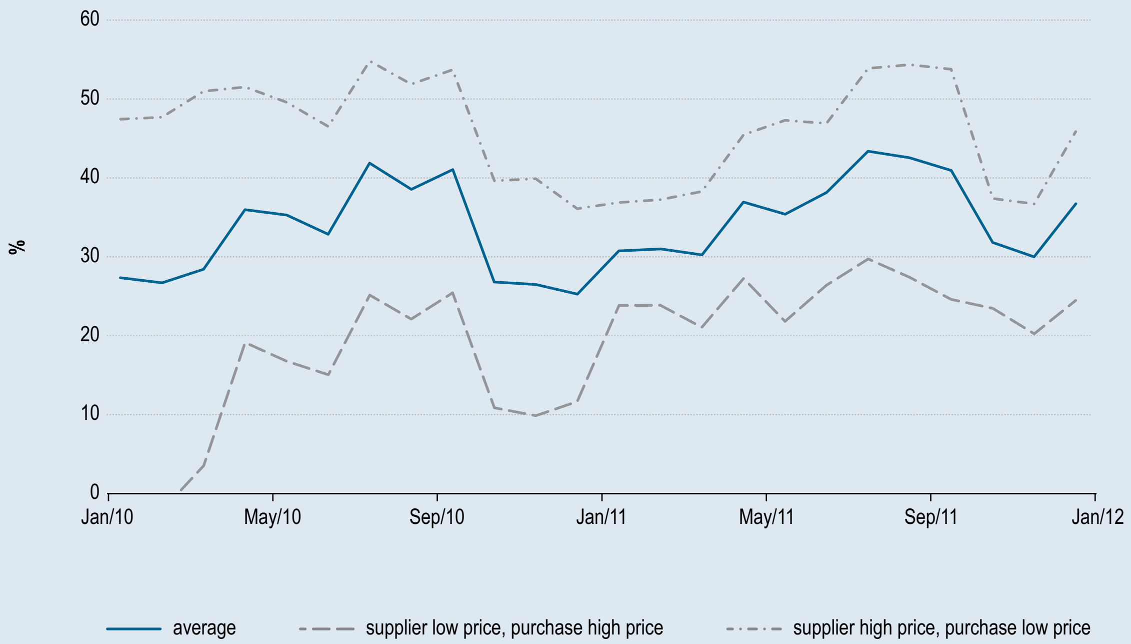
**Figure 12: Mark-up on the wholesale price for different purchasing scenarios – 2009 to 2011 (euro/MWh)**




*Source: Calculations by E-Control, EPEX Spot, EEX, APCS (2012)*

E-Control estimated supply mark-ups by taking into account the end-user prices for a typical Austrian household with a consumption of 3500 kWh/year. In 2011, the estimated average margins varied from 2.6 to 4.4 cents/kWh. Service costs, such as billing, must also be taken into account.[45] As the NRA expects these costs to be a maximum of 1 cent/kWh for a customer with an average yearly consumption of 3500 kWh, the profit for suppliers can be significant.

**Figure 13: An estimation of the mark-up of Austrian suppliers - January 2010 to November 2011 (%)**




*Source: Calculations by E-Control, EPEX Spot, EEX, APCS (2012)*

In August 2011, E-Control sent out a questionnaire addressing competition-related questions to 19 Austrian suppliers. The intention of the questionnaire was to further analyse the suppliers' purchasing strategies and margins. E-Control is legally empowered to inspect documents of market participants, as well as to initiate market surveys. Unfortunately, none of the suppliers contacted answered the questionnaire, as a result of which, the constitutional court became involved in the proceedings.[46]

45 National Report Austria 2012.

46 See footnote 45.

*(66)* Although it is difficult to draw any conclusions in terms of energy policy, low switching rates[47] are certainly not conducive to reducing the wedge between retail and wholesale prices.[48] Switching rates vary widely between countries without regulated prices, varying from 0.2% in Luxembourg to 15.5% in Great Britain. The British market seems to be mature, with lower price dispersion than a few years ago. Finland and Sweden are among the few countries where retail products are often directly linked to spot prices, thus enabling retail prices to directly react to spot market developments. Austria and Luxembourg have extremely low switching rates, even though the price difference between retail and wholesale spot prices is around 40 euro/MWh.[49] The Austrian market is dormant, with very stable retail prices and price divergence mainly due to one-off rebates. Germany experiences the same price wedge, but a much higher switching rate, which can only be partly explained by the size of the market, the saving potential and the number of offers in the market. For an overview of switching rates, see Annex 3.1.1. on retail markets.

**Figure 14: Wholesale-retail price differences versus switching rates for electricity household customers in selected EU countries without price regulation – Average 2009-2011**


*Source: CEER National Indicators, E-Control/VaasaETT (2012)*

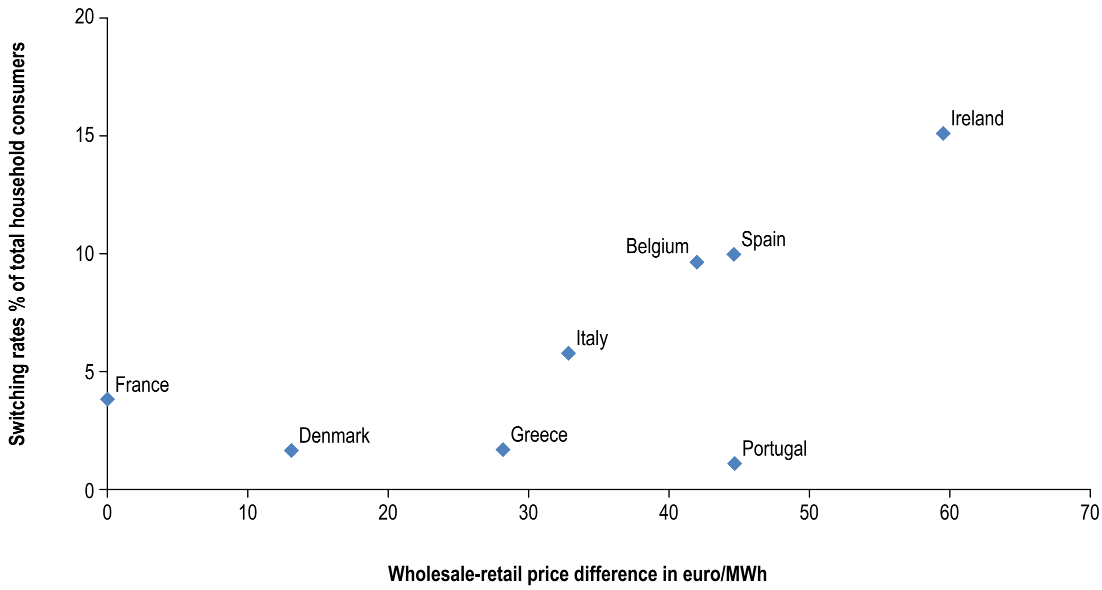
47 Reference figures for calculating yearly switching rates are the percentage of household customers having changed supplier on 31 December 2011 (switching rates by number). By definition, a "switch" additionally includes:
i. a re-switch: when a customer switches for the second or subsequent time, even within the same measured period of time;
ii. a switch back: when a customer switches back to his/her former or previous supplier; and
iii. a switch to a competitive company owned by the incumbent and vice versa.

48 The retail price is calculated as the market-share weighted average of the incumbent's and the largest competitor's commodity-only price, between 2009 and 2011, in the capital city. The wholesale price is calculated as the average of the spot price, between 2009 and 2011, for the country as a whole. The wholesale-retail price spread is then derived as the difference between the two prices defined above.

49 A high wholesale-retail price difference indicates potential for market entry, which could lead to more competition between suppliers for customers. This in turn should lead to more switches.

*(67)* In countries with existing price regulation, the average difference between wholesale and retail prices for the 2009-2011 period ranges from 0% in France to 59.6% in Ireland. It is expected that switching rates will generally be lower when prices are still regulated. However, it is more difficult to draw any conclusions based on the countries with regulated prices, due to different national specifics, with differences in switching rates ranging from 1.1% in Portugal to 15.1% in Ireland. For instance, France shows a negligible price difference, which is likely due to an overestimation of actual procurement costs. Further, the spot market in France plays a limited role in the supply of household customers. In Spain, switching rates have been increasing steadily from 2009 onwards, mainly due to a change in the regulatory system. The Irish market has become very active over the last few years, due to the increasing activity of suppliers.[50]

**Figure 15: Wholesale-retail price differences versus switching rates for electricity household customers in selected EU countries with price regulation – Average 2009-2011**




*Source: CEER National Indicators, E-Control/VaasaETT (2012)*

50 Further details can be found in Annex 3.1.1 on retail switching behaviour in a sample of European MS.

### 2.3.1 Smart metering (electricity and gas)

*(68)* Directive 2009/72/EC for the internal market prescribes the deployment of smart metering systems as a necessary measure to extend the benefits of retail markets to all users. This section deals with smart metering for electricity and gas. The background and the benefits of rolling out smart meters do not differ significantly between the electricity and gas sectors, even though the status of roll-out is more advanced in electricity.

*(69)* Smart metering creates additional value by enhancing product variety for consumers. Products could be customised as a function of customers' preferences and needs; for example, products could be developed with a stronger distinction between peak and off-peak. Moving away from fixed pricing and allowing more dynamic pricing models to develop should create an incentive to use energy more efficiently. Furthermore, smart metering might increase customer awareness and therefore encourage more efficient use of energy. It is likely that the product offers and price models will evolve with the implementation of smart metering.

*(70)* Ensuring better peak-shaving might not only lower overall consumption and save customers money, but also reduce the need for additional network investment and additional flexible peaking plants. At present, most MS are only just preparing for the roll-out of smart meters[51] (depending on the results of the cost-benefit analysis), therefore it is too early to monitor any outcomes for 2011.

*(71)* The issue of smart metering is addressed in the case studies provided in this report.

**Development of smart metering in Italy**

The implementation of smart meters in Italy began with the project "Telegestore", conceived by Enel Distribuzione in 2000, which brought smart meters to over 30 million Low Voltage (LV) customers. In 2006, AEEG, the Italian NRA, issued a decision that introduced the mandatory roll-out of smart meters for all DSOs. All policy leadership, key functional requirements and rules relating to the security of data are set by AEEG. The meters are maintained by the DSO. Italy will probably be the only country in the world with 95% deployment of smart electricity meters at LV level by the end of 2012, meaning that more than 33 million smart meters will be installed. Under the mandatory roll-out, all distribution companies have started their own replacement projects, and most customers (including those located outside Enel's licensed areas) are now equipped with smart meters. This has led to the experimental introduction of Time-of-Use electricity prices, which helps to ensure cost-reflective pricing. Mandatory Time-of-Use tariffs were first introduced in July 2010 and were fully phased in by the end of 2011. Time-of-Use Tariffs are now mandatory for more than 25 million household customers and for more than 3 million small businesses.

The next steps continue to focus on demand response and customer services. This should help suppliers develop more innovative products.

In the natural gas sector, the Italian regulator had initially (in 2008) decided to install 17.5 million smart meters by 2016. However, in 2011 this plan was revised. In early 2012, problems with the physical production and delivery of the new meters, together with the changing regulatory requirements and

51 Where roll-out of smart meters is assessed positively, at least 80% of consumers shall be equipped with intelligent metering systems by 2020 (Dir. 2009/72/EC Annex 1 (2)).

technological developments (which led to the decision that it would be worth waiting for new telecommunication technologies), prompted the regulator to postpone the adoption of smart meters for gas and possibly to re-examine the 2008 cost-benefit analysis by reconsidering its outcomes in light of the recent replacement of old gas meters with modern (but not smart) meters in 2010. This replacement activity might be viewed by some as a pre-emptive strategy on the part of the incumbent. Prior to the above-mentioned modifications, the energy regulator determined in 2008 that (subject to a positive cost benefit analysis) smart meters for gas would be rolled out in full to large consumers (the deadline was February 2012), to small industrial and commercial users by the end of 2014, and to all remaining customers by 31 December 2018.[52]

### Development of smart metering in Great Britain

The British electricity and gas markets cover 30 million households and businesses, and over 50 million meters. Both gas and electricity markets are fully competitive. In Great Britain, the Department for Energy and Climate Change (DECC) leads smart metering policy. DECC undertook an impact assessment in 2011, which demonstrated that there would be net public welfare benefits from the implementation of smart metering. The government also defined a set of functionalities, including in-home displays for domestic customers only, wide area connection modules to provide two-way communications with a central data management body, as well as a network connecting smart meters to smart devices in customers' homes. The essential elements of meter functionalities will be translated into regulations. The British NRA, Ofgem, is responsible for monitoring regulatory compliance and for managing the future development of specifications in the area of smart metering.

In most countries, smart meters are owned by DSOs, but in Great Britain it is the supplier who owns and maintains the meters. Suppliers are allowed to recover costs by charging them to the customer. Although all provisions must comply with existing data privacy legislation, it is the customer who chooses how their data from the smart meter is used and by whom.

The issue of accurate and timely settlement of customer bills is under examination. For the time being, bills are settled initially on the basis of estimated profiles instead of real consumption data.

A preliminary cost benefit analysis carried out by DECC determined that smart meters for gas will be rolled out across England, Wales, and Scotland. The government will perform an early review of requirements for roll-out by 2014, and further evaluation of the policy will be conducted by 2017. At the moment, roll-out is not a strict short-run priority, but full roll-out should be completed sometime during the 2017-18 financial year.[53]

52 AEEG, ICER Report on Experiences in the Regulatory Approaches to the Implementation of Smart Meters (2012); Lo Schiavo et al. "Changing the regulation for regulating the change – Innovation-driven regulatory developments in Italy: smart grids, smart metering and e-mobility" (2012).

53 Ofgem; DECC; ICER Report on Experiences in the Regulatory Approaches to the Implementation of Smart Meters (2012).

## 2.4 Market design

(72) Retail market design significantly shapes the outcome of a market. The retail market design provides a common set of rules and procedures to be followed. One of the most important issues is ensuring that any chosen retail market model can meet the needs of customers and allow market participants to behave competitively. For the time being, retail markets are, at least for household and small consumption customers, national or sub-national in scope.

(73) Having well-functioning retail markets does not necessarily mean that only one interpretation of a retail market model is suitable; market models as well as consumer preferences differ widely from country to country. In fact, the parameters of what constitutes a "good" market have previously been analysed by some NRAs and CEER. In order to reach a harmonised European energy market, a step by step approach is required for putting the necessary policies into practice. There is consensus that the "supplier-centric" model, with the supplier being the main but not the only contact point with the customer, could be best suited to enable efficient processes and clearly define the responsibilities of the market actors, so as to enable competitive retail energy markets. However, it must be noted that retail markets in MS have different characteristics and that there is no legal obligation for MS to implement any specific kind of retail market model.[54]

(74) The Agency and CEER strongly believe in cross-border retail markets, which are a logical step forwards following the harmonisation of wholesale markets. It would seem highly important to define a framework of issues that should be addressed by each MS. Moreover, the national characteristics of retail markets and the needs of the country-specific customer should be taken into account. As already stated, the question of how to implement this framework in practice should be left to the MS. However, MS ought to take the following considerations into account:

- Affordability, transparency, satisfaction, trust, and the empowerment of consumers should be further promoted across all EU-27 countries;
- Harmonisation of the roles and responsibilities across Europe for procedures that imply direct contact with the customer, such as switching and billing;
- A universal interface/format with easy access to relevant data for all market actors (DSOs, suppliers, customers); and
- The elimination, or at least the limitation, of barriers to entry. Entry barriers are obstacles that make it difficult for an electricity supplier to enter a given market. There exists a huge variety of factors that might prohibit suppliers from entering a market in which they have not already been active and this may prohibit effective competition from taking place. Among other things, barriers to entry include regulated prices, low switching propensity, inelastic demand and the perceived complexity of market models.

54 CEER GGP on retail market design, with a focus on supplier switching and billing, Ref: C11-RMF-39-03.

## 2.5 Conclusions

*(75)* Great disparities in price levels, as well as developments for household and industrial electricity consumers, persist throughout the EU. Taxes and levies play a very crucial role by driving prices up in many countries, which can be explained by the increasing support for renewables.

*(76)* Electricity retail prices do not converge across the EU, but an upward trend can be seen irrespective of whether prices are regulated, with very few exceptions.

*(77)* While regulated prices remain a main feature of retail markets in 2011, very different price setting rules and methodologies, with potentially different impacts on competition, co-exist among countries with regulated prices and might deserve further investigation in the future. Household customers in seventeen countries[55] still feature regulated prices, as in 2010. Even though the number of customers supplied under regulated prices might have slightly decreased in some countries, no significant change can be identified.

*(78)* Switching rates for household customers remain low in most countries. Although causality is difficult to prove, low switching rates, in combination with market shares and price levels, seem to suggest that retail competition needs further improvement.

*(79)* As prices do not seem to be the only driver of competition in the European retail markets, in future, the impact of non-price elements might have to be analysed further.

*(80)* The development of cross-border retail markets should be further addressed in future work. It is recommended that key issues be addressed in a detailed future framework. Due to the differences in retail markets, implementation of these key issues should lie in the hands of each individual MS.

55 Northern Ireland also features regulated prices, but is not included in the number of countries having regulated prices for household customers.

# 3 Electricity wholesale market integration

## 3.1 Introduction

(81) This chapter reports on the developments in electricity wholesale market integration. Firstly, this chapter presents the general developments in wholesale markets. Secondly, it shows the benefits of market integration by presenting simulated results. Thirdly, it identifies some barriers to market integration. Lastly, the chapter provides conclusions and recommendations.

## 3.2 Developments in wholesale market integration

(82) This section focuses on wholesale price convergences, market liquidity and key developments in generation.

### 3.2.1 Wholesale price convergence

(83) The convergence of wholesale electricity prices can be regarded as an indicator of market integration. Table 3 shows the annual development of a set of European day-ahead prices. During the period 2005-2011, the Dutch, Belgian, French and German spot prices clearly showed signs of convergence. The Nordic system price followed a similar trend; however, the actual price was usually lower due to the limited transmission capacity in the Central West Europe (CWE) region. Additionally, low reservoir levels could quickly shift the Nordic price closer to, or even push it above, the Continental price levels (as in 2010). In normal circumstances, Nordic prices follow coal prices closely, since coal condensing units are the generation technology that usually sets the price in the Nordic power market. In the CWE region, the price-setting generation technology is either gas or coal. The price of emission allowances affects all power prices based on carbon emitting technologies.

**Table 3: Annual average price at European spot exchanges – 2005 to 2011 (euro/MWh)**

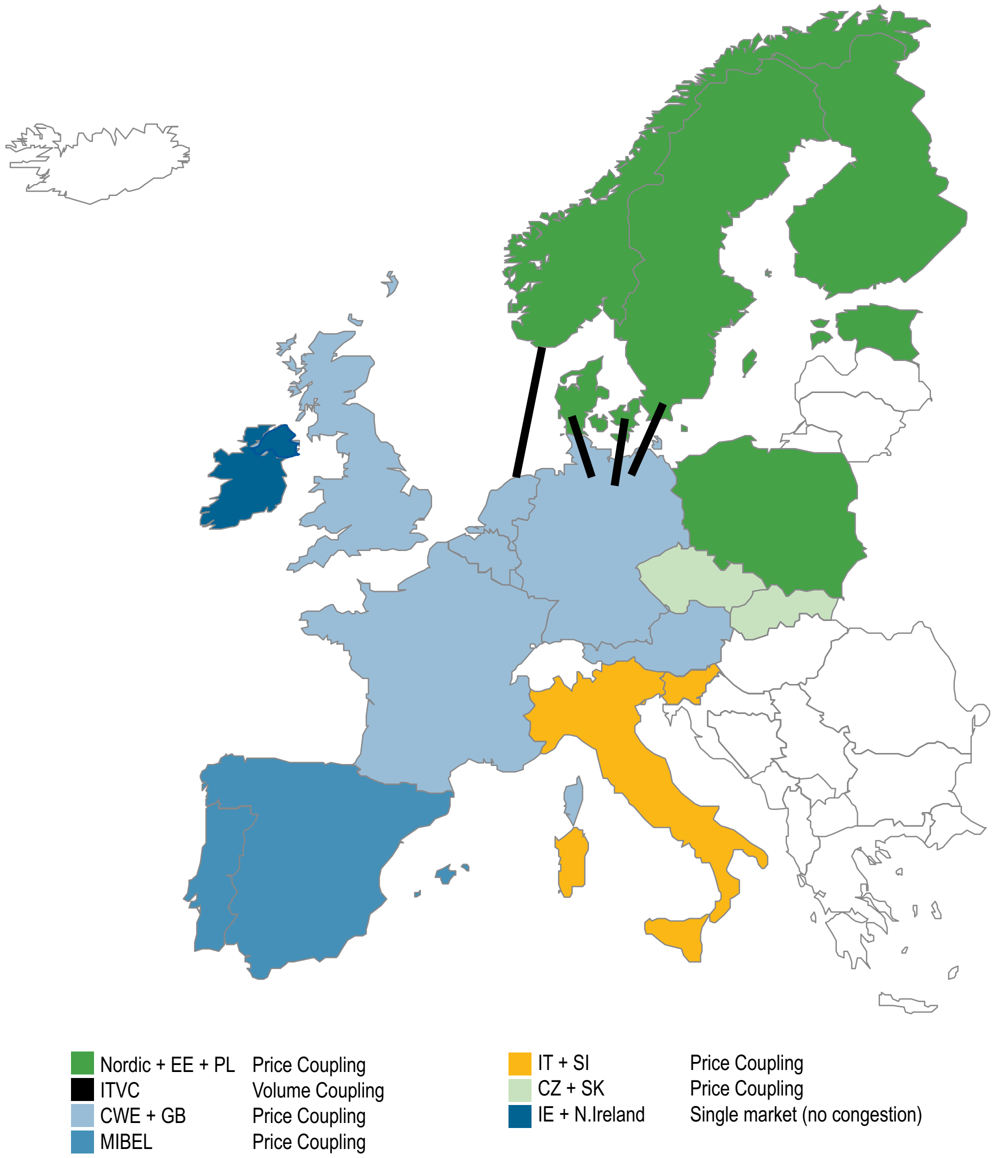
| Area | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|
| CWE | | | | | | | |
| Netherlands | 52.4 | 58.1 | 41.9 | 70.1 | 39.2 | 45.4 | 52.0 |
| Belgium | NA | NA | 41.8 | 70.6 | 39.4 | 46.3 | 49.4 |
| France | 49.3 | 49.3 | 40.9 | 69.2 | 43.0 | 47.5 | 48.9 |
| Austria | 46.4 | 51.0 | 39.0 | 66.2 | 38.9 | 44.8 | 51.8 |
| Germany | 46.0 | 50.8 | 38.0 | 65.8 | 38.9 | 44.5 | 51.1 |
| NORDIC | | | | | | | |
| Nord Pool | 29.3 | 48.6 | 27.9 | 44.7 | 35.0 | 53.1 | 47.1 |
| MIBEL | | | | | | | |
| Spain | 53.6 | 50.5 | 39.4 | 64.4 | 37.0 | 37.0 | 49.9 |
| Portugal | NA | NA | 52.2 | 70 | 37.6 | 37.3 | 50.5 |

*Source: Data provided by NRAs (2012)*

*Note: Based on available data. Austrian prices refer to EXAA.*

(84) A vital factor in the convergence of electricity wholesale prices is market coupling. Market coupling guarantees optimal use of the available daily cross-border transmission capacity between the various bidding zones. The coupling of electricity wholesale markets has initially developed at regional level. Figure 16 shows the current status of European market coupling.

**Figure 16: Market coupling in Europe – 2011**




*Source: The Agency (2012)*

**Market Coupling models**

There are different types of market coupling models in EU MS and Norway. However, they all have the integration of cross-border transmission capacity allocation in energy markets as a common feature. In practice, this means that market participants do not actually receive cross-border capacity allocations, but instead offer energy bids in their areas for production or consumption. The different forms of market coupling are described below.

- **Market Splitting** uses implicit auctions in which participants do not actually receive allocations of cross-border capacity themselves (as is the case in explicit auctions) but offer energy bids in their areas for production or consumption. A single Power Exchange managing the process uses the available cross-border transmission capacity to minimise the price difference between two or more areas. As a result, market splitting maximises economic welfare, avoiding any artificial splitting of the markets and sends the most relevant price signal for investment in cross-border transmission capacities.

- **Market Coupling** is similar to market splitting, since it applies implicit auctions; however the process is managed by several Power Exchanges. It is worth noting that the roadmaps for the completion of the wholesale internal electricity market, endorsed at the Florence Forum in December 2011, envisaged the integration of different market coupling areas through a single pricing algorithm.

- **Volume Coupling** determines only flows, while prices are set by each Power Exchange in a second step.

*(85)* The Nordic market (i.e. Denmark, Finland, Norway and Sweden) has adopted a model known as Market Splitting. The model was first applied in Norway and Sweden in 1996. Finland and Denmark joined in 1998 and 2000, respectively, while Estonia (through the Estlink cable) and Poland (through the Swepol cable) joined more recently. The CWE operates a model known as Price Coupling, which originally included Belgium, France and the Netherlands (Trilateral Market Coupling from 2006). Germany joined in November 2010, followed by the UK in April 2011 (through the Britned cable). The two regions are coupled through the Interim Tight Volume Coupling (ITVC) between Denmark and Germany (from 2011), through the NordNed cable between the Netherlands and Norway (from 2011) and through the Baltic Cable between Sweden and Germany (from 2010).

*(86)* Market Coupling also operates between Slovenia and Italy (2011), and between the Czech Republic and Slovakia (2010), while Market Splitting is applied in the Iberian market MIBEL between Portugal and Spain (2007).

*(87)* The impact of market coupling on price convergence is shown in Table 4. Following the inclusion of Germany in CWE Market Coupling, prices between France and Germany completely converged from 8% of all hours in 2010 to 68% in 2011. Similar results are shown for the Netherlands and Germany, where the percentage of hours during which prices were identical soared from 12% in 2010 to 87% in 2011. Prior to 2010, prices had not been identical in a single hour on this border. Following the introduction of the so-called Trilateral Market Coupling in 2006, full price convergence significantly increased between France and the Netherlands, from 4% to 60%.

*(88)* On the Nordic market, prices fully converged only 26% of the time in 2011. This low level of price convergence can be explained by insufficient infrastructures or insufficient transfer capacities.[56] Low price convergence in 2008 in particular was mainly due to a cable interruption between Sweden and Norway, which limited transfer capacity. A further and more detailed assessment of price convergence in Sweden has been provided in a box (Introduction of bidding zones: prices of the swedish bidding zones) in the continuation. In Sweden, the market design changed in 2011 from a single zone to four bidding zones.

*(89)* Between Spain and Portugal, prices converged gradually from 19% in 2007 to 92% in 2011. This can partly be explained by network expansions, which increased the cross-border capacity between Spain and Portugal. Another factor contributing to the above mentioned convergence has been the change in importance of gas-fired units in setting the price in both countries. In Portugal, the share of gas-fired power plants was low before 2007, though this increased between 2007 and 2011, due to the commissioning of gas-fired plants causing prices in Portugal to be more often set by gas units. However, in Spain, where in 2007 the share of gas-fired plants was higher compared to Portugal, gas-fired plants contributed less to the supply in Spain due to – *inter alia* – lower demand – in particular since 2009, a higher share of renewables and a change in the role of coal-fired power plants.

**Table 4: Percentage of hours in a year when hourly day-ahead prices were equal for a selection of European regions – 2003 to 2011 (%)**

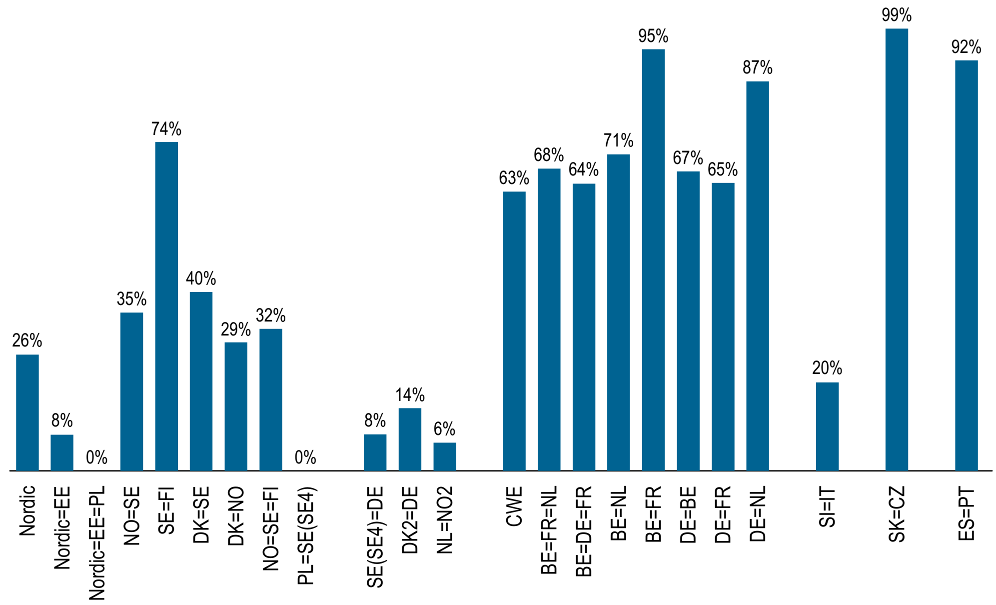
| Area | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| FR=DE | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 8% | 68% |
| FR=DE=NL | NA | NA | NA | 0% | 0% | 0% | 0% | 8% | 63% |
| FR=NL | NA | NA | NA | 4% | 60% | 66% | 54% | 58% | 67% |
| NL=DE | NA | NA | NA | 0% | 0% | 0% | 0% | 12% | 87% |
| NORDIC | 27% | 26% | 30% | 33% | 28% | 9% | 25% | 19% | 26% |
| ES-PT | | | | | 19% | 38% | 75% | 79% | 92% |

*Source: Data provided by the Swedish Energy Markets Inspectorate (EI) and a selection of power exchanges (2012)*

*(90)* Figure 17 provides a more extensive overview of the development of hourly price convergence across the relevant bilateral borders within several regions in 2011.

56 See, for instance, NordREG NMR, 2012, https://www.nordicenergyregulators.org/upload/Reports/NMR%202012%20-%20publication.pdf

**Figure 17: Percentage of hours when hourly day-ahead prices were equal for a selection of European regions – 2011 (%)**




*Source: Data provided by NRAs and a selection of power exchanges (2012)*

*(91)* Czech-Slovak day-ahead prices were the same during 99% of all hours during 2011, representing the highest level of price convergence in Europe.

*(92)* The Belgian-French and the Dutch-German borders experienced the highest full price convergence in the CWE region in 2011 (95% and 87% respectively). On the other borders, full price convergence ranged from 63% to 71%.

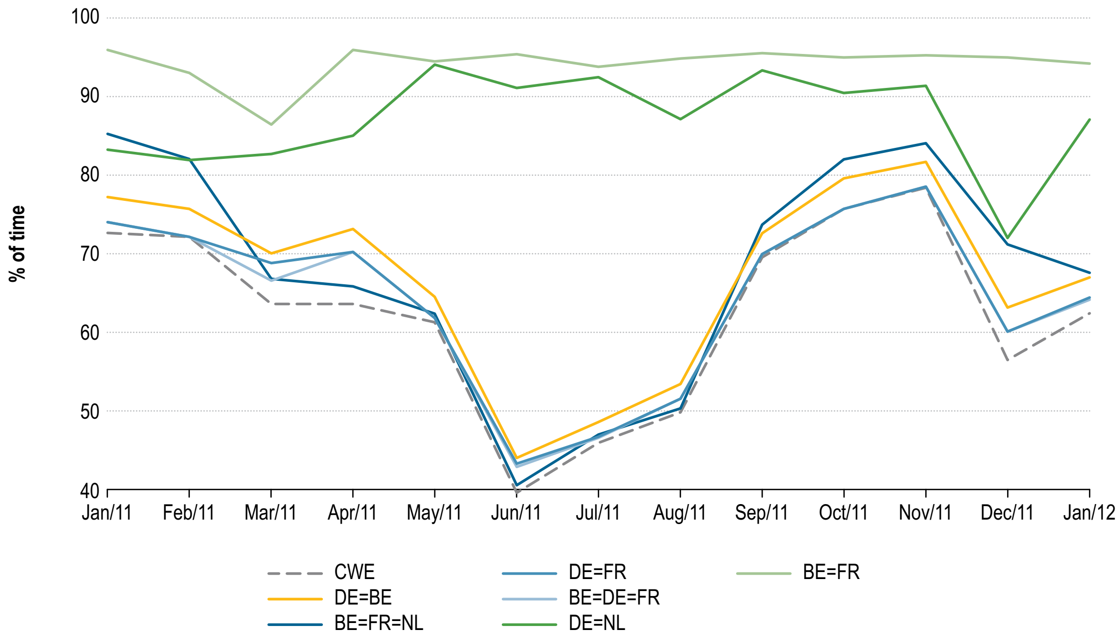
*(93)* In the Nordic region, full price convergence was the highest between Finland and Sweden (74%) and the lowest between Denmark and Norway (29%). In 2011, full price convergence between Estonian, Finnish, Swedish, Danish and Norwegian prices stood at only 8%. The Nordic system is also linked with Poland through the SwePol-link, but no full price convergence was observed in 2011.

*(94)* Frequencies of full price convergence were in general lower on cables linking the Nordic region and the CWE region, between the Netherlands and Norway, Germany and Denmark, and Sweden and Germany. The interconnection between East Denmark (DK2) and Germany shows the highest price convergence, with the same price in 14% of all observed hours. The Dutch and Norwegian (NO2) prices were the same in 6% of all hours, while the Swedish (SE4) and the German prices stayed the same in 8% of all hours.

*(95)* On a monthly basis, price convergence within the CWE region varied considerably, with the lowest values from June to August 2011, as presented in Figure 18. The reduced price convergence in spring and summer was reportedly related to the low nuclear availability in France and Germany, along with low wind levels in Germany.

*(96)* At the beginning of June, periods of low wind output in Germany and limited transmission capacity between the relevant zones caused German and Dutch prices to exceed the French (and Belgian) prices by several euro/MWh. During the last quarter of 2011, higher nuclear availability in France in conjunction with unusually mild weather throughout North Western Europe contributed to an improved hourly price convergence within the CWE region.[57]

**Figure 18: Percentage of hours when hourly day-ahead prices were equal in the CWE region during each month – 2011 (%)**



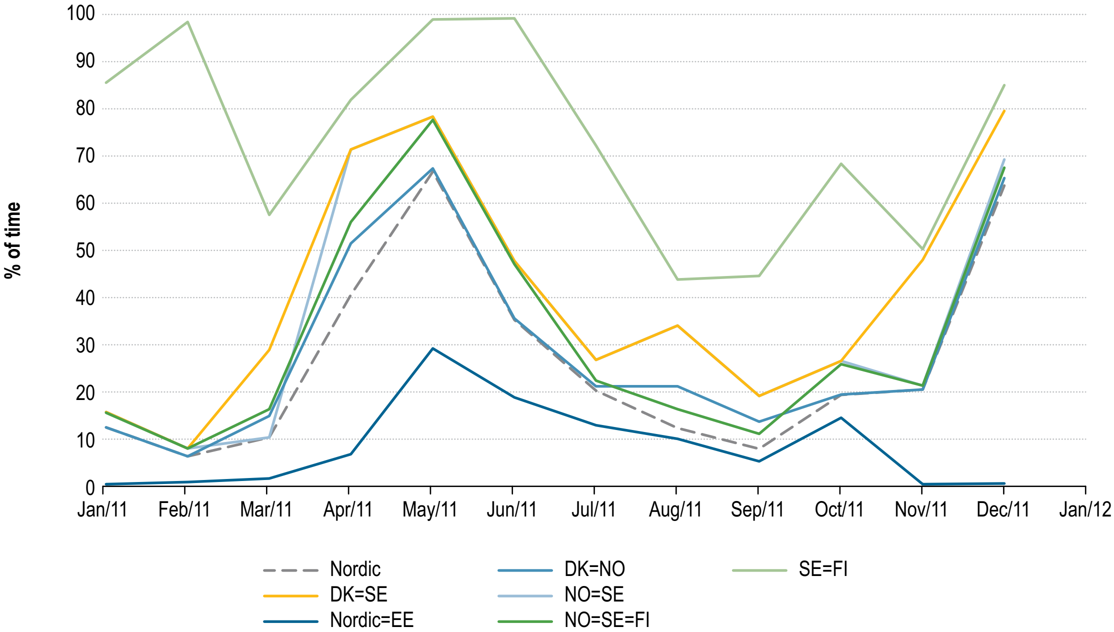

*Source: Data provided by NRAs (2012)*

*(97)* The degree of price convergence in the Nordic region shows clear seasonal variations on a monthly basis, with the highest values in May and December, as presented in Figure 19. During the first quarter of 2011, cold weather and limited nuclear availability in Sweden caused regional congestion that resulted in diverging Nordic prices. Higher Swedish nuclear production at the beginning of March 2011 temporarily improved price convergence. Halfway through the second quarter and during the summer, resurging hydro production created congestion, which reduced price convergence. From the beginning of the fourth quarter, mild temperatures significantly improved price convergence.[58]

57 European Commission, "EC Quarterly Report on European Electricity Markets Q2 2011", see: http://ec.Europa.eu/energy/observatory/electricity/doc/qreem_2011_quarter2.pdf

58 Swedish Energy Markets Inspectorate, Swedish electricity market April-September 2011, see: http://www.ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202011/Halvarsrapport_om_elmarknaden_EIR_2011_11.pdf

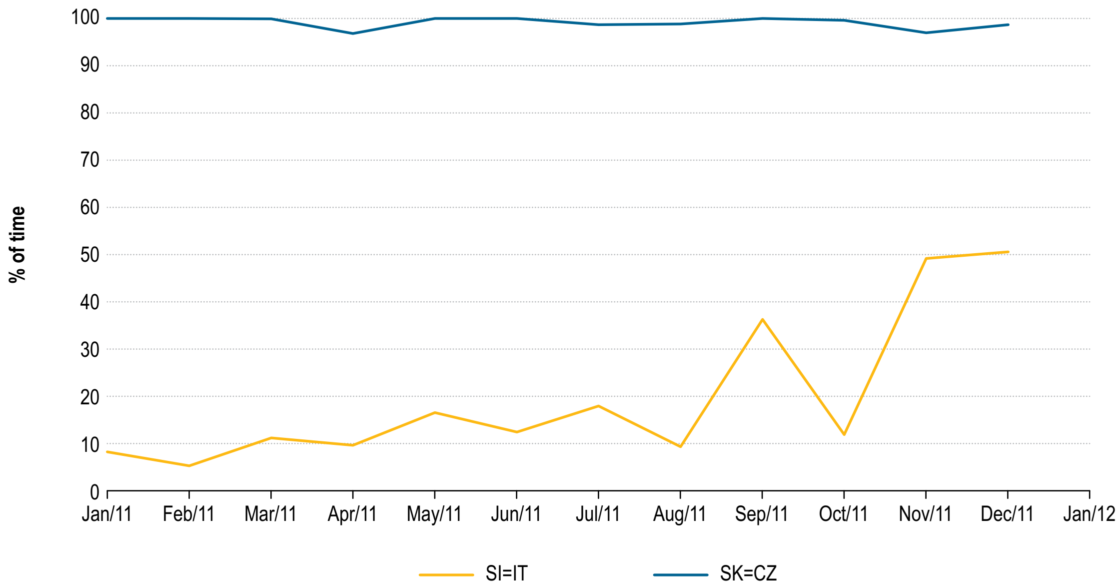
**Figure 19: Percentage of hours when hourly day-ahead prices were equal in the Nordic region during each month – 2011 (%)**




*Source: Data provided by NRAs (2012)*

(98) Figure 20 shows the percentage of hours per month that prices were identical in 2011 for Italy and Slovenia, and for Slovakia and the Czech Republic. Price convergence between Italy and Slovenia increased significantly throughout 2011. The highest price convergence was seen in December (51%), while the lowest price resemblance between the two countries was noted in February (5%). Furthermore, Slovakia and the Czech Republic experienced almost total price convergence through all of 2011. The lowest values were seen in April (97%). Full price convergence was achieved between January and March, May and June and September and October. Periods of market decoupling were reportedly related to supply issues, as well as a capacity problem on the border between the two countries.

**Figure 20: Percentage of hours when hourly day-ahead prices were equal between Italy and Slovenia, Czech Republic and Slovakia during each month – 2011 (%)**




*Source: Data provided by NRAs (2012)*

*(99)* The results from this section show that, although market integration is accelerating, wholesale electricity prices remain to some extent regional. Full price convergence occurs 68% in the CWE region and around 26% of the hours in the Nordic region. However, only 6% of the hours to 14% of the hours between the two regions themselves. In any case, market coupling implementation significantly contributes to EU price convergence.

### Introduction of bidding zones: prices in the Swedish bidding zones

On 1 November 2011, the Swedish electricity market was subdivided into four bidding zones as the result of an assessment by the European Commission which raised competition concerns.[59] Due to this change in market design, price convergence can be compared before and after this change.

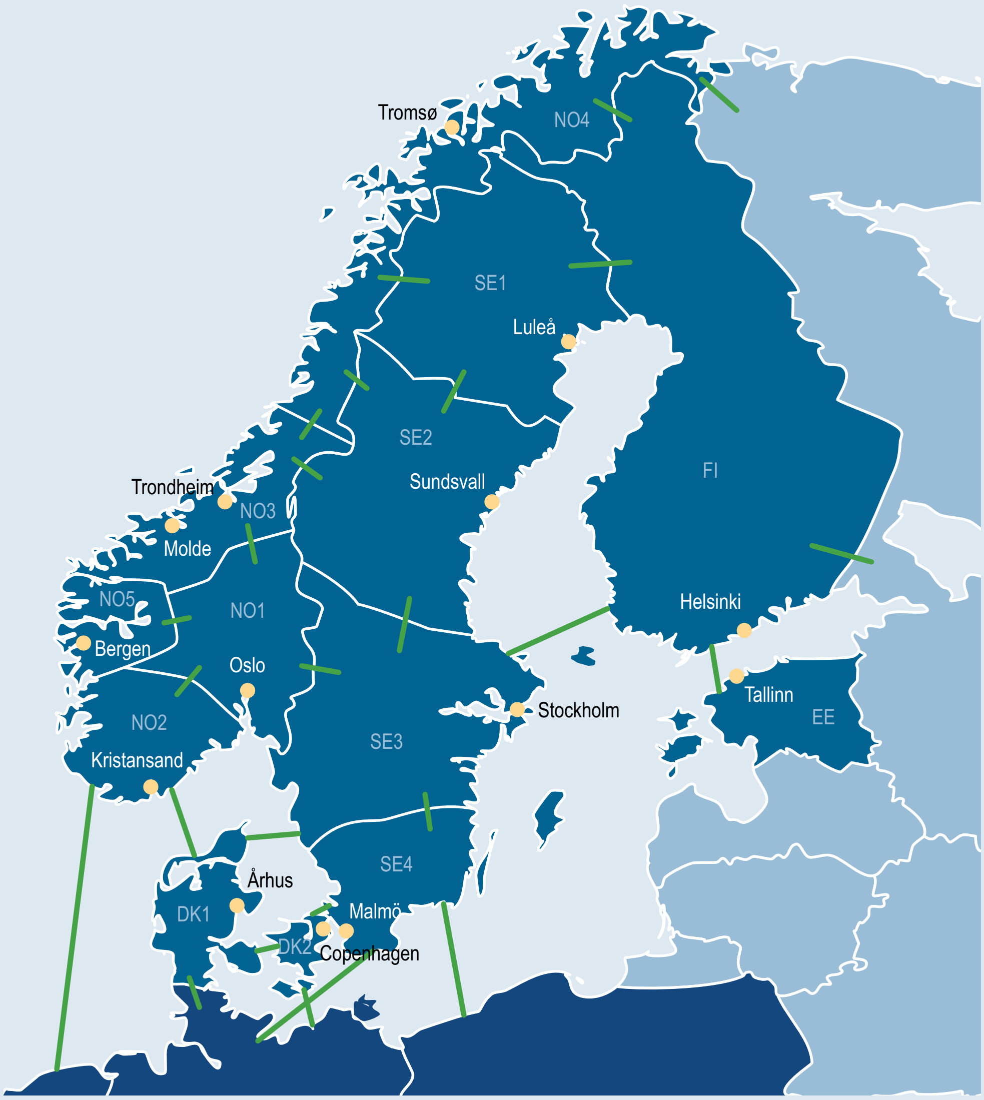
Sweden is part of the Nordic Region, where market splitting has been applied as the method of congestion management, with Sweden remaining a single-price zone until 2011. Furthermore, most (85% in 2010, see Figure 24) electricity is traded through the Nordic exchange on a day-ahead basis. The electricity system in Sweden can be characterised as follows. In Northern Sweden, there is a surplus of electricity generation compared to demand. In Southern Sweden, the situation is the opposite. Moreover, the Swedish electricity production system is divided between hydro (low marginal cost generation) in the North, while nuclear and other thermal generation (with a higher marginal cost than hydro) dominate in the South. As a result, during peak hours, electricity flows from Northern to Southern Sweden, in particular during years with high precipitation. However, due to bottlenecks in the transmission network, the transport of these north-south flows cannot always be accommodated, resulting in congestion, which is aggravated due to exported electricity from Southern Sweden to the CWE region and to Denmark.

Following these findings, the European Commission expressed its concerns that in the 2005-2008 period, the Swedish Transmission System Operator, Svenska Kraftnät (SvK), may have abused its dominant position in the electricity transmission market by curtailing export capacity on the Southern Swedish interconnectors when it anticipated internal congestion within the Swedish transmission system. By doing so, SvK, while regarding Sweden as one price zone, discriminated between network users essentially in and outside Sweden.

In response to the concerns raised by the European Commission, in April 2010, SvK voluntarily offered a set of measures that would remedy the above mentioned concerns. A key measure was to subdivide the Swedish electricity market into several bidding zones, bordered by congestion points within the Swedish electricity system. Figure 21 shows the four zones of the Swedish networks (from SE1 to SE4) following the subdivision from November 2011.

59 Case No COMP/M.39351 (14.04.2010). See: http://ec.Europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_39351

**Figure 21: Nordic bidding zones**



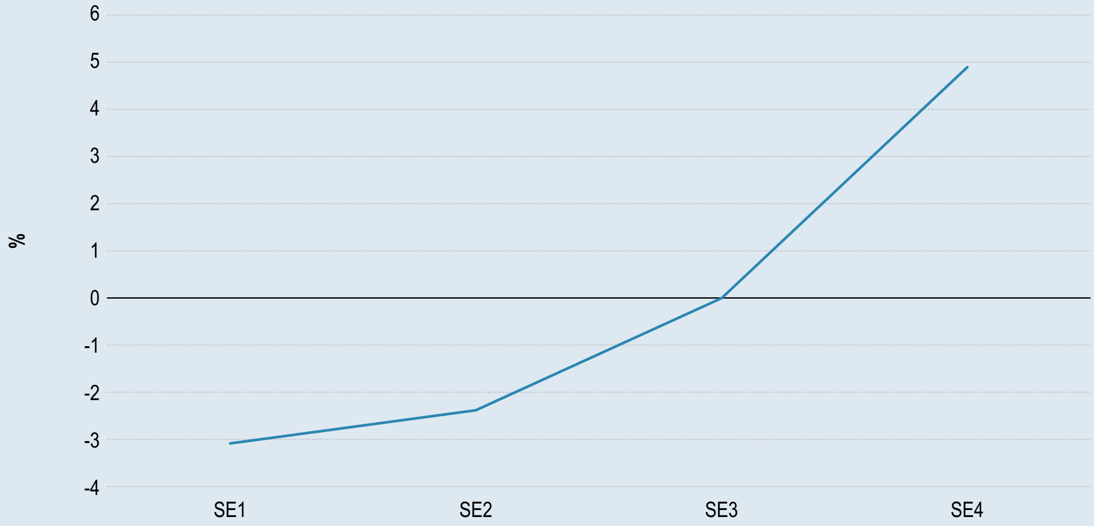

*Source: Nord Pool Spot and Swedish Energy Markets Inspectorate (2012)*

*Note: The green lines indicate cross-zonal and cross-border transmission lines.*

Following the introduction of the subdivision, zone-specific prices emerged in Sweden. This enabled the calculation of price differentials for specific zones and the assessment of whether the altered market design has contributed to price convergence at a regional level.

As illustrated in Figure 22, clear structural price differentials have emerged between Northern and Southern Sweden following the subdivision. The northern bidding zones have the lowest average prices while prices in the southern-most zone are the highest. This is consistent with the types of generation located in these zones. Although the magnitude of price level differences varied considerably between months, the analysis shows that the prices in SE1 are 3% lower than in SE3; the price in SE2 is just over 2% lower than in SE3, while prices in SE4 are almost 5% higher than in SE3.

**Figure 22: Price differences between Swedish bidding zones compared to SE3 – November 2011 to March 2012**




*Source: Swedish Energy Markets Inspectorate (2012)*

Table 5 shows that Sweden constituted a single price zone in close to 78% of all hours in the observed period. The northern bidding zones (SE1 and SE2) observed the same price in all hours, while the southern bidding zones kept a single price close to 84% of all observed hours.

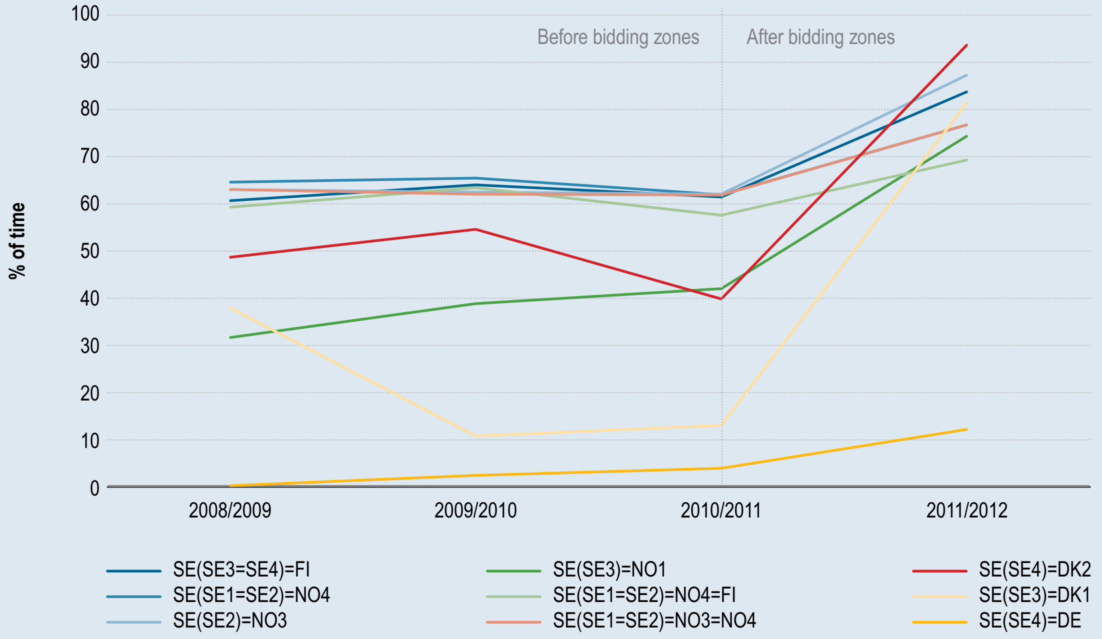
**Table 5: Percentage of hours when hourly day-ahead prices were equal within Sweden – November 2011 to February 2012**

| Bidding zone | % of hours when prices were equal, November 2011 to February 2012 |
|---|---|
| SE | 77.8% |
| SE1=SE2 | 100.0% |
| SE1=SE2=SE3 | 91.2% |
| SE3=SE4 | 83.8% |

*Source: Swedish Energy Markets Inspectorate (2012)*

Figure 23 illustrates a substantially increased level of market integration, in terms of price resemblance, on all Swedish national borders after November 2011. The most notable price convergence was observed in SE3 and Western Denmark (DK1), where the percentage of hours with the same prices rose from 13% in the November 2010–March 2011 period to 81% for the November 2011–March 2012 period. Price convergence in Eastern Denmark (DK2) and Southern Sweden (SE4) rose from 40% to 94% in the observed period. On the ITVC coupled border between Germany and SE4, prices converged from 4% to 12% in the same period.

**Figure 23: Percentage of hours when hourly day-ahead prices were equal between Sweden and surrounding countries – November to March period in 2008 to 2012 (%)**




*Source: Swedish Energy Markets Inspectorate (2012)*

The above price analysis shows increased regional and cross-regional price convergences after the introduction of subdivisions within the Swedish network. Most notable is the increased price convergence between the southern bidding areas of Sweden and Denmark, suggesting that these zones are parts of one area, due to, *inter alia,* the characteristics of generation capacity. In conclusion, the results show that the introduction of bidding zones in Sweden has further integrated the Nordic and partly the CWE market. More generally, this case study demonstrates the rationale for assessing bidding areas across national borders, on a case by case basis.

It is worth mentioning that there might have been other factors affecting price convergence, such as a new transmission line (i.e. the Fenno-Skan 2 cable[60] between SE3 and Finland), variations in precipitation, nuclear availability and electricity demand. Lastly, when more data become available in the future, these results may need to be confirmed.

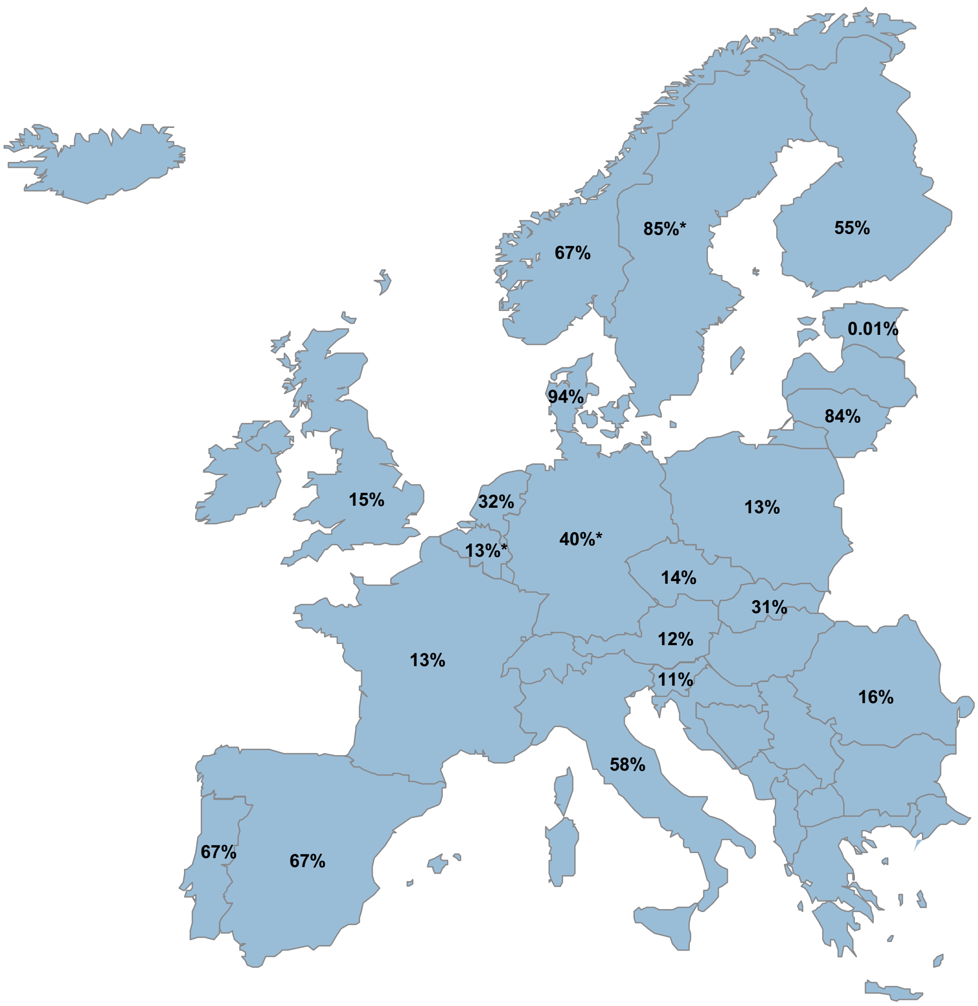
60 The Fenno-Skan 2 (800 MW) cable was fully operational in December 2011, see: http://www.svk.se/Start/English/Projects/Project/Completed-projects/Fenno-Skan-2/

### 3.2.2 Market liquidity

(100) A liquid wholesale electricity market facilitates the buying or selling of a desired commodity or financial instrument quickly, without causing a significant change in its price and without incurring significant transaction costs. A liquid market is less prone to market manipulation, and contributes to sound and transparent prices. The latter increases confidence for market participants when they make decisions, for instance, on investments, risk management and potential market entry.

(101) Liquidity in electricity wholesale markets is often measured by a proxy indicator, dividing the total quantity of electricity day-ahead marketed on any Power Exchange of the corresponding market by the total quantity of power consumed on the corresponding territory. Figure 24 shows the liquidity at Power Exchanges within Europe for 2011.

**Figure 24: Traded volumes at power exchanges as a percentage of national demand – 2011 (%)**




*Source: The Agency; CEER National Indicators (2012)*

*Note: Percentages have been calculated by dividing the annual day-ahead power exchange traded volumes by the annual total demand (including losses without pumped storage) per country on a power exchange. * refers to 2010 data.*

(102) The traded volume percentages versus domestic demand recorded by the European Power Exchanges averages at nearly 40%, with significant national differences. The highest values of the percentage Power Exchange traded electricity are observed in Denmark (94%) and the lowest in Estonia (0.01%).

(103) The amount of electricity traded at Power Exchanges has generally been increasing in the majority of national markets over the past eight years. Table 6 illustrates the day-ahead volumes traded at national Power Exchanges from 2004 to 2011 as a percentage of total demand. Although bilateral electricity trading still represents the majority of trade in a number of countries, there is an upward trend in market liquidity over time. For instance, the market volume of German Power Exchange traded increased from 11% to 40% between 2004 and 2010.

**Table 6: Traded volumes at power exchanges as a percentage of national demand – 2004 to 2011 (%)**

| Area | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Central West Europe | 6% | 7% | 8% | 11% | 13% | 14% | 18% | 22% |
| Belgium | 0% | 0% | 1% | 8% | NA | 12% | 13% | NA |
| France | 3% | 4% | 6% | 9% | 10% | 11% | 10% | 13% |
| Germany | 11% | 15% | 16% | 21% | 26% | 25% | 40% | NA |
| Great Britain | | 4% | 4% | 5% | 3% | 4% | 6% | 15% |
| Austria | 3% | 3% | 3% | 4% | 4% | 8% | 10% | 12% |
| Netherlands | 12% | 14% | 17% | 18% | 21% | 25% | 29% | 32% |
| | | | | | | | | |
| Nordic | 43% | 49% | 66% | 72% | 73% | 77% | 75% | 75% |
| Sweden | 41% | 36% | 70% | 85% | 86% | 85% | 85% | NA |
| Denmark | 55% | 73% | 96% | 99% | 96% | 91% | 88% | 94% |
| Norway | 37% | 41% | 54% | 57% | 61% | 63% | 71% | 67% |
| Finland | 38% | 46% | 42% | 46% | 50% | 54% | 56% | 55% |
| Estonia | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0.01% |
| | | | | | | | | |
| MIBEL | 45% | 47% | 26% | 51% | 72% | 85% | 74% | 67% |
| Portugal | 0% | 0% | 0% | 44% | 93% | 81% | 64% | 67% |
| Spain | 91% | 94% | 52% | 59% | 51% | 89% | 83% | 67% |
| | | | | | | | | |
| Czech Republic | 1% | 1% | 1% | 1% | 2% | 4% | 8% | 14% |
| Hungary | | | | | | | 2%* | 10% |
| Italy | 21% | 61% | 58% | 65% | 69% | 67% | 61% | 58% |
| Lithuania | 15% | 25% | 19% | 22% | 38% | 39% | 88% | 84% |
| Poland | 1% | 1% | 1% | 2% | 1% | 2% | 5% | 13% |
| Romania | 12% | 9% | 8% | 9% | 9% | 13% | 16% | 16% |
| Slovakia | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 31% |
| Slovenia | 2% | 0% | 0% | 0% | 1% | 0% | 2% | 11% |

*Source: CEER National Indicators (2012)*

*Note: Austria includes only EPEX traded volumes. * Data from 21 July.*

*(104)* MIBEL and the Nordic area are clearly the most liquid Power Exchanges, with an average of 75% traded electricity in the Nordic region and 67% in the MIBEL area. With an average of 18% Power Exchange traded electricity volumes, the CWE region is significantly less liquid than MIBEL and the Nordic region.

*(105)* Some of the differences in traded volumes can be attributed to the different designs of wholesale markets. In some countries and regions, market design supports (or supported) trade taking place at power exchanges. In the Nordic countries, for instance, cross-border trade must go compulsory through the Power Exchange. Further, in Spain the day-ahead market is a mandatory pool for all the electricity not committed as bilateral trade. Also, the liquidity level in Italy has been affected in the past by the so-called single buyer obligation, which has been gradually removed through the years. In 2011, the single buyer was responsible for 15.4% of the spot market liquidity. In this respect, though not directly related to liquidity, it is worth mentioning that the Target Model envisages the EU-wide harmonisation of market designs, including day-ahead markets.[61]

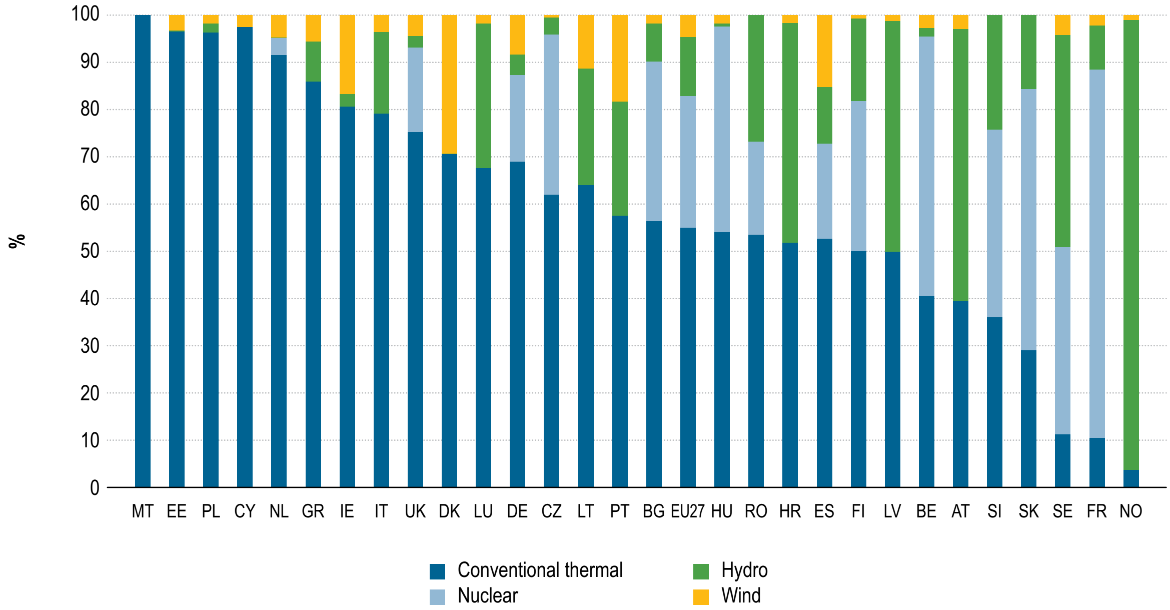
### 3.2.3 Key developments in European electricity generation

*(106)* According to Eurostat data, total electricity production in the EU in 2011 was 3,164.6 TWh (Table 7). Following a significant year-on-year increase in electricity production in 2010 (4.5%), electricity production decreased in 2011 by 0.5% compared to the previous year.

*(107)* Price differences, as shown in the previous section, are partly the result of differences in the generation mix across European countries. Figure 25 presents generated electricity, by fuel type and by country. The dominance of conventional thermal sources is clear, since all EU/EEA MS feature some thermal generation. The second dominant source is nuclear energy. Whilst in 2011 nuclear energy was not present in Austria, Italy and Norway, it represented an important source of energy in France (78%), Belgium (54%), Hungary (43.5%), Sweden, (39.6%), Slovenia (39.5%), Bulgaria (33.6%), the Czech Republic (33%) and Finland (31.6%). Hydro-generated electricity represents a minor source of electricity generation across the EU/EEA; it was, however, the key source of electricity in Norway (95.3%), Austria (57.6%) and Sweden (44.9%) in 2011.

61 In line with the 3rd Package, MS and NRAs are required to cooperate with each other and to promote cooperation among TSOs, both at the regional and EU levels, for the purpose of integrating national markets towards the creation of a fully liberalised electricity market. The Agency is tasked with coordinating the so-called Regional Initiatives. Mandatory elements were introduced in the framework guidelines/network codes process, again with the Agency as a central institutional player.

**Figure 25: European electricity generation by country in TWh – 2011 (%)**




*Source: Eurostat (2012)*

*(108)* Compared to 2010, conventional thermal generation decreased by 1.5% in 2011 and accounted for 54.2% of total generation. Nuclear power plants generated 27.4% of electricity; a percentage that remained stable in 2010 and 2011, despite the decommissioning of a number of nuclear reactors in Germany following the Fukushima nuclear disaster. EU-27 hydro production did not change year-on-year, whilst from 2008 to 2011 wind and solar power rose by 22% and 460%, respectively. In the same period, thermal production fell by 6.2% as a result of EU renewables policy,[62] and nuclear generation increased by 2.3%.

62 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: Energy 2020 - A strategy for competitive, sustainable and secure energy (2010). See: http://eur-lex.Europa.eu/LexUriServ/LexUriServ.do?uri=COM:2010:0639:FIN:En:PDF

**Table 7: European electricity generation development – 2008 to 2011 (TWh)**

| EU-27 | 2008 | 2009 | 2010 | 2011 | 2011/ 2010 | 2011/2008 |
|---|---|---|---|---|---|---|
| Total net production in (TWh) | 3203.1 | 3045.3 | 3181.4 | 3164.6 | -0.5% | -1.2% |
| of which : | | | | | | |
| Conventional thermal | 1830.0 | 1689.2 | 1742.8 | 1716.1 | -1.5% | -6.2% |
| Nuclear | 888.2 | 846.1 | 867.9 | 867.8 | 0.0% | -2.3% |
| Hydro | 352.0 | 354.4 | 390.0 | 390.0 | 0.0% | 10.8% |
| Wind | 117.8 | 132.0 | 147.8 | 143.6 | -2.8% | 21.9% |
| Solar | 7.4 | 14.1 | 23.0 | 41.5e | 58.9% | 459.9% |
| Geothermal | 5.4 | 5.2 | 5.2 | 5.5 | 5.0% | 2.3% |
| Other | 2.3 | 4.3 | 4.6 | | | |

*Source: Eurostat (2012)*

*Note: "e" refers to an estimated value by Eurostat.*

*(109)* At the national level, Germany and Spain have large shares of generation from wind production, with 46.5 TWh and 41.3 TWh respectively; however, as already presented in Figure 25 above, Denmark (with 9.7 TWh during 2011) records the largest relative share with 29% of its total national generation. European solar energy is mainly produced in Germany (19 TWh), Spain (9.1 TWh), Italy (9.3 TWh) and the Czech Republic (2.1 TWh).

## 3.3 Benefits of market integration

*(110)* Market integration is expected to provide several benefits, one of which is enhanced economic efficiency due to interconnectors, allowing the lowest cost producers to serve demand in neighbouring areas. The purpose of this section is to propose an indicator to measure this benefit. This indicator is called "gross welfare benefits".

*(111)* Gross welfare benefit includes, first, consumer and producers' surplus gained by consumers and producers who participate in power exchanges (welfare is measured as the difference between the bid prices and the obtained matched prices) and second, congestion rents. The first measures the gain (saving) that could have been obtained by consumers (producers) if prices had been different, due to changes in cross-border transmission capacity, for example. The second corresponds to price differences between interconnected markets multiplied by the amount of available cross-border capacity between these markets. It is important to note that gross welfare benefits, as opposed to net welfare benefits, exclude all costs incurred by TSOs for making this cross-border capacity available to the market.

*(112)* For the purpose of this section, several European Power Exchanges[63] were asked to perform simulations in order to estimate these gross welfare benefits. A disclaimer, the methodology and the results of these simulations are presented below.

*(113)* Many caveats underly the results presented in this section. For example, the gross welfare benefits include merely the power traded in organised day-ahead exchanges, thus excluding – for instance – forward products such as week-ahead, year-ahead and all OTC trade. As a consequence, the estimated surpluses cannot be considered as the whole welfare benefit in a given country. Moreover, not all borders in Europe are included, which is partly due to the fact that not all markets have been market coupled or because not all Power Exchanges have been included. A strong assumption underlying these simulations is that bids submitted in each market are kept unchanged, irrespective of the analysed scenario in terms of available cross-border capacity. Furthermore, the results represent merely one year (2011) and cannot be considered representative of several years, since many factors (such as the amount of wind and the dynamics of hydro power affected by precipitation levels) change significantly from year to year. In addition, the algorithms[64] used to simulate the gross welfare benefit are two prototypes, although they allow the coupling of the markets included in the Price Coupling of Regions (PCR)[65] initiative. It is important to mention that these algorithms need further improvement. Due to time constraints on conducting all simulations, the most recent and optimal setup of the algorithms was not used for these calculations. Finally, not all interconnectors were in use during the year; in this case, the gains presented on the graph have been inflated (assuming a constant average daily gain) to represent yearly values. Due to these caveats, the results presented in this section should be used cautiously and should be understood merely as a starting point for future analyses.

63 APX-Endex, Epex Spot, Nordpool, GME and OMIE.

64 Two algorithms were used for the simulation. One includes GME and NWE functionalities and the second includes OMIE and NWE functionalities. These two algorithms are prototypes and are currently being merged into one single algorithm.

65 The PCR Project is a joint effort between six power exchanges APX-ENDEX/BELPEX, OMIE, GME, EPEX SPOT and NORD POOL SPOT aiming for the implementation of a single European day-ahead price coupling of power regions.

