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The role of gas storage in internal market and in ensuring security of supply

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EUROPEAN COMMISSION

The role of gas storage in internal market and in ensuring security of supply

Directorate-General for Energy
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King Richard:
A horse, a horse! My kingdom for a horse!

Catesby:
Withdraw, my lord; I'll help you to a horse.

King Richard:
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And I will stand the hazard of the die.

W. Shakespeare, *Richard The Third*, Act 5, scene 4, 7–10

EXECUTIVE SUMMARY

1. Overview of the European gas storage industry and its recent evolution

The gas storage sector in Europe has been growing faster than gas consumption. Between 2006 and 2012, storage Working Gas capacity has grown at a pace of 5% per year, with lower rates in negotiated and higher in regulated regimes. Only after 2012 the growth rate has fallen to about 2% and seems to be the consequence of earlier investment decisions, which have now substantially halted.

Earlier growth has been pushed by the need to address the decrease of European production, the increasing consumption and flexibility requirements, and the opportunity to exploit price volatility of the new liberalised markets. The difficulty of accessing existing storage, booked through long term contracts, may have also played a role. It seems that only a minor role has been played be measures aimed at strengthening security of supply, like storage obligation and mandatory strategic storage.

The hope to exploit market fluctuations has particularly pushed faster storage facilities, like salt caverns and LNG tanks, therefore the average deliverability rate has increased even more than working gas capacity, and the industry' flexibility performance has definitely improved.

Whereas capacity has increased, fill level have not substantially declined in the last six years. However, some worries have been raised in particular for the decline that has occurred in 2013. The current (2015) year is also seeing reduced inventories.

It has often been feared that storage capacity utilization may be on a declining path, as its main economic driver (the gas price seasonal spread) has diminished and other competing flexibility tools, like production and import flexibility, LNG and interruptible demand, may be on the rise. Moreover, the role of alternative flexibility tools may be boosted by the more open trading that occurs in increasingly organized, interconnected and transparent gas hubs. The new European regulation, notably the implementation of the Balancing Network Code, could further strengthen such competition.

Summer-winter spreads have been generally declining since 2007 and short-term hub price volatility has been declining since 2008. Lower summer-winter spreads and short-term hub price volatility give traders less trading opportunities using gas storages. However, these factors did not in general result in a significantly lower utilization of existing storage capacity in Europe.

Although summer-winter spread certainly play an important role for market participants to use gas storage, in the last five years there is not always a clear relationship between seasonal spread and the maximum fill level at the beginning of the winter. In fact, although in 2013 the lowest ever recorded winter-summer spread occurred (< 1.5 €/MWh) and the maximum storage fill level remained generally lower than in the previous years, this can be mostly explained by other factors, such as late start of injection in 2013 and a few localized technical problems affecting key sites. Yet the 2015 decline may be worrying, as Ukraine's problems are far from solved.

Decreasing short term price volatility may have had an impact, mostly on demand for fast-cycle storage capacity, which is a relatively small share of the total storage working gas capacity in Europe, although more relevant in terms of withdrawal capacity. Therefore, the evolution of spot price volatility is not deemed to be an important driver of storage filling for slower storage facilities.

As far as the availability of alternative flexibility tools is concerned, declining demand and increasing interconnection of national gas markets have increased the competitiveness of different flexibility sources, notwithstanding a part of production flexibility was recently lost in some countries, like the UK and the Netherlands, as shown above. However, based on the analysis of demand swings we do not find evidence that alternative sources of flexibility, and imports in particular, displaced storage as a provider of seasonal flexibility. Available data evidence, although limited, shows that the role of storage in providing seasonal and short term flexibility has not decreased significantly between 2008 and 2014.

Summing up:

- despite declining seasonal spread and declining spot price volatility, storage utilization is not significantly lower than in the past, showing an unclear relationship between summer-winter spread and storage fill levels at the beginning of the winter;
- there is no robust evidence that increasing competition in the market for flexibility resulted in storage being significantly underutilized.

This suggests that others reasons, other than the gas price incentive only, bring suppliers to stock gas for the winter: inventories are often refilled even though limited seasonal spreads occur and price volatility is subdued. These reasons may include:

- the insurance value of storages towards unexpected events (including price spikes and supply failures). Particularly for large suppliers, in case of supply failures the reputation loss and supply restoration cost in the event of supply disruption would be very high;
- in some cases, mandatory storage obligations and other SRSMs;
- the fact that an important share of storage capacity was sold as yearly or longer term contracts years ago, before the declining trend in flexibility value started.

If persistently high storage utilization can be explained by "insurance" reasons that go beyond the normally expected seasonal swings, the price of storage should in principle reflect this: in fact, in several cases storage prices are reported to be above winter-summer spreads. However, such price is also affected by other factors: lately, the decline of gas demand and increasing availability of pipeline and LNG capacity have enhanced the competition for storage as well as for other flexibility services. In other words, the declining demand for storage services seems to have resulted in a fall of prices, rather than quantities.

Unfortunately, the analysis of storage prices is not easy, as the increasingly new opportunities - but also the recently shrinking market and regulatory pressure - have fostered the development of new products and allocation procedures. In particular, the market has seen a systematic shift towards auctions, which are now very common, although "first come first serve" and merit orders with prorating are still found in a few cases. Moreover, there has been a growth of short term products and of hub based products, which ensure service at a hub, including the necessary transmission capacity, rather than at the storage site.

Overall, posted prices (including regulated ones) have increased until 2012, but the trend has reverted in the last few years, particularly for short term and faster products and for prices set in auctions.

Posted prices are in some cases higher than the intrinsic value. However, the published prices often do not show the real storages prices, particularly in markets with negotiated prices, where storage products are mostly auctioned on exchanges or negotiated in bilateral-contracts. Due to lack of transparency concerning information of prices actually paid by users in negotiated regimes, a satisfactory overview could not be carried out. However, the price evolution in two countries where the storage regime is negotiated (Germany and the Netherlands) shows that storage users lately pay only the "intrinsic" value of storage. In other words, known storage prices in these (and possibly other) countries stay at the seasonal spread level, which considers the typical expected price variation of a normal winter season, but not that of unexpected events like extreme weather conditions or supply disruptions. The "insurance" value (the value that a gas supplier has gas volumes available in rare emergency circumstances) seems to be increasingly ignored by private operators, and this may lead to reductions of storage capacity and of their usage.

2. Comparative analysis

The Study has analysed other cases of Security of Supply policies outside Europe, however these are hardly comparable. In the U.S., large storages are provided by the private sector, also in order to keep production flows constant. Yet the issues of a system which – if considered together with Canada – is basically self-sufficient are very different from Europe's and no major policy has been implemented. Yet markets have been heavily affected by major disruptions, notably in the case of the Katrina and Rita hurricanes, which have triggered substantial and lingering price hikes.

Japan is almost totally dependent on LNG imports. It has substantial LNG storage, but its gas markets are fragmented and hardly competitive.

Australia is also a self-sufficient and actually an exporting country. The regulator has established a mechanism by which "contingency" gas to be supplied in emergencies is defined by means of auctions. Storage is just one way of providing such gas, which has in fact never been called for yet.

It is tempting to compare emergency stocks that are accumulated for oil with those of gas. Given the similar features of the two commodities, it is straightforward to think that experience and lessons from emergency response policy for oil can be used as reference point for the case of natural gas. However, emergency response measures differ substantially due to the unique nature of gas.

In fact, natural gas uses a highly capital-intensive, mostly fixed transportation and distribution infrastructure, and there is little demand-side response in large consumption sectors like households and space heating. While downstream gas transport is almost entirely performed by fixed infrastructure (i.e. pipelines), tanker trucks can be cheaply used to distribute the oil instead. This makes the gas distribution system less resilient, in the sense that where oil tanker trucks are used the loss of one of them will not have large consequences on the oil distribution, but if any part of a gas pipeline is damaged, supply downstream is heavily affected. Furthermore, the available spare capacity, either physically or contractually, is sometimes limited in existing gas pipelines, whereas more oil trucks can deliver more oil to petrol stations via the road system in case of extreme oil demand.

What is more, holding of oil resources is much cheaper, due to the physical nature of the commodity, which is liquid at common temperature and pressure levels. Holding an equivalent amount of natural gas is far more costly.

3. Security of Supply related storage measures

Mandatory storage obligations exist in the majority of sample countries: Bulgaria, Denmark, France, Poland, Spain, Czech Republic and Hungary. Italy and Hungary also require strategic storage. Only three out of 11 sample countries have no Security of Supply related Storage measures (SRSMs): the UK, Germany and Austria. In this respect 56% of totally available EU storage capacity lies in countries with mandatory storage obligations while 44 % is not restricted by any obligations.

Storage obligations consist mainly in an obligation for gas suppliers[1] to store a given amount of gas to be ready to use during the winter. In France, the obligation also concerns withdrawal capacity, as since 2014 suppliers have to ensure they hold a minimum withdrawal capacity, in addition to gas stocks. The total amount of mandatory storage is computed differently in each country and, more specifically, is determined with reference to:

- Protected consumers' winter demand, which generates «storage rights» in France;
- Imported quantity in a given period: in Poland, gas suppliers are obliged to maintain compulsory storage stocks equivalent to at least 30 days of the average daily import;
- Past firm sales in a given period: in Spain, gas suppliers must store volumes necessary to cover 20 days of their firm sale, computed from the previous year's sales; in Hungary suppliers shall store an amount of at least 10% of their gas sales (irrespective to their aggregated consumption profile or source portfolio) within a gas year;
- Total consumption: 10% of yearly consumption must be stored in Hungary(besides strategic storage);
- Supply standards: gas suppliers in the Czech Republic are obliged to fulfil at least the 20% of supply standards by storing gas in underground storage facilities.

Bulgaria and Denmark, to the best of our knowledge, have not disclosed criteria to determine storage obligations.

The amount of mandatory storage obligations is generally determined every year, although principles and criteria usually last more.

Mandatory storage stocks are mostly located within domestic boundaries. In Spain, volumes need to be located on Spanish soil in order to be considered security reserves unless subject to a bilateral agreement. However some countries, such as Czech Republic and Poland, explicitly allow mandatory storage to be located abroad. In the former, volumes can be stored abroad provided that suppliers procure the needed transmission capacity. Poland allows for mandatory stocks of natural gas to be maintained outside the national territory, provided that the volume of the compulsory stocks of natural gas maintained outside the territory of Poland can be delivered to the national transmission or distribution network within the maximum period of 40 days.

Only two sample countries have special strategic storage reserves: Italy and Hungary. The latter is the only country that requires both strategic storage and storage obligations on suppliers. While Italian strategic reserves are spread among existing storage operators and facilities, in Hungary a special facility (Szöreg) is mostly used as strategic reserve, but a smaller part of it can be used for commercial purposes. Hungarian reserves had never been used as of April 2015, but Italian ones have been used twice: in 2005 and in 2006; in those occasions the contribution from strategic resources reached 15% and 24% of the total volumes, respectively.

The amount of strategic reserves in Italy and Hungary is determined according to criteria set in national legislation and is set every year by the Government.

[1] In Denmark the obligation is born by storage users, rather than gas suppliers, but the former category includes the latter. In Spain the obligation is born also by direct consumers (users who are connected to the transmission grid, usually big gas consumers)

The current amount of total mandatory storage in each country (including both storage obligations and strategic storage) ranges from 3% of national consumption in Czech Republic to 24% in Hungary.

Three clusters can be identified:

- Countries choosing "tight" SRSMs, where the total mandatory storage amounts to more than 15% of national consumption: France and Hungary.
- Countries choosing "light" SRSMs, where the total mandatory storage amounts to less than 10% of national consumption: Czech Republic, Denmark, Poland, Spain, Italy, Bulgaria.
- Countries with no mandatory storage at all (UK, Germany and Austria).

In this Study, simplified versions of these models have been tested for their effectiveness and efficiency, by means of a simulation model.

4. Assessment of the costs and impacts of storage related security of supply measures

From a theoretical perspective, it is not sure that companies will fully consider the insurance value of storage in their private investment and capacity booking decisions. They might have done more in the past, when incumbents under state control were seen as responsible for Security of Supply of their countries. However, as their profit orientation increases and the market evolution shrinks their margins, even the largest gas companies may increasingly disregard the benefits of security of supply, which are of a public rather than private nature. Likewise, it is not even sure that Member States belonging to an integrated market will make the right choices, as not all benefits are likely to be internalised at country level, but some benefits arising from storage investments may spill over to other countries. Some regional or European coordination is therefore probably appropriate.

It has sometimes been claimed that mandatory storage may simply replace (crowd out) commercial one, so that total storage capacity and actual inventories are not really affected by SRSMs. Analysis of actual storage data in comparison with SRSM requirements show that storage measures are partly effective, but some crowding out by mandatory storage at the expense of private one is also likely. In fact, countries with no storage obligations like Austria and Germany have higher storage endowments than most Member States with mandatory storage, even though this is probably due to availability of suitable sites, and particularly to their focal position, which helps sites located there to offer services to several other, more peripheral European markets. It is likely that most European storage would have been developed anyway, but SRSMs have probably boosted capacities in countries like France, Hungary and Italy.

We have estimated the impacts, benefits and costs of extending some existing SRSM Models across all Europe. Benefits are mostly the reduced supply costs that would arise from using more storage resources instead of external sources (mostly LNG), whose prices are likely to spike in case of a serious crisis. Much higher would be, if necessary, the benefits of not resorting to other sources that are much more costly for Europe, like oil and coal, notably if their environmental costs are factored in. Even larger would be the costs of a supply outage (load shedding), but with the current infrastructure this appears as a very minor and remote case in almost all of Europe, expected only in very limited areas under the worse disruption scenarios like a 6-month all Russian gas supply interruption.

Whereas the case of disruptions that cannot be covered by spontaneous demand containment or fuel switching is probably limited to extreme cases, this does not mean that the study ignores this possibility. Outages for protected customers are indeed assessed and estimated at very high costs[2] In particular, the Study has analysed a one-month all-Russian February disruption scenario (aggravated by a cold spell) on a country by country basis, but no gas supply interruption is detected that cannot be addressed by fuel switching in any of the (11, above listed) sample countries. The situation would be of course worse in the Baltic Republics (not assessed in this Study), and could be worse also for longer disruption, which were only assessed in this Study for Europe as a whole.

On the other hand, costs of storage are certain and have been estimated by posted prices or by regulated prices, which are assumed to be cost reflective, rather than by currently depressed market prices.

Cost benefit analysis requires that the benefits of generalised SRSMs are weighted by the probabilities of the adverse event, assumed at 10% for a one-month or 2% for a six-month all Russian disruption, including in both cases a two-week extreme cold spell. If calculated in this way, netted of storage costs, the benefits of generalised SRSMs are negative in all examined scenarios (see Table below).

In other words, costs of SRSMs normally exceed benefits, if the latter are multiplied by reasonable probabilities of the expected disruption. In fact, even the efficiency of current strategic storage and obligation is dubious.

Indicator	Current SRSM (baseline)	No strategic storage & obligations	Light SRSM to all	Tight SRSM to all	Strategic storage to all
Scenario: six-month all-Russian supply disruption + two-weel cold spell in February (Probability assumed: 2%)					
Change in supply costs		4.90%	0.52%	0.47%	7.14%
Change in storage costs		-38.76%	0.32%	1.18%	31.31%
Probability-weighted net benefits		2.66%	-0.07%	-0.14%	-3.18%
Scenario: one-month all-Russian supply disruption + two-week cold spell in February (Probability assumed: 10%)					
Change in supply costs		3.62%	-0.12%	-2.27%	-6.85%
Change in storage costs		-6.84%	0.35%	5.41%	32.97%
Probability-weighted net benefits		0.29%	-0.02%	-0.24%	-1.59%
Note: storage is neutral over the considered period and returns to original level by end September					

This conclusion does not hold at European level only. Country by country analysis covering 13 Member States (sample countries plus Ireland and Portugal), or about 80% of the gas market, has shown that in no country net benefits of such mandatory storage increases are positive, with only one case that is barely neutral.

The lessons of these simulations are not obvious. In fact, the Study shows that in most cases storage does indeed have an insurance value, which is not necessarily considered by market forces, and perhaps not even by individual Member States. If

[2] In the order of 500-700 €/MWh

the insurance value is added to the traditional other components of the value of storage, like that those arising from seasonal (intrinsic) and short term (extrinsic) gas price swings, the efficient room of storage in the European gas industry remains remarkable.

Lack of storage price information prevents an appropriate assessment of whether such insurance value is included in current storage prices, and therefore considered by market forces. Improved price transparency would be necessary to ascertain whether prices are falling - and therefore losing the insurance value, as widely reported by industry sources.

It can be expected that the insurance value does not arise much from physical disruption requiring costly fuel switching or even load shedding, but rather from a growing feature of liberalised markets, i.e. their tendency to spike as a response to disruptive events that unexpectedly affect either the supply or demand side of the market. Since this insurance value may not be fully captured by private companies, which are likely to be able to transfer related costs to end users, there may be room for some policy measures.

On the other hand, it is clear that storage obligations and strategic storage, the traditional storage-related security of supply measures, are not the most efficient way of addressing the insurance value of storage. In most cases, spikes are reduced but only at the price of increasing gas prices after the disruption, as larger storages must be refilled at lingering firmer prices. Thus, it would be preferable to internalise the insurance value, either as a penalty for suppliers in case of disruptions (provided that their costs are not eventually passed through to end users); or as incentives and premiums offered for physical or virtual storage or other market driven tools, which may deliver to gas consumers the expected benefits of levelling price spikes, as well as reducing their size. This is indeed the typical role of inventories in almost all commodity markets.

INTRODUCTION

The recent Ukrainian crisis and more generally the process of revising the main Security of Supply provisions of the European Union, Regulation (EU) No 994/2010 ("SoS Regulation") require an assessment of the provisions aimed at safeguarding the security of gas supply. The SoS Regulation does not set a uniform supply standard but requires the Member States to set up and meet a supply standard. The use of commercial as well as strategic gas storage is only one possible option among various other supply-side measures. It is hence left to the Member States to decide which measures to put in place to best satisfy gas security of supply.

Gas storage can play an important role in providing flexibility and security of gas supplies. Depending on their design and characteristics, gas storages can secure supplies in times of high demand (for instance by providing seasonal flexibility) and high prices (by providing gas purchased more cheaply); but also facilitate the proper functioning of the gas market by providing short term flexibility. In the future, as shares of renewables in the electricity generation mix increase, the role of gas as flexible back-up fuel in promoting the security of gas supply may be further enhanced with the help of flexible storage facilities. Within this framework, the present Study has been prepared in order to fulfil four tasks:

- Task 1: Providing a factual overview of the storage sector in the EU;
- Task 2: Providing a description of existing Storage-Related Security of Supply measures (SRSMs), consisting of detailed country studies as well as of a comparative overview;
- Task 3: Providing a comparative analysis of existing SRSM in selected extra EU countries and in the oil sector;
- Task 4: Assessing the benefits and cost of existing SRSM patters and of their extension or generalisation throughout Europe, with a view to understand whether at European and/or National level it is feasible and worth to increase (or possibly reduce) storage obligations as insurance against risks, considering that - albeit unlikely - the alternative may be very costly to bear if feared events eventually happen.

Task 1 "Factual overview of the storage sector in the EU"

Task 1 is performed in Sections 1.1-1.4.

These parts are mainly based on the data evidence that is made available by Gas Storage Europe (GSE), complemented by additional, simplified data gathered by the Project Team regarding main available products, capacity allocation rules, and prices, as provided by links available through GSE's Transparency platform. We assess how storage capacity and filling rates have changed in the last ten years, and what are the main determinants of the evolution.

As far as storage prices are concerned:

- Posted prices are the main target of this study, and are likely to represent a better representation of full storage costs. In fact, the recent market evolution has led to more competitive prices, set in auctions or through bilateral negotiations, which are often below official prices, and possibly also below full costs: these cases are shown where available.
- The review on prices is mostly limited to standard products such as Standard Bundles Units (SBU), mainly for seasonal services, which are usually the most popular product. A preliminary investigation has been made also about new products and their role;

- The price review is not aimed at a geographical benchmarking of the prices, which is a difficult exercise that falls beyond the scope of the current Project. Instead, collection of price data is aimed at:
  - outlining the evolution of prices over time for the same sites and products (where available);
  - providing information that is necessary for the evaluation of costs of Storage Related Security of Supply Measures (SRSMs).
- The review of prices is limited to a subset of relevant storage companies, covering an adequate share of the industry.

The Task:

1. describes the development of storage capacity over the last 10 years for all Member States, based on GSE data, split between commercial and non-commercial storage and by regulatory regime and technology (*Section 1.1*);

2. describes the patterns of storage injection and withdrawal over the last 5 years (as available; *Section 1.2*);

3. discusses the drivers to storage filling, including winter/summer spreads, hub price volatility, availability of other flexibility sources (*Section 1.3*).

4. presents simplified data gathered by the Project Team regarding main available products, capacity allocation rules, and SBU posted prices, as provided by links available through GSE's Transparency platform (*Section 1.4*)

Task 2 "Overview of storage-related SoS measures"

Task 2 is performed in Chapter 3 and related Annexes.

The Study reviews storage related security of supply measures (SRSMs) and other security of supply information for 11 sample countries, covering nearly 80% of the EU gas market and over 80% of storage working gas capacity. The sample countries are chosen with a view to include all largest countries, and to cover a wide spectrum of situations as regards security of supply risks. The countries differ for their exposition to dominant suppliers, their role in gas transit, their endowment of domestic resources, and their availability of LNG.

The sample countries are:

- Austria
- Bulgaria
- Czech Republic
- Denmark
- France
- Germany
- Hungary
- Italy
- Poland
- Spain
- United Kingdom

The main source for the 11 case studies is Preventive Action and Emergency Plans ex art. 4, Reg. 994/2010, integrated by National legislation and data, interviews and own market knowledge.

Chapter 3 provides an overview and comparison of existing SRSMs for the sample countries. This is the basis for the identification of SRSM patterns, in terms of size, type and drivers. Such patterns will be also used for a quantitative assessment of a generalisation of typical SRSMs throughout Europe. More precisely, it will be analysed how the storage level of individual countries would change if different SRSMs were applied to national gas markets. These results form the basis of the assessment of the impact and costs of different SRSMs which is carried out under Task 4.

Task 3 "Comparative Analysis"

Task 3 is performed in *Sections 2.1-2.6*.

The analysis briefly considers SRSMs in three extra EU countries (Australia, Japan, USA) and crude oil.

Comparison between to storage-related SRSMs for oil crude and natural gas is presented, highlighting similarities and difference as well as lessons that can be learnt for natural gas.

The main source is relevant literature review, starting from information provided by the IEA.

Task 4 "Assessment of the impact and cost of existing storage-related SoS measures"

Task 4 is presented in *Chapter 4*.

This part performs an assessment of the benefits and costs of existing SRSM and a preliminary assessment of the impact and cost of cooperative approach to supply disruption versus a non-cooperative one. A cooperative approach allows gas to be transferred where necessary in order to minimise deficits, where in the cooperative scenarios this happens only if demand of the country where supplies land are fully satisfied. As a preliminary discussion to the assessment, the Study also analyses the effectiveness of existing SRSM in affecting storage users' behaviour, investigating whether crowing out occurs.

The Assessment exercise will be based on the Stress Tests illustrated in the EC Communication of 16.10.2014 on the short term resilience of the European Gas system[3]. Stress Tests were carried out by ENTSOG and have provided a valuable exercise for the evaluation of the impacts of possible supply disruptions, notably from the East. However, this exercise has been based on the specific situation at the time of the Stress Tests, and has not provided any analysis of their costs, or of the costs of matching gas deficits.

The main benefits of SRSMs consist of the larger availability of stored gas, which reduces the resort to more costly sources in matching gas deficit, in case of supply disruptions. This acknowledges the fact that a serious supply disruption is most likely to trigger market price spikes, as shown by several previous cases. More storage would help both to reduce the cost of supplying the market at spiked prices, as well as the extent of the spike.

[3] COM(2014) 654 final 16.10.2014.

On the other hand, the main cost of SRSMs consists in the those of having larger storage inventories.

Working in close cooperation with ENTSO-G, the Project team estimated, for selected scenarios and under different sets of SRSM, the costs of the gas and non-gas sources adopted to minimise the impact of disruptions, notably increased LNG and pipeline supplies, increased production, storage, fuel switching and load shedding.

Selected scenarios reflect those analysed by ENTSO-G in the Stress Tests underpinning the Communication:

- disruption of all Russian supplies for 6 months under normal winter, followed by a 2-week cold spell
- disruption of all Russian supplies for 6 months under normal winter, followed by a 2-week cold spell and uncooperative approach to the crisis
- disruption of all Russian supplies for 1 month under normal winter, followed by a 2-week cold spell

The selected SRSM pattern that are tested derive from measures outlined in the case studies (Task 2). The implementation of these patterns to all Europe is simulated, as applicable.

Costs of matching gas deficits, and of the corresponding supply mix (e.g. other pipeline gas, LNG, fuel oil, coal, or even load shedding), are computed for each scenario. The costs and benefits of storage under the different SRSM models are then estimated and compared. The first disruption scenario is also simulated in both a cooperative framework and in a non-cooperative one, where export of gas is prevented unless domestic customers are fully satisfied.

1. FACTUAL OVERVIEW OF THE STORAGE SECTOR IN THE EUROPEAN UNION

1.1 Gas storage capacity and its development in the EU Member States

The following table provides an overview of the available storage capacities (total quantity and the part available for third parties, TPA) in each of the EU Member States holding underground and/or LNG storage resources, broken down in firm capacities commercially offered and non-commercially offered (according to the definition in GSE's Gas Storage Map).

Table 1.1.1. Available storage capacities in Europe, commercial and non commercial (mcm)

Country	N. of facilities	Commercial	Not commercial*	Total	-of which strategic storage
Germany	51	21,833	0	21,833	0
France	15	12,965	0	12,965	0
Italy	10	11,950	4,665	16,615	4,665
Austria	9	7,794	372	8,166	0
Hungary	5	6,330	0	6,330	1,200
The Netherlands	5	5,378	0	5,378	0
United Kingdom	8	4,197	726	4,923	0
Spain	4	4,103	0	4,103	0
Czech Republic	8	3,497	0	3,497	0
Slovakia	2	3,135	0	3,135	0
Romania	8	3,100	0	3,100	0
Poland	7	2,474	50	2,524	0
Latvia	1	2,320	0	2,320	0
Denmark	2	998	0	998	0
Belgium	1	700	0	700	0
Croatia	1	553	0	553	0
Bulgaria	1	550	0	550	0
Portugal	1	239	0	239	0
Ireland	1	230	0	230	0
Sweden	1	9	0	9	0
TOTAL EU	141	92,355	5,813	98,168	5,865
* As defined in GSE Storage Map under the heading "non-TPA"					
Source: GSE July 2014					

Most Member States hold storage commercial capacities, except for Italy, Austria, the Netherlands, Poland and the UK[4], which have some capacities reserved for operational needs related to transmission and/or production, or strategic stocks. Italy has the highest portion of volume dedicated to strategic storage, representing almost 30% of the total gas reserves in the country. According to our case study (see below, Chapter 3), Hungary also has a large strategic stock reserved capacity (accounting for1,200 mcm), even though this is classified as commercial in the GSE database.

4 In the UK the "capacity reserved for operational needs is about 107 mcm. The UK has 4197 mcm of negotiated TPA capacity and about 1,000 mcm exempt capacity.

From the same table it is possible to infer that over 50% of total storage capacity in Europe is concentrated in three countries: Germany, Italy and France. The same three countries have the highest concentration of storage sites and together account for 54% of the total number of facilities in Europe.

In order to have an overview of the evolution of gas storage capacity in Europe made available through a negotiated or regulated third-party access regime, it can be useful to look at the following table.

Table 1.1.2. Evolution of storage capacity made available based on a regulated or negotiated third-party access regime

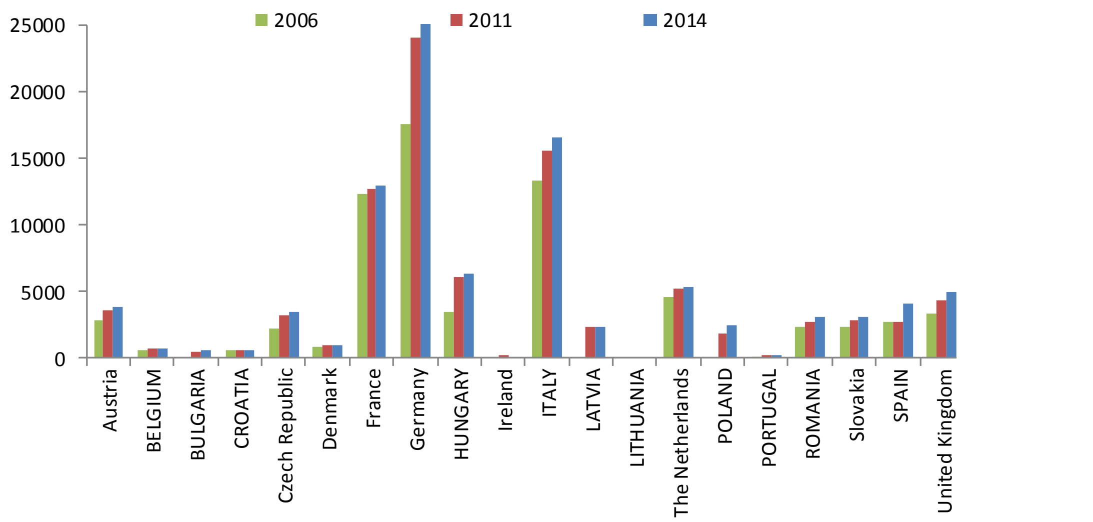
Storage capacity in GSE databases					Annualised growth rates	
		2006	2012	2014	2006-12	2012-14
Regulated TPA	Member States	8	10	11		
	Working Gas (Mcm)	23,641	35,164	37,034	6.84%	2.62%
Negotiated TPA	Member States	8	9	9		
	Working Gas (Mcm)	46,038	58,177	60,895	3.98%	2.31%
Total	Member States	16	19	20		
	Working Gas (Mcm)	69,679	93,341	97,929	4.99%	2.43%

Source: GSE, 2006, May 2012 and July 2014

For the scope of the analysis, only the countries that have an established third-party access regime to date have been considered.