*(114)* To obtain results three scenarios were simulated:

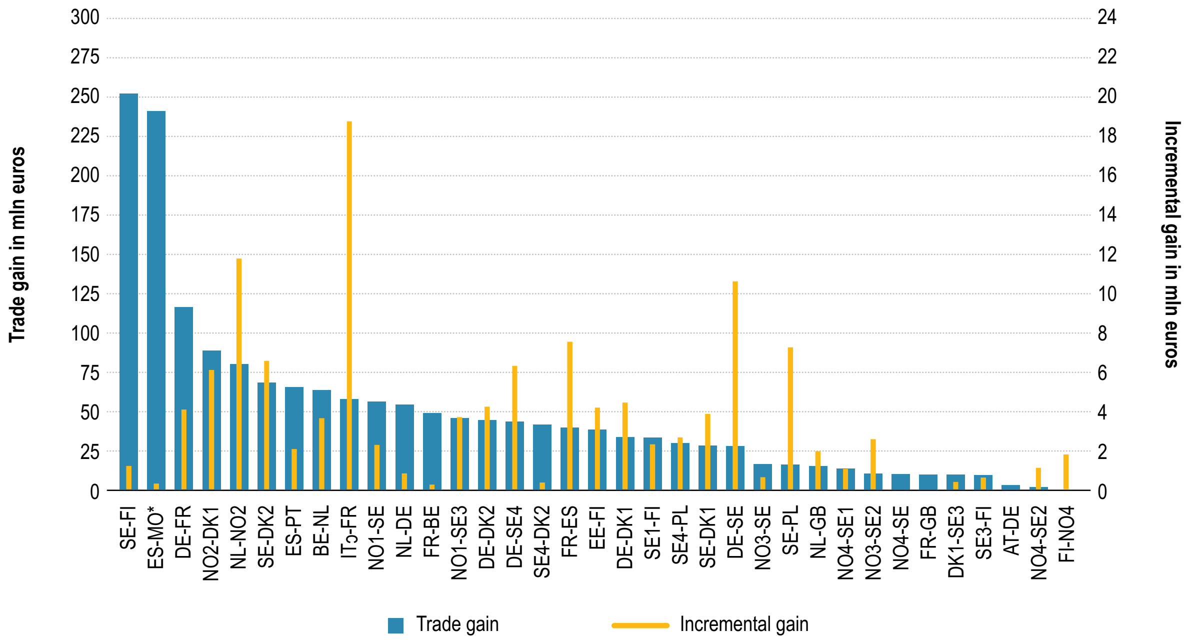
- *Historical scenario*: The gross welfare benefit for 2011, calculated on the basis of detailed historical information such as network constraints, the exchange participants' order books (that is supply and offer bids) and available cross-border capacity. For the latter, the Available Transmission Capacity (ATC) has been used as a proxy of capacity effectively made available for trade on 37 borders;
- *Zero scenario*: The same as in the *Historical scenario,* with the ATC values reduced to zero (that is, no cross-border trade). The assumption is that all other elements (market bids, network constraints, market rules, etc.) remain unaltered; and
- *Incremental scenario*: The same as in the *Historical scenario,* with the ATC values for each border increased by 100MW.[66]

*(115)* Figure 26 shows the welfare gain from trade (that is "Welfare Trade Gain") by border for 2011, in millions of euros. This is the difference between the simulated gross welfare benefit stemming from the Zero scenario and the Historical scenario.[67] The figure also shows the so-called "Incremental Gain", which is the difference between the gross welfare benefit from the Historical scenario and that from the Incremental scenario, which assumes on a selected border an increment of 100MW extra interconnector capacity for trade. Note that extra capacity in this context need not to be associated with more investments, but should instead be related to more efficient capacity calculation methods.

66 It can be argued that the 100MW threshold used is to some extent an arbitrary value. Absolute values allow for comparisons of borders across the EU, although 100MW is relatively large for some interconnectors and small for others. Secondly, this value is mentioned in the ERGEG Fundamental Transparency document as a threshold from which changes in transmission capacity should be reported.

67 The simulations were executed accordingly. Firstly, a complete batch with historical data for 2011 was created, including all order books, ATC values, etc. Based on this, the algorithm calculated the results of the Historical scenario. Secondly, the Zero scenario was calculated by altering the ATC value in the historical batch data to zero for one specific interconnector. Then the algorithm ran the calculations for the full year. This was repeated for each interconnector separately. The Incremental scenario was calculated in the same way, although increasing the ATC value in the historical batch data for one interconnector with 100MW.

**Figure 26: Simulation results: gross welfare benefits from cross-border trade and incremental gain per border – 2011 (millions of euro per year)**




*Source: PCR project, including APX-Endex, Epex Spot, Nordpool, GME, OMIE (2012)*

*Note: * refers to Morocco, ↄ indicates that the zone is a GME zone.*

*(116)* Figure 26 provides an insight into the relation between incremental and trade gains by interconnection. For instance, the figure shows that the interconnector between Sweden and Finland resulted in a trade gain of 252 million euros per year. The figure also shows which borders would benefit the most from making extra capacity available. For example, the figure indicates that additional capacity between the Netherlands and Norway would yield nearly an additional 12 million euros per year, which is an extra gain of 15%. Also, the case on the Italian–French border which has a percentage extra gain of 33% (19 million euros) is quite remarkable. In contrast, the link between Sweden and Finland has a negligible extra gain of 0.5% of the currently available capacity. Other interesting interconnector candidates for improving capacity include the following links: France-Spain, Germany-Sweden, Sweden-Poland and France-Great Britain.

*(117)* The social welfare indicator presented in this report provides some insight into the gross benefits of market integration. The indicator is to be further developed into a monitoring and planning tool which can be used to assess the utilisation of the existing network and track the progress of market integration.

### 3.4 Barriers to market integration

*(118)* The Agency is tasked with identifying barriers to the completion of the internal market in electricity.[68] The price convergences section (3.2.1) has shown that scope remains for further market integration.

*(119)* The lack of market integration mainly results from two key areas:

- Inefficient use of existing transmission networks stemming from inefficiencies in cross-zonal capacity allocation, cross-zonal capacity calculation and the assumed definition of possible bidding zones for long-term, day-ahead, intraday and balancing timeframes; and
- Lack of investments in electricity network infrastructure that would enable more cross-zonal capacities and more cross-zonal trade between areas with excess supply and areas with excess demand.

*(120)* It is vital to implement a common EU-wide cross-zonal approach to capacity allocation. Ongoing developments, such as the Agency's Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (CACM)[69], the respective Network Codes under development by ENTSO-E and the Regional Initiatives process[70], all aim to put in place a so-called "Target Model", which will require MS to conform to certain minimum criteria in order to facilitate the implementation of the internal market. This Target Model foresees (i) a single European Price Coupling for the day-ahead timeframe which should replace explicit auctions – see Annex 3.2.1 on day-ahead capacity allocation, (ii) a single continuous trading platform in the intraday timeframe (see Annex 3.2.1 on intraday capacity allocation), (iii) a single European allocation platform for the allocation and nomination of long-term transmission rights and (iv) a flow-based allocation method in highly meshed networks. Additionally, the Framework Guidelines on Electricity Balancing foresee the use of a TSO-TSO model based on a Common Merit Order list for the exchanges of balancing energy across control areas.

*(121)* Cross-zonal capacity calculation and the appropriate definition of bidding zones are another two important elements of an efficient electricity market. They influence the efficient use of the existing transmission infrastructure in terms of enhancing pan-European social welfare in electricity trade. In this respect, the CACM Framework Guidelines and respective network codes foresee (i) full coordination and optimisation of capacity calculation within regions, (ii) the use of flow-based capacity calculation methods[71] in highly meshed networks and (iii) regular review of bidding zones. These processes aim to provide the market[72] with more cross-zonal capacity, enabling the cheapest supply to meet the most expensive demand in Europe, subject to the capability of the existing network.

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68 See footnote 10.

69 See: http://www.acer.Europa.eu/Electricity/FG_and_network_codes/Pages/default.aspx

70 See the Agency (2012); "Getting to 2014: The Role of Regional Initiatives", see http://www.acer.Europa.eu/Official_documents/Acts_of_the_Agency/Publication/Regional%20Initiatives%20Status%20Review%20Report%202011.pdf

71 FBCM is a capacity calculation methodology limiting the cross-zonal exchanges between zones directly with the maximum flows on the critical branches of the grid and the so-called power transfer distribution factors.

72 See for a study "Enhanced CWE Flow-Based Market Coupling" (2011);
http://clients.rte-france.com/htm/fr/offre/telecharge/CWE_PLEF_20111028_FB_Report.pdf

*(122)* Investing in the network in order to increase transmission capacities is certainly one way of removing bottlenecks in the EU electricity network. In light of this, it is worth mentioning that ENTSO-E has identified 100 bottlenecks in the EU network, of which 80% are related directly or indirectly to the integration of renewable energy sources (RES). However, (according to ENTSO-E), the renewal or construction of roughly 52300 km of extra high voltage power lines requires a significant investment of 104 billion euros.[73] In addition, network investments require careful cost-benefit analysis in order to determine the net welfare benefit.[74] In this respect, convergence of prices in Europe should be pursued as long as the welfare benefits exceed the investment, operational and environmental costs of the new infrastructure. Moreover, it takes several years to render these network reinforcements operational. Therefore, achieving full efficiency in the use of existing infrastructure should remain the first priority.

*(123)* The remainder of this chapter focuses on how to improve the use of existing infrastructure. It focuses in particular on the problem usually referred to as “unplanned (electricity) flows”, and also sometimes referred to as “loop flows”. Unplanned flows have received increasing attention from stakeholders due to their distortion on the Internal Energy Market (IEM); the Agency and NRAs have already begun coordinating work to remedy this problem. By presenting the facts on unplanned flows, this report aims to contribute to the ongoing discussion as to how this barrier to market integration may be remedied efficiently.

73 ENTSO-E, “Ten-Year Network Development Plan 2012”, see:
https://www.entsoe.eu/fileadmin/user_upload/_library/SDC/TYNDP/2012/120705_TYNDP_2012_report_FINAL.pdf

74 Note that comprehensive cost-benefit analysis, including considerations on the cost of cross-border network expansion and a long-term analysis of expected benefits, is under development within the framework of the ENTSO-E Ten Year Network Development Plan and the proposed Energy Infrastructure Package. See: ENTSO-E, “10-Year Network Development Plan 2012”, 5 July 2012. https://www.entsoe.eu/fileadmin/user_upload/_library/SDC/TYNDP/2012/120705_TYNDP_2012_report_FINAL.pdf

## 3.5 Unplanned flows

(124) A range of studies have been produced on unplanned flows[75], demonstrating the complexity of this issue and the interrelation of the costs and benefits linked to unplanned flows for EU networks. Moreover, the terms "unplanned flows" and "loop flows" are often used interchangeably. However, it is important to note the difference between them, because the exact drivers, future developments and possible remedies are not necessarily the same in both cases.

(125) Loop flows usually refer to physical flows that deviate from their "shortest contractual paths" between injection and take-off points in the network. In this respect, this report distinguishes between loop flows that are caused by cross-zonal exchanges resulting from cross-zonal capacity allocation, and loop flows caused by exchanges internal to bidding zones without any capacity allocation. The latter is referred to, for the purpose of the report, as "unplanned flows".[76]

(126) Unplanned flows present two important challenges. Firstly, they threaten operational security, which requires TSOs to take remedial action; these come at a price. Secondly, unplanned flows can reduce the cross-zonal capacities that are made available for cross-zonal trade, thus reducing gross welfare benefits for EU market participants. The latter is the focus of this section.

(127) Unplanned flows are expected in highly meshed networks, which are characterised by strong interdependencies of power flows among particular systems with alternating current (AC) interconnectors. As the exact identification of the level of unplanned flow is a challenging task, this report assesses the difference between physical flows and scheduled cross-border exchanges on the bidding zone borders as a proxy indicator for the level of unplanned flows.[77] This unplanned flow indicator is merely a first step towards assessing unplanned flows. In the future, the Agency will investigate the possibility of using (arguably) more accurate indicators.

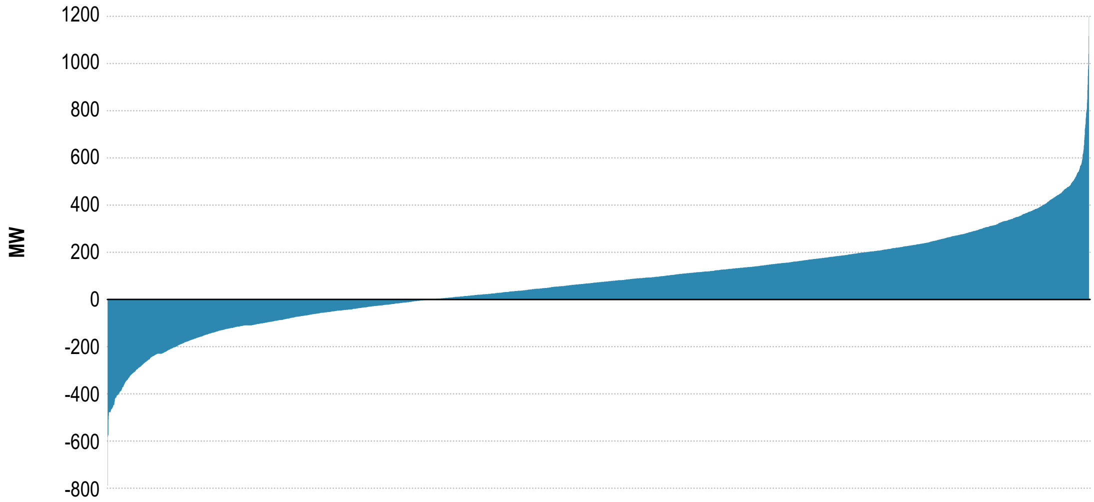
75 The Agency has already received relevant information, including: a study commissioned by Bundesnetzagentur (October 2011), though the focus of this study was to investigate the consequences of a potential split in the common bidding zone of Germany and Austria; an announcement to install phase-shifting transformers (PSTs) by some MS (EPD 14 February 2012); the proceeds of a high-level conference on loop flows in Brussels organised by the European Commission/DG ENER (19 March 2012); a joint response to the Bundesnetzagentur study by 4 Central Eastern European TSOs (March 2012); an open letter from the largest Austrian TSO (APG) to the aforementioned four TSOs (4 April 2012); a letter from the Polish TSO PSE-O to APG (16 April 2012); and an ENTSO-E briefing paper to the Commission (17 April 2012).

76 Flows in the network are caused by electricity exchanges between generation and load. In the case of a meshed network divided into three bidding zones, the unplanned flow on any network element is the sum of the flows caused by the internal exchanges in zone A, internal exchanges in zone B and internal exchanges in zone C. Exchanges between the zones also cause loop flows; however, in contrast to internal exchanges, cross-zonal exchanges are limited due to capacity calculation and allocation, thus the resulting flows are controlled in order to avoid overloading of network lines.

77 Physical flow is a sum of the actual flows measured in real time on different lines making up an interconnection, taking into account the direction of the actual flow on each line. At a given time, this physical flow can run in only one direction.

(128) As an example, Figure 27 shows the unplanned flow indicator values for the Slovenian-Italian border in 2011, on an hourly basis. The vertical axis shows hourly unplanned flow indicator values, ordered by magnitude from the lowest (including negative values) to the highest. The indicator value of zero implies no unplanned flows on this border. A negative unplanned flow indicator means that there are more commercial exchanges scheduled via this border than actual power flows, suggesting that some of the exchanges scheduled on this border flow through other interconnectors. The total absolute value of unplanned flows across this border was 1.4 TWh in 2011, which is the area marked blue in Figure 27.

**Figure 27: Hourly ranked unplanned flow indicator from Slovenia to Italy – 2011 (MW)**

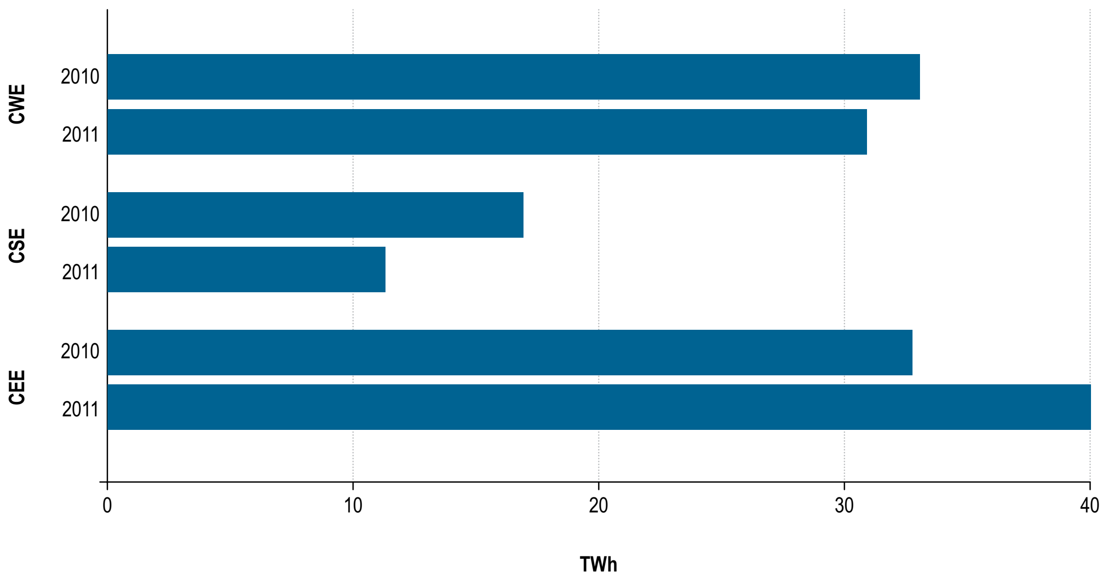



*Source: ENTSO-E (2012) Agency calculations*

*(129)* Using this definition, Figure 28 attempts to shed some light on where unplanned flows exist within the EU. It shows the sum of absolute unplanned flow indicators by border, aggregated by region.[78] The figure demonstrates that in the Central East Europe (CEE), Central South Europe (CSE), and Central West Europe (CWE) regions, the magnitude of unplanned flows is significant. Moreover, the figure shows that in the CSE and CWE regions, unplanned flows diminished, whilst in the CEE region they increased between 2010 and 2011.

*(130)* There is a consensus amongst NRAs that, among other things, the main reason why the level of unplanned flows across continental European borders has increased significantly over the past few years is the massive deployment of RES (renewable energy sources) and the delays observed in the development of sufficient network reinforcement.[79]

**Figure 28: Absolute aggregated sum of unplanned flow indicators for three regions – 2010 to 2011 (TWh)**




*Source: ENTSO-E (2012), Agency calculations*

*Note: for this figure, the unplanned flows (physical flows minus scheduled exchanges) are calculated on an hourly frequency. Then, the absolute values are summed across hours and aggregated for borders belonging to the relevant region. Note that the number of borders differs per region which affects the results.*

78 "Regions" in the meaning of Annex I in Regulation (EC) No 714/2009 (OJ L 211, 14.8.2009).

79 This was concluded among NRAs during a workshop dedicated to unplanned flows on 28 June 2012. For the high level conclusions see: http://acernet.acer.Europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/AESAG/10th_AESAG_meeting/A12-AEWG-15-08%20ACER%20workshop%20on%20unplanned%20flows%20-%20High%20level%20conclusions.docx

*(131)* Unplanned flows impact the operation of the network, since vast increased renewables based electricity has to be transmitted from where it is injected to where the demand is located. In the CEE, CSE and CWE regions, in which networks are highly meshed, unplanned flows originating from exchanges in one bidding zone may lead to challenges in the networks of adjacent bidding zones. Despite considerable efforts from TSOs, progress has been slow in expanding the transmission capacity to the necessary degree.

*(132)* On a daily basis, many TSOs in the CEE, CWE and CSE regions face operational security concerns caused by (*inter alia)* unplanned flows which require remedies. While adequate network reinforcements are pending, TSOs can apply several remedial measures in order to cope with the constraints on their networks and to maintain the demand-supply balance and operational security. The potentially available remedies include both preventive and curative measures:

1. Offering less cross-border capacity to the market (preventive);
2. Countertrading or (cross-border) re-dispatching (curative);[80]
3. Curtailment of the already allocated capacities (curative);[81] and
4. Changing the configuration of the system by redirecting flows (curative).[82]

*(133)* Most of these tools, which are not equivalent nor equally effective in dealing with constraints in the network, come at a cost to the TSOs. These costs could be subject to a sharing arrangement between TSOs within the regions, where sharing seems justified as a result of the interdependency of regional networks and the challenges they face. The suggestion of cost-sharing for certain TSO remedial actions was presented at the Florence Forum, in May 2012. To provide transparency, certain costs of the above-mentioned remedial measures (with the exception of the last measure) are presented in what follows. However, these costs also include remedial actions for causes other than unplanned flows.

*(134)* As regards the first measure, some TSOs in CEE have recently stated[83] that, due to the level of unplanned flows and the related uncertainty and also due to the lack of appropriate curative measures, they have chosen to offer less capacity to the market. Although this preventive measure does not entail any costs for the TSO, it does carry a “price” in terms of lower social welfare and the reduced price convergence that accrues from cross-zonal trade.

80 TSOs could trade in the opposite direction to the market price differential in order to remove a network constraint. In addition, there is the possibility to (internally) re-dispatch, whereby TSOs may activate offers, for instance via balancing. Re-dispatching measures are not treated here. Further, it should be noted that it is not straightforward to distinguish between re-dispatching and cross-border re-dispatching. This is because re-dispatching of internal lines can impact cross-border capacities.

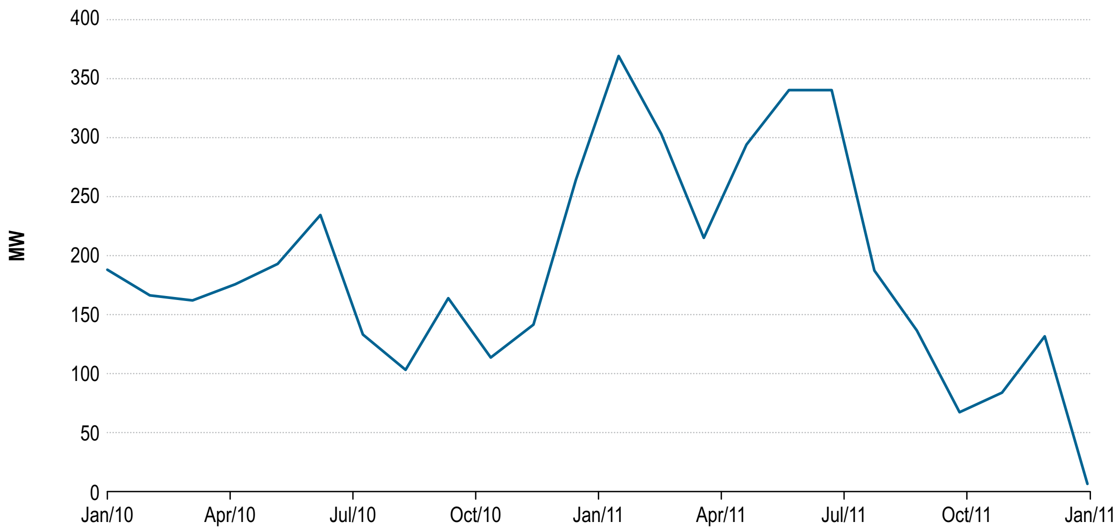
81 Subject to compensation, holders of long-term capacity can have some of their transfer rights reduced.

82 TSOs may switch connections in a substation, may adopt radial operation schemes for a line or they may use PST installed on certain lines to redirect flows on the grid in real time.

83 See: joint response to Bundesnetzagentur study by 4 Central/Eastern European TSOs, March 2012.

*(135)* Figure 29 illustrates the hourly average day-ahead import transmission capacity made available for Poland, part of the CEE region. Although the data available cover only two years, which makes it difficult to make any time-series analysis, it does show that imports into Poland from Germany, the Czech Republic and Slovakia were lower towards the end of 2011 compared to 2010. Finally, in more than 7400 hours during 2010 and 2011, the import NTC was reduced to zero.

**Figure 29: Monthly hourly averages of import NTC values to Poland – 2010 to 2011 (MW)**




*Source: ENTSO-E (2012), Agency calculations*

*Note: The figure excludes the border between Sweden and Poland due to lack of data.*

*(136)* Table 8 shows the costs incurred by TSOs for cross-border re-dispatching and countertrading for a selection of countries (part of the second measure mentioned above). It is difficult to draw conclusions from this table, however, because it does not report the costs incurred by other CWE or CEE countries. Moreover, and more importantly, the reported values in the table include merely the money spent on relieving congestion on cross-border lines. However, the available cross-border capacities are usually impacted by congestion on internal lines and the costs to relieve these internal congestions can be much higher than merely the costs to relieve congestion on cross-border lines. Further ongoing work by the Agency/CEER, in cooperation with ENTSO-E, should help to better define the scope of cross-border re-dispatching costs and propose an appropriate regulatory framework for cost sharing. The preliminary findings of such work was presented at the Florence (Electricity) Forum in 2012.

**Table 8: The costs of re-dispatching and countertrading per border – 2011 (000 euros)**

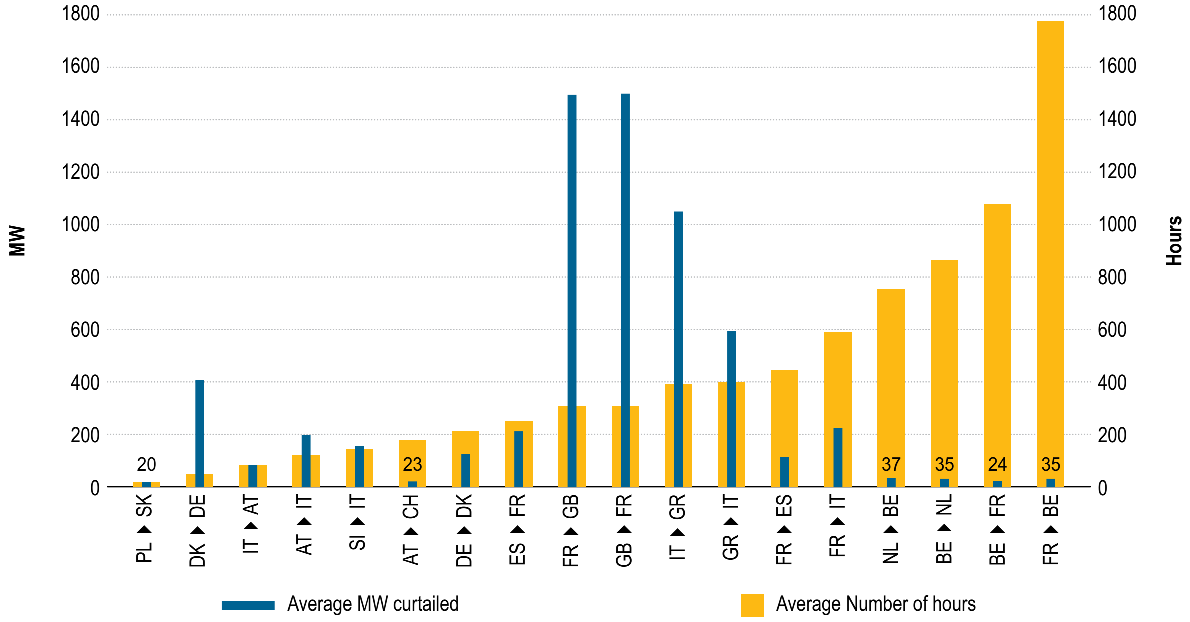
| Country | Border | Redispatching* and counter-trading* costs (000 euro) |
|---|---|---|
| France* | FR→BE | 1 |
| France* | FR→DE | 6 |
| Spain | ES→FR | 9 |
| France* | FR→CH | 9 |
| France* | FR→IT | 42 |
| Latvia | EE→LV | 70 |
| Spain | FR→ES | 154 |
| Finland | FI→SE | 351 |
| Poland | PL→All | 435 |
| Finland | FI→EE | 705 |

*Source: Data provided by NRAs through the Electricity Regional Initiative (ERI) and Agency calculations (2012)*

*Note: "All" relates to all borders, as information per border was not available. Austria and Hungary reported no costs. * For France, on the border between Spain and France, only re-dispatching is included. In addition, France provided costs for internal cross-border re-dispatching, which were 13.3 million euros in 2011. Sweden spent nearly 700 thousand euros in 2011 on essentially only internal re-dispatching.*

(137) The third measure mentioned above consists of TSOs compensating market participants who "lose" their cross-border transmission capacity when curtailments take place. Figure 30 provides information on the total number of MW curtailed on borders for which information is available. It also shows the number of hours for which capacity was curtailed. Note that these curtailments have not been made exclusively to remedy unplanned flows. The figure shows that substantial amounts of cross-border capacity were withheld from the market on the borders between Belgium and neighbouring countries, albeit for only a limited number of hours (on average, 52 hours across all Belgian borders). From Denmark to Germany and also from Italy to Greece, the number of hours were much higher (around 450 and 1200 respectively), although the amount of capacity actually curtailed was, on average, only 44 and 350 MW respectively. A more in-depth assessment is required to determine the impact of curtailments on market integration.

**Figure 30: Average MW and the average number of hours curtailed per border – 2011**



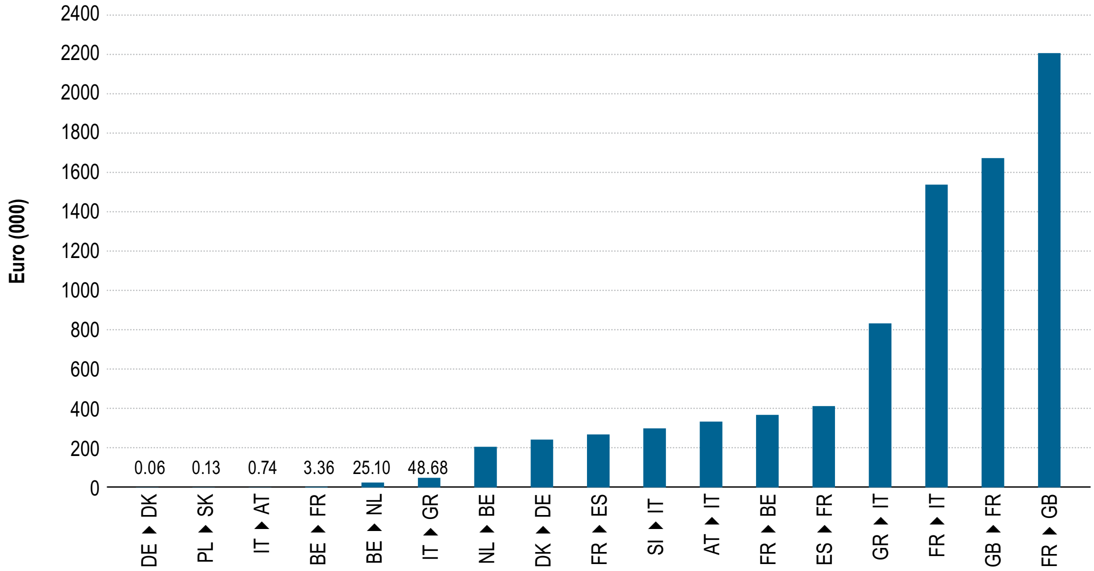

*Source: Data provided by NRAs through the ERI and Agency calculations (2012)*

*Notes: 1) in this figure "curtailment" is defined as "long-term capacity curtailment". It refers to a situation in which the sum of monthly and yearly auctioned capacity is higher in a specific hour than the day-ahead NTC value in the same hour. For further explanation see Annex 3.2.2 on capacity curtailments. 2) For the borders of FR→ES and AT→IT the average MW capacity curtailed and the average number of hours curtailed for 2011 are reported across both countries' TSOs.*

*(138)* The money paid by TSOs when resorting to capacity curtailment corresponds to the compensation payments offered to holders of cross-border transmission rights. Compensation schemes may differ from one region to another. For instance, whilst the CWE region offers market-based compensation, other regions usually propose a simple reimbursement. These costs are split between the TSOs involved in the operation.

*(139)* Figure 31 shows the curtailment costs for a selection of countries, which in 2011 was in total 8.5 million euros.

**Figure 31: Total of curtailment spent per border – 2011 (000 euros)**



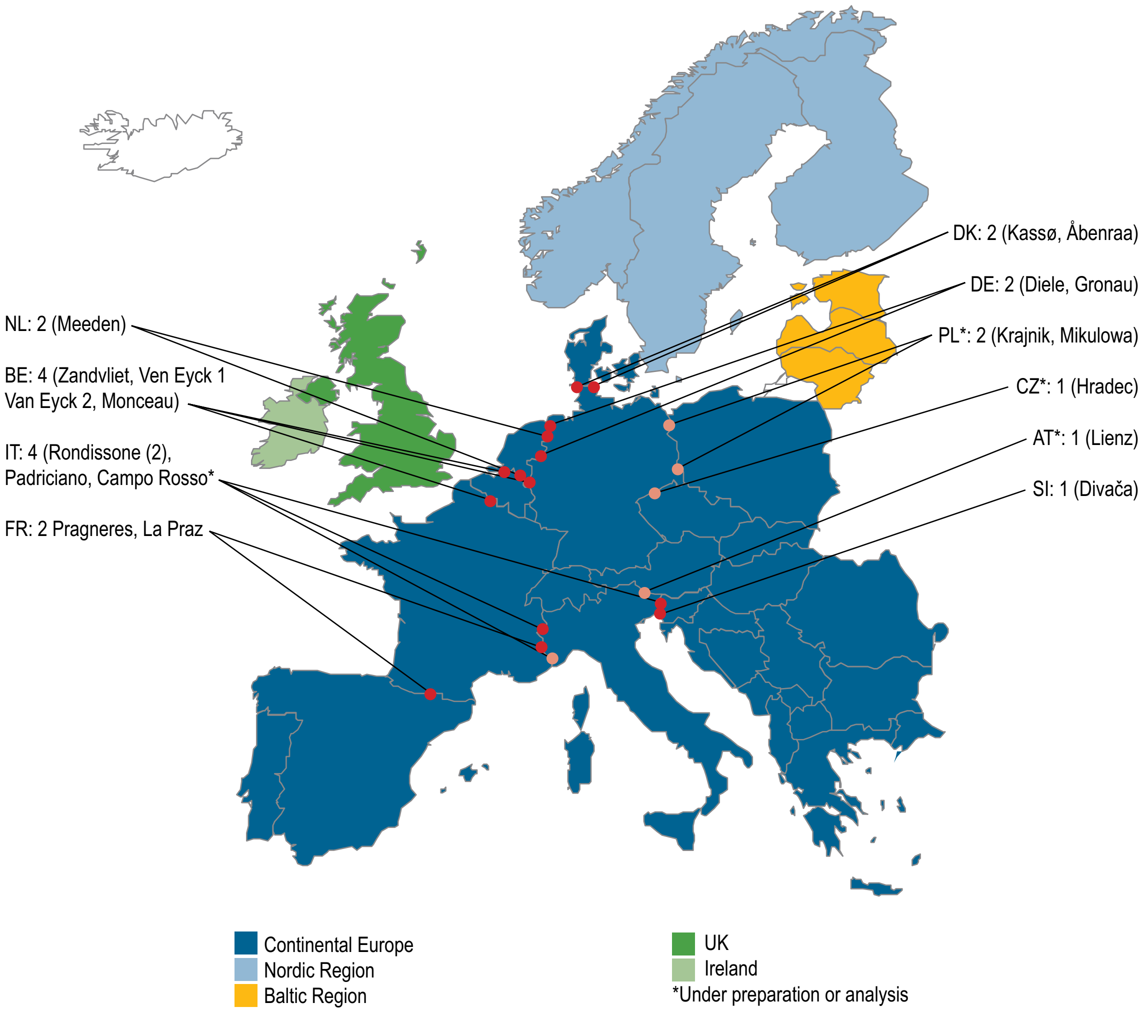

*Source: Data provided by NRAs through the ERI and Agency calculations (2012)*

*Note: The following countries either reported no costs relating to curtailments or indicated that this situation did not apply to them: DK, FI, HU, LT, LV, LU, NL, RO, SK and SE. For the borders of AT-IT, FR-IT and FR-ES the average total costs of curtailments for 2011 are reported across both countries' TSOs.*

*(140)* The fourth measure, which is changing the configuration of the system in order to redirect flows, does not result in any significant cost to the TSO that applies the measure, provided that it does not distort neighbouring networks.

*(141)* Furthermore, TSOs may install phase-shifter transformers (PSTs) to better manage unplanned flows. Figure 32 illustrates the status quo of these installations in the CEE and CWE regions, limited to cross-border interconnectors only and based on the information received so far by the Agency.

**Figure 32: Phase-shifting transformers installed in the EU/EEA at a selection of borders**




*Source: Data provided by NRAs through the ERI (2012) and information from CEE NRAs (presentation at the ACER Workshop on Unplanned Flows, June 2012).*

*Note: * Under preparation or analysis.*

*(142)* Assuming that installation is part of a wider coordinated effort among TSOs, the main purpose of PSTs is usually to improve operational security and capacity calculation within the EU. In the context of unplanned flows, such equipment should especially ease north-south flows in continental Europe.

*(143)* In terms of network planning, the major advantages of PSTs are that their deployment process is usually faster than that of new transmission lines and their installation normally requires shorter time-frames. Nonetheless, it may be argued that, in cost-benefit terms, new transmission lines could still present a better solution than PSTs in the longer term, since merely redirecting the flows can create new problems in other parts of the network previously unaffected. In any case, there exist valid arguments for sharing the cost of investing in such transformers among the relevant TSOs, provided that, once installed, they truly serve the interests of European market integration and that such a function is sustained and monitored over time.

*(144)* In the presence of PSTs, depending on how well the latter are correctly sited, managed and coordinated across networks, cross-border capacity can be used in a more efficient manner.

*(145)* This section has demonstrated that unplanned flows are an important issue and require TSOs to apply remedial actions. As shown, these actions come at a price for TSOs, since the latter must cover the costs of remedial action. In order to reduce the cost of remedial actions in the presence of increasing unplanned flows, TSOs may resort to offering less capacity for trade across borders. However, doing so reduces the efficiency of the internal market and the welfare gains from trade.

***Remedies***

*(146)* There is a consensus amongst NRAs that unplanned flows distort the functioning of the internal market and threaten the security of supply. With reference to the high level conclusions of the workshop on unplanned flows[84] the following measures could remedy unplanned flows:

*(147)* Firstly, through improved coordination between relevant TSOs, more capacity could be made available to the market. Initiatives such as Coreso (which is a Western Europe regional coordination centre for improving security of supply) and TSO Security Cooperation improve the information exchange among TSOs, which should in turn improve capacity calculation and help to identify the most effective and cost-efficient remedial actions at a regional level. Also, the application of appropriate flow-based congestion management can mitigate unplanned flows. These remedies are feasible in the short term.

*(148)* Secondly, the establishment of a sound regulatory framework for sharing and compensating the costs incurred by TSOs that apply these remedial actions is an important prerequisite for promoting the efficient use of remedial actions.

*(149)* Thirdly, in order to remedy unplanned flows, more network investments (including PSTs) have to be considered in order to increase (better manage) the available cross-border transmission capacity. However, as mentioned above, such reinforcements of networks come at price, and require many years of planning and building before coming online and may not necessarily yield a higher net welfare benefit.

*(150)* Finally, unplanned flows can be remedied by restructuring bidding zones. The launch of a pilot study based on the process of reviewing the bidding zones as defined in the Capacity Allocation and Congestion Management Network Code is a good starting point.

84 See footnote 79.

### 3.6 Conclusions and recommendations

(151) Prices have significantly converged due to market coupling. For example, in the CWE region on the German-Dutch border, the number of hours during which day-ahead prices were identical increased from 12% to 87% from 2010 to 2011. However, inter-regionally there remains significant scope for further market integration. For example, between the Netherlands and Norway, the total number of hours in which market prices were identical was just 6%.

(152) To further converge EU wholesale electricity prices, it is vital to implement the Target Models for long term, day-ahead, intra-day, balancing and flow-based both through the formal (Framework Guidelines/ Network Codes) and informal (Electricity Regional Initiative) processes.

(153) In terms of generation, the key development is the increasing share provided by RES. For instance, the contribution to electricity generated from solar energy increased between 2008 and 2011 in the EU-27, from 7.4 to 41.5 TWh.

(154) The social welfare indicator presented in this report provides some insight into the gross benefits of market integration. Despite the caveats underlying the results of this year's report, the indicator is to be further developed in order to become a monitoring tool which can be used to assess the utilisation of the existing network and track the progress of market integration.

(155) There is a consensus among NRAs that unplanned flows undermine the functioning of the internal market. These flows persist mainly in the Central East, Central West and Central South regions in Europe.

(156) In the context of unplanned flows, the following recommendations are made: firstly, improving co-ordination between the relevant TSOs; secondly, implementing flow-based congestion management as an appropriate way to make better use of existing network capacity; thirdly, establishing a sound framework to ensure that TSOs are properly compensated; if, and when, they apply efficient remedial actions to resolve network issues stemming from unplanned flows. Additional network investments (including PSTs) are also to be considered in order to increase (or better manage) available cross border transmission capacity. However, such reinforcements come at a price, take many years to be completed, and should be realised only if their welfare benefits exceed the costs. In addition, the restructuring of bidding zones is a remedial option that, subject to cost-benefit analysis, should also be explored in more detail. The launch of a pilot study based on the process of reviewing the bidding zones as defined in the Capacity Allocation and Congestion Management Network Code is a good starting point. Finally, improving the transparency on unplanned flows and monitoring these flows by means of developing indicators to understand and assess these flows and collect the appropriate data to fill these indicators.

# 4 Network access in electricity

## 4.1 Introduction

*(157)* This chapter addresses the issue of electricity network access, including connection-related aspects, since this is a prerequisite for granting third-party access.

*(158)* The terms "access" and "connection" appear several times in Directive 2009/72/EC. "Access" frequently refers to the supply of electricity, including *inter alia* the quality, regularity and cost of the service. Nevertheless, the term "access" is primarily used in the context of ensuring non-discriminatory tariffs.[85] "Connection" is mainly used in a technical context[86] and relates to the physical connection to the system. Therefore, it represents the necessary condition to gain access to the grid.

*(159)* Furthermore, Directive 2009/28/EC[87] plays an important role in the context of network access, since it lays down, in particular, the rules relating to access to the electricity grid for energy from renewable sources.[88]

*(160)* This chapter includes a number of network access topics and in particular addresses the access of renewable generation.[89] The analysis of each of these topics aims to identify any inefficiencies, or as potential barriers to the completion of the internal market. For the purpose of this chapter, no distinction has been made between the transmission and distribution levels. This implies that all the figures and tables shown throughout the electricity network access chapter refer to both the transmission and distribution networks. Moreover, this chapter includes recommendations which will be based on national case-studies provided by NRAs.

*(161)* The first section of this chapter presents a status review of network access in Europe, including the main challenges. The second section focuses on grid connection procedures and examples of inefficiencies. The third section focuses on usage and access to the network. The issue of transmission tariffs and connection charges is mentioned only briefly in the final section, since the Agency's work on tariffs has only recently begun and the information collected from NRAs on this topic was still unavailable at the time of completion of this monitoring report. The chapter concludes with recommendations.

85 Recital 4 and 32 (preamble) and Article 32 of Directive 2009/72/EC. of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing directive 2003/54/EC (OJ 2009 L211/55).

86 See footnote 85, Articles 5, 37.6(a) and 37.1(m).

87 Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

88 According to Article 16.2 of this Directive, MS shall provide for either prioritised or guaranteed access to the grid for electricity produced from RES.

89 Although the Agency has a duty to monitor the access of all network users, most of the publicly available information on network access for 2011 refers to renewable generation. Moreover, renewables access is particularly mentioned in Article 11 of Regulation EC/713/2009.

## 4.2 Challenges to network access

*(162)* During 2010 and 2011, most MS transposed Directive 2009/72/EC and Directive 2009/28/EC into their national legal frameworks. In particular, Directive 2009/28/EC introduced substantial changes regarding the grid integration of the electricity produced by RES.

*(163)* The main changes observed in national legislation[90] of the different MS during 2010 and 2011 aimed to:

- Review the processes for obtaining access to grids in order to accelerate the growth of generation from RES (e.g. the United Kingdom and Italy);
- Reduce the burden of regulation (e.g. in the United Kingdom);
- Streamline procedures and improve coordination to reduce the connection lead times of renewable energy plants to the network (as in Italy or Bulgaria);
- Differentiate between large and small installations in the connection procedure (e.g. Lithuania, Portugal or Spain);
- Provide a greater level of clarity to renewable generators on market operations as they affect RES, including dispatching rules such as priority issues; and
- Speed up planning and consent processes (e.g. Germany, the Netherlands, and the United Kingdom).

*(164)* Some other measures were introduced in order to overcome concrete difficulties faced in the past:

- The introduction of advance payments and other measures in order to reduce the number of speculative projects (e.g. Lithuania); and
- The obligation to allow the system operator to regulate renewable electricity production in order to enhance the security of the system (e.g. the Czech Republic).

*(165)* Some other measures were also put in place to provide for a more market-based approach. For instance:

- The possibility for RES-E (electricity from renewable energy sources) producers to temporarily opt out of the feed-in tariff scheme to directly participate in the market (e.g. Germany); and
- Specific restrictions to supplementary payments if the market price becomes negative, in order to encourage a producer providing the necessary system services to supply less energy whenever there is congestion in the grid (e.g. Denmark).

90 RES-Legal, RES-Integration and National Progress Reports on the Promotion and Use of Energy from Renewable Sources: i. RES-Legal Project, on behalf of the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2011; see: http://www.res-legal.de/en.html; and ii. RES-Integration Project on behalf of the Commission, 2011; see: http://www.eclareon.eu/en/res-integration-final-report
The sole responsibility for the content of RES-Legal and RES-Integration lies with the authors. It does not necessarily reflect the opinion of the European Union or the German Ministry; iii. National Progress Reports on the Promotion and Use of Energy from Renewable Sources drawn up under Article 22.1 of Directive 2009/28/EC on the promotion of the use of energy from renewable sources; see: http://ec.Europa.eu/energy/renewables/reports/2011_en.htm

*(166)* Finally, some other MS have also published new legal provisions to promote the development of intelligent and flexible electricity consumption in order to facilitate the integration of renewables in the network (e.g. Denmark and Italy).

*(167)* Most of the above-mentioned measures introduced into national legislation reflect the need to enhance procedures for grid connection, as well as the need to foresee adequate market rules for the integration of renewables. Today, these two can be considered the most challenging issues concerning network access. They are discussed using examples in sections 4.3 and 4.4.

*(168)* Regarding the connection and access regimes for renewables, Table 9 (column 2) shows that, in 2011, 7 out of the 28 EU/EEA MS provided priority connection for new RES-E installations. Also, different access regimes for renewables are in place throughout Europe.

*(169)* Table 9 (column 3) shows that, in 2011, 15 out of the 28 EU/EEA MS provided for priority access, while 12 provided for guaranteed access for renewables. Some countries did not apply priority dispatching in 2011.[91] Section 4.4 discusses the issue of priority access and dispatching in more detail.

91 According to Directive 2009/28/EC (Article 16.2.c), MS shall ensure that renewables are given priority dispatching in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria.

**Table 9: Connection and access regimes in Europe – 2011**

| Country | Grid connection (connection regime for RES-E) | Use of the grid (access regime for RES-E and priority dispatching) |
|---|---|---|
| Austria | Non-discriminatory | Guaranteed access |
| Belgium | Priority connection | Priority access |
| Bulgaria | Non-discriminatory | Guaranteed access |
| Cyprus | Non-discriminatory | Priority access |
| Czech Republic | Priority connection | Priority access |
| Denmark | Non-discriminatory | Priority access |
| Estonia | Non-discriminatory | Guaranteed access without priority dispatching |
| Finland | Non-discriminatory | Guaranteed access without priority dispatching |
| France | Non-discriminatory | Guaranteed access without priority dispatching |
| Germany | Priority connection | Priority access |
| Greece | Non-discriminatory | Priority access |
| Hungary | Non-discriminatory | Priority access |
| Ireland | Non-discriminatory | Priority access |
| Italy | Priority connection | Priority access |
| Latvia | Non-discriminatory | Absence of priority dispatching |
| Lithuania | Priority connection | Priority access |
| Luxembourg | Non-discriminatory | Guaranteed access without priority dispatching |
| Malta | Non-discriminatory | Priority access |
| Netherlands | Non-discriminatory | Guaranteed access without priority dispatching |
| Norway | Non-discriminatory | Guaranteed access without priority dispatching |
| Poland | Non-discriminatory | Priority access |
| Portugal | Non-discriminatory | Guaranteed access |
| Romania | Non-discriminatory | Guaranteed access |
| Slovakia | Priority connection | Priority access |
| Slovenia | Non-discriminatory | Priority access |
| Spain | Priority connection | Priority access |
| Sweden | Non-discriminatory | Guaranteed access without priority dispatching |
| United Kingdom | Non-discriminatory | GB: Guaranteed access, without priority dispatching<br>NI: Guaranteed access |

*Source: The Agency (2012), compilation of data from National Progress Reports on the Promotion and Use of Energy from Renewable Sources, RES Integration, RES Legal and NRAs.*

*Notes: For Belgium, based on RES Legal, legislation at federal level. Regional authorities with competences at distribution level might provide for different legal frameworks. The issue of dispatching is specified only for those MS without priority dispatching in place.*

### 4.3 Grid connection: procedures

*(170)* The process of grid connection usually starts when an applicant submits their first request to obtain connection, and ends upon receiving permission to use the grid. The time elapsed between these two points can be defined as the lead connection time.

*(171)* During 2011 and in previous years, one of the recurring complaints[92] of plant developers was the frequent delays in the grid connection process. For monitoring purposes, it is recommendable that NRAs are able to collect data on lead connection times in a systematic way, although there are several challenges to doing so. Firstly, it is difficult to provide an accurate and homogenous definition of connection time[93] as the connection process depends on several immeasurable variables, such as the precision of documentation provided by the applicant. It can also depend on ambiguous processes, such as administrative procedures; this also makes it difficult to derive a concrete definition of connection delay. Secondly, network access monitoring is not usually carried out on a regular basis, and in some cases, national regulators lack clear legal rights to collect data on this topic.[94]

*(172)* On the one hand, long connection times may lead to inefficiencies. These delays are prejudicial for investors, as they increase uncertainty, and thus the cost of capital[95], and frequently take place as a consequence of an insufficient network development.[96] On the other hand, inappropriate network investment, which aims to reduce lead connection times, could result in unnecessary costs which are then borne by end users.[97]

*(173)* Planning of network connections may worsen if, in addition to delays and insufficient network development, plant investors are entitled to pre-book capacity. This might lead to the problem of so-called virtual saturation. Below, a case is presented illustrating the issue of virtual saturation[98] in Italy, in 2011.

92 RES Integration-Final report, p.5, see footnote 90.

93 RES Integration-Final Report, p.175, see footnote 90.

94 For instance, in Austria, the national electricity law (ElWOG 2010) defines the framework provision (“Grundsatzbestimmungen”) for the electricity market. The competences for connection, however, are defined by each Federal State in the implementing legislation (“Ausfuehrungsgesetze”). The potential discrepancy in these statutes complicates the national monitoring of connection issues.

95 RES Integration-Final Report, p.45, see footnote 90.

96 RES Integration-Final Report, p.6, see footnote 90.

97 As explained later under the Connect and Manage Regime in the United Kingdom, placing liabilities on users may limit the occurrence of avoidable costs.

98 The problem of virtual saturation has been reported in 2011, according to RES Integration, in nine MS: Bulgaria, the Czech Republic, Estonia, Finland, Hungary, Italy, Latvia, Romania and Slovakia.

### Virtual saturation and connection fees in Italy

Over the past few years, due to availability of resources and attractive incentive schemes, renewable energy plants have been installed, mostly in Southern Italy, where the transmission and distribution networks are less developed and meshed than in other parts of the country.

The TSO and DSOs have therefore been facing the challenge of connecting new renewable plants to the network (network capacity is reserved by the system operators upon a connection request) and keeping the costs of reserving capacity to a minimum.

In circumstances where network capacity is relatively scarce and the grid is targeted by a large amount of connection requests within the same area, cases of virtual grid saturation arise. In other words, the grid is not physically congested, but all its available capacity is booked up by connection requests and no additional capacity can be allocated.

Two possible inefficiencies may arise as a consequence of this: on the one hand, generators could experience longer connection timing and, on the other hand, if the network is developed to accommodate all the reserved capacity, transmission assets could be stranded if the promoters cancelled the project at a later stage.

The following table illustrates the situation on 31 December 2011.

| | | |
|---|---|---|
| Capacity corresponding to accepted connection requests on 31 December 2011 (148 GW) | Plants authorised to be built | 8 GW |
| | Plants not yet authorised | 140 GW |

Notice that, in Italy, the overall installed capacity (both from renewables and conventional plants) amounted to 118 GW[99] at the end of 2011.

In order to limit problems arising from virtual grid saturation, the Italian NRA recently introduced a fee (20.25 euro/kW) for booking grid capacity. This fee has to be paid by the generators to DSOs or the TSO at the moment the connection request is accepted. This fee is returned once the power plant is built, or in the case that the producer leaves the project in the subsequent two years. For those cases in which the connection request was already accepted, the fee was due by 31 May 2012. These rules are applied in "critical areas", i.e. areas where saturation (real or virtual) is identified by the system operators.

In May 2012 (following the suspension of fees as a consequence of the decision by the Council of State), the Italian NRA determined that the "technical solution" (project plan proposed by the relevant system operator) for connection would remain valid for a limited period of time depending on the voltage level and allowed for the temporary reservation of network capacity (exceptions for new installations up to 1 MW were introduced). The definitive reservation of network capacity occurs only at the end of the permitting procedure for authorising the construction and operation of the generation facility. This decision also applies in cases of connection requests already sent to the network operator.

99 Source: ENTSO-E; see: https://www.entsoe.eu/resources/data-portal/production/

This approach was considered as the most appropriate by the national regulatory authority during the public consultation[100]; however, it has not yet been applied in practice due to certain constraints on the implementation phase which would require the active cooperation of all stakeholders.

Following the suspension of fees, as decided by the Council of State, the alternative solution described above seems to be the only applicable solution. However, litigation is still pending.

The Italian case might serve as an example for those MS affected by virtual saturation.

## 4.4 Grid use: RES-E network access and market design

*(174)* This section evaluates how grid access for renewable plants is granted across MS, as well as how different national market arrangements respond to the integration of intermittent generation in the network.

*(175)* The first important element refers to the level of priority granted to renewables, according to Directive 2009/28/EC. In Table 9 it was already highlighted that MS have opted for different solutions with regard to renewables network access. The different solutions adopted influence wholesale market arrangements at a national level (an example of this is provided in the case box for Denmark).

*(176)* Furthermore, irrespective of the adopted regime (priority or guaranteed access), MS are required to give priority dispatch rights to renewables, and ensure appropriate measures to minimise the curtailment of renewable generation[101]. Therefore, measuring the level of curtailments[102] may be an indicator of the efficiency of priority dispatching, or lack thereof, bearing in mind that network expansions are subject to cost-benefit analysis (since zero is not necessarily the optimal level of curtailment)[103]. Making information available on curtailments may help increase transparency on the access of renewables to the network and evaluate underlying problems.

*(177)* The level of curtailment applied to wind power[104] in 2010 and 2011 is shown in Figure 33.

100 Noted by the stakeholders in the consultation process; see ARG/elt 187/11: http://www.autorita.energia.it/allegati/docs/11/187-11arg.pdf

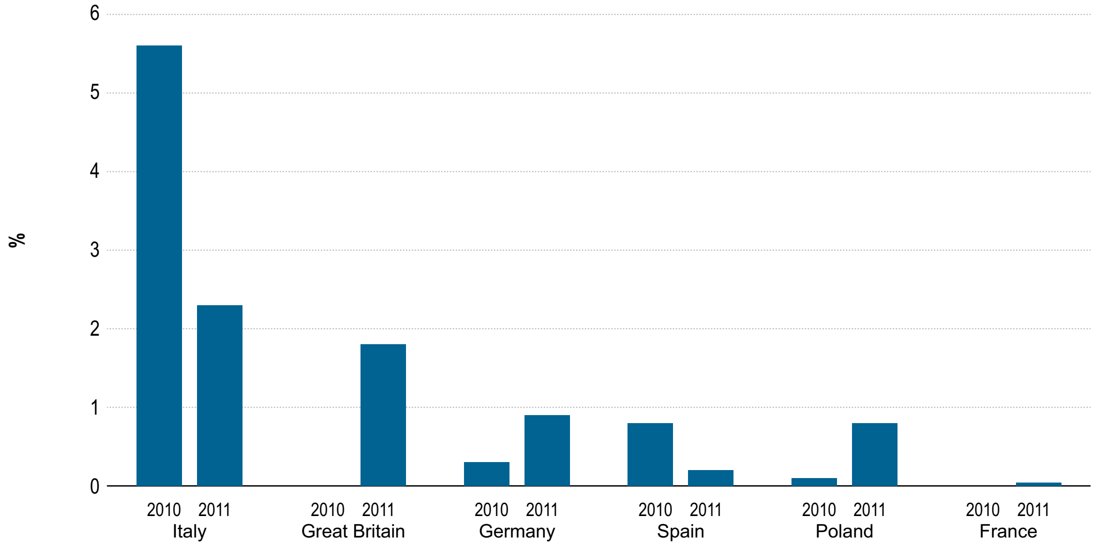
101 See footnote 87, Article 16.2(c).

102 Generation curtailment may be defined as an event that takes place when a deliberate action is taken by the relevant network operator (TSO or DSO) to reduce a portion or all of the energy that can be produced from a generating facility. Such action may be needed if the amount of generation injected in the grid within a particular control area exceeds either available network capacity or the demands of the load taking the energy off the grid, or a combination of these factors.

103 An example of cost-benefit analysis, including compensations due to curtailment, is included in this section in the British case study on Connect and Manage.

104 A data request on wind curtailments was made to those MS with more than a 10% of share of wind energy (MWh produced) or more than 2000 MW of wind capacity installed in 2011. Only MS with available information are shown; the Netherlands, Portugal and Denmark reported 0% of curtailments in both 2010 and 2011.

**Figure 33: Percentage of energy loss due to curtailment of wind-generated energy at a national level – 2010 to 2011 (%)**




*Source: NRAs/TSOs (2012)*

*Notes: Level of lost wind energy in terms of % of total wind generation. Wind curtailments with or without compensation rights are included, except for Germany where only curtailments entitled to compensation in accordance with Section 11 of the Renewable Energy Sources Act (EEG).*

*(178)* According to the information in Figure 33, the curtailment level of renewables is currently not too high. It has to be noted, however, that the figures shown are aggregated at a national level, whilst in some cases curtailments at a regional level within countries may be higher.[105] More detailed information, such as data on curtailments per time unit and according to underlying reasons, might help to address the problems more efficiently[106]. It is advisable that both NRAs and the Agency have access to this information.

*(179)* According to Figure 33, in 2010, Italy recorded the highest level of wind curtailments. This was due to significant network congestions in some areas of Italy (especially in the centre-south). However, in 2011, the curtailed wind energy declined mainly because of network expansions made in the most critical areas. In France, where the share of installed wind capacity is around 5%, the curtailment level of renewables in 2011 amounted to less than 0.05%.

105 Furthermore, according to RES Integration, the issue of curtailments may become more relevant in the coming years due to the expected increase in the share of renewable energy. The 2012 ENTSO-E Summer Supply Outlook has also highlighted that, during certain summer weeks of 2012, it might be necessary to reduce excess generation in various countries as a result of insufficient cross border export capacity. See ENTSO-E, "Summer Outlook Report 2012 and Winter Review 2011/2012", p.4 at https://www.entsoe.eu/news/announcements/newssingleview/article/entso-e-publishes-summer-outlook-and-winter-review/

106 For instance, curtailments due to constraints at a distribution level might require solutions based on smart grids or the reinforcement of distribution lines, while curtailments at a transmission level might suggest, inter alia, the need to enhance the rules for congestion management or to reinforce transmission lines.

*(180)* Figure 33 illustrates that increases in RES-E curtailments have taken place in Germany, Great Britain and Poland. Germany and Great Britain have recently put in place favourable connection regimes[107] to speed up the integration of new generation, in particular the integration of renewable plants in order to meet the 2020 targets. As shown below, in Great Britain, such regimes have proven to be effective in accelerating the process of grid connection. Such regimes contribute to network congestion and therefore increase curtailments if they are not accompanied by appropriate additional investment in infrastructure. Moreover, speeding up renewable deployment without sufficient network investment may lead to other constraint-related inefficiencies. Only an appropriate balance between the additional costs incurred and the benefits of fostering renewable deployment should justify the implementation of such connection regimes. It is not within the scope of this report to carry out a cost-benefit analysis[108] of those regimes; what follows will simply highlight the pros and cons of such approaches. The British case is presented below.

107 National Progress Reports on the Promotion and Use of Energy from Renewable Sources, see footnote 90.

108 An example of the cost-benefit analysis of different connection regimes is provided in the impact assessment on proposals for improving grid access conducted by the United Kingdom Department of Energy and Climate Change (DECC) in 2010; see: http://www.decc.gov.uk/assets/decc/Consultations/Improving%20Grid%20Access/253-improving-grid-access-ia.pdf

### Connect and Manage in Great Britain

In August 2010, the British government – in cooperation with Ofgem – introduced a new grid access regime called "Connect and Manage", in order to improve the timeliness of grid connection for the development of renewables and other low carbon generation.

In line with this regime, a new generation project can connect with full firm access to the network once its local connection works are completed, rather than waiting for wider network reinforcements to take place, as was previously the case. The new regime also continues to include compulsory user commitment, which plays a vital function in ensuring that adequate information is available to transmission operators so that they can plan investment efficiently. This aspect of the regime is meant to avoid undue stranded costs being borne by end consumers when a generator cancels its project or reduces capacity. Furthermore, user commitment places the liability on users in order to financially secure the cost of the investment, or to ensure avoidable costs are not incurred.

According to the last monitoring report on Connect and Manage, released in August 2012[109], 107 large generation projects – representing a total capacity of 30 GW – have put forward their connection dates under the regime by an average of six years. This can be viewed as the average difference between the estimated date for connection in an offer made under the previous regime (Invest and Connect) and in the new regime (Connect and Manage). Of the 107 projects, 100 are renewable generation projects with a total capacity of over 24 GW. In addition, 92 small-scale renewable generation projects have also benefitted from the scheme.

The above demonstrates the contribution of Connect and Manage to the reduction of lead connection times; however, there are additional costs to be considered. The connection of new generation ahead of wider network reinforcements is expected to cause additional "constraint costs" (materialising in compensations paid to generators when they alter their output in order to help ease transmission congestion). These costs are "socialised", which is to say, they are paid for by all consumers.

Before the decision was taken to implement the Connect and Manage regime, the United Kingdom government undertook an impact assessment[110] to analyse the different options for tackling the issue of network access. One area of concern raised by the assessment was that socialising constraint costs might not provide the right incentives for efficient decisions to be made by new generators. However, the impact assessment also argued that the signals and incentives for efficient investment decisions were already provided by the localised element charged to generators for the use of the high-voltage grid. The assessment eventually concluded that the "Connect and Manage socialised model" was, on balance, the preferred model to meet all desired objectives.

The Government has asked Ofgem to monitor the Connect and Manage regime regularly. Ofgem submitted two monitoring reports in 2011 and will produce annual reports from 2012. All in all, although the Connect and Manage regime is still at an early stage of development, the decision process linked to it may be used as an example of how to assess all the pros and cons of a new connection regime, taking into account different objectives and including a cost-benefit analysis.

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109 National Grid, "Quarterly Report on the Connect and Manage Regime", August 2012, p.16; see: http://www.nationalgrid.com/NR/rdonlyres/312CF94C-ACDC-4841-BBA6-1BE75A1242C1/56122/ConnectandManageQuarterlyReportMay2012withlinks.pdf

110 See footnote 108.

*(181)* As shown in Table 9, the different EU renewables access regimes range from full priority (priority access and dispatching) to no priority at all. The countries providing full priority access have usually introduced market arrangements which may run counter market-based allocation of resources through merit ordering. Moreover, electricity generated through subsidised renewables is usually not allowed to participate in balancing markets.[111]

*(182)* However, some MS that do not explicitly provide priority for renewables foresee a more market-based mechanism for the integration of renewables.[112] These MS argue[113] that a market based approach can implicitly provide for the priority dispatch of renewables. According to these regimes, it is the price signal that determines which generator should reduce its output (and receive compensation), where necessary, to manage access in order to ensure the reliability and safety of the network. Moreover, these regimes tend to promote output from renewable generation, since it will usually be more cost-effective for conventional generation to reduce output and hence avoid fuel costs. There are already MS who have experience of market based solutions for dealing with the challenge of integrating large amounts of renewable energy in cases of lack of demand or potential constraints in the network. Denmark, which introduced such a system in 2011, is an example here.

**A market-based supporting scheme for renewables: Denmark**

In Denmark in 2011, the feed-in-tariff support scheme for renewable energy plants for most technologies was replaced by a price premium on top of the market price. Under a fixed premium system, wind generators will offer their electricity to the market at the going prices, and will retain the premium. In practice, receiving a net price which incorporates the premium provides wind plants with a (limited) incentive to reduce output when prices, net of the premium, become (considerably) negative.

However, this premium system has not sufficiently incentivised wind plants to reduce electricity injections when network constraints occur. This is why a new market measure will be introduced starting with the “Anholt” offshore wind park (planned connection time 2012-2013). This measure is based on a restriction yielding no supplementary payments (premium) if the market price becomes negative. This should encourage the wind producer to supply less electricity if there is already congestion in the grid, and provides for a market-based solution to avoid network constraints (or costly re-dispatching measures), subject to the achievement of Denmark’s renewable targets.

111 Denmark, Germany and Spain are an example of this, considering the high penetration of renewable in these countries.

112 In these regimes, the system often treats all electricity producers equally and in a non-discriminatory way, and allows the participation of renewable plants in all segments of the market, including congestion management and balancing mechanisms. The United Kingdom, the Netherlands and Sweden are examples of MS not providing priority dispatching, but treating renewables as any other producer.

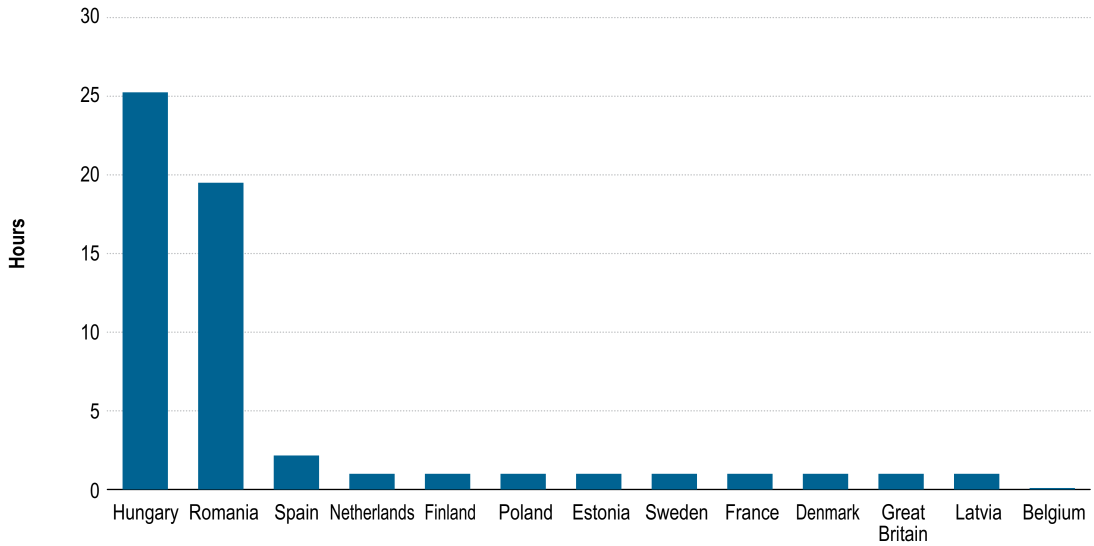
113 RES Integration National Reports - Great Britain, p.38, see footnote 90.

*(183)* As reported by CEER in 2010[114], shorter gate closure times may significantly reduce the variability impact of generation and demand, increase predictability of injection at times of gate closure and therefore reduce the need for additional flexible resources in power systems with a large penetration of intermittent renewable generation. Consequently, the need for ancillary services would be less pronounced and the costs of running the power system would be lower.

*(184)* In the absence of a European intraday platform[115], national intraday markets usually provide for the closest to real time market-based opportunity for generation adjustment. However, in order to improve output forecasts, generators should be financially responsible for the costs incurred by the system operator because of the deviations from their declared schedules.

*(185)* The lead time for RES generation forecasts, defined as the time elapsed between intraday gate closure time and time of delivery, is an interesting indicator of market adequacy to integrate renewables. However, in some MS, the latest RES generation forecasts are only provided at day-ahead gate closure time if there is no intraday market (or if intermittent generation is not allowed to participate in such a market). The following two figures show average lead times across Europe. Figure 34 refers to those MS featuring balance responsibility for renewables, while Figure 35 shows MS without RES-E balance responsibility.