The table can be complemented by the following graph, showing available gas storage capacity per country in different points in time (2006, 2011 and 2014). The Member States in capital letters are the ones with regulated TPA[5].

Figure 1.1.1. Storage development in Regulated and Negotiated regimes (mcm)



Source: GSE

Note: Countries in capital letters: Regulated TPA; Sites located in AT but serving DE included in DE

[5] The growth may be slightly overestimated by this Chart, as some operators have been included after 2006. On the other hand, GSE's data show storing capacity by year of site commissioning, but ignore the reinforcements that have been achieved in older sites (in WG, injection and withdrawal capacity). This would yield an even worse misrepresentation of the industry's capacity growth, as reinforcement of existing sites are more significant than entry of new operators after 2006.

Nearly the same number of Member States have chosen both regulatory approaches but countries with negotiated regimes are larger by capacity[6]. Capacity has grown remarkably in both regimes, although at a slowing pace, and has actually outpaced gas demand growth. Growth has been slightly larger in regulated regimes.

As usual in the energy industry, long lead investment times mean that capacity growth may be more related to factors driving investment decisions in the past. In particular, almost all gas industry has been driven by overoptimistic demand projections (for reasons that go beyond the scope of this Study). Storage has been no exception, so that its current capacity may well be in excess of what is currently optimal.

For various reasons, the willingness to invest has declined in Europe (except in "island locations") and there are even projects, if possible, stopped or cases of suspended implementation (*see Annex 7*).

The main reasons for this reduction in investments in storages are:

- The fall of gas demand in most EU Member States since 2005 has freed pipeline, LNG and even some domestic production capacity, so that import swings may have become a cheaper flexibility alternative to storage;
- Regulatory provisions opening the access to cross border pipelines have reinforced this tendency, as legal constraints for a more flexible use of pipelines have fallen, whereas short term transmission capacity products have become increasingly available;
- The development of organised markets has facilitated the procurement of flexible gas supplies, from a number of direct and indirect sources, often brokered by specialised dealers;
- Unbundling of trading and TSO business in separate entities. The investment decisions were made mostly in integrated companies under a security of supply view of their own customer portfolio or under a market view with a combined decision for storage and transport grid developments. In unbundled companies the synergies between different business units cannot be lifted anymore. Today, the needed capacities for storages are in competition with other grid users, and therefore in some cases the grid access and the capacity costs hinder the storage development.
- In the past dominant incumbents, particularly if state-owned, were often charged by governments of ensuring high SoS levels. At the same time they could overinvest at little risk due to lack of competition. This situation has changed and market oriented companies may be less and less concerned by SoS beyond their direct interests. The insurance value of storage towards major supply or demand shocks may therefore be increasingly neglected by market forces.
- The market in normal supply situations uses the cost optimisation options that follow the changed legal framework (after 3rd package was passed in 2009). The liquid market has taken this commodity position instead of the physical storages for the trading departments.
- In other cases, storage investments are made on a basis of long term commitments with storage users where the investor is ensured by agreeing to the payment of a fixed price, which is a reasonable return on capital employed. The willingness to commit to long term storage contract has declined, recent contracts in the storage industry rarely have durations longer than two years and most are limited to one year or less (see *Section 1.3*).

[6] Some countries report themselves as "hybrid" and "N.A.", but these are actually mostly negotiated in Czech Republic, Ireland and the United Kingdom, and regulated in Hungary, Bulgaria and Slovakia.

The following descriptive indicators are computed at Member State level with the aim of assessing the endowment of storage resource.

First, we look at the average "speed" (Withdrawal potential/Working Gas ratio) as a measure for the main characteristic of European storage endowment. The "speed" varies consistently between types of storage. Underground storage sites (UGS) can be categorised in three main types: depleted fields, aquifers and salt cavity. LNG terminals also provide a form of storage, usually suitable for peak performances.

The table shows the average "speed" across all EU Member States in 2014 by type of gas storage.

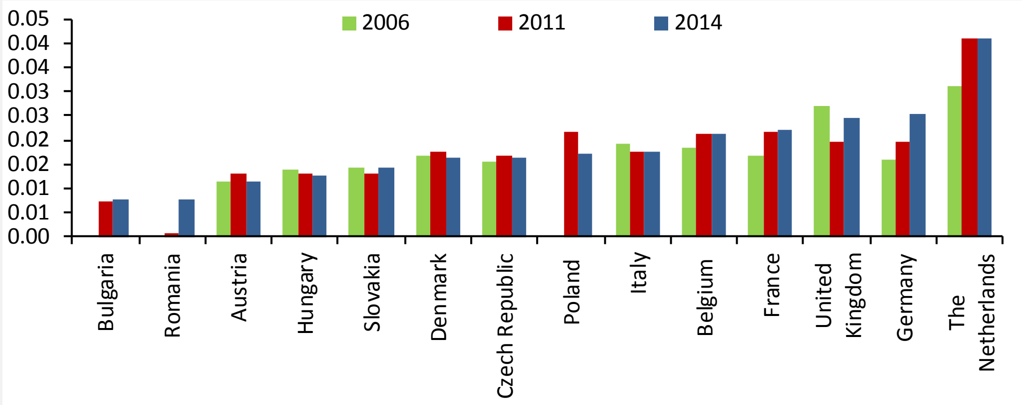
Table 1.1.3. Storage types characteristics in Europe and average speed (Withdrawal capacity/Working Gas)

	Aquifer	Depleted field	Salt Cavity	LNG Peak Shaving	Others
EU 28 average speed	3%	1%	5%	28%	5%
Total no. of sites	25	66	43	2	5

Source: GSE, July 2014

Salt cavities have the highest injection and withdrawal rates, and these are concentrated in Germany, France, UK, Netherlands, Poland and Portugal. Not surprisingly, these are also the countries with the highest average "speed" (Figure 1.1.2).

Figure 1.1.2. Evolution of the average "speed" of European storage endowment



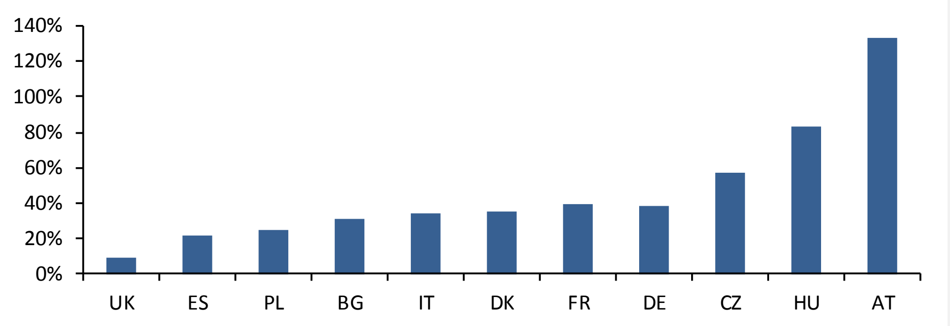
Due to a problem of data consistency between years (the list of storages changes significantly from 2011 to 2014) Spain and Portugal are not included.

Source: GSE 2006, May 2012 and June 2014

To bring about a complete overview of the situation of the storage endowment in Europe, it is interesting to compare it with other indicators related to the gas consumption development in each country.

The figure below illustrates the ratio between total available storage capacity in 2014 and an average of the winter demand for gas (from October to March, using an average of the years from 2009 to 2013), taking both underground and LNG storage capacities together (Figure 1.1.3).

Figure 1.1.3. Storage capacities (2014), as percentage of average winter natural gas consumption*



*Considering the total consumption in the coldest months (oct-mar) from winter 2009/10 to winter 2013/14

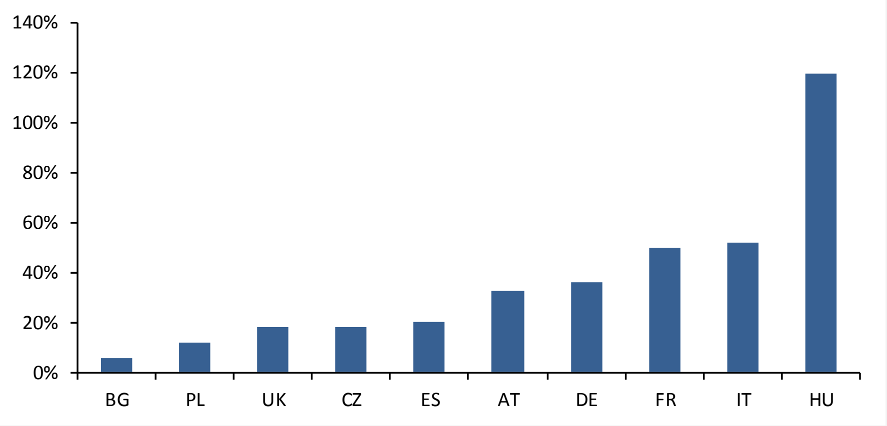
Source: GSE, Eurostat

The UK has storage capacity that can meet at least 10% of winter demand; storage capacity surpasses 20% of winter demand for seven countries, and 50% for Czech Republic and Hungary. Only Austria has gas storage capacity that surpasses 100% of its winter demand.

The reasons for the difference in storage endowment across the selected Member States may be related to the existence of other potential flexibility tools in the country.

More specifically, it is possible to make a comparison between the storage endowment and other supply sources such as pipeline and LNG imports (Figure 1.1.4) and national production (Figure 1.1.5).

Figure 1.1.4. Storage capacities (2014), as percentage of natural gas imports during winter*



Source: GSE and Eurostat

*Considering the total imports in Oct 2013- Mar 2014

In Figure 1.1.4 the average level of gas imports in each country during the coldest months of the year (from October to March) has been considered, taking into account the last years available from the Eurostat dataset[7]. In the large majority of the considered countries, storage capacity accounts for at least 10% of average winter imported volumes. Hungary stands out because in this country storage space capacity

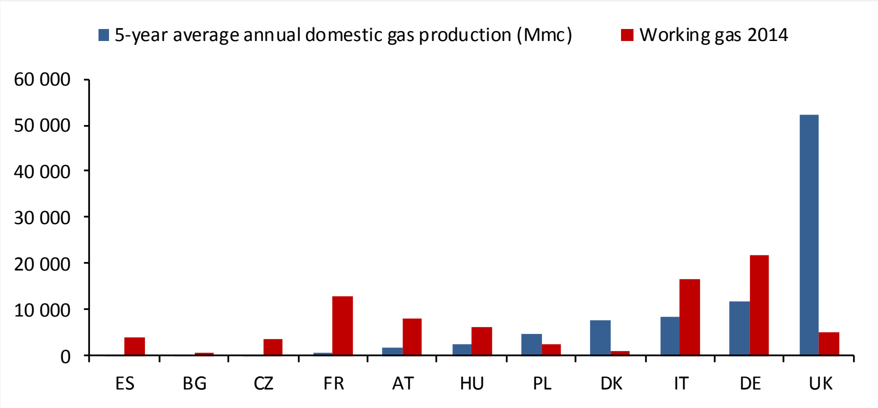
[7] Winter 2013/2014 has been considered, rather than the average imported gas volumes during the winter of the last 5 years. This is motivated by some inconsistencies in the Eurostat time series for gas imported volumes. Demark not included in the figure due to missing data.

exceeds winter imports. The higher the amount of gas imported in the winter season, the higher the working gas endowment tends to be: in fact, Germany and Italy, which have the largest storage endowment, also displays the highest winter gas imports. Despite having a level of gas imports during the winter similar to the one in Italy or France, the UK has a lower endowment of storage and this may be explained by the important - although declining in the recent years- contribution of domestic gas production.

Furthermore, the ratio between daily peak demand and daily maximum withdrawal from storage represents a useful indicator (Figure 1.1.6).

The next figure is based on two key assumptions, notably that the storage capacities would be filled to their maximum level (usually only true at the beginning of winter), as storage withdrawal capacities decline when storage is emptied; and that the dispatch of these volumes could be delivered to the area in which the demand originates. In this respect, it is worth noticing that national borders are somehow meaningless when it comes to storage contribution: for instance part of Austrian capacity primarily serves the German network and some German storage fields on the Dutch border are connected to the Dutch grid only.

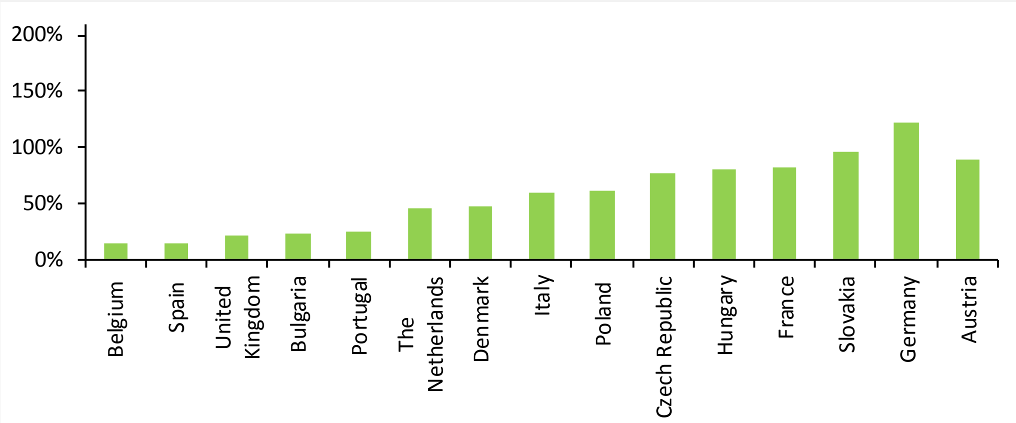
Figure 1.1.5. Comparison between storage capacity (2014) and annual national gas production* (mcm)



Source: GSE and Eurostat

*Considering cumulative national production per year from 2009 to 2013

Figure 1.1.6. Ratio between daily peak demand and daily maximum withdrawal from storage



Source: GSE, PAPs

According to the Preventive Action Plan provided by each Member State to The European Commission, eight of the member countries could meet 50% or more of their peak demand by means of a theoretical maximum drawdown on their storages.

Two countries - Austria and Germany - could cover all of their peak demand in this way. The very high ratio for Austria is somewhat misleading as part of Austrian capacity primarily serves the German network, yet even a joint consideration of both countries would put them at the top of reliance on storages to address peak demand.

1.2 Evolution of storage inventories, filling rate, injections and withdrawals over the last 5 years

1.2.1 Introduction

We now turn to a set of metrics useful to assess the use of existing storage capacities, described in the previous section. In particular, we aim to shed light on how much capacity is physically used through the year and to highlight any evidence of under-utilization.

To have an idea of the rate of utilization of European storage capacity, we look first at the evolution of the filling rate, injection and withdrawals over the year and then focus on the filling rate at end of injection period as well as on the filling rate at the end of the withdrawal season.

In this analysis we chose to focus on the filling rate, rather than on the absolute storage level, as this indicator appears more appropriate for a comparison over time. The AGSI database (see Annex 14), though accurate, does not allow for the comparison of long homogeneous data series of inventories. As more sites are included in the database, reported inventories may increase but this does not mean that they actually increase. Finally, we chose to focus on the filling rates, as suggested by GSE. However this indicator is also biased, as different types of storage may have been added, with an inherently different typical filling rate.

It is important to note that data on the recent past may not be sufficient to anticipate future trends in the storage utilization rate. Storage market is in fact in a transition phase, especially due to the fact that, in some countries, long term storage contracts, which have been the prevalent way to book storage, are expected to expire in a few years and will not likely be replaced by other long term contracts. This may significantly affect the way storage is used. Consequently the filling levels from the past may not be representative for the future market.

There are multiple reasons for reducing the long term position by storage customers. Before the liberalization, storage capacities were an integrated part of the gas supply structure and for this reason storage facilities have been booked long term by the importers according to their supply contracts. However, due to the adaption of the market design in recent years the incentive for suppliers to store gas for a longer period has been reduced (see Section 1.3).

With the development of gas trading, suppliers are less responsible for the physical availability of gas and the market offers virtual products for structuring the gas portfolio. Consequently, the historical physical long term contracts will likely not be extended by which the current filling rates at the beginning of the winter season will most likely drop significantly.

The anticipated change in the rate of utilization of storages may also affect the need for network expansion.

More specifically, even though flexibility products offered on the market are valuable for market efficiency, they may not be considered as appropriate to deliver sufficient standards of security of supply. Consequently, the need for flexibility for transmission system operators may increase leading to further requests for network expansions by the TSOs.

For example the assumed share of storage capacities in the market scenarios of the network development plans has a substantial impact on the resulting network expansion requirements. In this respect it should be noted that gas which was injected into storage facilities in low demand periods in the summer and can be withdrawn in high demand winter periods increases the capacity in emergency periods more efficient than gas which needs to be imported and transported via the border points and transmission systems. Consequently, the transmission system could be expanded less if the existing gas storages were used efficiently. For an efficient utilisation of gas storages the definition of balancing products should also be adopted in order to reduce the bias between the acceptances of flexibility provided by gas storages against imported gas via border transmission points.

1.2.2. Evolution of the filling rate through the year

Figure 1.2.1 below represents the evolution of the end-of-month filling rate of storage sites for selected regions[8] over the last 5 years (7 years, when 2007 and 2008 are available).

All analysed European storages present a cyclical filling pattern over time: inventories show a net rather steady growth from March/April to September/October of year t (injection period), then start to decrease in a rather constantly fashion until March/April in year t+1 (withdrawal period). This is related to the features of storage contracts: most storage contracts are based on the storage year (from April to the following March) and, especially in the past, in March customers have to sell their residual gas volumes if they chose not to extant the contract.

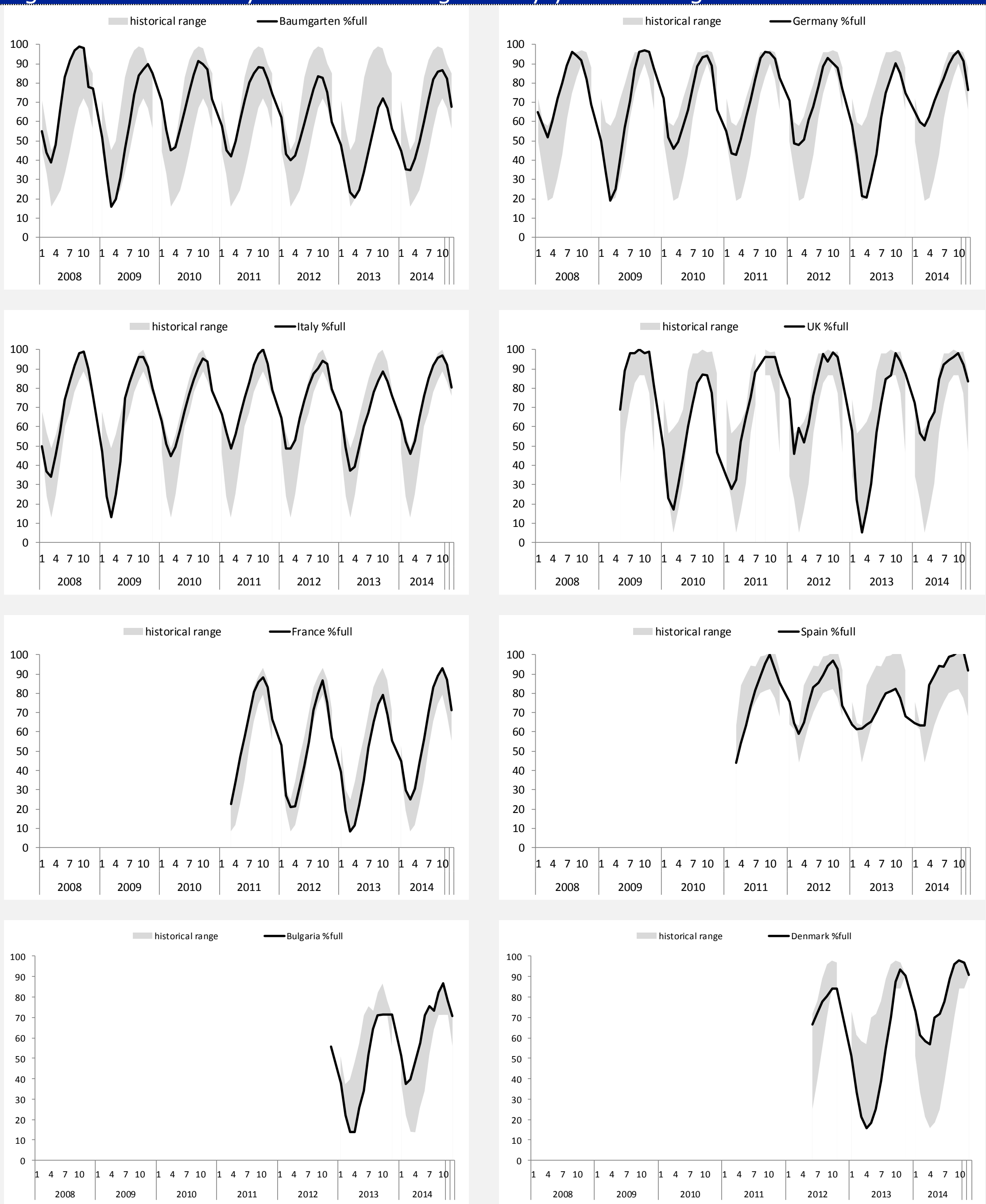
The lowest filling levels in a year are reached mostly in March or April (at least in the sample countries and in the considered time span), depending on temperature registered during the early spring. For instance, in 2013, stored volumes in all the analysed areas, with the exception of Spain, reached a yearly minimum in April, arguably as a result of a prolonged cold season spreading into the early spring[9] and leading to a prolonged withdrawal season and a late beginning of the injection season. 2009 and 2013 were the years when storages achieved the record-low levels. In particular, the lowest level among the considered areas occurred in 2013 in the UK, when UK storages were about 3% full in the first half of April. Within the Baumgarten region, Slovak storages were below 2% in the last week of April 2013.

Highest filling levels are instead reached mostly in October, showing that October tended to be a month when injections exceed withdrawals, allowing the stored volumes to generally increase from the end of September to the end of October. In 2013, however, growth in inventories continued in November.

[8] Please not that Baumgarten region may reflect very different national situations (eg Austrian storages' utilization may be significantly different from Czech storages' one), however, as data at country level are available only since 2012, while data for Baumgarten area are available since 2007, we refer to the latter in order to have a longer time series. According to AGSI plus database categorization, Poland is included in the Baumgarten region, even if Polish storages are not well connected with the rest of Baumgarten region.

[9] In 2013 heating degree days (HDD) in March exceeded the 2007-2014 average HDD for March by at least 20% in Germany, Austria, UK, France and Italy.

Figure 1.2.1 Last-day-of-month filling rate by year and region



Note: Baumgarten area includes Hungary, Austria, Poland[10], Czech Rep. and Slovakia

Source: GSE

1.2.3. Evolution of injection and withdrawals through the year

Now we turn to metrics which describe the usage pattern of injection and withdrawal capacity. Total injections and total withdrawals by month are presented by region and year[11] (Figure 1.2.2).

[10] According to AGSI plus database categorization, Poland is included in the Baumgarten region, even if Polish storages are not well connected with the rest of Baumgarten region.

[11] Denmark and Bulgaria not included due to limited historical record available for these variables in AGSI dataset. We may consider also injections/withdrawals as a share of the maximum technical declared injection/withdrawal capacity.

Figure 1.2.2. Total injections and withdrawals by month and region (mcm)

Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia.
Source: GSE

In general, Figure 1.2.2 shows that only in October and March/April storage sites record both significant physical injections and withdrawals. October, March and April are in fact "transition months" with highly volatile temperatures in the Northern countries: customer demand is difficult to forecast in this months This pattern also recalls that European storages mainly addresses season flexibility needs (which require net withdrawals from storage during the winter and net injections into the storages during the summer), rather than daily balancing needs or short term price arbitrage. However it should be noticed that a withdrawal/injection in the summer/winter may be achieved virtually, i.e. by reducing injections/withdrawals respectively. It is likely that a fast-cycle storage would show a higher volatility and more unpredictable pattern between injections and withdrawals.

Daily withdrawals at each selected region are presented below and compared to the declared total withdrawal technical capacity (DTMTW) (Figure 1.2.3)[12]. This indicator must be considered cautiously as it does not take into account the declining performance of the sites: the emptier the storage the lower the maximum withdrawal rate. This appears relevant especially when the site's working gas is depleted for over 80% of its total, and sometimes even earlier. DTMTW is only feasible when storages are full.

[12] In some cases exceptionally high/low withdrawal/injection is due to increase/decrease in working gas.

In any case, daily off-takes from storage are way lower than total declared maximum withdrawal capacity[13], which makes the decline in performance less relevant. In particular, for all considered regions with the exception of Bulgaria, the utilization rate of withdrawal capacity is below 20% in half of the days when withdrawals from storage take place, and 2 times out of 3 it stays below 40% (Figure 1.2.4). The maximum withdrawal performance in Germany, Baumgarten, France and Denmark never exceeded 80% in the considered period. A percentage above 90% of the total declared technical withdrawal capacity is very rarely used. It should be noted that the bookable withdrawal capacity is less than the DTMTW, for instance in Germany approximately 20% of the withdrawal capacity is TSO capacity which is not commercial available for storage users.

High resort to storage withdrawals occurs in few occasions, for instance during the cold spell in February 2012 (4-10 February 2012[14]), when we observe simultaneous peaks in withdrawals from storages, at least for the regions we have data for, with the exception of Spain.

Volatility of storage withdrawals is also related to exploitation of the "extrinsic value" of storage. This will be briefly analysed in the next section.

1.2.4. Filling rate at the end of the injection season and at the end of the withdrawal season

Having described the utilization of storage through the year, we now focus on defined moments during the year:

- the end of the injection season, which should shed light on the incentive to fill up available storage space and on the actual stored gas reserves which are available ahead for the winter
- the end of the withdrawal season, which should reveal how intense the resort to gas stocks is.

At the end of the injection season[15], storage sites normally are in general above 80% full (Figure 1.2.5) and they never fall below 70%. This suggests that storage users tend to book a large share of the available technical capacity and generally fill up with the commodity the available space they booked.

However, there are differences between the considered regions: there is a group with higher storage utilization rates over time (Germany, Italy, UK and, to a lesser extent, Spain and Denmark) and another group where storages tend to be less full after the injection season (France, Baumgarten and Bulgaria). More specifically, in Germany, in Italy and in the UK storage maximum load factor was at about 90% or above in all the years.

Spain shows very high maximum filling levels (above 95% in general) Spanish storage high filling rate may be related to the fact that there is not so much capacity and that there are mandatory storage levels to be kept (Annex 12). More specifically, it is also important to note that Spanish underground storage capacity is not high (in volumetric terms) compared with other EU countries, or even when compared with total Spanish gas demand. However, Spain has a binding requirement to maintain a minimum 20 days' worth of gas reserves. Consequently, the combination of having

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[13] In this respect it shall be noted that the DTMTW is a figure published by the storage operators, which may not be reached due to lack of transport capacities available to exit the storage and enter the network.
[14] In February 2012 the cold spell was coupled with a reduction in Russian gas volumes imported through the Ukraine route.
[15] As commented above, growth in inventories usually terminates in October, however it may continue in November in some years. In order to assess the level at the end of the injection season consistently across years and region, we present the maximum filling level by year and by region, regardless whether this was achieved in September, October or November.

significant minimum storage reserve requirements and relatively limited storage space means that Spain's storage facilities are generally relatively 'full' when compared with those of other EU countries. In 2013, however, when the ratio between stored gas and available storage space in Spain fell below 85%, a fact that can be also motivated by the fact that 2.3 TWh out of 29 TWh were not allocated for storage year 2013/14[16].

Instead, in the Baumgarten region, Bulgaria and France filling rate are constantly lower: they stay generally below 90%. In particular, French inventories were 90% full only in 2014, while in 2011-2012 did not grow above 88% and in 2013 achieved only 80%. Since 2011, the filling level of Baumgarten region's storages stayed below 90%, dropping down to 72% in 2013. Bulgarian storage in 2013 was at about 70% and in 2014 reached 88%.

When looking at the evolution over time within the considered regions, the variation over time in the maximum filling rate is rather limited, as it ranges from 83 to 100% for the first group (Spain, Italy, Germany, UK, Denmark) and from 71% to 93% for the second group (France, Baumgarten[17] and Bulgaria). Maximum filling levels in the UK are the most stable during this period, being constantly virtually 100% full.