**Figure 34: Lead time for forecasts (MS with balance responsibility for RES-E) – 2011**

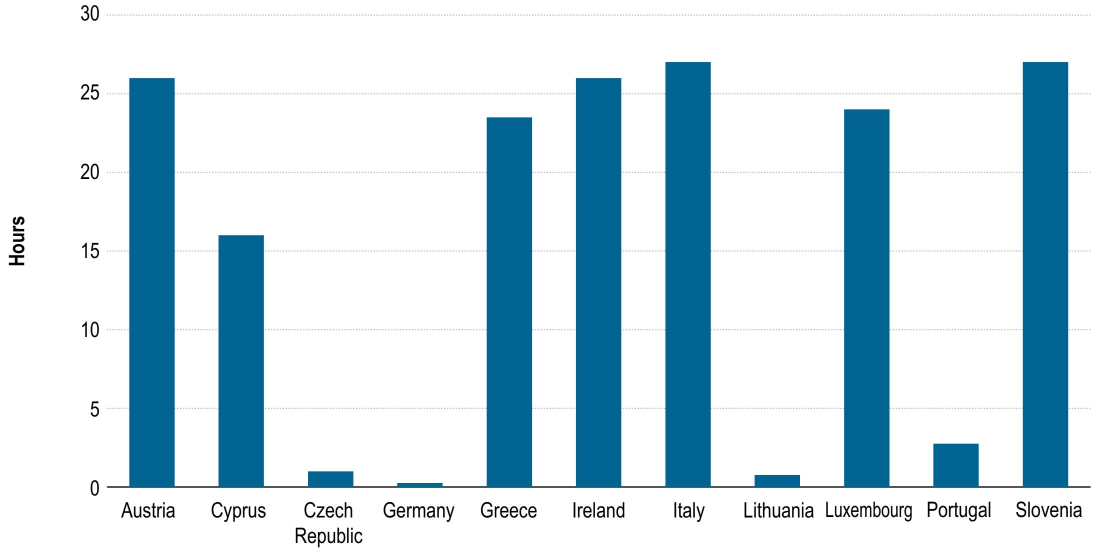



*Source: RES Integration (2011)*

114 CEER, Regulatory aspects of the integration of wind generation in European electricity markets, 2010, C10-SDE-16-03, p.6; see: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2010/C10-SDE-16-03_CEER%20wind%20conclusions%20paper_7-July-2010.pdf

115 According to the Agency's Framework Guidelines on Capacity Allocation and Congestion Management for Electricity, July 2011, a pan-European intraday platform to enable market participants to trade energy as close to real time as possible is proposed. Trading energy as close to real time as possible should make it easier for market participants to rebalance their positions and should facilitate the efficient and reliable use of transmission network capacity in a coordinated way.

**Figure 35: Lead time for forecasts (MS without balance responsibility for RES-E) – 2011**




*Source: RES Integration (2011)*

*(186)* Firstly, Figure 34 and Figure 35 indicate that there appears to be a link between the existence of short lead times for intermittent generation forecasts and balance responsibility. This means that in general, when producers are incentivised to provide their best forecast (see Figure 34), they are also allowed to provide it quite close to real time when the most reliable information is available. The existence of balance responsibility for renewables without the possibility of them enhancing their forecast close to real time (as occurs in Hungary and Romania[116]) could lead to inefficiencies in the system.

*(187)* Secondly, Figure 35 shows that, in those countries with no balance responsibility for renewables, lead times for generation forecasts tend to be longer because the latest forecasts are usually provided to the day-ahead market instead of the intraday market. This leaves more time available for balancing, but also gives rise to higher balancing costs as a result of greater uncertainty due to the lower accuracy of forecasts. Even when TSOs assume responsibility for balancing renewable producers and use intraday markets for re-scheduling their programmes (as is the case in Germany and Portugal), the system could nevertheless end up with higher balancing costs if TSOs are not properly incentivised to reduce them. These costs are typically passed on to all network users (consumers) through network tariffs.

*(188)* The Agency's 2012 Framework Guidelines on Electricity Balancing[117] stipulate that generation units from intermittent RES should not receive special treatment for imbalances, meaning that they should be part of a BRP (Balance Responsible Party) which is financially responsible for their imbalances. Moreover, such generators must be allowed to participate in intraday markets as close as possible to real time. In this context, the target model, which includes implementation of continuous intraday cross-border trade, will contribute to this task.

116 In Romania, this disadvantage is reduced due to the application of more favourable terms than to conventional generation when they are out of balance.

117 The Agency, "Framework Guidelines on Electricity Balancing", 2012, FG-2012-E-009, p.24; see: http://www.acer.Europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/Framework%20Guidelines%20on%20Electricity%20Balancing.pdf

## 4.5 Transmission tariffs

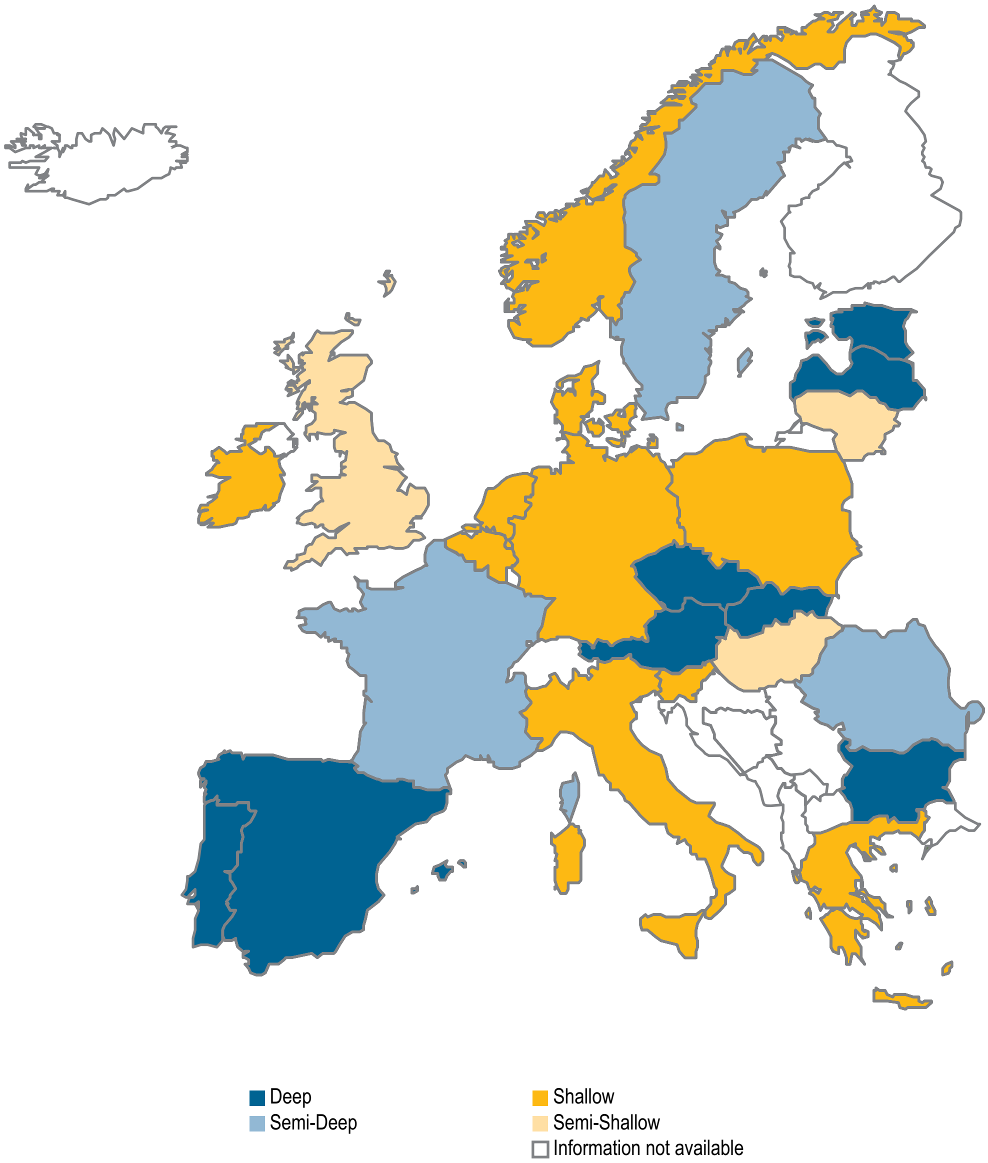
(189) Since 2009, stakeholders have benefitted from the annually published ENTSO-E Overview of Transmission Tariffs in Europe, which has provided interested parties with an accessible and consistent overview of the alternative approaches used across Europe. Additionally, the increasing interest of stakeholders in achieving a higher level of transparency on this topic, among other reasons, has led the Agency to start working on the issue of transmission tariffs. The Agency has started to collect relevant information from all NRAs on transmission tariff structures and the underlying methodologies for determining the amount of relevant components. This includes all costs incurred by the Transmission System Operators, ranging from the capital and operational costs for providing and operating the transmission assets (both the connection and the wider network) to the operation of the transmission system on a daily basis (for example, the losses and various ancillary services). The aim is to improve the level of transparency of transmission tariffs in all MS and to analyse to what extent further harmonisation might be justified based on any evidence of the impact on cross-border trade and/or market integration. This work is still ongoing.

(190) The Agency's work on tariffs also includes an analysis on connection charges. This wider perspective is consistent with the strong link between connection charges and network tariffs. Although this work on tariffs analyses all aspects of network tariffs for all generation and demand users, the main focus of the network access chapter is on renewables, as explained in the introduction. Consequently, an overview of connection charges for RES-E is included below

(191) Regulatory practices regarding connection charges vary widely among MS. Such charges might cover shallow or deep network costs. Shallow costs refer to the equipment needed to connect a generation plant to the nearest point of the electricity grid, while deep costs include shallow costs plus the cost stemming from the network reinforcements necessary to connect that plant. In general, renewable generators take more advantage from shallow regimes for several reasons which are inherent to their characteristics. Renewable generators are often located farther away from the demand, and hence their cost of connection is likely to be higher in comparison with the size of the installation. Further, renewable generators are usually smaller than conventional ones and could face financial barriers if they are charged the full amount. Deep charging incentivises generation to locate closer to demand, but it may hinder the exploitation of renewable sources.

(192) Some MS have designed connection regimes allowing renewable energy plants to benefit from more favourable connection charges than those applying to conventional producers. Figure 36 provides an overview of the different connection charges applied to renewable plants throughout the group of EU-27 countries, in 2011.

**Figure 36 : Connection charges regime in Europe – 2011**




*Source: The Agency compiling from RES Integration (2011) and NRAs*

*Note: Generators will usually pay for connection to the nearest grid point (exceptions apply). Beyond this point, connection charging regimes typically vary according to one of the following four categories: Deep (Generator Pays), Semi-deep (Generators and System Operators Share Costs), Semi-shallow (RES Generators Pay Less) or Shallow (System Operator Pays).*

*(193)* In some cases, non-deep charging implies that the costs which are not covered by connection charges are socialised. Such connection regimes might send inappropriate price signals to potential new generators who need to connect to the network. The impact of this distorting element should be evaluated when analysing the pros and cons of socialising connection charges.

*(194)* Moreover, a wider perspective is needed: both connection charges and network tariffs should aim to ensure an efficient use of the network; connection charges should be considered within the framework of network tariff design at a European level, as per current Agency work on this topic.

### 4.6 Conclusions and recommendations

(195) The following main conclusions can be drawn from this chapter:

- In 2011, timeliness of grid connection continued to be one of the main challenges to network access for several MS. Some MS have been affected by virtual saturation due to inefficient connection procedures;
- Another challenge observed in 2011 is the increase of costs due to network congestion (e.g. the compensation paid to generators when their electricity production is curtailed) that may emerge after the implementation of regimes to speed up the connection to the grid of renewable plants;
- Renewable curtailments are still rare, albeit increasing; and
- The FGs on Balancing and Capacity Allocation and Congestion Management (CACM) propose that renewable plants become financially responsible for their imbalances and that gate closure times move closer to real time as this increases the efficiency of the whole system. In 13 MS, renewable plants are already financially responsible.

(196) In light of these conclusions, the Agency and CEER recommend the following:

- Transparency on network access should be enhanced. This should apply not only to connection procedures and access regimes themselves, but also to the data made available to the Agency, NRAs and stakeholders alike, including network users, so that investment decisions are made on an informed basis and regulators can fulfil their monitoring obligations;
- Connection procedures should be streamlined to avoid unnecessary costs to plant developers and final consumers. In particular, connection regimes leading to virtual saturation should be avoided, as they induce high connection delays; and
- Renewable plants should be made financially responsible for their imbalances and should be allowed to participate in intraday markets as close as possible to real time. In this context, the target model, which includes the implementation of continuous intraday cross-border trade, will contribute to this task.

# Part II: The gas sector

## 5 Gas retail markets

### 5.1 Introduction

*(197)* The components making up final (end-user) gas prices usually include the commodity price, transportation, distribution and retail supply costs (metering, billing, customer service, additional services) and margins plus levies, surcharges and taxes, as applicable. These components can fluctuate widely between MS due to different regulatory schemes and market developments.

*(198)* In principle retail price monitoring should concentrate on the commodity component of the final price and on the retail mark-up[118], as these are the elements in the end-user price which retail market participants can directly influence (the other components being regulated network charges and government-imposed taxes and levies).

*(199)* It is important to note that retail prices alone generally do not tell the whole story about whether markets are working well or not, for instance in relation to barriers to entry or any other non-competitive conditions. Therefore, it is important to know the dynamics of demand and supply in order to fully understand price movements and entry barriers.

*(200)* In 2011, European gas markets throughout the value chain provided mixed signals. Like all energy markets, gas markets were influenced by macroeconomic conditions. Such conditions were very challenging in many parts of Europe and this was reflected, at least partially, in the main results reported in this document.

118 Retail market monitoring encompasses a variety of indicators including (but not limited to) retail price levels, switching rates, differences between wholesale and retail prices and concentration rates. The interactions between these indicators were discussed in the electricity retail chapter. The discussion therein also applies to retail gas markets.

*(201)* In 2011, natural gas POTP in the EU increased in comparison with the previous year. On average, in nominal euro cent per kWh, total household prices throughout the Union increased by 10% while yearly gas demand in the EU decreased in 2011 by 10.5% in comparison with 2010.

*(202)* The Agency and CEER used the following data sources to develop the gas sections of this market monitoring report:

- National reports submitted by NRAs to CEER;
- National indicators collected by CEER on a yearly basis;
- Eurostat (energy retail prices – yearly series);
- Publicly available gas hub data; and
- Individual NRAs' analysis and underlying data.

*(203)* Due to data availability and presentational reasons, a distinction was made in certain cases in order to separate EU-15 from EU-27 MS. In addition, a split between EU-15[119] and non EU-15 MS was made for the same reason, whenever appropriate. This is for purely practical purposes.[120]

*(204)* This report distinguishes between regulated and non-regulated consumer prices. The Agency and CEER are aware that the very different price setting rules and methodologies in place in MS with regulated prices could have a different impact on retail market conditions. For the purpose of this report, the distinction between MS with regulated and non-regulated retail prices has been kept for reasons of data availability and continuity. The price monitoring section includes price developments, indices, spreads and the relationship between wholesale and retail prices.

*(205)* In the electricity chapters, Norway (as a member of the EEA and CEER) was also included in appropriate sections. The same procedure was taken in the present chapter, although it is important to note that Norway's domestic gas market is of limited size and that data for Norway was not always available.

119 The EU-15 countries are the member countries of the European Union prior to 1 May 2004. They are Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden, and the United Kingdom.

120 In all figures and tables, when "UK" (United Kingdom) and Ireland data occur, the following definitions apply: UK means the United Kingdom (England, Wales, Scotland, and Northern Ireland); Ireland means the Republic of Ireland; and Northern Ireland is the constituent country within the UK which shares a land border with the Republic of Ireland. In terms of consistency, data relating to different subsets of the UK are separately reported, depending on availability and source, using the name of the relevant constituent country or subset, for instance Great Britain (GB) or Northern Ireland (NI). In some but not all cases, data are available for the UK as a whole.

## 5.2 Natural gas prices for final customers

### 5.2.1 The development of natural gas prices

*(206)* In 2011, a considerable number of MS still featured regulated end-user gas prices. The breakdown between MS with regulated and unregulated price regimes is provided in Table 10.[121]

*(207)* In 2011, 100% of household customers were supplied under regulated prices in seven MS (Bulgaria, Greece, Hungary, Latvia, Lithuania, Poland and Romania). In Slovakia, the share of household customers still under regulated prices was 99.9%. In other MS, the share of household customers under regulated prices was, for the countries which provided data, in excess of 85% with the exceptions of Belgium[122], Ireland and Spain.

121 For some tables and figures, data about Norway (a member of CEER, albeit outside the EU) were not provided. Data from Denmark, not initially available, were provided by the Danish Energy Regulatory Authority (DERA) directly. Retail prices for Greece were provided directly by RAE, the Greek energy regulator.

122 Only social tariff prices are regulated in Belgium, for those consumers that fall under the conditions to benefit social tariffs.

**Table 10: Regulation of retail gas prices in Europe – 2011**

| Country | Household regulated prices | % of household customers under regulated prices |
|---|---|---|
| Austria | No | |
| Belgium | Yes | 10.6% |
| Bulgaria | Yes | 100.0% |
| Cyprus | No | |
| Czech Republic | No | |
| Denmark | Yes | 85.0% |
| Estonia* | No | |
| Finland | No | |
| France | Yes | 86.3% |
| Germany | No | |
| Great Britain | No | |
| Greece | Yes | 100.0% |
| Hungary | Yes | 100.0% |
| Ireland | Yes | 72.9% |
| Italy | Yes | 89.6% |
| Latvia | Yes | 100.0% |
| Lithuania | Yes | 100.0% |
| Luxembourg | No | |
| Netherlands | No | |
| Northern Ireland | Yes | 92.9% |
| Poland | Yes | 100.0% |
| Portugal | Yes | 93.6% |
| Romania | Yes | 100.0% |
| Slovakia | Yes | 99.9% |
| Slovenia | No | |
| Spain | Yes | 35.4% |
| Sweden | No | |

*Source: CEER National Indicators (2012)*

*Note:*
**According to the Estonian Competition Authority (CA), the Estonian gas household market should be considered as non-regulated, as final gas prices are not set by the regulator. Nonetheless, CA is responsible for approving retail gas prices for household customers as proposed by the gas supplier, which for the moment operates as a monopoly.*

*(208)* With the exception of Spain[123] and the specific case of Belgium, when regulated end-user prices exist, consumers have no strong incentive to switch away from regulated end-user tariffs and, when they do, they do not switch in large percentages. This trend has been sustained for a number of years[124] in most MS.

*(209)* Even if low levels of consumer switching are not necessarily an indicator of lack of effective competition, in immature markets with regulated prices that do not always reflect costs, the simultaneous presence of non-market based pricing and a low level of dynamism might indicate that competition is being suppressed.

*(210)* Regulated prices should be set at levels which avoid stifling the development of a competitive retail market, must be consistent with the provisions of the 3rd Package, and should be removed where a sufficient level of retail competition is achieved. Indeed, regulated prices can suppress competition if they are set at a level which does not allow costs to be recovered.

*(211)* In 2011, natural gas POTP[125] in the EU[126] increased in comparison with the previous year. On average,[127] in nominal euro cent per kWh, total household prices throughout the Union increased by 10% while yearly gas demand in the EU decreased in 2011 by 10.5% in comparison with 2010.

*(212)* Industrial POTP[128] rose by a similar extent on average (11%) but with a relatively high degree of dispersion. For instance, the increase was in the order of 21.4% in Hungary and 24.7% in Lithuania.

123 Among other reasons, the higher liberalised market share in Spain can be explained by the fact that the energy component of the end-user regulated price is determined through a price-setting methodology, using a gas cost index that includes long-term gas contract prices (related to oil prices and EUR/USD exchange rate fluctuations), international hub prices (NBP, Henry Hub) and spot gas prices resulting from market auctions (with 8-14 shippers as participants). This price setting methodology brings final regulated prices closer to the real cost mix of shippers (a mixture of long and short term/OTC gas contracts). As a result, free market shippers can more equitably compete in terms of margins and try to attract household regulated customers on a profitable basis. An additional reason is that, in Spain, all gas DSOs share the same IT platform for switching, which should facilitate the switching process.

124 Electricity and gas retail markets for all consumption levels were nominally liberalised across the EU on 1 July 2007.

125 The final consumer price includes the commodity price, regulated transmission and distribution charges, retail components (billing, metering, customer services, and a fair margin on such services) plus any tax or levy (as applicable: local, national, environmental) and applicable surcharges.

126 There were no data available for three EU-27 MS. Malta and Cyprus did not have any functioning retail gas market in 2011.

127 Annual non-weighted average per country, based on half-yearly data, using Eurostat Band D2 (20 GJ/year to 200 GJ/year) as reference.

128 Non-weighted average per country using Eurostat Band I3 (10.000 GJ/year to 100.000 GJ/year) as reference.

**Table 11: Natural gas post-tax total prices in EU-27 countries – 2010 and 2011 (euro cent/kWh)**

| Country | Household regulated prices (2011 data) | Household prices (euro cent/kWh) | | Industrial prices (euro cent/kWh) | |
|---|---|---|---|---|---|
| | | 2010 | 2011 | 2010 | 2011 |
| Austria | No | 6.12 | 7.08 | NA | NA |
| Belgium | Yes | 5.67 | 6.83 | 2.96 | 3.29 |
| Bulgaria | Yes | 4.00 | 4.51 | 2.94 | 3.36 |
| Czech Republic | No | 4.93 | 5.70 | 3.54 | 3.73 |
| Denmark | Yes | 10.77 | 11.23 | 7.38 | 8.06 |
| Estonia | No | 3.82 | 4.28 | 3.30 | 3.43 |
| Finland | No | NA | NA | 3.74 | 5.40 |
| France | Yes | 5.48 | 6.13 | 3.17 | 3.22 |
| Germany | No | 5.68 | 6.14 | 4.18 | 4.66 |
| Greece | Yes | 5.09 | 6.23 | 3.78 | 4.85 |
| Hungary | Yes | 5.45 | 5.66 | 3.88 | 4.71 |
| Ireland | Yes | 5.12 | 5.64 | 2.59 | 2.89 |
| Italy | Yes | 7.02 | 7.85 | 2.85 | 3.25 |
| Latvia | Yes | 3.60 | 4.22 | 3.30 | 3.70 |
| Lithuania | Yes | 4.14 | 4.88 | 3.64 | 4.54 |
| Luxembourg | No | 4.54 | 5.45 | 2.78 | 3.76 |
| Netherlands | No | 7.08 | 7.29 | 3.20 | 3.31 |
| Poland | Yes | 4.65 | 4.82 | 3.36 | 3.45 |
| Portugal | Yes | 6.12 | 6.74 | 2.90 | 3.43 |
| Romania | Yes | 2.77 | 2.80 | 2.41 | 2.75 |
| Slovakia | Yes | 4.41 | 4.89 | 3.57 | 3.78 |
| Slovenia | No | 6.28 | 7.30 | 4.60 | NA |
| Spain | Yes | 5.37 | 5.38 | 2.91 | 3.35 |
| Sweden | No | 10.33 | 11.76 | 7.21 | 8.58 |
| United Kingdom | No for GB/Yes for NI | 4.14 | 4.74 | 2.44 | 2.97 |

*Source: Eurostat (online), data downloaded on 15 July 2012. Consumption Household Band D2. Industrial Band I3. Prices in nominal euro of the day*

*(213)* Table 11 shows a one-to-four ratio between the household price in Romania and that in Sweden, and almost a one-to-three ratio between Romania and Denmark in terms of industrial prices.

*(214)* A considerable fraction of the difference in final natural gas retail prices across the EU is driven by different government policies regarding energy taxation and environmental goals.

*(215)* Much of the price variation in new MS is due to taxes and levies. Environmental surcharges and other schemes are especially predominant in Scandinavian and North/Central Western European jurisdictions.

*(216)* However, PTP differences are still very important, as shown later in this chapter.

*(217)* Unfortunately, the current format of Eurostat gas retail price data prevents the Agency and CEER from breaking prices down into individual components, as it was the case in electricity. This can, however, be achieved using alternative data sources, as explained later.

*(218)* Regulated commodity prices tend to distort retail competition and do not normally allow final prices, unless tracking formulae are used, to relate to the wholesale cost of energy or other underlying fundamentals. Retail price regulation could serve macroeconomic or social purposes, which might sometimes be better tackled through general taxation or wider social policies.[129]

*(219)* Figure 37 to Figure 40 show that, in 2011, unregulated end-user gas prices across the EU correlated to each other, albeit with significant differences, much more closely than regulated prices. This is obviously due to a phenomenon of underlying correlation (the main common driver being wholesale energy prices), with persistent retail price differences being arguably a function of individual MS energy taxation policies, and differences in distribution, transportation and storage costs, as well as differing wholesale-retail price transmission mechanisms.

*(220)* Another important distinction for statistical reporting purposes is the breakdown of EU MS into EU-15 and non EU-15 (which, in the case of gas, means the post-2004 and 2007 EU-10 MS, with Malta and Cyprus not yet featuring an active retail market in natural gas). The above distinction only partially overlaps[130] with the regulated versus non-regulated prices breakdown and, for this reason, is still worth emphasising.

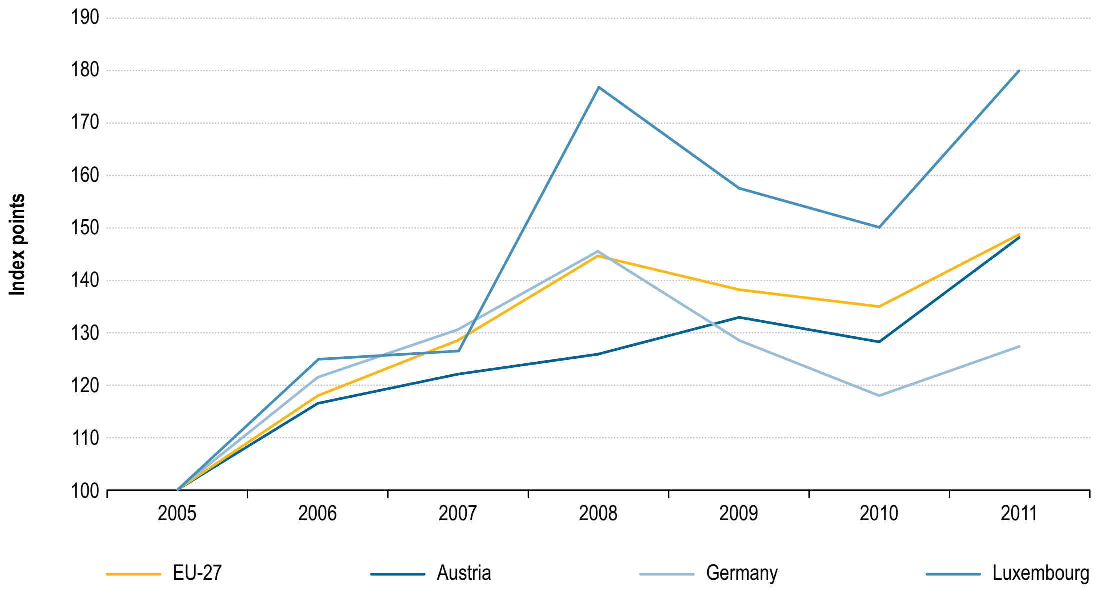
*(221)* Interestingly, non EU-15 countries with regulated prices still show a more consistent retail price correlation picture than the EU-15 countries still featuring regulated household prices, probably due to the fact that new MS still regulate final prices based on relatively similar underlying policies, possibly reflecting macroeconomic or social concerns.

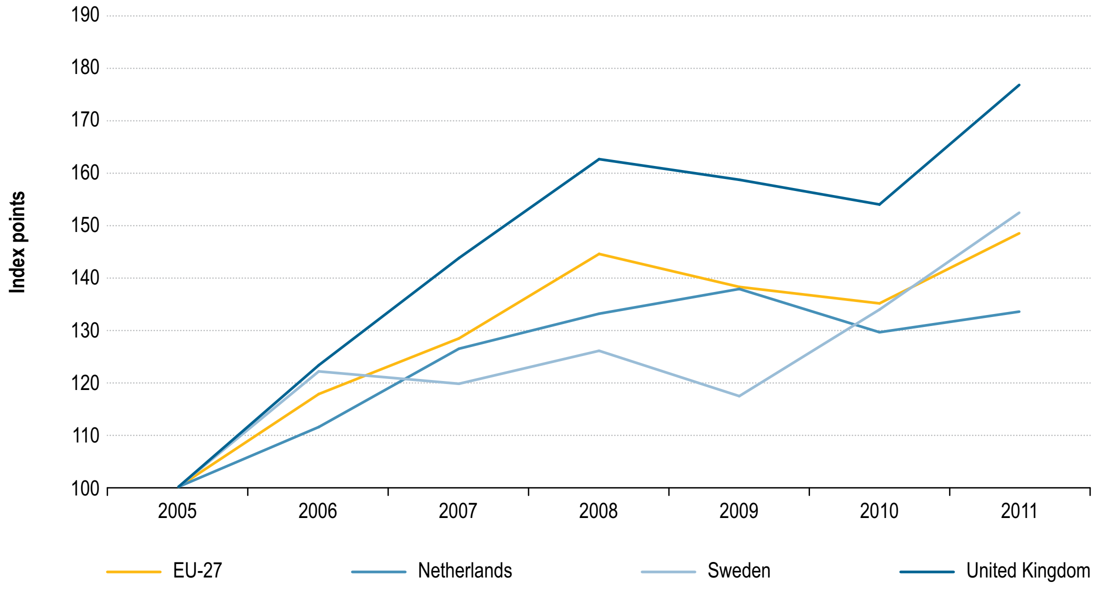
*(222)* Looking at the POTP spread in countries with regulated prices, it becomes clear that the lowest price on offer does not differ too much from the regulated price. This form of competition might prevent customers from reaping the full benefits of competition because, in an immature retail market, high regulated prices could be viewed as a focal point which competing suppliers can cluster around and – at least in markets featuring consumer inertia – slow the switching process down.

129 The notion of “regulated prices” is becoming less and less well defined, as many different types of end-user price regulation still exist throughout the EU. The degree of competitive distortion induced by regulated end-user prices will depend on price setting rules and methodologies. In this report, the Agency and CEER do not make policy recommendations in terms of non-regulatory aspects of prices, however important, including the trade-off between price regulation and general taxation or social security measures.

130 The Czech Republic, Estonia, and Slovenia were the only three post-2004 MS which featured liberalised household end-user gas prices in 2011. However, even within the historical EU-15 group, a prominent number of MS still had regulated household end-user gas prices in 2011.

**Figure 37: Indexed natural gas post-tax total price for households across EU-15 MS without regulated prices – 2005 to 2011 (2005 = 100 index points)**

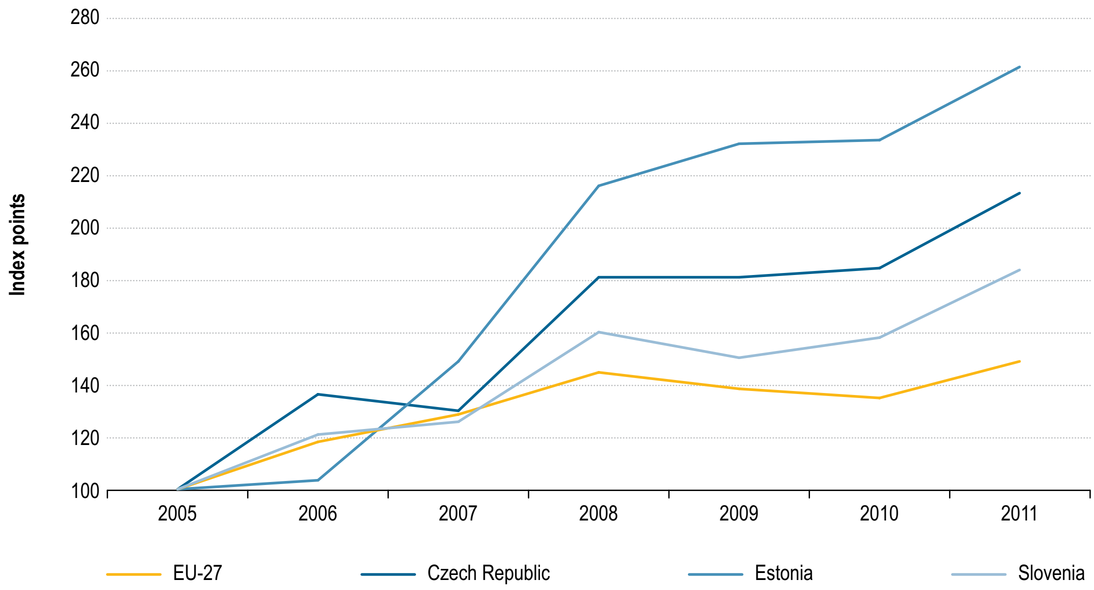



*Source: Eurostat (2012)*

*Note: The vast majority of the United Kingdom features non-regulated natural gas prices, with Northern Ireland still featuring mostly regulated prices in 2011.*

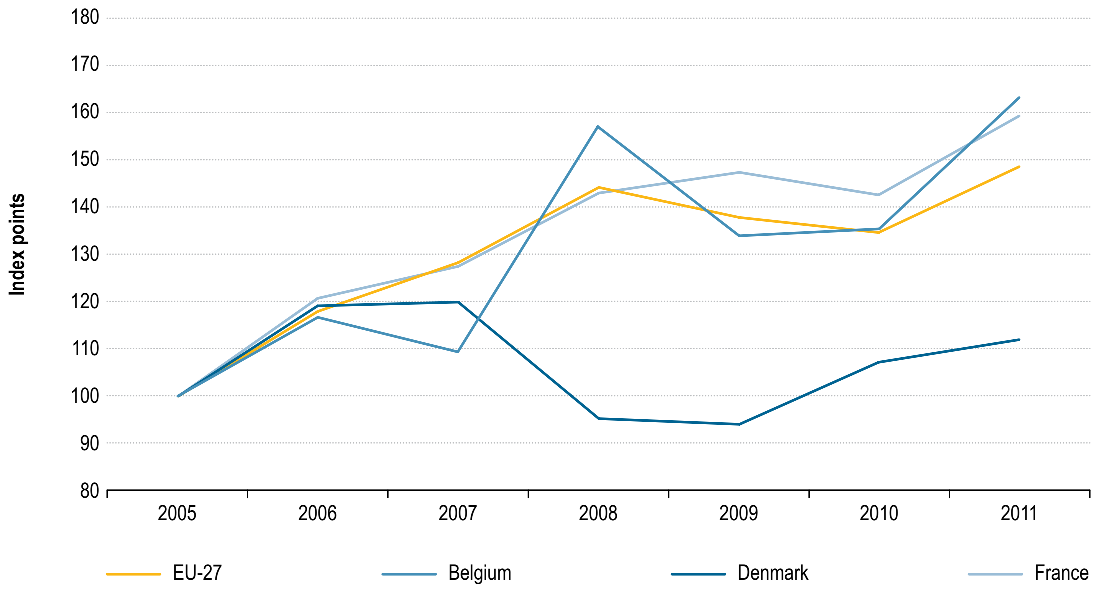
**Figure 38: Indexed natural gas post-tax total price for households across non EU-15 MS without regulated prices – 2005 to 2011 (2005 = 100 index points)**

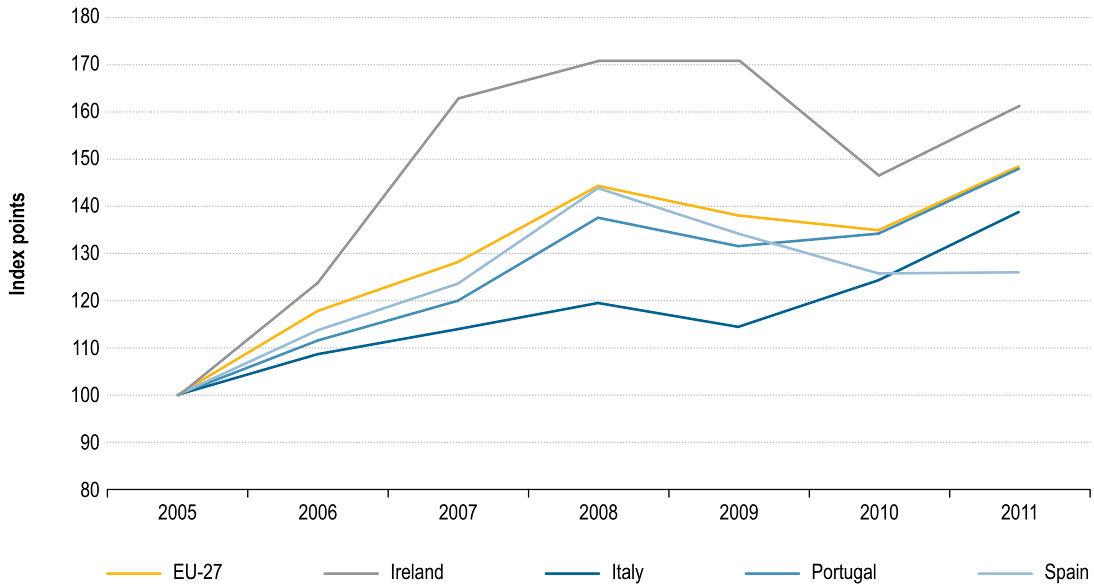



*Source: Eurostat (2012)*

*(223)* Compared to the accession years of 2004/05, end-user price liberalisation in, for instance, Estonia has led to a 2.5-fold nominal price increase. Other new MS which liberalised prices have seen smaller, but still important, price increases since then. Liberalisation of final prices in new MS has typically led to substantial increases, because pre-accession levels in many of these countries did not reflect underlying costs to start with. The situation in EU-15 countries might be analogous for those MS which also lacked cost reflectiveness initially.

**Figure 39: Indexed natural gas post-tax total price for households across EU-15 countries with regulated prices – 2005 to 2011 (2005 = 100 index points)**

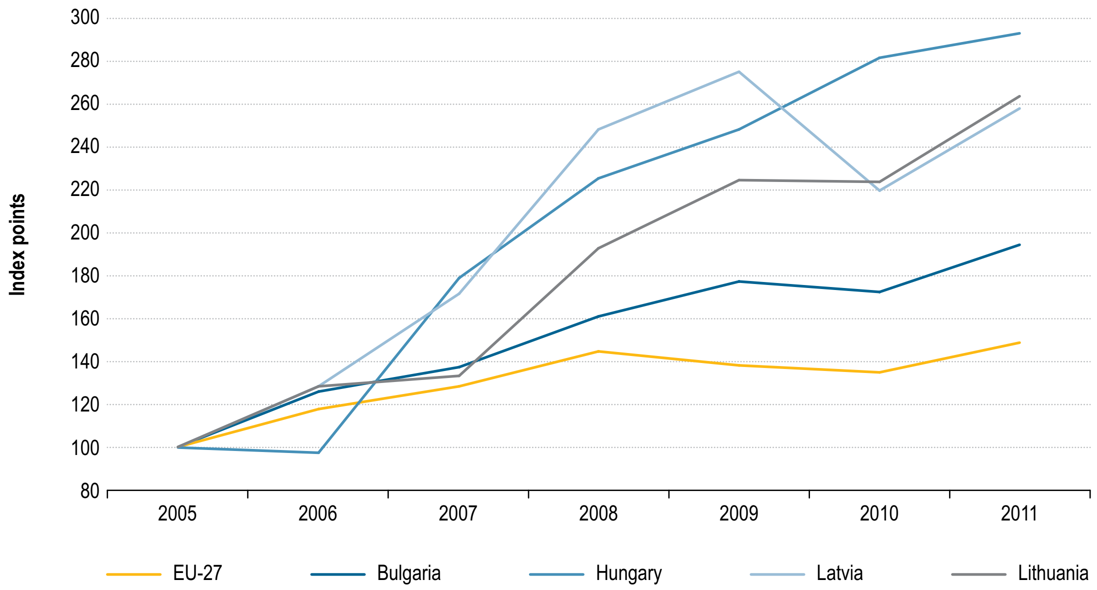


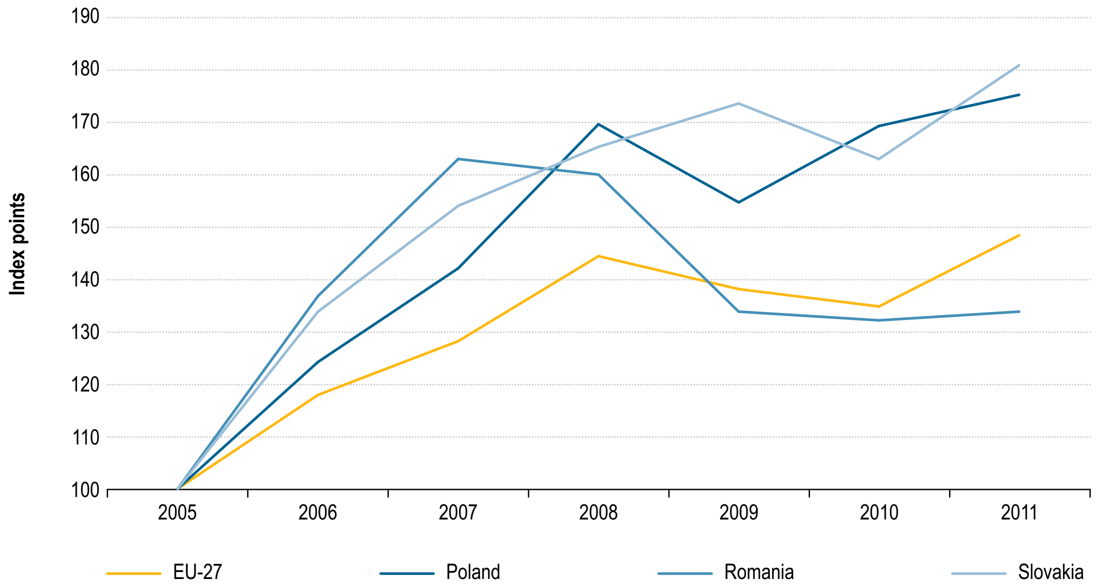




*Source: Eurostat (2012)*

*Note: With reference to the United Kingdom, only Great Britain featured non-regulated natural gas prices in 2011, while Northern Ireland still featured mostly regulated prices.*

**Figure 40: Indexed natural gas post-tax total price for households across non EU-15 countries with regulated prices – 2005 to 2011 (2005 = 100 index points)**




*Source: Eurostat (2012)*

(224) It is worth noting that the effects on gas prices of the economic downturn of 2008-09 were more pronounced in some countries than in others. Generally speaking, all retail prices seem to have recovered by now, on average, to their pre-recession level. However, since gas demand throughout the EU is still subdued and the macroeconomic outlook has continued to be weak well into 2012, the recent recovery in end-user prices is not necessarily a healthy signal, as it might be due mainly to upstream fuel costs (still linked to oil prices to some extent) that no longer reflect underlying gas market fundamentals in Europe.

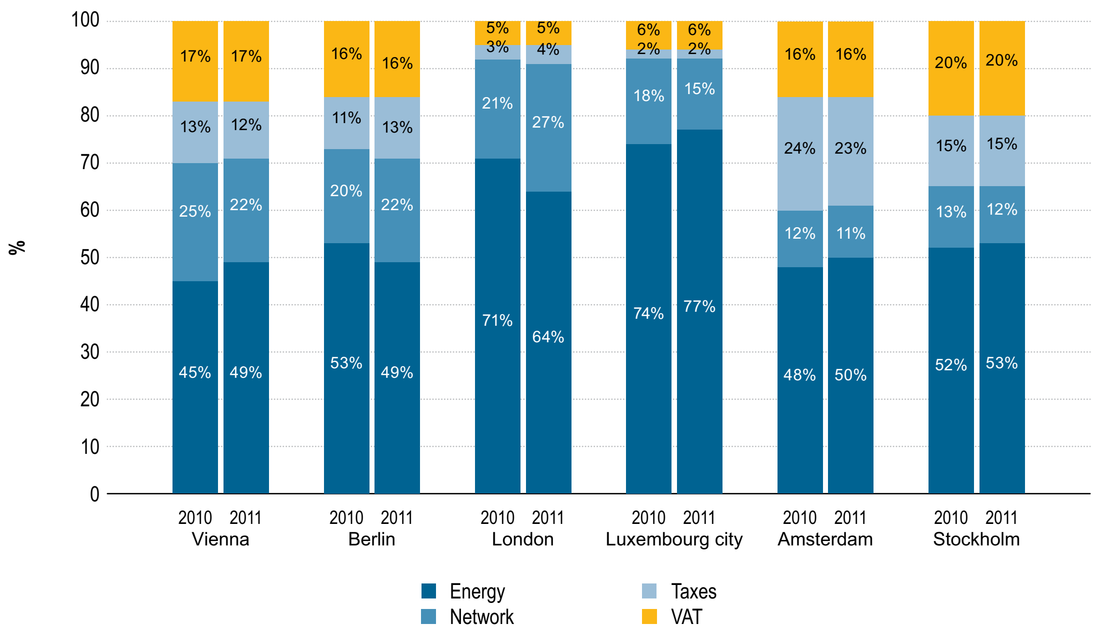
(225) The wholesale gas-oil link has been widely cited across the industry as one of the main causes of this problem, possibly leading to a "margin squeeze" during the early stages of the economic recession.

(226) By 2009-10 and throughout the recent economic conjuncture, several EU-based utilities had eventually entered long-term contract renegotiation procedures (some of which were settled in early 2012) with their EU and non-EU wholesale suppliers.

### 5.2.2 Retail price breakdown

(227) Figure 41 and Figure 42 present a breakdown[131] of the POTP for households[132] in a selection of 14 capital cities across the EU.

**Figure 41: Breakdown of the natural gas post-tax total price for a selection of capital cities without regulated prices – December 2010 to December 2011**

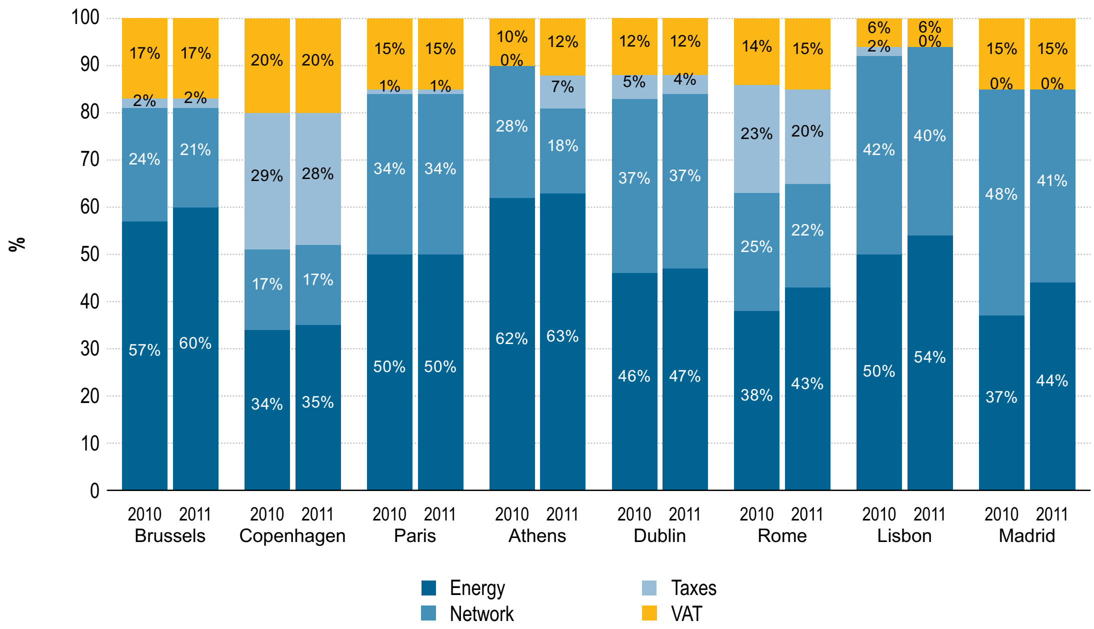



*Source: E-Control/VaasaETT (2012)*

131 The decomposition presented here is based on nominal prices charged by the incumbent supplier.

132 Differently from electricity, the current structure of Eurostat's retail gas price data does not allow us to break final prices down into individual components. However, the Agency and CEER used a database prepared by VaasaETT to arrive at a breakdown. VaasaETT figures are for capital cities only, not for countries as a whole, and for this reason any conclusions reached by the correlation analysis must be taken with some caution. POTP are presented for consumption levels ranging from 10 000 to 18 000 kWh/year.

**Figure 42: Breakdown of the natural gas post-tax total price for a selection of EU capital cities with regulated prices – December 2010 to December 2011**




*Source: E-Control/VaasaETT (2012)*

*(228)* Apart from Berlin and London, in all other EU capital cities the share of the energy component of the end user price went up in 2011. In Paris, it remained stable.

*(229)* In those countries where network investment is a priority for technical or policy reasons (ageing assets, decarbonisation), the share of the network component went up from 2010 to 2011 (Berlin, London) as regulators allowed higher investment in the regulatory asset base. In other countries facing different phases of the investment cycle, the share of the network component (transportation and distribution) either remained stable or went down.

*(230)* Taxes and levies did not generally go up in 2011 versus 2010, with the exception of those countries under increased budget pressure, or facing other policy priorities addressed through either energy or general taxation.

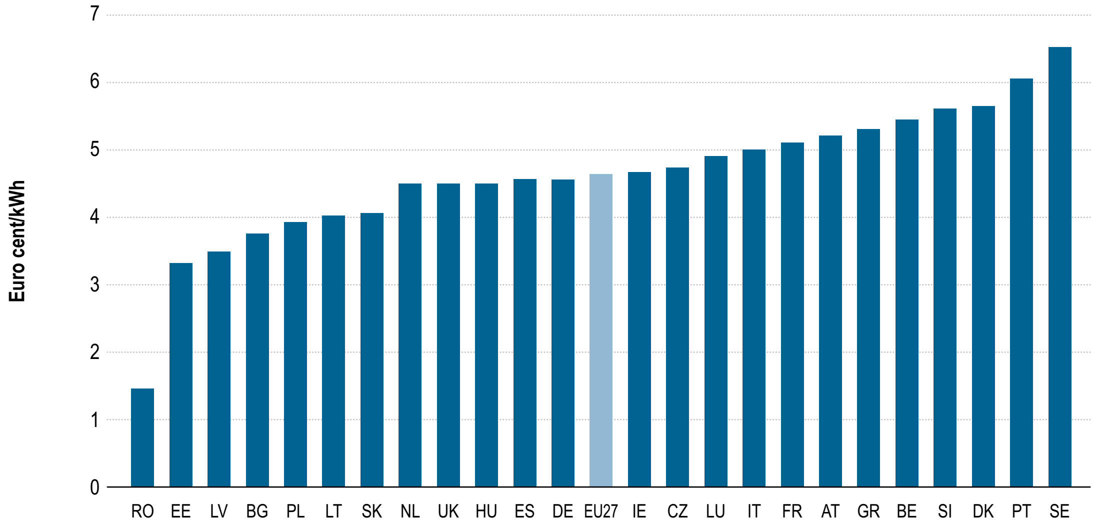
*(231)* It is worth noting that EU MS continue to adopt different policies regarding VAT on fuels. This results in a difference in international price comparisons.

*(232)* Traditionally, the United Kingdom has preferred to keep its VAT level on final energy bills for households at the reduced rate (which also applies to other basic necessities) of 5%.

*(233)* Scandinavian countries, Germany, Belgium and the Netherlands tax final consumption of energy heavily, albeit not necessarily through VAT (for households; sometimes this is reversed in the case of industrial consumption), whereas other MS, especially in Southern Europe, tax less heavily (but this trend might be reversed due to recent macroeconomic pressures on some of these MS). In Southern Europe, Italy constitutes the main exception, as its energy taxes are significantly higher.

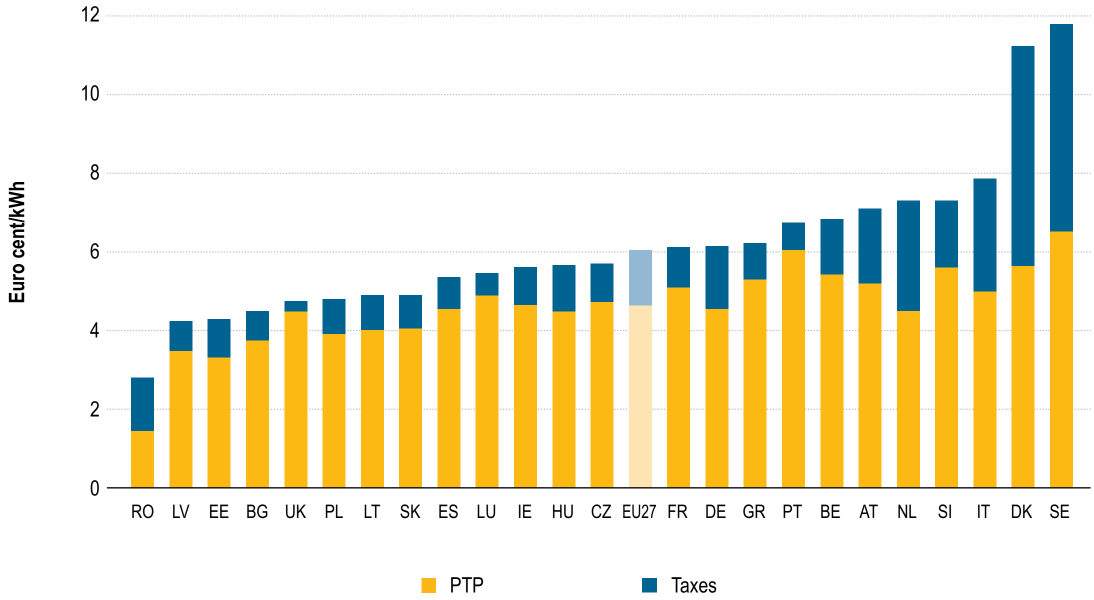
*(234)* Figure 43 and Figure 44 provide evidence on the impact of taxes on the relative prices of natural gas to households[133] in EU-27.

**Figure 43: Natural gas pre-tax total price in EU-27 – 2011 (euro cent/kWh)**




*Source: Eurostat (2012)*

**Figure 44: Natural gas post-tax total price in EU-27 – 2011 (euro cent/kWh)**




*Source: Eurostat (2012)*

133 Using Eurostat's consumption band D2 as reference.

*(235)* Some countries such as Romania, Latvia and Estonia, had simultaneously the lowest Pre-Tax Total Price (PTP)[134] and the lowest Post-Tax Total Price[135] (POTP).

*(236)* Similarly, some countries had simultaneously the highest Pre-Tax Total Price (PTP) and the highest Post-Tax Total Price (POTP): Sweden, Denmark and Slovenia.

*(237)* Portugal, France and the United Kingdom ranked higher in 2011 in the PTP league than in the POTP one, meaning that (ceteris paribus) they had relatively lighter taxation regimes at the time.

*(238)* In contrast, there are countries like the Netherlands and Italy with prices before taxes comparing more favourably with respect to those in other MS than prices after taxes.

### 5.2.3 Price variations using the PPS methodology

*(239)* The substantial POTP differences observed across MS are not only due to the underlying energy component and other elements (taxes and surcharges) of the final price. Some of these differences can indeed be explained away once one considers the different purchasing power of currencies (including the euro itself) across different MS, driven by heterogeneous levels in the cost of living as represented by a basket of goods and services.

*(240)* Using the PPS methodology[136] is one possible way to determine by how much end-user prices converge or diverge once they are adjusted for different purchasing powers. PPS would typically correct prices upwards in those MS whose cost of living is below the European average, and downwards otherwise. Those MS which are more in line with average European purchasing power would typically have PPS prices aligned to unadjusted euro prices.

134 The price of gas, defined as the sum of the commodity price, regulated transmission and distribution charges, and retail components (billing, metering, customer services and a fair margin on such services).

135 The final price to consumers, including as above the commodity price, regulated transmission and distribution charges, retail components (billing, metering, customer services and a fair margin on such services), plus any tax or levy (as applicable: local, national, environmental) and/or surcharge (as applicable).

136 The purchasing power standard, abbreviated as PPS, is an artificial currency unit. Theoretically, one PPS must be able to buy the same amount of goods and services in each MS. However, price differences across borders mean that different amounts of national currency units are needed for the same goods and services, depending on the country. PPS are derived by dividing any economic aggregate of an individual country in national currency by its respective Purchasing Power Parities (PPP). PPS is a measure developed by Eurostat and adopted by the European Commission. Together with related indicators, it is described at: http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Glossary:PPS

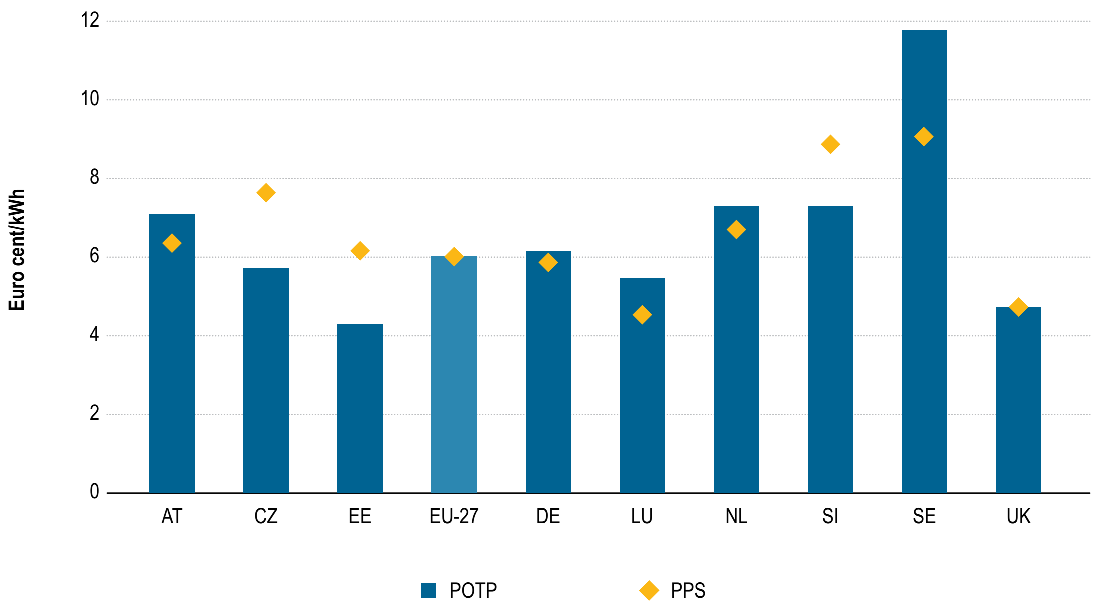
*(241)* The maximum 2011 end-user price divergence throughout the EU in PPS terms for households is in the order of 1:2, rather than 1:4, vis-à-vis unadjusted 2011 Eurostat final gas prices.

*(242)* Those new MS where gas appears to be priced extremely low in standard euro terms become relatively expensive after adjusting for purchasing power.

*(243)* PPS-adjusted household gas prices in Bulgaria, Hungary and Slovenia look much higher than average in PPS. It is also worth noting that Central Eastern and South Eastern European countries, where retail gas proves expensive after adjusting for purchasing power (and, sometimes, even in purely nominal terms), are also those countries which generally feature very limited wholesale gas supply choice due to monopolistic conditions upstream.

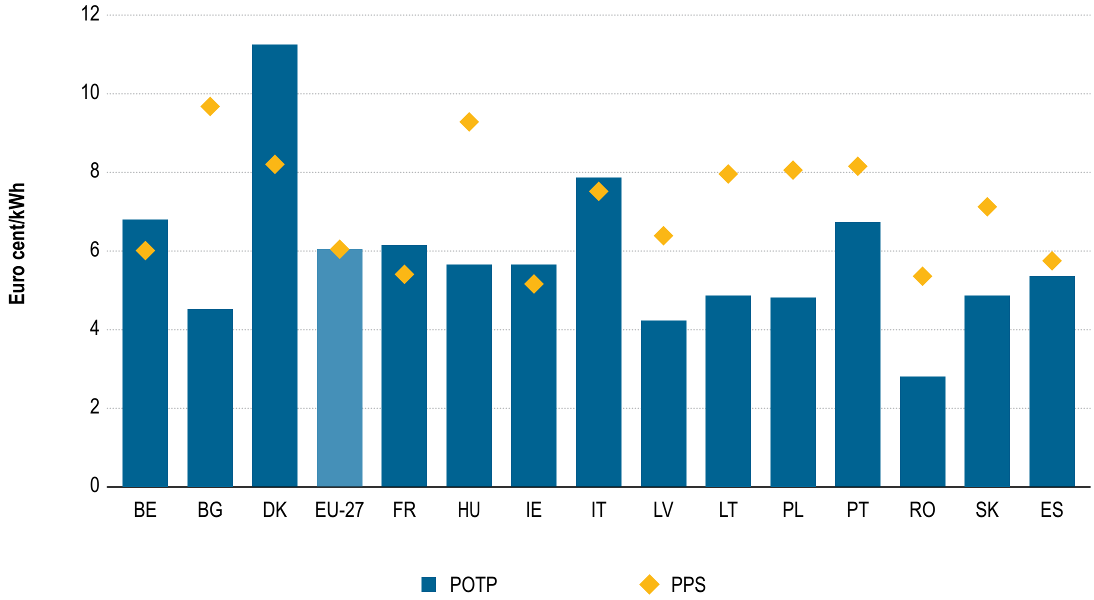
*(244)* After adjusting for purchasing power, it becomes evident that, should new MS have to increase substantially taxes and levies on the final product due to macroeconomic pressures at some point in the future, the affordability of gas for the average household in many of these countries might become an issue. In some, but not all, of these countries gas for domestic usage might eventually face serious substitution pressures; especially where electricity is in a competitive position to replace natural gas, other primary fuels can compete and/or taxes are increased unevenly.

**Figure 45: Natural gas post-tax total price versus PPS for MS without regulated prices – 2011 (euro cent/kWh)**




*Source: Eurostat(2012)*

**Figure 46: Natural gas post-tax total price versus PPS for MS with regulated prices (euro cent/kWh)**




*Source: Eurostat (2012)*

### 5.2.4 Other retail price monitoring indicators

*(245)* As already discussed in the electricity chapter, in order to analyse the evolution of retail prices for typical average households, two price indexes that reflect household consumption profiles for each country were used: the HEPI index and the ACER index.

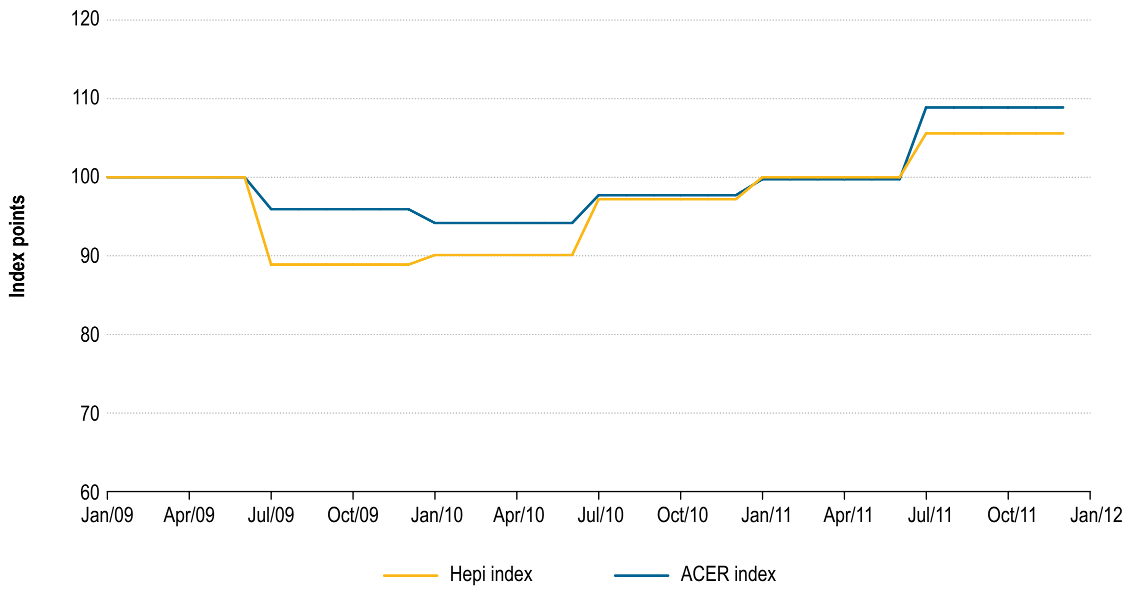
*(246)* The HEPI is a weighted average end-user price index that assesses overall price developments in Europe, based on electricity and natural gas prices collected for both incumbents and competitors in the capital cities of EU-15 MS[137].

*(247)* The ACER price index is similar to the HEPI index, but describes price developments for EU-27 on a half-yearly basis and covers the period from 2009 to 2011.

*(248)* The ACER price index shows how much the average European consumer pays per unit used. In contrast to the HEPI, the ACER Price Index considers the average national prices and average national consumption profiles of all EU-27 MS.

137 The Austrian energy regulator E-Control, in cooperation with VaasaETT, compiled this index.

**Figure 47: HEPI versus ACER price index – 2009 to 2011 (first semester 2009 = 100 index points)**




*Source: Agency/CEER calculations based on E-Control/VaasaETT data (2012)*

*(249)* As Figure 47 suggests, both the HEPI and ACER price indices[138] (defined in the electricity chapter) show that end-user gas prices across EU capital cities, indexed to 2009, decreased during the most acute phase of the recession (in 2009) to recover in 2010-11.

*(250)* Nonetheless, using the ACER price index's weighting methodology, one can see that retail gas prices eventually reached, on average throughout EU-15, the same (nominal) levels of early 2009 in mid-2011.

*(251)* This reflects a combination of improved macroeconomic conditions (before the alleged "double dip" in late 2011 and into 2012, not covered by this year's report), but also of increasing fuel prices (linked to oil dynamics) and more severe budget constraints for some MS, which resulted – in a few instances – in an increase of fiscal pressure on final energy prices.

138 The HEPI index is calculated on a monthly basis. In order to arrive at a single price base, the first semester of 2009 was normalised to a 100 index base through a monthly arithmetic average.

### 5.3 The relationship between retail and wholesale prices

*(252)* The effectiveness of competition in the retail market cannot be decoupled from the wholesale-retail price transmission mechanism. As with all commodities, the price of gas on retail markets should at least in part relate (once network components, retail mark-ups and taxes are discounted) to the wholesale price. It is therefore useful to look at the correlation between wholesale prices and the energy component of the retail price. This correlation analysis between wholesale and retail gas prices is performed in Annex 3.1.3.

*(253)* Even considering data limitations leading to the current unavailability in Eurostat of separate data on the energy-only component of retail prices for natural gas, performing a simple correlation analysis between wholesale and retail prices[139] is still informative.

*(254)* The price correlation figures in Annex 3.1.3 display gas prices in twelve MS from the EU-15.[140]

*(255)* As it will be pointed out in Chapter 6.2, gas hub prices – especially in North West and, to some extent, Central Europe – are reasonably correlated with each other, whereas long-term contract prices tend to follow a different pricing logic.

*(256)* In what follows, depending on the individual country, import (border) wholesale prices or hub average reference prices are compared with average retail prices from capital cities in order to perform wholesale-retail correlation analysis.

*(257)* From the figures available in Annex 3.1.3 dealing with the correlation analysis between wholesale and retail gas prices, one can conclude that:

- Even in those MS where final prices are unregulated, a moderate correlation between wholesale and retail prices can be observed over time, using a quarterly moving average for wholesale prices;
- At least in some markets, the difference between wholesale and retail prices has been decreasing since 2009 (possibly due to macroeconomic fluctuations and the revived regulatory interest in the dynamics of gas retail prices in a number of MS, following the economic downturn); and
- With the only possible exceptions of Spain and Italy (where regulated prices are determined by formulae, linking them to underlying wholesale dynamics), all MS which still featured regulated end-user prices in 2011 unsurprisingly show little or no correlation between wholesale and retail prices.

139 The energy component of retail prices (before taxes) was used in this exercise.

140 In the specific case of natural gas, since punctual wholesale price data from long-term contracts is normally not in the public domain, the Agency and CEER used either reference import (border) prices or hub prices, as applicable.

*(258)* The observations above imply that the correlation between wholesale and retail prices was moderate in 2011 in individual retail markets.

*(259)* Interestingly, in some cases there was higher correlation in those countries featuring wholesale-indexed regulated prices than in those with (nominally) unregulated prices.

*(260)* For a number of European capital cities, the Agency and CEER examined the relationship between the energy component price spread (measured as the difference between the incumbent's energy-only price and the energy-only price of the largest competitor within the same jurisdiction) and the consumer switching rate[141] in 2010-11.[142]

*(261)* From the available data, it is difficult to establish a consistent relationship between the energy-component price spread and the switching rate. This suggests that switching rates might be related not only to the price attractiveness of competing offers, but also to other underlying variables which are sometimes less easy to quantify, such as loyalty, consumer psychology, bundled offers and quality of service.[143] It is also likely that, in some European countries, bundling (dual fuel) strategies across electricity and gas might have had a negative impact on switching rates, as dual fuel offers can give rise to higher switching costs and/or lead times. This effect may be particularly strong in countries where bundled products are offered by the gas incumbent.

*(262)* It is also worth noting that in mature local markets such as London, price spreads seem to be decreasing and non-price competition is now emerging. Whether this sort of competition is a genuine substitute for traditional price-based competition remains to be seen: in 2011, the GB regulator carried out a comprehensive retail market probe to ascertain whether the degree of retail market competition in mainland UK was still acceptable, and as a result proposed a series of remedies[144].

*(263)* In Figure 48, the difference between the energy component of the retail price and the wholesale gas price in countries is plotted against the average switching rate[145].

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141 See footnote 47 for the definition of switching rates in this context.

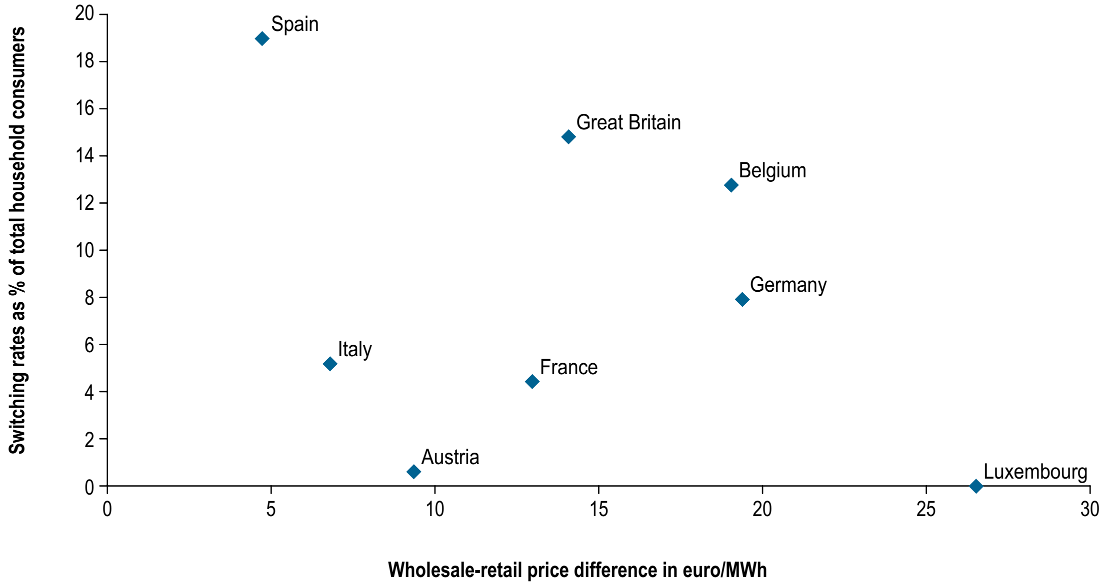
142 Based on data provided to the Agency by the Austrian energy regulator E-Control.

143 For example, some UK retailers have recently moved away from price or even quality of service competition, towards a form of competition based on building a rapport with the end-customer (energy saving advice, provision of in-house demand response devices, "quasi"-smart metering). It remains to be seen whether this sort of non-price behaviour will support the existence of a proper competitive retail market in the traditional microeconomic sense (whereby effective competition is typically measured in terms of relative price/quality levels and price/cost margins).

144 http://www.ofgem.gov.uk/domestic-consumers/Pages/mp.aspx

145 The retail price is calculated as the market-share weighted average of the incumbent's and the largest competitor's commodity-only price, between 2009 and 2011, in the capital city. The wholesale price is calculated as the average of either the spot or import price, between 2009 and 2011, for the country or relevant hub as a whole. The wholesale-retail price spread is then derived as the difference between the two prices defined above.

**Figure 48: Wholesale-retail price differences versus switching rates for natural gas household customers in selected EU countries – Average 2009-2011**




*Source: CEER National Indicators, E-Control/VaasaETT (2012)*

*(264)* Spain and Great Britain have relatively higher switching rates, but show differences in terms of price spread between wholesale and retail, possibly reflecting different stages of the retail liberalisation process. Some information about the different stages of maturity in the liberalisation process for some EU MS is provided in Annex 3.1.1 on switching behaviour in retail markets.

## 5.4 Market design

*(265)* The overall suggestions presented in the market design section of the electricity retail markets chapter are also valid for natural gas.[146]

## 5.5 Conclusions and recommendations

*(266)* In 2011, important disparities in terms of retail gas price levels for households and industrial customers persisted throughout the EU. Taxation plays a relevant role in setting final prices. However, it is far from being the only element that explains disparities in retail prices. Overall, prices rose in 2011 for both households and industrial customers in the majority of MS, in nominal terms and – in many cases – above inflation (the latter statement can be substantiated by comparing nominal price changes with prevailing 2011 inflation rates in MS as published by Eurostat).

*(267)* Regulated gas prices are still applied in all but three new MS, as well as in a non-negligible number of EU-15 MS.

*(268)* Household switching rates remain generally low in most of continental Europe, irrespective of whether end-user prices are regulated or not. Although causality is hard to prove, low switching rates seem to suggest, in correlation with market shares and price levels, that effective retail competition in European gas markets has large room for improvement.

*(269)* Supplier concentration rates might be misleading in some MS. Given retail market design, some countries feature a high number of small suppliers, generally owned by local councils or jurisdictions (municipalities, provinces) and such multi-utilities sometimes encompass other services as well (e.g. water, waste, local transport) with differing degrees of accounting separation, transparency and cross-subsidisation. Low Herfindahl-Hirschman indices (which attempt to measure market concentration) calculated on a country basis are not necessarily an indicator of active competition, because smaller suppliers are, in many cases, locally dominant players, as some retail gas markets currently have a local geographical scope.

146 See section 2.4 for further information.

# 6 Gas wholesale market integration[147]

## 6.1 Introduction

*(270)* In 2011, yearly gas demand in the EU decreased by 10.5% compared with 2010. Indigenous EU production decreased and gas imported into the EU stood at around 70% of consumption. No "shale gas revolution" was observed in the EU in 2011, mainly due to persisting environmental concerns.

*(271)* In late 2011, CEER published a vision for a European Gas Target Model (GTM), which was endorsed by the Madrid (Gas) Forum in December 2011. The themes underlying the present report reflect a convergence towards the GTM (in the context of the IEM 2014 target) and the need to ensure gas flexibility and gas-on-gas competition to the benefit of all European consumers.

*(272)* Linked to the GTM and to market monitoring is the availability of information. Transparency regulations dictate the need for data availability and transparency in the European gas market. In spite of recent progress, there is still a lot of work to be done before full transparency is achieved in line with the provisions of the 3rd Package[148].

*(273)* Throughout 2011, the European gas sector witnessed the further development of continental hubs. However, the Energy Markets Observatory within the European Commission's DG ENER noted, in its quarterly status reports, that the British hub, NBP, had churn rates[149] which were at least twice as high as those of the most liquid mainland European hubs, with a monthly churn ratio at NBP in the range of 8-15 as compared to 3-7 for hubs based in the Netherlands and Belgium.

147 It is well known that access to wholesale EU gas sector statistics is more problematic than access to wholesale electricity data and statistics. This is reflected in the lower density of wholesale gas data analysis in this report compared to the corresponding electricity analysis in Chapter 3. First-hand access to wholesale EU gas data and statistics should be thoroughly improved and made readily available to the Agency and CEER for future editions of this report.

148 See: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas%20Transparency/CD.

149 The churn rate is the ratio between the amount of gas traded at a given hub or marketplace and the amount of gas physically produced and exchanged (production plus net exports) in the area or region covered by the hub.

*(274)* However, even the most liquid European hub (NBP) has much higher prices than the reference hub in the US[150] (Henry Hub in Louisiana, a benchmark for NYMEX), typically up to 3 times higher.[151]

*(275)* Starting in 2009 and continuing into 2010-11, due to the combined effects of the economic downturn and the ample availability of non-piped gas in North West Europe, mature hubs have emerged, leading to a decoupling, to some extent, of wholesale gas prices from oil indexed ones. According to studies published in the European Energy Review in 2011, 56% of physical trade pricing in Europe was oil-based, down from 67% in 2009[152].

*(276)* Although cross-hub price correlation improved in 2011 (from European Commission data and reports[153]), it is important to note that price premiums remained. In other words, correlation was high on a time-series basis, but this does not necessarily imply price convergence.

*(277)* In the absence of underlying cost data, it is of course impossible to draw any conclusion as to whether existing price differences (especially between North West Europe and other European regions, with the notable case represented by the Italian virtual trading point PSV in 2011[154]) are driven by underlying cost fundamentals (transportation and access tariffs included), poor liquidity hindering price transparency, and/or the sheer unavailability of tradable gas on the market due to, inter alia, cross-border capacity congestion.

*(278)* Already in 2011, hub-traded volumes in continental Europe had reached more than 550 billion cubic metres, which is close to physical gas consumption in EU-27.

*(279)* Some of the drivers behind the recent shift away from long-term, take-or-pay, oil-based priced contracts towards short term, spot-based gas trading and related forwards/derivatives could be:

- Fuel substitution between oil and gas no longer being a price driver;
- Gas demand variability being mainly driven by multi-utility companies (gas and power); and
- European utilities and traders – now spurred by growing liquidity at some European gas hubs – no longer being willing to take losses on gas trades and being ready to go to arbitration with upstream suppliers on gas pricing issues under long-term contracts.

150 One (but not the only) reason for this large price differential is the so-called “shale gas (and other unconventional gas) revolution” observed in the US over the last decade. Shale gas has also released theoretical export capacity from the US towards other regions of the world, including the EU.

151 See: http://www.bp.com/extendedgenericarticle.do?categoryId=2012968&contentId=7075274

152 Based on European Commission data available at: http://ec.Europa.eu/energy/observatory/gas/gas_en.htm.

153 See footnote 144.

154 The situation at the Italian PSV has evolved in early 2012 following capacity release at the Austrian-Italian entry point, leading to price convergence. This phenomenon will be described in next year’s monitoring report.

*(280)* Nonetheless, a vast area of the Eastern and South-Eastern EU has no gas hubs and, being mostly landlocked, no LNG. This lack of sufficient diversity in supplies, coupled with little connectivity between national markets (and insufficient backhaul flows from the West), makes this region particularly vulnerable to security of supply and market abuse dangers.

*(281)* Central and Eastern Europe (including South Eastern regions) suffered the most from supply interruptions during the Russia-Ukraine disputes of recent years. To compound the problem, the lack of price references/benchmarks and available TSO data on capacity congestion (both through individual data platforms and ENTSOG's Transparency Platform) makes the establishment of a gas price benchmark for such areas particularly difficult. Apart from Austrian, Czech and Italian hubs (some, if not most, of which still lack liquidity), the only market really close to security-critical areas will be the planned Hungarian hub (to be run by the Hungarian Power Exchange).

*(282)* Hubs need a large number of suppliers via multiple access routes (gas-on-gas competition through pipeline supplies, LNG, cross-border interconnection and price-responsive storage facilities) to become mature. For this reason, infrastructure development and supply diversification are directly related to, and heavily influence, gas market structure – even more so in a region of the world such as the EU, which lacks sufficient indigenous gas supplies. Access to LNG (either physical or traded), with connected/traded gas storage, seems to facilitate market integration and the spread of price signals across spot markets. LNG exports to the EU are strictly linked to the availability of both conventional and unconventional gas in other continents. The wide availability of LNG on international markets might be contingent and subject to change in either direction in the future: this report does not attempt to make any forecasts in this respect.

*(283)* LNG plays an increasingly important role in EU gas supply. Even if LNG supply volumes decreased in the last part of 2011 – mainly due to demand reductions and price competition from Asian markets – it is expected that EU imports of LNG will continue to rise in the future.

*(284)* LNG provides security of supply, diversity and gas-on-gas competition. Investments in new LNG infrastructure are planned over the coming years. In some cases, subject to technical constraints, some LNG plants showed signs of price reactivity in those jurisdictions where strong spot and forward price signals exist and are easily verifiable (for instance, England and Wales).

*(285)* There was no strong indication in 2011 that LNG supplies would be diverted away from Europe on a permanent basis (but spot cargoes were diverted in some instances and in the second half of 2011 EU imports dropped). However, this might change in future due to the global and price-sensitive nature of the LNG market.

*(286)* The EU has now several vehicles for pan-European infrastructure development and diversification (Ten Year Network Development Plans, Projects of Common Interest under the Energy Infrastructure Package/TEN-E Regulation). The Agency contributes to, and coordinates in, these areas. CEER is also involved in this work stream through its contributions and studies on market-based investment procedures.

*(287)* In addition, the development and implementation of network codes is of critical importance for intra- and interregional gas hub development across Europe: this is another area where the Agency plays an important role. Some of the issues addressed in this report are currently being dealt with through the Agency's framework guideline/network code process. For example, under the gas interoperability framework guideline, the harmonisation of measurement units is being sought. Under the gas congestion management comitology guidelines, capacity buy-back and overselling will be stimulated. Meanwhile, the gas capacity allocation framework guidelines introduce capacity auctions. Capacity calculations will now be dealt with through the capacity allocation network code. In addition, pursuant to the forthcoming gas balancing network code, TSOs will be obliged to deal in market-priced balancing gas, and some hub trading in Central/Eastern Europe should hopefully start as a result.

*(288)* The 3rd Package mandates an entry-exit gas target model whereby point-to-point deliveries are banned. The Agency investigated the situation in 2011 and 2012 with existing international gas transit contracts, reviewing the overall contractual framework and – specifically – the access regime to existing and future high-pressure pipelines used for the intra-EU transfer of natural gas across countries.

*(289)* The Agency found that there is still no clear information on the different access regimes for transportation or transit, or on the differentiated treatment of the primary allocation of capacity. In some cases, it is unclear whether or not the capacity rights and access rules offered by the foreign and domestic pipeline operator are subject to the same rules within the country, and there is strong evidence that historical capacity holders still obtain preferential access to transit capacity.

*(290)* Furthermore, it appears that the terms and conditions of individually negotiated transit contracts are not publicly available, and sometimes they are not even known to the regulator.

*(291)* In what follows, this document describes, by means of facts and figures, the convergence process (or lack thereof) towards the internal gas market in 2014 in terms of:

- Wholesale markets;
- Storage/LNG;
- Flexibility, balancing, gas to power;
- Capacity congestion; and
- Transportation tariffs.

## 6.2 Developments in wholesale market prices and liquidity

### 6.2.1 Wholesale price convergence

*(292)* As illustrated in the European Commission's Quarterly Reports on European Gas Markets[155], during 2011 gas hub prices showed some degree of correlation in North West Europe[156]. Gas-on-gas competition and the liquidity of the three main hubs in that region (NBP, TTF and Zeebrugge), coupled with a good degree of physical interconnection, may explain this relationship.[157]

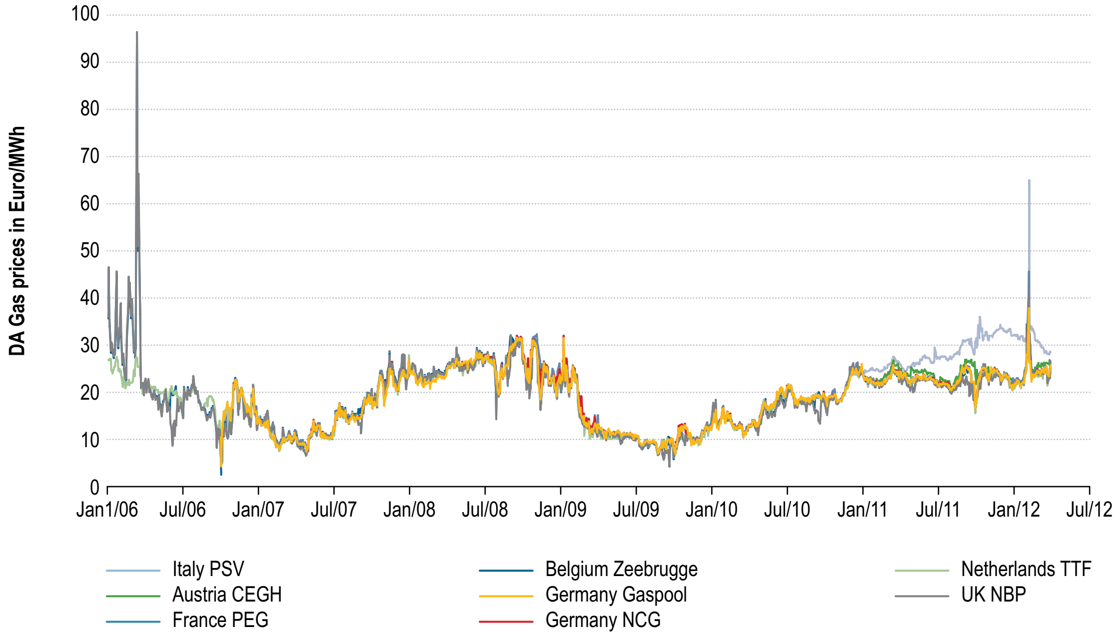
*(293)* However, when looking at the full set of European gas hubs, the picture differs. Figure 49 below shows that price correlation became less pronounced farther away from coastal North Western Europe and into the continent. Persistent price differences remained across EU wholesale gas markets in 2011 in spite of price correlation.

155 See footnote 144.

156 The situation has changed partially in 2012. However, 2012 is not covered by this report.

157 NBP, Zeebrugge, TTF, and – to some extent – PEG Nord hub prices mostly correlate during the whole year. NBP, being the most liquid and the largest trading hub in terms of volumes, usually sets the lowest prices, leading the other hubs with minor spreads above (and occasionally below) its benchmark. The reasons behind this overall correlation are that, in general, these systems benefit from a good level of interconnection and storage capacity, as well as moderate availability of capacity for contracting. Their supplies are less reliant on long-term contracts and a fairly large number of players participate in their hubs as a result of easier hub access. These hubs encompass both long-term supply coverage operations and active spot markets – supported by LNG access. These hubs normally provide balancing, thus adding liquidity and extra market participants.

**Figure 49: Day-ahead prices at European gas hubs – 2006 to 2012 (euro/MWh)**




*Source: ICIS Heren European Gas Markets and graphical elaboration by GTS Netherlands (2012)*

*(294)* The most visible price outliers are from CEGH, the Central European Gas Hub, in Baumgarten (Austria) and from the Italian Virtual Trading Hub (*Punto di Scambio Virtuale*), which decouple especially (but not only) in winter.[158] Even Germany's NCG, which generally correlates well to North West Europe, tends to decouple in winter. The other major German hub, Gaspool, fares somewhat better. As mentioned, the other hubs correlate well (Great Britain, Belgium, the Netherlands and – to some extent – Northern France).[159]

158 Decoupling is particularly visible during cold spells if and when they lead to supply crises in the region. Price differences between Austria/Italy and North West Europe are further explained by the fact that Baumgarten is a transit position hub and (up to now) not a virtual trading point based on a market zone, and that the Italian trading point relies to a large extent on oil indexed contracts in the presence of capacity constraints (now being partially eased, but still quite strong in 2011), which dampens gas-on-gas competition.

159 The role of German organised markets, even if increasing in terms of liquidity and trading volumes, is still mostly confined to domestic market coverage of balancing positions and short-term supply, supported by physical underground storage sites. Moreover, Germany's distinction between high and low calorific gas (and market zones) contributes to the mostly national perspective of Germany's hubs.

*(295)* In 2011, due to geopolitical instability outside the EU and macroeconomic fluctuations, Austria and Italy followed separate patterns from the rest. Price separation was corroborated by supply disruptions in and around Italy, with crucial pipelines running below capacity or being shut (Libyan unrest) and by delays in the establishment of a functioning gas balancing point in Italy[160] (which only went live towards the end of 2011).

*(296)* The other European hubs continued to correlate relatively closely. In particular, German spot markets started to fall more and more in line with North West Europe, notably more so than the Austrian market, thus showing a disconnection between Central and South/South Eastern Europe. The increasing influence of spot and LNG beach prices on German wholesale gas markets in 2011 reportedly triggered some long-term contract re-negotiation between different actors in the value chain.

### 6.2.2 Hub price comparison

*(297)* Figure 50 shows day-ahead prices at European gas hubs[161] from the beginning of 2009 until the present[162]. Additionally, German cross-border (import) gas prices are shown. Hub prices are primarily driven by the fundamentals of supply and demand, based on so-called gas-on-gas pricing. Hub prices can therefore fluctuate significantly on a daily basis, as demand and supply fundamentals change.

*(298)* In contrast, the German cross-border (import) price[163] is primarily based on oil-indexed gas contracts, with a proportion of the contract linked to oil prices and a proportion linked to gas and other fuels such as coal. These contracts are indexed to rolling averages over, generally, six- to nine-month periods. For this reason, any fluctuation in oil prices is smoothed out, making German cross-border prices less volatile.

*(299)* Figure 50 also indicates a high level of correlation between gas prices in North-West Europe, but some marked differences remain. This is particularly the case when comparing North-West European hubs and the PSV (the Italian hub), the Central European Gas Hub on the Austrian-Slovak border (not yet a virtual trading point[164]) and the German cross-border gas price. This is due to the large influence of oil-linked contracts on the PSV and German cross-border gas prices. High oil prices throughout 2010-11 (and later) have therefore maintained these gas prices at higher levels (note that renegotiations of long-term contracts only began halfway through 2011).

160 There might be a correlation between the churn rates observed across hubs and the level of spot prices at those hubs. However, price variability at illiquid hubs (such as those in Central-Southern Europe) should statistically go in both directions, i.e. prices at illiquid hubs should be generally more volatile (unstable) due to limited trades, and not just upward-biased. If this were the case, then the real underlying problem might not be a lack of liquidity in itself, but the malfunctioning of the hub. Problems might include, for instance, capacity hoarding or withholding at the interconnection point(s) linking the hub's underlying geographical market with adjoining regions.

161 Excluding PEG South and PEG TIGF in France.

162 Data from the Italian gas hub (PSV) only available from October 2011.

163 Based on data provided by the German Federal Agency for Foreign Trade (BAFA).

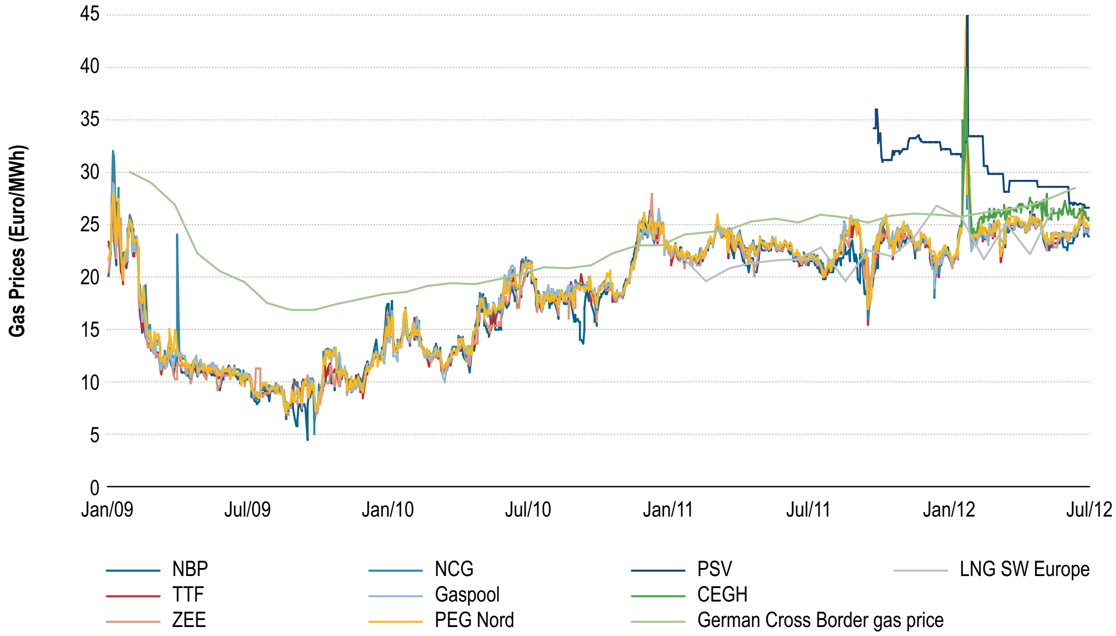
164 A virtual point at which gas can be traded within the market area after entry and before exit; the virtual trading point is not assigned to any physical entry or exit point, and enables gas buyers and sellers to buy and sell gas without booking any capacity (Source: Open Grid Europe).

*(300)* However, since 2012, North-West European hub prices and Italian and German cross-border gas prices have shown signs of convergence. There could be several potential reasons for this:

i) German cross-border gas prices moving towards hub pricing through the renegotiation of long-term contracts;
ii) Increasing wholesale costs for procuring natural gas in North West Europe, driven by declining indigenous production and a heavier reliance on more expensive imports;
iii) The gradual opening (in late 2011/early 2012) of the Austrian-Italian capacity market (via auctions) at the Tarvisio-Arnoldstein border along the TAG pipeline, releasing capacity between the two countries[165], thus allowing gas flows to follow price signals;
iv) The divestment of ENI infrastructure along the Austrian-Italian route following a competition enquiry by the European Commission;
v) The increasing availability of LNG facilities in Mediterranean Europe (at least over the last few years); and
vi) The demand reduction triggered by the macroeconomic situation.

165 For the time being, in the default Austria-Italy direction only, and in the future on a bi-directional basis.

**Figure 50: Natural gas wholesale day-ahead prices at selected EU hubs – 2009 to 2012 (euro/MWh)**




*Source: Bloomberg, Eurostat COMEXT and Ofgem elaboration (2012)*

### 6.2.3 Market liquidity

*(301)* Liquidity is an important feature of a well-functioning market[166]. Throughout Europe, lack of liquidity has been a significant obstacle to achieving increased competiveness in energy markets (see, for example, Ofgem's analysis of the GB[167] electricity market and Oxford Energy's assessment of gas markets in continental Europe[168]).

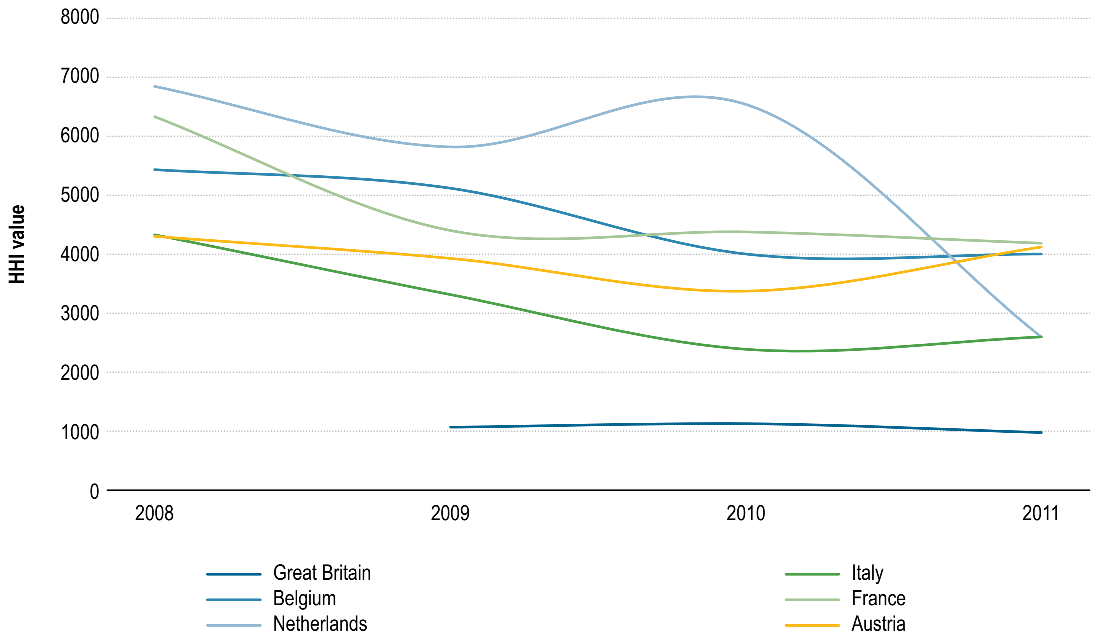
166 Liquidity is defined as the ability to trade, buy, or sell a desired commodity or financial instrument without causing a significant change in the price of a product and without incurring excessive transaction costs. Churn is a statistic that is often monitored as a measure of liquidity, particularly in commodity markets. Churn is the ratio of the total volume of a commodity traded, expressed as a multiple of the volume of the underlying physical commodity. A higher churn rate, ceteris paribus, indicates a more liquid market overall. Churn is therefore a useful measure for comparing markets across countries, even when markets are of differing sizes.

167 "Liquidity in the GB wholesale energy markets", available at: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20in%20the%20GB%20wholesale%20energy%20markets.pdf

168 "The Transition to Hub-Based Gas Pricing in Continental Europe", available at: http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/03/NG49.pdf

*(302)* Figure 51 depicts wholesale market concentration in a number of MS and Figure 52 shows churn ratios in several European hubs between 2008 and 2011. Market concentration in the former instance is measured using the Herfindahl–Hirschman Index (HHI).[169]

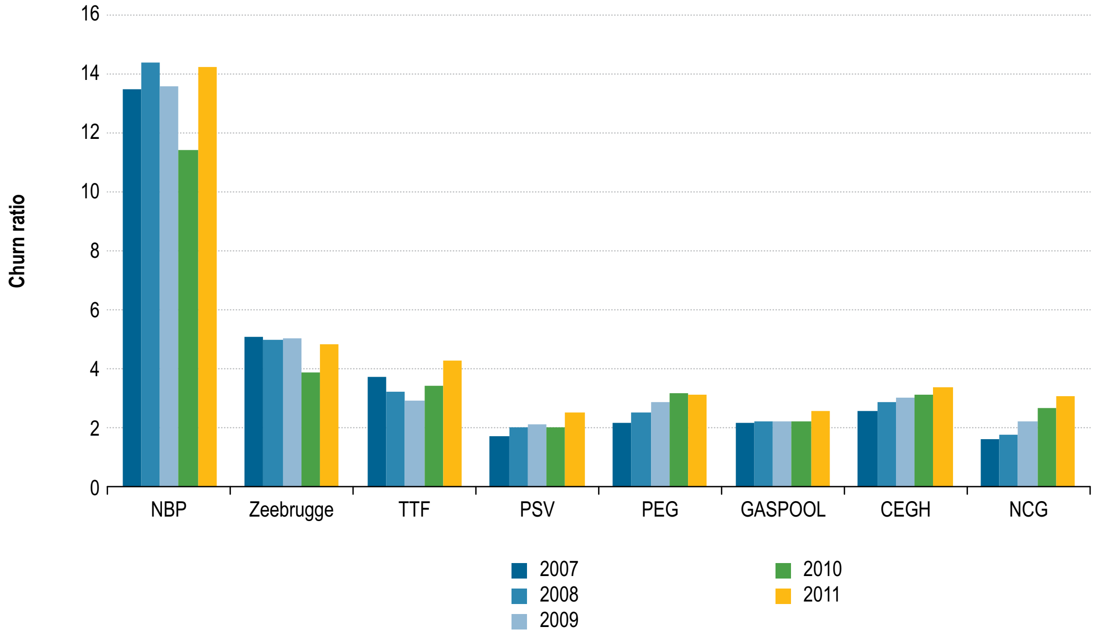
**Figure 51: Wholesale gas markets' HHI in selected MS – 2008 to 2011**




*Source: CEER National Indicators (2012), IEA/OECD*

169 NBP: National Balancing Point (GB), TTF: Title Transfer Facility (NL), PEG: Point d'Echange de Gaz (Nord) (FR), PSV: Punto di Scambio Virtuale (IT), NCG: NetConnect Germany, CEGH: Central European Gas Hub (AT).

**Figure 52: Churn rates at European hubs – 2007 to 2011**




*Source: CEER National Indicators (2012), IEA/OECD*

*(303)* From Figure 51 and Figure 52, it is possible to infer that:

i) The GB domestic market is the least concentrated (as measured by the HHI) and has the most liquid gas hub in Europe (churn rates are several times higher than those elsewhere). Churn has been consistently close to 14 in the last four years. The HHI has been around 1,000 over the same period;

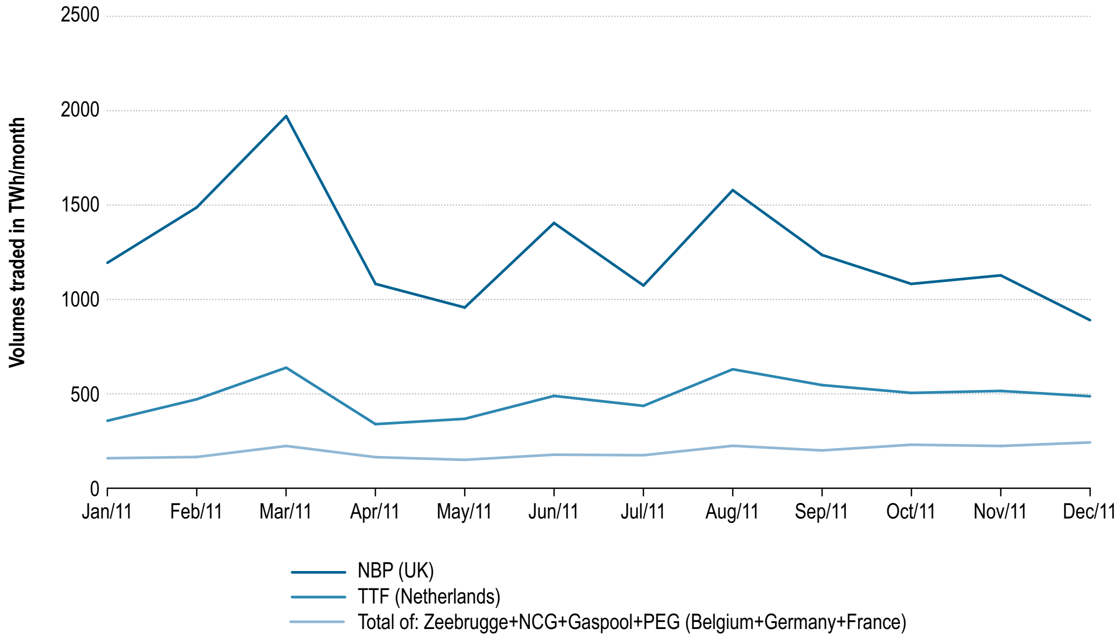
ii) Both Germany and Italy, despite relatively low levels of domestic concentration, have illiquid hubs, as measured by churn rates. Churn ratios at the two hubs have been approximately 2 in the period between 2008 and 2011; and

iii) The group of countries with high levels of domestic concentration, i.e. countries with HHIs above 2,500, show relatively different trends with regards to market liquidity. Churn rates at Belgian and Dutch hubs were markedly higher than the rates in France and Austria between 2008 and 2011. Hence, TTF and – to a lesser extent – Zeebrugge (which was still only a physical hub in 2011) qualify as fully functioning European gas hubs when compared to their counterparts in France and Austria.

*(304)* In terms of churn rates, continental hubs still lag behind NBP, although Benelux-based hubs show an acceptable level of liquidity. Zeebrugge is now facing the challenge of converting from a physical intake point to a virtual trading hub. Churn rates of four and above are not generally observable on the continent, with the possible exception of Benelux-based hubs. According to data taken from the public domain, NBP had a time-weighted average churn rate of 12/14 in 2011, which is generally regarded as sufficient for spot market prices to become the benchmark for long-term contracts and financial derivatives.

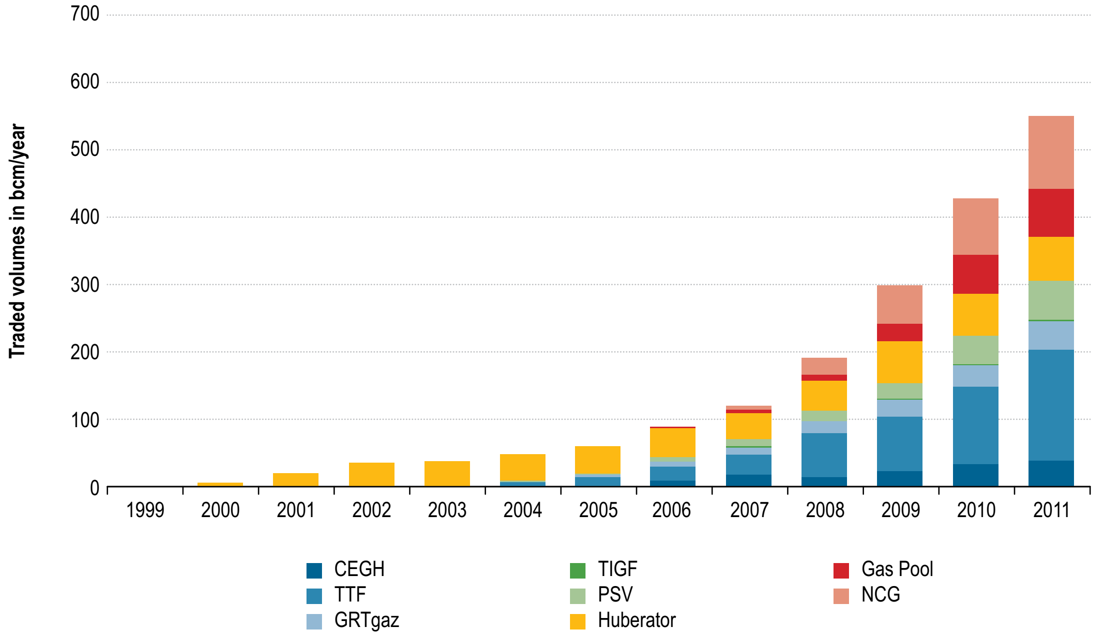
(305) Figure 53 and Figure 54 illustrate the different levels of traded volumes at gas hubs and OTC deals in 2011. NBP shows the highest traded volumes among North West European hubs (Germany, France, Belgium and the Netherlands). Traded amounts on the continent are, however, rising fast and, by the end of 2011, TTF amounts were about half of NBP volumes. German hubs (Gaspool and NCG) still lag behind in absolute volume terms and their trades are mainly spot-based. PEG Nord is the most liquid hub in France.

**Figure 53: European traded volumes (Heren Transaction volumes) of natural gas in North West Europe – 2011 (TWh per month)**




*Source: ICIS Heren European Gas Markets and graphical elaboration by GTS Netherlands (2012)*

**Figure 54: Natural gas traded volumes in selected European hubs – 1999 to 2011 (billion cubic metres)**




*Source: P. Heather, Continental European Gas Hubs Report, Oxford Institute for Energy Studies, University of Oxford (2012)*

*(306)* A crucial aspect of wholesale gas market integration – also in view of the European Gas Target Model[170] – is the existence of daily, or within day, balancing obligations/regimes and the introduction of cross-border balancing to enhance liquidity and the efficient allocation of gas.

*(307)* Especially in smaller gas markets, sometimes along the EU's perimeter (the Baltics, Slovenia/Hungary, Romania), cross-border cooperation will be critical to expanding the number of active trading players beyond the purely traditional suppliers. Poland, France, Austria, Italy and Germany are currently making (or have recently made) pro-active changes to their balancing regimes and national network codes.

*(308)* Wind and solar power in the EU are expected to increase significantly over the next two decades. Although the expectations of individual studies or scenarios vary widely, in particular after 2020, available studies generally show a strong increase in both wind and solar power. In parallel, most studies anticipate the need to construct additional gas-fired power plants, although this may not necessarily result in a simultaneous growth of gas consumption.

170 See: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/PRESS_RELEASES/Tab1/B411198E647066E9E040A8C03C305068

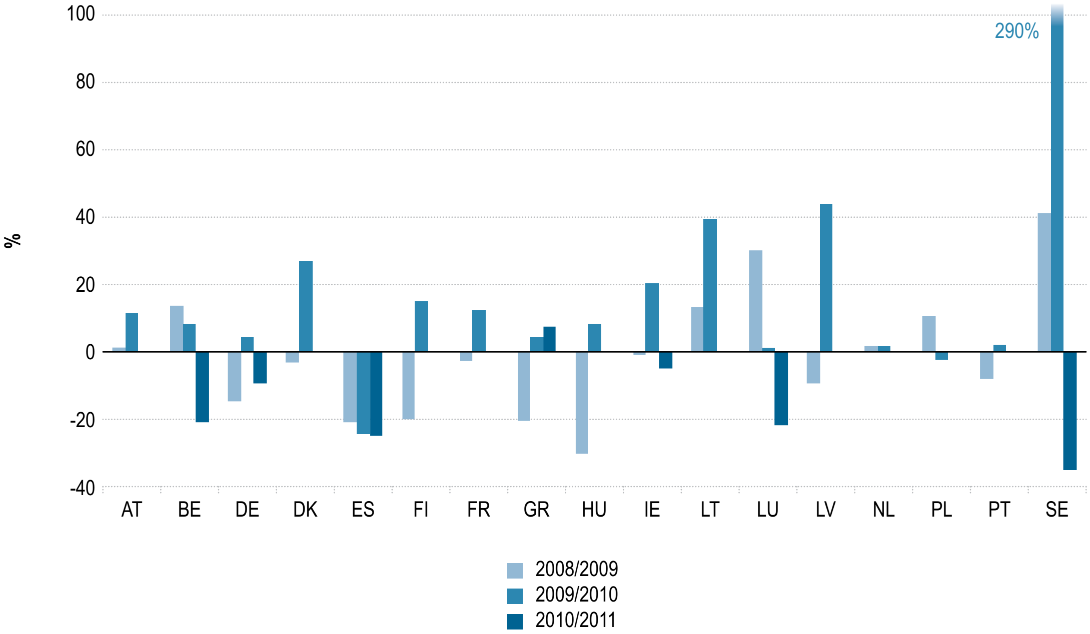
*(309)* Gas balancing can be affected by the interaction between gas and power generation. The output of wind and solar power plants may be subject to fast and unpredictable changes during the day, even when taking into account the fact that corresponding deviations will partially compensate each other in an enlarged region. As a consequence, an increased penetration of renewable energy sources (RES), in particular wind power, may require increased ramp rates to be provided by other generating technologies. Again, it seems reasonable to expect that a considerable share of the corresponding flexibility will have to be provided by gas-fired plants, as the latter generally provide a more rapid response than coal. This might translate into a need for within-day gas balancing.

*(310)* In fact, during the last four years, gas-fired power plant utilisation rates have been very volatile in almost all MS, both in low gas-intensive countries such as Sweden and in high gas-intensive ones (in terms of power generation) like Spain.

*(311)* Figure 55 shows natural gas-fired power plant utilisation rates in selected[171] EU countries.

171 Data were not available for those countries not represented in Figure 55.

**Figure 55: Changes in natural gas-fired power plant utilisation rates in selected EU countries – 2009 to 2011**



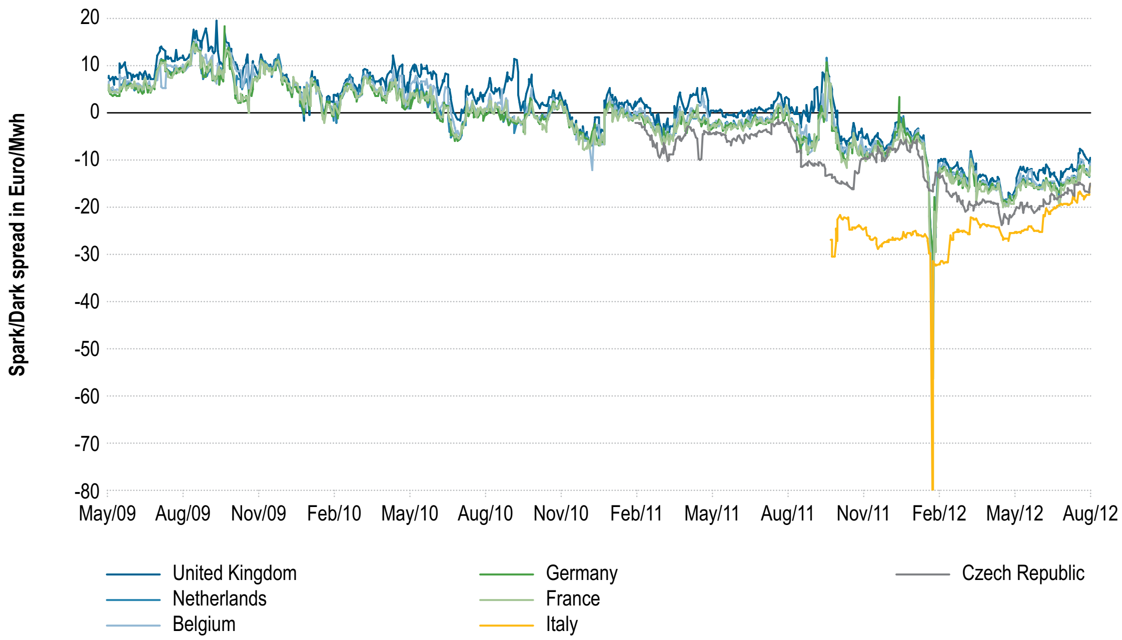

*Source: Eurelectric (2012)*

*(312)* The increasing amount of electricity produced from renewables, especially wind, and the negative externalities this situation may create in terms of balancing the gas system in countries where gas-fired power plants play an important role to ensure security of supply, help explain the volatility observed in gas-fired plant utilisation rates.

*(313)* Moreover, recent developments in clean spark/dark spreads[172], reported in Figure 56, with values close to zero or even negative for 2011, have also resulted in increased volatility in the utilisation rate of gas-fired power plants. The lower the clean spark/dark spread, the more likely it will be that coal-fired plants become a competitive alternative to gas-fired plants (other things being equal).

172 The spark spread is the gross margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. The dark spread is the gross margin of a coal-fired power plant. All other costs (operation and maintenance, capital, and other financial costs) must be covered through spreads. If they are not covered in full, the company owning the plant would be, other things being equal, better off selling the fuel rather than burning it. Clean spreads include the price of $CO_2$ emission certificates under the EU Emissions Trading System (EU ETS).

**Figure 56: Natural gas clean spark/dark spread evolution in selected EU countries – 2009 to 2012 (euro/MWh)**




*Source: Ofgem (2012)*

*Note: In the calculation of gas/coal spreads, the following assumptions were made regarding the efficiency and operation and maintenance costs of the respective representative plant: thermal efficiency (gas) = 49%; thermal efficiency (coal) = 36%; O&M cost (gas) = 0.40 GB pence/therm; O&M cost (coal) = 2 USD/tonne; Transportation cost (gas) = 2 GB pence/therm; Transportation cost (coal) = 10 USD/tonne. $CO_2$ prices are considered. The outlier for 6 Feb 2012 in Italy is probably due to the 5-10 February 2012 cold spell, prompting an over-reaction in the Italian market when Russian gas for power stations was curtailed/diverted to domestic usage and the government ordered previously mothballed heavy fuel-oil power plants to step in for a few days.*

*(314)* From 2010 to 2011, almost all MS for which data are available reported decreases in gas power plant utilisation rates. For example, in Germany the estimated decrease was 9%, and in Belgium, Spain, Sweden and Luxembourg the decrease exceeded 20%[173].

173 Greece was an exception, with an estimated increase of 8%.

### 6.3 Underground storage and LNG

*(315)* One of the main arguments put forward for the differences in approach between electricity and gas with respect to balancing issues is the easier storability of gas. Gas can be stored in different ways, although only some of these provide real flexibility in the short run. Stored gas can generally be used in two ways: to meet base load and foreseeable seasonal swing requirements and to meet short run peak requirements, including unforeseen supply disruptions. Storage installations can react to price changes, depending on their technical characteristics and on the availability of a transparent wholesale price reference in the market concerned.

*(316)* Gas Storage Europe (GSE) and Gas LNG Europe (GLE)[174] have made data available on their respective websites data on existing, new, or planned storage and LNG facilities. Based on their data, it is worth noting that countries which were recently hit by politically unstable supplies are now building more storage (Italy[175], Austria).

*Underground storage*

*(317)* Underground storage is mainly operated on a cyclical basis, as base load to adapt to foreseen yearly seasonal demand. The general annual cycle involves larger injection values and increasing storage levels during the spring and summer months in order to cover higher autumn-winter demand, when gas is withdrawn from storage to accommodate higher demand. Seasonal, base load gas storage can also react to price signals, and in a functioning wholesale gas market it is intended to do so. Particularly in certain systems, storage is also used as a flexible tool in the short run to react to short-term market prices.

*(318)* Storage utilisation by shippers and the role storage sites fulfil in high-pressure gas systems depend on a series of factors such as available storage volumes, the injection and withdrawal capacity of the facilities, the nature of storage sites in terms of access, the regulatory obligations imposed on shippers for security of supply reasons and the role played by storage in terms of system balancing and market making (for instance, to ensure liquidity in organised markets (hubs)).

*(319)* Storage system operators (SSOs) must provide non-discriminatory third-party access to their facilities and, according to the 3rd Package, must not trade in the commodity themselves, similarly to TSOs.

174 See: http://transparency.gie.eu.com/ and http://www.gie.eu/maps_data/GLE/database/index.asp

175 In Italy's case, the development of storage facilities was not linked to recent political decisions following gas supply problems; it was planned and started long before market opening and the latest gas supply crises, mainly in response to security of supply issues.

*(320)* Given the price reactivity of (short term) storage and the link between wholesale gas and electricity markets due to the important role played by gas in electricity generation, one would expect power generators to be located close to flexibility sources, including gas storage. This expectation is confirmed by a cursory look at the European storage map[176].

*(321)* The figures in Annex 3.3.2 on gas storage show total underground storage capacity, gas volumes and injection and withdrawal levels in a representative subset of EU MS, based on public domain data provided online by Gas Storage Europe. The following comments are based on those figures.

*(322)* Spain and Italy have imposed a series of regulatory obligations on shippers to maintain a certain level of gas volume at the beginning of the winter season. Therefore, in those countries the utilisation of storage is more cyclical, even if the demand curve is flatter because of mild weather in winter and higher electricity demand in summer.

*(323)* In the United Kingdom, in addition to the seasonal cycle, storage plays a role in the short run, offering flexibility to react to spot market prices. This is not surprising, given higher NBP liquidity and lower market concentration. In such a framework, storage might also contribute to balancing regimes/markets, including within-day obligations.

*(324)* In Germany and France, storage sites play a relevant role in the provision of liquidity to these countries' organised markets (NCG and, particularly, Gaspool in Germany, and the three PEGs in France). In these two countries, trading operations mostly cover short-run balancing positions. An important number of these operations are performed via physical gas storage volumes, thus increasing the number of operations registered and reducing, to a certain extent, storage seasonality.

*LNG*

*(325)* LNG plays an increasingly important role in EU gas supply. In 2011, LNG imports represented around 20% of total European gas supplies.

*(326)* In 2011, LNG imports into the EU as a whole accounted for around 95.38 billion cubic metres – an increase of 0.3% on 2010. The main importing countries were the UK (28%), Spain (26%) and France (16%)[177].

*(327)* LNG provides security of supply, import diversification and gas-on-gas competition, encouraging arbitrages between the three LNG market areas of Europe, America and East Asia. Even if there is a certain excess of regasification capacity (the average rate of use of LNG terminals in Europe is around 50%) the increasing LNG usage trend, together with the reduction in indigenous EU gas production, is enhancing the attractiveness of new LNG infrastructure throughout Europe.

176 See: http://www.gie.eu.com/maps_data/downloads/2011/GSE_STOR_August2011_MAP.pdf

177 BP Statistical Review Report – 2012.

*(328)* The countries with the highest LNG flexibility, both current and future (including the use of LNG facilities for storage purposes) are Spain, France, the Netherlands, the United Kingdom, Belgium, Greece, Italy and possibly Germany, in terms of future planned investment. In Germany, some LNG projects have been put on hold, while storage capabilities remain high (albeit not increasing at the same rate as in some other countries).

*(329)* It must also be noted that the only countries not situated along the Atlantic/North/Baltic Sea which have increasing LNG facilities are Greece and Italy – Romania also proposes to develop facilities, which have not been completed. Southern European countries with either poor or absent LNG facilities tend to be subject to politically unstable piped supplies and higher gas prices. Western Balkan countries that are not yet in the EU (Croatia) do not seem to have sufficient LNG capabilities at the moment, but development is under way. Infrastructure issues might conflict with environmental concerns in particularly sensitive areas of the Mediterranean, in shallow basins such as the Northern Adriatic and areas of the Black Sea, for instance.

*(330)* LNG plants can also be viewed as storage sites[178] (regardless of whether they are subject to third party access exemptions) and, as such, they should react to wholesale commodity price signals. The rise of LNG imports into the EU since 2007/08 has stimulated, at least in Western Europe, gas-on-gas competition. Relatively isolated gas systems with ample and perhaps under-utilised regasification capabilities, generally situated on the Atlantic coast, have benefitted most from the recent LNG wave. However, LNG is part of a global market and will only travel to where it can be delivered at the highest profit. For this reason, LNG deliveries to Europe will always be a function of the wholesale price differential between Europe and other regions around the world[179]. LNG should, in principle, react to prices if it is able to store gas on site.

*(331)* What has influenced the evolution of wholesale prices in Great Britain and, to some extent, North West Europe around the North Sea is LNG-driven competition. However, Asian markets compete with European ones in terms of willingness to pay for LNG gas from (potentially) the Americas, Africa and the Middle East. As a result, LNG deliveries react to prices quite quickly and are not fully foreseeable.[180]

*(332)* Table 12 reports on existing regasification capacity and the new LNG projects planned over the coming years by EU MS[181].

178 Subject to technical constraints and higher average costs than underground storage.

179 Price differentials between Europe, North America and East Asia are regularly reported on by commercial data aggregators such as Platts, ICIS Heren, Bloomberg and Argus.

180 The evolution of wholesale prices in Great Britain and North West Europe is influenced, inter alia, by the current availability and potential export of unconventional gas from North America, as well as both conventional and unconventional gas from other continents, which may be more easily shipped to Atlantic and North Sea coasts than to any other location in the EU.

181 According to GLE data from August 2011.

**Table 12: Regasification capacity and new projects planned for LNG terminals – 2011 (nominal entry capacity in billion cubic metres/year)**

| | Nominal entry capacity in bm³/year | | | | |
|---|---|---|---|---|---|
| Country, Terminal | Existing | Expansion/ Under construction | Sub-total | Proposed developments | Total |
| Italy | 11.0 | 8.4 | **19.3** | 80.0 | **99.3** |
| Italy, Brindisi | | | **0.0** | 8.0 | **8.0** |
| Italy, Falconara Marittima (off-shore) | | | **0.0** | 4.0 | **4.0** |
| Italy, Gioia Tauro | | | **0.0** | 12.0 | **12.0** |
| Italy, Panigaglia | 3.4 | 4.6 | **8.0** | | **8.0** |
| Italy, Porto Empedocle | | | **0.0** | 8.0 | **8.0** |
| Italy, Porto Levante | 7.6 | | **7.6** | | **7.6** |
| Italy, Porto Recanati (off-shore) | | | **0.0** | 8.0 | **8.0** |
| Italy, Rada di Augusta – Priolo | | | **0.0** | 8.0 | **8.0** |
| Italy, Rosignano (off-shore) | | | **0.0** | 8.0 | **8.0** |
| Italy, Taranto | | | **0.0** | 8.0 | **8.0** |
| Italy, Toscana Offshore | | 3.8 | **3.8** | | **3.8** |
| Italy, Zaule | | | **0.0** | 8.0 | **8.0** |
| Italy, Monfalcone | | | **0.0** | 8.0 | **8.0** |
| UK | 51.1 | 0.0 | **51.1** | 26.4 | **77.5** |
| UK, Anglesey, Amlwch (off-shore) | | | **0.0** | 13.0 | **13.0** |
| UK, Canvey Island | | | **0.0** | 5.4 | **5.4** |
| UK, Dragon LNG | 6.0 | | **6.0** | | **6.0** |
| UK, Isle of Grain (Grain LNG) | 19.5 | | **19.5** | | **19.5** |
| UK, Port Meridian (FSRU) | | | **0.0** | 8.0 | **8.0** |
| UK, South Hook LNG | 21.0 | | **21.0** | | **21.0** |
| UK, Teesside | 4.6 | | **4.6** | | **4.6** |
| Spain | 60.1 | 9.6 | **69.7** | 0.0 | **69.7** |
| Spain, Barcelona | 17.1 | | **17.1** | | **17.1** |
| Spain, Bilbao | 7.0 | | **7.0** | | **7.0** |
| Spain, Cartagena | 11.8 | | **11.8** | | **11.8** |
| Spain, El Ferrol (Mugardos) | 3.6 | | **3.6** | | **3.6** |
| Spain, Gijón (Musel) | | 7.0 | **7.0** | | **7.0** |
| Spain, Gran Canaria (Arinaga) | | 1.3 | **1.3** | | **1.3** |
| Spain, Huelva | 11.8 | | **11.8** | | **11.8** |
| Spain, Sagunto | 8.8 | | **8.8** | | **8.8** |
| Spain, Tenerife (Arico-Granadilla) | | 1.3 | **1.3** | | **1.3** |
| France | 23.8 | 29.3 | **53.0** | 8.0 | **61.0** |
| France, Dunkerque | | 13.0 | **13.0** | | **13.0** |
| France, Fos Cavaou | 8.3 | 8.3 | **16.5** | | **16.5** |
| France, Fos Tonkin | 5.5 | 1.5 | **7.0** | | **7.0** |
| France, Fos-sur-Mer | | | **0.0** | 8.0 | **8.0** |
| France, Montoir-de-Bretagne | 10.0 | 6.5 | **16.5** | | **16.5** |
| Germany | 0.0 | 0.0 | **0.0** | 18.0 | **18.0** |
| Germany, Rostock | | | **0.0** | 2.0 | **2.0** |
| Germany, Wilhelmshafen | | | **0.0** | 10.8 | **10.8** |
| Germany, Wilhelmshafen 2 | | | **0.0** | 5.2 | **5.2** |
| Netherlands | 12.0 | 0.0 | **12.0** | 0.0 | **12.0** |
| Netherlands, Rotterdam | 12.0 | | **12.0** | | **12.0** |

| | Nominal entry capacity in bm³/year | | | | |
|---|---|---|---|---|---|
| Country, Terminal | Existing | Expansion/ Under construction | Sub-total | Proposed developments | Total |
| Belgium | 9.0 | 3.0 | **12.0** | 0.0 | **12.0** |
| Belgium, Zeebrugge | 9.0 | 3.0 | **12.0** | | **12.0** |
| Croatia | 0.0 | 0.0 | **0.0** | 10.0 | **10.0** |
| Croatia, Adria LNG | | | **0.0** | 10.0 | **10.0** |
| Greece | 5.3 | 2.0 | **7.3** | 2.2 | **9.5** |
| Greece, Palei Galini – Iraklion – Crete Island | | | **0.0** | 2.2 | **2.2** |
| Greece, Revithoussa | 5.3 | 2.0 | **7.3** | | **7.3** |
| Albania | 0.0 | 0.0 | **0.0** | 8.0 | **8.0** |
| Albania, Fiere (off-shore) | | | **0.0** | 8.0 | **8.0** |
| Portugal | 6.5 | 1.4 | **7.9** | 0.0 | **7.9** |
| Portugal, Sines | 6.5 | 1.4 | **7.9** | | **7.9** |
| Ireland | 0.0 | 0.0 | **0.0** | 6.5 | **6.5** |
| Ireland, Shannon | | | **0.0** | 6.5 | **6.5** |
| Poland | 0.0 | 5.0 | **5.0** | 0.0 | **5.0** |
| Poland, Świnoujście | | 5.0 | **5.0** | | **5.0** |
| Latvia | 0.0 | 0.0 | **0.0** | 5.0 | **5.0** |
| Latvia, Riga or Ventspils | | | **0.0** | 5.0 | **5.0** |
| Finland | 0.0 | 0.0 | **0.0** | 4.0 | **4.0** |
| Finland, Inkoo or Skoldvik | | | **0.0** | 4.0 | **4.0** |
| Estonia | 0.0 | 0.0 | **0.0** | 3.0 | **3.0** |
| Estonia, Paldiski | | | **0.0** | 3.0 | **3.0** |
| Lithuania | 0.0 | 0.0 | **0.0** | 3.0 | **3.0** |
| Lithuania, Klaipeda | | | **0.0** | 3.0 | **3.0** |
| Romania | 0.0 | 0.0 | **0.0** | 3.0 | **3.0** |
| Romania, Constanta | | | **0.0** | 3.0 | **3.0** |
| Cyprus | 0.0 | 0.0 | **0.0** | 1.0 | **1.0** |
| Cyprus, Vasilikos | | | **0.0** | 1.0 | **1.0** |
| **TOTAL** | **178.7** | **58.6** | **237.3** | **178.1** | **415.4** |

*Source: GLE (2011)*

## 6.4 Cross-border capacity congestion

*Capacity utilisation*

*(333)* Capacity calculation in gas is less immediate than in electricity[182]. Historically, DG ENER and ENTSOG have tried to map out the degree of contractual capacity congestion at cross-border Interconnection Points (IPs). In 2010, they jointly published calculations of utilisation rates at crucial borders and on projected congestion at major EU IPs.

*(334)* Table 13 clearly shows that capacity was fully pre-booked at a number of crucial points for a long time into the future (in some cases, up to 2025), generally in the absence of fully functioning secondary capacity markets. Therefore, unused capacity in many cases could not be easily returned to the market.

182 Cf. Framework Guidelines and Network Codes on gas system interoperability at: www.acer.europa.eu

**Table 13: Capacity bookings at European gas interconnection points – 2011 to 2035**

| | | | | | Capacity booked | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| IP name | Countries | Direction | TSO | Size | 2011 | 2015 | 2020 | 2025 | 2030 | 2035 |
| Tarvisio | AT>IT | Exit | TAG | large | | | | | | |
| Blaregnies Segeo | BE>FR | Exit | Fluxys | large | | | | | | |
| Bacton | BE>UK | Entry | Interconnector | large | | | | | | |
| Waidhaus | CZ>DE | Entry | GRT. DE | large | | | | | | |
| Waidhaus | CZ>DE | Entry | OGE | large | | | | | | |
| Medelsheim | DE>FR | Exit | GRT. DE | large | | | | | | |
| Bunde | DE>NL | Exit | WIN | large | | | | | | |
| Bunde | NL>DE | Entry | WIN | large | | | | | | |
| Julianadorp | NL>UK | Exit | GTS | large | | | | | | |
| Mallnow | PL>DE | Entry | WIN | large | | | | | | |
| Baumgarten | SK>AT | Entry | BOG | large | | | | | | |
| Baumgarten | SK>AT | Entry | TAG | large | | | | | | |
| Lanzhot | SK>CZ | Exit | Eustream | large | | | | | | |
| Bacton | UK>BE | Exit | National Grid | large | | | | | | |
| H. S. Kateriny | CZ>DE | Exit | N4G | medium | | | | | | |
| Lanzhot | CZ>SK | Entry | Eustream | medium | | | | | | |
| S-Gravenvoeren | NL>BE | Exit | GTS | medium | | | | | | |
| Bocholtz | NL>DE | Entry | ENI D. | medium | | | | | | |
| Zevenaar | NL>DE | Entry | OGE | medium | | | | | | |
| Hilvarenbeek | NL>BE | Exit | GTS | N/A | | | | | | |
| Winterswijk | NL>DE | Exit | GTS | N/A | | | | | | |
| Oberkappel | AT>DE | Entry | GRT. DE | small | | | | | | |
| Oberkappel | AT>DE | Entry | OGE | small | | | | | | |
| Eynatten | BE>DE | Entry | ENI D. | small | | | | | | |
| Eynatten | BE>DE | Entry | OGE | small | | | | | | |
| Eynatten | BE>DE | Entry | Thyssengas | small | | | | | | |
| Eynatten | BE>DE | Entry | WIN | small | | | | | | |
| Sidikastiron | BG>GR | Entry | DESFA | small | | | | | | |
| Oberkappel | DE>AT | Exit | GRT. DE | small | | | | | | |
| Oberkappel | DE>AT | Exit | OGE | small | | | | | | |
| Eynatten | DE>BE | Exit | ENI D. | small | | | | | | |
| Eynatten | DE>BE | Exit | OGE | small | | | | | | |
| Eynatten | DE>BE | Exit | WIN | small | | | | | | |
| H. S. Kateriny | DE>CZ | Exit | Ontras | small | | | | | | |
| Medelsheim | DE>FR | Exit | OGE | small | | | | | | |
| Bunde | DE>NL | Exit | GUD | small | | | | | | |
| Bunde | DE>NL | Exit | OGE | small | | | | | | |
| Lasow | DE>PL | Exit | Ontras | small | | | | | | |
| Larrau | ES>FR | Entry | TIGF | small | | | | | | |
| Badajoz | ES>PO | Exit | Enagas | small | | | | | | |
| Larrau | FR>ES | Entry | Enagas | small | | | | | | |
| Gorizia | IT>SL | Entry | Geoplin | small | | | | | | |
| Bocholtz | NL>DE | Entry | OGE | small | | | | | | |
| Bocholtz | NL>DE | Entry | THY | small | | | | | | |
| Bunde | NL>DE | Entry | GUD | small | | | | | | |
| Bunde | NL>DE | Entry | OGE | small | | | | | | |
| Zevenaar | NL>DE | Entry | Thyssengas | small | | | | | | |
| Badajoz | PO>ES | Entry | Enagas | small | | | | | | |
| Gorizia | SL>IT | Entry | SRG | small | | | | | | |

= 100%   100% > ≥ 90%   90% > ≥ 50%   50% > > 0%   = 0%   = No data available

*Source: ENTSOG (2010) for DG ENER and Ofgem (2012)*

*Note: Data for IP Julianadorp have been more recently reviewed and modified by the British energy regulator Ofgem, in contrast to the version published by ENTSOG and DG ENER in 2010. Table 13 reflects these changes as submitted to the Agency and CEER by Ofgem.*

*(335)* The border points where capacity seemed to be pre-booked in the ENTSOG/EC analysis for the longest period were a number of Dutch-German border points, borders between Germany and Belgium/Austria/Czech Republic, borders between Spain and Portugal and, to a considerable extent, the crucial corridor between Slovakia, Austria and North East Italy (including a spur from Austria into Slovenia). These capacity limitations accompany the existence of decoupled, and generally higher, prices at Austrian and Italian gas hubs with respect to German spot benchmarks.[183]

*(336)* The Agency and CEER analysed not only contractual congestion, but also physical utilisation at the most relevant IPs in 2011[184]. To do so, the Agency and CEER selected a sample of IPs representing an assortment of main gas flows throughout Europe. In some cases, appreciable differences between physical and contractual utilisation rates were found, as shown in Table 14 and in the capacity and flow figures reported in the Annex on IP capacity utilisation.[185]

*(337)* In the seven IPs with fully contracted firm capacity in 2011, the effective utilisation rate ranged from 42% to 92%, with a central value of around 60%.

*(338)* The largest divergences between contracted and utilised capacity were found at Oude Statenzijl/Bunde (the Netherlands/Germany), Interconnector (Belgium/UK) and Julianadorp (the Netherlands/UK), all of which feature contracted capacity near to, or at, 100%, but much lower physical utilisation. These differences can be explained either by capacity hoarding or by shippers enacting balancing trades in either direction to offset flows on both sides of the interconnection. These two situations can co-exist.

183 But note that releases of capacity by the Italian TSO in early 2012 have contributed to easing this constraint. Such releases, however long invoked, did not take place in 2011. They took place almost immediately leading, to spot price convergence, in early 2012.

184 The Annex on IP capacity utilisation includes a list of commissioned projects in the EU taken from ENTSOG's ten-year network development planning process.

185 These figures are derived from ENTSOG's Transparency Platform and from a sample of individual TSO websites. Individual TSO data do not always correspond to what is shown in the Transparency Platform. This is probably because booked capacity (firm plus interruptible) can exceed technical firm capacity, and net flows can also exceed technical firm capacity when interruptible capacity is allocated and runs as firm.
When reporting technical capacity values at IPs, the ENTSOG Transparency Platform uses a conservative ("minimum") rule, so that the lowest capacity (in each direction) out of the respective values declared by bordering TSOs on either side of a given border is published as "IP capacity" in each direction.
Note that the above collection of entry and exit points is not aimed at providing a symmetric view of the situation. In many cases, gas flows are one-directional, with the opposite direction of flow being either not technically available or only available as virtual backhaul. "Entry" in this context means the entry point into the country of destination, and "exit" means the exit point out of the country of origin or from the country of origin into the country of destination. Due to the way in which the ENTSOG Transparency Platform is currently organised, sometimes the "exit" point carries the name of the actual border flange in the exit country, and sometimes it carries the name of the entry flange in the country of destination.

**Table 14: Used capacity versus booked capacity at natural gas IPs – Averages for 2011**

| IP name | Direction | Physical capacity in GWh/day | As a % of physical capacity: Booked capacity (1) | Used capacity (2) | Difference (3) = (1) - (2) |
|---|---|---|---|---|---|
| Veľké Kapušany/Uzghorod | UA > SK | 3.088 | 95% | 68% | 27% |
| Baumgarten | SK > AT | 1.632 | 99% | 66% | 33% |
| Lanzhot | SK > AT | 1.266 | 100% | 64% | 36% |
| Tarvisio/Arnoldstein | AT > IT | 1.184 | 100% | 62% | 38% |
| Waidhaus | CZ > DE | 1.118 | 100% | 57% | 43% |
| Mallnow* | PL > DE | 931 | 100% | 65% | 35% |
| Interconnector | BE > UK | 807 | 100% | 43% | 57% |
| | UK > BE | 630 | 100% | | |
| Oude Statenzijl/Bunde** | DE > NL | 677 | 96% | 21% | 75% |
| | NL > DE | 410 | 91% | | |
| Medelsheim/Obergailbach | DE > FR | 648 | 77% | 37% | 40% |
| Dunkerque | NO > FR | 619 | 94% | 74% | 20% |
| Taisnieres/Blaregnies H+L | BE > FR | 588 | 82% | 57% | 25% |
| Bocholtz | NL > DE | 527 | 100% | 62% | 38% |
| Julianadorp | NL > UK | 475 | 95% | 42% | 53% |
| Tarifa | AL > ES | 355 | 71% | 62% | 9% |
| Oberkappel | AT >DE | 146 | 95% | 92% | 3% |
| | DE > AT | 107 | 100% | | |
| Larrau | FR > ES | 100 | 94% | 63% | 31% |

*Source: Agency/CEER calculations based on ENTSOG data, downloaded in August 2012*

*Notes:*
** Data from May 2011.*
*** The Oude Statenzijl IP cluster only shows values from the TSOs flowing high-quality gas through the cluster.*
*Note that, for certain reversible IPs, (2) and (3) values are maximum values in terms of daily dominant flow. Note that AL = Algeria in the above table.*

*(339)* Based on the relevant figures from Annex 3.3.2 on IP capacity utilisation, Central European IP average utilisation indicates that there is some excess capacity, but that, at times of seasonal peak demand, flows match total technical capacity. Central Europe is congested at winter peak times, when the lack of eastbound capacity may become an issue. As contracted values cover nearly all technical capacity offered in winter, secondary markets and congestion management mechanisms may become necessary.

*(340)* Eastern European IPs are highly congested in terms of contracted capacity, with very limited space for new entrants in winter.

*(341)* An increase in Spain-bound flows from the rest of Europe via France can be observed, thus signalling the diversion of LNG deliveries away from Spain in Q4/2011.

*Network access transparency*

*(342)* Transparency is essential to ensuring that congestion is managed in the appropriate way at EU level.

*(343)* A high level of transparency in network access conditions is essential in order to increase competition by enhancing cross-border trade and removing entry barriers.

*(344)* In September 2012, the Agency and CEER performed an analysis of the compliance by European TSOs with the transparency requirements stemming from Annex I of Regulation (EC) No 715/2009. The analysis concluded that, in general, there is a good level of TSO compliance with existing transparency requirements. The situation is positive, in particular, in relation to descriptive information about transmission systems and services provided, transmission contracts and procedures, network codes and, more generally, in terms of data on technical, available and booked capacity at relevant points.

*(345)* However, there is still a lack of compliance in a number of areas, especially in terms of information to be published close to real time (as soon as available to the TSO), in particular as regards actual gas flows and bookings. Missing data include, in particular, historical (time series) information on:

- Capacity;
- Nominations and flows;
- Flexibility and tolerances;
- Interruptions; and
- Information relating to secondary markets and balancing.

*(346)* In addition to the timeliness of information, another outstanding issue identified by stakeholders is the large diversity and lack of standardisation observed so far (units of measurement, data format, quality of information). Stakeholders have asked for common standards, as well as the establishment of a genuinely functioning and readily accessible EU-wide Transparency Platform.