However, in the 2011-2013 period, we observe a decline in the maximum yearly filling rate for Baumgarten, Germany, Italy, France and Spain. The observed negative trend reached an halt in 2014, when gas stocks after the injection period achieved record high levels (above 88%) in all the considered regions.

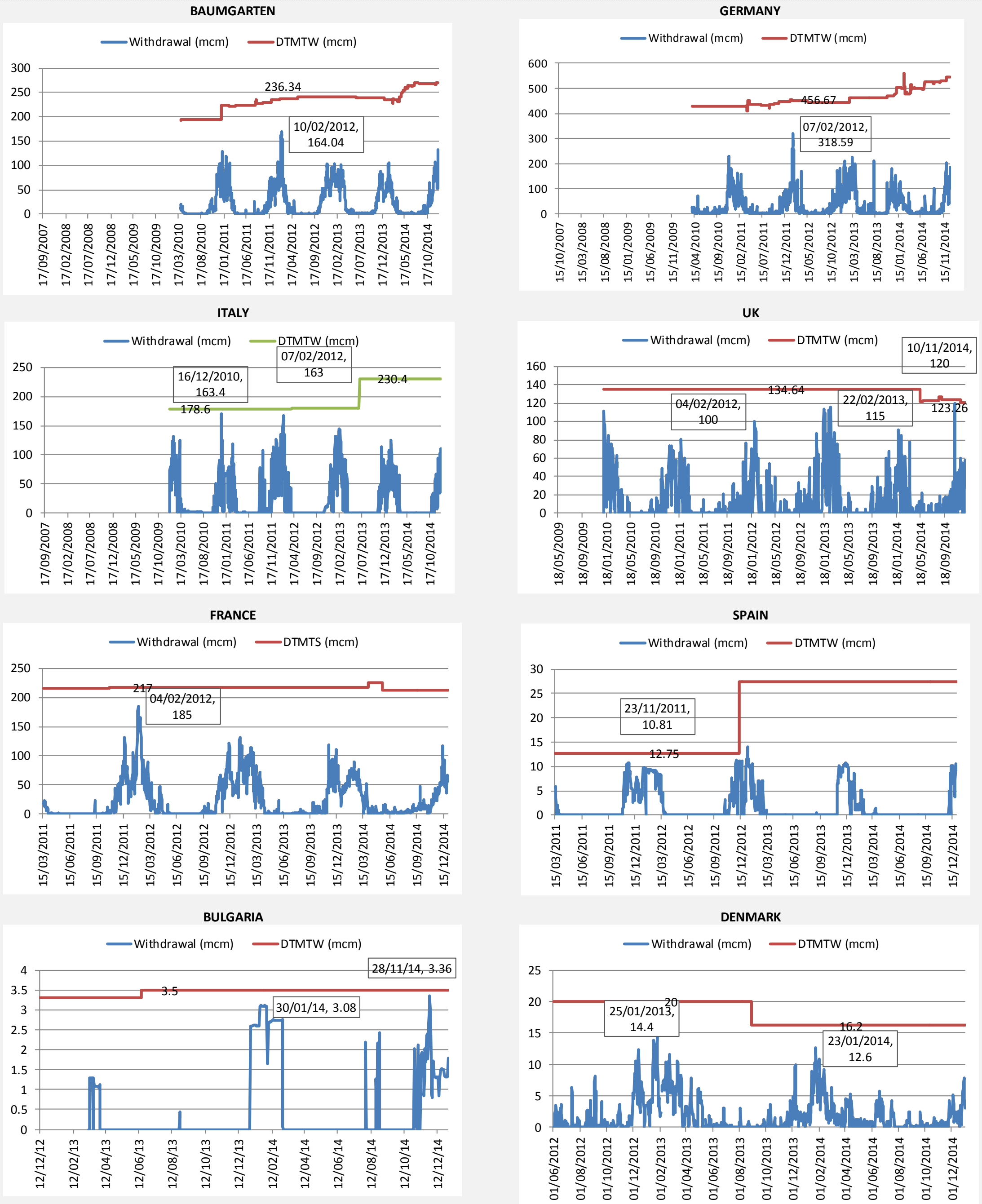
In 2013, as anticipated above, all considered regions, with the exception of UK and Denmark, were considerably less full than in the past after the injection-period: filling rate were below or only slightly above 90%. In 2013, the most remarkable drop in stored gas occurred in the Baumgarten region and Spain, where inventories stockpiled at the end of the injection season were, respectively, 14% and 15% lower compared to the maximum level recorded the year before. Focusing on filling rate at the end of the 2013 injection period, the Bulgarian storage was the emptiest (71%) among those considered, followed by storages in the Baumgarten region (72%) and in France (80%).

In part, this pattern in gas stocks may be explained by the legacy of the previous winter. In 2014, the extremely high storage filling levels may be explained by storages not being significantly depleted during the mild 2013/14 winter, as we will show below.

Symmetrically, the decline in gas stocks ahead of the 2013/2014 winter, compared to the year before, may be explained by a prolonged 2012/13 winter: in fact, as mentioned above, in the spring of 2013 injections started later than usual, arguably as a result of a prolonged cold spell spreading into the early spring which meant that withdrawals from storages continued until April and storages remained emptier than usual, as we will show below. As a result of the very low starting point, the filling level ahead of the 2013/2014 winter remained subdued compared to the other years, notwithstanding the fact that the volumes injected into storage sites during the 2013 storage season were higher than in the past in all the considered regions, with the exception of Spain (Figure 1.2.6). The decline from 2011 to 2012 has less clear reasons, due to the fact that storage levels at the end of the previous cold seasons were rather similar.

[17] 2008 data for Baumgarten is not considered in this comparison, due to inconsistency: before June 2009 the Hungarian storage operator MMBF and the Austrian storage operator RAG, accounting together for 2.6 bcm of working gas and representing more than 10% of the total working gas in the Baumgarten region, were not included in the Baumgarten region.

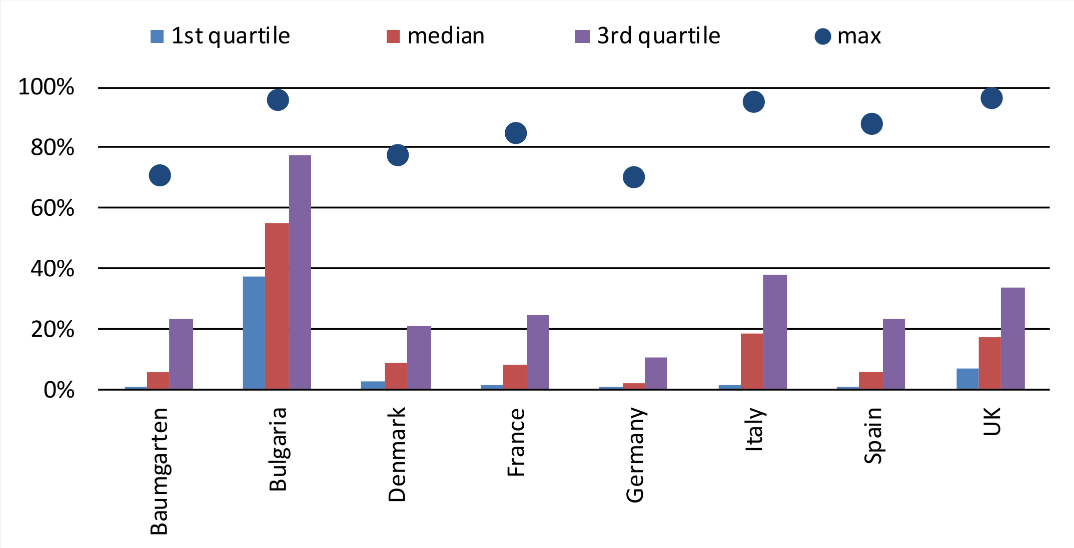
Figure 1.2.3. Daily withdrawals against total declared maximum withdrawal capacity



Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia

Source: GSE

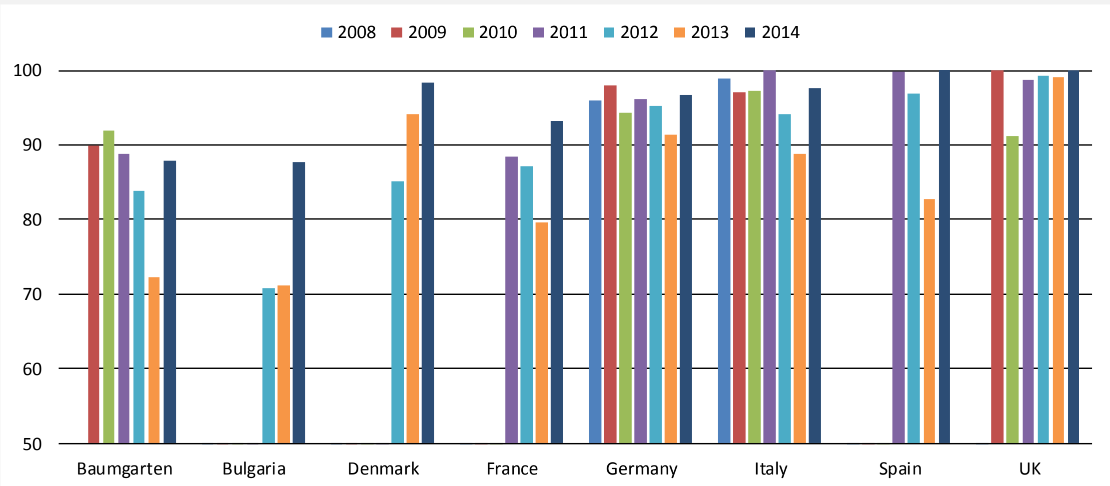
Figure 1.2.4. Descriptive statistics[18] for the utilization rate of daily withdrawal capacity (% of total declared maximum withdrawal capacity)



Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia

Source: GSE

Figure 1.2.5. Filling rate at the end of the injection period by region and year (%)

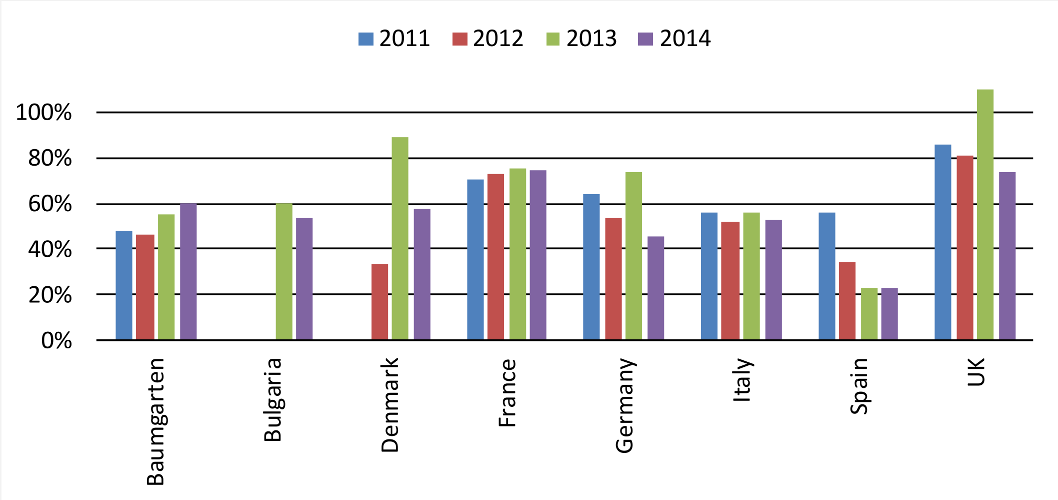


Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia

Source: GSE

[18] In descriptive statistics, the quartiles of a ranked set of data values are the three points that divide the data set into four equal groups, each group comprising a quarter of the data.

Figure 1.2.6. Total injections into storage from March to November by year and region (as a % of DTMTS)[19]



Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia
Source: GSE

Turning the focus on the end of the withdrawal season[20], data evidence shows that the working gas is never fully pulled out from storages (Figure 1.2.7), suggesting that there is typically a "buffer" to cope with unexpected events at the end of the winter season. However, it is worth saying that this buffer is limited due to the fact that the last X% cannot be withdrawn without a refill within the next 2 weeks. During the considered time span, if we exclude France and the UK in 2013, storage levels remain at least 10% full after the withdrawal season. Spanish storages stand out as they never fall below 40%, of total declared technical space capacity. French storage sites are usually the emptiest after the winter, as they never stay above 25%. The UK shows the most volatile pattern in stored volumes at the end of the withdrawal season. This may be the consequence of storage use that is entirely driven by market signals; in other words, gas left in stock depends on whether, in a given moment in time, it is more economical to withdraw gas than carry over to the next storage year.

For all the considered regions, the filling rate at the end of the withdrawal season varies considerably over time, as it ranges from 2% to over 60%.

The variation is, at least partly, explained by the temperature recorded in the corresponding winter (Figure 1.2.8), which in turn determines the extent of resort to storage during the cold season (Figure 1.2.9). Data evidence shows that the colder the weather (the higher the sum of HDD[21] in the winter season), the more consistent withdrawals are. Being storage a provider of "short notice" flexibility, as it is very close to the consumption centers, in the event of a cold spell the gas system usually resorts to underground stored volumes. Therefore, cold temperature prompts steady storage

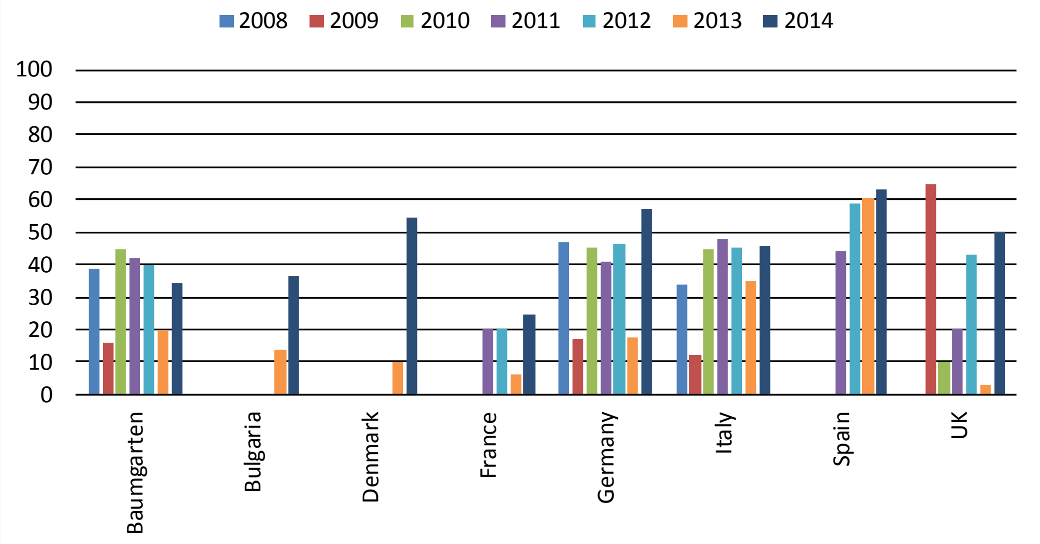
[19] The Figure shows gross injections, rather than net ones. For this reason is possible that total volumes injected in the March-November period exceed total working gas capacity, as some volumes might be withdrawn during the same period.
[20] As commented above, decline in inventories usually terminates in March, however it may continue in April in some years. In order to assess the level at the end of the withdrawal season consistently across years and region, we present the maximum filling level by year and by region, regardless whether this was achieved in March or April.
[21] Heating degree-days (HDD) express the severity of the cold in a specific time period taking into consideration outdoor temperature. We adopt the following method for the calculation of monthly HDD: (18 °C - Tm)*d if Tm is lower than or equal to 15 °C (heating threshold)
0 if Tm is greater than 15 °C where Tm is the average monthly outdoor temperature, and d is the number of days in the considered month. Monthly temperatures were computed as simple averages of daily values.
For this Project, we compute monthly heating degrees days (HDD) for selected sample countries since Jan 2007. The sources are noaa.gov (metering stations granularity, simple average over daily values) and meteo.it (city granularity, every city is weighted according to gas consumption). Data collected by Eurostat data exist but are available only up to 2010.

depletion. A clear example is 2013, when, as mentioned above, extremely low levels can be explained by greater-than-average resort to storage resources in the 2012/13 winter due to a prolonged cold season spreading out to the early spring. Symmetrically, after the 2013/2014 winter, storage inventories achieved a 5-year record filling percentage rate in Germany, UK, France and Spain: this was arguably due to a mild 2013/14 winter[22], when the use of inventories to fulfill consumption needs was therefore reduced.

Winter temperatures, however, are not the sole driver of end-of-winter filling level: security of supply reasons, filling rates ahead of the winter (i.e. the “starting point” filling level), the presence of special mandatory storage stocks (“strategic storage”) affect gas quantities left in storage after the cold season.

In fact, low levels at the end of the winter season observed in 2009 for Italy, Germany and Baumgarten occurred in the presence of winter temperature in line with the historical average, and may reflect the intense use of storage resources to cope with supply cuts following the January 2009 Ukraine-Russia crisis[23].

Figure 1.2.7. Filling rate at the end of the withdrawal period by region and year (%)

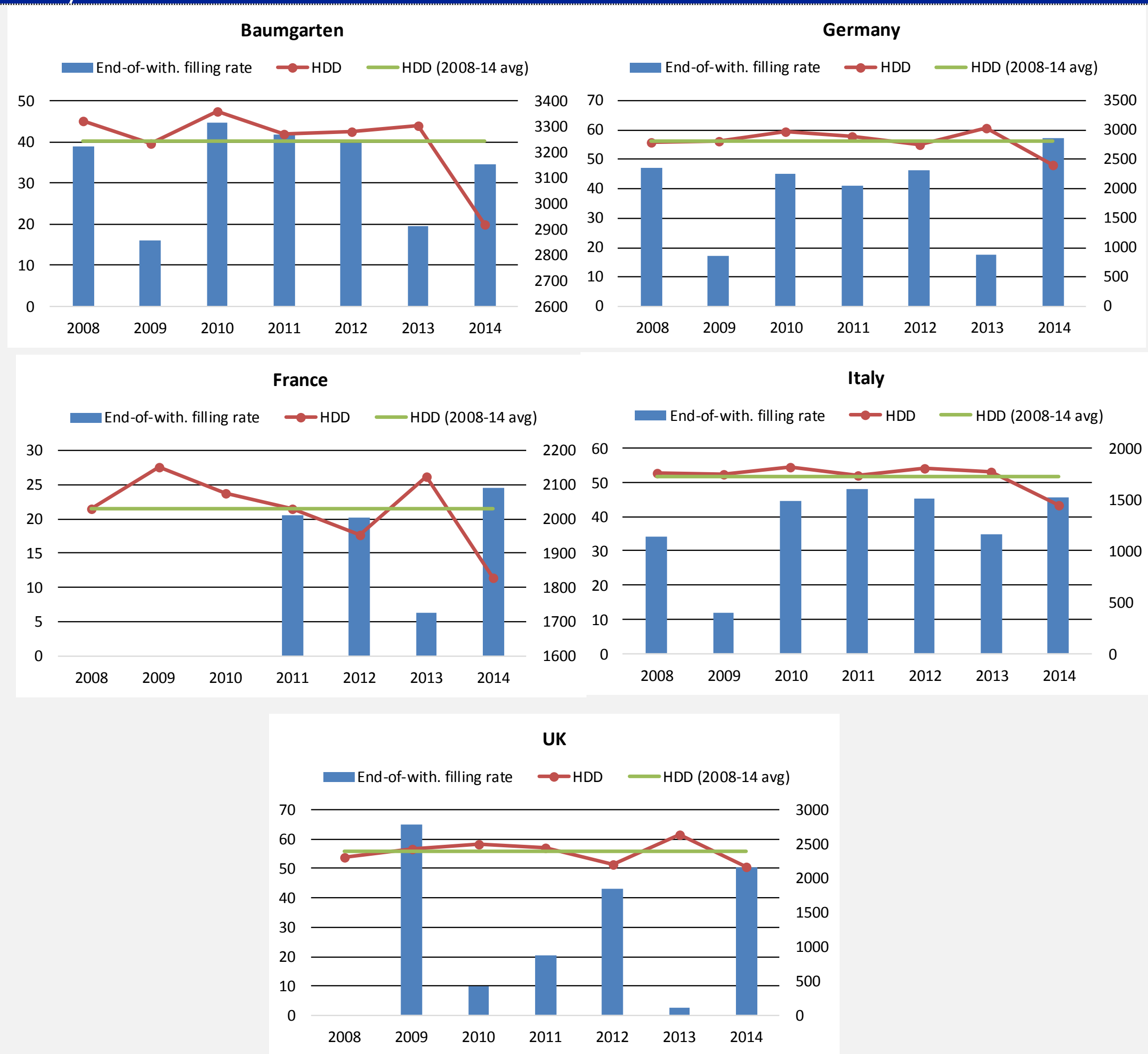


Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia
Source: GSE

Further, low levels after the 2012/2013 winter may be explained also by lower-than-average stocked gas during the preceding injection season in Italy, Germany, Baumgarten, France (Figure 1.2.10 where black circles highlight the decline): as noticed above, at the end of the 2012 summer storages were less full compared to the previous years.

[22] Total HDD in the 2013/2014 winter were at least 10% less than the 2008-2014 average in Italy, Germany, Austria, UK and France.
[23] On the 1st of January 2009 Gazprom cut all supplies for Ukrainian consumption, while Russian supplies to Europe were drastically reduced on the 6th of January and completely cut off on the 7th of January. On the 22nd of January gas flows from Russia to all European customers returned to normal levels (Source Pirani, Stern, Yafimava, «The Russo-Ukrainian gas dispute of January 2009: a comprehensive assessment» (2009).

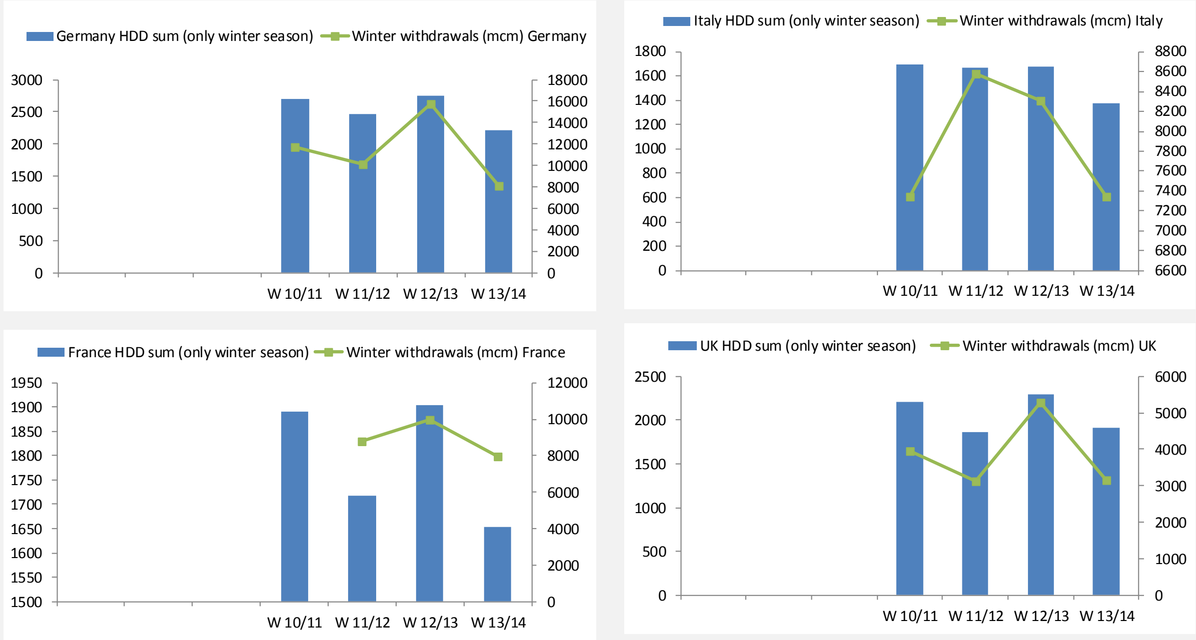
Figure 1.2.8. Filling rate at the end of the withdrawal period (%), total HDD during the corresponding withdrawal season (°C) and 2008-14 average for HDD by region and year



Note: Baumgarten area includes Hungary, Austria, Poland, Czech Rep. and Slovakia. HDD are computed based on temperatures recorded in Austria.
HDD series represents total HDD in the preceding winter, for instance for 2008 end-of-withdrawal-season filling rate, the corresponding winter is 2007/2008.

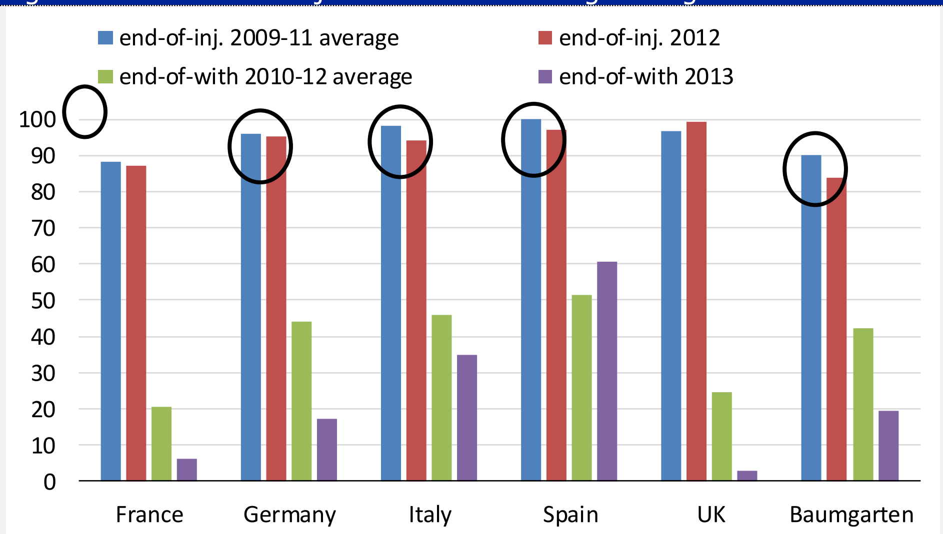
Source: GSE, meteo.it, noaa.gov

Figure 1.2.9. Total withdrawals from storage and HDD by winter months and year, for selected regions



Source: GSE, meteo.it, noaa.gov

Figure 1.2.10 End-of-injection season storage filling levels



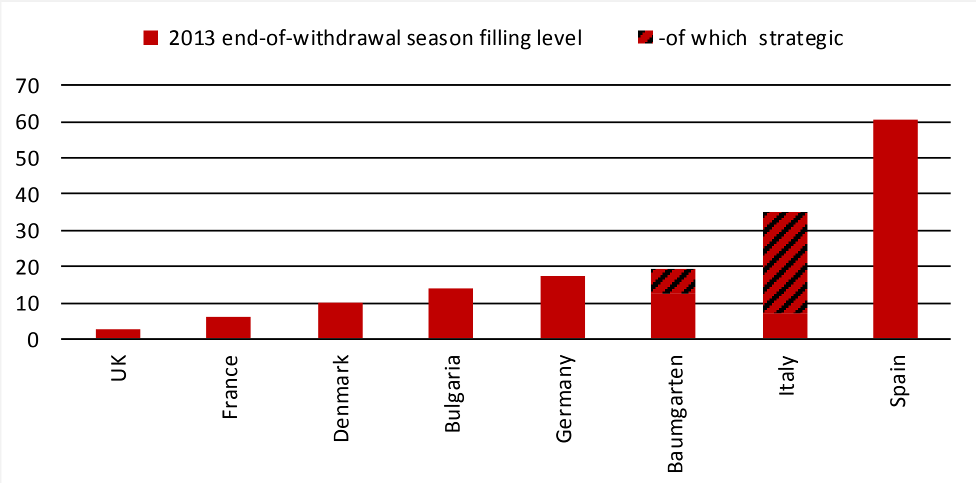
Source: GSE

As shown, in 2013 high resort to storages due to prolonged cold weather, and possibly less stockpiling during the preceding injection season, contributed to the occurrence of a record-low level of inventories at the end of the withdrawal period in all considered regions as well as to lower filling rate ahead of the 2013/2014 winter.

The 2013 picture (Figure 1.2.11) is quite uneven across countries, though: extremely tight situations (filling level below 5%) occurred in France, UK and locally in

Germany[24], whereas Spain and Italy remained well-endowed with gas stocks: their storages remained at 60% and 35% full, respectively. In particular, British storages at the end of the 2012/2013 cold season, which lasted until April, were below 5% of total working space and a similar situation occurred in France. Considering that about 28% (4.5 out of 16.2 bcm of working gas) of Italian DTMTS should be always full due to the existence of strategic storage, which has to be used only in the event of an emergency, this may explain the relatively high levels recorded in Italy even after a cold and prolonged winter.

Figure 1.2.11. End-of-withdrawal season storage filling levels in 2013



Source: GSE

In 2013, storage sites in the Baumgarten region did not fall below 15%, also thanks to the presence of 1.2 bcm of strategic storage located in Hungary. Bulgaria and Denmark were in the range of 10%-15%.

1.3. Factors driving storage filling

In the previous section we described the utilization of storage capacity across time and regions accounting for over 85% of total European storage capacity. To sum up, we found out that:

- In the past 5 years, storage sites have been refilled ahead of the winter at a good level, as they were always at least 70% full;
- However, there are differences across Europe: in particular, filling rates ahead of the winter in the Baumgarten region, Bulgaria and France are constantly lower than in the other considered regions;
- There is no clear evidence that market players have been reducing the use of storage capacity over time.

In this Section, we present a theoretical analysis of the drivers for storage filling, including winter/summer spreads, hub price volatility, availability of other flexibility sources as well as long term commitments resulting from long term storage contracts concluded in the pre-liberalization period. The effect of storage related security of supply measures on storage filling will be examined in *Chapter 4*.

[24] German storage were at 20% full due to the fact the Rehden storage facility (controlled by Gazprom and serving also the UK and the Netherlands) was fuller than other German storage sites.

The objective of this analysis is to assess which are the reasons why storages are usually refilled ahead of the winter. This theoretical analysis may shed light on the potential developments by which the filling levels may change in the future, compared to recent years.

In the next *Section* (*1.4*) we focus in more detail on the evolution of storage prices and storage products. The evolution of the price of storage resources is in fact key to offer an insight on what drives investments in this sector and on what affects the usage of existing storage resources.

1.3.1 Multiple functions of storage and its drivers

An energy market player may have different reasons to book (physical and virtual[25]) storage capacity and use it. These reasons relate to the multiple functions of storage and include:

- seasonal flexibility needs: storage may be used by a gas supplier to balance its portfolio to fulfil its clients' consumption seasonal swings;
- short-term flexibility/balancing needs: needs to have flexibility to respond to short term variations in demand; storage, being close to consumption areas, may be used by a gas supplier to adjust supply promptly to short term changes in its clients' consumed quantities (for example due to an extra-ordinary cold snap). In particular, storages can be used by traders to balance their own balancing accounts or to support balancing energy markets with day ahead and within day products at the virtual trading point and local points (if the systems requires balancing energy at local points);
- willingness to exploit trading opportunities emerging from short term price volatility or seasonal price spreads (the "price gain" from storage);
- insurance against the risk of supply disruptions, with a view to ensure security of supply for end users even in unexpected emergency situations;
- insurance against the risk of market price spikes, with a view of containing total gas procurement costs;
- security of delivery needs: a producer may use storage to ensure the transport of gas over long distances against the risk of en route disruptions (such as Gazprom storages on their transport routes);
- production needs: a gas producer may need storage to optimize production delivery performance;
- system "safety" needs: a TSO may use storage for some of its balancing needs[26];
- mandatory security of supply requirements.

As regards the last bullet, as described in Chapter 3, an energy player may be obliged to have storage capacity ready to be used when storage-related SOS measures (SRSMs) are in place. In particular suppliers' storage obligations and strategic storage stocks exist in some MSs.

[25] Virtual means that it is offered at the hub, see Section 1.4.
[26] For instance some storage resources may be reserved for the TSO, to be used as balancing services. This is the case for Italy and UK (see *Chapter 3*). The CEER Report on gas storage regulatory vsion P.10 recognises that « here are also peak shaving storage facilities that tend to be used exclusively by Transmission System Operators (TSOs) for system management. In many cases, they are not subject to Third Party Access and hence are not discussed".

As far as seasonal flexibility needs are concerned, it may be worth to dig into the exact meaning of this. When we refer to seasonal flexibility needs, we refer to the need to react effectively to seasonal changes in demand of gas from end customers. This need stems from the design of long-term bilateral upstream gas supply contracts[27], which are one of the main instruments gas suppliers procure the physical molecule from producers. Typically, long term gas supply contracts do not provide suppliers with the perfect delivery profile suppliers would need to accommodate fluctuations in their end users clients throughout the year[28]. Since gas is a storable commodity, gas inventories act as a buffer, provide suppliers with additional flexibility they need to fulfil consumption swings[29] and reduce transport cost for importers. In addition to this, maximum daily import capacity may be lower than the winter demand peak, and hence storage becomes necessary from a infrastructural, rather than contractual, point of view.

On the other hand, pipeline flexibility is limited by its cost. The longer the supplying pipeline, the larger the costs increase required to ensure the necessary flexibility. This was actually the original reason why integrated suppliers in the past started to develop storage in the neighborhood of consumption areas.

Seasonal flexibility needs are in fact different from the need to have a tool to replace missing supply of gas in the event of a disruption (such as importing infrastructure failure or supply cuts or impossibility to deliver for the producer). Flexibility need is there also without the occurrence of a systemic shock reducing the available supply.

In light of this, incentives to storage use and development include:

- winter/summer spreads, as they are a key price signal of the value of seasonal flexibility and the simplest metric to measure the "arbitrage gain from storage".
- hub price volatility, which may generate trading opportunities
- transport capacity costs, energy costs and taxes (countries compete in the storage markets)
- availability and cost of other flexibility sources, which in a liberalized market compete with storage
- any factor leading to a more remarked yearly swings in consumption, such as the evolution of temperature or changes in the demand mix
- SoS measures (unless perfect crowding out occurs, see *Chapter 4*).
- long term commitment to book storage (long term storage contracts).

1.3.2 Seasonal price spread

Seasonal price spread definition and evolution

The seasonal price spread (also known as summer-winter spread) represents the expected premium of the price of gas to be delivered during the coldest months

[27] Also known as gas supply and purchase agreements (GSPAs). Here we refer to them also as « long term import contracts ».
[28] Delivery flexibility is actually included in these contracts and is known as pipeline flexible swing.
[29] If we simplify the reality and ignore that these contracts include delivery flexibility, the situation may be effectively illustrated by a supplier who 1) procures gas with a flat profile through the year thanks to an import contract for a annual quantity X and 2) serves end users using gas for space heating and therefore demanding ½ X in the summer season and 3/2 X in the winter season. Imported quantity exceeding consumption needs in the summer may then be stored to be used in the winter and hence to address the seasonal flexibility needs of this supplier. Note that the supplier may have also contracted a lower annual quantity (1/2 X for instance) and procure additional required volumes on the wholesale market using standard contracts available OTC or on a energy exchange, without the use of storage. In this case additional volumes procured on the wholesale market ("at the hub") were originally procured upstream and possibly stored by other market players.

(typically the gas winter season[30], when gas consumption peaks mainly due to the households' heating needs) with respect to the price of gas to be delivered during the mildest months (typically the gas summer season[31], when gas consumption drops).

Generally, the seasonal spread for year t is computed as the difference between:

- the price for the forward[32] or future[33] contract envisaging flat delivery of gas during the gas winter season, spanning from the end of year t and the beginning of year t+1(so called Winter t contract) and
- the price for the forward[34] or future[35] contract envisaging flat delivery of gas during the gas summer season in year t (so called Summer t contract)

While the former is traded until 30th of September of year t, the latter is traded until the 31th of March of the year t. Trading of the Winter t and Summer t contract may start way in advance with respect to delivery start date. When the delivery season corresponds to the season ahead of the trading date, the contract is referred to as Front Winter or Front Summer.

Alternatively the seasonal spread may be expressed as the difference between the price for the contract envisaging flat delivery of gas during the first quarter of year t+1 (this being typically the coldest quarter of the winter) and the price of the Summer t contract.

The winter gas premium that is reflected in the forward market reflects the expectation of actually higher winter prices. For example, the January-March spot price (2008-14) average of British NBP prices exceeded those of July-September by 9.8%. In the case of Dutch TTF, the largest European Continental hub, such difference has been only 4.7%. However, prices have been converging and seasonal differences with them. Yet, it is generally agreed that what matters for suppliers' storage decisions are forward prices rather than actual ones, although it cannot be ruled out that operators also consider the accuracy of forward price forecasts.

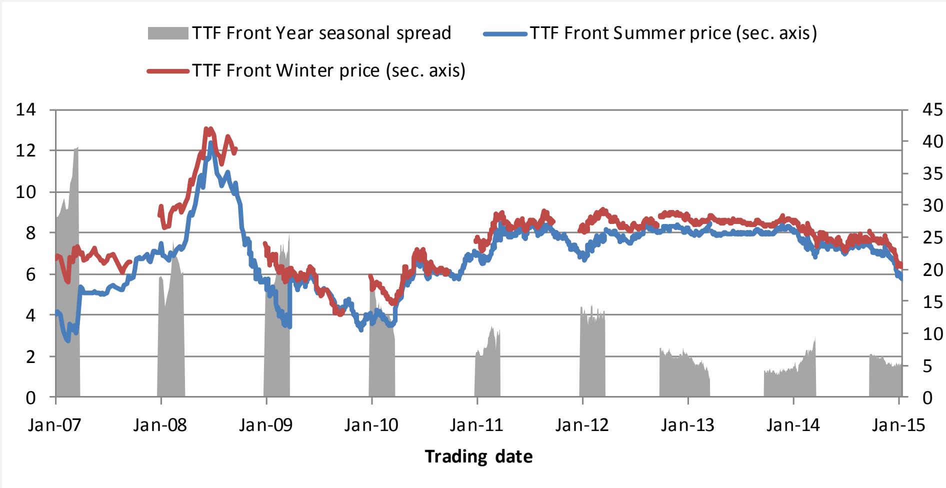
Figure 1.3.1 below shows the evolution of Front Year TTF seasonal spread. This was computed as the difference between the daily OTC price[36] for Winter t contract[37] and the daily OTC price[38] for the Summer t contract, where t is the year when delivery occurs.

Due to high liquidity over the whole maturity curve, the TTF prices may represent a good benchmark for the whole Continental Europe. In fact in less traded markets, forward curves may not be reliable but for the very short term deliveries.

Anyway, seasonal spreads at other hubs in Continental Europe show a similar patter to TTF, as shown in Figures 1.3.2-4 below. PSV however showed higher W-S spreads than TTF, especially before 2012. The Austrian market CEGH recorded lower spreads compared to TTF.

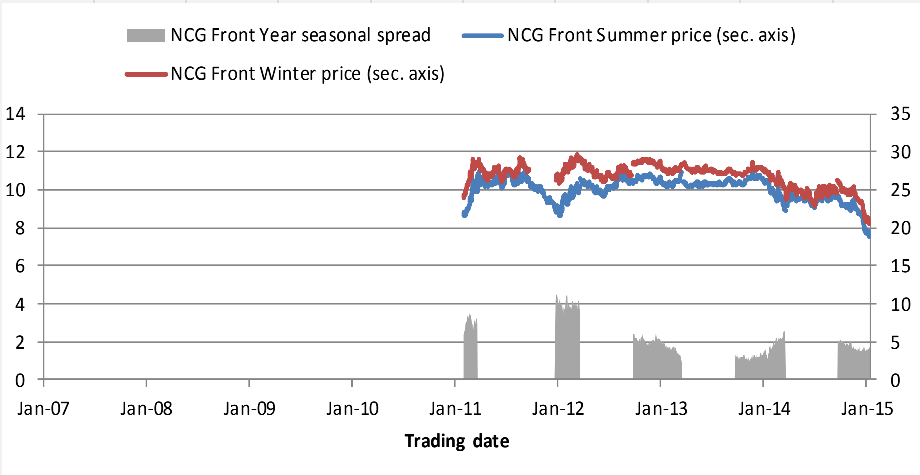
[30] Gas winter season runs from October to March of the following year.
[31] Gas summer season runs from April to September of the same year.
[32] Where forward indicates that the contract is traded OTC.
[33] Where future indicates that the contract is traded on an energy exchange.
[34] Where forward indicates that the contract is traded OTC.
[35] Where future indicates that the contract is traded on an energy exchange.
[36] Based on Albasoluzioni price assessments.
[37] Front winter means that delivery takes place the immediately next winter season after the quotation date.
[38] Based on Albasoluzioni price assessments.

Figure 1.3.1 Historical daily TTF front year seasonal price spread (€/MWh)



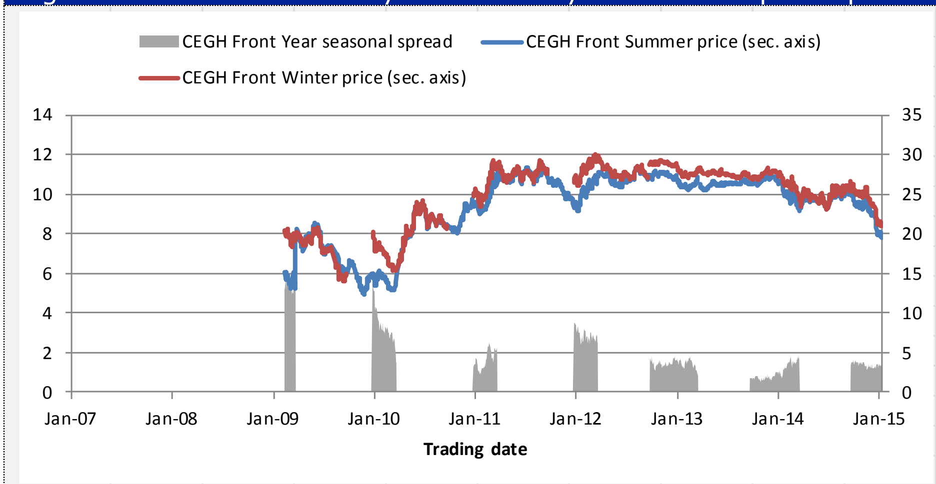
Source: Albasoluzioni

Figure 1.3.2 Historical daily NCG front year seasonal price spread (€/MWh)



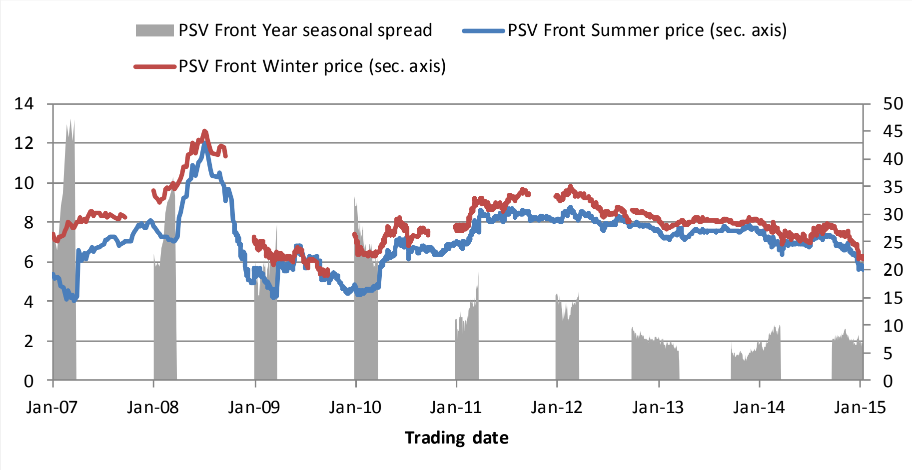
Source: Albasoluzioni

Figure 1.3.3. Historical daily CEGH front year seasonal price spread (€/MWh)



Source: Albasoluzioni

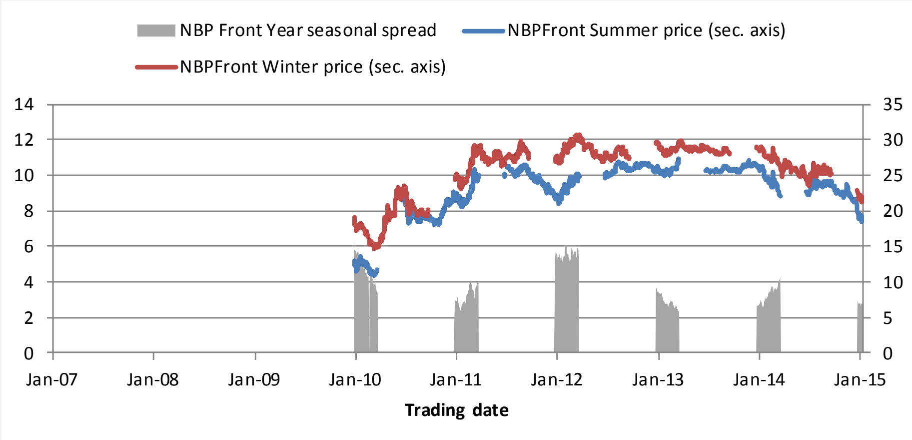
Figure 1.3.4 Historical daily PSV front year seasonal price spread (€/MWh)



Source: Albasoluzioni

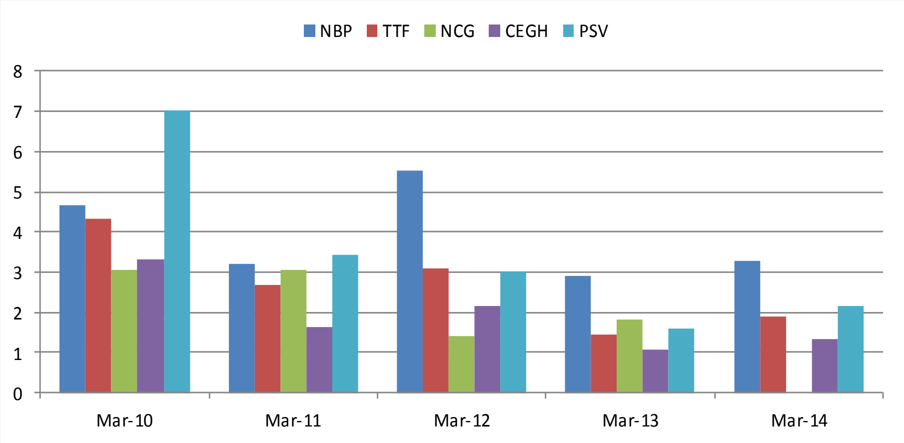
The seasonal spread at the British NBP (Figure 1.3.5) presents more remarkable differences, it is generally higher than TTF's. However the evolution over time resembles that of TTF.

Figure 1.3.5 Historical daily NBP front year seasonal price spread (€/MWh)



Source: Platts

Figure 1.3.6 Historical front year seasonal price spread, yearly average at selected hubs (€/MWh)



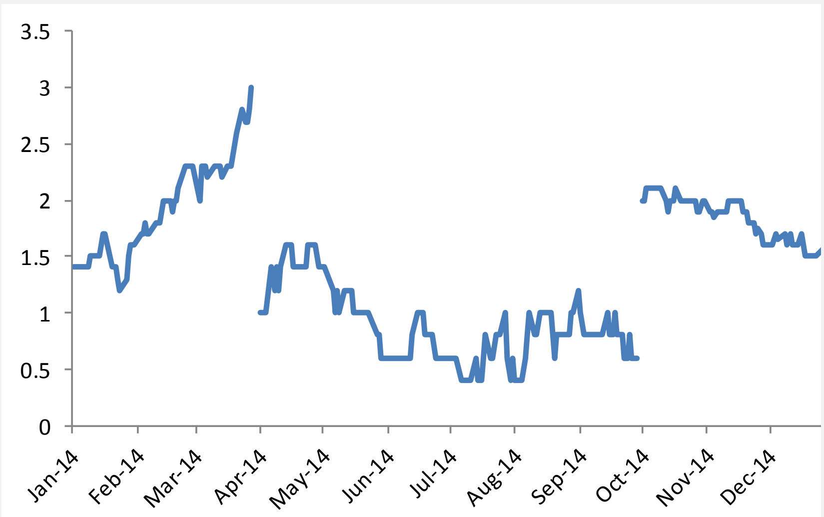
Source: Albasoluzioni, Platts

Seasonal spreads show a clear downward trend since 2007. Winter premium plummeted from above 6 €/MWh for seasonal contracts traded in 2008 and 2009, down to less than 2 €/MWh for contracts traded in the last three years (2013-2015).

TTF seasonal spread fell over the course of 2013, reaching record low levels right before the start of the 2013 summer season. The winter 2014/15 premium instead started at very low levels and then went up in the first quarter of 2014, although never exceeding 3 €/MWh. The seasonal premium for gas to be delivered in winter 2015/16 remained subdued in the latest available data and has been declining since it was quoted for the first time.

The within-year recoveries in the spread, such as the one taking place in 2014, were actually short lived. In the first months of 2014 (Figure 1.3.7), the spread raised as relatively full storage sites, after a very mild 2013/2014 winter, led to a temporary sharp fall in front summer prices which translated into a temporary rise in winter/summer premium. At the start of 2014/15 winter, on the contrary, the spread was supported by the security of supply concerns triggered by the Russia-Ukraine crisis, and then the winter premium began to drop as soon as Russia and Ukraine, in October 2014, reached an agreement on the Ukraine gas supply (Figure 1.3.7).

Figure 1.3.7 Evolution of the TTF front year seasonal price spread in 2014 (€/MWh)



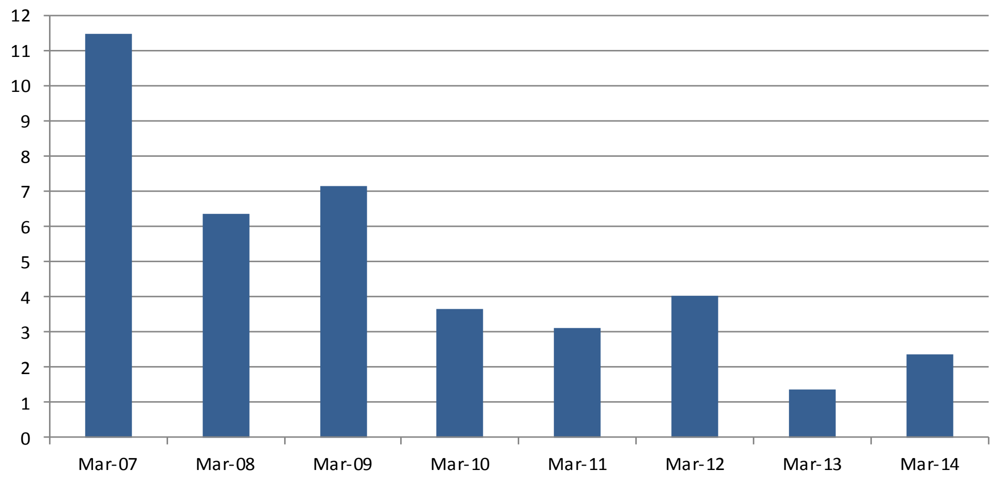
Source: Albasoluzioni

The fall in the seasonal spread is even more evident when considering the average level of the spread quoted by traders in March (Figures 1.3.8-9), the month when usually storage yearly allocation of the SBU takes place. The spread hit historically low values in March 2013, when it was below 2 €/MWh, half the value of the previous year and less than one fifth of the level reached in the same month of year 2009.

Arguably the seasonal spread was driven down by the development of a flexibility oversupply compared to a declining gas demand, which pulled down price volatility across the seasons. An in-depth assessment of the drivers of the decline in W-S spread is out of the scope of this study, however two important factors that should be mentioned here are the increasing interconnection of national markets and the expansion of available storage capacity.

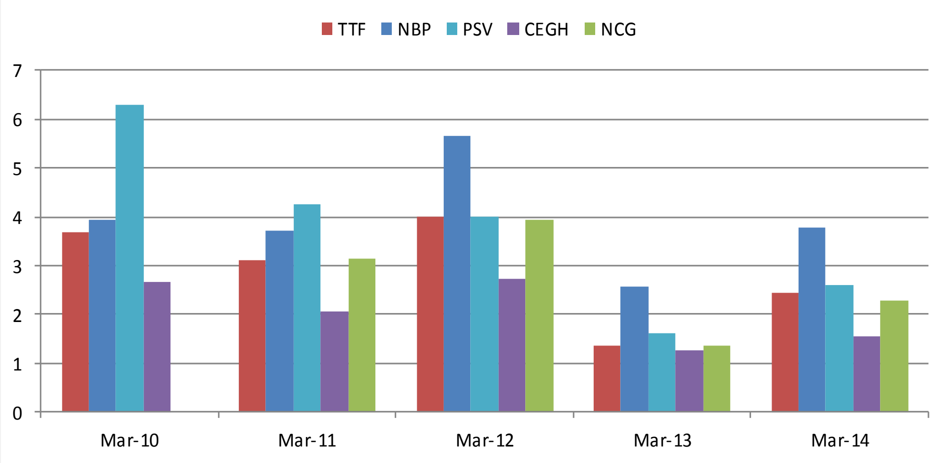
In particular, the increasing interconnection of national markets, fostered by European Union energy policies, allowed flexibility to be traded beyond national borders and triggered the flexibility glut in an environment of unanticipated declining gas demand in the European Union. Further, the abundance of flexibility was also fostered by the expansion of available storage capacity: storage investment decisions taken in mid-2000s based on forecast demand have resulted in overcapacity. As shown in *Section 1.1*, increasing growth in European working gas in the 2006-2014 outpaced growth of demand (-0.2%/year) & imports (+1%/y). In addition, the gradual shift towards faster facilities (*Section 1.1*) increased the average speed of European storage endowment, allowing for increasing flexibility.

Figure 1.3.8 Historical TTF front year seasonal price spread, monthly average in March (€/MWh)



Source: Albasoluzioni

Figure 1.3.9 Historical front year seasonal price spread, monthly average in March for selected European hubs (€/MWh)



Source: Albasoluzioni

1.3.2.2 Seasonal price spread and storage

In a fully market-oriented environment, seasonal spreads are normally seen as a key price signal for the value of seasonal flexibility and as the major market drivers for building up gas inventories. This holds true in particular for those storage facilities with a relatively low deliverability rate, like most depleted fields and aquifers, which correspond to over 70% of European capacity (*Section 1.1*).

In other words, the expected premium of winter prices to summer ones is one of the factors which provide an incentive to refill storage sites and purchase storage resources. In fact, in case the expected premium of winter prices to summer prices is above zero - or anyway higher than the cost of storage endowment - there is the possibility to extract value from booked storage capacity, using the forward market and the storage infrastructure to lock a margin[39]. More specifically, being the Front Winter price (Pw) higher then Front Summer price (Ps), the agent would commit to purchase volumes during the summer at price Ps, and contemporary would commit to sell volumes during the winter at price Pw. Gas purchased at Ps will be then injected into storage during the summer and eventually withdrawn from storages during the winter, so that it can be sold at price Pw. The gross gain that storage gives to the agent is Pw-Ps, that is the summer-winter price spread. The net gain is instead Pw-Ps – C, whereby C is the unit cost of the storage endowment.

The cost of storage endowment may include: the cost of the transmission capacity to move gas from storage facility into the grid, or from the grid into the storage facility[40] as well as the operational cost and fees to inject or withdrawal gas from the stock (energy cost including energy fees and taxes[41]). Another significant component is the financial burden, as storage users have to immobilize gas volumes in the storage facility and may also be asked to provide financial covenants in order to book storage capacity.

The cost of storage endowment may include or not transmission capacity costs. This may be rather important when comparing national storages with alternative flexibility

[39] Note that there may be barriers to fully extract the arbitrage value of storage: no coordination between transport allocation procedures (necessary to get the gas to be injected in storages) and storage allocation procedures for instance.
[40] This may be rather important when comparing national storages with alternative flexibility tools. The gas stored nationally has been imported in general such that it already paid an entry and exit transmission capacity. In some countries, e.g. Germany, stored gas pays « network costs » twice while imported gas from other markets is only charged with single entry/exit fees.
[41] For example in Germany SSO have to pay EEG-costs like a small households for the energy which they need for the compressors.

tools in other countries. The gas stored nationally has been imported in general so that it has already paid at least an entry capacity tariff. In some countries, e.g. Germany, the use of storages induces again entry and exit costs by which the stored gas pays network costs twice, while imported gas from other markets is only charged with single entry exit fees.

It is important to say that the net gain coming from summer-winter spread is not the only source of value from storage. According to literature and industry practice, the seasonal price spread represents in fact the "intrinsic" value of storage. In a competitive market-based environment, the intrinsic value (less the cost of using storage) should represent the minimum ("floor") price storage users are prepared to pay for storage resources to be used to cover seasonal consumption swings.

Any value that the storage users are willing to pay over and above the intrinsic value usually reflects, on the one hand, the value the users attach to the opportunity to use storage to take advantage of short term price volatility (including very large differences between effective - not expected- winter spot prices and effective summer spot prices), as well as to the opportunity to use storage to extract value from refined hedging in the medium term (known as the "extrinsic" value of storage); on the other hand, it may also reflect the value, if any, that the users attach to the utility to use storage as an insurance tool against supply disruptions or extreme weather conditions and their prices impacts (insurance value)[42].

The opportunity to use storage to take advantage of short term price volatility and to extract value from refined hedging in the medium term will be addressed in the next section.

We attempt to measure the relative importance of different storage drivers in *Section 1.3.6* below. In what follows, we explore whether there is some preliminary evidence of the influence of seasonal spread[43] on the amount of gas that storage users choose to stock ahead of the winter.