*(347)* In order to improve the level of compliance by TSOs in terms of network access transparency, NRAs and TSOs should cooperate in identifying areas where 3rd Package requirements are still not met and in taking consequential action. In particular, NRAs should identify the data available to TSOs on a within-day basis and close to real time whose publication may be necessary in the interest of system balancing and other operations.

## 6.5 Transportation tariffs

(348) The 3rd Package specifies that gas transportation tariffs should not be dependent on the path of the gas flow and that they should be as cost reflective as possible. The Framework Guidelines (FG) on harmonised gas transportation tariffs aim at providing guidance on the structure and methodologies for setting gas transmission tariffs to be paid by network users.

(349) The FGs advocate the principles of independent entry and exit point tariffs – independent of contract paths – and the avoidance of cross subsidies in the interest of transparency and cost reflectivity.

(350) The cost reflectivity of entry-exit (e/e) tariffs depends on how the e/e regime is specified. Such tariffs can still be dependent on the modelling of expected gas flows. E/e points can be designed in such a way as to provide locational signals on the siting of injection and withdrawal facilities (or those facilities for which some siting flexibility exists, such as LNG or storage plants). Cost allocation is also key when addressing the issue of economic incentives for users of the transmission system and of non-discrimination between domestic and cross-border usage.

(351) The Agency has performed a separate study of different NRA practices regarding the setting, approval and regulation of national gas transportation tariffs.

(352) Table 15, elaborated on the basis of information provided by NRAs, explains the different roles of some NRAs within the EU-27 with respect to regulating and/or setting transportation tariffs.

**Table 15: Examples of regulatory responsibilities for gas access tariff calculation and approval – 2011**

| Regulatory Authority | Roles in setting tariffs |
|---|---|
| **ERO (Czech Republic), ERSE (Portugal)** | • NRA sets the tariffs using a methodology established in regulatory provisions. |
| **E-Control (Austria), CREG (Belgium), AEEG (Italy)** | • NRA approves the methodology or criteria for setting tariffs.<br>• TSO calculates the tariffs and submits them for NRA approval ex ante. |
| **EI (Sweden)** | • NRA approves the methodology or criteria for setting tariffs.<br>• TSO calculates the tariffs and submits them for NRA approval ex post*. |
| **Ofgem (GB)**** | • NRA sets the total revenue allowance for the TSO.<br>• The charging methodology is elaborated by the TSO and submitted to the NRA for ex ante approval. |
| **CRE (France), HEO (Hungary), ILR (Luxembourg)** | • NRA is responsible for setting tariffs.<br>• Tariffs are then approved by the Ministry. |
| **BNetzA (Germany)** | • NRA calculates the allowed revenues based on a regulatory formula set out in law.<br>• Tariffs calculated by TSOs based on a revenue cap. |
| **CER (Ireland)** | • NRA sets the total revenue allowance for the TSO and approves the methodology for setting tariffs.<br>• TSO calculates the tariffs and submits them annually to the regulator for ex ante approval. |
| **CNE (Spain)** | • NRA approves the methodology for tariff setting.<br>• The Ministry sets tariffs. |
| **NMa (Netherlands)** | • TSO calculates tariffs using a methodology established in regulatory provisions<br>• TSO submits them for ex ante NRA approval. |
| **PUC (Latvia)** | • NRA sets the tariff calculation methodology.<br>• TSO calculates tariffs and submits them for NRA approval. |
| **ECA (Estonia)** | • NRA sets domestic transmission and distribution tariffs ex ante.<br>• For transit tariffs only, ex post supervision applies. |

*Source: NRAs (2012). Note that the tasks assigned to some NRAs are likely to change following the implementation of the 3rd Package.*

*Notes: * The system will change in 2015.*
*** A different regulatory regime applies to the two interconnectors, IUK and BBL.*

*(353)* Reports on gas transportation tariff benchmarking are sometimes difficult to access and their results are normally heavily qualified. Reports from ERGEG and consultancy firms KEMA/REKK date back to 2007 and 2009, respectively. Other studies, limited to North West Europe, have been undertaken more regularly for industry stakeholders (see below). The Agency and CEER are not aware of any tariff comparison study carried out by ENTSOG.

*(354)* The KEMA study showed that even though the majority of EU MS apply an entry-exit regime (at least for domestic trade and supply), there is considerable variety in the implementation of these systems.

*(355)* A consultancy study[186] commissioned by GTS, the Dutch gas TSO, updated for 2011, takes annual tariffs (entry-exit and postalised) as reference, based on 100 cubic metres' worth of transportation over 8000 hours per year, at entry or exit flanges. The study shows significant differences across Europe, in the order of two- to threefold. In the presence of multiple tariffs, the consultants take an average per country, having considered that no obvious weights could be found to construct a weighted average of individual tariffs. On the high side of the spectrum, the consultants identify Sweden, Spain, Ireland and Austria. The United Kingdom, Italy, France and Luxembourg seem to feature tariffs in the middle of the spectrum, while North Western Europe (Benelux, Germany and Denmark) seems to enjoy lower transportation tariffs.

*(356)* Cross-border tariffs are designed separately from domestic ones. Their magnitude and structure vary greatly. In some cases, as also highlighted by ENTSOG's Transparency Platform data, entry and exit points are priced – according to GTS's consultants – in very different ways. For instance, entry points into Southern Europe (Italy) are priced at three to four times the European average (for instance, from Algeria/Tunisia and Libya into Sicily), and exit pipeline points at Northern Italian borders are priced at two to three times the European average (for exits to Switzerland and Austria).

*(357)* While these pricing strategies are generally compatible with incentivising the flow of gas where it is most needed (i.e. to avoid flows that go against price differentials), the magnitude of such differences is impressive, and no public evidence has been provided so far by TSOs either to the Agency or CEER or ENTSOG of whether such pronounced tariff differences are corroborated by any robust underlying demand elasticity or cost reasons.

*(358)* According to the GTS study, the range of the weight of transportation tariffs in total end-user prices is quite wide (1 to 5% in many cases, but 10 to 20% and above for Ireland and Spain), which points to the importance of transportation tariffs precisely in those countries which are least interconnected to the core European system.

*(359)* The study is, once again, mainly about domestic rather than interconnection tariffs, but preliminary evidence from the ENTSOG Transparency Platform (for instance, on entry-exit tariffs between Austria and Italy, and between Austria and Slovenia) points to a similar situation at a cross-border level, whereby countries that are gas peninsulas and are connected via only one entry point will typically experience a higher weight of transportation tariffs in the final gas bill.

*(360)* As with all price benchmarking studies, the lack of control for underlying TSO costs, the possible existence of underlying structural factors and the differences in units of measurement and weights (in addition to the tariff structures themselves) must be noted as caveats. Nonetheless, the Agency and CEER would welcome the development of similar initiatives to compare network access tariffs, especially in Central Eastern and South Eastern Europe.

186 See: http://www.gastransportservices.nl/en/downloads/publications/studies

*(361)* An independent preliminary study carried out by the Florence School of Regulation (FSR)[187] shows that entry-exit network charging in the presence of a cost reflectivity requirement could give rise to potential trade-offs, depending on whether non-path dependent tariffs (for instance, stemming from an entry-exit model) are able to provide locational signals or not. The study finds that tariff pancaking exists at cross-border points. For those countries featuring domestic zones (such as France), pancaking might exist even within borders. The study also finds that the lower the locational signals provided, the higher the pancaking effects.

*(362)* Focusing on the case of e/e tariffs in Portugal and Spain, the FSR study argues that locational signals (to provide cost reflectiveness) might be weak. Since transportation tariffs (at high pressure) account for as much as 10-15% of overall final prices in these two countries, cross-border tariff differences are non-negligible in terms of end-user impact.

*(363)* In the case of France, the study signals that policy-makers decided to increase zone sizes (by merging pre-existing zones), which is not conducive to a highly granular entry-exit system and *de facto* trades off increased liquidity (due to larger domestic zones) with (and to the expense of) the cost reflectiveness of tariffs, including the provision of correct locational signals.

*(364)* In addition, creating domestic zones will increase liquidity, but in the absence of correct market design might increase the temptation of pancaking domestically, rather than (or in addition to) confining the issue to cross-border tariffs.

*(365)* The study recommends that any (even if path-related) discounts should be transparent, and notes that, more generally, there seems to be no such thing at the moment as a "unified" e/e system in the EU. Rather, one observes the coexistence of different e/e concepts, with highly different levels of market zone size and granularity throughout the EU.

*(366)* The Agency and CEER collected cross-border tariff information published by ENTSOG through its Transparency Platform[188]. The information covers only a subset of European interconnection points. However, what is provided is sufficient to identify sizeable variations in the magnitude of entry and exit tariffs for connection and the use of the system at cross-border interconnection points.

*(367)* While it is not within the scope of this report to judge the structure of tariffs (EU framework guidelines and network codes will change the picture of how cross-border gas tariffs are set from 2013 onwards), it is worth noting that there are very pronounced differences in terms of magnitude. These can result from a number of factors, including:

- National regulation(s);
- Cost allocation strategies and rules;
- Structural factors (geographical characteristics of the network, terrain, climate, local regulations); and
- Supply and demand characteristics, including the nature of gas flows.

187 Florence School of Regulation/European University Institute: unpublished discussion paper by Michelle Hallack and Miguel Vazquez, September 2012 (mimeo), shared with the Agency and CEER. It must be noted that this study considered only a limited number of instances, not necessarily including individual countries where the entry-exit regime may be able, by design, to accommodate locational signals.

188 See: www.gas-roads.eu

*(368)* As highlighted in the aforementioned studies, the actual weight of transportation and connection tariffs in final gas bills can vary from a few percentage points to 10 % and higher.

*(369)* Across Europe, tariff variability, without replicability of calculations, different charging methodologies at either side of the same border and different units of measurement sometimes even within the same country (for instance, where multiple supra-regional TSOs are present), are difficult to reconcile with the idea of interoperable and comparable network access systems, and – ultimately – the Internal Energy Market.

*(370)* The Agency and CEER therefore recommend that, as a minimum, calculation methodologies be made compatible (this does not necessarily mean that the structure of tariffs must be 100% homogenised and/or that tariffs themselves should converge) so that different tariffs can be compared. The Agency and CEER also recommend that units of measurement be standardised.

*(371)* In some cases, even for Western Europe, the Transparency Platform is not complete. This is not necessarily due to data limitations. For instance, some TSOs did not provide ENTSOG with point tariffs, because tariffs can be computed on their websites via price calculators. This is a laudable initiative, but makes standard tariff comparisons impossible.

*(372)* The TSOs in question should provide ENTSOG's platform with standard tariffs, in order to make ready comparisons possible. In other cases, connection and access at borders is granted by an auction, which obviously makes ex-ante unit price comparisons not feasible. However, auctions are used in only a limited number of cases and, if well designed and sufficiently liquid, they may represent a somewhat acceptable price to pay for the absence of direct ex-ante price comparability.

*(373)* For the majority of MS, the availability of connection and use of system tariff information is limited. In some cases, no data has been provided to ENTSOG, and even commercial consultancy studies do not normally include any information from new MS. Having noted variable degrees of progress in the Regional Initiatives across electricity and gas in 2011, the Agency and CEER would like to see a much higher degree of regional engagement in this respect.

*(374)* The information gathered by the Agency and CEER on cross-border tariffs[189] is used in what follows for price and capacity analysis (after harmonising different tariff structures and measurement units, which ENTSOG reports without prior harmonisation on its Platform). There is no information on underlying TSO/ISO costs. This greatly limits the usefulness of any price benchmarking exercise.

*(375)* A sample of relevant major European IPs was selected to perform an assessment of gas transmission cross-border charges.

189 See: www.gas-roads.eu

*(376)* Table 16[190] displays entry-exit charges applied by TSOs based on the information gathered by the Agency and CEER from TSO websites and the Transparency Platform, and reviewed by some ENTSOG members. In those cases where IP charges differ depending on the duration of the contract, annual charges have been considered as a basis. Annex 3.3.2 on IP capacity utilisation includes a description of the structure of tariffs by country. TSOs do not provide data for those borders where auctions are held. This problem should be tackled in future analysis.

*(377)* This tariff assessment exercise should be considered as a preliminary analysis, carried out by the Agency and CEER (in the absence of coordinated industry initiatives at EU level) on the basis of publicly available information from individual TSOs' websites. The assessment is a challenge, as tariffs can vary significantly between IPs for a variety of reasons[191].

190 The first set of columns contains descriptive information on the IP: name, border, flow direction, technical capacity, gross calorific value and TSO operating in each direction. The second set of columns reflects applicable charges by IP, distinguishing where possible between capacity and commodity. In those cases where IP charges differ depending on the duration of the contract, annual charges have been considered as the basis. The existence of different tariff structures and different charging units add complexity to the analysis. To perform a comparison, total charges were first converted into common comparable units, then the total cost of flowing a given amount of gas was simulated. All data were shared for confirmation and cross-checking with ENTSOG

191 As a consequence, the following caveats apply:

- This is not a full comparison exercise, since for an objective comparison it is of extreme importance to take all tariff components into account. In the calculations, no seasonal or daily factors are taken into account because the computed price refers to an average daily value for a given value of (yearly) booked capacity. Other value added services, apart from commodity and capacity charges, were not taken into account (balancing, metering, tolerance levels, quality conversions);
- Any network tariff will always be a function of potentially differing network cost drivers, such as size (length) of networks and zones, configuration, maximum capacity, topology/morphology of networks and zones, density and other structural or regional factors;
- These tariffs might reflect individual regulatory choices by the MS, in terms of allowed total TSO revenues, regulatory rates of return and valuation of the regulatory asset base, for instance;
- These tariffs are a function of possibly diverging national cost allocation policies, which will be coordinated through the Agency's ongoing work on harmonised gas transportation tariffs;
- These tariffs represent firm daily products, which might have different underlying "general TSO conditions" attached regarding force majeure, liabilities, credit, interruptions in case of emergencies or extreme cold, etc.;
- These tariffs do not reflect different purchasing powers and, for those countries not in the euro area, they are exposed to currency fluctuations;
- The tariffs represent a value at one point in time and may vary within each system (due to tariff indexation, changing regulatory regimes etc.)
- The analysis does not consider entry-exit revenue splits (the latter could heavily alter the level of charges applied at cross-border IPs);
- Actual distances are replaced by average ones;
- Tax levels generally differ; and
- Other factors relevant to access charges, such as system morphology, are not considered.

## Table 16: IP utilisation charges from TSO websites' data – 2011

| Interconnection Point Description | | | Total IP utilisation charges from TSO websites' data | | | | | | | Total IP charge in harmonised units | Cost simulation for a certain consumption profile |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IP Name | Border | Direction | Technical physical capacity in GWh/day (July 2012) | Assumed Gross Calorific Value for conversion in kWh/Sm³ | TSO/ISO | Commodity related charges (in TSO charging units) | Capacity related charges (in TSO charging units) | TSO charging units | Comments on tariff components/structure | Total IP utilisation charge in euro/GWh/day | Cost in euro of flowing 1 (MWh/h)/day through the IP |
| Baumgarten/ Oberkappel | SK-AT-DE | P2P | AT-DE E/E: 146-97.2 | 11.1 | BOG | 8.5620 | 0.1866 | Euro m³/h year - m³/h *km year | P2P Tariff. Two tariff concepts: distance and non-distance related costs. BG to OB Distance 245 km. Assumption: single IP tariff = Total P2P Tariff/2. From 2013, e/e tariffication through auctions will be applied. | 279.1 | 6.699 |
| Oberkappel | AT>DE | Entry | 132.7 | 11.1 | GRTgaz Deutschland | | 1.64 | Euro/kWh/h/day (summer/ winter day) - kWh/h/year | Two tariff mechanims: Daily fee or Annual fee. Annual fee considered and then averaged. | 187.2 | 4.493 |
| Oberkappel | DE>AT | Exit | 12.9 | 11.1 | GRTgaz Deutschland | | 2.04 | Euro/kWh/h/day (summer/ winter day) - kWh/h/year | Two tariff mechanims: Daily fee or Annual fee. Annual fee considered and then averaged. | 232.9 | 5.589 |
| Oberkappel | AT>DE | Entry | 13.3 | 11.1 | Open Grid Europe | | 0.00694 | Euro/(kWh/h)/day | | 289.2 | 6.940 |
| Oberkappel | DE>AT | Exit | 94.3 | 11.1 | Open Grid Europe | | 0.00971 | Euro/(kWh/h)/day | | 404.6 | 9.710 |
| Ueberackern* | AT>DE | Entry | 230.1 | 11.7 | Gascade | | 2.5 | Euro/(kWh/h)/day | | 285.4 | 6.849 |
| Ueberackern* | DE>AT | Exit | 113.6 | 11.7 | Gascade | | 2.36 | Euro/(kWh/h)/day | | 269.4 | 6.466 |
| Ueberackern* | AT>DE | Entry | 230.1 | 11.7 | Bayernets | | 0.00613 | Euro/(kWh/h)/day | | 255.4 | 6.130 |
| Ueberackern* | DE>AT | Exit | 113.6 | 11.7 | Bayernets | | 0.00613 | Euro/(kWh/h)/day | | 255.4 | 6.130 |
| Ueberackern | AT>DE | P2P E/E | E/E 230.1 - 113.6 | 11.7 | Gas Connect Austria | - | - | Euro/m³/h per month | P2P tariff. Oberkappel to Ueberackern. Cost from web tool simulation for a flow of 85m³/h = 193 euro per month. Assumption: single IP tariff = Total P2P Tariff/2. From 2013, E/E tariffication through auctions will be applied. | 134.8 | 3.234 |
| Baumgarten/ Tarvisio | SK-AT-IT | P2P | 1135 | 11.2 | TAG | 2.0260 | 0.128 | Euro/Sm³/year --- euro/ Sm³/h*km/year | P2P Tariff. Two tariff concepts: distance and non-distance related costs. Distance 380 km. Assumption: single IP tariff = Total P2P Tariff/2. From 2013, E/E tariffication through auctions will be applied. | 258.2 | 6.197 |
| Tarvisio | AT>IT | Entry | 1135 | 11.2 | SNAM Rete Gas | 0.0030 | 0.908 | Euro/Sm³ --- euro/Sm³/day per year | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 490.0 | 11.759 |
| Tarvisio | IT>AT | Exit | 190.9 | 11.2 | SNAM Rete Gas | 0.0030 | 0.3609 | Euro/Sm³ --- euro/Sm³/day per year | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 356.1 | 8.547 |
| Eynatten | BE>DE | Entry | 136.5 | 11.2 | Gascade | | 2.5 | Euro/(kWh/h)/year | | 285.4 | 6.849 |
| Eynatten | DE>BE | Exit | 87.7 | 11.2 | Gascade | | 2.36 | Euro/(kWh/h)/year | | 269.4 | 6.466 |
| Eynatten | BE>DE | Entry | 2.1 | 11.2 | Thyssengas | | 2.19 | Euro/(kWh/h)/year | | 250.0 | 6.000 |
| Eynatten | BE>DE | Entry | 34.4 | 11.2 | ENI DE | Auction | Auction | | | Auction | - |
| Eynatten | BE toDE | Entry | 91.4 | 11.2 | Open Grid Europe | | 0.00508 | Euro/(kWh/h)/day | | 211.7 | 5.080 |
| Eynatten | DE>BE | Exit | 215.3 | 11.2 | Open Grid Europe | | 0.00727 | Euro/(kWh/h)/day | | 302.9 | 7.270 |
| Eynatten | DE>BE | Entry | 303 | 11.3 | Fluxys | 0.08% | 8.79 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 88.8 | 2.131 |
| Eynatten | BE>DE | Exit | 264.4 | 11.3 | Fluxys | 0.08% | 34.86 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 352.2 | 8.452 |
| Blaregnies Segeo | FR>BE | Entry | - | 11.3 | Fluxys | 0.08% | 8.79 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 88.8 | 2.131 |
| Blaregnies Segeo | BE>FR | Exit | 570 | 11.6 | Fluxys | 0.08% | 19.28 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 189.7 | 4.554 |
| Taisnieres | BE>FR | Entry | 570 | 11.6 | GRTgaz | | 103.07 | Euro/MWh/day per year | | 282.4 | 6.777 |
| Taisnieres | FR>BE | Exit | - | 11.6 | GRTgaz | | 20.614 | Euro/MWh/day per year | | 56.5 | 1.355 |

| Interconnection Point Description | | | Total IP utilisation charges from TSO websites' data | | | | | | | Total IP charge in harmonised units | Cost simulation for a certain consumption profile |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IP Name | Border | Direction | Technical physical capacity in GWh/day (July 2012) | Assumed Gross Calorific Value for conversion in kWh/Sm³ | TSO/ISO | Commodity related charges (in TSO charging units) | Capacity related charges (in TSO charging units) | TSO charging units | Comments on tariff components/structure | Total IP utilisation charge in euro/GWh/day | Cost in euro of flowing 1 (MWh/h)/day through the IP |
| s-Gravenvoeren | BE>NL | Entry | | 11.9 | GTS | | 0.993 | Euro/kWh/hour/year | | 113.4 | 2.721 |
| s-Gravenvoeren | NL>BE | Exit | 351.5 | 11.9 | GTS | | 1.435 | Euro/kWh/hour/year | | 163.8 | 3.932 |
| s-Gravenvoeren | NL>BE | Entry | 351.5 | 11.3 | Fluxys | 0.08% | 8.79 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 88.8 | 2.131 |
| s-Gravenvoeren | BE>NL | Exit | | 11.3 | Fluxys | 0.08% | 22.83 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 230.6 | 5.535 |
| Zelzate | BE>NL | Entry | 209.3 | 11.9 | GTS | | 1.495 | Euro/kWh/hour/year | | 170.7 | 4.096 |
| Zelzate | NL>BE | Exit | 303.8 | 11.9 | GTS | | 1.72 | Euro/kWh/hour/year | | 196.3 | 4.712 |
| Zelzate | BE>NL | Exit | 209.3 | 11.3 | Fluxys | 0.08% | 22.83 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 230.6 | 5.535 |
| Zelzate | NL>BE | Entry | 303.8 | 11.3 | Fluxys | 0.08% | 8.79 | Euro/Sm³/h/year | Commodity charges at Fluxys are calculated as a percentage of the gas flowing through entry and exit points multiplied by the gas price (ZIG reference price). | 88.8 | 2.131 |
| Passo Gries | CH>IT | Entry | 638.8 | 11.4 | SNAM Rete Gas | 0.0030 | 0.45178 | Euro/Sm³ --- euro/Sm³/day per annum | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 371.1 | 8.906 |
| Passo Gries | IT>CH | Exit | - | 11.4 | SNAM Rete Gas | 0.0030 | 1.733014 | Euro/Sm³ --- euro/Sm³/day per annum | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 678.5 | 16.283 |
| Passo Gries | IT-CH | Entry/Exit | 638.8 | 11.4 | SwissGas | | | Auctions | | Auction | - |
| Hora Sv. Kateriny-Neudorf | CZ>DE | Entry | 222 | 11.3 | Gascade | | 2.5 | Euro/(kWh/h)/year | | 285.4 | 6.849 |
| Hora Sv. Kateriny-Neudorf | CZ>DE | Entry | 270 | 11.5 | ONTRAS-VNG | | 2.26 | Euro/(kWh/h)/year | | 258.0 | 6.192 |
| Hora Sv. Kateriny-Neudorf | DE>CZ | Exit | 108 | 11.5 | ONTRAS-VNG | | 1.71 | Euro/(kWh/h)/year | | 195.2 | 4.685 |
| Lanzhot-Neudorf | SK-CZ-DE | P2P | CZ-DE E/E: 492/108 | 11.5 | Net4Gas | | 60728 | CZK/1000m³ per day/year | P2P Tariff: Single IP tariff = Total Tariff /2 – 1 euro ~ 24 CZK | 301.4 | 7.234 |
| Waidhaus | CZ>DE | Entry | 552 | 11.1 | Open Grid Europe | | 0.00549 | Euro/(kWh/h)/day | | 228.8 | 5.490 |
| Waidhaus | DE>CZ | Exit | - | 11.1 | Open Grid Europe | | 0.00727 | Euro/(kWh/h)/day | | 302.9 | 7.270 |
| Waidhaus | CZ>DE | Entry | 458 | 11.1 | GRTgaz Deutschland | | 1.64 | Euro/kWh/h/day (summer/inter day) - kWh/h/year | Two tariff mechanims: daily fee or annual fee. Annual fee considered and then averaged. | 187.2 | 4.493 |
| Waidhaus | CE>CZ | Exit | - | 11.1 | GRTgaz Deutschland | | 2.04 | Euro/kWh/h/day (summer/inter day) - kWh/h/year | Two tariff mechanims: daily fee or annual fee. Annual fee considered and then averaged | 232.9 | 5.589 |
| Lanzhot-Waidhaus | SK-CZ-DE | P2P | CZ to DE 1000 | 11.1 | Net4Gas | | 60728 | CZK/1000m³ per day/year | P2P Tariff: Single IP tariff = Total Tariff /2 – 1 euro ~ 24 CZK | 312.3 | 7.495 |
| Wallbach | DE-CH | Entry/Exit | 250.3 | 11.5 | ENI Gas International | Auctions | | | | Auction | - |
| Wallbach | DE-CH | Entry/Exit | 114.4 | 11.5 | SwissGas | Auctions | | | | Auction | - |
| Wallbach | CH>DE | Entry | - | 11.2 | Open Grid Europe | | 0.00693 | Euro/(kWh/h)/day | | 288.8 | 6.930 |
| Wallbach | DE>CH | Exit | 218.5 | 11.2 | Open Grid Europe | | 0.00971 | Euro/(kWh/h)/day | | 404.6 | 9.710 |

| Interconnection Point Description | | | | | Total IP utilisation charges from TSO websites' data | | | | | Total IP charge in harmonised units | Cost simulation for a certain consumption profile |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IP Name | Border | Direction | Technical physical capacity in GWh/day (July 2012) | Assumed Gross Calorific Value for conversion in kWh/Sm³ | TSO/ISO | Commodity related charges (in TSO charging units) | Capacity related charges (in TSO charging units) | TSO charging units | Comments on tariff components/structure | Total IP utilisation charge in euro/GWh/day | Cost in euro of flowing 1 (MWh/h)/day through the IP |
| Lasow | DE>PL | Exit | 42.6 | 11.1 | ONTRAS-VNG | | 2.11 | Euro/(kWh/h)/year | | 240.9 | 5.781 |
| TGPS to Lasow | DE>PL system | transmission | 42.6 | 11.1 | GAZ SYSTEM PL | | 0.0221 | PLN m³/h per h | Total Transmission system tariff / 1 euro ~ 4 PLN | 497.7 | 11.946 |
| Mallnow | TGPS>PL-DE | Entry | 931.5 | 11.3 | Gascade | | 2.5 | Euro/(kWh/h)/year | | 285.4 | 6.849 |
| TGPS to Mallnow | DE-PL>TGPS | transmission | 931.5 | 11.3 | Europol Gaz | | 23.21 | PLN/1000m³/day | Total Transmission system tariff / 1 euro ~ 4 PLN | 513.5 | 12.324 |
| Oltingue | CH>FR | Entry | - | 11.4 | GRTgaz | | 359.6 | Euro/MWh/day per annum | | 985.2 | 23.645 |
| Oltingue | FR>CH | Exit | 223 | 11.4 | GRTgaz | | 71.92 | Euro/MWh/day per annum | | 197.0 | 4.729 |
| Oltingue/ Rodersdorf | CH-FR-CH | E/E | 223 | 11.4 | ENI Gas International | | Auctions | | | Auction | - |
| Medelsheim | FR>DE | Entry | - | 11.3 | GRTgaz Deutschland | | 1.64 | Euro/kWh/h/day (summer/inter day) - kWh/h/year | Two tariff mechanims: daily fee or annual fee. Annual fee considered and then averaged | 187.2 | 4.493 |
| Medelsheim | DE>FR | Exit | 620 | 11.3 | GRTgaz Deutschland | | 2.04 | Euro/kWh/h/day (summer/inter day) - kWh/h/year | Two tariff mechanims: daily fee or annual fee. Annual fee considered and then averaged | 232.9 | 5.589 |
| Medelsheim | FR>DE | Entry | - | 11.3 | Open Grid Europe | | 0.00503 | Euro/(kWh/h)/day | | 209.6 | 5.030 |
| Medelsheim | DE>FR | Exit | 117.7 | 11.3 | Open Grid Europe | | 0.00727 | Euro/(kWh/h)/day | | 302.9 | 7.270 |
| Obergailbach | DE>FR | Entry | 737.7 | 11.3 | GRTgaz | | 103.7 | Euro/MWh/day per annum | | 284.1 | 6.819 |
| Obergailbach | FR>DE | Exit | - | 11.3 | GRTgaz | | 20.614 | Euro/MWh/day per annum | | 56.5 | 1.355 |
| Gorizia | SI>IT | Entry | 27.9 | 11.2 | SNAM Rete Gas | 0.0030 | 0.7544 | Euro/Sm³ - euro/Sm³/day per annum | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 452.4 | 10.858 |
| Gorizia | IT>SI | Exit | - | 11.2 | SNAM Rete Gas | 0.0030 | 0.9381 | Euro/Sm³ - euro/Sm³/day per annum | A 60% discount is currently applied to commodity charges for gas flowing through the Italian national network if regional distribution networks are by-passed. | 497.3 | 11.936 |
| Cersak/Gorizia | SI>IT | Exit | 27.9 | 11.2 | Plinovodi Slovenia | - | - | Euro/Sm³/day/year | P2P values obtained from tariffs simulation with web tool. Flow of 10000 m³/day/year (offtake 2000000 Sm³) = 68805 euro year (except for billing and metering fees) . Single IP tariff = P2P tariff /2 | 841.5 | 20.197 |
| Bocholtz | DE>NL | Entry | - | 11.5 | GTS | | 0.933 | Euro/kWh/hour/year | | 106.5 | 2.556 |
| Bocholtz | NL> DE | Exit | 450.6 | 11.5 | GTS | | 1.435 | Euro/kWh/hour/year | | 163.8 | 3.932 |
| Bocholtz | NL>DE | Entry | 67.3 | 11.5 | Open Grid Europe | | 0.0051 | Euro/(kWh/h)/day | | 212.5 | 5.100 |
| Bocholtz | DE>NL | Exit | - | 11.5 | Open Grid Europe | | 0.00727 | Euro/(kWh/h)/day | | 302.9 | 7.270 |
| Bocholtz | NL>DE | Exit | 370.9 | 11.5 | Fluxys TENP | | Auction | | | Auction | - |
| Bocholtz Vetschau | NL>DE | Entry | 12.4 | 11.5 | Thyssengas | | 2.19 | Euro/(kWh/h)/year | | 250.0 | 6.000 |
| Oude Statenzijl | NL>DE | Entry | 36.7 | 11.5 | Gascade | | 2.5 | Euro/(kWh/h)/year | | 285.4 | 6.849 |
| Oude Statenzijl | DE>NL | Exit | 96 | 11.5 | Gascade | | 2.36 | Euro/(kWh/h)/year | | 269.4 | 6.466 |
| Oude Statenzijl | NL>DE | Entry | 71.5 | 12.2 | Open Grid Europe | | 0.00665 | Euro/(kWh/h)/day | | 277.1 | 6.650 |
| Oude Statenzijl | DE>NL | Exit | 242.9 | 12.2 | Open Grid Europe | | 0.00556 | Euro/(kWh/h)/day | | 231.7 | 5.560 |
| Oude Statenzijl | NL>DE | Entry | 71.1 | 11.9 | Gasunie | | 0.595 | Euro/(kWh/h)/day | Tariffs refer to H-Gas (high calorific gas) and not to L-Gas (low calorific gas) | 247.9 | 5.950 |
| Oude Statenzijl | DE>NL | Exit | 27.1 | 11.9 | Gasunie | | 0.7825 | Euro/(kWh/h)/day | Tariffs refer to H-Gas (high calorific gas) and not to L-Gas (low calorific gas) | 326.0 | 7.825 |
| Oude Statenzijl | DE>NL | Entry | 366 | 11.8 | GTS | | 0.934 | Euro/kWh/hour/year | | 106.6 | 2.559 |
| Oude Statenzijl | NL>DE | Exit | 179.3 | 11.8 | GTS | | 0.736 | Euro/kWh/hour/year | | 84.0 | 2.016 |

| Interconnection Point Description | | | | | Total IP utilisation charges from TSO websites' data | | | | | Total IP charge in harmonised units | Cost simulation for a certain consumption profile |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IP Name | Border | Direction | Technical physical capacity in GWh/day (July 2012) | Assumed Gross Calorific Value for conversion in kWh/Sm³ | TSO/ISO | Commodity related charges (in TSO charging units) | Capacity related charges (in TSO charging units) | TSO charging units | Comments on tariff components/structure | Total IP utilisation charge in euro/GWh/day | Cost in euro of flowing 1 (MWh/h)/day through the IP |
| Moffat | UK>IE | Exit | 342.4 | 11.6 | NGG | 0.0242 | 0.001 | (Commodity exit fees) + Capacity fees. units: GB pence/kWh/day | | Administered price / Short term capacity auctions | - |
| Moffat | UK>IE | Entry | 342.4 | 11.6 | GASLINK IE | 0.0820 | 189.884 | per MWh / + euro/MWh/year fixed | | 103.7 | 2.488 |
| BBL | NL-UK | E/E | 453.6 | 12.2 | BBL | | | | In BBL exit is possible as a virtual interruptible product with 0 capacity reserve price and commodity charges (0.0242) | Auctions for reverse capacity | - |
| Julianadorp | NL>UK | Exit | 453.6 | 12.2 | GTS | | 1.172 | Euro/kWh/hour/year | | 133.8 | 3.211 |
| Julianadorp | UK>NL | Entry | - | 12.2 | GTS | | 1.649 | Euro/kWh/hour/year | | 188.2 | 4.518 |
| Bacton | NL>UK | E/E | 449 | 12.2 | NG | 0.0499 | 0.0098 | GB pence/kWh/day | The figures show entry prices. Auctions start above a reserve price of 0.0098 GB pence/kWh/day. The commodity charge refers to SO plus TO services. For exit, capacity is priced at an administered level just above zero. | Auction | - |
| Interconnector | UK>BE | Exit | 631.7 | 11.6 | Interconnector | | | | | N/A | - |
| Interconnector | BE>UK | Entry | 805.4 | 11.6 | Interconnector | | | | | N/A | - |
| Zeebrugge IZT | UK>BE | Entry | 631.7 | 11.3 | Fluxys | 0.08% | 8.79 | Euro/Sm³/h/year | | 88.8 | 2.131 |
| Zeebrugge IZT | BE>UK | Exit | 805.4 | 11.3 | Fluxys | 0.08% | 34.86 | Euro/Sm³/h/year | | 352.2 | 8.452 |
| Bacton | BE-UK | E/E | 631.7/805.4 | 11.6 | NG | 0.0242 | 0.0001 | (Commodity e/e fees) + Capacity fees. units: GB pence/kWh/day | The figures show entry prices. Auctions start above a reserve price of 0.0098 GB pence/kWh/day. The commodity charge refers to SO plus TO services. For exit, capacity is priced at an administered level just above zero. | Auction | - |
| Larrau | ES>FR | Entry | 30/50 | 11.6 | TIGF | | 56.34 / 40.24 | Euro MWh/day/year - different values for summer /winter season | Different values for summer/winter season - average value considered. | 264.6 | 6.350 |
| Larrau | FR>ES | Exit | 100 | 11.6 | TIGF | | 172.08 / 122.9 | Euro MWh/day/year - different values for summer /winter season | Different values for summer/winter season - average value considered. | 808.2 | 19.396 |
| Larrau | FR>ES | Entry | 100 | 11.6 | Enagas | | 10.499 | Euro/(MWh/day)/month | | 350.0 | 8.399 |
| Larrau | ES>FR | Exit | 30/50 | 11.6 | Enagas | 0.0595 | 2.7736 | Euro cent/kWh - euro cent kWh/day/month | | 1063.7 | 25.528 |

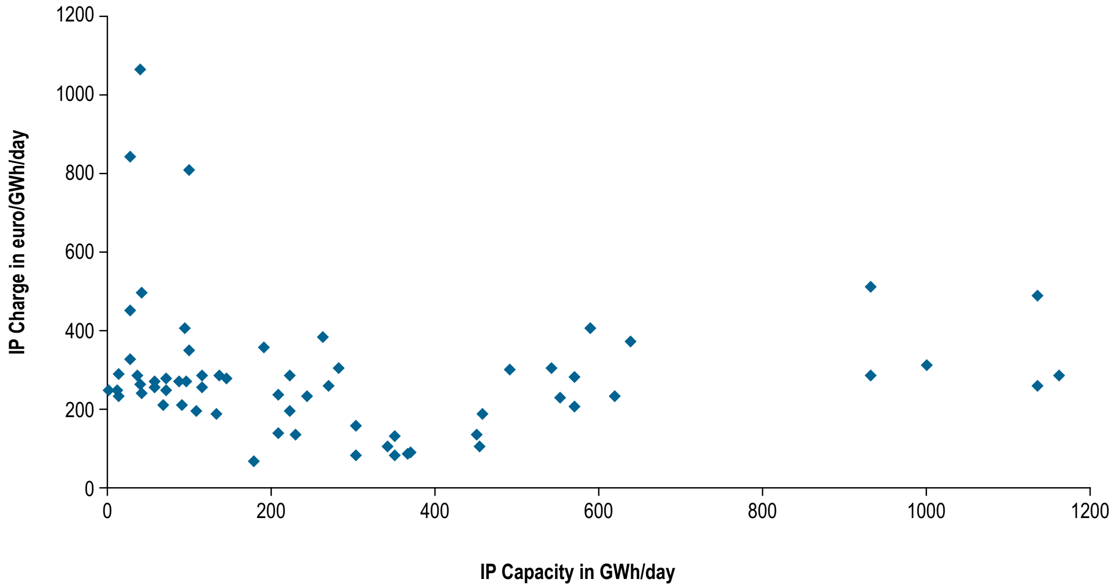
*Source: ENTSOG and Agency/CEER (2012)*

*Note: P2P refers to point to point tariffs. Sm³ means "standard cubic metres". TGPS (Transit Gas Pipeline System) is the Polish section of the Jamal international transit pipeline. * Overall cumulative capacity for both TSOs, Gascade and Bayernets.*

*(378)* A simple statistical analysis of IP cross-border charges illustrates that there is a very weak correlation between the total capacity offered at an IP and the unit capacity charges levied by TSOs on that IP. Many factors can affect final border tariffs, and tariffs charged by monopolists are in any case only rough proxies for underlying costs.

*(379)* Figure 57 shows the charges applied by each TSO across borders. Capacity is offered by each TSO in each direction. Particularly at those points with more than one active TSO, capacity and tariffs vary by TSO, even at the same border. Those IPs organising auctions to allocate capacity do not normally publish summary averages of realised auction prices; for this reason, they are not included. Significant differences can be detected for different entry-exit TSOs operating at the same IP.

**Figure 57: Natural gas IP total access charges versus IP capacity – 2011**




*Source: Agency/CEER elaboration based on TSO and ENTSOG information (2012)*

*(380)* Those country pairs with precise directional preferences openly discriminate between entry and exit tariffs (for instance, borders between Italy and Austria/Switzerland). Interruptible day-ahead capacity is (or will be) auctioned between some of these countries (for instance, in 2012 between Austria and Italy), but it was not in 2011. Countries which are partially landlocked and depend on monopolistic sources in terms of both commodity and capacity face, somewhat punitive charges (for instance, gas entry into Slovenia from Austria and, virtually, backhaul from Italy). There are big differences in entry-exit charges at multi-point borders, depending on the TSO counterparty (this is observed, for instance, at Dutch-German flanges, but also at Dutch-Belgian and Belgian-French borders).

*(381)* Although German cross-border points which are managed by lower-tariff TSOs are exceptions[192], entry from Central and Eastern MS (for example, the Czech Republic) into Germany is sometimes expensive.

*(382)* Other Central European borders also seem to be expensive (such as those between Germany and Poland) and tend to lack backhaul capacity, even if only virtual (the situation improved in 2012).

*(383)* Some Swiss borders seem, at least on a firm basis, to be much more expensive than others (for instance, French versus German borders to Switzerland). Interruptible capacity to and from France tends to be priced at much lower levels than at other borders, but firm capacity seem to be expensive.

*(384)* The above-mentioned GTS consultancy study found interesting results when looking at entry-exit points at borders within domestic systems and also within countries featuring smaller networks and postage-stamp tariffs (for instance, expensive connections in and out of Spain; this is also confirmed by the FSR study). However, it is worth noting that, as part of the Gas Regional Initiative, Spain and Portugal started a project in early 2012 to harmonise their respective cross-border access tariffs. This effort entails close cooperation between regulators, TSOs and governments in the two countries.

*(385)* The Agency and CEER encourage ENTSOG to improve its knowledge of cross-country transportation tariffs and work together with individual TSOs to undertake price and, arguably, underlying cost benchmarking in the near future.

*(386)* More generally, the Agency and CEER recommend that ENTSOG improve its Transparency Platform with respect to interconnection point capacity and price data, including the availability of storable time series capacity and bookings data. Data on capacity (bookings, prices, nominations, contracted values) should not only be pre-projected into the future, but also stored in the Platform (not erased) for historical statistical analysis. The Platform should contain up-to-date and unit-consistent, fully and readily comparable information on cross-border transportation tariffs and general terms and conditions of international gas transmission at each and every IP, including new MS, in order to make tariff evaluation possible to the maximum practical extent. Data formats should be friendly for download by anyone from the general public – including independent researchers – not only IT or industry specialists. Tariff methodologies should be published by all TSOs, as well as by ENTSOG as a data aggregator and verifier. The Transparency Platform should become a compulsory, not only a voluntary exercise. Data and transparency improvements should take place by 1 October 2013 at the very latest, in accordance with EU legislation on data transparency at the transmission level.

192 These are mainly vis-à-vis France and Switzerland.

## 6.6 Conclusions and recommendations

*Wholesale markets*

*(387)* Hub price correlation remained strong among North Western (including GB) European gas hubs in 2011, with liquidity and churn rates improving quickly at those hubs, although liquidity and churn were much lower in continental Europe away from the Atlantic and North Sea coasts.

*(388)* In any case, price correlation does not mean price convergence, and spot price differences (premiums) persist across the continent. Absolute price differences depend on a number of factors, such as liquidity, system characteristics and the role of hubs in the national gas market; for instance, the role played, inter alia, by some continental hubs essentially as balancing tools.

*(389)* There are regions, especially in some new MS, where price transparency is still a problem and where, in general, long-term oil indexed contracts persist, monopoly suppliers are difficult to deal with and capacity issues (contractual congestion and/or lack of access to cross-border transmission capacity) limit the free and efficient flow of gas throughout MS and across them, thus hampering European market integration and, possibly, security of supply.

*(390)* Spark/dark spreads indicate that gas-fired power generation might eventually be less profitable than coal-fired generation, should the recently observed spread values persist, and should carbon allowance prices remain at the levels prevailing over the last couple of years. However, EU $CO_2$ regulations relating to the allocation of emission rights may reverse the gas versus coal profitability comparison from 2013. However, coal-fired plants – even if sometimes cheaper – may not be perfect substitutes for gas-fired plants, because they do not react as quickly when called on to generate and balance intermittent power sources.

*(391)* The majority of continental European wholesale contracts remain oil-linked, with a recent downward tendency mainly driven by the harshness of the recession rather than by increasing market efficiency.

*(392)* Producers, albeit to different extents, prefer to keep the oil link in their contracts in the interest of revenue certainty. The specialist press reported long-term wholesale contract renegotiations in 2011, continuing in 2012, spurred by the current economic climate and by the rise in gas-on-gas competition (mainly through LNG) driving down spot prices at Western hubs and counteracting wholesale-retail margin squeezes.

*(393)* However, non-EU gas producers and shippers still (re)negotiate separate deals with individual EU countries, and there is some evidence of a “divide and rule” approach (price discrimination). The European Commission began proceedings to open a competition investigation against Gazprom on 4 September 2012.

*Transits and capacity*

*(394)* Gas should transit freely throughout the EU, according to rules which must not discriminate between domestic transmission and international shipping. Nevertheless, a significant number of MS still allow transit contracts which are not in accordance with domestic transmission regulation and the provisions contained in the 3rd Package. Notwithstanding long-haul transits, gas "islands" in Europe still persist where 3rd Package provisions are not fully applied.

*(395)* Contractual capacity congestion is still an issue, especially in Central and Eastern Europe, where bookings are long-term and the land locked nature of those regions, in addition to the lack of liquid hubs and the absence of secondary capacity markets, prevents direct gas-on-gas competition (LNG). Physical capacity congestion remains an issue at some critical border points, with capacity utilisation levels increasing, and possibly saturating, during crucial winter months.

*(396)* In order to improve the level of compliance by TSOs on network access transparency, NRAs and TSOs should cooperate on identifying areas where 3rd Package requirements are still not met and in taking consequential action. In particular, NRAs should identify the data available to TSOs, on a within-day basis and close to real time, whose publication may be necessary in the interest of system balancing and other operations.

*Cross-border tariffs*

*(397)* Network charges at cross-border points differ greatly and are difficult to compare directly given the lack of tariff homogenisation and regulatory data on underlying cost drivers (it is more robust to benchmark costs than prices) and control factors (for instance, structural or regional issues).

*(398)* Entry-exit tariffs and zone mergers might generate challenging issues in future, in terms of how best to provide (where needed) locational signals at crucial connection points for instance, given the potential trade-off between capacity market liquidity and the granularity loss in terms of locational signals if entry-exit zones, within and/or across countries, are merged.

# 7 Network access in gas

## 7.1 Introduction

(399) The monitoring of network access is a new aspect of the Agency's activities. In this first annual market monitoring report, the Agency and CEER concentrate on a narrative account of the status quo on cross-border gas transit contracts, country experiences with network access (connection) monitoring and the connection of priority gas sources (biogas). Country case studies on Germany and Italy have been included in this section.

## 7.2 Gas transit contracts

(400) In 2012, the Agency reviewed (by means of a survey) the access regime and regulatory treatment of the high-pressure transmission lines used for the transfer of natural gas within the EU for the purpose of delivery to another country ("transits") in order to provide an assessment of the status quo and to set out the current legal status of the access to transit capacity, as well as the validity of the pre-liberalisation capacity contracts.

(401) One of the main findings of the inquiry is lack of information and transparency. The information received by the Agency, although moderately accurate, is in some cases abstract and incomplete. The inquiry shows that there is still no clear information as to the different access regimes for transportation and transit, as well as the differentiated treatment of the primary allocation of capacity.

(402) In some cases, it is unclear whether the capacity rights and access rules offered by foreign and domestic pipeline operators are subject to the same rules; whereas there is strong evidence that historical capacity holders still obtain preferential access to transit capacity. Furthermore, the investigation indicates that the terms and conditions of the transit contracts are still usually not publicly available, often remain negotiated individually, and are not always known to the regulator. Overall, the assessment shows that compliance with the legal requirements of the 3rd Package (as well as the general principles of EU competition law) remains problematic in some parts of the EU.

(403) Detailed results of the inquiry per country are shown in the Annex 3.3.1 on gas transit contracts in existence. The inquiry points out that, according to the information obtained by the Agency, there are still transit contracts in ten MS. In most of these cases, there is evidence that different treatment is given to gas in transit compared to gas for national consumption. Where available, the actions needed or expected to be taken by regulatory authorities, MS, or other parties, are indicated. A visual map of the status quo is included in the Annex.

(404) Cooperation with regulators on the monitoring of remaining transit contracts will continue beyond the mandate of the Madrid Forum.

## 7.3 Country case studies on gas network access conditions and monitoring

### Germany

(405) The German gas market, together with the United Kingdom, is the largest EU gas market by consumption (around 96 billion cubic metres per annum) and the fifth in the world. It is characterised by a complex, highly meshed network featuring 14 TSOs and more than 700 DSOs. A feature of the German and Dutch gas markets is the co-existence of high and low calorific gas, which is amenable to (virtual) conversion in both directions.

(406) Having recently reduced its market areas to two (mixed quality), Germany now has an area managed by Gaspool and another managed by NetConnect Germany (NCG).

(407) Germany is a major transit country to and from the Netherlands, Switzerland, France, Poland, the Czech Republic, Austria and Belgium. It is characterised by substantial underground storage facilities (flexible gas) but has no fully integrated nationwide high-pressure network at a constant quality, and its storage sites are unevenly distributed throughout its territory.

(408) The German Energy Industry Act (EnWG)[193], amended in 2012, transposed the 3rd Package into German legislation. A number of ordinances (statutory instruments, subordinate to the EnWG) make up the necessary secondary legislation:

- The Gas Network Access Ordinance (Gas NZV);
- The Gas Network Charges Ordinance (Gas NEV);
- The Incentive Regulation Ordinance (ARegV);
- The Low Pressure Connection Ordinance (NDAV); and
- The Metering Framework Conditions Ordinance (MessZV).

The BundesNetzAgentur (BNetzA) is authorised by the above instruments to adopt “determinations”.

(409) The general framework for third-party access to gas networks in Germany, according to the EnWG, works through a “two-contract” model whereby third-party access is granted without the definition of a transaction-dependent transport route, i.e. there is a separation of physical and contractual flows.

(410) The model follows an entry-exit framework which is in accordance with 3rd Package prescriptions. As a result, the shipper must conclude an “entry contract” for the booking of entry capacity with the TSO and an “exit contract” with the (same or another) TSO/DSO for booking exit capacity. Entry and exit capacity products are not currently bundled.

(411) In each of the two market areas, there is only one trading point (a virtual trading point), which imposes an obligation on all relevant TSOs to cooperate and ensures the standardisation of contracts to enable market liquidity.

193 EnWG, of 7 July 2005, BGBI. I 2005, 1970, latest amendment on 16 January 2012;
see: http://www.gesetze-im-internet.de/enwg_2005/index.html#BJNR197010005BJNE000108360

*(412)* The obligation for grid operators to connect producers and shippers of gas is set out in Articles 17 and 19 of the EnWG, which state that the technical and commercial conditions of connection must be reasonable, non-discriminatory and transparent. Connected customers include final consumers, gas-fired power generation, storage and other network operators or pipelines (either at the same level or downstream). The network operator must publish the minimum technical requirements for the connection of LNG, distributed generation (including CHP fuelled by biogas), storage, other TSOs/ DSOs and direct lines. There are minimum requirements to ensure system interoperability. However, to date no standard connection contract has been established via a determination by either BNetzA or a multi-operator agreement. Connection may only be refused where it is "technically impossible" or "economically unreasonable".

*(413)* Cost allocation issues in gas connections are much less developed than in electricity. Questions remain on whether network operation costs arising from new connections should be recovered through the network charges paid by the connected customer, or socialised. When connections are at medium to low pressure level (for instance, in most biogas installation cases), costs should in principle be borne by the DSO, unless the construction and/or any changes to the connection are initiated by the connecting customer.

*(414)* Connection tariffs follow the average cost principle, based on benchmarks taken from comparable cases (if applicable). There are capital contributions available to facilitate building connections ("Baukostenzuschüsse"), but connection charges are only partially deep. At present, the cost recovery level for the construction or reinforcement of local distribution systems to accommodate a new connection is limited to 50% of costs. At a transmission system level, socialisation is also partial via network charges. The rules for connection are set out in Articles 38 and 39 of the Gas Network Access Ordinance. They can be summarised as follows:

- Exit or entry capacity may be reserved as far as technically possible;
- Reservation fee for gas power plants: 0.50 euro/kWh/h per year;
- Reservation fee for other uses: 0.40 euro/kWh/h per year; and
- Where existing technical capacity is not sufficient for reservation, the customer requesting a connection is entitled to capacity extension, unless such capacity extension is "economically unreasonable" (there is a presumption of economic reasonability, where capacity is booked at least 18 months before the completion of the plant or installation to be connected).

*(415)* For the time being, no coordination is envisaged between the above rules for connection and the forthcoming national ten-year network development plan.

*(416)* Special rules for the connection of biogas plants are set out in Article 34 of the Gas Network Access Ordinance. Firstly, biogas enjoys priority over natural gas. Secondly, a refusal to connect biogas is justified only where the grid operator can demonstrate that the connection would be technically and physically impossible, or economically unreasonable (the rules for such an economic test are, however, not explicitly defined). Network operators must take capacity-increasing measures to ensure the technical and physical ability of biogas absorption (for instance, reverse feed-in). The network operator must ensure 98% availability of the connection.

*(417)* There is an open policy question as to whether socio-economically favourable options for connection should be considered in any cost-benefit or market testing (open season) analysis for the connection of biogas installations. As stated above, such rules or thresholds are not defined in the Ordinance.

*(418)* The cost allocation structure for the grid connection of biogas is defined by Article 33 (1) of the Ordinance from the connecting customer's point of view. 25% of connecting cost is borne by the user up to a 10km length. For any feeder length higher than 10km, the connecting party must pay for all connection costs. This effectively incentivises local connection at a distribution (lower pressure) level, other things being equal. Biogas (however connection-prioritised) does not receive feed-in tariffs.

*(419)* The ordinance also defines minimum standards (which are monitored ex post) for gas quality and safety in the case of biogas, as well as the maintenance and operational constraints of the installation. The grid operator must ensure availability, "interruptibility" if requested, and measurement activities. A standard biogas grid connection contract is set out in inter-operator "Cooperation Agreements". The Contract of Cooperation of all TSOs and DSOs includes, from January 2011, a standardised contract for biogas covering grid connection and use of system, including feed-in contracts (but no feed-in tariffs) and yearly balancing contracts. No obligation is imposed upon the network operator to use biogas under a guaranteed rate of return, a special ad-hoc WACC, or subsidised price: biogas must be sold on the wholesale market at going rates.

*(420)* According to the standard access contract, the party seeking to feed in biogas (the "connectee") applies for a network connection from the network operator of its preferred grid. The network operator must identify a network connection point on either its own or a neighbouring grid, in concert with the other network operators (unfortunately, no practical choice criteria are mentioned in the Gas Ordinance). Because of the cost allocation regime for connection and use of system, the applying party has an obvious interest in a short connection in order to minimise its own portion of the connection costs. The network operator prefers the network connection point which is the most convenient for its own network and *de facto* determines the network connection point without necessarily optimising the connection from the biogas installation's viewpoint. As far as needed, network operators have to work together on the "acceptance test" for network connection, although legislation provides no clear rule as to how network operators should cooperate in this respect. In particular, it is unclear whether the network operator responsible for the final connection decision can access and handle the (projected connection cost) information provided by the neighbouring network operators.

*(421)* Since no cost benchmarking is envisaged, in practice any extra costs due to technical inefficiency will not be allocated to all grid users within a market area. Instead, they will be covered by the network operator who eventually proceeds with the connection (the network operator will socialise them on behalf of all other operators). This might create an investment hold-up (negative externality) situation, whereby connections could be under-provided.

*(422)* When signing the connection contract, the network operator must commit to a plan for the realisation of the connection. In a case of connection refusal, the network operator responsible must justify any reasons for denial. If the network operator fails to comply with the committed timeline due to its own error, it will eventually have to pay for the first 1000 metres of pipe and for the physical connection point to the grid.

*(423)* Actual biogas feed-in for Germany, according to BundesNetzAgentur[194], in 2011 was about 0.27bn standard m³/year, about 4.5% of the governmental policy target for 2020 and 2.7% of the policy target for 2030. For 2011, the feed-in is estimated at 0.44bn standard m³/year, equal to 7.3% of the government's policy goal for 2020.

*(424)* The usual capacity of biogas plants in Germany is around 150 – 750 standard m³/h at 8,000 hours of use/year, equalling 1.2m – 6m standard m³/year of total notional production. According to this observed standard capacity of existing installations, a total of more than 1,500 average-sized biogas processing plants should be built and operational by 2030 in order to reach the government goal.

*(425)* Since April 2008, special regulations have been introduced to cover, inter alia, biogas connections: the Regulations on Access to Gas Supply Networks (GasNZV) and the Regulations on Gas Network Tariffs (GasNEV), amended in September 2010.[195] As mentioned above, these guarantee priority of grid connection to biogas plants (Article 33); in principle, they admit no refusal due to a lack of capacity in the grid, requiring the network operator to take all economically reasonable measures to increase the existing capacity of the grid (Article 34). Biogas plants are allowed to balance themselves no more frequently than on a yearly basis (Article 35) and the connection costs of an approved biogas installation are socialised across all grid users within a gas market area (NetConnect Germany or Gaspool).

### Italy

*(426)* AEEG, the Italian energy regulator, has a predefined set of access rules for new gas connections, including biogas installations. Such rules cover both physical and commercial access.

*(427)* Regarding physical access, it is a TSO's obligation (Italian Republic Decree 164/2000, Article 8.2) to connect users who require access, provided enough capacity is available and the work needed to carry out the connection is technically and economically feasible, according to criteria set by the regulatory authority.

*(428)* For each location of a new connection (entry or exit), the TSO must know:

- The annual, daily and hourly planned flow volumes; and
- The gas composition (in case of a nationwide high-pressure delivery point).

194 See:
http://www.bundesnetzagentur.de/cln_1932/SharedDocs/Pressemitteilungen/EN/2012/120611BiogasMonitoringReport.html?nn=48242

195 GasNZV: Gasnetzzugangsverordnung - GasNZV, of 03.09.2010, BGBl. I 2010, 1261, latest amendment on 30.04.2012;
see: http://www.gesetze-im-internet.de/gasnzv_2010/

GasNEV: Gasnetzentgeltverordnung - GasNEV, of 25.07.2005, BGBl. I 2005, 2197, latest amendment on 03.09.2010;
see: http://www.gesetze-im-internet.de/gasnev/

*(429)* The economic aspects of a new connection are currently dealt with by the TSO. The TSO lays out a connection project, estimates the necessary investment and timing of the project, carries out the economic (cost, business planning) analysis and eventually makes a standard offer. If network access (connection) tariffs fail to cover the full cost of the project, the TSO will be entitled to cover the difference through a special surcharge.

*(430)* Measurement and recording issues are the responsibility of the connecting party, according to specifications included in the national network code (also covering data transmission formats). Once the planning and measurement phases are complete, the construction phase begins. The TSO communicates with the customer and publishes the relevant information on its website, indicating the date starting from which the new point is available for capacity assignment.

*(431)* Regarding transmission (high pressure) network connections, the regulator sets minimum standards. The minimum percentage of connection offers to be communicated in total by the TSO within the maximum period of 60 days, after the signature of the memorandum for the definition of the entry or exit point, is 90%. At the distribution level, the time window for budgeting simple works is 15 working days, rising to 40 working days for complex works.

*(432)* Regarding exempted pieces of infrastructure (LNG terminals, interconnectors, storage), commercial access is granted before physical access, but because of the non-standard nature of many of these initiatives, it is difficult to identify any standard ex ante indicators for monitoring purposes in such circumstances, and the regulator has not attempted to do so for the time being. An “open season” procedure (market interest testing) is put in place, but it is not subject to any specific form of monitoring.

### 7.4 Conclusions and recommendations

*(433)* There is no uniformly shared and standardised regulatory dataset on natural gas network access at EU level (for instance, in terms of statistics about times to connect, disconnection terms and curtailment counter-measures). Such a dataset is needed in the future if gas network access monitoring is to be taken seriously at a micro level. It might be argued that aspects of network access monitoring are, however, national rather than cross-border in nature, so a finer definition of European gas network access monitoring is still needed from the legislator.

*(434)* Biogas connections are treated in very different ways across Europe and, although biogas is generally prioritised, it must still be sold at market rates in most cases (no “feed-in” tariffs). This will probably prevent any sudden take-off of biogas installations throughout the EU, marking a stark difference in comparison with what has been observed in the electricity sector with respect to RES installations. Other reasons for this difference are mainly related to quality standards and the cost of quality homogenisation, with relevant national differences playing a role. As a result, biogas still accounts for a very limited share of total injected gas in the EU as a whole.

*(435)* It is important to take into account the nature of biogas in the future as a renewable gas source, with all due caveats in terms of quality and safety and subject to cost-benefit assessment, similarly to what has been observed in electricity with respect to the promotion of renewable sources for power generation.

# Part III: Compliance monitoring, consumer protection and empowerment

## 8 Consumer empowerment and protection issues

### 8.1 Introduction

(436) The electricity and gas market have been open to all consumers in the European Union since 1 July 2007 (apart from derogations granted to some MS). The introduction of choice for households as well as small businesses raised a range of problems that did not occur to the same extent in the market for large-scale consumers[196]. In the market for small-scale consumers[197], the termination of the traditional monopolistic structures led to problems on both the demand and supply sides. On the demand side, small consumers in particular were completely unaware of their decision rights and did not have the information or understanding of the process necessary to choose their electricity or gas supplier. On the supply side, the way certain measures were imposed on suppliers were not reasonable in a competitive environment. The transition from the old monopolistic to a competitive retail market created new challenges for legislative bodies, market participants, consumer bodies and regulators.

(437) One of the main prerequisites of fair competition is a level playing field for all market participants. Therefore, consumer protection rules including information requirements have to be established and enforced, and public service obligations (formerly imposed on monopoly companies) have to be rearranged and secured in a non-distorting way. The 3rd Package supports these principles through its provisions on improving the operation of retail markets, as well as on consumer protection and empowerment measures.

(438) The first section of this chapter delivers information on where and to what extent consumer protection and empowerment issues are considered and developed. The second section focuses on compliance with 3rd Package provisions; it examines the bundle of provisions which should help all consumers to make informed and rational supplier decisions in a safe market environment with well-defined and efficient market processes, while separately considering measures that protect consumers in special need of support. The third section of the chapter concentrates on consumer satisfaction and presents the results of complaint data analyses available to regulators in 2011. Whenever appropriate, recommendations are made on how to improve consumer satisfaction in the future.

196 Big industrial consumers with high energy demand usually employ their own experts to manage their energy purchases.

197 In this chapter, “small-scale consumers” or “small consumers” refer to household and small business customers.

## 8.2 Background

*(439)* Article 3 and Annex I of Directives 2009/72/EC and 2009/73/EC contain a set of provisions concerning consumer protection and consumer empowerment for all customers in the single energy market. The key issues of these provisions are as follows: the period for supplier switching, the obligation to provide all customers with certain information and the frequency with which this has to be done, the handling of final bills, the creation of single points of contact for customers, alternative dispute resolution mechanisms, the concept of vulnerable customers and suppliers of last resort.

*(440)* Additionally, in 2007, the European Commission (EC) established the Citizens' Energy Forum in London as a new regulatory platform. Its aim is to implement competitive, energy efficient and fair retail markets. The last Forum, in 2011, emphasised explicitly that consumers should be at the centre of EU energy policy and that closer involvement of consumer associations is needed.

*(441)* It is clear that many forward-looking steps are needed to strengthen the consumers' position and put consumer interests at the heart of the development of the single energy market. In June 2012, CEER held a conference as part of its process to build a vision of the future for Europe's energy consumers. The interactive event, involving consumers, industry and institutional representatives was designed to generate feedback on the key principles that CEER had identified as important for the present and future up to 2020. This feedback was used to shape the final vision, which was presented to the 2012 Citizens' Energy (London) Forum as a joint statement with BEUC, the European consumers association. The four principles in the 2020 vision are reliability, affordability, simplicity, protection and empowerment. These constitute a common reference for understanding consumer needs and ensuring that markets are developed in a way that delivers for consumers.

## 8.3 Compliance monitoring

*(442)* In spring 2012, CEER launched a review process among its members to gather information on the implementation of selected provisions of Article 3 and Annex I of Directives 2009/72/EC and 2009/73/EC across MS. The resulting Status Review[198] attempts to capture a first snapshot of how the customer provisions of the 3rd Package were implemented on 1 January 2012, giving an insight into how the provisions were interpreted across MS and what individual arrangements have been made to implement such provisions[199]. Hence, the Status Review is not a legal review of compliance with the 3rd Package, but rather reflects the status quo on a given date with respect to the handling of specific customer provisions.

*(443)* The following section evaluates the implementation of these provisions. For this purpose, they are grouped into two parts according to their content and intention.

198 "CEER Status Review of Customer and Retail Market Provisions from the 3rd Package as of 1 January 2012"; CEER, C12-CEM-55-04, November 2012.

199 The CEER questionnaire was targeted at all EU/EEA NRAs, including the Norwegian NRA as a member of CEER. Responses were received from all NRAs, except for the Maltese and Cypriot NRAs.

(444) "Consumer empowerment" summarises measures concerning market processes and information requirements which aim to make consumers feel safe, free and well-informed to choose and switch supplier, and guarantee prompt access to assistance in case of problems in the market. This first part considers the implementation of the switching process and complaint handling provisions as well as information requirements from the 3rd Package.

(445) "Consumer protection" focuses on the development of measures to give support to those customers who need particular protection, for whatever reason. This part focuses on the implementation of supply of last resort and on the concept of vulnerable customers.

### 8.3.1 Consumer empowerment

(446) A rapid switching process is vital to well-functioning energy retail markets. The 3rd Package contains a provision requiring operators to complete a supply switch within three weeks.[200] The majority of countries have legally implemented a maximum period for supplier switching. In most cases, it is a three-week period, in accordance with the 3rd Package.

(447) Of those countries complying with the provisions for electricity (23 out of 26 respondents), a small group set a two-week maximum switching period. Of those countries complying with the gas stipulations (21 out of 26 respondents), most (15 out of 21) have a three-week period. Only a few countries have no provisions at all.

(448) An impressive number of MS (19 out of 26) stated that, for electricity, they comply with the requirements of the 3rd Package not only from a legal point of view, but also in practice. For gas, the practical picture looks less optimistic. Only 12 countries comply with the 3-week maximum period, while five do not. The main reasons for implementation delays are of a technical or legal nature. Measures to reduce long delays are only foreseen in some MS.[201]

(449) Annex I of Directives 2009/72/EC and 2009/73/EC states that customers are to receive a final closure account no later than six weeks after the change of supplier has taken place. A majority of regulatory authorities (18 out of 26 for electricity and gas) stated that a maximum period for the receipt of a final closure account is already in place or currently about to be implemented. Approximately 50 % of MS (14 for gas and 15 for electricity out of 27) meet the six-week requirement of the 3rd Package.

200 Furthermore, CEER strongly emphasises the need to execute a switch as quickly as possible. This could be as quickly as within 24 hours and, in any case, within three weeks. In addition, a supplier switch should be possible on any day of the week. See Guidelines of Good Practice on electricity and gas retail market design, with a focus on switching and billing, CEER, Ref. C11-RMF-39-03, January 2012.

201 For electricity: Austria, Denmark, Germany, Hungary, Lithuania, Luxembourg, Slovakia, Spain and Sweden; for gas: Austria, Denmark, Germany, Great Britain, Hungary, Luxembourg, Slovakia and Sweden.

*(450)* The 3rd Package sets out provisions requiring MS to ensure that suppliers make available a certain set of information to customers in, or along with, bills and in promotional material.[202]

*(451)* Most MS (20 out of 27) confirmed that, for electricity, the information requirements in bills and promotional material are fulfilled not only in legal terms but also in practice.

*(452)* Regarding the contribution of each energy source to the overall fuel mix, nearly all MS have implemented the obligation to make available information to customers of a given supplier in a comprehensive and, at a national level, clearly comparable manner. The obligation, concerning only electricity, is also transposed practically in a large number of countries.

*(453)* According to the 3rd Package, MS must ensure that there is a single point of contact to provide consumers with all necessary information regarding their overall rights. These points of contact may be part of general consumer information services. A vast majority of MS have a single point of contact in place. The organisational arrangements under which the single point of contact operates differ; most reside within regulators or consumer organisations, although various other combinations exist. In general, single points of contact were established between 2000 and 2012 and can be funded through a wide variety of sources (e.g. public funds, state budgets, industry, EU funds).

*(454)* Under another 3rd Package provision, the Commission must establish an energy consumer checklist in cooperation with regulators and other relevant bodies.[203] Electricity suppliers and distribution system operators in cooperation with regulators should take the necessary steps to provide consumers with the checklist. The implementation of the consumer checklist is still in progress and at different stages in individual MS. Around half of the NRAs have already contributed to the process; others deem that the current information basis for customers is sufficient, and others again report that the provision of information has already been incorporated into their legislation. However, only a few MS have already started a coordination process with suppliers and DSOs.

*(455)* The 3rd Package requires MS to ensure that an independent mechanism, such as an energy ombudsman or a consumer body, is in place in order to ensure the efficient treatment of complaints and out-of-court settlements. Nearly all MS indicated that there are mechanisms for complaint handling in their countries, regardless of whether the 3rd Package has been implemented or not. The mandate and authority of the different mechanisms vary across MS. One NRA stated that the mechanism in place does not function adequately because of the high administrative costs, making it difficult for household customers to take advantage of this service.

202 CEER stresses that, as an overall principle, the supplier should be the main point of contact for the customer. See Guidelines of Good Practice on electricity and gas retail market design, with a focus on switching and billing, CEER, Ref. C11-RMF-39-03, January 2012.

203 According to Article 3 of Directives 2009/72/EC and 2009/73/EC, MS shall ensure that electricity suppliers or distribution system operators, in cooperation with the regulatory authority, take the necessary steps to provide their consumers with a copy of the energy consumer checklist and ensure that it is made publicly available. This consumer checklist provides key information that energy consumers need to know, including information on their rights and sources of assistance.

*(456)* European energy regulators have repeatedly expressed the importance of independent and transparent alternative dispute resolution (ADR) structures in order to allow customers to directly communicate their needs and concerns.[204] Results have shown that, in an overwhelming majority of member countries, a single central institution is in charge of complaint handling. In most cases, it is the energy regulatory authority, but other types of central institutions are almost as widespread. In some MS, ADR structures have existed for a fairly long time. The majority of existing ADR mechanisms is state-funded, followed by a smaller number of industry-funded mechanisms.

*(457)* The results in the Status Review have shown that it is difficult to assess whether MS comply with the 3-month period for out-of-court settlement foreseen in the 3rd Package, as the average duration of out-of-court settlements varies greatly across MS and a number of NRAs could not provide data on this subject (mostly in cases where the NRA is not the only dispute settlement authority or is not responsible at all). As a consequence, it is still unclear if customers can count on having their disputes settled within three months in a number of MS. Given that a number of MS reported on settlement periods longer than three months, it seems that the requirements stipulated in the 3rd Package have not yet been implemented across MS.

### 8.3.2 Consumer protection

*(458)* Article 3(3) of Directives 2009/72/EC and 2009/73/EC requires MS to ensure that all household customers and, where MS deem it appropriate, small enterprises, receive universal service. To ensure the provision of universal service, MS may appoint a supplier of last resort (SoLR).

*(459)* The CEER Status Review on the customer and retail market provisions of the 3rd Package reveals that the vast majority of MS have a SoLR system in place in order to guarantee universal service (23 for electricity and 21 for gas, out of 26 respondents). However, the definitions vary between MS.

*(460)* Often, SoLR mechanisms apply only under certain conditions. These comprise the failure of suppliers to meet their contractual obligations or suppliers becoming insolvent, economically restricted to vulnerable consumers or other conditions set by regulators or by law. The number of appointed SoLR varies greatly. For example, in some countries all suppliers are considered potential SoLRs. In other cases, they are appointed for a defined geographical area; in some countries, only a single SoLR is appointed.

*(461)* The consumer groups that may benefit from a SoLR mechanism are defined rather generously in some countries, with all customers being eligible. In a few other countries, protection is restricted to those with a specified annual consumption level. Still, in other MS, the SoLR mechanism applies only to household consumers, and in others it includes small businesses, vulnerable consumers or customers that conduct activities of general interest such as hospitals, nurseries etc. Sometimes, customers whose supplier has lost its license, or as mentioned above, failed to fulfil its contractual obligations, gone bankrupt or ended its activity are also covered by the SoLR.

204 CEER Position Paper on the Commission Proposal Directive on Consumer ADR, COM(2011) 793, Ref. C12-CEM-49-05, March 2012.

*(462)* The 3rd Package also contains a provision requiring MS to develop a concept of vulnerable customers which may refer to energy poverty and, inter alia, to the prohibition of disconnection of vulnerable customers from electricity at critical times[205]. As a consequence, MS were asked whether such a concept was in place in their jurisdiction. [206] The majority of countries responded that a concept of vulnerable customers existed in either their energy laws or in other pieces of legislation (or a combination of both).

*(463)* Those MS which claimed not to have a concept in place still showed that protective measures exist for vulnerable customers. The measures in place in the gas sector are slightly less strict compared with the electricity sector. Nevertheless, the same conclusions can be drawn. Whether a concept of vulnerable customers exists or not is subject to different interpretations across MS. Thus, the existence or absence of a concept of vulnerable customers does not provide an indication of how well vulnerable customers are protected in the various MS.

*(464)* The protection of vulnerable customers is approached in very different ways across MS. The picture is very diverse, given that a multitude of combinations of different measures exists in individual countries. While some countries focus more on energy sector specific measures to protect vulnerable customers, others have a focus on overall social security benefits that comprise protection efforts for vulnerable energy customers as well. Yet, in the majority of MS a combination of energy-specific and social security measures prevails.

*(465)* Only a few regulators are able to provide data on the number of vulnerable customers in their MS (e.g., Sweden was carrying out an investigation on this topic at the time of drafting this report). When figures on vulnerable customers are provided, they remain difficult to compare, as the definitions (if available) vary substantially between MS.

## 8.4 Monitoring complaints and consumer satisfaction

*(466)* The provisions of the 3rd Package give regulators more monitoring tasks with respect to the consumer's position in, and perception of, the liberalised market. In addition, the 2009 Directives on electricity and gas internal markets[207] state that NRAs shall monitor complaints made by household customers. Where a MS has assigned monitoring duties to another authority, the information resulting from such monitoring activity shall be made available to the regulatory authority as soon as possible.

*(467)* Customer complaints constitute a valuable resource for market monitoring, as they can provide evidence of market malfunctioning. Furthermore, consumer complaints are considered high level indicators that also reveal the severity of certain problems. This information is one of the main prerequisites for deciding on the further development of a market design that fosters the integration of electricity and gas retail markets. ERGEG's October 2010 Final Guidelines of Good Practice (GGP) on Electricity and Gas Retail Market Monitoring [208] include indicators reflecting customer satisfaction.

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205 Article 3, paragraph 7 Directive 2009/72/EC and Directive 2009/73/EC.

206 The ERGEG Status Review on vulnerable customers carried out in 2009 already confirms that protection strategies have traditionally incorporated social policies to a large extent. See ERGEG Status Review on the Definitions of Vulnerable Customer, Default Supplier and Supplier of Last Resort, Ref. E09-CEM-26-04.

207 Article 37(j) of Directive 2009/72/EC and 41(j) of Directive 2009/73/EC.

208 ERGEG: "Final Guidelines of Good Practice on Indicators for Retail Market Monitoring for Electricity and Gas", Ref: E10-RMF-27-03, 12 October 2010, p. 11 et seq.

*(468)* By definition, a customer complaint is an expression of dissatisfaction. In the GGP, ERGEG assumes that such expressions are addressed to providers of gas or electricity (suppliers or distributors) or any other third party, such as NRAs, the authorities or ministries for competition and consumer affairs, ombudsmen etc. Essential information could therefore be gathered by collecting categorised complaints, if possible, from DSOs, suppliers, third parties and NRAs. ERGEG suggested that data on the number of complaints be collected at least annually from DSOs, suppliers and third parties. Ideally, complaint data from all relevant sources should be available to NRAs in order to facilitate their work on the development of the market framework.

*(469)* ERGEG's proposal for a consumer complaint classification covered complaints to both DSOs and suppliers and foresaw the following 14 categories:[209]

- Connections (only DSO);
- Metering (only DSO);
- Quality of supply (only DSO);
- Unfair commercial practices;
- Contracts and sales;
- Activation;
- Disconnection due to delayed payment;
- Invoicing/billing and debt collection;
- Insufficient payment methods;
- Prices/tariffs;
- Redress;
- Provider change/switching;
- Termination of contract due to refusal to accept the supplier's new conditions; and
- Customer service.

### 8.4.1 Collection of complaint data

*(470)* The CEER Status Review on the implementation of the ERGEG GGP on Indicators for Retail Market Monitoring as of 1 January 2012[210] shows a variety of situations in terms of how and by whom complaints are collected. In the Status Review, 25 countries provided information on electricity market monitoring and 21 countries did so for gas.

*(471)* On the whole, the results show that almost all MS collect figures on customer complaints by one means or another. Complaints are monitored either by NRAs receiving complaints directly from customers or indirectly, via data from third-party bodies, suppliers and DSOs.

209 See ANNEX 3 – ERGEG complaint handling classification system in "Final Guidelines of Good Practice on Indicators for Retail Market Monitoring for Electricity and Gas", Ref: E10-RMF-27-03, ERGEG, 12 October 2010, p.27.

210 "Status Review of the implementation of the ERGEG GGP on Indicators for Retail Market Monitoring as of 1 January 2012", CEER, Ref: C12-RMF-46-03, 3 September 2012.

*(472)* Strictly speaking, the indicator as recommended in the GGP refers to the number of complaints to be obtained from DSOs, suppliers and third-party bodies. However, the findings indicate that a variety of situations is present. These might include NRAs collecting complaints from customers directly, without keeping a systematic record, or obtaining statistics only from some of the suggested actors. Thus, the report reveals that NRAs do not generally monitor the indicator in the precise way that is envisaged by the strict definition in the GGP, with the exception of Belgium[211]. Nonetheless, they collect a significant amount of additional information (for example, from customers).

*(473)* Complaints are monitored in a comprehensive manner in 8 out of 25 countries for electricity, and in 10 out of 21 countries for gas, where NRAs receive complaints from DSOs and suppliers. It was observed that several NRAs use two or three different sources to collect data on customer complaints. In those countries where the data come either from the DSOs or from suppliers and/or from third-party bodies, it was considered that the indicator is monitored partially (7 out of 25 countries for electricity, and 3 out of 21 countries for gas) by the NRA.

*(474)* Both to electricity and gas, only 3 NRAs apply the proposed ERGEG customer complaints classification to the full extent. In Belgium, this same classification is fully applied by the NRA, by the Federal Ombudsman and by the Flemish regulator, who will impose it on suppliers active in the Flemish region. As market players will use the same classification, the comparability of results will increase and monitoring will become more efficient.

*(475)* Most of the countries which answered the questionnaire use the classification partially (12 countries for electricity and 10 countries for gas). Some countries have their own complaints classification besides the ERGEG classification, so they either use both or they use only the ERGEG one partially. In Hungary, for example, the use of the ERGEG classification is partial, but the NRA and the National Consumer Protection Authority (as a third party) use the same customer complaints classification to improve monitoring.

*(476)* The source and frequency of customer complaint data collection in the electricity and gas markets vary across countries. In both cases, the most frequently used source of information for this indicator is direct customer complaints, collected on a continuous basis, which is higher than the threshold frequency recommended by ERGEG. CEER observes that several NRAs use two, or even three, different sources from which they collect data on customer complaints.

*(477)* In countries like Belgium, where the NRA works closely with the Federal Energy Ombudsman on this issue, or the Czech Republic, the collection of complaints forms part of the regulator's competences. In Italy, the NRA is responsible for evaluating complaints and requests of information submitted to it (Consumer Helpdesk) by customers and consumer associations.

211 The 3rd Package (Article 37(j) of Electricity Directive 72/2009 and Article 41(j) of Gas Directive 73/2009) only requires the monitoring authorities to collect complaint data, but does not indicate where this data should come from.

*(478)* In Great Britain, the NRA does not deal directly with customer complaints, but there is a statutory requirement for the NRA to collect complaint information from energy companies. The NRA also receives information from the relevant bodies dealing with complaints (i.e. Consumer Focus and the Energy Ombudsman).

*(479)* This is similar to countries where this indicator is monitored only partially because of provisions whereby NRAs have to collect data from other sources, as in France, or because no systematic record has been kept, as in Spain. However, following the new piece of legislation that transposes the 3rd Package into Spanish law, which entered into force on 30 March 2012, the Spanish NRA will become responsible for reporting the number of complaints.

*(480)* It is encouraging to see that some countries plan to use or maintain the ERGEG classification when a more systematic complaints collection mechanism is put in place. The Agency and CEER believe that regulators do not necessarily have to deal with consumer complaints directly and collect them in categories, but they should have detailed access to the information and to the reasons for complaints.

### 8.4.2 Consumer dissatisfaction and remedies

*(481)* The 2012 edition of the National Report questionnaire collected for the first time not only total complaint numbers available to regulators, but also more detailed information. The part of the questionnaire designed to collect this was based on the complaint classification recommended by ERGEG in its GGP for Indicators on Retail Market Monitoring.[212] NRAs were asked to indicate which complaint categories accounted for more than 5% of all complaints, specifying which issues deserved a closer look and further investigation.

*(482)* The vast majority of MS entered complaint data into the CEER database. For electricity, 28 MS provided a total, and 25 (26 for certain questions) provided detailed complaint figures. For gas, 25 made total figures available, and 21 (22 for certain questions) made detailed figures available.[213]

*(483)* In those MS where only total numbers on complaints are available, the data are often not collected by regulators themselves. For example, complaint data for Great Britain and France are collected by separate entities. In Great Britain, consumer representation is dealt with by a separate body, which is independent of the NRA. This separate body, called Consumer Focus, has a duty to investigate consumer complaints from vulnerable customers only. The Energy Ombudsman settles disputes between energy companies and consumers. In France, the Ombudsman handles and settles disputes with suppliers, and those disputes with network operators related to supply contracts. Complaints about access to the network are handled by the French Committee for Dispute Settlement and Sanctions. The NRAs in turn receive complaint data or reports from these bodies.

212 The CEER questionnaire for National Indicators included all complaint categories recommended by ERGEG, except the "termination of contract due to refusal to accept the supplier's new conditions" category. The categories are defined in ERGEG, "Final Guidelines of Good Practice on Indicators for Retail Market Monitoring for Electricity and Gas, Ref: E10-RMF-27-03, 12 October 2010.

213 Iceland, Malta and Norway did not have a gas system as of 31 August 2012.

*(484)* In general, data comparability is very limited for several reasons. Firstly, the sources (NRA's own data or also data from DSO, supplier, ombudsman, consumer bodies and/or other entities) used for complaint data are not always the same. Secondly, the definition and allocation of received complaints obviously differ between regulators: e.g. the categorisation method for complaints and enquiries is not harmonised between MS[214] and sometimes complaints are not categorised at all, but only overall figures were available.

*(485)* With this in mind, only some very general tendencies can be deducted from the collected complaint data, as outlined below.

*(486)* On the whole, complaints occur to a similar extent in both markets. The absolute number for complaints is certainly higher for electricity, but if the number of 2011 complaints for electricity and gas, respectively, is calculated in proportion to the number of electricity/gas households, the shares are quite similar.

*(487)* When it comes to the evolution of total complaints since 2008, different countries show different trends. While some countries registered decreasing numbers (e.g., the Netherlands for both electricity and gas), others have seen steady increases (e.g., Portugal and Hungary for electricity).[215] It can be observed that more complaint categories exceeded the threshold of 5% of the total number of complaints about electricity rather than gas.[216]

*(488)* A closer look at complaint categories reported for the year 2011 reveals that some problems occur with greater regularity in both markets. These problems are outlined below.

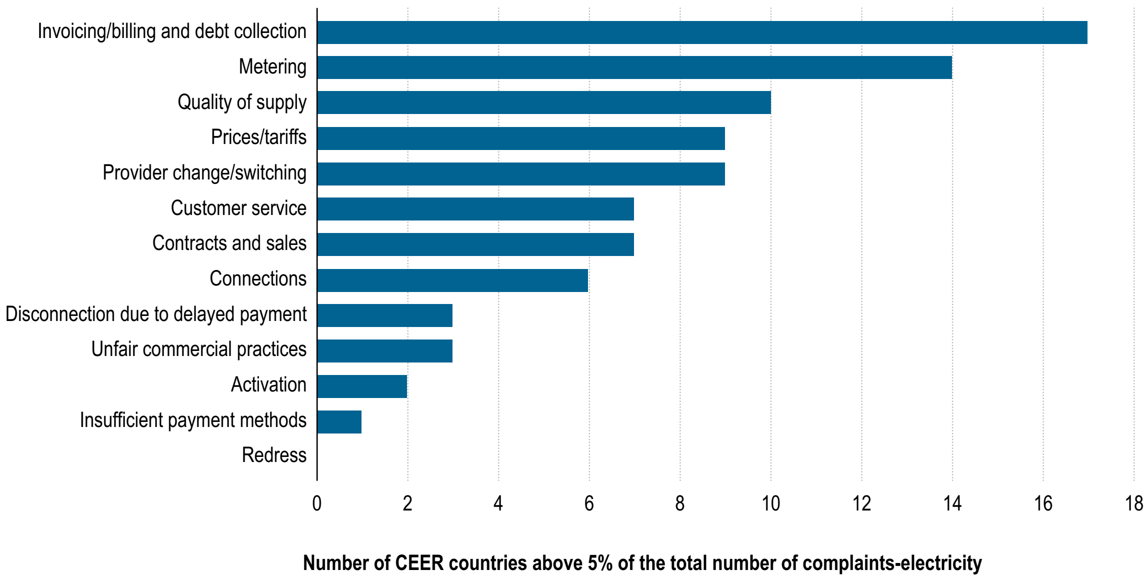
*(489)* For electricity, complaints about invoicing, billing and debt collection exceed the 5% threshold in 17 (out of 25 responders) MS. The second highest complaint frequency for electricity is metering, which exceeded the 5% value in 14 MS, followed by complaints on the quality of supply (10 countries), tariffs and prices (9 countries) and provider change/switch (9 countries). The number of electricity complaints is fairly low for activation, insufficient payment methods and redress issues (see Figure 58).

214 For example, a complaint on wrong meter data used in a bill could be allocated to the category "billing/invoicing and debt collection" as well as to the category "metering".

215 Some of these changes may be due to differences in data collection methodologies.

216 MS reported 89 instances of complaint categories that exceeded the 5% threshold for complaints relating to electricity; for gas, this number drops to 66.

**Figure 58: Number of countries where electricity complaints (by category) exceed 5% of the total number of complaints received by NRAs – 2011**



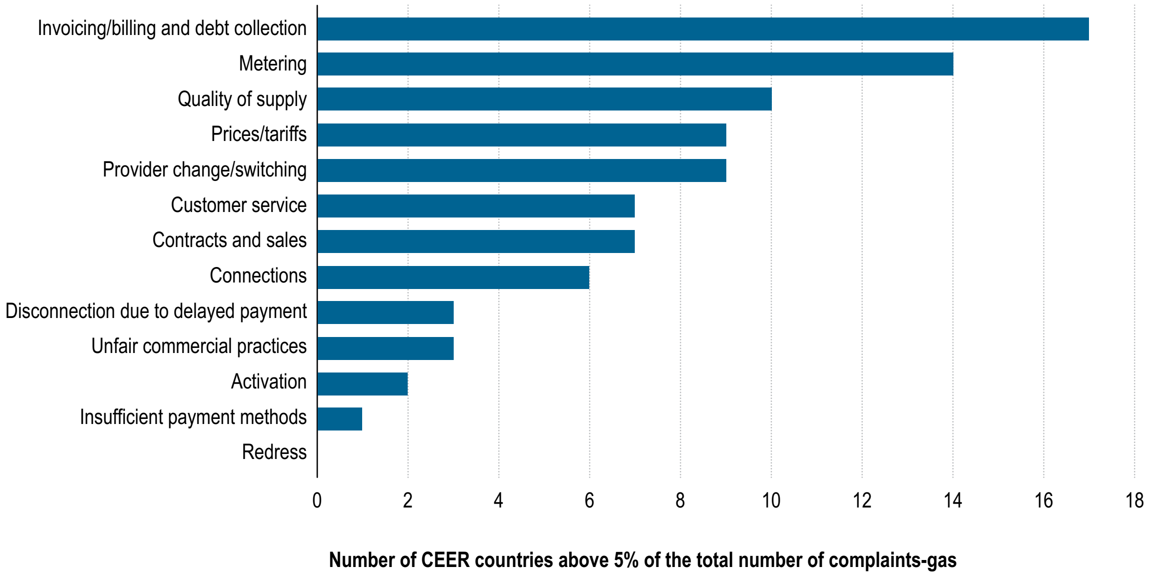

*Source: CEER National Indicators (2012)*

*(490)* In the gas market, the analysis of data on complaint categories reveals quite a similar picture to the electricity market, with one great exception. The two most frequently mentioned complaint categories are the same for gas and electricity: complaints about invoicing, billing and debt collection for gas exceed the 5% threshold in 13 (out of 22 respondents) MS, followed by metering complaints (9 countries).

*(491)* Quality of supply problems (the third most important complaint category in electricity) generates a smaller proportion of complaints in the gas market. Only one country reported that quality of supply complaints accounted for more than 5% of total complaints.

*(492)* Complaints on customer service, contracts, sales and connections are in the middle ground and above the 5% threshold, similarly to the electricity market. The categories with the lowest proportion of complaints are similar to those observed for the electricity market. The number of gas complaints is low for insufficient payment methods, and for redress and activation issues (see Figure 59).

**Figure 59: Number of countries where gas complaints (by category) exceed 5% of the total number of complaints received by NRAs – 2011**




*Source: CEER National Indicators (2012)*

*(493)* The analysis of the CEER database on complaints shows that invoicing/billing and debt collection, as well as supplier switching (albeit to a slightly lesser extent) frequently lead to problems in the electricity and gas retail markets. The two processes of billing and switching – where the customer has frequent and direct contact with the market actors – are the most complex. In some countries, problems might be caused by the way responsibilities are allocated between DSOs and suppliers,[217] which can be confusing for customers, as the latter do not know whom to contact first. In its GGP on electricity and gas retail market design with a focus on supplier switching and billing[218], CEER addressed market design issues. The internal survey by CEER showed that different market models are in place across the EU. Some countries have a dual point of contact model and others a single point of contact or other models.

*(494)* CEER's GGP recommend, as an overall principle, that the supplier should be the main (but not only) point of contact for the customer. CEER considers that providing the customer with one main point of contact is convenient and service-oriented, especially as the energy market is increasingly complex and the customer has multiple parties to deal with.

217 "Market design" in this report refers to the following: "Clearly defined roles and responsibilities of different market actors, the processes between them and the framework for empowering customers".

218 "Guidelines of Good Practice on Electricity and Gas Retail Market Design, with a Focus on Supplier Switching and Billing", CEER, Ref: C11-RMF-39-03, 24 January 2012.

*(495)* In addition to the supplier generally being the main point of contact for the customer, CEER finds that in the processes that require the most interaction between the customer and the energy retail market, the supplier should be the first point of contact for the customer. CEER considers that it is most intuitive for the customer to contact the supplier when they have questions about billing, moving or switching supplier. The supplier as first point of contact is then responsible for redirecting the customer to the relevant market actor if it cannot deal with the question itself. Therefore CEER recommends that the supplier should always be the first point of contact for questions regarding switching, billing and moving in or out.

*(496)* Metering is the second most common complaint category (13 for electricity and 9 for gas). For meter data management, most MS already have a regulated framework in place where the DSO plays a central role. Meter data management is crucial for all processes including switching, billing, moving etc. Again, for customers it is often not clear whom to contact if there is a question on meter data or incorrect meter readings used in bills. Well-defined processes for meter data management within a binding regulatory framework are of essential importance to achieve well-functioning processes.

*(497)* CEER advocates the following role for DSOs in dealing with problems with meter data in the billing and switching process. The DSO, as a neutral market facilitator, should carry out the switch without delay or discrimination.[219] However, CEER believes that the DSO should, as a neutral market facilitator, speed up the process of collecting or correcting data and thus assist the customer. Furthermore, CEER believes that the DSO, as a neutral market facilitator, should give all suppliers access to the same information on their customers' data with regard to billing. It should be guaranteed that the incumbent supplier does not have advantage due to, for example, combined IT systems.[220]

219 If the DSO is not able to carry out a switch because of absent or incorrect data, the DSO could technically reject the message, and thus prevent the switch process from being initiated, depending on the legal framework.

220 "Guidelines of Good Practice on Electricity and Gas Retail Market Design, with a Focus on Supplier Switching and Billing", CEER, Ref: C11-RMF-39-03, 24 January 2012, p.19-21.

*(498)* Consumer dissatisfaction with tariffs and prices is also quite high in some MS, as is indicated by this complaint category exceeding 5% of total complaints in more than one third of countries. Even though details of the reasons for the complaints in the respective MS are not reported, it is well known that problems on transparency, comparability and accuracy of energy products and prices hinder consumers from taking part in the energy market in an active and effective way. Price comparison tools (PCTs) should offer clear and transparent information to customers, thus helping them to actively engage in the market. There is a broad variety of price comparison tools across MS, not only for energy but also for other market sectors such as insurance and mobile phones. In the energy sector, these tools are either publicly offered by the NRA or by an authority dealing with customer protection issues, or they can be privately owned, for example by PCT providers that may receive a fee for mediation.

*(499)* CEER considered how to provide this information to customers and decided to establish the Guidelines of Good Practice for Price Comparison Tools (PCTs). The resulting document presents 14 recommendations for price comparison tools which cover the following topics: independence, transparency, exhaustiveness, clarity and comprehensibility, correctness and accuracy, user-friendliness, accessibility and customer empowerment.[221] By implementing the PCT recommendations, customers will gain access to neutral, objective information that empowers them to take an active role in the liberalised energy market, by switching contracts or suppliers to obtain a better deal. Furthermore, it is likely that smart meters will increase the availability of consumption information and the complexity of tariffs, which makes price comparison tools ever more important for consumers. The development and evolution of price comparison tools should go hand in hand with smart meter issues, as in future PCTs should allow the comparison of much more complex products.

*(500)* The 2020 Vision for Europe's energy customers initiated by CEER recognises that markets still have some way to go before they truly deliver for consumers, and puts the customer and their problems at the centre of policy making. One important outcome of the Consumer Conference in June 2012 is the recognition that it is essential that NRAs, relevant ministries, consumer bodies, and stakeholders work together more closely.

221 "Guidelines of Good Practice on Price Comparison Tools", CEER, Ref: C12-CEM-54-03, 10 July 2012.

## 8.5 Conclusions and recommendations

(501) Liberalisation is slowly penetrating the retail market, and its effects are reaching small consumers' homes. However, many challenges remain and further work is needed. In particular, energy retail for small business and household customers deserves increased attention. The very diverse stages of liberalisation, different market designs and allocation of roles to actors, different protection schemes and the extent to which customers are protected, as well as the learning process of customers to get used to, and feel comfortable with, choosing their suppliers are the main hurdles to overcome on the way to a harmonised landscape of retail markets.

(502) One first big step on this road was the 3rd Package, with provisions concerning consumer protection and empowerment in the single energy market. CEER members have worked continuously to implement the provisions stipulated in Article 3 and Annex I of Directives 2009/72/EC and 2009/73/EC. Overall, the key aspects of the provisions have been implemented in legislation across MS, but in some cases only to a partial extent.

(503) Market processes and information requirements are legally implemented by a large majority of MS, sometimes in quite different ways. In certain cases, a divergence between the legal transposition of requirements and their implementation in practice has been observed. The approaches taken by MS in terms of customer complaint handling and out-of-court settlements (ADR) through an independent mechanism also vary widely. Complaint handling and out-of-court settlements are often dealt with by regulators, but in other cases they are the responsibility of ombudsmen or consumer bodies. Almost all MS have a supplier of last resort mechanism in place. However, the preconditions, target groups and the number of appointed SoLRs differ strongly between countries.

(504) Important gaps still remain in a number of countries, particularly when it comes to fulfilling time frame requirements such as maximum periods for switching supplier and settling disputes. In certain cases, there is a divergence between the legal and practical implementation of 3rd Package requirements. The nuances and differences with respect to the various ways customer provisions are implemented still exist even with the 3rd Package in place.

(505) Other cases have proven that goals can be met even without transposing specific provisions. The 3rd Package contains a provision requiring MS to develop a concept of vulnerable customers. MS have different understandings of what a concept of vulnerable customers entails. Some countries claimed not to have a definition or specific measures for vulnerable customers. In spite of this fact, most MS ultimately tend to protect their vulnerable customers through a combination of energy specific and social security measures. In fact, the level of protection of vulnerable customers can ultimately be assessed only by examining the full range of protective measures in place.

(506) Information on customer complaints constitutes a valuable resource and indicator for market monitoring, as complaints data may provide evidence of malfunctioning in the market. The collection of complaints data involves NRAs, consumer bodies, ombudsmen, and other consumer protection authorities. Only a few regulators do, or plan to, collect complaint information from different sources (DSOs, suppliers and consumer bodies) according to the complaint classification suggested by ERGEG.

*(507)* Comprehensive knowledge on consumer complaints is vital to identify customer problems, to develop a framework for enhancing consumer trust and satisfaction, and ultimately to empower consumers to become more proactive. The Agency and CEER believe that regulators do not necessarily have to deal with consumer complaints directly and collect them in categories, but they should have access to the information and to the details on the reasons for complaints. In view of this, there is a clear need for close cooperation on consumer complaint issues between NRAs, stakeholders, consumer protection bodies, ombudsmen, etc.

*(508)* Although the available complaint data collected by NRAs and analysed in this joint report has to be treated with caution, the data nevertheless shows some general tendencies. One general outcome is that invoicing/billing and debt collection, metering, prices and supplier switching frequently lead to problems for consumers in both the electricity and gas retail markets.

*(509)* Through its work on consumer issues, CEER has developed a number of GGPs addressing a variety of consumer concerns, including complaint handling, reporting, and classification. These GGPs adopt a consumer perspective, identifying the problems or sources of dissatisfaction and recommending ways to improve processes and structures in retail markets.. For example, the implementation of CEER's GGP on Price Comparison Tools can considerably improve the situation. Transparency and clear, simple and understandable information is essential to increase customer engagement and to keep (or win back) their trust. The GGP on Price Comparison Tools is a robust basis for empowering customers so that they can make fast and well-informed choices. The development of such a tool is key to future work in this area, as price and product variety will increase through the implementation of smart metering. Additionally, the GGP on Electricity and Gas Retail Market Design, with a focus on supplier switching and billing, address the roles and responsibilities of market actors. They define the DSO as a neutral market facilitator serving and supporting the switching and billing process in a non-discriminatory way, and put the supplier to the fore as a single point of contact for customers. The GGP form the basis for further developing Europe's retail market design and working towards a supplier-centric model.

*(510)* To further improve consumer protection and empowerment measures in the market, not only NRAs are needed; depending on the national system, many more parties have to cooperate. It is paramount for NRAs to work closely together with consumer protection bodies, ombudsmen, responsible ministries and market participants.

# Annex 1 ACER and CEER

The **Agency for the Cooperation of Energy Regulators (the Agency)** is the European Union body created by the Third Energy Package to achieve the IEM.

The Agency was officially launched in March 2011 and has its seat in Ljubljana, Slovenia. As an independent European body which fosters cooperation among European energy regulators, the Agency ensures that market integration and harmonisation of regulatory frameworks are achieved in accordance with the EU's energy policy objectives.

The overall mission of the Agency, as stated in its founding regulation, is to complement and coordinate the work of national energy regulators at EU level and to work towards the completion of a single EU energy market for electricity and natural gas.

The Agency's missions and tasks are defined by the Directives and Regulations of the Third Energy Package, especially Regulation (EC) No 713/2009 establishing the Agency. In 2011, the Agency received additional tasks under Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT).

In particular, the Agency plays a central role in the development of EU-wide networks and market rules with a view to enhancing competition. It coordinates regional and cross-regional initiatives which favour market integration. It monitors the work of the two European networks of transmission system operators (ENTSOs) for electricity and gas, and notably their EU-wide network development plans. Finally, it monitors, or will monitor, the functioning of gas and electricity markets in general, and of wholesale energy trading in particular.

The **Council of European Energy Regulators (CEER)** is the voice of Europe's national electricity and gas regulators at an EU and international level. Through CEER, a not-for-profit association, national regulators cooperate and exchange best practice within and beyond Europe's borders. CEER includes national regulatory authorities from 31 European countries (EU-27, Iceland, Norway, Switzerland, FYROM and growing).

One of CEER's key objectives is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest. More specifically, CEER is committed to placing consumers at the core of EU energy policy. CEER believes that a competitive and secure EU single energy market is not a goal in itself, but should deliver benefits for energy consumers.

CEER works closely with, and supports, the Agency. CEER, based in Brussels, deals with many areas which are complementary to, and do not overlap with, the Agency's work, such as international issues, smart grids, sustainability and customer issues. European energy regulators are committed to a complementary approach to energy regulation in Europe, with ACER primarily focusing on its statutory tasks related to EU cross-border market development and oversight.

The work of the Agency and CEER is structured according to a number of working groups and task forces composed of Agency staff and expert staff members from national energy regulatory authorities.

# Annex 2 List of abbreviations

| Term | Definition |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| ADR | Alternative Dispute Resolution |
| AEWG | ACER Electricity Working Group |
| ATC | Available Transmission Capacity |
| BRP | Balancing Responsible Party |
| CACM | Capacity Allocation and Congestion Management |
| CAM | Capacity Allocation Management |
| CEE | Central East Europe (electricity region) |
| CEER | Council of European Energy Regulators |
| CEGH | Central European Gas Hub (Austrian gas hub) |
| CMP | Congestion Management Procedures |
| CSE | Central South Europe (electricity region) |
| CWE | Central West Europe (electricity region) |
| DA | Day-ahead |
| DECC | Department of Energy and Climate Change |
| DSO | Distribution System Operator |
| E/E | Entry/exit |
| EC | European Commission |
| EEA | European Economic Area |
| EEG | German Renewable Energy Act |
| EEX | European Energy Exchange |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ENTSOG | European Network of Transmission System Operators for Gas |
| ERGEG | European Regulators' Group for Electricity and Gas |
| ERI | Electricity Regional Initiative |
| EU | European Union |
| EXAA | Energy Exchange Austria |
| FG | Framework Guidelines |
| GGP | Guidelines of Good Practice |
| HEPI | Household Energy Price Index |
| IEM | Internal Energy Market |
| IP | Interconnection Point |
| LNG | Liquefied Natural Gas |
| LT | Long Term |
| LV | Low Voltage |
| mcm | million cubic metres |
| MS | Member States |
| NBP | National Balancing Point (GB gas hub) |
| NCG | Net Connect Germany (one of Germany's gas hubs) |
| NRA | National Regulatory Authority |
| OTC | Over-the-Counter |
| P2P | Point to Point |
| PCR | Price Coupling Region |
| PCT | Price Comparison Tool |
| PEG | Point d'Echange de Gaz (the name of France's gas hubs; Nord, Sud and TIGF) |
| POTP | Post-Tax Total Price |
| PPP | Purchasing Power Parities |
| PPS | Purchasing Power Standards (EU definition) |
| PST | Phase-Shifting Transformer |
| PSV | Punto di Scambio Virtuale (Italian gas hub) |
| PTP | Pre-Tax Total Price |
| RES | Renewable Energy Sources |
| RES-E | Electricity from Renewable Energy Sources |
| $Sm^3$ | Standard cubic metres |
| SoLR | Supplier of Last Resort |
| TPA | Third Party Access |
| TRM | Transmission Reserve Margin |
| TSO | Transmission System Operator |
| TTF | Title Transfer Facility (Dutch gas hub) |
| VAT | Value Added Tax |
| WG | Working Group |
| ZEE | Zeebrugge (Belgian gas hub and interconnection point) |

# Annex 3 Additional information

## Annex 3.1 Additional information on electricity and gas retail markets

### Annex 3.1.1 Information on switching rates and the maturity of retail electricity and gas markets in a selected number of MS

**Information on switching rates and maturity of the retail electricity and gas markets in a selected number of MS**

**Austria**

More than a decade after the liberalisation of the electricity market in October 2001 and the gas market in October 2002, the Austrian market is still dormant, showing very inelastic demand and high market shares in terms of Herfindahl-Hirschman Index (HHI) and Concentration Ratio (CR).

Over the last ten or eleven years, household customers rarely took advantage of the possibility to switch supplier. At the end of 2011, only 11% of household electricity customers had ever switched supplier compared to 76% of all other metered customers. For gas, the figure is even lower, with 6% of household customers having switched supplier compared to 36% of all other metered customers. Within the last two years, new products were offered to consumers, such as "floaters" (price linked to the development of wholesale prices) and online products (yearly bill delivered by e-mail). Price divergence for the commodity component of consumer tariffs in the electricity and gas sector remains high and can be only partially explained by political influence, which leads to lower price levels in certain Federal States. Price divergence is mainly due to one off rebates, which suppliers offer customers when switching.

In a survey, the Austrian NRA found that psychological switching costs prevent customers from switching supplier, even though the saving potential is very high. While there is a relationship between the saving potential and the level of switching in electricity retail markets, this relationship is not always strong. Several studies have sought to assess the determinants of switching behaviour and the ways in which psychological switching costs can be reduced.[222] The main parameters preventing a customer from switching are:

- The switch is expected to be extremely complex and time consuming;
- The saving potential is expected to be (very) low; and
- The switching procedure, roles, and responsibilities are unclear.

As barriers to switching are not due to monetary but also to psychological switching costs, which differ from customer to customer, the removal of these barriers is extremely complex. Research has shown that only combined measures such as transparent information from an independent authority are able to build trust in the market, and therefore reduce the resistance to switching supplier.

222 Other parameters regarding switching behaviour and obstacles to switching are not addressed here, as they are beyond the scope of this report.

### France

In France, in spite of nominal retail market liberalisation in 2007, only industrial customers have found it profitable to switch supplier. In both electricity and gas, domestic consumers face minimal price spreads in terms of offers if they switch. At some locations, especially in rural areas, switching away from the nationalised incumbent is *de facto* not an available option. The French example shows that there is no correlation between switching rates and price spreads in the absence of fully observable switching behaviour (since customers do not switch very much). Moreover, it can be argued that when switching is available, price advantages (for domestic customers) are so low on a yearly bill basis that the vast majority of customers do not consider that embarking on the switching process is worth their time.

### Great Britain

In Great Britain, switching rates were initially low at liberalisation (1998-99), but once the market for all customers was fully liberalised, including small domestic customers (2002), switching picked up considerably and soon entered double digit territory. Price divergence across offers was initially wide, especially considering dual fuel and web-only offers. As the market matured and the number of retail suppliers decreased due to concentration, both switching rates and price divergence decreased. Starting in 2006 and with the onset of the economic and financial downturn in late 2007 and 2008, up to now, switching rates have decreased and price dispersion is now lower, with many “teaser” offers around (temporary discounts, cash back etc., i.e. no real long-term benefits). Fixed-price offers have been declining since 2009. Effectively, the UK retail market is in a state of maturity, partially induced by a more concentrated industry structure and partially triggered by the economic climate, whereby supply has shrunk and most customers, now used to switching, do not switch any longer just for the sake of doing so. However, competition concerns have entered the picture and, over the last few years, especially given adverse economic conditions, the British regulator has launched two probes into electricity and gas retail markets whose effects in terms of competition, switching, and price spreads are still to be felt.

### Republic of Ireland

In the Republic of Ireland, after electricity market liberalisation, switching rates increased considerably. Price divergence across offers is gradually decreasing as switching rates increase. Throughout the economic recession, the Irish market has been much more dynamic than the British one, with high switching rates and sustained differences in terms of offers, especially after dual fuel and web deals are accounted for. The Irish retail market, which is also undergoing liberalisation in gas (following the electricity example), might follow the maturity stages of the GB one, and is currently comparable to the GB retail market in the early 2000s (i.e., it is quite dynamic).

### Spain

In Spain, electricity end-user price regulation was abandoned in 2009, although most households (those connected at low voltage with contracted power equal to or less than 10 kW) can still choose whether to be supplied under last resort tariffs by the SoLR (Supplier of Last Resort) or to contract energy on the liberalised market.

From 2009, switching rates rose from less than 1% to approximately 10% in 2011. The following factors have contributed to this increase:

- A significant share corresponds to customers switching away from SoLR to the liberalised supplier of the same mother company. In particular, most switches have taken place in the distribution area of one of the biggest electricity companies whose liberalised supplier was almost inactive before 2009.
- Those household customers with higher consumption (in particular, those with a contracted power between 10 and 15 kW) are charged penalties if they stay with the SoLR. Therefore, they have been incentivised to switch away from the SoLR to a competitive supplier.
- Switching procedures have been constantly revised and enhanced by the OCSUM (Supplier Switching Office), whose work is monitored by the Spanish National Regulator (CNE).

Finally, it is remarkable that, while switching rates have been constantly increasing, price spreads are still rather low. Future developments in Spanish price regulation will be likely to influence the evolution of switching rates in the future.

The Spanish gas market has rapidly evolved since liberalisation. Demand and market competition increased over the last decade. The market is now reasonably mature at around 35 bcm/year, with more than 40 suppliers. Regulated prices still exist for certain household consumers, but in contrast to other European regulated markets, the retail market is now liberalised to a fair extent. The retail price setting methodology brings final regulated prices closer to the real mix of shippers' supply costs. As a result, free market shippers can compete more fairly (with sustainable margins) for household customers currently under regulated prices. This fact, and the additional reason that in Spain all gas DSOs share the same IT platform for switching, has made it much easier to compete, and has contributed to higher switching rates in the household market segment.

### Netherlands

In the Netherlands, the energy market for residential customers and small businesses ("small consumers") has been fully liberalised since July 2004. In the Netherlands, consumers tend to be very loyal to their traditional supplier. This is reflected in their switching behaviour. For instance, 37% of customers have never switched. Dutch customers rate the level of service of their own energy supplier as very high, but seem to distrust the energy sector as a whole. This is a major hurdle for many consumers to actually switch. However, due to improved transparency for consumers, such as energy supply price comparison websites, switching rates gradually increased between 2006 and 2012 from around 6% to nearly 10% for gas and electricity. Further, those who do switch, tend to switch again (serial switchers). Until now, almost 36% of all consumers have switched supplier.[223]

223 NMa, Trendrapportage Marketwerking en Consumentenvertrouwen in de energie market, 2012.

**Table A- 1: Annual switching rates in electricity and gas retail markets in the EU-27 plus Norway – 2011**

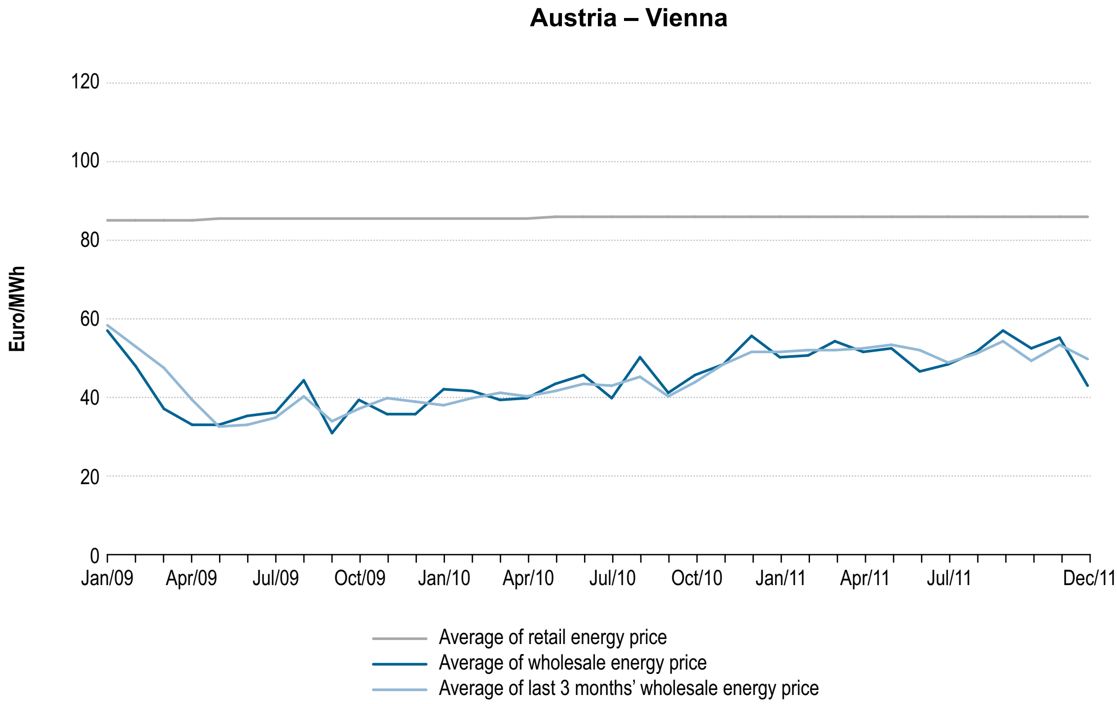
| | (% of customers who switched supplier by number of eligible meter points) | |
|---|---|---|
| Country | Gas | Electricity |
| Austria | 1.0 | 1.4 |
| Belgium | 12.8 | 9.7 |
| Bulgaria | 0.0 | 0.0 |
| Cyprus | 0.0 | 0.0 |
| Czech Republic | 12.5 | 7.4 |
| Denmark | NA | 1.8 |
| Estonia | 3.6 | 0.0 |
| Finland | NAP | 8.6 |
| France | 4.4 | 3.9 |
| Germany | 7.9 | 7.8 |
| Great Britain | 14.8 | 15.4 |
| Greece | 0.0 | 1.8 |
| Hungary | NA | NA |
| Ireland | 17.3 | 15.1 |
| Italy | 5.2 | 5.8 |
| Latvia | 0.0 | 0.0 |
| Lithuania | 0.0 | 0.0 |
| Luxembourg | 0.1 | 0.2 |
| Malta | NA | 0.0 |
| Netherlands | NA | NA |
| Northern Ireland | 7.5 | 2.0 |
| Norway | NA | 11.3 |
| Poland | 0.0 | NA |
| Portugal | NA | 1.1 |
| Romania | NA | 0.0 |
| Slovakia | 1.5 | 1.4 |
| Slovenia | 1.7 | 4.0 |
| Spain | 19.0 | 10.0 |
| Sweden | 0.8 | 8.9 |

*Source: CEER National indicators (2012)*

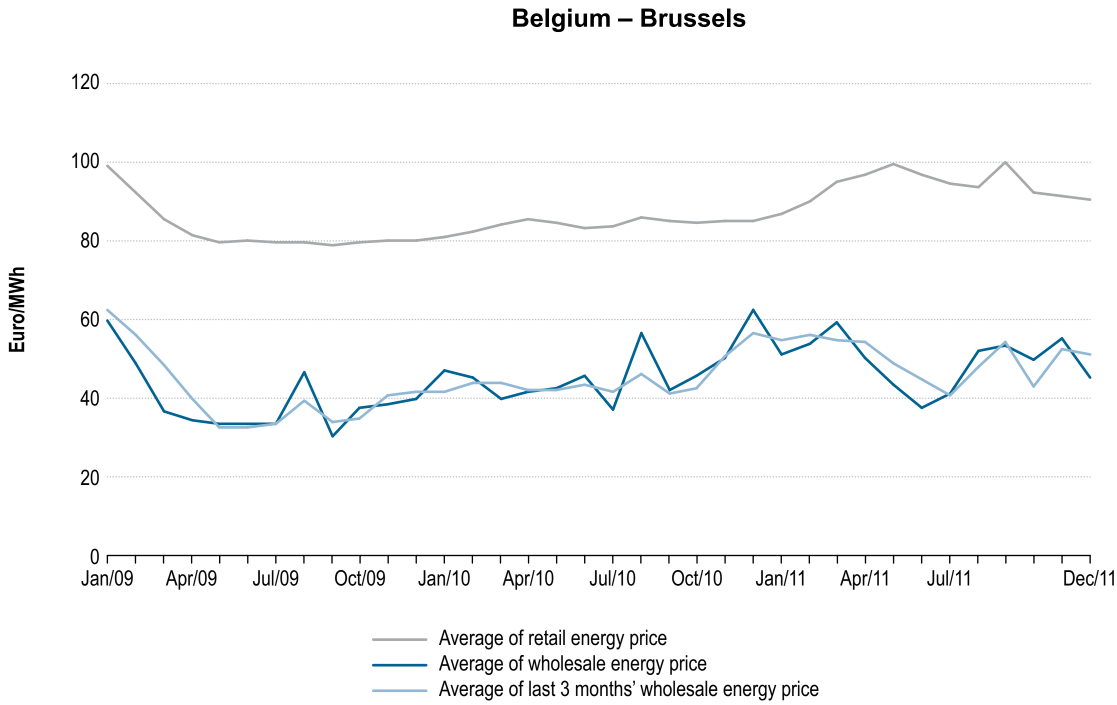
*Note: The percentage of household customers under regulated prices, and/or the existence of a single supplier, can help explain the differences in switching rates. Detailed information on the percentage of household customers under regulated prices can be found in Tables 1 and 10.*

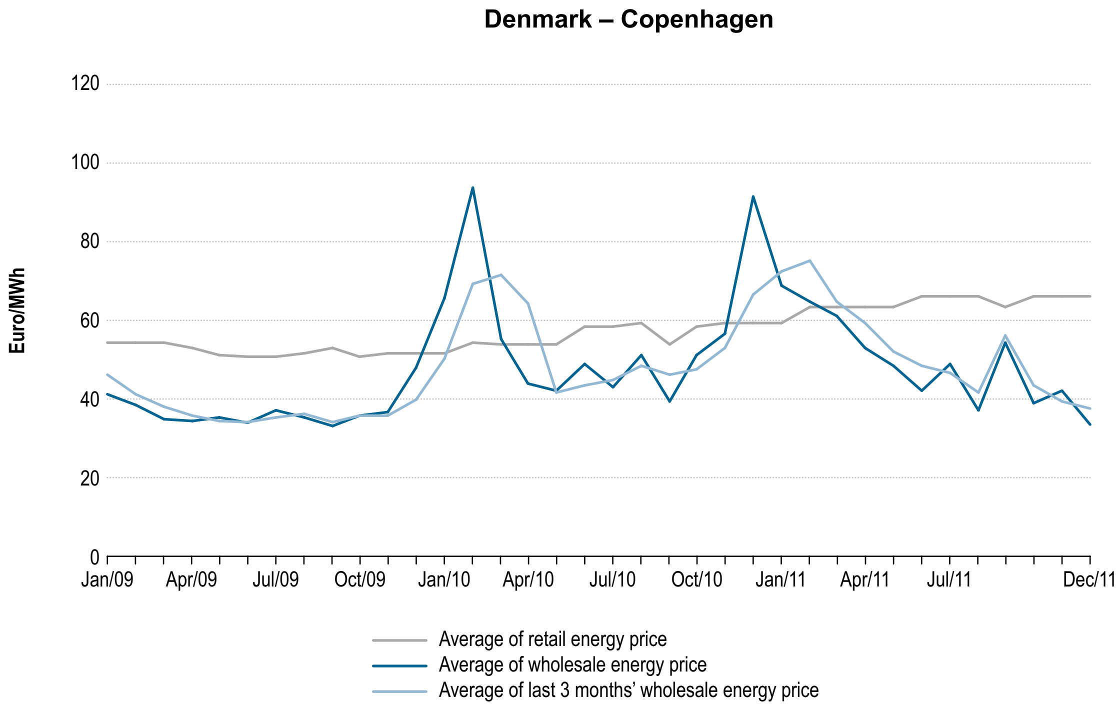
## Annex 3.1.2 Correlation between wholesale and retail (energy component) electricity prices

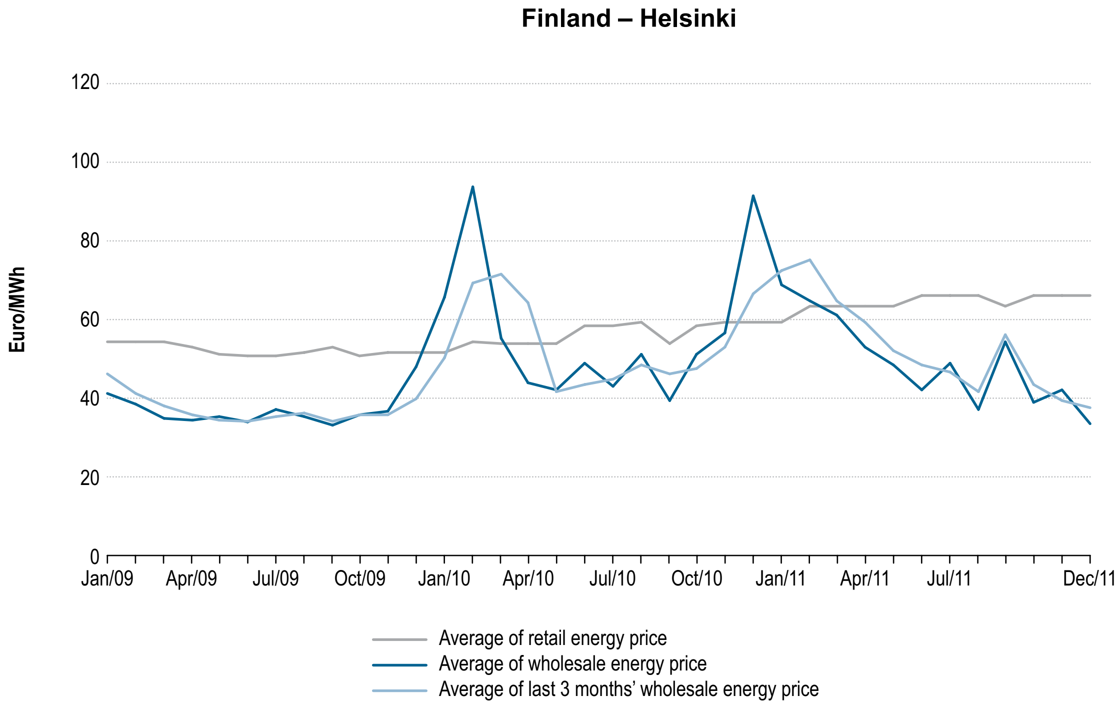
**Figure A-1: Correlation between wholesale prices (Power Exchange day-ahead prices) and retail prices (energy component only, excluding network charges, taxes, and levies)** [224]

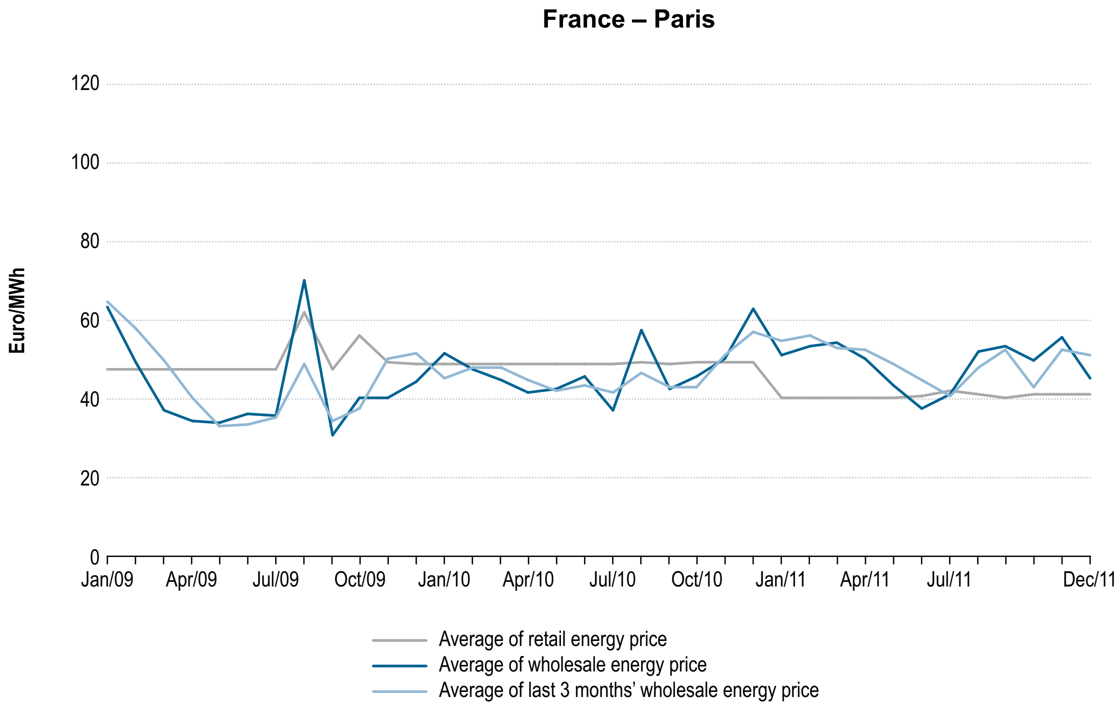


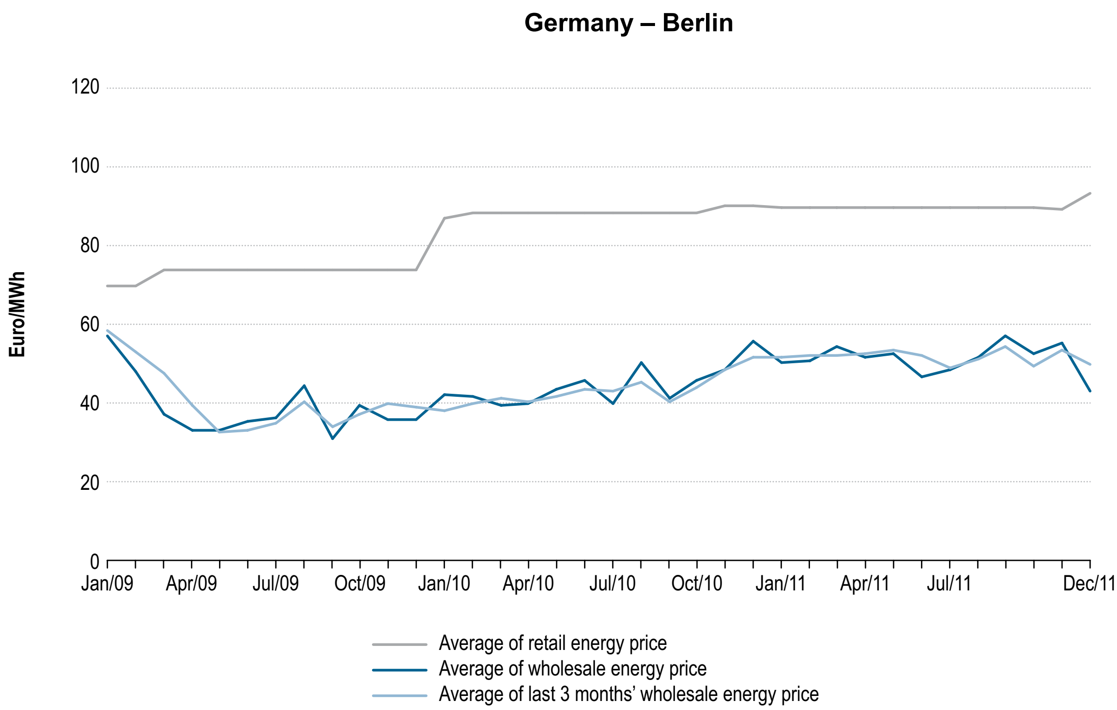

224 The difference between retail and wholesale prices was calculated by using the average of the commodity price between 2009 and 2011 in the capital cities for retail, and a quarterly rolling average of spot market prices between 2009 and 2011 for wholesale.

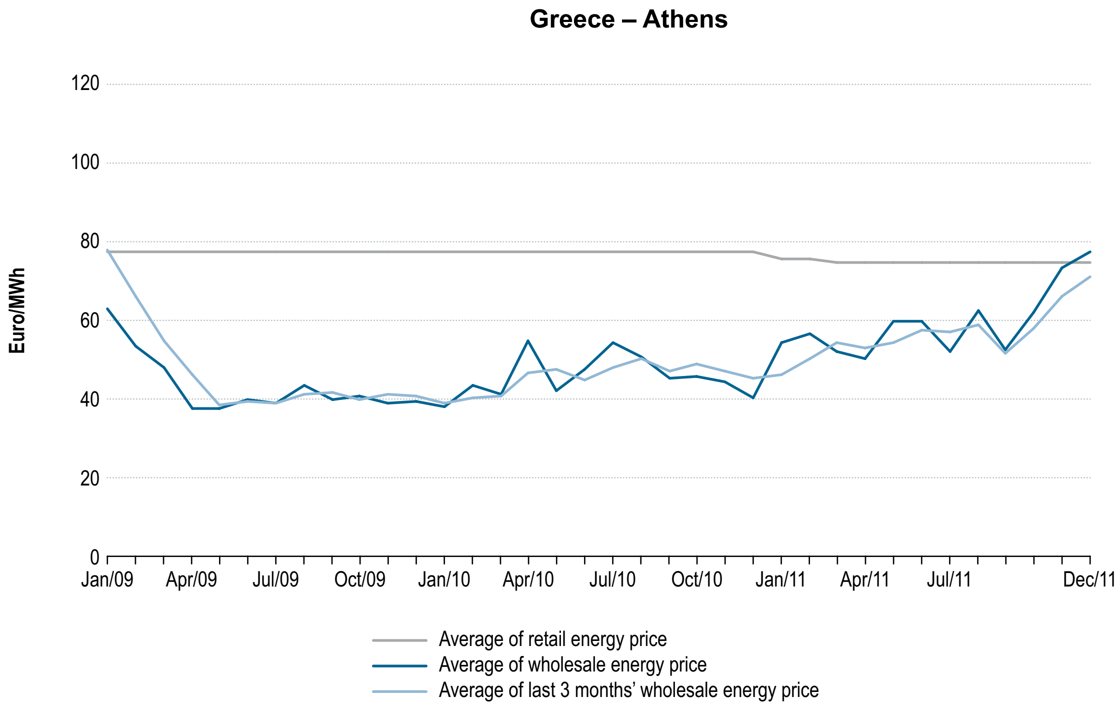

Belgium – Brussels
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

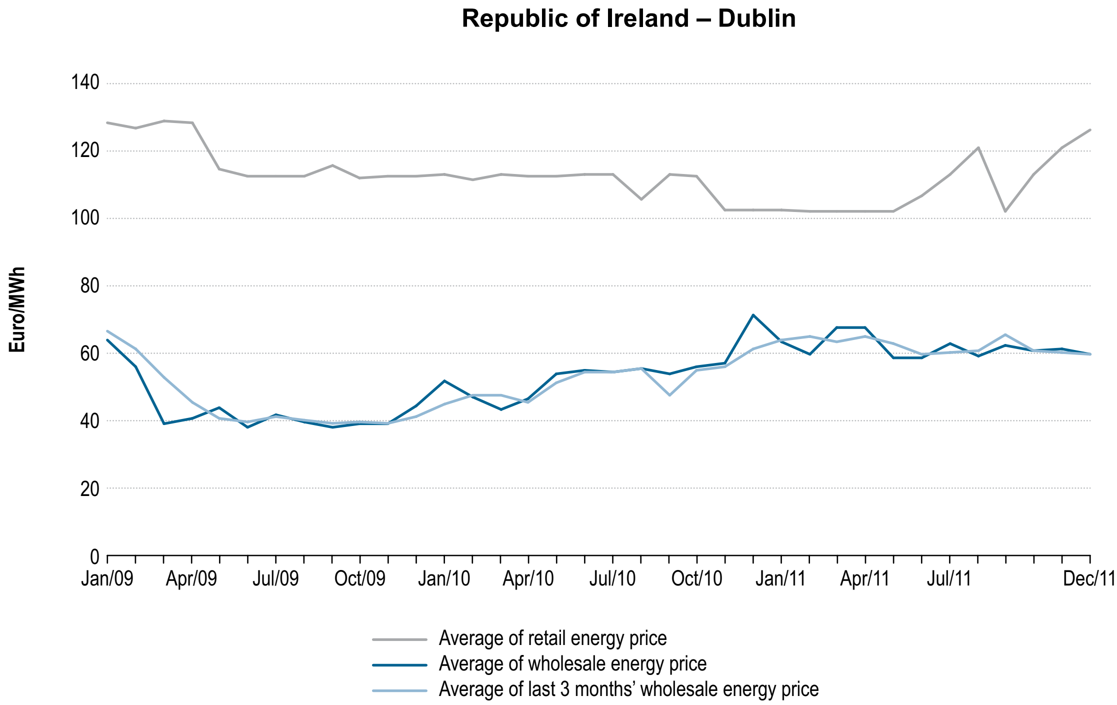

Denmark – Copenhagen
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

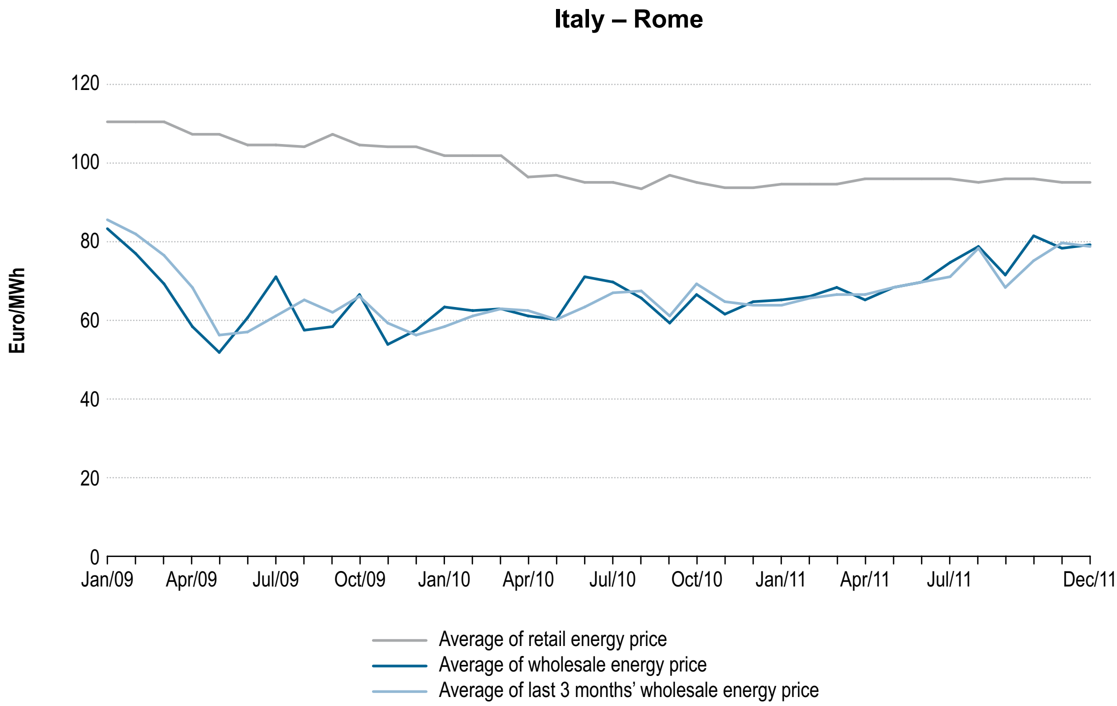

Finland – Helsinki
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

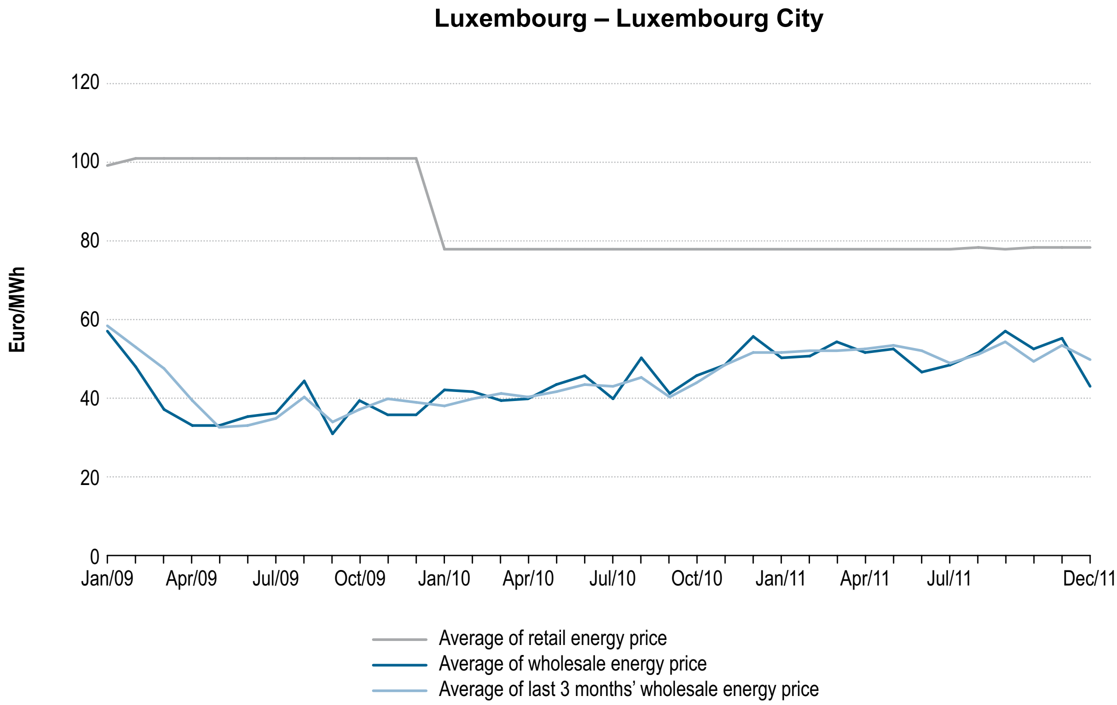

France – Paris
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

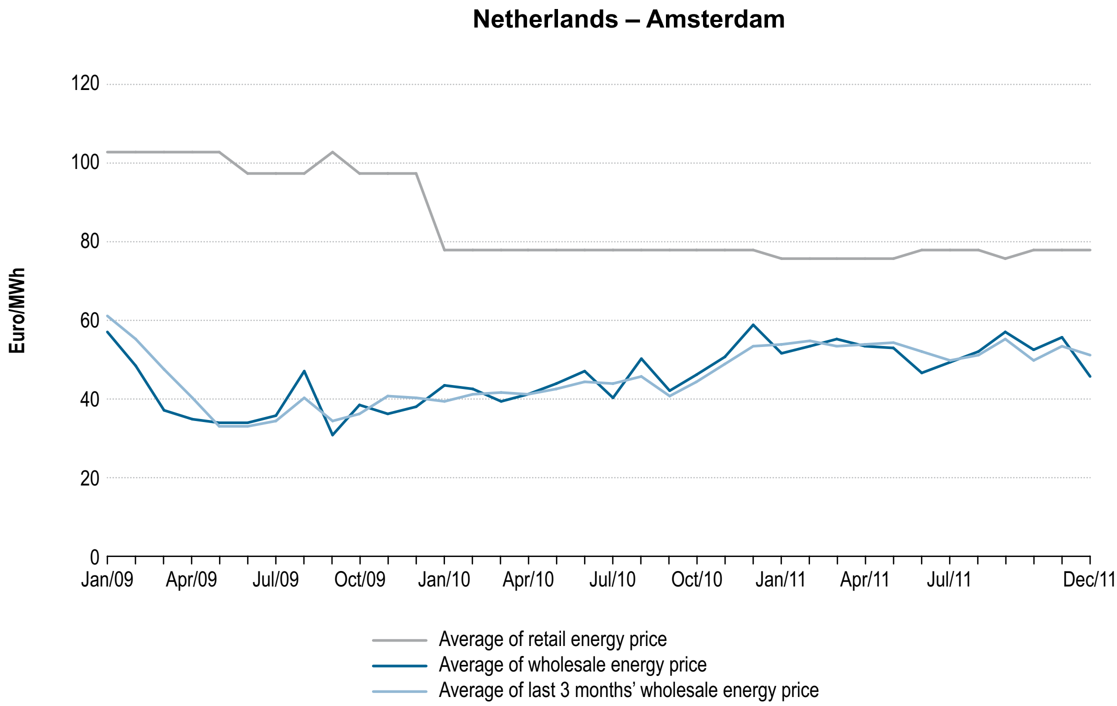

Germany – Berlin
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

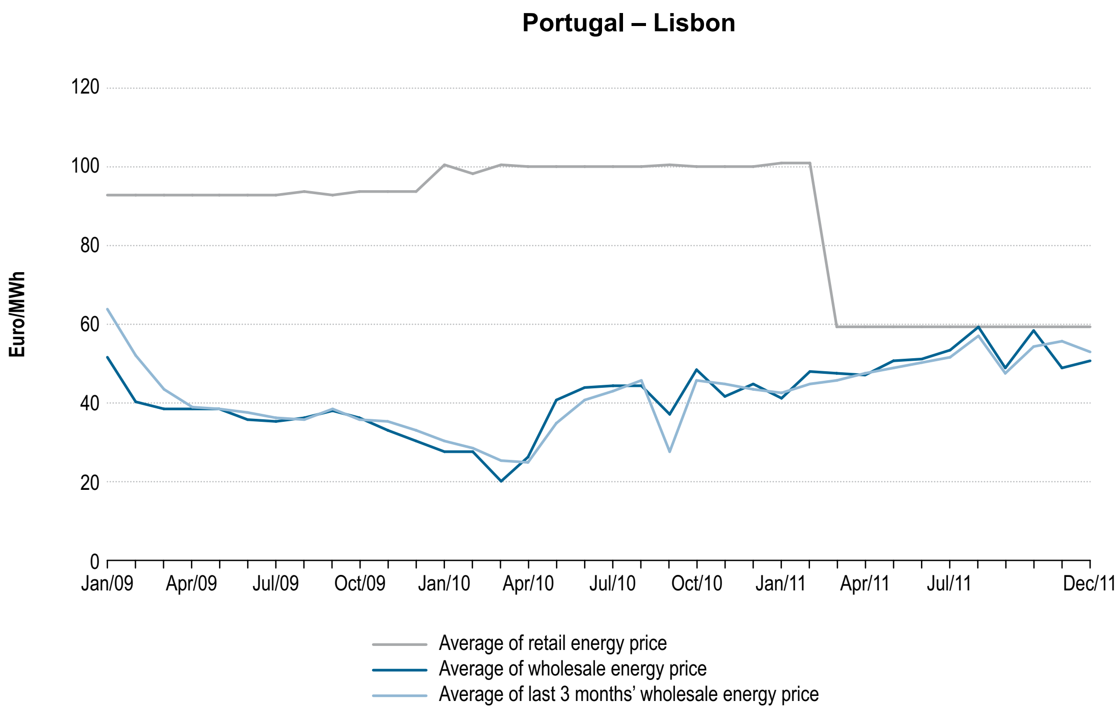

Greece – Athens
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

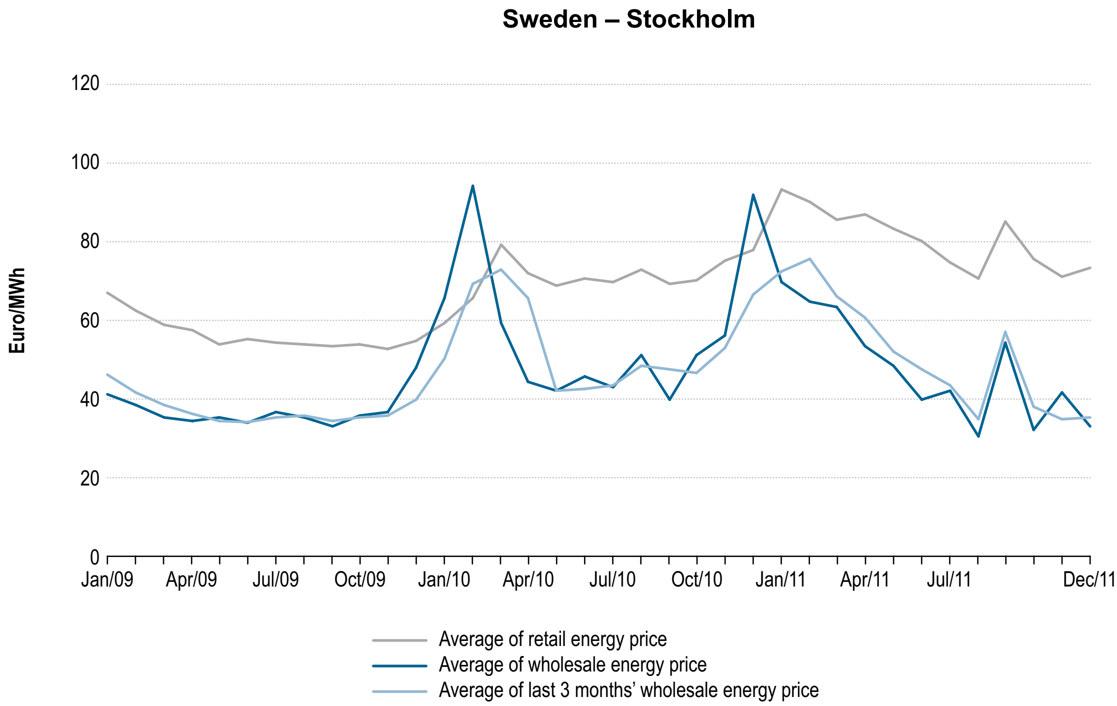

Republic of Ireland – Dublin
Euro/MWh
140
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