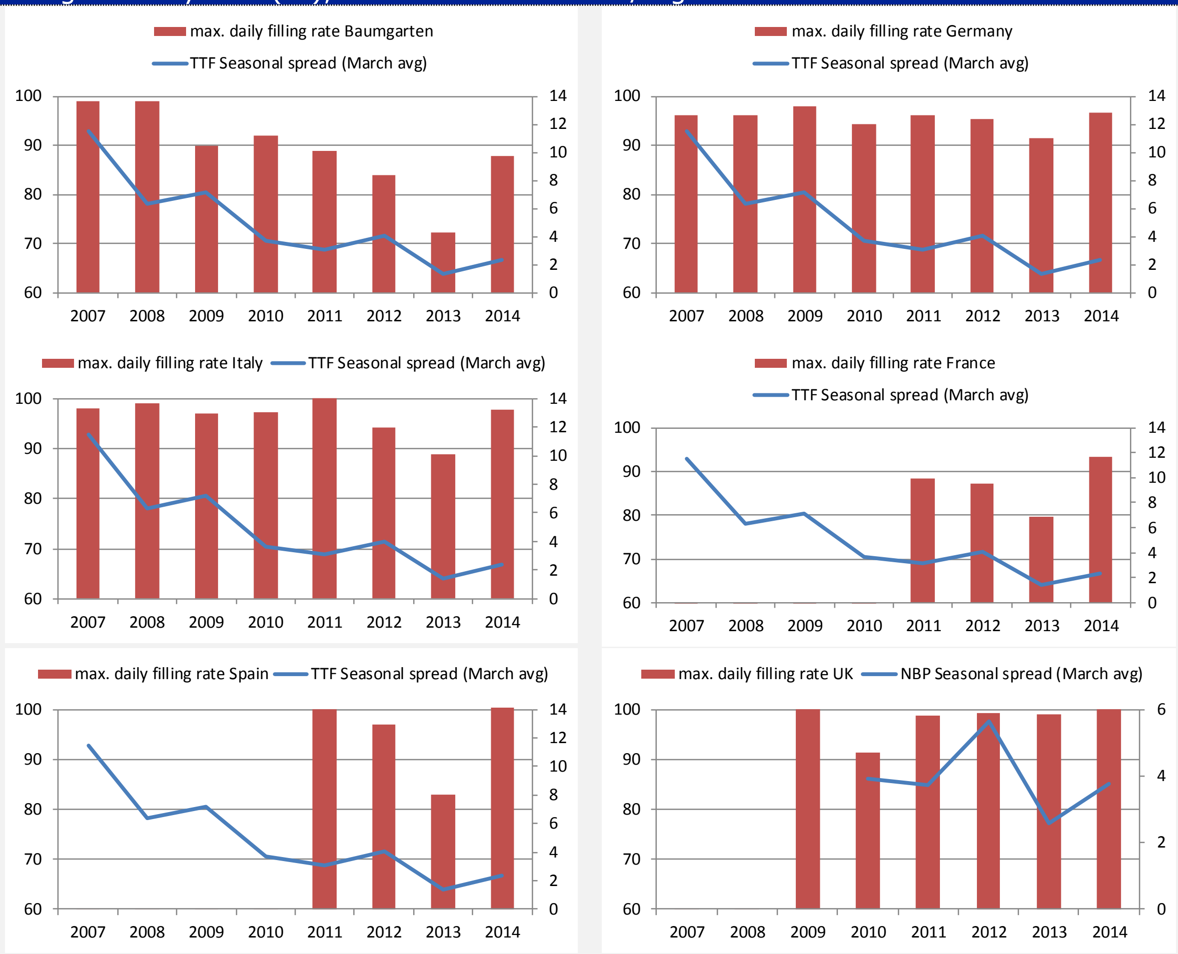
Visually, there does not appear to be a clear relationship between average seasonal spread in year t and the maximum filling level in the gas summer season of year t. Over the 2010-2012 period maximum filling levels slightly declined (as analyses in *Section 1.2*) but the spread was instead rather stable.

However, in 2013 when the negative record for the spread occurred (< 1.5 €/MWh), storage filling level remains clearly lower than in the other years, with the exception of UK storages. This said, as explained in *Section 1.2*, other reasons, other than low seasonal spreads, may explain low filling levels (such as late start of injection in 2013 and technical restrictions on injection capacity).

[42] For a discussion on the value of storage refer to CEER Public Consultation Paper "Vision on the Regulatory Arrangements for the Gas Storage Market", Ref: C14-GWG-112-03, 22 October 2014.

[43] In what follows we refer to the average winter-summer spread registered in March. As the seasonal price spread may vary over the year widely, the value that typically prospective storage users look at when taking their decision on their annual storage booking is the seasonal price spread quoted immediately before storage allocation procedures take place (usually March).

Figure 1.3.10[44] Average seasonal spread in March of year t (€/MWh) and the maximum filling rate in year t (%), for selected countries/regions



Source: GSE, Albasoluzioni, Platts

Finally, it is worth noticing that the relationship between storage levels and seasonal spread is a bidirectional one. It is not just expected seasonal spread that influences storage use but also the level of gas inventories that affects the observed seasonal spread. For instance, in the first months of 2014 the spread increased as, after a very mild 2013/2014 winter, relatively full storage sites led to a temporary sharp fall in front summer prices which translated into a temporary rise in the winter/summer premium. The latter, in turn, prompted stockpiling during the 2014 storage season.

1.3.3 Spot gas price volatility

Spot gas prices are generally defined as the price for the standardized forward[45] or future[46] contract envisaging flat delivery of gas during the day after trading date. Such contract is commonly referred to as the Day Ahead contract/product (or Front Day contract/product). Delivery takes place at the agreed delivery point. The most common delivery points are the gas hubs, where deliveries concentrate.

Day ahead contract is traded on the wholesale market and its price is determined by supply/demand forces (and therefore by buyers' and sellers' bargaining powers), in contrast with the price paid for long term contracted gas, which traditionally resulted

[44] Data after 2010 for Spain and France, data after 2009 to avoid inconsistency in the historical time series of stored gas in the AGSI dataset (see *Annex 2*)
[45] Where forward indicates that the contract is traded OTC
[46] Where future indicates that the contract is traded on an energy exchange

from the application of an oil indexed formula. However, this has changed recently due to challenges in the gas market which resulted in renegotiation of price formula in long term contracts.

The more day ahead gas is traded with delivery at a given hub, the more the hub's day ahead contract is liquid and therefore able to provide a reliable price reference.

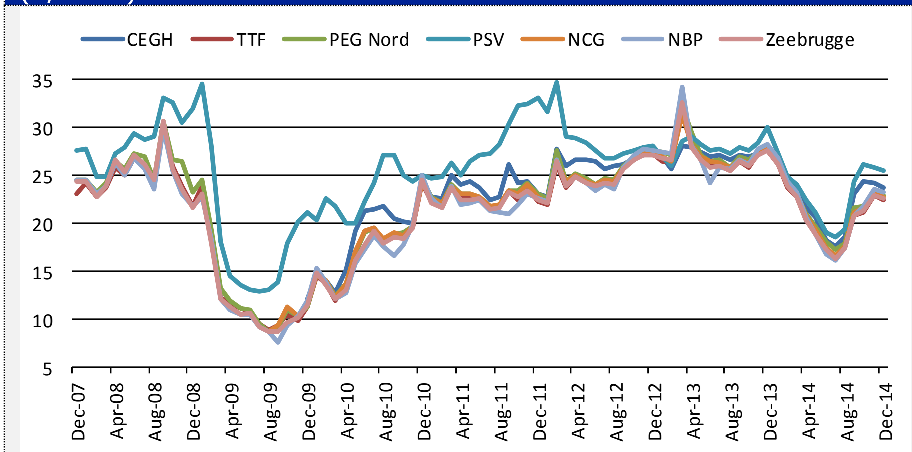
In Europe, the day ahead contract is frequently traded at different hubs (including Dutch TTF, British NBP, Zeebrugge in Belgium, the PEGs in France, NCG and Gaspool in Germany, the Italian PSV, the Austrian CEGH). However, liquid wholesale markets have not developed yet in some areas, so for some of our sample countries (Bulgaria, Poland, Spain and Hungary) no spot/day ahead price reference is available. The Czech Republic has an embryonic market that is now reported by specialized publications, though with a tiny liquidity. Hungary, Poland and Spain (with Portugal) are also in the process of developing more transparent wholesale markets. Other countries' suppliers (like Croatia, Slovenia, Ireland, Denmark and Slovakia's) tend to refer to more liquid, neighbouring hubs.

We choose TTF as a main reference for North West Continental Europe, backed by the assumption that, in integrated national markets, the prices of these markets should converge net of transaction costs. NBP price is the reference for the British gas market.

Figure 1.3.11 shows the evolution of spot gas prices at selected hubs in Europe.

Volatility[47] of spot gas prices has remarkably decreased in the last 7 years (Figure 1.3.12). The price peaks in February 12 and April 13 reflects the problems in the European gas markets due to Ukraine Crisis and technical interruptions (2013 Russian local gas consumption). Without these SOS scenarios the volatility is low and more or less on the same level since 2010.Note that within-day market (balance energy markets) may be more volatile and may offer at the moment profit opportunities for storage products

Figure 1.3.11 Spot gas prices at selected hubs in Europe, monthly averages (€/MWh)

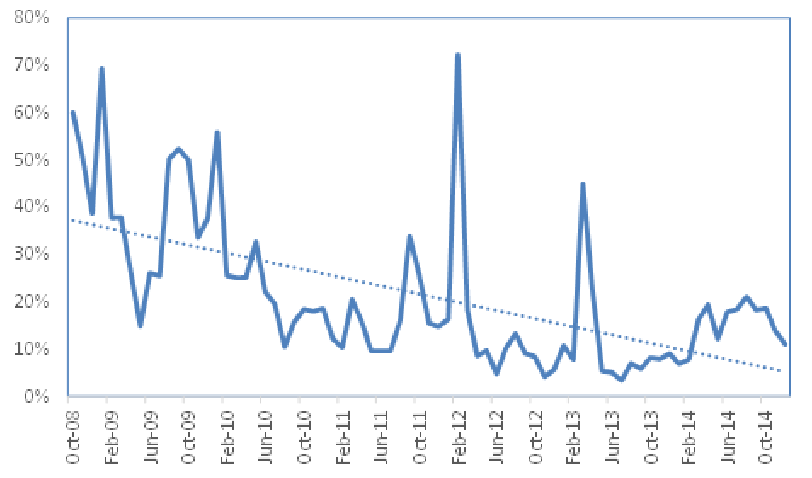


Source: Platts

47 Volatility is measured using the annualized monthly volatility of daily price returns.

Similarly to what happened to volatility across seasons, short-term price volatility was dampened by the development of a flexibility oversupply compared to a declining gas demand.

Figure 1.3.12. Volatility indicator for TTF day ahead gas prices[48]



Source: Platts

Users of fast-cycle storage can take advantage of price volatility. So the more volatile the price, the higher is the incentive to book fast-cycle storage capacity. Note that there may be barriers to fully extract the arbitrage value of storage: such as regulatory or technical limits in the usage of storage withdrawals/injections. In addition the incentive is highly impacted by the costs of each withdrawal from and injection in storages as well as the availability of capacities. If storage users has to pay the same price for each use of the storages as for the provision of gas from outside the local market (interconnection points) and at the same time the capacity may only be interruptible the advantage of using price volatility is reduced.

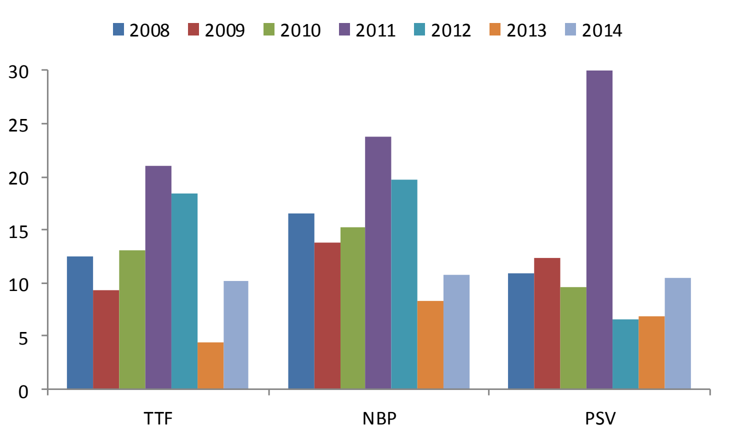
Decreasing short term price volatility, which may occur in future from more integrated markets and adoptions to the balancing regime, may have an impact on demand for fast-cycle storage capacity, which is, however, a small share of the total storage capacity in Europe. Therefore evolution of spot price volatility is not deemed to be an important driver of storage filling. In order to support the day ahead and balancing markets, a large storage space capacity is not necessary, rather there is the need for fast and high performing injection and withdrawal capacities, which virtual storages and salt caverns can offer.

This said, one way to extract the extrinsic value of storage may be related to very large differences between observed - not expected- winter spot prices and effective summer spot prices. Notwithstanding less volatile spot prices, the difference between the lowest daily price observed in the summer and the highest daily price in the following winter has been always above 5 €/MWh in the past 3 years.

This fact may have been an incentive to fill storages, even in the presence of low seasonal spread. However, extrinsic value is mostly an incentive for fast storages (LNG and salt caverns), which represent only a minor part of total capacity.

[48] Annualized monthly volatility of daily price returns.

Figure 1.3.13. Difference between observed maximum winter daily price and minimum summer daily price, for NBP, TTF and PSV

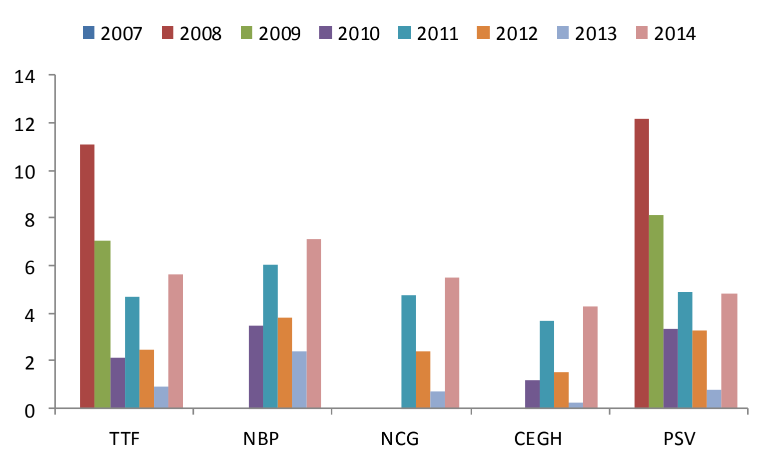


Note: 2008 stand for the difference between maximum price in winter 2008/2009 and minimum price in summer 2008
Source: Platts

Additionally any positive difference between spot prices during the injection season and the expected winter prices (Figure 1.3.14) can generate additional "extrinsic" value from storage, as mentioned above.

It is worth noticing that the relationship between storage use and volatility is a bidirectional one. It is not just price volatility that influences demand for storage, but also the actual use of storage that affects the observed price volatility: the use of storage to exploit trading opportunity generated by short term price differences may dampen short term price volatility.

Figure 1.3.14 Difference between spot and winter prices during the April-October period (average in the year, €/MWh)



Source: Albasoluzioni

1.3.4 Alternative tools for flexibility

Storage is one of the possible tools providing volume flexibility in Europe[49]. Alternative flexibility tools include:

- Variation in supply by domestic producers, known as flexible domestic production (such as the UKCS the UK used to rely on)
- Variation in pipeline import, known as pipeline swing
- Variation in supply by flexible LNG imported volumes
- Demand side response (e.g. by interruptible customers)[50]

In addition, from the traders' perspective, trading at the hub may be included among storage competitors. In fact, even if trading refers necessarily to the transfer of title concerning molecules that have been originally procured by the counterpart using "physical" flexibility instruments (including storage itself), from the point of view of a single supplier deciding whether to own directly storage endowment himself or whether to resort to flexibility offered by others on the hub, are both valid options. In particular, suppliers have begun to use hubs to accommodate demand swings, and to settle shorter term commercial imbalances. In an increasingly interconnected market, shippers began settling imbalances and covering their clients consumption needs through trading at the so-called gas hubs rather than by using physical means. Traders combine physical flexibility of import contracts, differences in the balancing regimes and their own storage portfolios to virtual storage products. They deliver gas in balancing accounts at the hubs and are offered at storage markets as a competitor to physical storages. The responsibility for physical balancing at least within day has been mostly transferred to the network operator by the recommendations of the Network Code Balancing in the daily balancing regime.

From a more general perspective, hubs are not a flexibility tool, but just a place where different flexibility tools are traded. This does not mean that they do not provide a value added: on the contrary, transparent trading of flexibility opportunities (including those on the demand side), its pooling by specialised players and the intervention of financial parties that may provide hedging services as an alternative to long term contracts and physical storage, may have well changed the flexibility market. Implementation of the European Network Code on Balancing will further strengthen the role of hubs and presumably reinforce competition of other tools against storage or at least a more efficient usage of the latter. However, with respect to security of supply it should be noted that hedging services or financial flexibility opportunities at hubs are not really comparable to physically available gas stored in storage facilities, which can deliver in the market when the physical transport routes are interrupted. Consequently there may be an additional value of stored gas due to its physical availability.

While European indigenous production is declining, the other flexibility tools, and LNG in particular, gained a growing importance in the last few years. LNG imports are not available to all European countries, due to the lack of regasification terminals or even due to the geographical position; however an increasingly integrated gas internal market in the EU allow the transfer of these molecules across border (within technical limits). Further, notably after the financial crisis, reduced overall gas demand and the increasing interconnection of national markets have triggered a relative abundance of

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[49] With respect of the value of different flexibility tools, it has to be distinguished between volume and load flexibility. While interconnection capacities and LNG primarily offer volumetric flexibility, storages offer in addition the needed load flexibility for local system stability.

[50] Data on the availability of DSR are generally not available, see *Section 3* for any available information provided by Preventive Action Plans and Emergency Plans for the sample countries. Anyway, the role of DSR as a flexibility tool is deemed limited.

alternative flexibility tools. The market value of flexibility is therefore perceived as lower than before the 2008 crisis.

Finally, with respect of the value of different flexibility tools, it has to be distinguished between volume and load. While interconnection capacities and LNG primarily offer volumetric flexibility, storages offer in addition the needed load flexibility for local system stability.

In this section we analyse the role of storage in fulfilling demand compared to that of other sources of flexibility (pipeline and LNG imports, national production), in particular during the winter and in the event o\f peak demand situations, such as the one that occurred in February 2012, or during supply disruptions, such as the one that occurred in January 2009 when Russian gas volumes flowing through Ukraine were suspended. In the investigation of the role of storage in fulfilling demand fluctuations we rely on data sourced from Eurostat, which is the only known source presenting monthly gas balances for each Member State. A monthly granularity is the minimum required for a comparative analysis of flexibility sources. However, even these data do not allow for a consistent comparison of time series over the 2008-2014 for some countries, due to a break in reporting practices in January 2013. Therefore a robust investigation of the changing role of different source of flexibility in covering seasonal demand was not possible. We therefore mostly focus on the situation in most recent years: 2013 and 2014. Furthermore, Eurostat data do not distinguish between LNG and pipeline imports from the same origin, so that a specific analysis of different flexibility features of LNG versus pipeline supplies is not possible.

Finally, it is worth noticing that available data do not allow covering a large time span. We rather rely on a short period (most storage filling time series start not earlier than January 2011) and this does not allow to properly identify long term and structural trends, but rather to understand how flexibility needs have been addressed in recent years. On the other hand, considering the purposes of this study, lack of historical data is no major problem.

Nevertheless, the analysis is still worth as the Eurostat monthly gas balances database is, to the best of our knowledge, the only instrument that allows for a consistent comparison of the recent role played by storage across the sample countries.

Figure 1.3.15 presents monthly gas demand by source of origin in the 2008-2014 period, for the sample countries. Note that gas demand is the sum of gas consumption in the country and transit/export gas volumes; the latter exceeds by large the former in countries such as Bulgaria, Austria, Czech Republic. Arguably, due to different reporting rules[51], a consistent long term comparison of the time series is not possible for Austria, Bulgaria, Czech Republic and Poland.

In all considered countries, the bulk of gas demand is met by imports, the only exception being the UK, the Netherlands and Germany where domestic production still accounts for an important share of the supply mix. Imports (and national production where available) work “baseload”, providing the amount of gas that is constantly required through the year. On top of this “baseload” gas demand, any additional request of gas is accommodated by a mix of storage withdrawals[52] and increase in imported gas. In the UK until 2012 national production provided a significant source of swing; however, due to the declining output of British gas production, its role as a flexibility provider decreased in the most recent years (from: 12 Bcm in 1999 to 1

51 Eurostat does not provide an explanation; however based on the analysis of data it appears that transit gas was not included within import volumes before January 2013 (February 2012 for Austria). This leads to a significant jump in total supply starting from January 2013 for the following countries: Bulgaria, Czech Republic, Poland; from February 2012 for Austria.

52 This confirms that, as noticed above, European storages mostly provide seasonal flexibility, acting as source of gas supply virtually only during the winter months, while during the summer they increase demand for gas.

Bcm in 2014). UK is importing flexibility now via the interconnections with Norway, The Netherlands and Belgium from Continental flexibility sources.

Additional gas demand typically occurs in the winter and originates from space heating requirements; this is commonly referred to as seasonal demand swing[53]. Swings in consumption depend strongly on weather conditions. In countries where natural gas is used for space heating, if the temperature decreases below a certain value ("heating threshold") more gas is consumed due to increased need for space heating. Natural gas consumption, and consequently both the volumetric and load flexibility needs, will be noticeably higher in the winter compared to the summer and noticeably higher in severe winters. In particular due to fast changes in temperature in winter periods the short term flexibility in load is necessary rather than volumetric flexibility.

The weight of storage in the supply mix depends on the country, however, a common feature of sample countries is that storage supply, in relative terms, is always more flexible than import supply: deliveries from storage facilities can be reduced and increased more remarkably than imports. In particular, in 2014, although import varies substantially between months (average coefficient of variation[54] equal 13%), storage withdrawals were more variable (average coefficient of variation equals 61%) for most of the countries, suggesting that storage is able to bring most of the swing required to meet demand fluctuations.

As already noticed, apart from the UK, national production plays a minor role in fulfilling demand swing, as it has a fundamentally constant output over time, with no difference between winter and summer. Even in the UK the role of national production in providing flexibility has been significantly decreasing: between 2000 and 2010 domestic production's flexibility dropped in UK by 50%. The additional gas volumes requested during cold season is provided mostly by an increase in imports, followed by storage withdrawals.

However, it is worth saying that flexibility provided by imports may actually originate from flexibility of storage facilities and gas production facilities located in other countries. This can be effectively illustrated by the UK which, thanks to pipeline interconnections with Continental Europe, accesses to ample seasonal flexibility on the Continent, which in turn may be also provided by German and Dutch storages, as well as by Norwegian production.

The increase in imported gas to match demand swing also depends on the ability of European and not European gas producers to modulate their production. Except the Norwegian production, all major European local producers have significantly decreased their flexibility in their production. The Dutch production provided a significant flexibility tool for the Continental markets until 2010 when the Dutch government and courts curtailed production. Due to geological problems in the Groningen area flexibility provision production fell from 13 Bcm in 2009 to 3.4 Bcm in 2014 (-72%). The Dutch production reached its maximum with 54 bcm in 2013, while the provision of flexibility was reduced to 40% of the historic average flexibility in the decade before within the last 4 years.

In the UK and Germany the losses of flexibility are in line with the reduced local production. In total the Netherlands, UK and Germany lost 16 bcm of their flexibility from production sources in the last 15 years. In contrast the Norwegian production increased the flexibility provision in the last six years, by which the lost flexibility in the other countries could partly been compensated.

53 defined as the difference between winter and summer gas demand.
54 The coefficient of variation (CV), or relative standard deviation, is an indicator used to measure the volatility of a variable. For a given sample, it is defined as the ratio between standard deviation and the absolute value for the arithmetic average. In other words, the higher the CV of the storage withdrawals/imports the larger the changes in storage/imports use between months are.

As anticipated above, the importance of storage seasonal flexibility varies widely across the considered countries. In 2014 the role of storage withdrawals in fulfilling seasonal demand swings ranges from 5% in Bulgaria to over 40% in France and Austria (Figure 1.3.16).

There is a group of countries where withdrawals from national storage facilities provided a relatively high share of the necessary seasonal swing (about 40% or above) in the last two years (2013 and 2014): Austria, France, Hungary and Italy.

On the contrary, in Bulgaria, Poland, Spain and the UK the contribution of storage to demand swing is below 15%. In particular, Spanish storage accommodated only 3% of demand swing in 2014 and always less than 20% over the period.

German storage covers about 20% of seasonal demand fluctuation, with an exceptionally high contribution in 2013. Also in Czech Republic, the contribution of storage was very high in 2013 (over 50%), while in 2014 storage accounted for the 20% of demand swing.

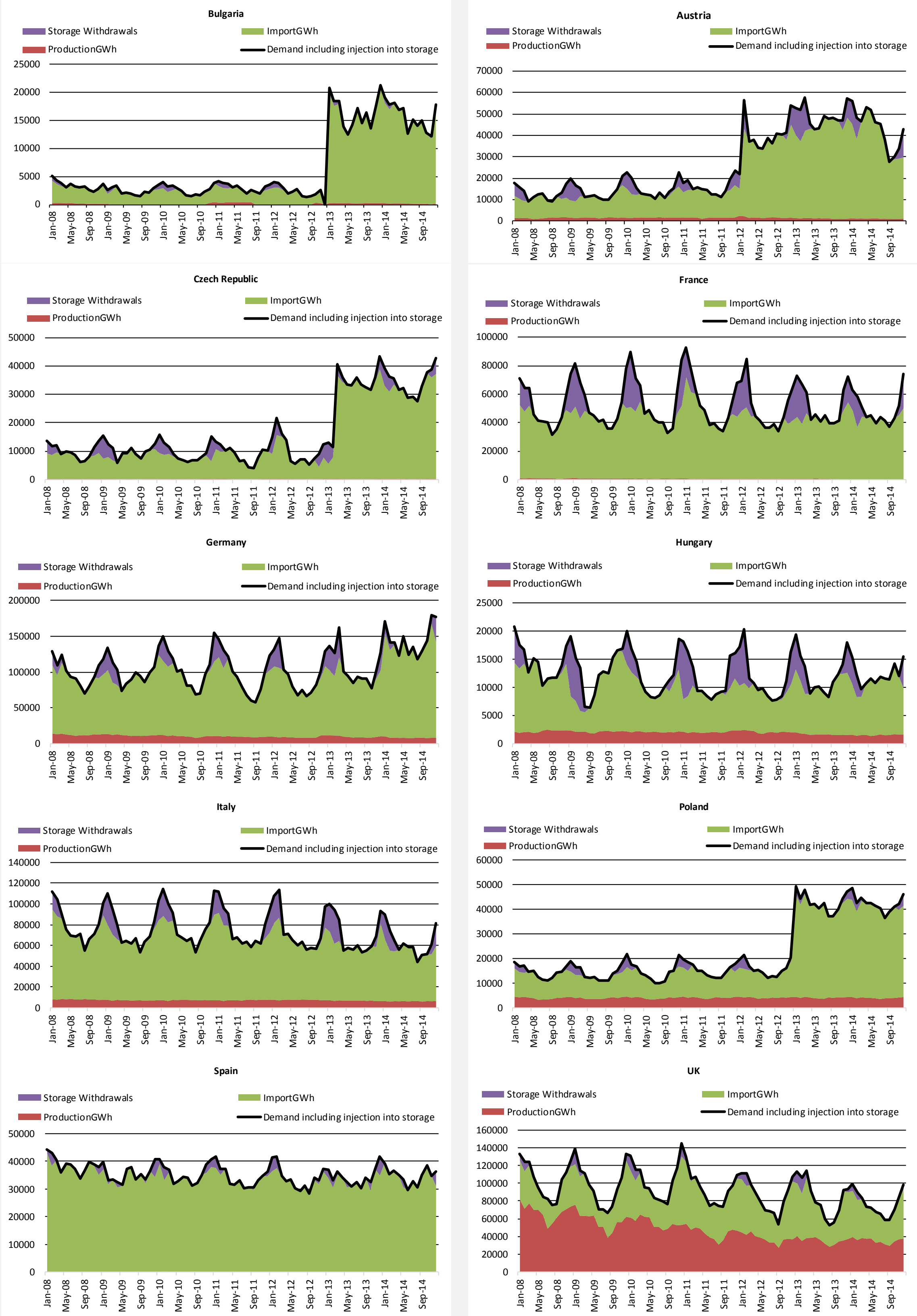
Table 1.3.14 Coefficient of variation by source of flexibility and country, 2014 and 2008

	2014		2008	
country	**Storage withdrawals**	**Imports**	**Storage withdrawals**	**Imports**
AT	60%	24%	-	-
BG	57%	15%	-	-
CZ	41%	10%	-	-
DK	N/A	N/A	N/A	N/A
FR	54%	9%	63%	14%
DE	64%	11%	55%	14%
HU	74%	17%	53%	15%
IT	40%	11%	58%	17%
PL	84%	4%	-	-
ES	84%	5%	117%	4%
UK	54%	23%	64%	32%

Note: Eurostat data for Denmark present missing values on import data so Denmark is not presented.
- indicates that consistent data are not available for the comparison.

Source: Eurostat

Figure 1.3.15. Monthly gas demand by source of origin



Note: Eurostat data for Denmark present missing values on import data so Denmark is not presented

Source: Eurostat

This evidence suggests that less liquid markets do not rely more on storage: in fact among the less liquid markets included in the sample (Bulgaria, Czech Republic, Poland, Spain, Hungary) the contribution of storage to demand swing varies widely, from 3% to 58%. Countries such as Spain or Bulgaria, where gas wholesale markets are less developed, rely more on import variation rather than storage to meet demand increase in the winter period. This can be explained also by the fact that storages were built before the liberalization, when differences between market structures were less marked across Europe.