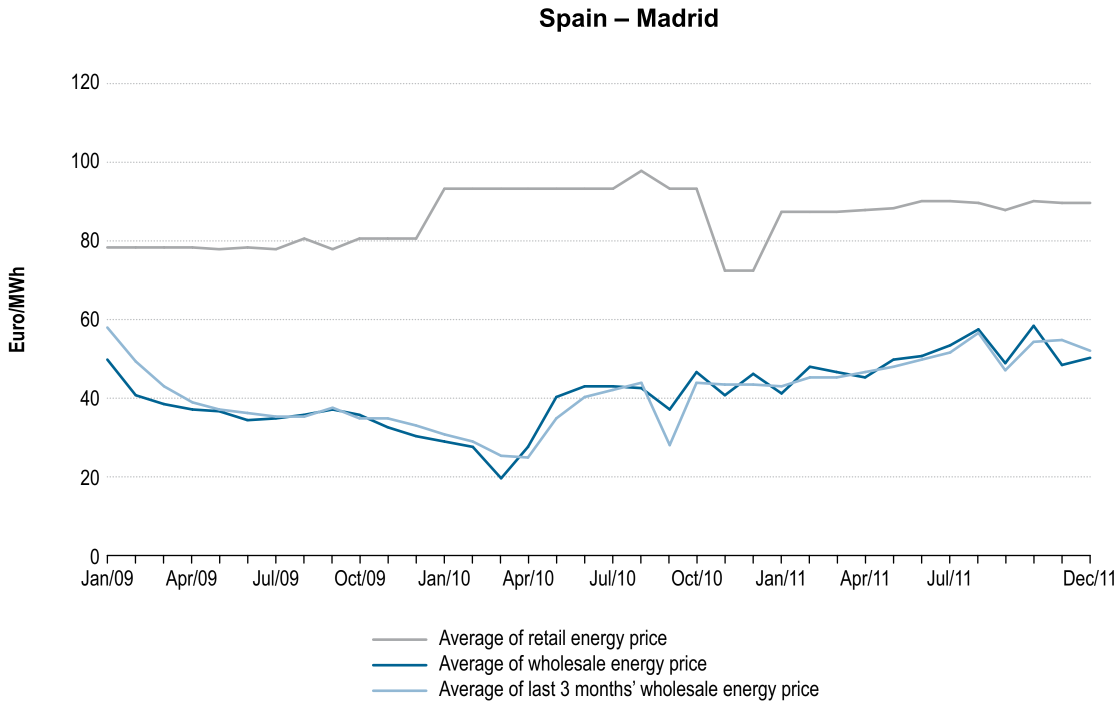

Italy – Rome
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

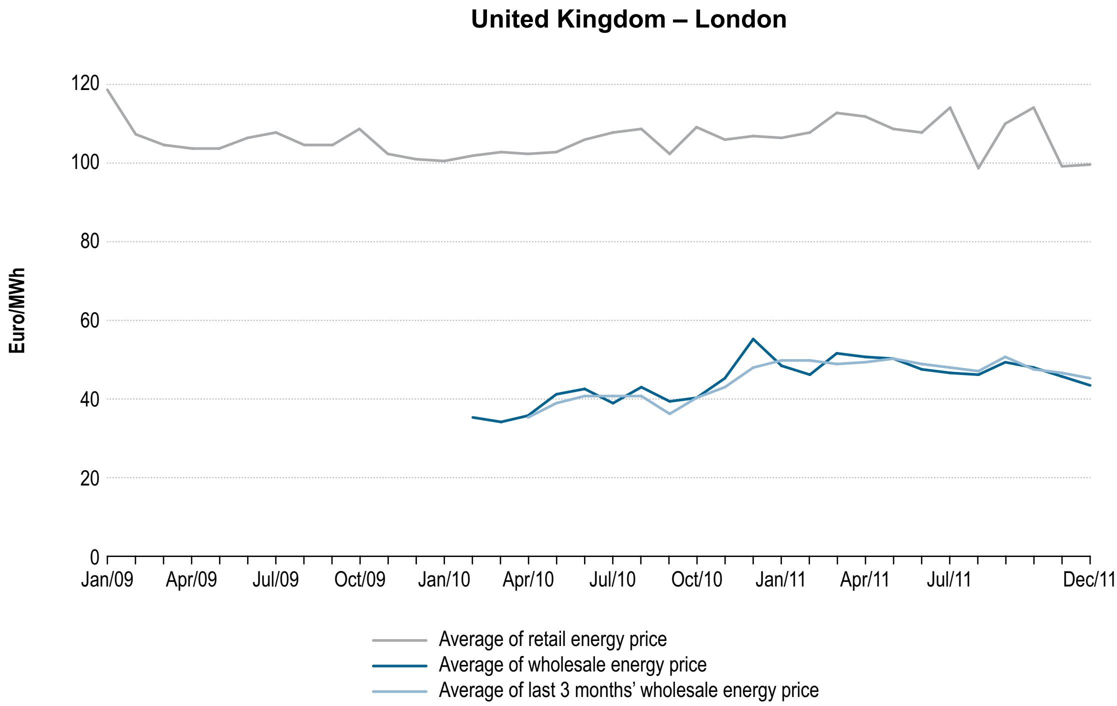

Luxembourg – Luxembourg City
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price


Netherlands – Amsterdam
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price


Portugal – Lisbon
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price


Sweden – Stockholm
Euro/MWh
120
100
80
60
40
20
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price



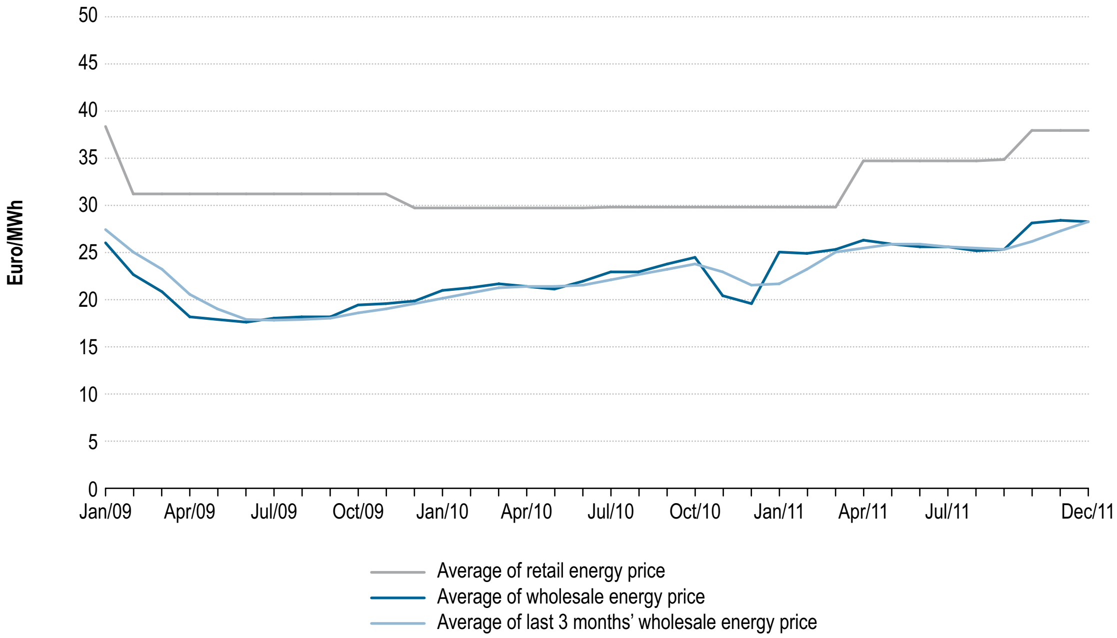




*Source: European Power Exchanges, NRAs and E-Control/VaasaETT (2012)*

## Annex 3.1.3 Correlation between wholesale and retail (energy component) gas prices

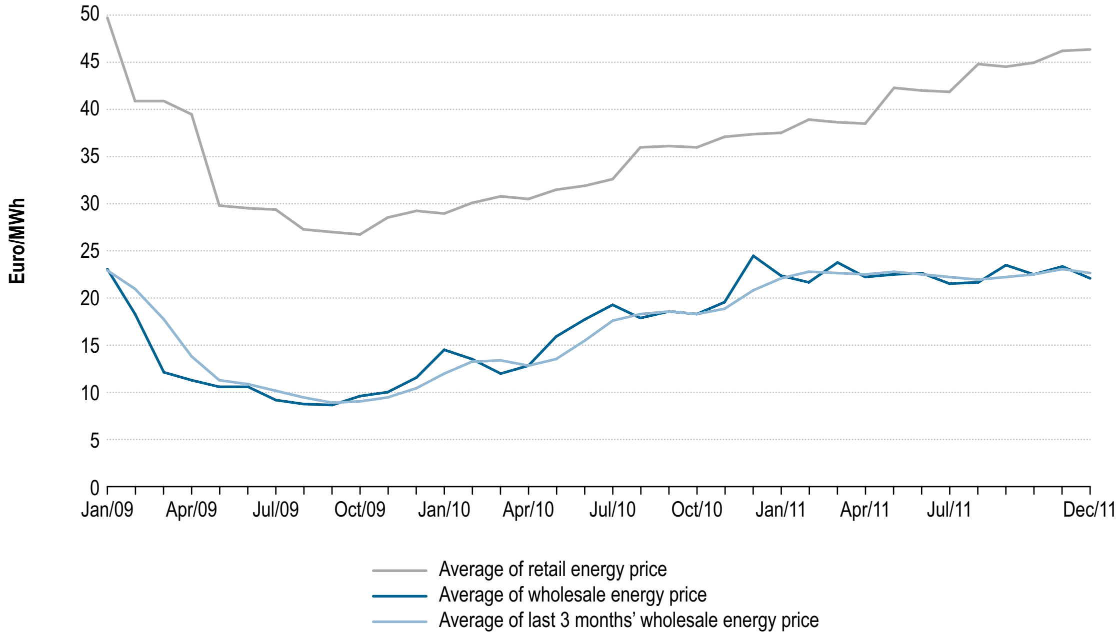
**Figure A-2: Correlation between wholesale and retail (energy component) prices in EU-15 countries[225]**

**Austria – Vienna (Wholesale reference: Import price)**

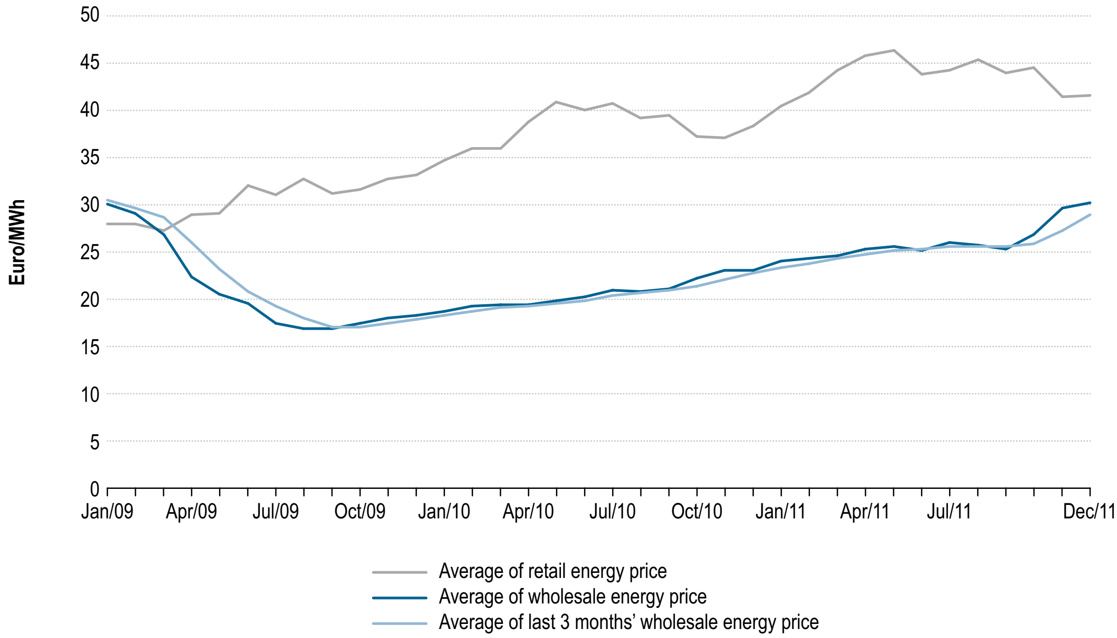



225 The difference between retail and wholesale prices was calculated by using the average of the commodity price between 2009 and 2011 in the capital cities for retail, and a quarterly rolling average of spot market prices between 2009 and 2011 for wholesale.

**Belgium – Brussels (Wholesale reference: Zeebrugge)**

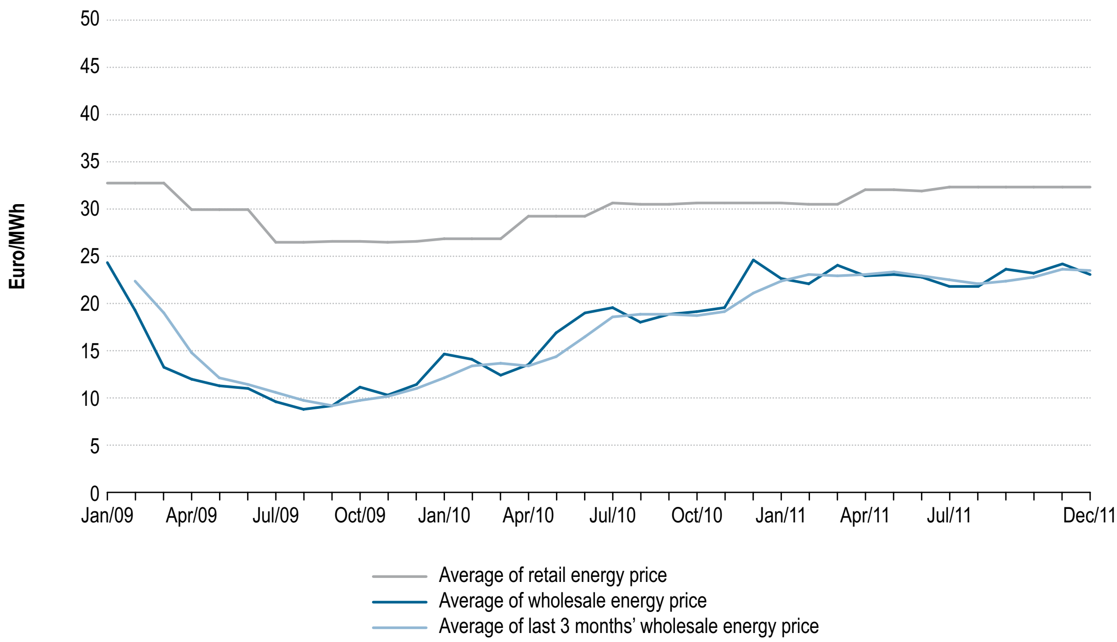



**Denmark – Copenhagen (Wholesale reference: BAFA[226])**

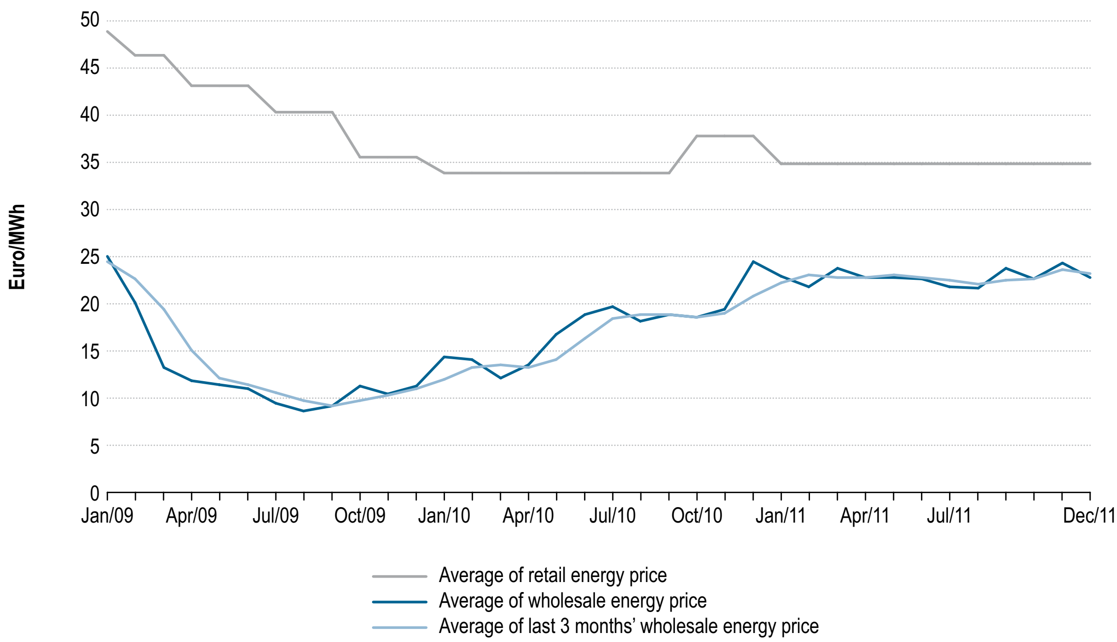


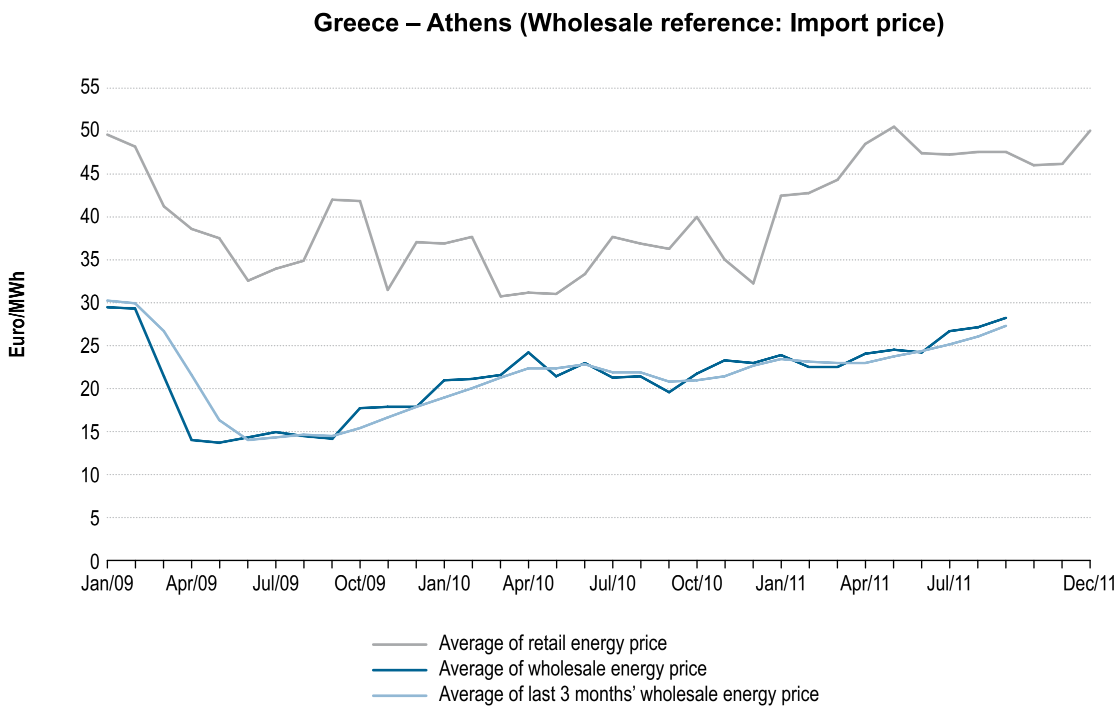

226 The German border gas import price index, BAFA, is the best approximation to the Danish wholesale price as indicated by DERA.

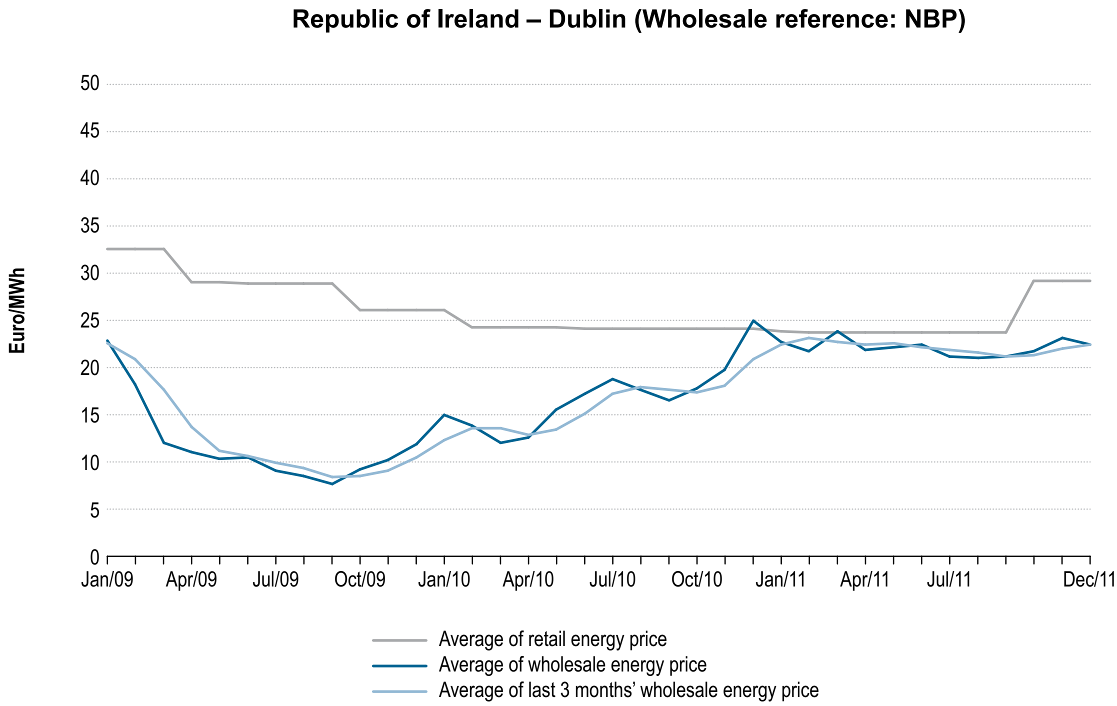
**France – Paris (Wholesale reference: PEG Nord)**



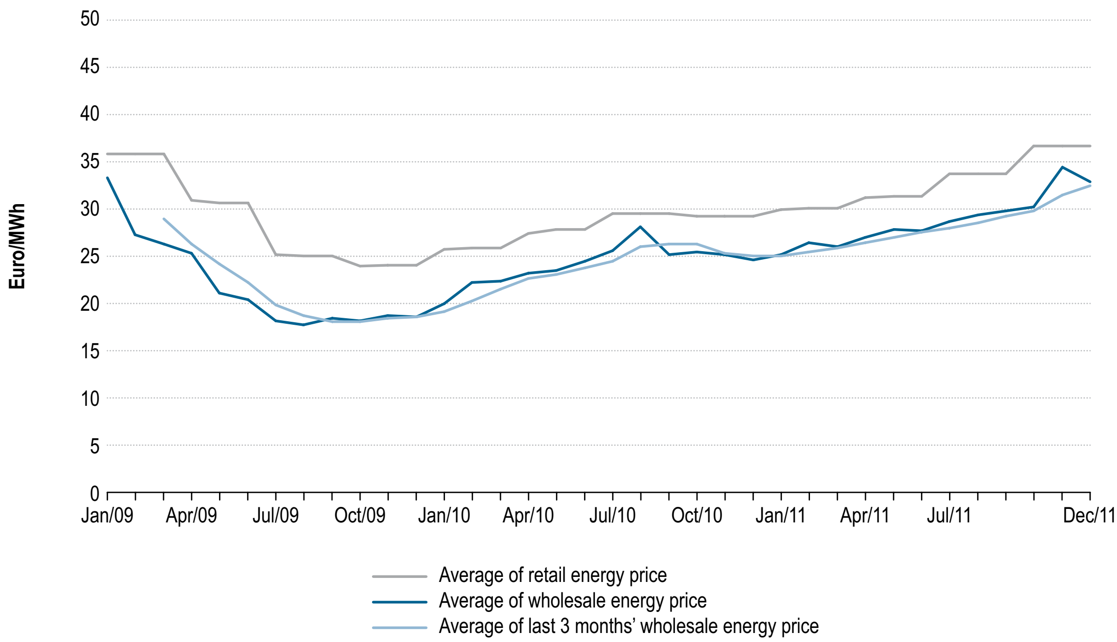

**Germany – Berlin (Wholesale reference: NCG)**



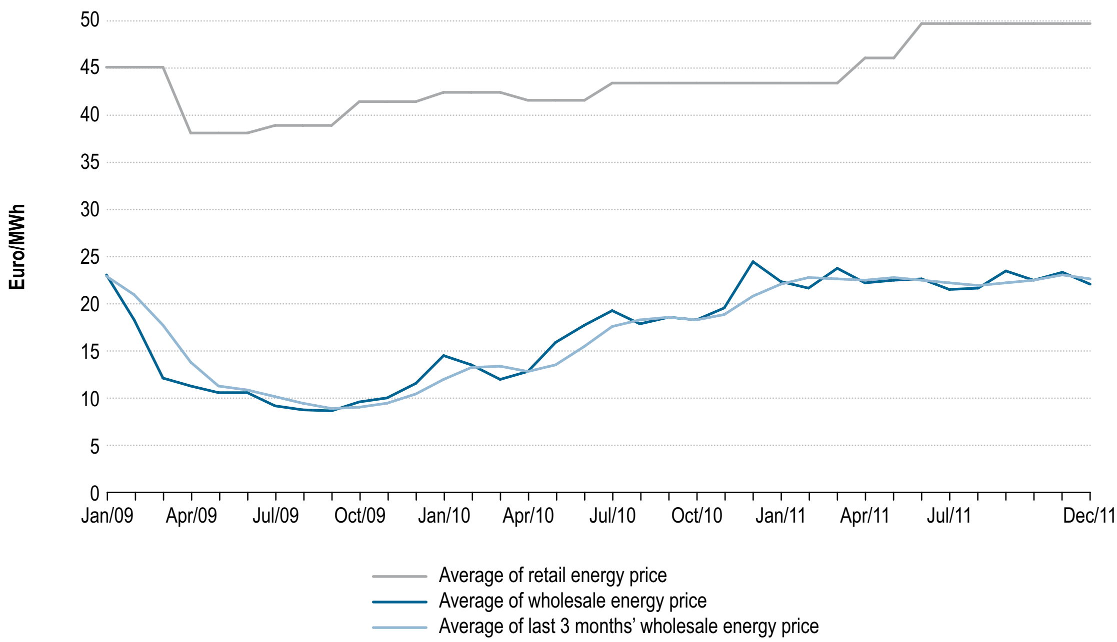

Greece – Athens (Wholesale reference: Import price)
Euro/MWh
55
50
45
40
35
30
25
20
15
10
5
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

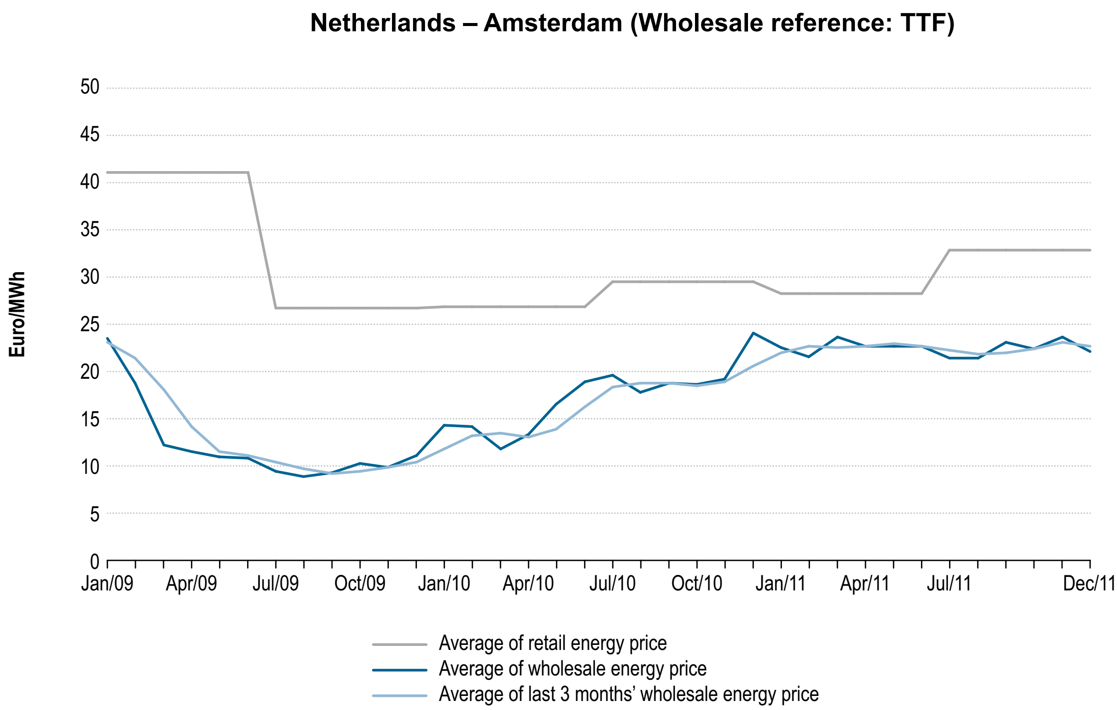

Republic of Ireland – Dublin (Wholesale reference: NBP)
Euro/MWh
50
45
40
35
30
25
20
15
10
5
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

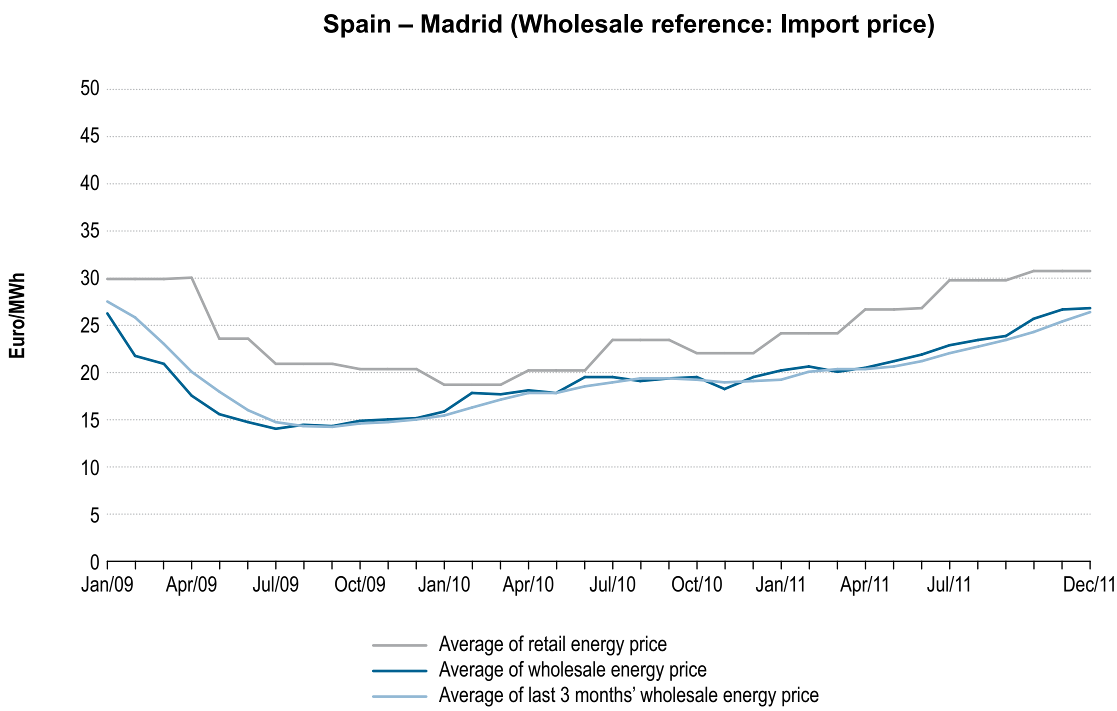
**Italy – Rome (Wholesale reference: Import price)**



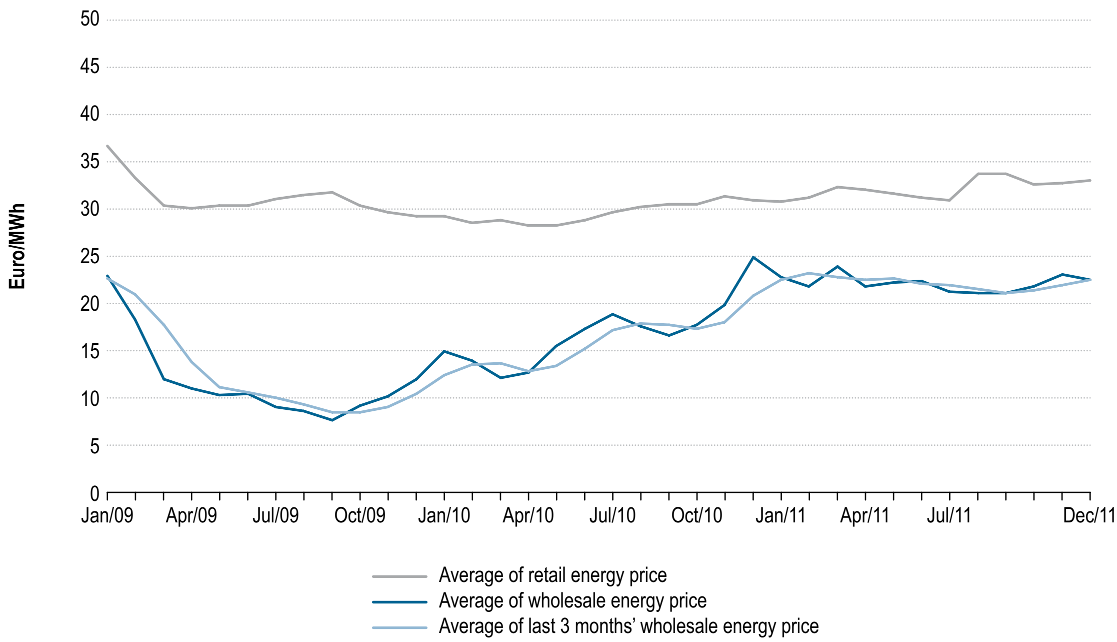

**Luxembourg – Luxembourg City (Wholesale reference: Zeebrugge)**




Netherlands – Amsterdam (Wholesale reference: TTF)
Euro/MWh
50
45
40
35
30
25
20
15
10
5
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price


Spain – Madrid (Wholesale reference: Import price)
Euro/MWh
50
45
40
35
30
25
20
15
10
5
0
Jan/09
Apr/09
Jul/09
Oct/09
Jan/10
Apr/10
Jul/10
Oct/10
Jan/11
Apr/11
Jul/11
Dec/11
Average of retail energy price
Average of wholesale energy price
Average of last 3 months' wholesale energy price

**United Kingdom – London (Wholesale reference: NBP)**




*Source: European Hubs, NRAs and E-Control/VaasaETT (2012)*

## Annex 3.1.4 Regulated electricity prices – Romania

In 2011, the total number of customers supplied under regulated prices was 8.96 million, of which 94% were households. The electricity consumption of customers supplied under regulated end-user prices was 11,589 TWh for household customers and 8,699 TWh for non-household customers.[227]

For industrial customers, the market has been open to competition since 2007. The timelines for abandoning regulated prices for commercial and small industrial customers and household customers differ significantly. By January 2014, 100% of all commercial and small industrial customers will be supplied under non-regulated prices, whereas this will be the case for household customers only by the end of 2017.

**Table A-2: Proposed schedule for abandoning regulated tariffs [228]**

| Implementation date | Supply under non-regulated end-user prices (commercial/ small industrial customers/ social institutions) | Supply under non-regulated end-user prices (household customers) |
|---|---|---|
| 01/09/2012 | 15% | - |
| 01/01/2013 | 30% | 0% |
| 01/04/2013 | 45% | 0% |
| 01/07/2013 | 65% | 10% |
| 01/09/2013 | 85% | 10% |
| 01/01/2014 | 100% | 20% |
| 01/07/2014 | 100% | 30% |
| 01/01/2015 | 100% | 40% |
| 01/07/2015 | 100% | 50% |
| 01/01/2016 | 100% | 60% |
| 01/07/2016 | 100% | 70% |
| 01/01/2017 | 100% | 80% |
| 01/072017 | 100% | 90% |
| 31/12/2017 | 100% | 100% |

*Source: ANRE (2012)*

In 2011, regulated prices were calculated according to the underlying methodology approved by the Romanian regulator ANRE[229] which determines suppliers' quantity of electricity acquired and the price at which the electricity component is sold. The price for the electricity component and the tariffs for transmission and distribution vary across the country, whereas the total price for household customers is the same across the whole country.[230]

227 CEER National Indicators (2012).

228 Memorandum signed by the Romanian government regarding the proposed schedule for regulated tariffs cut out. This is available at: http://www.anre.ro/documente_tot.php?id=212

229 ANRE. Order no 133/2008.

230 According to ANRE, variations in the total price should be kept to a minimum across the country.

Customers supplied under regulated end-user prices are supplied by one of the eight default suppliers. These suppliers buy most of the electricity from the biggest generators out of a “basket” at an average price[231], a minor part in the day-ahead market, and also electricity for balancing purposes from the balancing market administered by the Romanian TSO SC Transelectrica SA.

ANRE sets the quantities and prices at which each electricity producer contributes to the “basket” of electricity available under regulated tariffs. For example, in 2010, SN Nuclearelectrica SA contributed 60% of its output to the electricity “basket”.

The acquisition of electricity is done through:

- regulated bilateral contracts with the possibility of annual and bi-annual adjustment by the NRA;
- transactions on the day-ahead market; and
- energy bought in the balancing market and charged to suppliers due to registered imbalances.

The principles of determining the regulated electricity price are the following:

- all costs incurred by suppliers for electricity acquisition, ancillary services, transmission services, distribution services, for market settlement including energy taxes according to the legislation in force, have to be covered by the tariffs; and
- justified costs related to supplier services are also included (e.g. billing, maintenance of data base management system).

The revenue of any supplier should cover all of the afore mentioned costs, plus a pre-defined, regulated profit. The regulated profit for 2011 is 2.5 % of the total acquisition costs. Ex-post adjustments of regulated tariffs are made in the following cases:

- variation of costs acknowledged in regulated tariffs;
- variation of taxes and levies related to the energy, e.g. VAT or excise tax; and
- regulated profit exceeds 2.5 % of acquisition costs.

Adjustments are accomplished based on the forecast volume of sales for the next 12 months, which have to be communicated to the NRA by each supplier. The amount of electricity needed for customers supplied under regulated prices is set annually and can be updated biannually based on the load forecast. Regulated contracts comprise hourly regulated quantities on standard days and can be reviewed, due to the migration of consumers to other suppliers, or to increased forecast accuracy when approaching the point of delivery.

231 The costs of generation differ between nuclear, hydro and thermal production, and prices are calculated as a weighted average, with weights representing different output shares in total production by generation technology.

## Annex 3.2 Additional data on electricity wholesale markets

### Annex 3.2.1 Overview of cross-border day-ahead and intraday allocation mechanisms

On several congested interconnectors, TSOs make use of explicit auctions for the allocation of, for instance, day-ahead capacity.

Table A-3 provides an overview of the allocation mechanisms for a selection of borders for day-ahead and intraday (ID) capacity. For instance, on the interconnector between France and Spain explicit auctioning applies for day-ahead capacity. This mechanism is considered unsatisfactory, because it suffers from a time lag between capacity allocation and wholesale market clearance, resulting in a less efficient use of available cross-border capacity. Evidence of this has been shown in several documents, including the Final Report on the Energy Sector Inquiry by the European Commission.[232]

232 European Commission Final Report on the Energy Sector Inquiry (2007), p.184, see: http://ec.Europa.eu/competition/sectors/energy/inquiry/full_report_part2.pdf

**Table A-3: Overview of existing explicit and implicit auctions for DA and ID capacity – 2011**

| | | Explicit | | Implicit | |
|---|---|---|---|---|---|
| Region | Border | Day-ahead | Intraday | Day-ahead | Intraday |
| BALTIC | Estonia-Finland | | | X | X |
| BALTIC | Estonia-Latvia | | | X | X |
| BALTIC | Lithuania-Latvia | | | X | X |
| CEE | Austria-Czech Republic | X* | X* | | |
| CEE | Austria-Germany (No congestion) | | | X | |
| CEE | Austria-Hungary | X | X | | |
| CEE | Austria-Slovenia | X | X | | |
| SEE | Bulgaria-Greece | X | ID not available | | ID not available |
| SEE | Bulgaria-Romania | X | X | | |
| CEE | Czech Republic-Germany | X | X | | |
| CEE | Czech Republic-Poland | X | X | | |
| CEE | Czech Republic-Slovakia | | X | X | |
| CEE | Germany-Poland | X | X | | |
| SEE | Hungary-Romania | X | X | | |
| CEE | Hungary-Slovakia | | X | X* | |
| CEE | Poland-Slovakia | X | X | | |
| CSE | Austria-Italy | X | ID not available | | ID not available |
| CSE | France-Italy | X | X | | |
| CSE | Germany-France | | X | X | X |
| CSE | Greece-Italy | X | ID not available | | ID not available |
| CSE | Italy-Slovenia | | X | X | |
| CWE | Belgium -France | | X | X | |
| CWE | Belgium -Netherlands | | | X | X |
| CWE | Germany-Netherlands | | X | X | |
| F-UK-I | France-Great Britain | X | X | | |
| F-UK-I | Great Britain-Ireland | X | | | X |
| F-UK-I | Great Britain-Netherlands | | X | X | |
| F-UK-I | Great Britain-Northern Ireland | X | | | X |
| F-UK-I | Ireland-Northern Ireland (No congestion) | | | | |
| NE | Denmark-Norway | | | X | X |
| NE | Denmark-Sweden | | | X | X |
| NE | Finland-Norway (No congestion) | | | | |
| NE | Finland-Sweden | | | X | X |
| NE | Germany-Denmark | | | X | X |
| NE | Germany-Sweden | | | X | ID not available |
| NE | Netherlands-Norway | | | X | X |
| NE | Norway-Sweden | | | X | X |
| NE | Poland-Sweden | | ID not available | X | ID not available |
| SWE | Spain-France | X | X | | |
| SWE | Spain-Portugal | | | X | X |

*Source: The Agency (2012)*

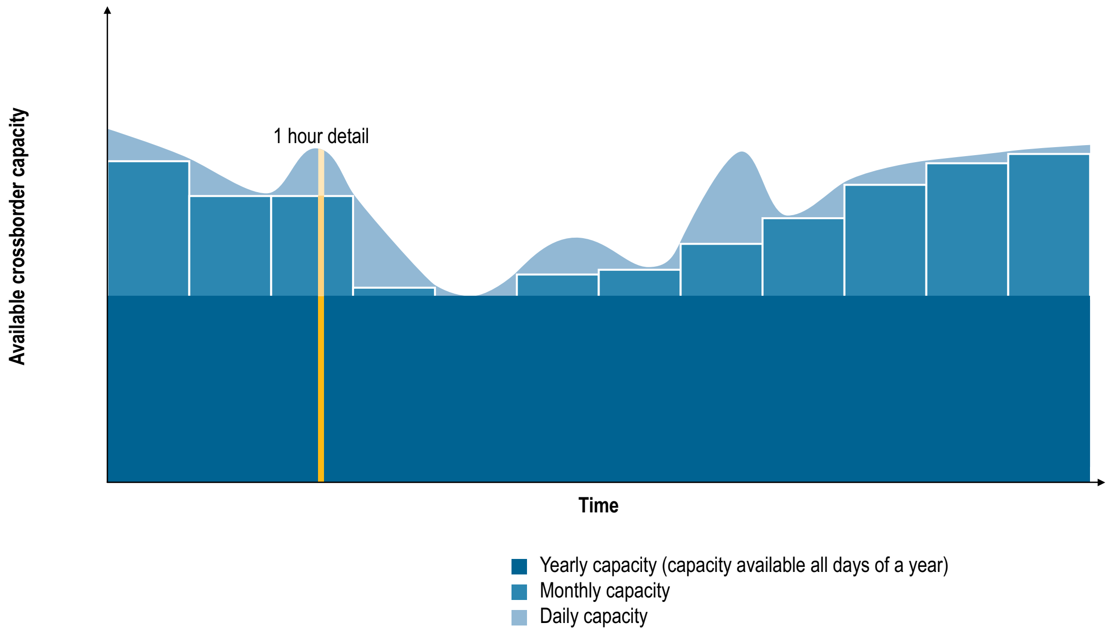
*Note: "X" indicates that the type of auction is operational, * refers to 2012.*

## Annex 3.2.2 Curtailment of cross-border capacity

To establish a common understanding of the meaning of the reduction and curtailment of cross-border capacity for trade, this Annex explains which factors determine the level of cross-border capacity. This Annex does not focus on the procedure from TSOs by which these capacities are assessed.

The level of cross-border capacity offered for trade by TSOs is determined by many factors. They include generation patterns, atmospheric conditions that can have an impact on the physical capacity of the transmission lines, expected output from renewables and technical outages. These factors are not constant over time and, as a result, the capacities for cross-border trade should also change over time. To illustrate this, the curve in Figure A-3 below represents the potential changes in cross-border capacity over a year. The figure shows blocks of capacity for the different timeframes (that is, yearly, monthly and daily). On some borders, additional time frames are offered (e.g. weekly), which are not described in this Annex.

**Figure A-3: Cross-border capacity on an interconnection. The minimum values over the time frames considered define the amount of capacity that can reliably be offered to the market**



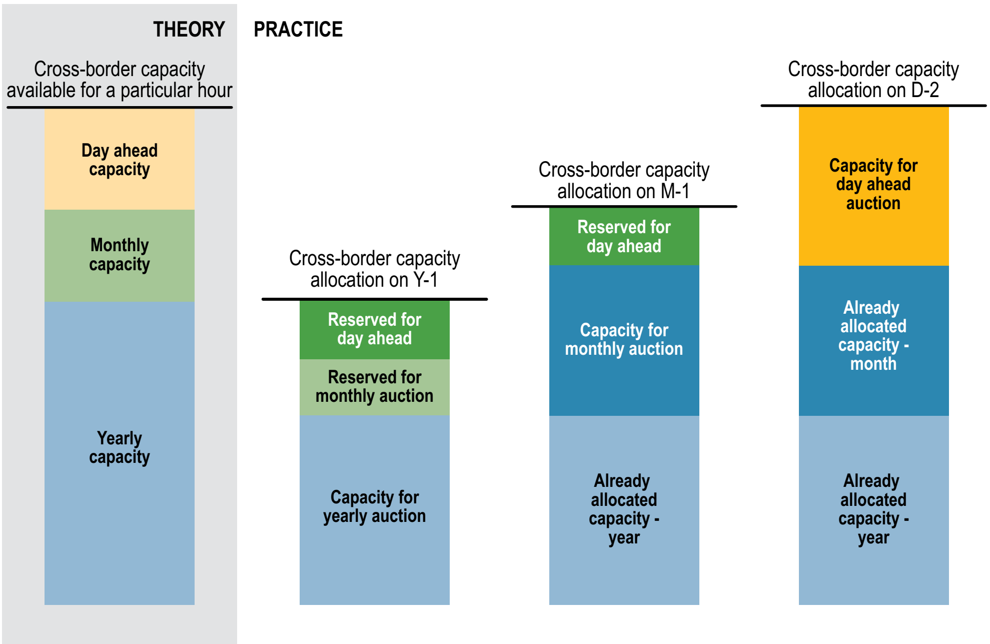

*Note: This figure is an illustration of a hypothetical example.*

The capacity that can be guaranteed at all times throughout a year is the minimum of the foreseen capacity over the entire year (yearly capacity). Further, the capacity that can be guaranteed at all times in a month is the minimum of the foreseen capacity over the considered month (blue area). Finally the available capacity, in addition to the yearly and monthly capacities (long-term capacities, that is LT), can be auctioned on a daily basis (implicitly or explicitly). The capacity offered to the day-ahead market is meant to fill the gap between what has already been auctioned LT and the total expected cross-border capacity for every hour when calculated for the day-ahead.

Figure A-4 illustrates the variability of cross-border capacity over time. Apart from this variability, uncertainty about the capacity that will be available also plays a role. Closer to the point of operation, more information is known on the factors influencing cross-border capacity. Therefore, under normal circumstances, TSOs can offer more capacity as the point of operation approaches. Both variability and uncertainty determine the capacity that can be offered for yearly, monthly or day-ahead auctions.

Figure A-4 illustrates the effect of variability and uncertainty over time. It focuses on one hour (indicated in Figure A-3) and shows the breakdown of cross-border capacities made available for trade across different time-frames. In theory (indicated in the figure in the left bar), the minimum available capacity is determined well in advance across all time-frames. For example, the cross-border capacity allocated to the yearly time-frame is determined in Y-1 and fully offered through yearly capacity auctions. In practice, also accounting for uncertainty, TSOs have some discretion to allocate capacity between time-frames. For instance, as indicated in the three bars to the right in the figure, TSOs may reserve some capacity in a given time-frame for use at a later stage. In Figure A-4, some capacity available at the yearly auction is reserved for monthly and daily auctions. Figure A-4 also shows that TSOs can supply more capacity to the market when approaching the relevant hour. This is because, closer to the point of operation, more information on the above-mentioned factors is known. With lower uncertainty, more capacity can reliably be offered to the market.

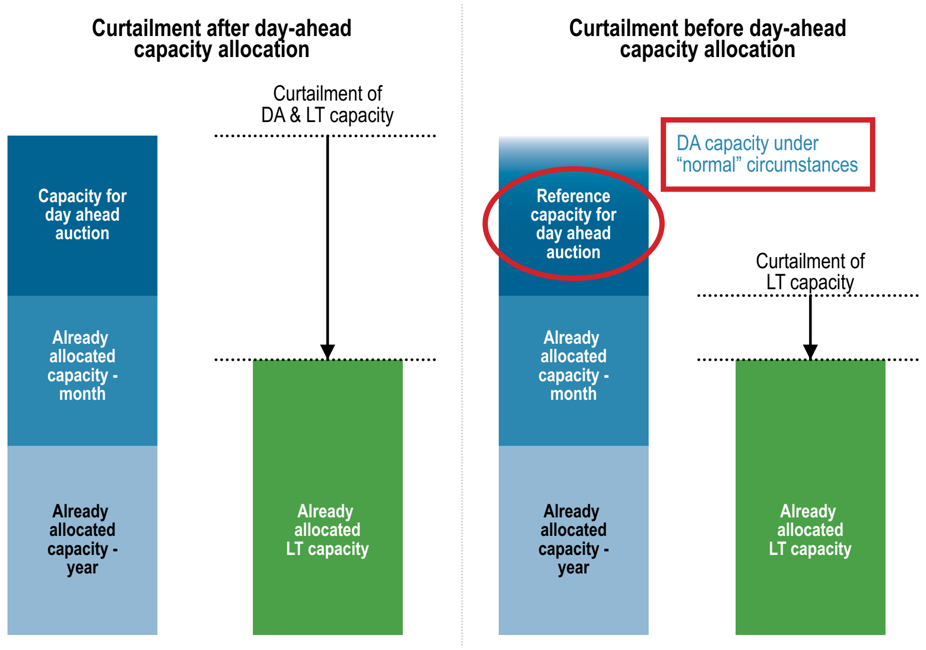
**Figure A-4: Detailing the offered cross-border capacity for different time horizons for one hour – theory and practice**




*Note: This figure is an illustration of a hypothetical example.*

Figure A-5 shows curtailments of cross-border capacity at two different points in time. The left-hand side depicts a situation where the day-ahead (DA) cross-border capacity has already been allocated (by explicit or implicit allocation). If the capacity is reduced, as indicated in the figure, this leads to a curtailment of transactions of both DA and LT capacities. In most situations, allocated DA capacity will be firm (unless there is a case of *force majeure*). Curtailment of allocated DA capacity occurs rarely. The right hand side of Figure A-5 shows a situation where DA capacity has not yet been allocated. Therefore the curtailment of transaction relates only to the LT time-frame, since no DA transaction has taken place.

**Figure A-5: Curtailment of cross-border capacity after and before day-ahead auctions**




*Note: This figure is an illustration of a hypothetical example. The first situation depicts a curtailment of both day ahead capacity and LT capacity, and the second situation depicts curtailment of LT capacity only.*

The curtailment on the right-hand side of Figure A-5 merely deals with the reduction of capacity that has already been allocated, namely the LT capacity. To better assess total capacity levels in a situation prior to the DA capacity allocation, a reference value is needed. The right-hand side figure illustrates such a reference situation of DA capacity under “normal” circumstances where full capacity is available. Since no DA capacity has already been allocated, the reference value for DA capacity could, for example, be the average DA capacity offered in the other hours during the respective month, under normal conditions.

Due to lack of data, the situation depicted in Figure A-5 has not been quantitatively developed in the main body of the report.

## Annex 3.2.3 Additional reporting on data received through the Electricity Regional Initiatives on electricity wholesale markets

The electricity wholesale market chapter in this report has made extensive use of the data provided by NRAs. Firstly, this Annex provides information about the procedure that was followed to collect this data through cooperation between NRAs and the Agency. Secondly, and more importantly, this Annex provides additional reported data in the form of figures and tables. This includes information on themes that have been only partially covered in the electricity wholesale market chapter.

*Procedure*

The above-mentioned data regarding electricity wholesale market integration has been collected for the first time this year by the Agency/CEER in cooperation with the NRAs. The data collection effort was initiated through the Coordination Group for the Electricity Regional Initiative (CG for ERI).

The data that has been made available to the Agency/CEER include information about cross-border auction participants, long term auctions, daily auctions, intraday allocation, balancing, prices, cross-border capacity curtailments, dispatching, security reserve margins and congestion revenues.

The data collection through the Regional Initiatives started at the 9th CG for ERI meeting on 28 February 2012. The Agency/CEER provided the NRAs with a template showing the requested information, as well as a set of indicators with a view to assessing cross-border market integration issues. Prior to this request the Agency and CEER endeavoured as much as possible to use information that is already publicly available, such as information that is made available by ENTSO-E. With regard to the latter, the Agency asked for NRA assistance to perform additional consistency checks on cross-border data.

In March, consultations took place between the Agency, CEER and the NRAs on the data requested and any anticipated difficulties in obtaining data. Further, during monthly CG for ERI meetings, the Agency and CEER provided progress reports on the state of data delivered to the Agency. Out of 25 countries participating and accepting the data request through the CG for ERI group, 18 provided data; almost all of them were incomplete. The Agency and CEER have made use of the available data.

*Additional reporting*

Through the above-mentioned cooperation with the NRAs, the Agency received some data that did not fit the scope of the electricity wholesale market chapter of this Market Monitoring Report. However, the Agency and CEER realise that these data are valuable, which is why this Annex provides additional information on this information. The following topics will be presented: first, exchange of balancing across borders; second, auction participants per region and capacity holders by region; and finally, Transmission Reserve Margins (TRM).

## Annex 3.2.3 a) Balancing

The notion of balancing refers to manual (or possibly automatic) actions undertaken by TSOs to ensure that production (plus imports) is equal to consumption (plus exports).

Currently, cross-border balancing exchanges mainly correspond to cross-border exchanges undertaken by TSOs to correct anticipated imbalances. Unlike automatic reserves, these actions are manual and preventive, as they are undertaken usually from 15 minutes to a few hours before real time.

The development of balancing trades between neighbouring countries has the following advantages: firstly, it helps to improve security of supply; and secondly, it allows a reduction in the imbalance settlement price by providing the TSO with cheaper supplies and by increasing competition on the balancing market.

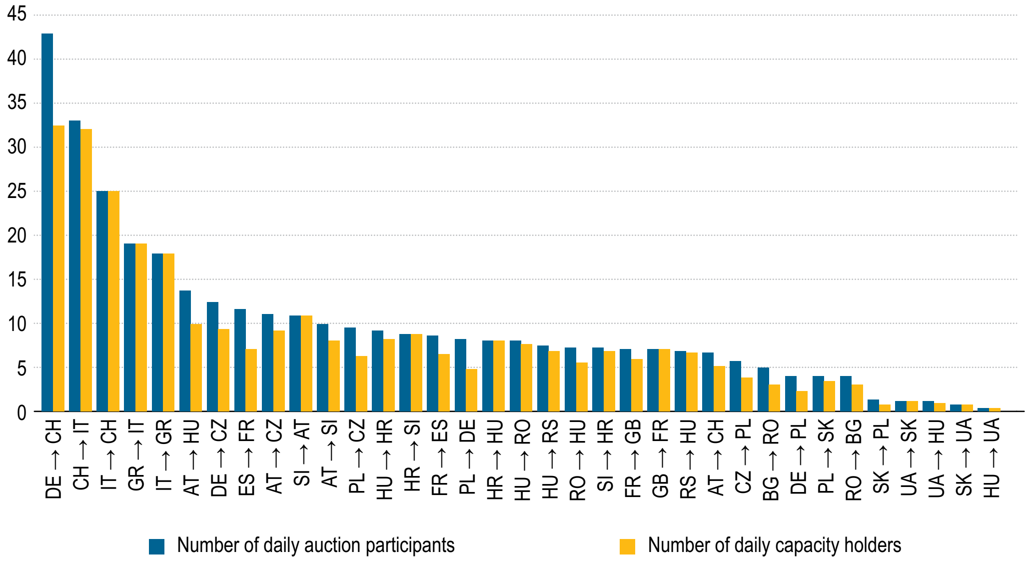
In the template used to collect information from NRAs through the Regional Initiative, the Agency asked for data on balancing energy across neighbouring borders. The result of the data collection shows that cross-border balancing is rare. To be precise, the share of reserves (secondary and tertiary) contracted abroad as a percentage of total reserves has been reported by NRAs as zero. The exceptions are Luxembourg, Lithuania, Slovenia, Denmark, Finland, Norway and Sweden.

## Annex 3.2.3 b) Number of auction participants and capacity holders per border

The following figures present the data provided by the NRAs on the average number of auction participants and capacity holders for their borders. Only those borders for which data was received are presented. In case of discrepancies due to rounding error on either side of a specific border, the average for the border in question was calculated. In case of significant differences, the NRAs were asked for clarification. If none were provided by the finalisation stage of this report, the respective figures have not been included.

The number of auction participants is the total of participating companies, whatever the relationship between them (for example: subsidiaries). The results below are presented by border and by auction (that is day-ahead, month-ahead and year-ahead). Borders managed through implicit auctions are not included in the figures.

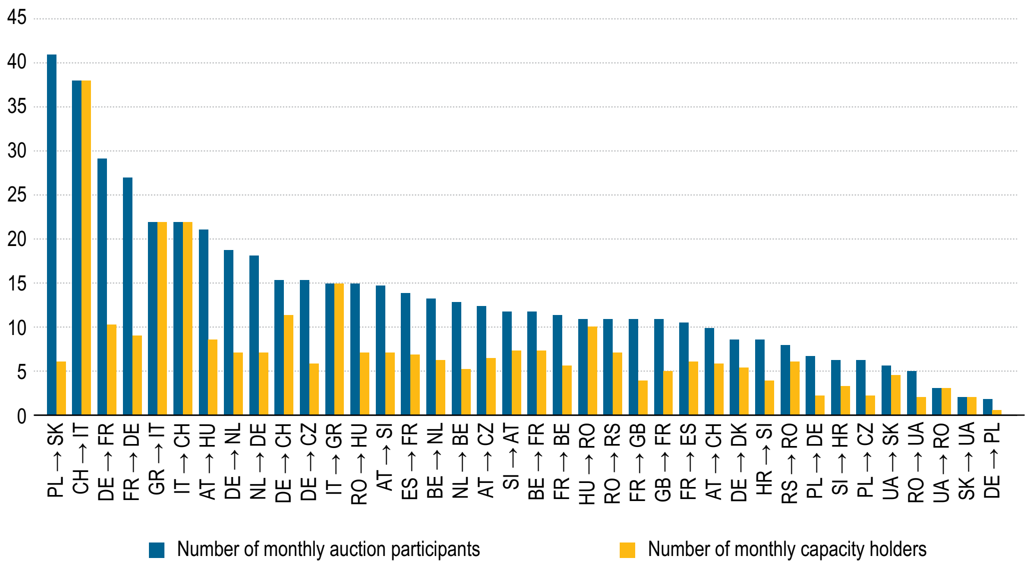
**Figure A-6: Number of daily auction participants and daily capacity holders per border – 2011**




*Source: Data provided by NRAs through the CG for ERI (2012)*

Figure A-6 shows for a selected number of borders the average number of participants and capacity holders for daily cross-border auctions for 2011. On average, there were 9.7 auction participants and 8.3 capacity holders involved in daily auctions in 2011 for the reported borders. This means that the average number of participants represents a ratio of 1.2 of the average number of capacity holders for the reported borders. The highest number of auction participants (43) is reported on the German-Swiss border, while less than one auction participant on average is involved in the daily auction on the Slovakian-Ukrainian and Hungarian-Ukrainian borders. On the Slovakian-Polish and German-Polish borders, the ratio between daily auction participants and daily capacity holders was the highest (close to 2).

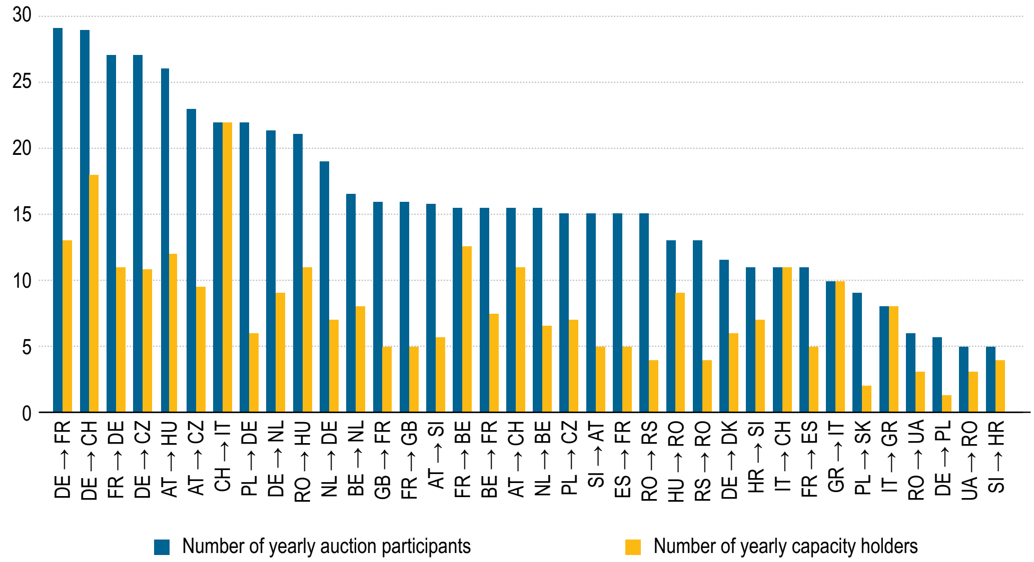
**Figure A-7: Number of monthly auction participants and capacity holders per border – 2011**




*Source: Data provided by NRAs through the CG for ERI (2012)*

Figure A-7 shows, for a selected number of borders, the average number of participants and capacity holders for monthly cross-border auctions for 2011. On average, 14 auction participants were involved in monthly auctions across the reported borders and almost half (7.6) of capacity holders, representing a ratio of 1.8 auction participants to one capacity holder. This ratio was the highest at 8.6 for the Polish-Slovakian border, with 41 auction participants on average and 6 capacity holders on average across all months in 2011. The lowest numbers of average monthly auction participants and capacity holders have been reported on the Ukrainian-Romanian, Slovakian-Ukrainian and German-Polish borders.

**Figure A-8: Number of yearly auction participants and capacity holders per border – 2011**




*Source: Data provided by NRAs through the CG for ERI (2012)*

Figure A-8 shows, for a selected number of borders, the average number of participants and capacity holders for yearly cross-border auctions for 2011. There were 16.1 auction participants and 7.9 capacity holders on average involved in yearly auction across the reported borders, which is a ratio of more than 2. The highest number (above 25) of auction participants was on the German-French, German-Swiss, French-German, German-Czech and Austrian-Hungarian borders. The highest number of capacity holders was recorded on the Swiss-Italian border, followed by the German-Swiss border. The lowest ratio auction participants and capacity holders in yearly auctions was 4.5 on the Polish-Slovakian border.

## Annex 3.2.3 c) Transmission reserve margins per border

The following table presents the data provided by NRAs on average transmission reserve margins (TRM) in MW for their borders.

**Table A-4: Transmission reserve margins by border – 2011 (MW)**

| Row labels | Average TRM (MW) | Row labels | Average TRM (MW) | Row labels | Average TRM (MW) |
|---|---|---|---|---|---|
| All → PL | 644 | ES → PT | 240 | NL → NO | 300 |
| AT → CH | 140 | FI → SE | 100 | NL → UK | 300 |
| AT → CZ | 200 | FR → BE | 250 | NO → SE | 150 |
| AT → HU | 173 | FR → DE | 200 | PL → All | 466 |
| AT → IT | 15 | FR → ES | 200 | PL → DE | 280 |
| AT → SI | 100 | FR → IT | 175 | PL → SK | 200 |
| BE → FR | 250 | HR → HU | 200 | PT → ES | 220 |
| BE → NL | 250 | HR → SI | 200 | RO → BG | 100 |
| BG → RO | 100 | HU → AT | 200 | RO → HU | 100 |
| BY → LT | 50 | HU → HR | 200 | RO → RS | 100 |
| CH → AT | 140 | HU → RO | 100 | RO → UA | 100 |
| CH → DE | 370 | HU → RS | 100 | RS → HU | 100 |
| CH → IT | 271 | HU → SK | 200 | RS → RO | 100 |
| CZ → AT | 200 | HU → UA | 200 | RU → LT | 50 |
| CZ → DE | 330 | IT → AT | 15 | SE → DK | 50 |
| CZ → SK | 200 | IT → CH | 288 | SE → FI | 100 |
| DE → CH | 370 | IT → FR | 172 | SE → NO | 150 |
| DE → CZ | 330 | IT → SI | 25 | SI → AT | 100 |
| DE → DK | 100 | IT → SI | 500 | SI → HR | 200 |
| DE → FR | 200 | LT → BY | 50 | SI → IT | 500 |
| DE → NL | 250 | LT → LV | 50 | SK → HU | 200 |
| DE → PL | 280 | LT → RU | 50 | SK → PL | 200 |
| DK → DE | 680 | LV → EE | 100 | SK → UA | 200 |
| DK → SE | 50 | LV → LT | 50 | UA → HU | 200 |
| EE → LV | 100 | NL → BE | 300 | UA → RO | 100 |
| ES → FR | 330 | NL → DE | 300 | UA → SK | 200 |

*Source: Data provided by the NRAs through CG for ERI (2012)*

*Note: "All" is the total TRM for all borders. In case of discrepancies in the data provided by two NRAs for a specific border, the data from the NRA from the "Country of origin" has been taken into account. For the DE-CZ and CZ-DE borders, the data in the table represents the sum provided by two German TSOs. The DK→SE and SE→DK borders represent the sum of DK2→SE4 and DK1→SE3 and vice versa. The FI→SE and SE→FI borders represent the sum of FI→SE1 and FI→SE2 and vice versa. The SE→NO and NO→SE borders represent the sum of SE3-NO1, SE2-NO3, SE2-NO4, SE1-NO4 and vice versa.*

## Annex 3.3 Additional information on gas wholesale markets

### Annex 3.3.1 Transit contracts in existence

**Table A-5: Country-by-country results of the Agency's 2012 gas transit contracts enquiry**

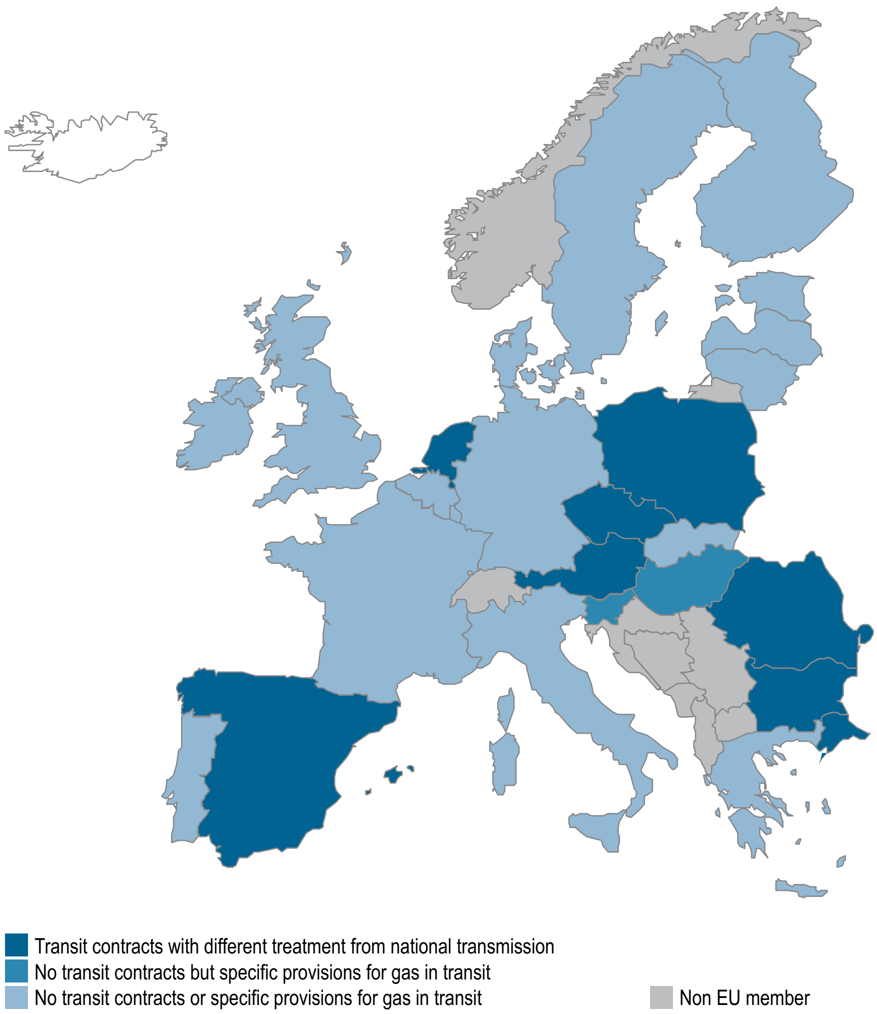
| Country | Transit contracts exist? | Different treatment from national transmission? | With respect to what? | Other legal provisions specific for gas in transit? | With respect to what? | Actions expected to be taken (as reported by the NRA) and other comments |
|---|---|---|---|---|---|---|
| Austria | Yes | Yes | N/A | No | - | Successful implementation of the new Natural Gas Act and market rules by 1 January 2013. |
| Belgium | No | No | - | No | - | Approved entry-exit rules to become operational as of 1 October 2012. |
| Bulgaria | Yes | Yes | Tariffs, TPA, CAM | - | - | The transposition of the 3rd Package and introduction of an entry-exit (E/E) model should enforce compliance, but the recent extension of the transit contract in 2007, until 2030, creates serious legal issues. |
| Cyprus | No | - | - | No | - | - |
| Czech Republic | Yes | Yes ("first type": contracts signed before the unbundling of the incumbent in 2006) | Allocation of gas flows, tariff methodology and prices, units of measurement | No | - | 3rd Package transposition foresees a 6-month transition period to bring the contracts of the "first type" into line with a decoupled E/E system. The regulator (ERU) expressed doubts about the feasibility of this deadline. |
| Denmark | No | - | - | No | - | - |
| Finland | No | - | - | No | - | - |
| France | No | - | - | No | - | - |
| Germany | No | - | - | No | - | - |
| Greece | No | - | - | No | - | - |
| **Hungary** | * | N/A | N/A | Yes | Transit cannot be disrupted, based on the Energy Charter Treaty agreement. | Establishment of a virtual trading point in progress, to be run by the Hungarian Power Exchange (HUPX) |
| **Ireland** | No | - | - | No | - | The Common Arrangements for Gas (CAG) aim to introduce a common E/E model and effective gas transportation on the whole island of Ireland. Transit arrangements are being considered. All EU requirements will be taken into account. |
| **Italy** | No | - | - | Yes | In case of emergency, transit must not be interrupted. | - |
| **Latvia** | No | - | - | No | - | - |
| **Lithuania** | * | N/A | N/A | - | - | - |
| **Luxembourg** | No | - | - | No | - | - |
| **Malta** | No | - | - | No | - | - |

| Country | Transit contracts exist? | Different treatment from national transmission? | With respect to what? | Other legal provisions specific for gas in transit? | With respect to what? | Actions expected to be taken (as reported by the NRA) and other comments |
|---|---|---|---|---|---|---|
| **Poland** | Yes | Yes | Capacity allocation | No | - | The Grid code was implemented on 31 August 2011. EuroPol has reported to regulator ERO that it is aiming to amend the transit contract. ERO is now monitoring the process. |
| **Portugal** | No | - | - | No | - | - |
| **Romania** | Yes | Yes | TPA, tariffs, CAM, CMP | Yes | Same aspects | An infringement procedure by the EC is ongoing. Negotiations are in progress between Romania, Russia, and Bulgaria, in order to amend the intergovernmental agreements. The NRA is involved. |
| **Slovakia** | No | - | - | No | - | - |
| **Slovenia** | No | - | - | Yes | Tariffs | - |
| **Spain** | Yes | Yes | Tariffs, CAM, CMP | Yes | Tariffs | According to regulator CNE, a new tariff methodology is being developed in the context of an all-Iberian market (ES/PT), which also addresses the issue of transits. In future, actions will be taken to adapt all contracts to the 3rd package. |
| **Sweden** | No | - | - | No | - | - |
| **Netherlands** | Yes | Yes | Balancing provisions, transportation rates | - | - | One transit contract is still in place. Its adaptation to EU law is currently being monitored by regulator NMA. |
| **United Kingdom** | No | - | - | - | - | The new CAM/CMP rules may introduce processes that would differentiate between transit and national transmission. The only gas transits are to Ireland via mainland UK. |

*Source: The Agency (2012)*

*Notes: “N/A” = Not Applicable.  “-“ = Not Available.*
* There are transit contracts, although they do not fall exactly under the terms of reference of the Agency’s enquiry.

**Figure A-9: Country map of gas transit contracts or provisions in EU MS (1 October 2012)** [233]




*Source: The Agency (2012)*

*Note: Cyprus and Malta do not currently have an organised gas market.*

233 In several cases (e.g. Lithuania and Hungary), transit contracts have been identified involving gas in transit from a non-EU origin to a non-EU destination. Such contracts, although falling out of the scope of the current transits inquiry, will be further investigated by the Agency.

## Annex 3.3.2 Capacity utilisation at gas interconnection points

This section shows capacity utilisation rates at a number of major gas interconnection points (IPs) in Europe. The emphasis of the analysis lies in the assessment of the registered flows and its interrelation with available capacities. The aim is to identify those IPs – and associated regions – with excess capacity and, vice versa, those possible bottlenecks featuring either physical or contractual congestion.

The following figures illustrate firm technical and firm booked capacities[234] at a number of IPs, as well as net physical flows[235]. The selected IPs represent an assortment of principal gas flows distributed through the European continent.

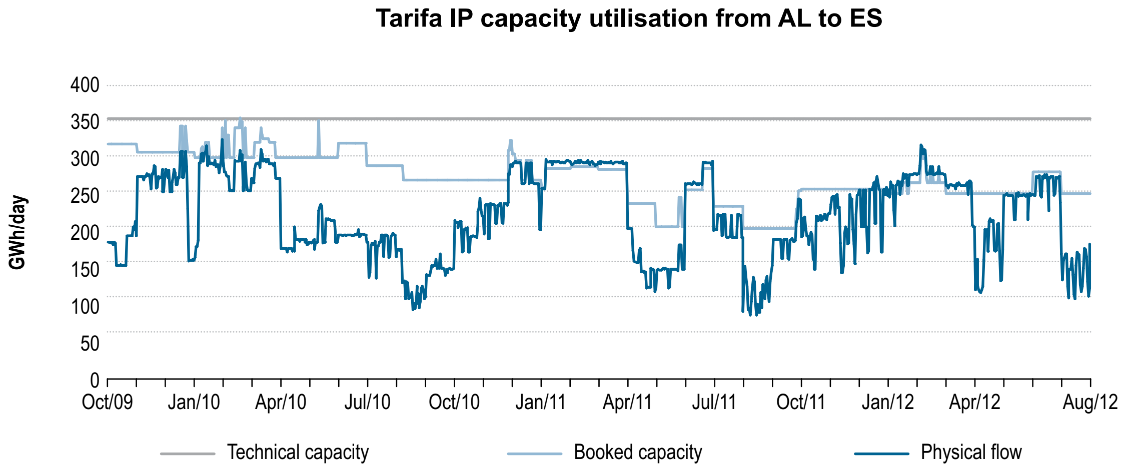
The figures have been constructed based on the information obtained from individual TSO websites and from ENTSOG's Transparency Platform. In the latter case, www.gas-roads.eu does not store data prior to 2009 for utilised capacity, thus preventing any quantitative analysis of possible past capacity hoarding. Data have been collected from January 2009 to July 2012, with some missing data in between.

The capacity utilisation information collected can be divided into the following regions: South West, Central North, and Eastern areas. These areas reflect geographical realities and do not necessarily follow the design of the Gas Regional Initiative.

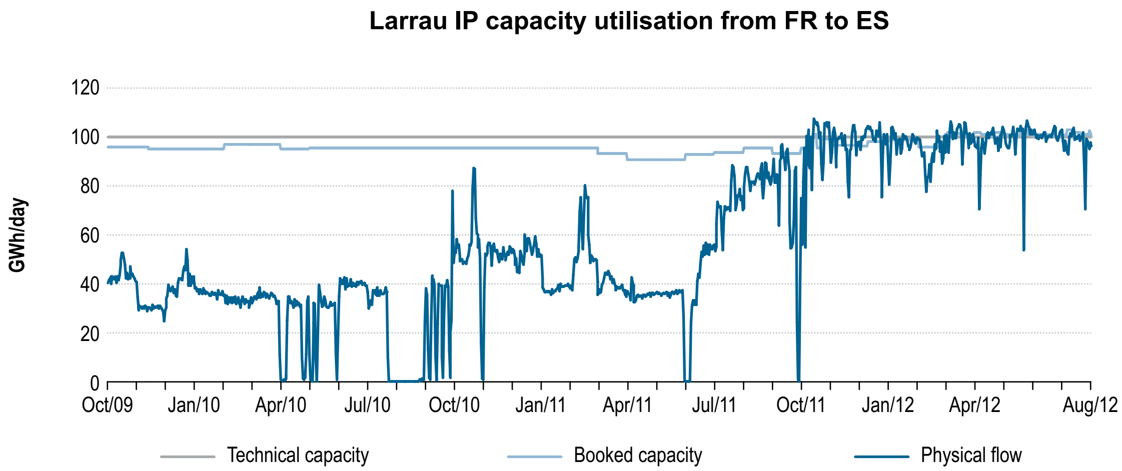
234 Published firm technical capacities are defined as the maximum firm capacities that TSOs can offer to users, taking into account system integrity and the operational requirements of the network. In this respect, capacities can depend on several factors: flows, pressure, network configuration, and demand/supply conditions and forecasts. In general, the technical capacities published by TSOs can be considered as a (possibly very) conservative approximation of what TSOs think they can commit unconditionally as firm capacity. As there is no common European methodology on this matter yet (the Framework Guidelines on Interoperability aim to tackle the issue), the adopted approaches can differ widely between TSOs. Interruptible capacities were not considered in this analysis.

235 The figures illustrate real measured aggregated physical flows across IPs, although – in some cases – published flows can coincide with commercial ones. Commercial flows can be used as an approximation, subject to compensation factors. Where IPs are directionally reversible, aggregated net flows were considered.

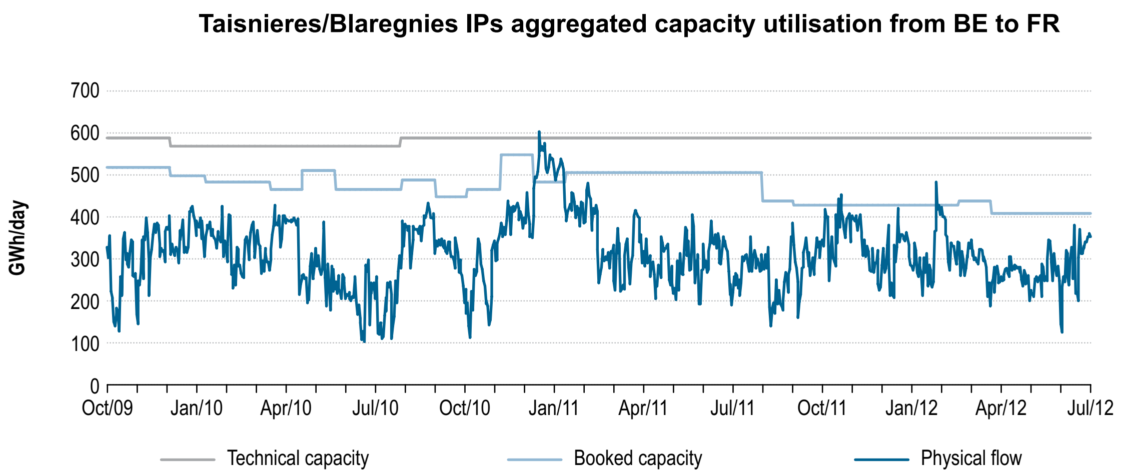
**Figure A-10: Capacity utilisation at a selected sample of European IPs up to 2012**




*Source: Enagas (2012)*

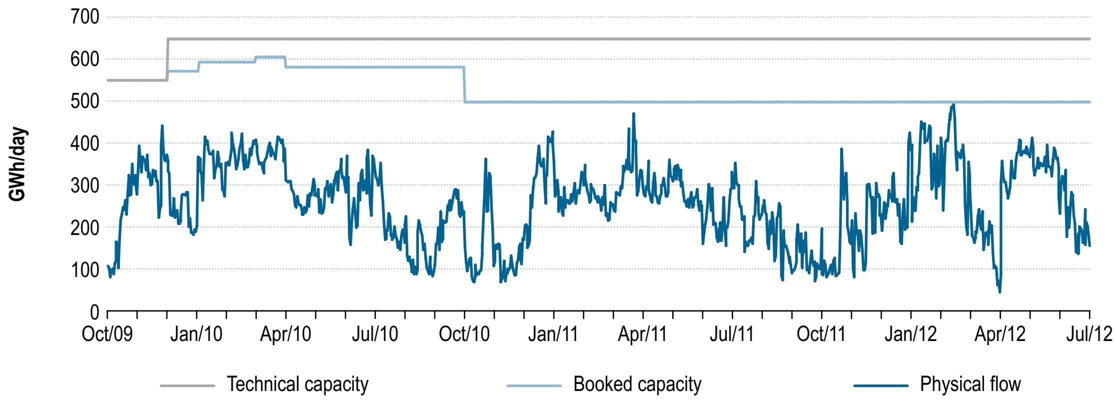



*Source: Enagas (2012)*



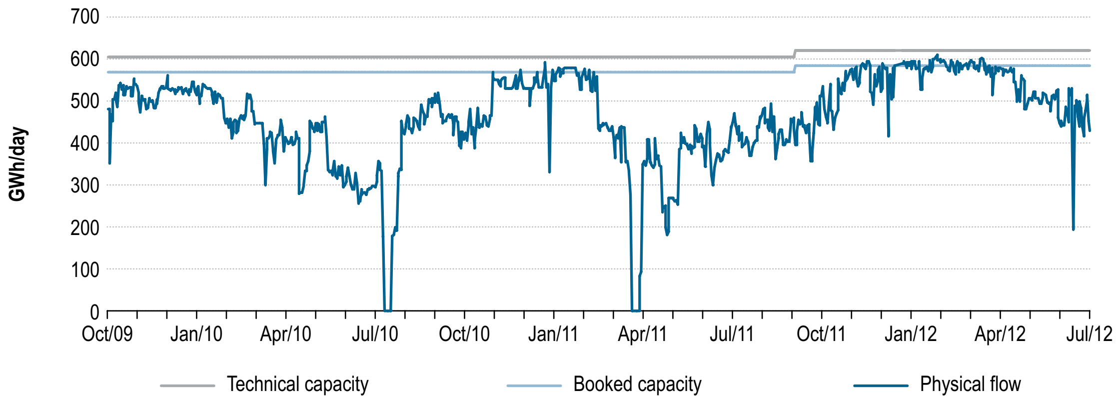

*Source: GRT-Gaz (2012)*

**Medelsheim/Obergailbach IP aggregated capacity utilisation from DE to FR**



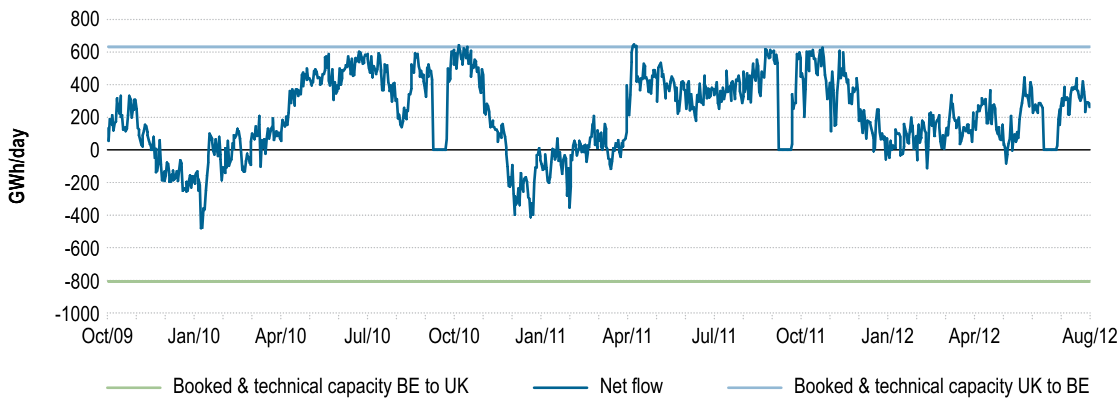

*Source: GRT-Gaz and Open Grid Europe (2012)*

**Dunkerque IP capacity utilisation from NO to FR**



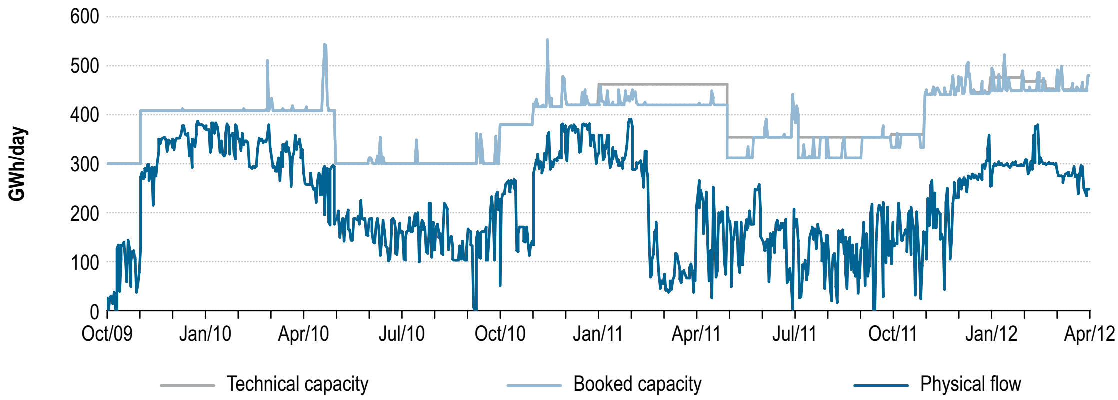

*Source: GRT-Gaz (2012)*

**Interconnector (IUK) capacity utilisation between UK and BE**



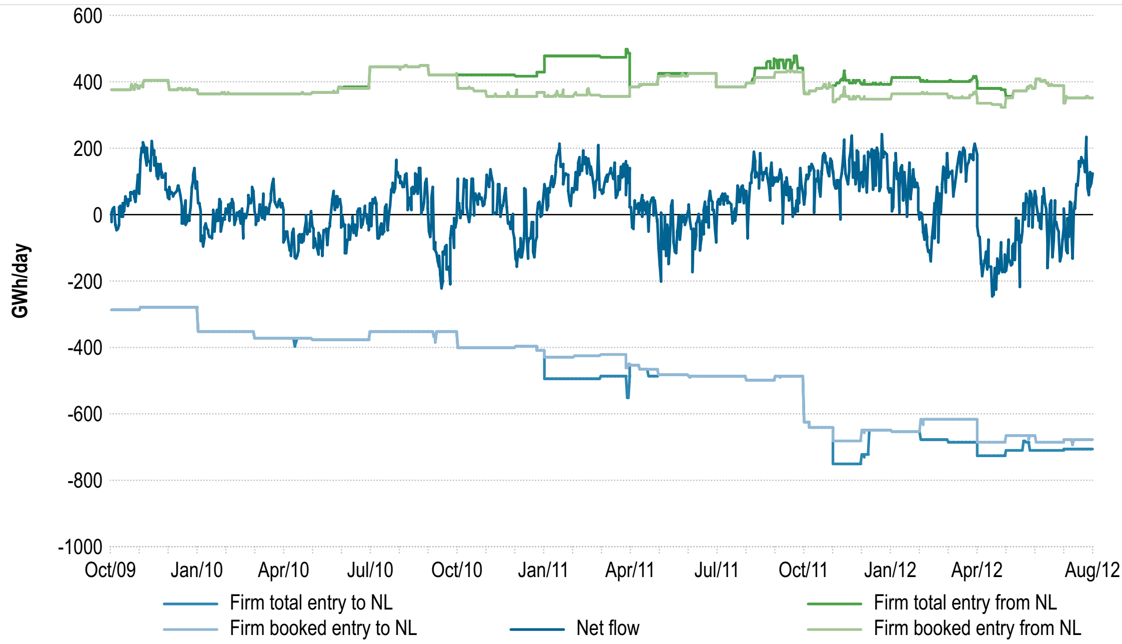

*Source: IUK and Fluxys (2012)*

**Julianadorp IP capacity utilisation from NL to UK**




*Source: Gas Transport Services (2012)*

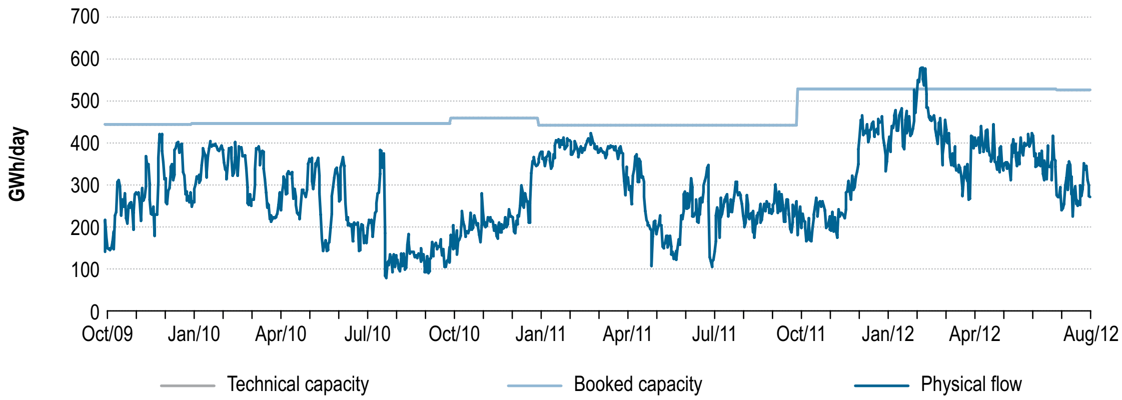
**Oude Statenzijl/Bunde capacity utilisation between NL and DE[236]**




*Source: Gas Transport Services (2012)*

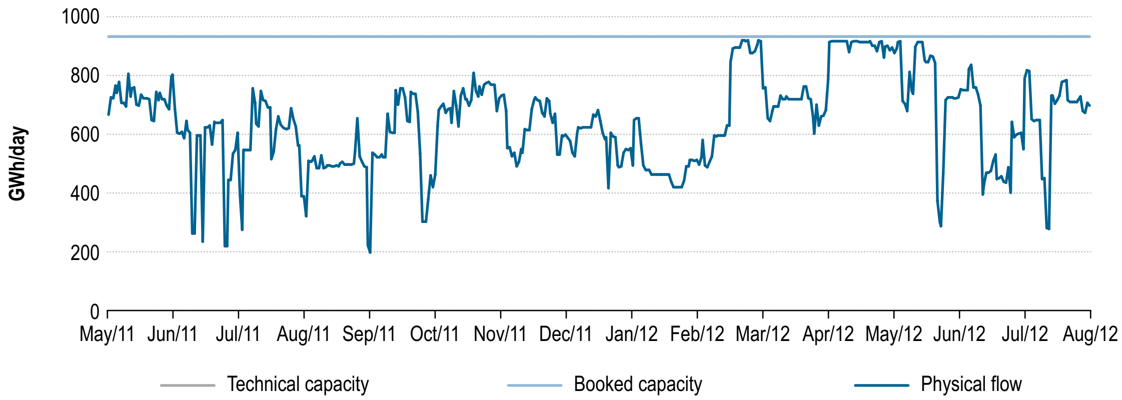
236 The figures relating to the Oude Statenzijl IP cluster show values only from those TSOs flowing high-quality (H) gas through this complex border cluster. Low calorific gas and storage-related flows are not considered. The figures have been calculated according to the methodology explained in Gas Transport Services' Transport Insights: http://www.gastransportservices.nl/en/downloads/publications/reports

**Bocholtz IP capacity utilisation from NL to DE**



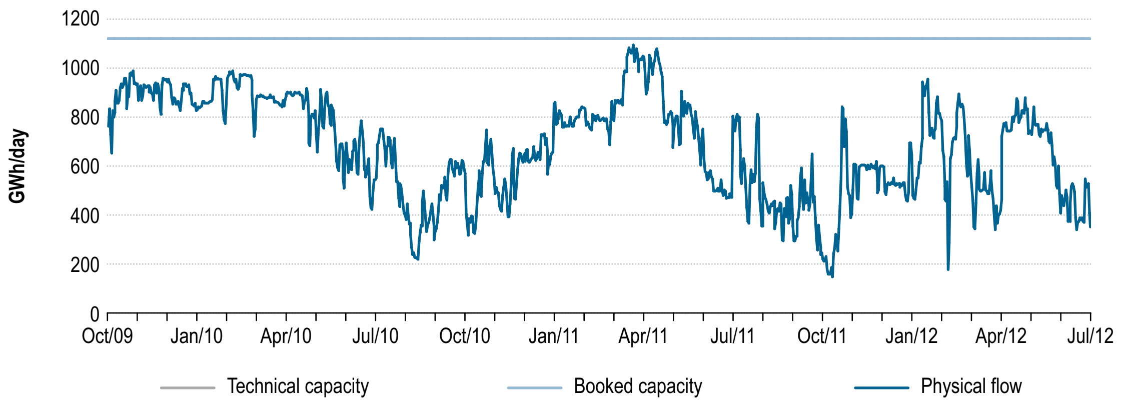

*Source: Gas Transport Services (2012)*

**Mallnow capacity utilisation from PL to DE**



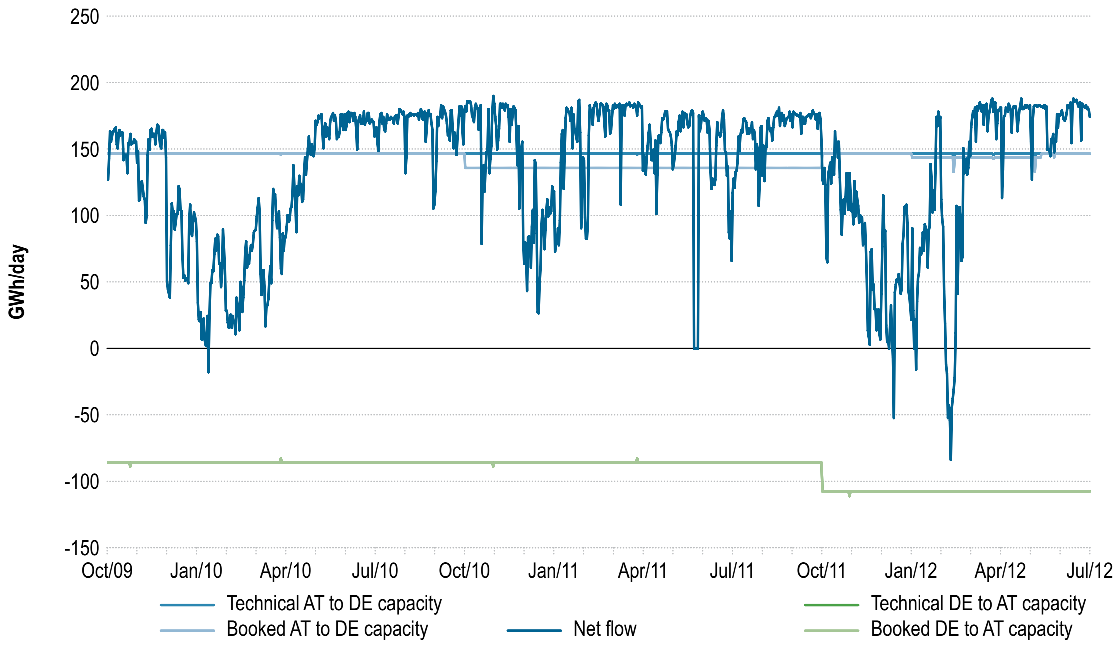

*Source: Gascade (2012)*

**Waidhaus capacity utilisation from CZ to DE**



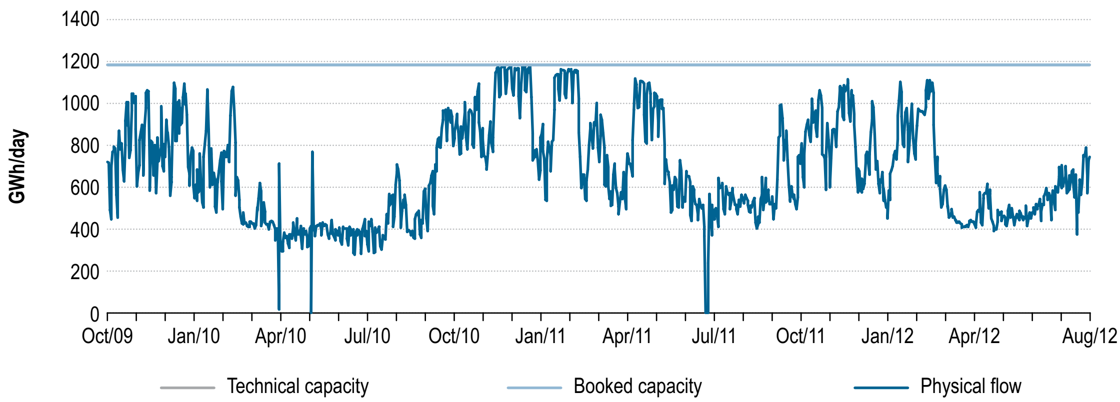

*Source: Open Grid Europe and GRT-Gaz (2012)*

**Oberkappel IP capacity utilisation between DE and AT[237]**




*Source: Gas Transport Services (2012)*

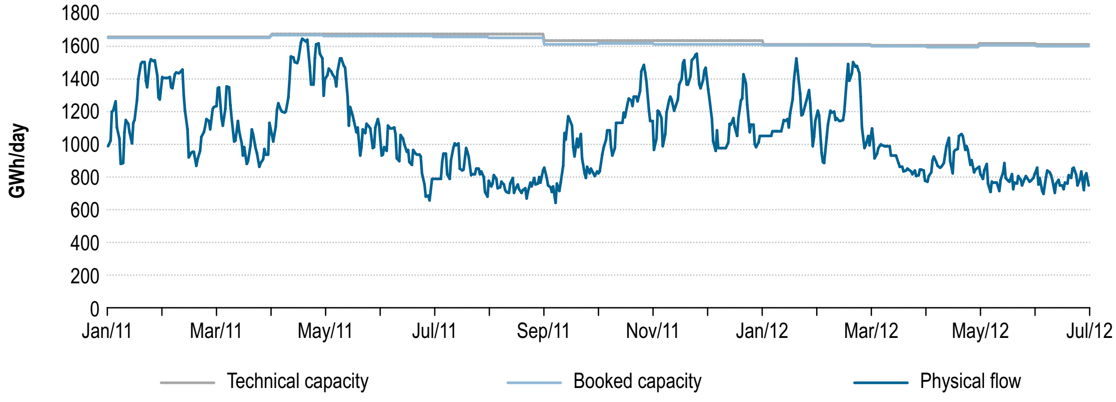
**Tarvisio/Arnoldstein IP capacity utilisation from AT to IT**




*Source: Snam Rete Gas (2012)*

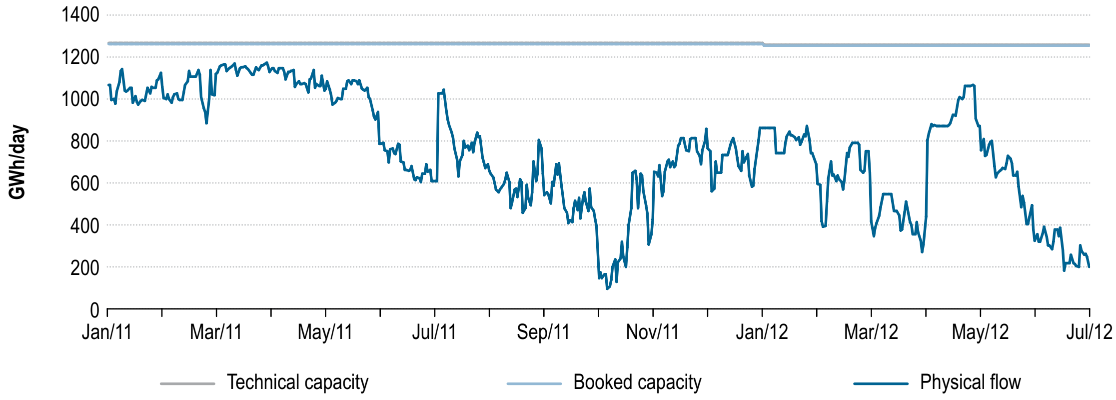
237 Net flows can exceed technical firm capacity when interruptible capacity is allocated and runs, *de facto*, as firm.

**Baumgarten IP capacity utilisation from SK to AT**



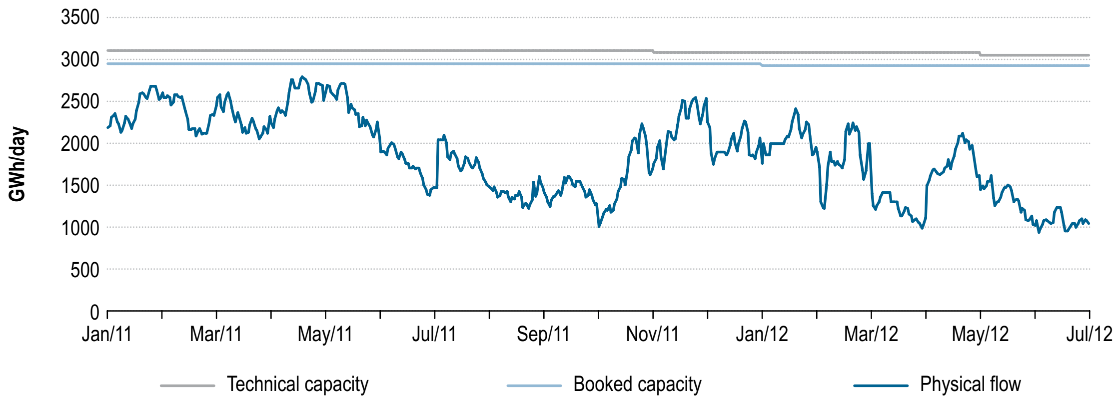

*Source: Eustream (2012)*

**Lanzhot IP capacity utilisation from SK to AT**




*Source: Eustream (2012)*

**Veľké Kapušany/Uzghorod IP capacity utilisation from UA to SK**




*Source: Eustream (2012)*

**Table A-6: Transmission projects submitted to ENTSOG for the TYNDP 2011-2020 and commissioned over the last two years**

| Project name | Interconnection name | Year of commissioning | Capacity (GWh/d) | From | From TSO | to | To TSO |
|---|---|---|---|---|---|---|---|
| PL - CZ interconnector | Cieszyn | 2011 | 4.18 | Hub Czech Republic | NET4GAS | Hub Poland | GAZ-SYSTEM |
| Montalbano-Messina | Gela | 2011 | 25.3 | Libya | | Hub Italia | Snam Rete Gas |
| BG-RO interconnection | BG-RO interconnection | 2012 | 45.1 | Hub Bulgaria | Bulgartransgaz | Hub Romania | Transgaz |
| BG-RO interconnection | BG-RO interconnection | 2012 | 45.1 | Hub Romania | Transgaz | Hub Bulgaria | Bulgartransgaz |
| Interconnection HR-HU | Dravaszerdehaly | 2011 | 195.8 | Hub Hungary | FGSZ Naturel Gas Transmission | Hub Croatia | Plinacro |
| GAZELLE pipeline | Hora Sv. Kateřiny/Brandov | 2012 | 951.5 | Interconnector OPAL | OPAL NEL Transport | Hub Czech Republic | NET4GAS |
| Reverse Flow Projects - Net4Gas | Lanžhot | 2011 | 275 | Hub Czech Republic | NET4GAS | Hub Slovakia | Eustream |
| CZ-PL interconnection (STORK) | Cieszyn | 2011 | 4.18 | Hub Czech Republic | NET4GAS | Hub Poland | GAZ-SYSTEM |
| Artère du Béarn | Larrau | 2012 | 157.3 | Hub Spain | Enagás | Hub France TIGF | TIGF |
| Artère du Béarn | Larrau | 2012 | 62.7 | Hub France TIGF | TIGF | Hub Spain | Enagás |
| System Enhancements | Emden EPT | 2012 | 20.9 | Supplier Norway | Gassco | Hub Germany NCG | Open Grid Europe |
| System Enhancements | Oberkappel | 2012 | 110 | Hub Germany NCG | Open Grid Europe | Hub Austria | BOG |
| System Enhancements | Bocholtz | 2012 | 74.8 | Hub Netherlands | Gas Transport Services | Hub Germany NCG | Open Grid Europe |
| System Enhancements | Oude Statenzijl | 2012 | 24.2 | Hub Germany NCG | Open Grid Europe | Hub Netherlands | Gas Transport Services |
| System Enhancements | Dornum | 2012 | 6.6 | Supplier Norway | Gassco | Hub Germany NCG | Open Grid Europe |
| System Enhancements | Eynatten | 2012 | 77 | Hub Germany NCG | Open Grid Europe | Hub Belgium | Fluxys |
| System Enhancements | Vreden | 2012 | 25.3 | Hub Netherlands | Gas Transport Services | Hub Germany NCG | Open Grid Europe |
| System Enhancements | Elten | 2012 | 18.7 | Hub Netherlands | Gas Transport Services | Hub Germany NCG | Open Grid Europe |

| Project name | Interconnection name | Year of commissioning | Capacity (GWh/d) | From | From TSO | to | To TSO |
|---|---|---|---|---|---|---|---|
| System Enhancements | Oberkappel | 2012 | 12.1 | Hub Austria | BOG | Hub Germany NCG | Open Grid Europe |
| System Enhancements | Eynatten | 2012 | 88 | Hub Belgium | Fluxys | Hub Germany NCG | Open Grid Europe |
| N Messimvria CS | Sidirokastron | 2011 | 24.53 | Hub Bulgaria | Bulgartransgaz | Hub Greece | DESFA |
| N Messimvria CS | Kipi | 2011 | 26.84 | Hub Turkey | Botas | Hub Greece | DESFA |
| RO-BG Interconnection | RO-BG Interconnection | 2012 | 30.8 | Hub Romania | Transgaz | Hub Bulgaria | Bulgartransgaz |
| RO-BG Interconnection | RO-BG Interconnection | 2012 | 22 | Hub Romania | Bulgartransgaz | Hub Bulgaria | Transgaz |
| Reverse flows in the eustream transmission system | Baumgarten | 2011 | 244.2 | Hub Austria | BOG | Hub Slovakia | eustream |
| Reverse flows in the eustream transmission system | Lanžhot | 2011 | 205.04 | Hub Czech Republic | NET4GAS | Hub Slovakia | eustream |
| M1-1 Ceršak – Kidričevo | Murfeld /Ceršak | 2011 | 146.3 | Hub Austria | Gas Connect Austria | Hub Slovenia | Plinovodi d.o.o. |
| Loop Tivissa-Paterna | Larrau | 2012 | 62.7 | Hub France TIGF | TIGF | Hub Spain | Enagás |
| Loop Tivissa-Paterna | Larrau | 2012 | 157.3 | Hub Spain | Enagás | Hub France TIGF | TIGF |

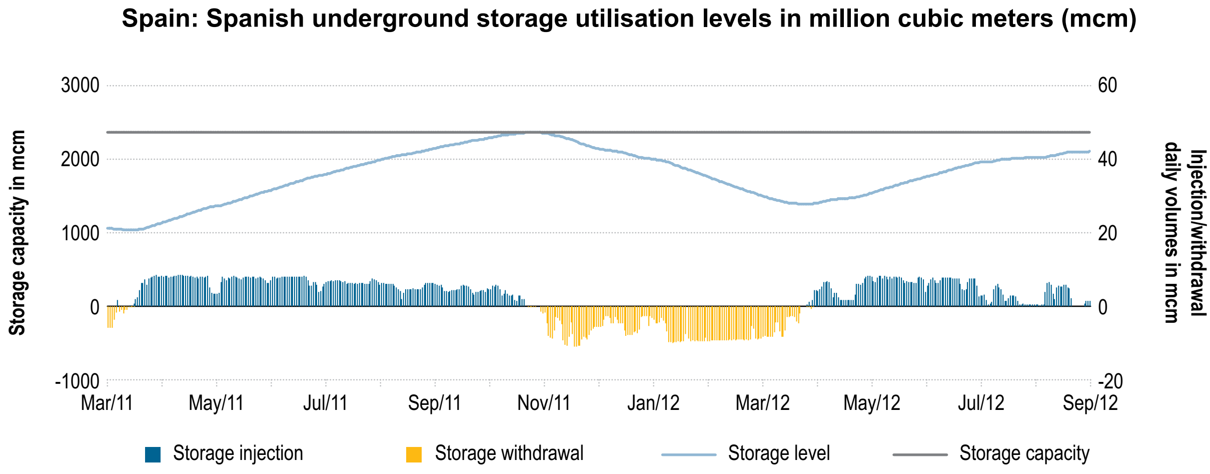
*Source: ENTSOG (2012), private correspondence with the Agency. The data might be subject to further verification by ENTSOG after the publication of this report.*

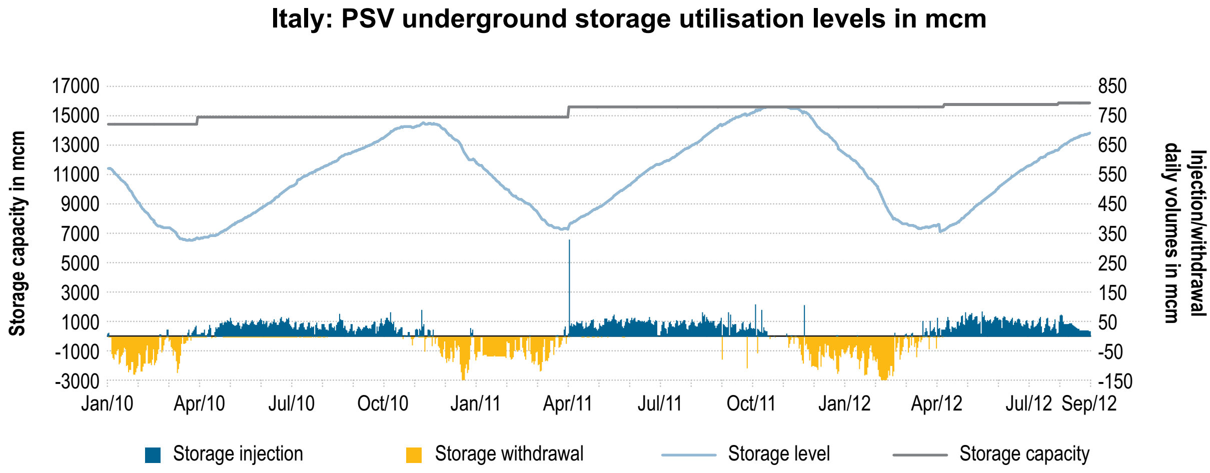
**Table A-7: Access charging regimes for gas transportation – 2012**

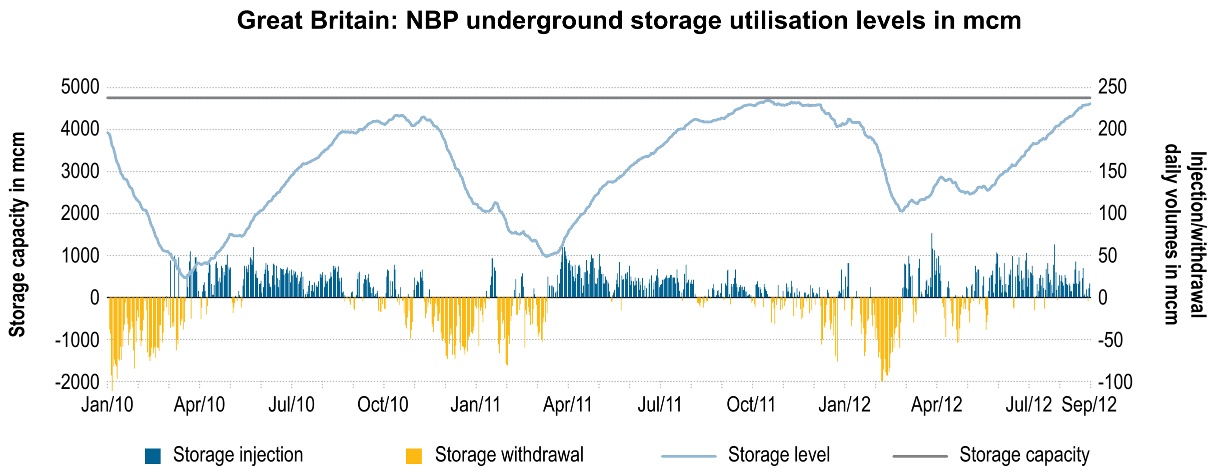
| Country | Tariff Structure |
|---|---|
| **Austria** | Until the 3rd Package is implemented, Austrian transmission tariffs will be calculated on the basis of contract paths. The tariff paid reflects the distance both in terms of border to border and of domestic transmission. |
| **Belgium** | As a general rule, tariffs are determined by dividing the allocated costs by reference quantities.<br>For transmission services, cost is allocated pro-rata with a weighting factor corresponding to a distance: the weighting factor for cost allocation to the entry points is the same for all entry points (entry tariffs are thus the same at all entry points). The weighting factor or distance allocated to the exits at IPs represents the distance the gas has to travel to reach the exit point from the physically connected entry zone. A new transportation entry-exit model was introduced on 1 October 2012. |
| **Bulgaria** | Tariffs for the transmission system are regulated, but details are not published. The transmission charge is uniform for all customers (postage stamp). The only shipping customer is Bulgargaz.<br>Standard contracts generally do not have a specified duration. There is a separate pipeline system for transit. Transit tariffs are not subject to regulation, but are negotiated bilaterally. |
| **Czech Republic** | The Czech Republic's tariff transmission system is structured as a fully decoupled entry-exit system with one virtual hub. The same methodology applies to cross-border gas flows and to flows that are intended for domestic consumption. |
| **Estonia** | The Estonian transmission network has three entry points and no exit interconnection point. A breakdown of costs between entry and exit IPs has therefore not been made. The gas market is dominated by one supplier. There is no distinction between costs related to cross-border and domestic networks. |
| **Finland** | The gas TSO Gasum applies a postage-stamp tariff to gas transmission. Transmission tariffs are charged based on contracted capacities, differentiated by annual gas volume, number of hours of usage, and peak capacity. More generally, the energy regulator applies an incentive-based regulation method, including the possibility of setting comparative efficiency targets. |
| **France** | The tariff transmission system is based on a full entry-exit capacity regime, separately bookable, with no restrictions. There is one virtual hub per balancing zone (3 zones), with a planned strategy of widening the balancing zones. The transmission tariff applies in the same way to cross-border and domestic flows. Gas transmission tariffs are determined on the basis of the costs specific to the main and regional networks, distinguishing between the costs necessary for the reinforcement of the core part of the main transmission grid and those necessary for the creation of additional capacity at interconnection points. |
| **Germany** | The tariff transmission system is structured as a fully decoupled entry-exit system, with one virtual hub per balancing zone. The same transmission tariff structure applies to both cross-border and domestic flows. The breakdown of allowed revenues is undertaken according to a causation principle for both entry and exit points. |
| **Great Britain** | Users purchase entry and exit capacity, some of which is allocated to shippers through the use of auctions. The transmission tariff applies in the same way to cross-border and domestic flows. National Grid's revenue allowance is solely based on the returns from the domestic national transmission system, plus other incentives.<br>Interconnectors recover their revenues separately, i.e. only those network users that use interconnectors pay for them. The TSO aims to recover its allowed revenue on a 50/50 basis from entry and exit points. The use of auctions means that the same is not necessarily true for individual entry-exit points that connect the GB system with other networks. |
| **Greece** | The tariff transmission tariff system is currently based on a postage stamp methodology. Transmission tariffs apply in the same way to both cross-border and domestic flows. Regulator RAE is in the process of establishing a new tariff system based on an entry-exit model and on cost reflectivity. This system will be applied from 2013. |
| **Hungary** | The transmission tariff system is based on commodity and capacity charges. Entry and exit capacity can be booked separately. There is one balancing zone in Hungary, with one virtual hub and a virtual balancing market. A different methodology is applied for setting tariffs for cross-border transmission and those for the domestic transmission network, although both are based on costs specific to the network. |
| **Ireland (Republic)** | A decoupled, entry-exit regime is implemented for using the Irish transmission system. Under the entry-exit regime, CER has implemented a postage stamp exit system whereby gas delivered at the Inch and Moffat entry points is treated as being capable of off-take at any exit point where a shipper holds capacity. Regulator CER is currently examining the regulatory treatment of the interconnector system. It has proposed to introduce auctions at all entry points and to calculate entry tariffs on the basis of the estimated long run marginal cost (LRMC) of transporting gas at each entry point. |

| Country | Tariff Structure |
|---|---|
| **Italy** | The Italian tariff for the national transmission system is based on full entry-exit capacity, separately bookable, with no restrictions. Transmission charging applies the same criteria to cross-border and domestic flows, and allowed TSO revenues are geographically split between regional allowed revenues and national allowed revenues. However, cross-border flows do not require the use of the regional transmission grid, and therefore the regional transmission grid charge is not applied. Regional allowed revenues are used to calculate the regional grid charge (a postage stamp tariff), while national allowed revenues are used to calculate entry-exit charges. A 50% split of allowed revenues is applied between entry and exit points. |
| **Lithuania** | The entire cost of transmission is charged to consumers by means of postage stamp tariffs. An entry-exit model will be implemented. |
| **Luxembourg** | In the absence of transit flows, all flows from different entry points are considered in the same way. All bookings at interconnection points are currently entry bookings; exit points on the system are for domestic consumption only, e.g. exit points to final consumers or distribution grids. |
| **Netherlands** | The methodology applied is based on an entry-exit uncoupled model, with distance taken into account. The same methodology is applied to cross-border and domestic flows. |
| **Portugal** | The transmission tariff calculation methodology changed in 2010 from a postage stamp system to a fully decoupled entry-exit tariff system. The transmission tariff applies in the same way to cross-border and domestic flows, and is charged at each entry and exit point of the national transmission network. Gas transmission tariffs are determined (through an algorithm) on the basis of the costs specific to each entry and exit point. |
| **Romania** | A regulated postage stamp system for gas transmission is applied. The entry-exit tariff regime is awaiting governmental approval. The transmission tariff is the sum of a fixed component for reserving capacity in the system, plus a volume component for the use of the transmission system. |
| **Spain** | The tariff model applied in Spain is an entry-exit model with a single balancing area (uniform for the entire country) and includes both transmission and distribution costs.<br>The charge for entry points consists of a uniform value for reservation capacity at any given entry point in the system. For exit points, two uniform charges are applied, independently of the exit location: the reservation charge and the usage charge, both dependent on pressure and annual consumption at each exit point. The usage charge is based on the volume of gas which is shipped to that exit point. |
| **Sweden** | An entry-exit uncoupled charging model is applied. There is no difference between costs related to cross-border and domestic flows or systems. The Swedish transmission network has only one entry point. A breakdown of costs between entry and exit IPs has not been made, as Sweden has no exit points. |

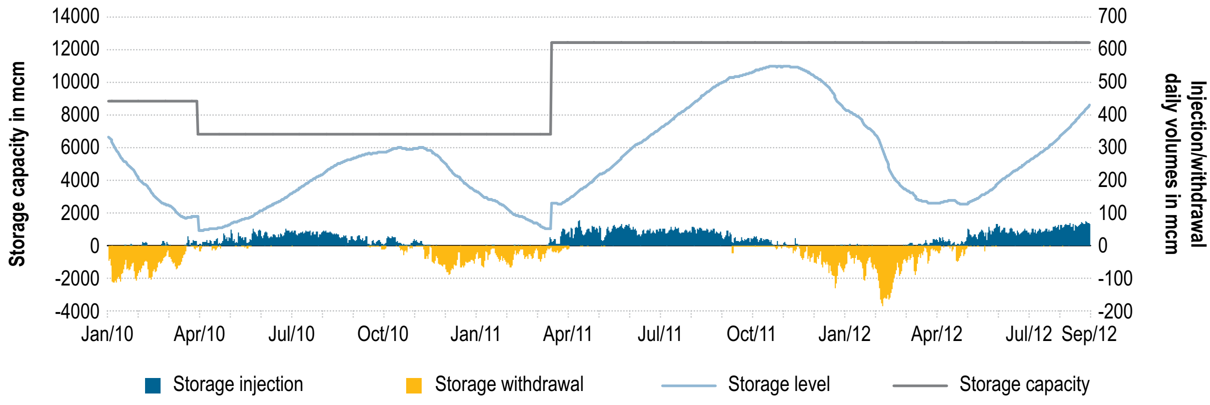
**Figure A-11: Storage capacity utilisation in a sample of EU MS**



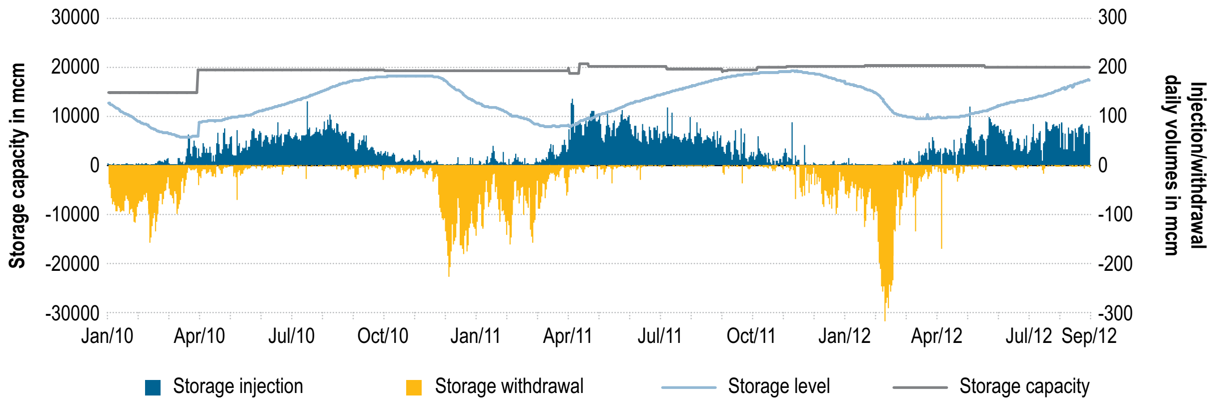



**France: PEGs underground storage utilisation levels in mcm**




**Germany: NCG and Gaspool underground storage utilisation levels in mcm**

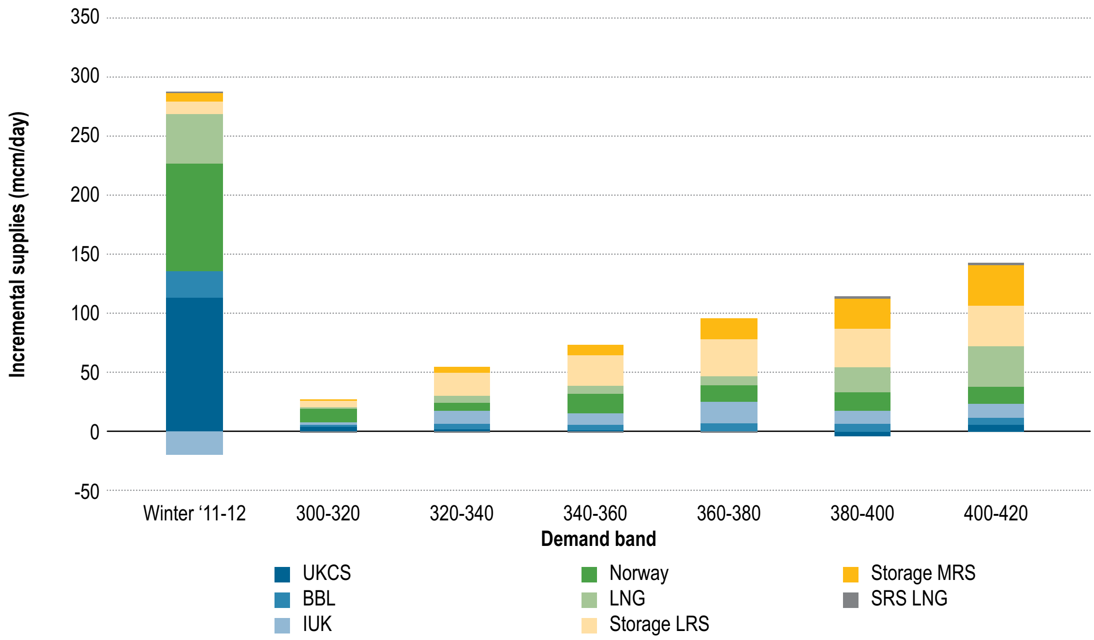



*Source: Agency/CEER elaboration based on GSE (Gas Storage Europe) data (2012)*

## Annex 3.3.3 Supply of gas flexibility in the GB system

Traditionally, the United Kingdom Continental Shelf (UKCS) has provided the necessary flexibility (or "swing") to meet variable gas demand in Great Britain (GB). However, as production levels declined, the capability of UKCS to provide swing has diminished. Up to two winters ago, seasonal storage and, to a lesser extent, Norwegian imports and the IUK interconnector (the gas interconnector between Belgium and GB) have supported the UKCS in delivering the necessary flexibility. However, over the past two winters a different picture has begun to emerge. Figure A-12 shows the incremental supplies for gas days with demand greater than 300 million cubic metres (mcm).

**Figure A-12: Incremental supply sources at the NBP, winter 2011-12**




*Source: National Grid UK (2012)*

*Note: UKCS: UK indigenous production; SRS LNG: short range storage provided by LNG; BBL: the interconnector between GB and the Netherlands; IUK: the interconnector between GB and Belgium; LNG: Liquefied Natural Gas; Storage LRS: long range storage; Storage MRS: medium range storage; SRS LNG: short range storage. Demand bands are expressed in mcm/day.*

The bar on the far left of Figure A-12 indicates that storage was the primary provider of winter flexibility in 2011/12. However, as the level of demand increased, LNG began to play an increasingly significant role in meeting demand. For example, the contribution of LNG on demand days between 400-420 mcm was 26% of incremental supplies. This was slightly higher than the contribution provided by GB's only long range storage facility (Rough).

In contrast to recent winters, IUK was operating in export mode (GB to BE) through the majority of winter 2011/12. This can be attributed, in part, to subdued gas demand in GB. The average incremental contributions by supply source in Figure A-12 are presented in Table A-8.

**Table A-8: Entry points' flexibility contribution to UK demand**

| Source Type | Winter 2011-12 | Average incremental contribution for demand greater than 300 mcm/day | Incremental contribution for demand greater than 400 mcm/day |
|---|---|---|---|
| UKCS | 112.9 | 4.3% | 4.5% |
| BBL | 22.8 | 7.4% | 4.5% |
| IUK | -20.3 | 14.9% | 8.5% |
| Norway | 90.4 | 23.1% | 11.5% |
| LNG | 42.2 | 14.4% | 26.0% |
| Storage LRS | 11.0 | 33.3% | 25.5% |
| Storage MRS | 6.8 | 16.5% | 26.3% |
| SRS LNG | 0.2 | 0.6% | 1.8% |
| Total | 286.5 | 100.0% | 100.0% |

*Source: National Grid UK (2012)*

The trend highlighted in Figure A-12 suggests that certain LNG terminals are reacting to some extent, as far as allowed by technical constraints, to demand and price movements[238]. There is tentative evidence of such behaviour at least for certain individual LNG terminals, as shown in Figure A-13 and Figure A-14.

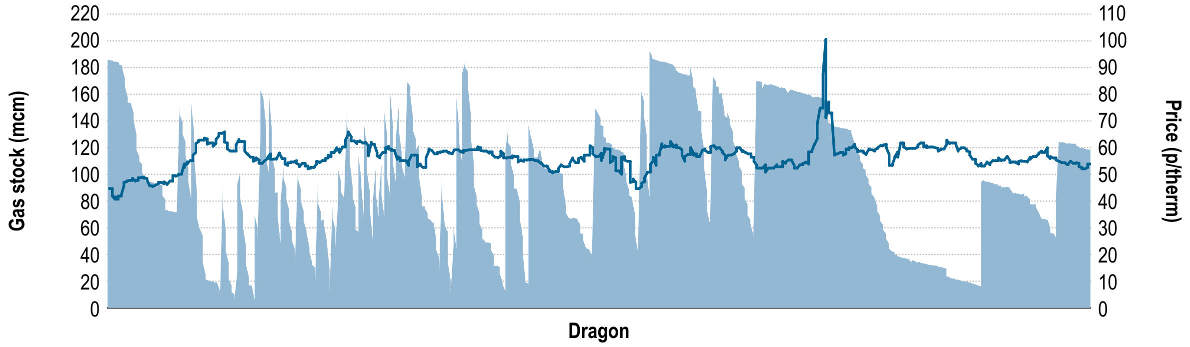
Figure A-13 shows the flows of LNG from the South Hook (left) and Dragon (right) LNG terminals[239] and NBP[240] wholesale gas prices. It indicates that withdrawals from the (Qatargas owned) South Hook terminal appear to follow a more mechanical injection/withdrawal pattern, as highlighted by the relatively uniform peaks and troughs for South Hook. This can be explained by this terminal's technical procedures, the role played by shippers at this terminal, and operational management flexibility. However, the smaller (Petronas/BG owned) Dragon LNG terminal in South Wales appears to have supplementary flexibility to follow a less mechanical injection/withdrawal pattern, suggesting that this terminal's behaviour can follow demand variations and wholesale market prices more closely than South Hook.

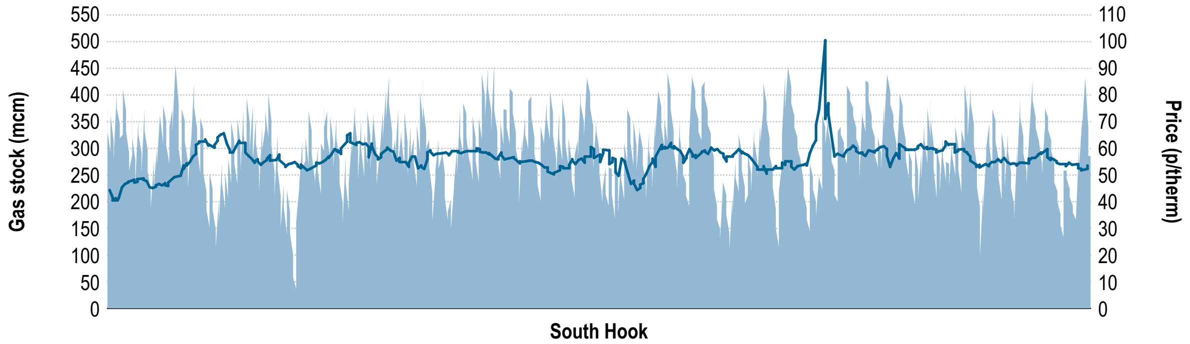
238 This analysis does not consider technical constraints at LNG terminals.

239 Both terminals are situated in South West Wales.

240 NBP: the National Balancing Point, GB's virtual gas hub run by APX-Endex.

**Figure A-13: South Hook and Dragon LNG flows versus NBP price movements**



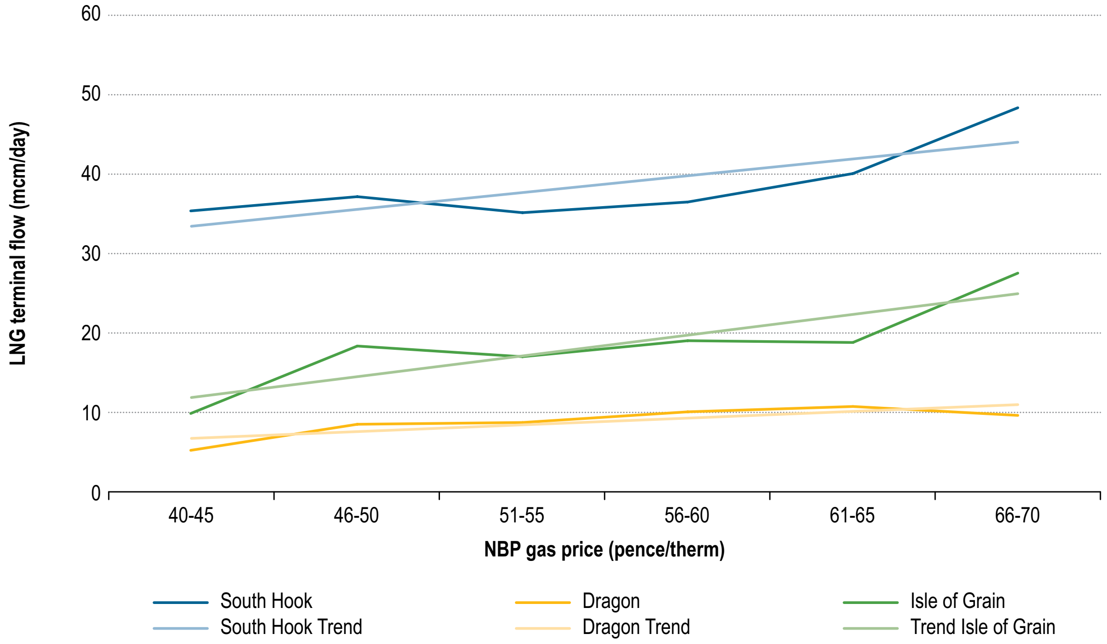




*Source: National Grid UK (2012)*

Figure A-14 shows the average flow of gas from GB LNG terminals to the NTS[241], at incremental price ranges, between October 2010 and August 2012. The upward trend indicates that, as price levels rise, flows from LNG terminals increase. Although Britain's energy regulator Ofgem was yet to complete formal research on the reactivity of LNG terminals to price signals at the time of going to press, these trends provide early evidence that LNG terminals in GB can respond, as far as technical constraints and operational management flexibility allow, to both demand and price signals.

241 This is the National Transmission System, GB's high pressure gas transmission network, owned by National Grid.

**Figure A-14: LNG flows at different NBP price ranges**




*Source: Ofgem elaboration based on National Grid UK and Bloomberg information (2012)*

*Note: The third terminal shown in this Figure is located on the Isle of Grain. It is one of the largest LNG terminals in Europe and is owned by National Grid Gas. This terminal is situated in Kent, South East England, outside the Medway Estuary.*

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