In general, there is no clear trend in the relative importance of different flexibility tools in fulfilling consumption swing. In general, storage role as a seasonal flexibility provider has not decreased significantly between 2008 and 2014 (Figure 1.3.15).

We can spot some cases where increased flexibility from imports displaced storage (Figure 1.3.15), but these are limited in time and not sufficient to detect a structural tendency. More specifically, over time the contribution of import to the coverage of demand swing increased, displacing storage flexibility, for Austria (at least from 2008 to 2012), Germany (2009-2012), Czech Republic (2009-2011), Hungary (2011-2013), Poland (2008-2012), Spain (2009-2011).

In the UK, the flexibility provided by imports clearly increased over time, however this occurred to compensate the diminishing role of domestic production, while storage role do not varied significantly over time. The growth in import flexibility in the UK was possible thanks to the significant increases in gas import capacity (see Case study on UK in Annex).

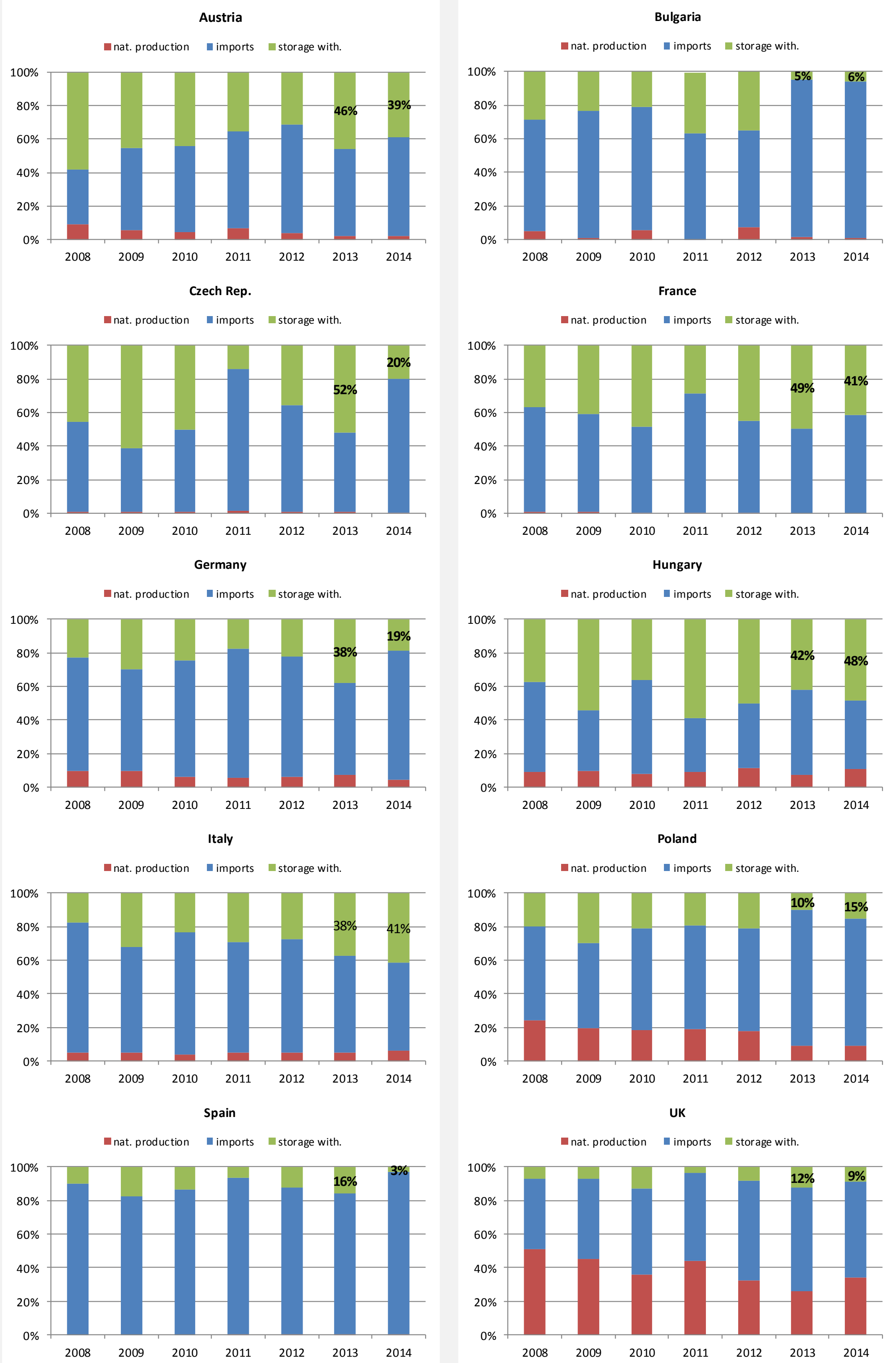
On the contrary, in Italy, the role of storage in meeting seasonal demand fluctuation increased over the 2008-2014 period (Figure 1.3.16), while seasonal flexibility of import decreased. This may be the results of two factors: first, the increasing role of storage may be the result of the commissioning of new storage capacity which displaced some pipeline import flexibility; secondly the increasing role of storage may be the forced consequence of the revision of contractual conditions in import contracts aimed at reducing flexibility clauses, possibly in exchange for price discounts. Similarly, the role of storage in meeting seasonal demand also increased in Spain in the 2011-2013 period, and at same time that of import decreases.

We now focus on how shorter[55] swings in consumption, or demand peaks, are addressed. Withdrawals from storage are expected to play a key role in guaranteeing supply in short-lived peak conditions, as it may take a while for the import supply chain to respond to an unexpected peak in demand, whereas storage should be a provider of fast-flexibility, being near to the consumption centers.

The role of storage against other sources of flexibility, at different demand levels, can be summed up in a load duration curve (LDC). Daily/monthly LDC is formed by sorting daily/monthly demand from the highest to the lowest in a given period and rearranging accordingly the daily/monthly mix of supply sources (production, import, LNG, storage). Alternative source of flexibility may be used sequentially according to a merit order logic, starting from the cheapest one to the most expensive one: more costly sources should be bought on stream only at high levels of demand. Consequently when alternative flexible supply sources become available and at a cost that is cheaper than storage, then storage may be crowded out or bought on stream only in case of extreme demand peak. However, different flexibility sources may have different reaction times, therefore in the case of unexpected peak in gas demand, some sources may not be put in place, even if they would be cheaper.

55 Eurostat data have a monthly granularity, so the analysis considers monthly demand peaks (2008-14), and not daily demand peaks.

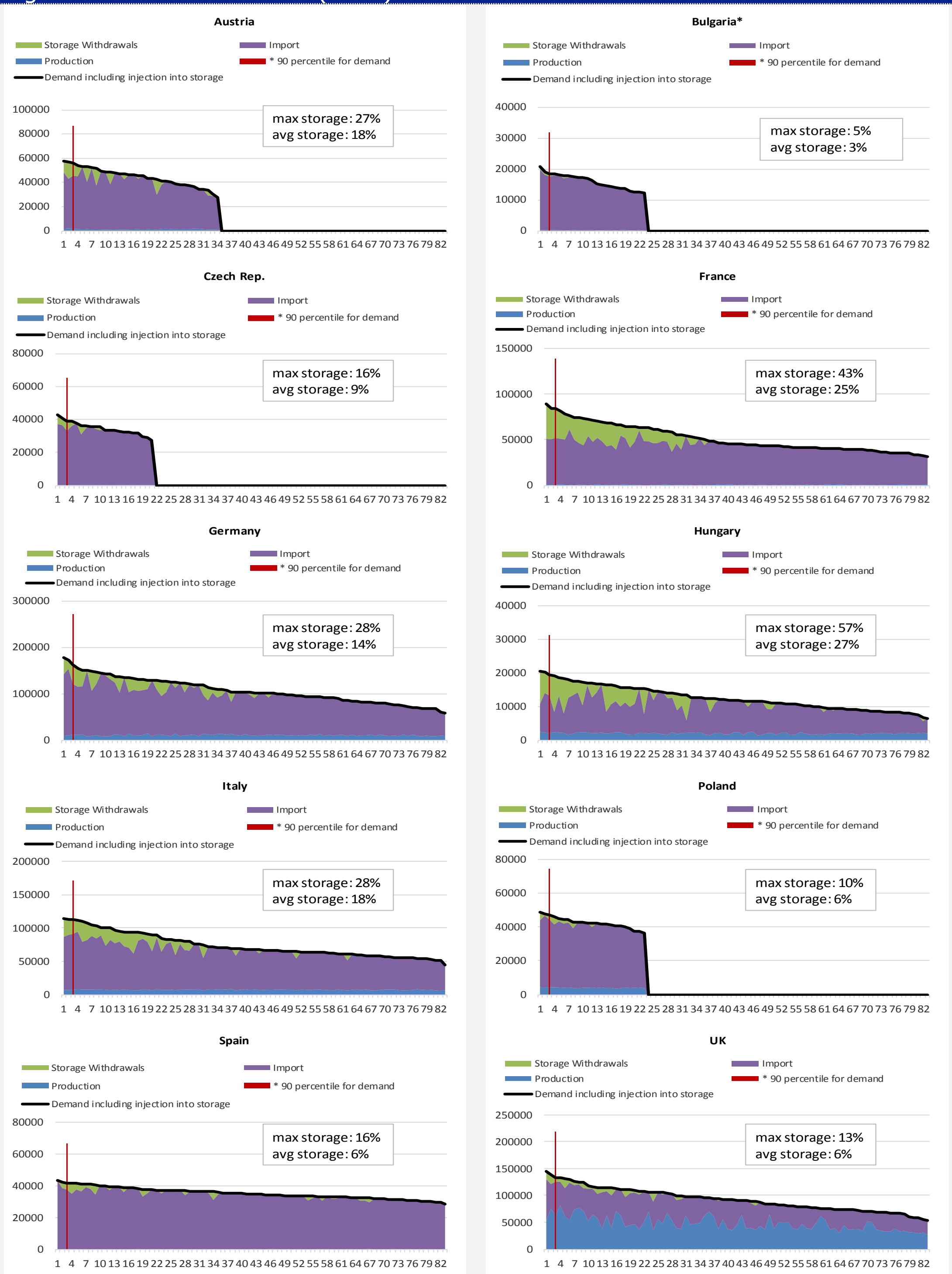
Figure 1.3.16 Demand swing matching by source of origin



Note: Eurostat data for Denmark present missing values on import data so Denmark is not presented.

Source: Eurostat

Figure 1.3.17 Load curves (GWh)



"Max storage" means the maximum contribution of storage withdrawals to the fulfilling of demand during peak months in the considered period "Avg storage" means the average contribution of storage withdrawals to the fulfilling of demand over the considered period, provided that withdrawals from storage occur. The horizontal represents the ranking for monthly demand data, where 1 is the highest monthly demand in the period. * In order to compare consistent figures, data for Bulgaria, Czech Republic and Poland are for the January 2013-December 2014 period; data for Austria are for the February 2012-December 2014 period; all the others are for the January 2008-December 2014 period

Source: Eurostat

Typically, the import supply chain may take a while to provide additional gas volumes and storage withdrawals are alternatively used as they are faster providers of flexibility. Note that also in the import supply chain storages are included: Austrian, Dutch, German and Slovak storages are a part of the import chain for countries like France, Belgium or UK.

In fact, for all countries, storage performance in high demand months can almost double compared to average performance. For instance, in Hungary gas injected from storage facilities into the grid covers on average 27% of monthly demand, but storage withdrawals amounted to 57% in the highest load periods. In peak conditions, the share of consumption supplied by storage withdrawals ranges between over 55% of monthly demand in Hungary and 5% of monthly demand in Bulgaria. With the exception of Poland and Bulgaria, in peak demand conditions storage supplied at least 15% of the required gas volumes.

The best known recent example when storage proved to be a fundamental source of short-term additional supply was the cold spell occurring in February 2012. In that month storage withdrawals accounted for a substantial share of demand: above 20% for all countries excluding the UK and Spain. The UK significantly relied on import flexibility coming from the Continent (provided in turn by Continental storage to a large extent), while Spain was less affected by the cold spell at all. For all countries excluding Austria, the storage share in the cold spell was remarkably higher than its average contribution to the supply mix.

Another circumstance when storage proved to be a fundamental source of short-term additional supply is January 2009 when Russian flows passing through Ukraine were disrupted. During this period, storage withdrawals accounted for a substantial share of demand, for those countries affected by the disruption: above 20% and this share was remarkably higher than the average storage contribution to the supply mix.

Summing up, based on the analysis of demand swing there is no straightforward evidence that alternative sources of flexibility, and imports in particular, displaced storage as a provider of seasonal and short term flexibility. Available data evidence shows that storage importance in providing seasonal flexibility has not decreased significantly in the 2008-2014: storage still play an important role in fulfilling demand swing (especially in Austria, France, Hungary and Italy).

1.3.5 Long term storage contracts

In the pre-liberalization period, storage capacities were an integrated part of the gas supply structure. For this reason in some European countries, such as Germany, Austria, The Netherlands, Czech Republic, Slovak Republic storage facilities have been booked on a long term basis by the importers in relation to their supply contracts and import routes.

This may contribute to the fact that, although the price incentive to use storage is low (due to low summer-winter spread and subdued price volatility), storages in Europe have been constantly refilled at very high rates.

Currently a huge part of the storages is still booked by large market players that were already dominant players before the market liberalisation (*incumbents*) with long term contracts in the free markets. These storage volumes will be free for marketing in the next 2-10 years and increase the revenue problems of SSOs. The old contracts are mostly priced at levels that are more profitable for the SSOs and above the currently paid market prices resulting from last storage auctions[56]. Sources from the industry report that some storages are not open actually to the market yet. Almost all booked storage capacities with a termination period later than 2 years in front are likely to be

[56] The most storage contracts have price revision clauses triggered every 3 years. Consequently the most old storage contracts should be adjusted on a market level observed 1-3 years ago.

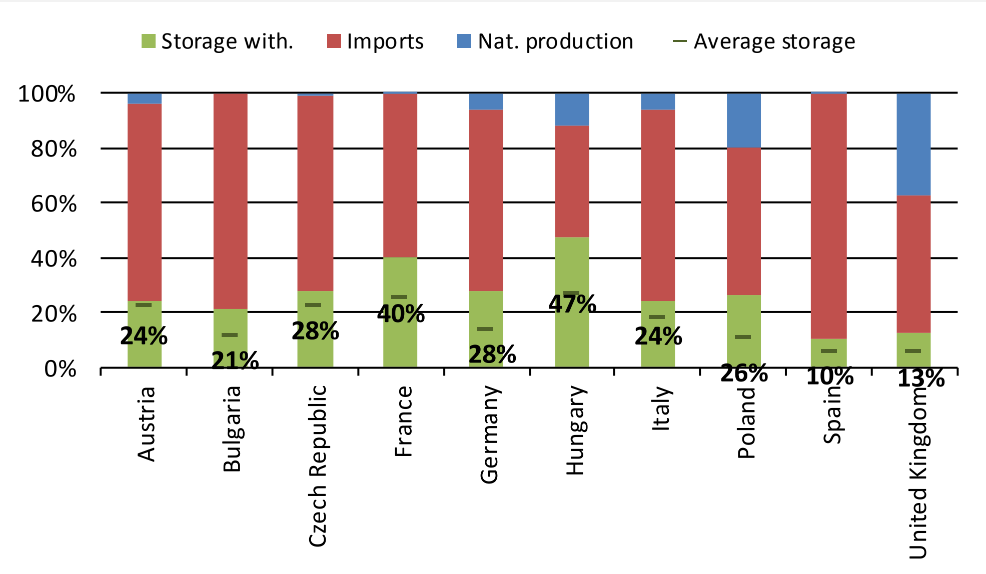
the legacy long term contracts, as recent contracts in the storage industry rarely have durations longer than two years and most are limited to one year or less.

Data on the share of storage capacity and on the expiring date of long term existing storage contracts are not disclosed, however it is likely that in Germany and Austria currently a large part of storage capacity have been contracted on a long term basis. Also in the Netherlands, in the allocation procedures held prior to 2014 13 TWh has been sold on a long term basis.

In the UK long term storage contracts exist but are not contracted on a historic fixed price, as it may occur in Germany and Austria, but are rather spread-indexed contracts. While the fixed price long term contract provide a particularly high degree of protection from declining spreads, the spread indexed contracts do not.

On the contrary, in Italy and France storage is mostly purchased on a yearly basis. In Spain, long term storage contracts do not exist: shippers can book up to a maximum of one year and capacity is marketed for the period starting every 1st of April of the year and ending on 31st March of the following year.

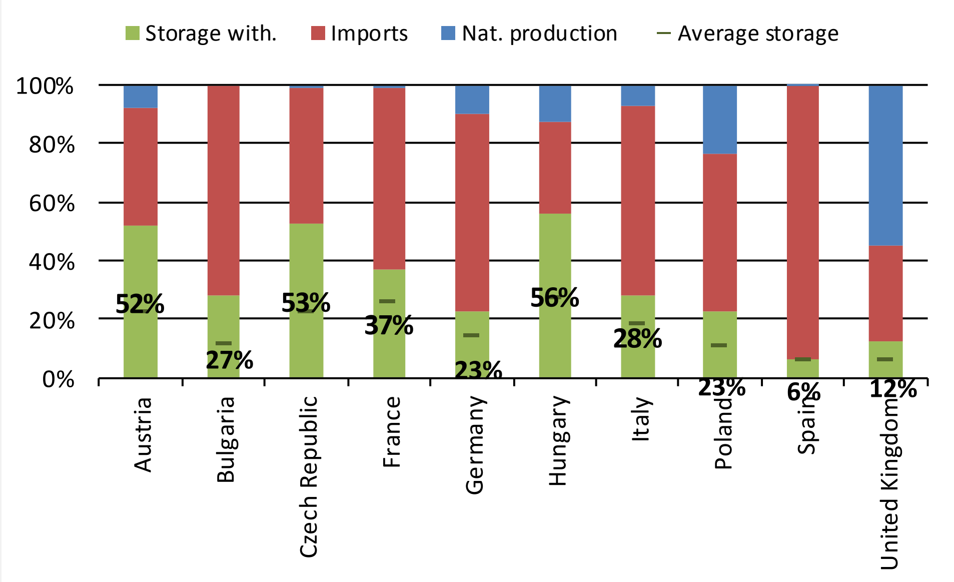
Figure 1.3.18 February 2012 demand by source of origin, by country (%)



Note: "average storage" is the average share of demand covered by storage withdrawals over the 2008-2014 period

Source: Eurostat

Figure 1.3.19 January 2009 demand by source of origin, by country (%)



Note: "average storage" is the average share of demand covered by storage withdrawals over the 2008-2014 period

Source: Eurostat

As shown above (*Section 1.1.*), lately the incentive for suppliers to store gas for a longer period has reduced. There are multiple reasons for reducing the long term position by storage customers. For instance, the market offers virtual products for structuring the gas portfolio of supplier in an efficient way, without the need of directly booking storage capacity.

Consequently, it is likely that the long term storage contracts will not be extended and that the filling rates at the beginning of the winter season may drop significantly as soon as the long term commitments expire across Europe. Termination of long term commitment may result in lower booking activities and lower storage filling rate ahead of the winter period. This may have substantial impact on the level of security of supply in particular for unexpected cold spells which the market does not anticipate. Consequently the market will not provide a reasonable level of stored gas by the end of the injection period as nobody can afford the extra costs. In addition market participants can rely partly on the provision of gas by the network operators for such extraordinary market situations as they have to operate the balancing markets and socialize the costs of imbalances to the market participants.

1.3.6 Conclusions

When looking at the price-incentive to storage use, we found that storage assets became a less attractive tool to exploit trading opportunities. In fact, winter/summer spreads have been generally declining since 2007 and hub price volatility have been declining since 2008. However, these factors did not in general result in a significant under-utilization of existing storage capacity in Europe.

We have shown that there is no clear relationship between seasonal spread and filling level. In fact, although in 2013 the lowest ever recorded winter-summer spread occurred (< 1.5 €/MWh) and storage filling level remained generally lower than in the previous years, this can be mostly explained by other factors, such as late start of injection in 2013 and a few localized technical problems affecting key sites.

Decreasing short term price volatility may have had an impact mostly on demand for fast-cycle storage capacity, but this is yet a small share of the total storage capacity in Europe. Therefore, the evolution of spot price volatility is not deemed to be an important driver of storage filling.

As far as the availability of alternative flexibility tools is concerned, declining demand and increasing interconnection of national gas markets have increased the competitiveness of different flexibility sources, notwithstanding a part of production flexibility was recently lost in some countries, like the UK and the Netherlands, as shown above. However, based on the analysis of demand swings we do not find evidence that alternative sources of flexibility, and imports in particular, displaced storage as a provider of seasonal flexibility. Available data evidence, although limited, shows that storage importance in providing seasonal flexibility has not decreased significantly in the 2008-2014: storage can still play an important role in fulfilling demand swing.

Summing up:

- storage filling levels continue to be high despite declining seasonal spread and declining spot price volatility
- increasing competition in the market for flexibility did not result in storage being significantly under-utilized.

This suggests that others reasons, other than the gas price incentive only, bring suppliers to stock gas for the winter: inventories are usually refilled of even though limited seasonal spreads occur and price volatility is subdued. These reasons may include:

- The insurance value of storages towards unexpected events (including price spikes and supply failures). Particularly for large suppliers, in case of supply failures the reputation loss in the event of supply disruption would be very high;
- Mandatory storage obligations and other SRSMs (provided that these are effective: see *Section 4.1*);
- The fact that an important share of storage capacity was allocated long term years ago, before the declining trends in flexibility value started.

If storage utilization can be explained by insurance reasons, the price of storage should reflect this. In the next Section (*Section 1.4*) we will analyze the storage prices and see whether market players are prepared to value storage also for its insurance value, that is whether storage users are willing to pay storage above the intrinsic value. We will also see whether the above mentioned adverse factors hitting the storage sector, like increasing competition and reduced seasonal spreads, may have resulted in a fall of storage prices more than in reduction of booked and used capacity.

1.4 Storage products, allocation methods and prices

In this Section we focus in more detail on the evolution of storage prices and storage products. In particular, we present a short overview of rules concerning access to the storage and main capacity allocation procedures in sample Member States. Furthermore, we analyse the evolution of gas storage prices and their main components in selected sites.

The evolution of the price of storage resources is in fact key to offer an insight on what affects the usage of existing storage resources. More specifically, the analysis of storage prices is a way to investigate whether storage utilization is also driven by insurance reasons, as in this case storage users should be prepared to pay storage above its intrinsic value[57].

1.4.1 Main products and access rules for the sample Member States

In sample Member States capacity allocation procedures are various, but usually included among:

- First come first serve (FCFS)
- Merit Order (that is when storage is allocated in order of priority, with priority given to a certain category of storage users, usually consisting of suppliers of protected consumers)
- Auction
- Pro-rata

Merit orders often prevail and other criteria are used to allocate storage capacity among users of the same merit class.

An overview of the regime to storage access and the main allocation procedure is provided in Table 1.4.1.

In France the use of underground natural gas storage facilities is made available first to TSOs and operators of UGS facilities for balancing of transmission systems connected to such storage facilities. Then, the remaining storage capacity is allocated with priority access to suppliers of end customers. Finally, if some storage capacity remains available after the priority access, it will be placed on the market.

Also in Bulgaria, the access is allocated on the basis of a merit order principle and the priority is granted to public suppliers.

In some other countries storage capacity allocation is set by means of market procedures. Auction process is implemented in Italy, Czech Republic, Hungary, Portugal and Spain. In particular, in Portugal all capacity is allocated by means of auctions including time windows for each product, whereas in Spain the remaining storage capacity, once the auction process has been completed, is sold on the basis of FCFS principle. Lately, new Italy's allocation procedures also provide for a series of consecutive auctions, which are carried out on a monthly basis, from March to September.

In some other countries, the allocation system is based on the combination of different procedures that vary depending on the type of storage product. For example Denmark designed an allocation mechanism based on FCFS principle for short-term products and an auction process[58] for products covering a longer time horizon. The combination of these two procedures is implemented also in Austria and Germany. In UK the procedure is different depending on facility. In the Rough storage site, holding nearly 90 percent of the UK's TPA total capacity, capacity is allocated through auctions for non-indexed products and on the basis of FCFS principle for indexed products[59].

In the group of sample Member States, only Poland adopted a pro-rata method for allocating storage capacity.

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57 Note that the evidence that users pay storage service above the intrinsic value is not sufficient to conclude that they are valuing the insurance value of storage, as they may value instead the opportunity to use storage to exploit trading opportunity emerging from short term price volatility (as explained in Section 1.3.3). However it is a necessary condition.
58 Auction process can include sealed bid auctions and multi-round ascending clock auctions.
59 In this case prices are agreed bilaterally. Indexed products are products whose price varies depending on the seasonal spread.

As regards storage products, storage capacities are generally sold in bundles called Standard Bundled Units (SBU). SBUs include a mix of available volume, injection and withdrawal capacities, with determined technical ratios. The features of SBUs differ across storage facility: actually there is no common SBU available. SBU are defined by the technical characteristics of each storages facility. GSE advise each SSO to offer SBUs in their Guidelines.

In order to better understand what a bundled unit is, it could be useful to analyse different compositions of standard bundle units offered by companies operating facilities located in the selected sites.

- in Belgium, a standard bundled unit contains both firm and conditional capacity and it consists of specific value for storage volume, injection and withdrawal services. The price for the standard unit is established by the national Authority.
- In France, TIGF offers three different types of bundles (Balancing bundle, Dynamic bundle, Super dynamic bundle) differing in working volume and the associated injection and withdrawal capacities. The bundled product mostly sold by TIGF is the Dynamic Offer product which has a duration of 52 days (withdrawal) and 100 days (injection)[60].
- In Hungary, the non-interruptible seasonal service includes the mobile capacity, withdrawal and injection capacities, and injection and withdrawal services related to the quantity of gas to be stored. Its fee is determined by the Hungarian Energy Office.
- In Poland long-term storage services offered in the form of a bundled unit consist of a defined working volume equal to 5,486 MWh, whereas the injection capacity and the withdrawal capacity vary depending on the considered storage site.
- In the UK, the Rough site is subject to legally binding undertakings and consequently the majority of its technical capacity is offered as a standard bundled unit which consists of:
- 67 kWh of space
- 1 kWh/day deliverability
- 0.35 kWh/day injectability

In addition to standards products, other more flexible products are often (and increasingly) available. For instance in Germany and Austria there is a great variety of individual products offered by the storage operators for which reason a SBU cannot reasonably be calculated.

Non-standard products, which are not generally considered an alternative but rather an addition to existing products, can include:

- unbundled products which provide for any combination between volume, injection and/or withdrawal capacity
- a day ahead storage capacity product
- a monthly ahead storage capacity product
- a multi-year storage capacity product.

60 Based on inputs from SSOs.

Table 1.4.1 Type of access and main allocation procedure

Country	Access	Main allocation procedure
AUSTRIA	negotiated	FCFS/Auction
BULGARIA	regulated	Merit order
CZECH REPUBLIC	negotiated	Auction
DENMARK	negotiated	FCFS/Auction
FRANCE	negotiated	Merit order
GERMANY	negotiated	FCFS/Auction
HUNGARY	regulated	Auction
ITALY	regulated	Auction
POLAND	regulated	Pro-rata
PORTUGAL	regulated	Auction
SPAIN	regulated	Auction
UNITED KINGDOM	negotiated*	Bilateral trading

*The study focuses only on facilities which are not exempted from the TPA provisions.
Source: GSE and storage system operators' websites

Furthermore, a storage product can be based on the storage site or on a gas trading virtual point. Regarding physical products, the transmission capacity and its costs must be secured and paid by the user, whereas a virtual product has the same characteristics as physical ones but without the associated transmission cost, in fact transmission capacity from/to the storage site to the virtual point are included in the product. For example, outside our sample, the Netherlands no longer offer physical storage products but only virtual ones, which are allocated by auctions.

The following table provides an overview of storage products available in sample Member States. A product is considered as present in a single Member State if it is present in at least one of its sites. In the event that no information was found, the product was considered as absent.

All sample countries offer bundled products, which are generally seasonal (yearly) products. In almost all countries, except Spain and Portugal, unbundled products are made available[61]. Only Austria, Denmark, Germany and the United Kingdom provide a complete commercial offer including all types of products and services previously described.

In order to better understand commercial offers, we can focus on some sample countries' commercial proposals.

In Bulgaria, in addition to short and long term bundled services, Bulgartransgaz EAD proposes unbundled products that are allocated only once the initial bundled service capacity has been fully allocated.

In France, Storengy provides several alternatives to standard products. They offer simplified products, unbundled products and multi-year products which are spread across a variable term from 2 to 10 years. Furthermore Storengy's commercial offer includes virtual storage products (PEG profiled and PEG day-ahead products). TIGF, the other company operating French underground storage facilities, offers different standard packages differing in storage capacity, daily injection and withdrawal capacities. Multiple-year contracts are also possible.

61 Italian storage operator Stogit sells unbundled capacities (User Balancing Service) on monthly and weekly basis

In Hungary, MFGT, the main operator[62], offers various products apart from seasonal basic ones. Optional services comprise unbundled products, daily nomination, multi-year booking commitments and hub-based products.

Table 1.4.2. Type of storage products (1 = present; 0 = absent)

Country	Type of product						
	Bundle	Unbundled	Site*	VP**	DA***	Monthly	Multi-year
AUSTRIA	1	1	1	1	1	1	1
BULGARIA	1	1	1	1	0	1	1
CZECH REPUBLIC	1	1	0	1	1	1	1
DENMARK	1	1	1	1	1	1	1
FRANCE	1	1	1	1	1	0	1
GERMANY	1	1	1	1	1	1	1
HUNGARY	1	1	1	1	1	0	1
ITALY	1	1	1	0	0	1	1
POLAND	1	1	1	0	1	1	1
PORTUGAL	1	0	1	0	1	1	0
SPAIN	1	0	0	0	0	0	0
UNITED KINGDOM	1	1	1	1	1	1	1

** Site: product based on the storage site*

*** VP: product based on a a gas trading virtual point (VP)*

**** DA: a day-ahead storage capacity product*

Source: storage system operators' websites

In Italy, products awarded by auction include seasonal and monthly products associated with the peak and flat modulation service. Since the gas year 2015-2016 a multi-year product has been introduced.

In Poland the storage services are provided as a firm storage service or an interruptible service. Furthermore, storage services can be classified as:

- long-term storage services if they comprise 1, 2, 3 or 4 consecutive storage years
- short-term storage services if they are provided for a period from 1 to 11 consecutive gas months (monthly storage service) or 7, 14 or 21 consecutive gas days (weekly storage service)
- a daily storage service provided for a single gas day, or a part of a gas day (intra-day service).

Polish SSO offers storage services as bundled units, on an unbundled basis or as flexible bundled units which are a combination of unbundled storage services offered according to a proportion predefined by the SSO.

In Spain all underground gas storages are commercialized under one single Virtual Storage. Shippers can book the storage capacity up to a maximum of one year and this gives them "rights" to inject and withdraw which are based on formulas that are established in the national regulation.

In the UK, Centrica Storage offers various products. The standard products, consisting of standard bundle units, include within-day and day-ahead re-nomination rights

62 There is no clear and exploitable information concerning commercial offers by MMBF, the other Hungarian operator.

delivered at Easington or the National balancing Point (NBP). Moreover, Centrica Storage offers also a (within-day and day-ahead) storage service delivering gas nominated for withdrawal from Rough direct to the NBP. Centrica Storage also offers unbundled injection and withdrawal capacity products, a shorter duration storage service offered in 30 day bundled units, a day-ahead nominated virtual storage service and a non-standard product flowing in reverse to typical seasonal storage spreads (injection period restricted to the winter season and withdrawal permitted only within summer).

For instance in Germany and Austria there is a great variety of individual products offered by the storage operators for which reason a SBU cannot reasonably be calculated.

1.4.2 Evolution of prices and technical features of standard bundle products in the last ten years, for selected sites.

In this section we present an analysis of storage prices[63], focusing on the evolution rather than cross-site comparison. Although it is always tempting to "benchmark" prices across sites, countries and regulatory or allocation regimes, it is always appropriate to beware of any such simple comparisons. Storage sites heavily differ by physical characteristics and performances, location, availability of cushion gas, type of products, as well as by commercial policy, regulation, competition from other storage sites as well as from other flexibility resources. Albeit comparisons are not entirely impossible, they should be rather regarded as an academic exercise and are beyond the scope of the present Report. As a partial exception, we will only include a graphical description of the relationship between prices and deliverability, which is one of the main cost drivers of storage facilities.

Thus, we have considered a sample including 53 facilities belonging to 20 companies, with a view to show the price evolution of similar products. These facilities are located in 16 Member States: Austria, Belgium, Bulgaria, Czech Republic, Denmark, France, Germany, Hungary, Italy, the Netherlands, Poland, Portugal, Romania, Slovakia, Spain, and the United Kingdom. The working capacity of these facilities represents 64% of the total GSE TPA[64] working capacity. As regards UGS types, selected sites include depleted fields, aquifers, salt cavities, rock caverns and a non-depleted gas field (see Figure 1.4.1).

Information on storage prices and products was collected through storage companies' websites as well as direct inquiries to storage operators.

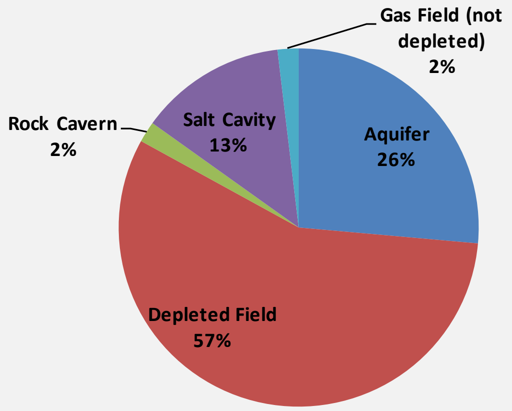
Given the limited data availability, we considered the posted prices for the main SBU product available in the country. As noticed above, this means focusing on products with different technical features, pricing rules and allocation procedures, depending on what is available in storage facilities located in the country. Due to such differences in the products considered in this analysis, as mentioned above, cross-site comparison is not feasible, we rather focus on the evolution of prices within the same country over time.

In countries where bundled units are available, we took into account their prices. We took into consideration tariffs or auction prices[65]. For example in Italy there is not a specific bundle unit but in order to compare prices we considered the outcome of the first auction (a marginal price auction held in March), related to the awarding of

63 Since GCVs vary across Europe, for the scope of this study we supposed that 1 Mmc is equivalent to 10500 MWh unless more site specific information is provided by the operator.
64 In this area, TPA means capacity that is open to (negotiated or regulated) third party access. Non-TPA capacity is usually reserved for special uses, like «strategic» storage that is under control of public authorities.
65 Our analysis is based on information found in storage operators' websites or inputs received by SSOs.

seasonal products associated with the peak modulation service. For Bulgaria we took into consideration the tariff applied to Chiren site and for Romania we took into account the regulated tariffs related to the capacity booking, injection and withdrawal services.

Figure 1.4.1 Type of storage in selected sites



Source: GSE

It is worth noticing that this analysis is limited as in fact, many customers do not pay SBU posted prices, but rather purchase tailor-made products which may be priced very differently from the prices considered in this analysis. In particular in markets with negotiated third party access the prices currently contracted are below SBU due to higher costs of storages than other flexibilities or oversupply of storage capacities. The latter is demonstrated by the recent shutting downs of existing storage capacities or postponements of storage projects e.g. in Germany. In the end of this Section we report some evidence on the prices of storage products which have been recently auctioned in Germany and in the Netherlands.

When possible, we separate the price of the storage product from the price paid for the transmission capacity to and from the grid. The former includes the main bundle capacity price and, if present, injection/withdrawal variable fees.

The prices of the selected sites are often representative of the country where they are located. As such, their (working gas weighted) means have been also used as a measure of national storage costs for the assessment of storage related SoS Measures (see Section 4.2). However, in several cases other sites that could not be considered or prices of other products that cannot be observed – notably in negotiated regimes - may lead to a different estimation of storage prices at national or hub level.

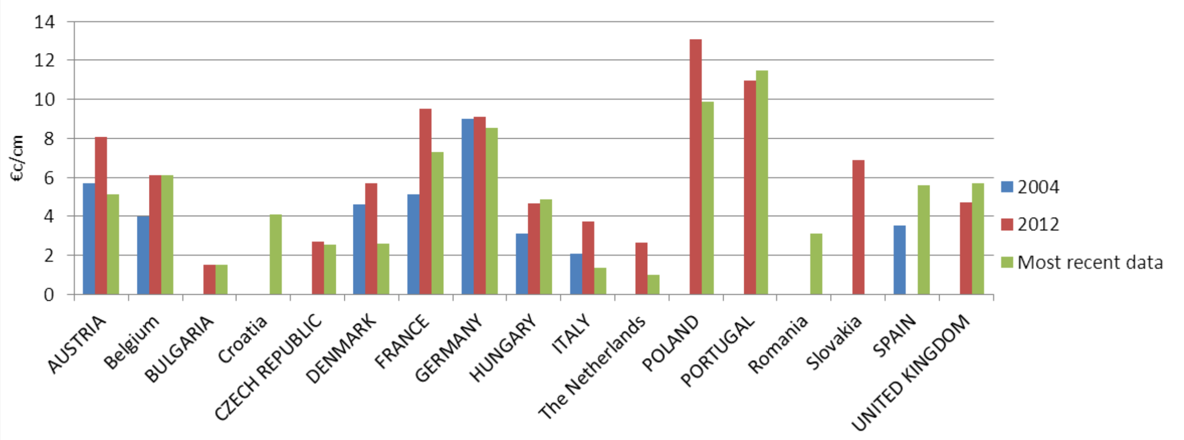
The following graph shows the gas storage posted prices[66] per country over time. Older data (2004 and 2012) are based on previous research by members of the team[67]. For the most recent period we mostly considered 2014 or 2015 data[68] concerning the same sites selected for 2004 and 2012 research.

66 The values reported in the graph include the main bundle capacity price and, if present, injection/withdrawal variable fees.
67 Presenting a longer time series of storage prices Is out of the scope of this study.
68 As regards Croatia, we took into consideration 2014 tariff for the standard bundled unit.
For Czech Republic, we considered yearly price resulted from 2014 auctions concerning 1 year products as reported by RWE.

As explained above, this Figure is not meant to compare prices of sites and countries, which differ for their performances and characteristics, but rather the evolution of prices for each of them. We were able to build a complete time series only for 7 countries out of 17 where prices for bundle services in the same facility and which have not changed over time could be compared. Concerning these countries, only Hungary shows a clear upward trend whereas German prices are nearly steady. In the remaining 5 countries, 2012 prices are higher than those in 2004 and the most recent ones.

Comparing 2012 data with the most recent ones and focusing on percentage variations, the largest rise was in in the United Kingdom, whereas the smallest increase was in Hungary. In Belgium, the price fell by 67% and the Netherlands and Italy are not far behind with a 63% decrease. As regards Italy, it would be useful to underline that storage capacity has been allocated through auctions since 2013 and this change in allocation mechanism might have affected the level of prices. Italian regulation foresees a compensation mechanism in order to guarantee the storage companies with the allowed regulated revenues when storage price resulting from auction is lower that the officially regulated tariff set annually by the Italian Energy Authority.

Figure 1.4.2. Evolution of prices in selected sites



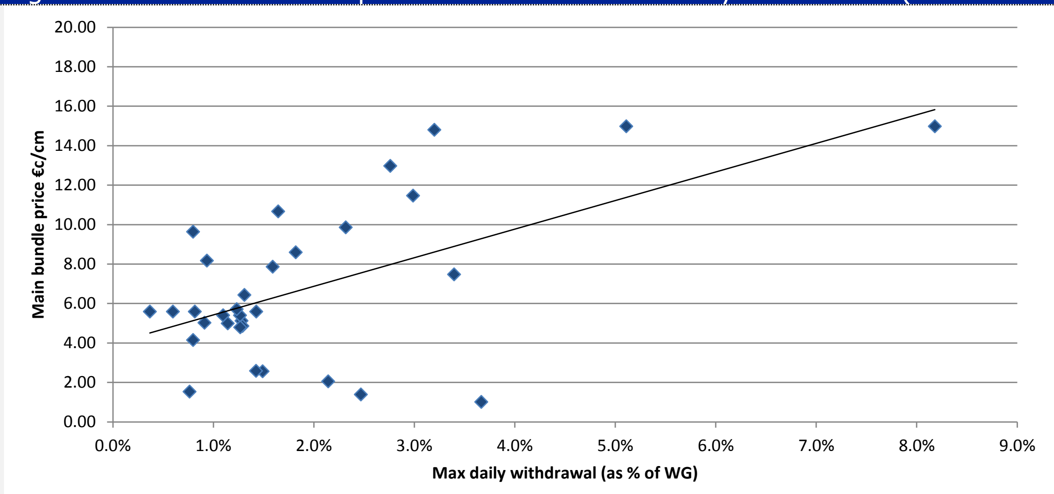
The Member States in capital letters are the ones belonging to the list of sample Member States.
Source: SSOs' websites, inputs by SSOs

The following scatter plot shows the relationship between the main bundle price related to each selected site for the most recent years whose data are available (from 2014 onwards) and the associated maximum daily withdrawal calculated as percentage of working gas capacity. From the scatter plot it can be inferred that there

French storage price shown in the graph is calculated taking into account Storengy and TIGF prices related to products sold in the gas year 2014-2015 and published on their websites. The average figure related to bundle capacity price seems to be consistent with the value estimated by TIGF. More precisely, according to TIGF, the 2014 total SBU price (without injection/withdrawal variable fees) is equal to 6.2 €/MWh.
With regard to Italy we considered the average price for capacities allocated in March 2014 related to peak service (Stogit and Edison allocations). Auction prices for capacities allocated since April 2015, reported by Stogit, are much lower. In particular, the weighted average price for capacities allocated since April 2015 (forseen compensation mechanism for storage operator in order to reach regulated revenues) concerning peak service with seasonal injection is equal to 0.13 €/MWh/year.
In order to calculate Dutch storage price we applied the cut off multiplier related to 1 year product sold in 2014 auctions (as notified by TAQA) to the summer-winter spread recorded in September 2014 on the TTF market (source: Albasoluzioni).
Polish prices in the graph concern the annual cost of 1 MWh of bundled unit referred to the firm storage service (excluding gas transportation cost) as transmitted by the Polish SSO.
As regards the UK, in the graph we reported price for 2016/17 fixed products. The 2014 average SBU price reported by Centrica Storage was slightly lower.

is a direct correlation between the two variables: the higher the maximum daily withdrawal (and therefore the "speed"), the higher the price of storage. Consequently, the deliverability rate can be assumed as one of the drivers of the storage price. Fast gas storage facilities are more costly as they require more compression and often another type of geology. It is out of the scope of this report to analyse other possible determinants of storage prices.

Figure 1.4.3. Main bundle price versus maximum daily withdrawal (as % of WG)



Source: GSE, SSOs' websites, inputs by SSOs

We now investigate the relationship between the seasonal spread and the actual price of storage services. Figure 1.4.4 compares the price of a SBU to its theoretical "intrinsic" value (average seasonal spread in March[69]), for individual seasonal[70] gas storage facilities (we hence exclude fast cycle storage)[71] in 2014, excluding from the analysis regulated prices.

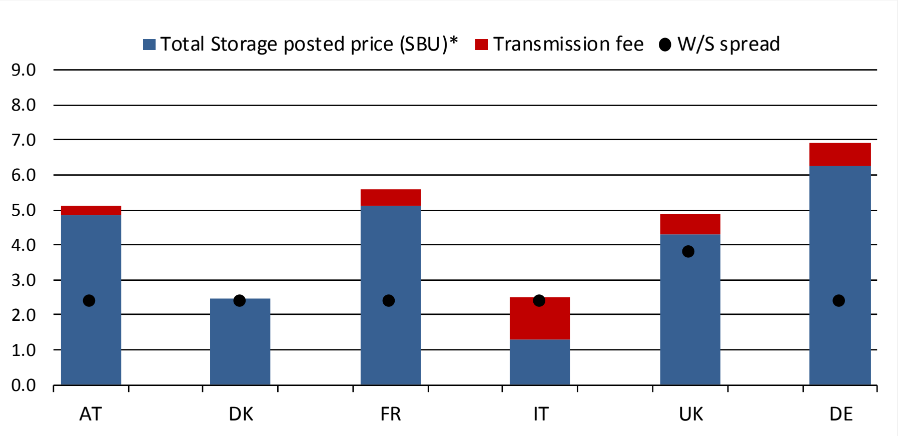
The analysis shows that the price of storage SBU, even if we ignore the transmission fee, is in same cases above the seasonal spread. .

Posted SBU prices may be higher than the intrinsic value. In the case published prices were actually the prices paid by most storage users, the premium above the winter-summer spread may reflect the insurance value attached to storage or its extrinsic value relating to the possibility to exploit short term price volatility.

However, as anticipated, the published prices often do not show the real storages prices in markets with negotiated prices, where storage products are mostly auctioned on exchanges or negotiated in OTC-contracts. Due to lack of transparency concerning information of prices actually paid by users in negotiated regimes, we could not perform a complete overview but rather present price evolution in two selected countries where storage regime is negotiated: Germany and the Netherlands.

69 We assume that the spread implicit in the TTF spread is by and large representative of the winter premium all over Continental Europe. While this assumption appears to be reasonable for the main developed hubs in Continental Europe, due to good alignment in hub prices, it may be less reasonable for less integrated markets. NBP is the reference for the UK.
70 In the analysis only storage facilities with speed below 2% are considered, provided that price data are available.
71 Fast-cycle gas storages have relatively higher prices per cm of working volume compared to slower seasonal storages. Fast gas storage facilities are more costly as they require more compression and often another type of geology

Figure 1.4.4. Storage price, transmission fee and seasonal price spread for individual seasonal gas storage (€/MWh, 2014)



* main official SBU capacity price and, if present, injection/withdrawal variable fees
AT refers to the following facilities: Schönkirchen / Reyersdorf,Tallesbrunn,Thann
DK refers to the following facilities: Stenlille
FR refers to the following facilities: Serene Nord
DE refers to the following facilities: Breitbrunn Uelsen Kirchheilingen Rehden
IT refers to the following facilities: all Stogit sites (capacity allocated in March 2014)
UK refers to the following facilities: Rough
Where the bar refers to more facilities, it represents the working gas weighted average.
Source: Albasoluzioni, SSO websites and inputs received from SSOs, GSE

The lack of information is due to several reasons: it is regarded as confidential information, the storage products are tailored made so it is difficult to identify a reference storage price for a country, information on revenues from storage services is not disclosed by storage companies.

Figure 1.4.5 shows the development of free negotiated storage prices in auctions in Germany including network access costs at the virtual trading points for different types of storages characterized by their time to turnover their working gas volume. Standard seasonal storages have a turnover period between 200 and 300 days, faster storages can turnover their working gas volume twice or more times a year. Very fast storages can turnover their volumes up to seven times a year and are used for peak shaving or short term trading. At many storages sides (e.g. caverns) SSO invested in the last years to improve the time to turnover their storages. Higher turnover rates offered the storage operators higher profits than slow seasonal storages at least in the recent years (see orange and dotted line in Figure 1.4.5). However, recent auctions showed that prices of the fast storages decreased much faster than the less expensive and mostly bigger seasonal storages and nearly converged to the same price level. On average the real storage prices for fast storages with a short turnover period declined by about 80% and for long term seasonal storages by about 50% compared to the officially published storage fees by storage operators (see Figure 1.4.5 the dotted black line and the red line). The actual price level of German storages both fast and slow storages almost equals or is slightly below the current summer-winter spread (see Figure 1.4.6). The storage industry claims that due to this development it is very challenging for storages to operate economically.

However, it is likely that German storage that was allocated on a long term basis in the past (and especially before the decline in winter-summer spread began) was charged at a level which is similar the German SBU price presented in Figure 1.4.4 (above 7 €/MWh). As these long term contracts have price negotiation clauses the current prices might be on a level of current or a least a level two-three years ago. Anyway, the long term storage contracts will most likely expire on short notice. Consequently the new prices which will most likely be agreed on will reflect the low price level emerging from recent auctions, which is, at least for some storage facilities, just at or below marginal costs.

An interesting factor is the disproportionate loss of value of faster storages in recent auctions. The balancing markets and the short term trading markets can be considered as competitors to such storage service. The loss of value of storage can be motivated by:

- the existence of relative cheap “virtual storages” provided by traders between the physical and financial markets;
- the relatively high premiums for such storages the published tariffs;
- the reduced volatility at spot markets and the European wide implementation of the daily balancing systems.

The value of very fast storages in balancing markets has fallen for suppliers as the intraday balancing and delivery of profiled consumption is now mostly a business of transport companies (except markets where the national regulators will further allow strong within day restrictions for suppliers in the national balancing systems).

The within day market (which might be attractive for very fast storages) exists only in some countries for the industrial and power plants segments. For most downstream customers the daily balancing system covers the needs of within day balancing. The balancing energy for these customers is traded in the balancing market between a small number of traders and TSOs. This has reduced the value of fast storages for the market as a whole. Additionally fast storages compete with imported cheaper storage capacities or flexibilities from balancing markets abroad and flexibilities from import contracts which are used by the small number of international traders.

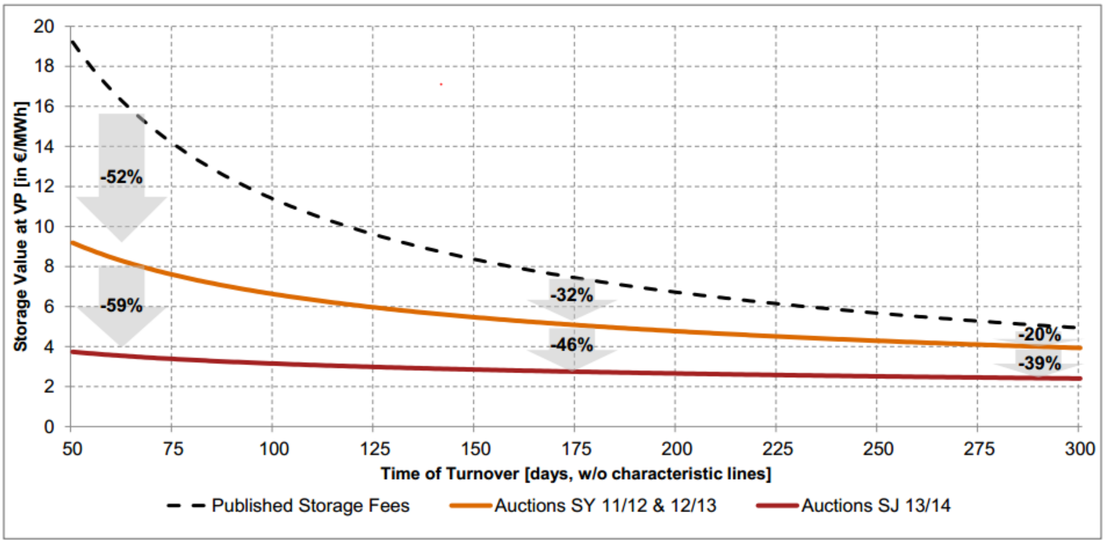
At the same time, as the demand side has changed fundamentally, most storage companies invested in the last years in upgrading their injection and withdrawal capacities as these capacities allow them to provide more valuable products (see Figure 1.4.5). Therefore supply overtakes demand in a reducing market segment which resulted in steeper price reductions for faster storages than for slow seasonal storages.

As shown in Figure 1.4.5, the prices in the last auctions run asymptotically towards a level of 2 €/MWh including transport costs. This is according to storage system operators this might be the minimum price to cover variable operations cost + transport fees between storage site and VTPs.

The summer-winter spreads on the Net Connect Germany (NCG) market (Figure 1.4.7), which sets the benchmark price for seasonal storages, does not show an increase of storage values for the next few years (as discussed in *Section 1.3.2*). The spreads at the market rather stabilized at less than 2 €/MWh in the German trading markets and decreased significantly in the last few years. Also the current forward prices do not show an increase of summer-winter spreads for the next tradable periods.

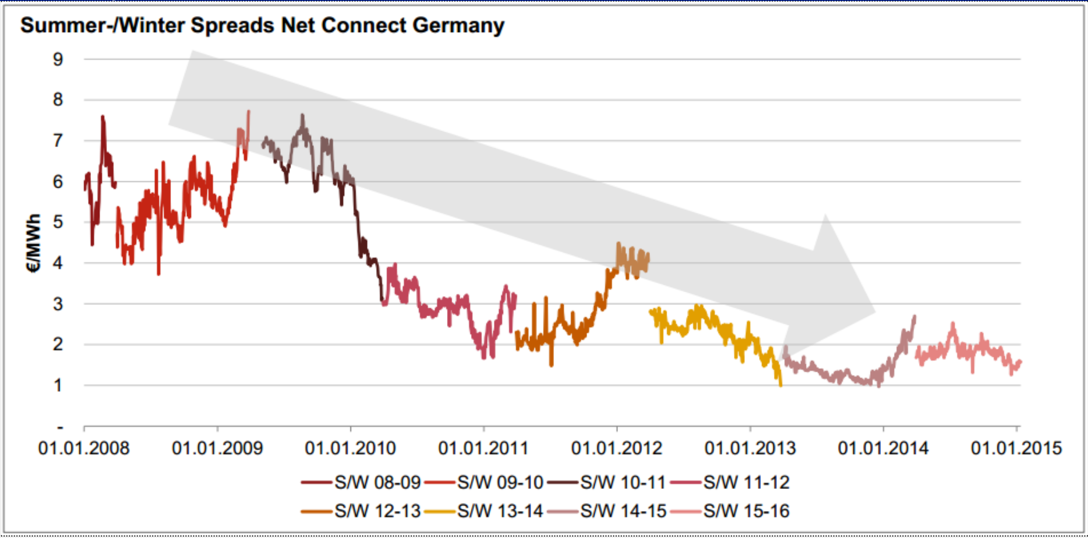
Decline in the storage price paid by storage users are also shown by officially published storage auction results for SBU in the Netherlands (Figure 1.4.8).

Figure 1.4.5 Development of storage prices in auctions in Germany



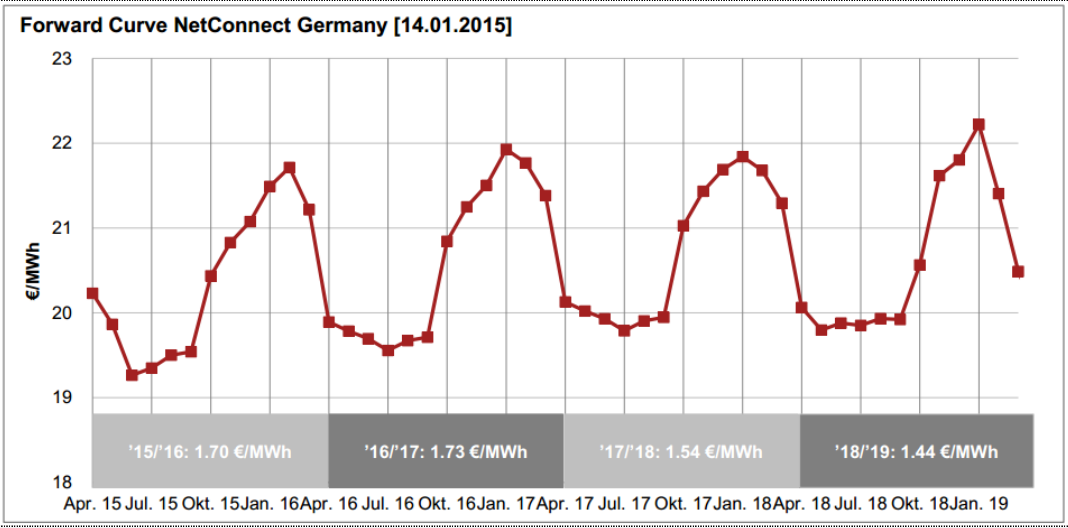
Source: PWC Introduction of Strategic Gas Storage in Germany, Gas Transport and Storage Summit 2015. 23rd March 2015

Figure 1.4.6 Development of summer-/winterspreads at the VP Netconnect Germany



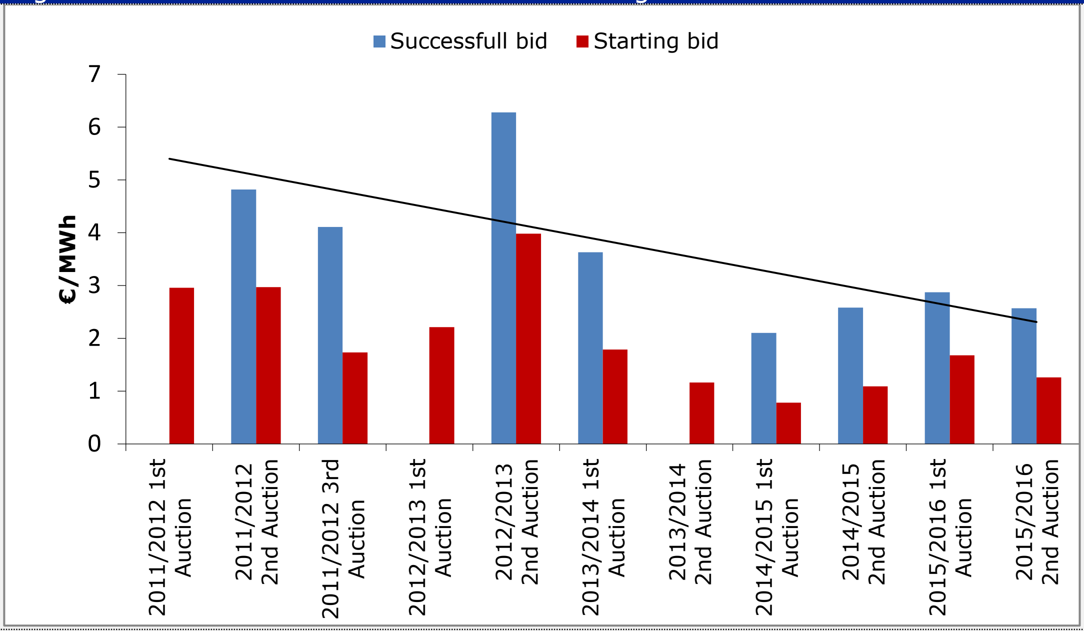
Source: PWC Introduction of Strategic Gas Storage in Germany, Gas Transport and Storage Summit 2015. 23rd March 2015

Figure 1.4.7 Summer-/Winter Spreads in the forward market in Germany



Source: PWC Introduction of Strategic Gas Storage in Germany, Gas Transport and Storage Summit 2015. 23rd March 2015

Figure 1.4.8 Auction results of the Dutch storage markets



Source: APX Gas Storage auction results

Summing up, officially posted SBU prices are in same cases higher than the intrinsic value. However, the officially published prices often do not show the real storages prices in markets with negotiated prices, where storage products are mostly auctioned on exchanges or negotiated in OTC-contracts. Due to lack of transparency concerning information of prices actually paid by users in negotiated regimes, we could not perform a complete overview. However the price evolution in two selected countries where storage regime is negotiated, Germany and the Netherlands, shows that storage users pay only the intrinsic value of storage (i.e. storage prices stay at the seasonal spread level). According to storage operators in these countries this is the minimum price to cover variable operations cost and transport fees between storage site and the virtual trading point.

2.COMPARATIVE ANALYSIS

2.1 Introduction

This Chapter provides an overview of Security of Supplies policies and measures undertaken in competitive markets for natural gas and for oil, the most similar commodity in the world.

There is basic difference between competitive markets and others, which are dominated by (often state-owned) companies with a significant monopoly power, even though neither competitive nor monopolistic markets are perfect and some elements of competition is often found in mostly monopolistic markets, and vice versa.

This is the basic reason why the analysis has been limited to Member Countries of the International Energy Agency located outside Europe, which share the choice of mainly competitive markets, though subjects to different models and regulatory frameworks.

A brief view at other markets shows that little could be learned from countries outside the IEA. In most cases, dominant companies are also in charge of securing supplies and it by their own means. These solutions may well be effective, but are basically corporate decisions - though possibly subject to some formal or informal government oversight. As such, thy can hardly provide useful regulatory and policy lessons for Europe or for other competitive markets, even though technical solutions may be similar.

2.2 USA

2.2.1 Country Overview[72]

The share of natural gas in the country's TPES (Total Primary Energy Source) was 28% in 2012, up from 26% in 2011 and 25% in 2010. The share of natural gas had been in steady decline since the early-1970s, but the past couple of years have seen a rapid reversal of this trend. Sources of demand in the United States are relatively diverse, with electricity generation, the industrial sector and road transport all expected to drive future demand growth thanks to low natural gas prices.

Domestic natural gas production was sufficient to cover 95% of domestic demand in 2012, with only around 5% of demand met through imports. Gas production has grown rapidly in recent years, largely owing to surging shale gas production, and is expected to continue to grow faster than consumption. Forecasts indicate that the country will become a net exporter of natural gas by 2018. Yet in the recent past the USA have been net importers, not only from Canada but also of LNG (see below).

The United States has a high degree of natural gas infrastructure reliability underpinning its security of supply, including the diversification of supply routes and substantial storage capacity. The country's supply security is further enhanced by the fact that border crossing points have "reverse flow" capacity that can be used when needed.

[72] Energy Supply Security 2014 - USA Review.

Table 2.2.1. USA Natural Gas Key Data				
	2000	**2010**	**2012**	**2018E**
Production (mcm)	544,335	603,857	681,385	796,749
Demand (mcm)	661,261	683,107	720,862	791,601
Net imports (mcm)	116,926	79,250	39,477	-5,148
Import dependency (%)	17.7	11.6	5.5	-1
Natural gas in TPES - Total primary energy source (%)	24	25	28	-

2.2.2 Gas production and reserves[73]

Surging shale gas production is the key reason for ongoing rapid growth in total US natural gas production levels. Shale gas currently comprises around 30% of total US natural gas production but is growing so quickly that, if production continues to increase as projected, it will offset an expected decline in production rates from conventional domestic natural gas sources.

Two reasons behind the continuing success of US unconventional gas production, despite low domestic natural gas prices, are high crude prices, which significantly improve the economics of natural gas plays that have a high liquids content, and improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with fewer rigs and higher initial production rates. The recent fall of oil prices is already triggering serious difficulties for some shale based (oil & gas) producers, but it is too early to say what the outcome of sustained current prices will be.

2.2.3 Gas demand[74]

Natural gas use in the industry sector is expected to increase, driven by an extended period of relatively low natural gas prices. Natural gas consumption is also expected to grow in the transport sector where LNG will increasingly be used as a fuel for heavy-duty trucks and natural gas will increasingly be used as a feedstock for producing diesel and other liquid fuels.

2.2.4 Gas company operations[75]

The US natural gas market is dynamic and highly competitive, it has an active spot and futures market. The industry has a high degree of private ownership with little vertical integration. Production, transmission and distribution are usually separate entities, although some large gas distributors own transmission pipelines. The only public ownership in the US gas industry is in gas distribution.

73 Energy Supply Security 2014 - USA Review.
74 Energy Supply Security 2014 - USA Review
75 Energy Supply Security 2014 - USA Review

2.2.5 Gas supply infrastructure[76]

a) Pipelines and ports

The US natural gas pipeline network is a highly integrated transmission grid that can transport natural gas to and from nearly any location in the lower 48 States. There were 38 active entry/exit points for pipeline imports/exports and ten active entry/exit points for LNG imports/exports in 2011, totaling 48 total entry/exit points. Overall the US has a high degree of natural gas infrastructure reliability, including the diversification of supply routes and substantial storage capacity. The country's gas supply security is further enhanced by the fact that border crossing points have reverse flow capacity that can be used when needed.

b) Storage

There are 419 natural gas underground storage facilities with a total working gas capacity of 275 Bcm[77] (about 38% of annual consumption). These facilities are widely dispersed geographically and consist of a combination of salt caverns (40), aquifers (47) and depleted reservoirs (332). The advantage of the significant amount of salt caverns is that it allows rapid injection and withdrawal to respond to market conditions and other short-term events.

2.2.6 Emergency policy[78]

The US government does not hold strategic reserves of natural gas or place a minimum natural gas stockholding obligation on industry and has no demand restraint policies in place at the federal level for use during a natural gas supply disruption.

In recent years, the United States has built four LNG regasification terminals (plus one in Baja California, Mexico, that is basically aimed at the US market), but at present most of them are significantly under-utilized because of the boom in domestic gas production. Most of them are going to be converted into liquefaction terminals). The low level of import dependency in the United States means that domestic storage already provides a very high level of resilience. However, the federal government has provided grants to state energy offices to develop energy emergency response plans, including natural gas allocation and demand restraint policies and associated regulations.

There are no policies in place in the US to promote fuel switching away from natural gas in an emergency. However, the electricity generation sector has significant fuel-switching capacity. Likewise, the US government has no policies in place to promote surge production or interruptible contracts as natural gas emergency management tools. According to the IEA, USA is indeed able to cope with a N-1 situation, but has not designed any other emergency policy.

76 Energy Supply Security 2014 - USA Review
77 As of 2013. Source: EIA. http://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm
78 Energy Supply Security 2014 - USA Review

2.3 Japan

2.3.1 Country Overview[79]

The share of natural gas in the country's TPES (Total Primary Energy Source) increased significantly from 17% in 2010 (before the March 2011 earthquake) to 23% in 2012, because of the growing demand from the electricity generation sector. Japan's domestic natural gas production is limited (around 3.2 bcm in 2012) and accounted for about 3% of total domestic natural gas demand.

The remaining supplies are entirely based on LNG. Natural gas supply sources to the country are well diversified. In 2012, Australia was the largest supplier, representing 20% of total imports followed by Qatar (17%), Malaysia (16%), Russia (10%) and Brunei (7%).

Table 2.3.1. Japan Natural Gas Key Data

	2000	2010	2012	2018E
Production (mcm/y)	2,499	3,343	3,177	2,431
Demand (mcm/y)	83,499	109,344	130,737	130,622
Net imports (mcm/y)	81,000	106,001	127,560	128,191
Import dependency (%)	97.0	96.9	97.6	98.1
Natural gas in TPES - Total primary energy source (%)	13	17	23	-

Key elements of Japan's overall gas security policy are:

- diversifying its long-term supply contract portfolio;
- ensuring that long-term contracts include flexibility to increase imports during an emergency;
- using voluntary commercial LNG stocks in industry.

Even though industry is not obliged to hold any emergency gas stocks, industry has commercial stocks equivalent to about 20 to 30 days of consumption. There is no single gas transmission system operator (TSO) in the country as the trunk line networks have developed separately around LNG terminals, are relatively short and often not connected to each other. Each gas company is asked to ensure its natural gas supply to its distribution area. Each industry (mainly electricity utilities and city gas companies) owns and operates its gas pipelines.

Japan has the largest import capacity in the world. As Japan has no cross-border pipelines, the country imported natural gas through 31 LNG terminals with around 10 billion cubic meters (bcm) of natural gas storage capacity. LNG terminals are owned and operated by electricity utilities, city gas companies and other industries such as steel companies and local governments. Electricity companies own close to half of the total LNG storage capacity, followed by gas utilities (over 40%). Third-party access to both pipelines and distribution networks was introduced in 2004 and is to be individually negotiated by the parties proposing to supply costumers.

[79] Energy Supply Security 2014 - Japan Review

2.3.2 Storage, LNG terminals and emergency policy[80]

The country has no underground storage for natural gas in its gaseous state, but has 31 LNG receiving terminals with around 10 bcm of natural gas storage capacity. But LNG storage in tanks are expensive and technically complex, therefore Japan can rely on a total storage capacity that meets only 30 days of domestic natural gas consumption.

The government is planning to build new LNG facilities and / or to expand the storage capacity of existing terminals. Plans envisage an increase of 2.2 Bcm of natural gas storage and foster investigation of the possibilities for strategic underground storage, including medium- and long-term prospects for underground storage. Moreover, as its primary means of maintaining supply security, the country takes advantage of diversity of supply sources, contract flexibility and spot market purchasing.

There is no legal obligation for the industry to hold any emergency stocks in the form of natural gas, LNG or alternative fuels in the country, but the industry adjust the level of commercial stocks to meet around two weeks of natural gas demand in normal times as well as in high demand. In the event that LNG import is disrupted, importing companies can allocate their gas imports through reciprocal backup supply. Japan has no legislation allowing the government to oblige electricity utilities to switch fuels away from natural gas. The country has 22 dual-fired power generation units as of 2012. However, it has very limited impact to reduce gas demand in a gas supply shortage, as electricity generation largely depends on natural gas. During a supply disruption, TSOs will reduce gas supplies according to interruptible contracts. Tokyo gas, which has around 34% of the total market sales of city gas, reduces gas supply to its customers consuming over 0.5 mcm per year with the exception of priority customers such as hospitals, welfare institutions and government offices.

In order to strengthen resistance to disasters such as earthquakes, the Japanese gas industry has replaced old low-pressure gas pipes with polyethylene pipes and high seismic resistant pipes. For the prevention of secondary disasters, it has also been building a shutting-off system which uses block formations and devices for automatic remote shutdown.

In case of supply shortage it is possible to adequately deal with the situation by combining the following methods, as Japan LNG supply sources are diversified and include 8 countries on a long-term contract basis):

- voluntary liquidation of gas stocks (equivalent to about 20-30 days) by private companies;
- use of excess supply capacity from other international LNG exporting projects (it is estimated that around 10% excess supply capacity is available with respect to each project);
- mutual accommodations among LNG importers, such as LNG cargo swaps, as well as LNG volume exchanges in case of companies sharing the same LNG import terminals, in the face of differing storage or demand conditions between companies.

While Japan’s LNG procurement focuses on the voluntary efforts of private companies, the government is also making efforts to diversify supply sources by enhancing its bargaining power through active development of summit and ministerial-level resource diplomacy with gas-producing countries. According to the IEA, Japan is able to cope with an N-1 situation, but has not yet designed any other emergency policy.

80 Energy Supply Security 2014 - Japan Review.

2.4 Australia

2.4.1 Country Overview

The Australian gas market consists of three distinct regional markets, with different market dynamics and all geographically separated from one another, making generally uneconomic the transmission and distribution of gas between those markets[81]:

- Western (Western Australia), characterized by:
  - both domestic and LNG export markets;
  - long-term contracts;
  - a small number of supply points and a few major pipelines;
  - Gas consumption (2012) = 347 PJ (15%)
- Gas consumption (2018E) = 347 PJ (15%)Northern (Northern Territory), characterized by:
  - both domestic and LNG export markets;
  - small market;
  - gas supplied to the domestic market is used predominantly for electricity generation;
  - Gas consumption (2012) = 22 PJ (1%)
- Gas consumption (2018E) = 22 PJ (6%)Eastern (Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania and South Australia), where :
  - gas is produced and used within the domestic market only;
  - long-term contracts and pool-based trading market that operates alongside existing market arrangements and long-term gas contracts;
  - a large number of supply points and a high degree of interconnection via transmission pipelines.
  - Gas consumption (2012) = 687 PJ (30%)
  - Gas consumption (2018E) = 687 PJ (13%)

To sum up, because of the large geographical distance between these three areas, involving their separation, production is therefore either consumed within each market or exported as LNG:

- (LNG exports (2012) = 1219 PJ (54%);
- LNG exports (2018E) = 4420 PJ (81%))

Table 2.4.1. Australia Natural Gas Key Data

	2000	2010	2012	2018E
Production (mcm/y)	32,819	48,370	53,850	140,577
Demand (mcm/y)	22,567	35,370	48,662	55,121
Net imports (mcm/y)	-10,252	-13,000	-5,188	-85,456
Import dependency (%)	-45.4	-36.8	-10.7	-155
Natural gas in TPES - Total primary energy source (%)	18	21	26	-

81 Australian Government - Department of Resources, Energy and Tourism, National Energy Security Assessment 2011.

2.4.2 Gas production and reserves

Australia benefits from large natural gas resources (3.67 trillion cubic meters[82] at end 2011)[83], that are increasingly being developed both for domestic use and for LNG exports. In recent years, closer attention has been given to unconventional resources, in particular coal seam gas (CSG, also called coal-bed methane or CBM). Over the medium term, the production of gas is expected to continue to rise as developments now under construction or in the advanced stages of planning are completed. Australia is a net exporter of natural gas and all exports occur as LNG.

2.4.3 Gas supply infrastructure[84]

The Australian gas industry comprises around 150 gas companies active in different parts of the gas value chain with six major companies that account for 70% of the supply to the domestic market (as of 2009/10). In the 1990s, vertically integrated gas utilities were disaggregated and most government owned transmission pipelines were privatized. If transmission pipelines are determined to be anti-competitive, they are regulated under the National Gas Law and National Gas Rules. Major transmission pipeline companies include the APA Group, Jemena and Epic Energy.

The major gas distribution systems in Australia are privately owned but regulated by government to ensure that gas can be transported on reasonable terms by third parties. There is some duplication among companies owning transmission and distribution networks. At of the end of 2012, Australia had three active LNG export terminals, with seven more terminals under construction, between 2014 and 2018. Australia has also a single international gas pipeline. This pipeline supplies the Darwin LNG terminal with natural gas imported from the Joint Petroleum Development Area (JPDA) with Timor Leste (10.9 Bcm in 2012).

2.4.4 Gas Storage[85]

In order to meet seasonal variations, there are 4 underground operating storage facilities and 1 LNG peak shaving plant, representing a working storage capacity of 1.3 Bcm, of which over 1.1 Bcm is located in the Eastern market, the most prone to seasonal variations in demand, caused by increased heating demand during winter. Storage facility contracts and terms of access are worked out on a confidential bilateral basis between storage providers and customers. No public storage is held by the Australian government and access to storage facilities is not regulated.

The storage facility of Silver Springs, is currently being developed and the project should be completed by end-2015 as well as a new LNG storage facility in New South Wales which should be in operation starting from winter 2015[86.] Storage facility contracts and terms of access are worked out on a confidential bilateral basis between storage providers and customers. No public storage is held by the Australian government and access to storage facilities is not regulated.

82 Trillion cubic meters.
83 BP's Statistical Review 2012.
84 Energy Supply Security 2014 - Australia Review.
85 Energy Supply Security 2014 - Australia Review.
86 http://www.agl.com.au/about-agl/how-we-source-energy/gas-storage/newcastle-gas-storage-facility-project/the-project.

Table 2.4.2. Australian underground storage facilities					
Facility	**Basin**	**Working Capacity**	**Withdrawal rate**	**Company**	**Online date**
Mondarra	Perth	127	5	APA Group	n.a.
Moomba	Cooper	623	4	Santos	1981
Newstead	Surat	234	5.2	Origin	1997
Iona	Otway	308	6	TXU	1999
Silver Springs	Surat	n.a.	n.a.	AGL	2011-2015
Source: IEA					

2.4.5 Emergency policy[87]

The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. The gas industry has good arrangements, such as interruptible contracts, in place to manage a range of issues that can temporarily impact on gas supplies. For larger issues, each state and territory has legislation conferring emergency powers, which may be exercised in natural gas emergencies affecting only one jurisdiction. Several options can be used in the event of a gas shortage, including fuel switching in the power and industry sectors.

Contingency gas (CG) may be used at the short-term trading market hubs in Sydney, Adelaide and Brisbane. This represents an emergency mechanism, which may be called on by the AEMO[88] to balance supply and demand if normal mechanisms in the STTM (Short-term Trading Market) are unlikely to achieve this balance. The use of CG reduces the risk of supply issues for customers, however it has never been called for by AEMO so far. CG may be offered by shippers who can increase the supply to the hub and users who can reduce withdrawals from the hub in cases of shortage. In such a case, the shipper and the user will be paid a price higher than the ex ante market price for additional gas they make available.

In the case of a major gas crisis affecting more than one jurisdiction, the National Gas Emergency Response Advisory Committee (NGERAC), created in 2005, will advise energy ministers across jurisdictions. The NGERAC is currently chaired by the Australian Commonwealth, and includes government representatives from each jurisdiction as well as industry representatives. The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. There are no strategic stocks of natural gas in Australia, as there are no government stocks or requirements placed on grid owners, system operators or other industry participants to hold minimum reserves of natural gas. There are no policies to promote fuel switching away from natural gas in an emergency. According to the IEA, Australia is able to cope with an N-1 situation.

87 Energy Supply Security 2014 - Australia Review.
88 Australlian Energy Market Operator. Source: http://www.aemc.gov.au/Rule-Changes/Contingency-Gas-Evidentiary-Changes.

2.5 Overview of oil emergency response measures in IEA countries[89]

2.5.1 IEA Membership requirements

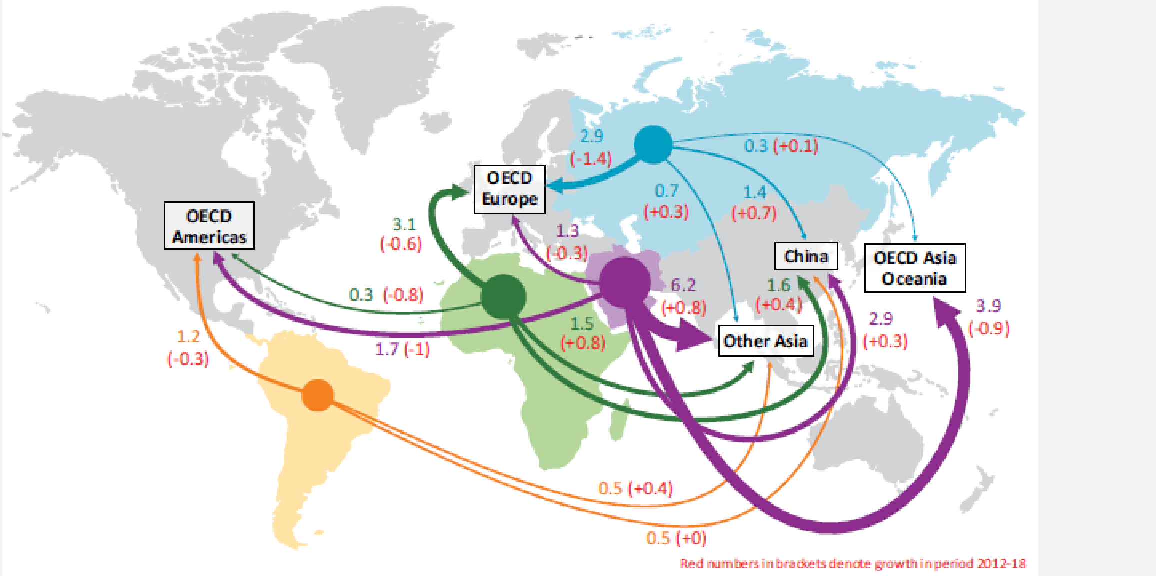
The measures described in this section are the primary means through which IEA countries participate in a collective response during a short-term oil supply disruption. Each country determines which emergency response measures are most appropriate, depending on their domestic market conditions. IEA countries can take different measures in a coordinated manner, relying on a single measure or a combination of several measures.

Emergency response is still one of the main pillars of the IEA. Membership requires countries to meet two key obligations:

- to hold oil stocks equivalent to at least 90 days of net oil imports;
- to maintain emergency response measures that can contribute to an IEA collective action in the event of a severe oil supply disruption.

Response measures include both measures to increase oil supply (stockdraw and surge oil production) and measures to reduce oil demand (demand restraint, fuel switching).

Figure 2.5.1. Expected crude exports in 2018 and growth over 2012-18 for key trade routes

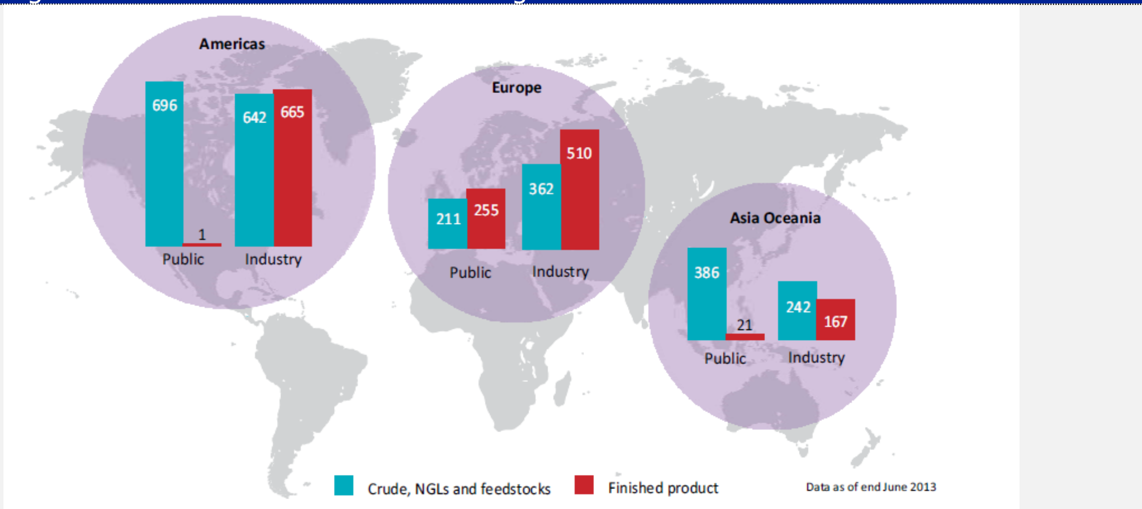


2.5.2 Stockdraw

Stockdraw is currently the most used emergency response measure: it represents the most effective response to an oil supply disruption and can be complemented by other emergency measures through coordinated action. IEA members are obliged to hold stock levels equivalent to at least 90 days of their net imports, but there is flexibility in meeting this minimum stockholding requirement using both crude and refined products.

89 Source: IEA, Energy Supply Security 2014.

Figure 2.5.2. Total oil stocks in IEA regions



Source: IEA, ESS 2014

Stocks are generally held either by industry, the government or an agency established for this purpose. The use of stocks in an IEA coordinated action may thus involve public stocks (held either by agencies or owned directly by governments), industry stocks or a combination of both, depending on each country's stockholding system. In countries where there is a substantial obligation on industry to hold stocks, the most common course of action is for the government to allow, temporarily, a decrease in industry's compulsory stockholding levels in line with the country's share of the total IEA response. Stock held by industry to meet minimum stockholding obligations have the advantage of already being in the supply chain, and therefore very rapidly available to the market during a crisis.

For countries with publicly held stocks, stock release typically involves offering specified amounts from these public reserves through processes such as tenders or loan offers. The IEA stockdraw potential for both public and compulsory industry stocks is sufficient to cope with the largest historical supply disruption experienced to date.

2.5.3 Production surge

Surge production is another emergency response measure that aims at increasing the availability of supply.

It is thought as a short-term measure to increase national oil production within a very short time period and can only be implemented by countries with significant levels of production. The main issue with this measure emerges by the fact that potential volume available in a crisis depends on the amount of spare or surge production capacity maintained in individual member countries, which is usually very little. In addition, the need to maintain good oil field practices limits the extent to which oil production can be increased on a short-term basis.

2.5.4 Demand restraint

Demand restraint measures lead to short-term reductions in the use of oil by freeing up oil in an under-supplied market. This can be done either by reducing the amount of oil actually used or by limiting the amount of oil supply available to consumers. The initial emphasis is usually on light-handed, voluntary measures, reached through public campaigns, but compulsory measures, ranging from medium to heavy-handed policies are also used in a crisis. The transportation sector accounts for about 55% of total oil consumption in IEA member countries and offers the largest potential for rapid reductions in demand through restraint measures. In the case of oil used for transportation, a light-handed approach would use public campaigns to promote eco-driving or carpooling, a medium way would be to impose certain measures like speed reduction and a heavy-handed approach would be to enforce driving restrictions.

2.5.5 Fuel switching

Fuel switching is also seeking to reduce the use of oil during a supply disruption by encouraging the use of alternative energy sources. Switching to other energy sources reduces the use of oil, thereby making additional supply available to the market. This includes, for example, using coal or natural gas rather than oil in electricity production.

However, the role of oil in economic sectors has changed significantly in the past years. While the growth in the use of oil both in the transportation and in the industry sector has limited the potential for fuel switching, the share of oil used for heat and power generation has decreased significantly, leaving little scope for fuel switching in power generation during a disruption. Today, even though short-term fuel switching would be possible in these sectors, there are doubts about its potential to be effective in a time of crisis.

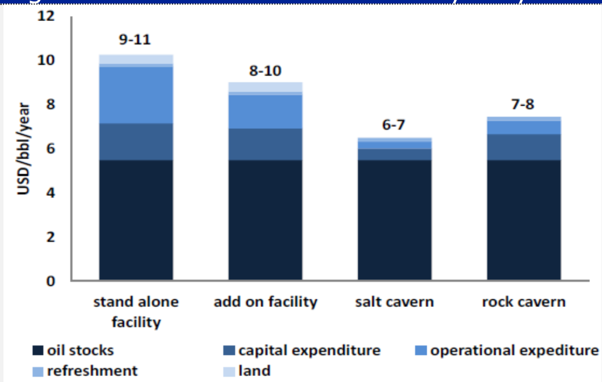
2.5.6 Oil stockholding costs

In 2012 and 2013 the International Energy Agency (IEA) carried out a review of the costs and benefits of Oil Stockholding. The IEA Report developed costs for storage facilities to hold emergency stock. Facility costs were developed for above ground facilities (both standalone and add on to existing facilities), salt caverns and rock caverns.

Stockholding cost figures are based on size and type of storage facilities (above-ground tanks and underground caverns) as well as composition of stocks (crude/product). Total yearly costs range from USD 7-10 per barrel, reflecting the fact that holding emergency stocks in underground caverns is about 30% cheaper than holding oil in above-ground facilities. These values include the acquisition of stocks, which represents at least 40% and up to 85% of the overall costs, based on recent oil price levels of 55-110 $/bbl. The expenditures for building the storage facilities and the related infrastructure amount up to one fifth of yearly costs. The share of expenses for operating and maintenance of the storage sites vary considerably between storage options, amounting to as little as 5% for caverns and as much as one quarter for above-ground facilities. Refreshment of oil products and land costs both represent a marginal proportion of overall costs. The interest rate has a considerable impact on yearly cost figures. Annualized costs are based on an interest rate of 3%. Higher interest rates lead to higher yearly expenses.[90]

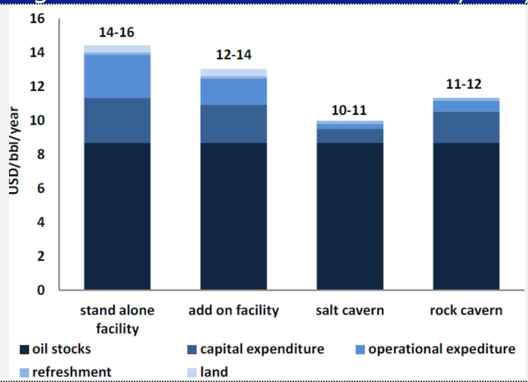
[90] IEA (Costs, Benefits and Financing of Holding Emergency Oil Stocks, 2013)

Figure 2.5.3. Breakdown of total yearly costs (3% interest rate)



Source IEA (2013)

Figure 2.5.4. Breakdown of total yearly costs (7% interest rate)



Source IEA (2013)

Cost differences across world regions

Cost differences between different world regions are principally the result of varying labour costs. Moreover the utilization of smaller tanks can increase construction costs on a per barrel basis considerably and the design of the storage facility also has a significant impact on construction costs. Generally, a terminal for the sole purpose of holding emergency stocks is as basic as possible while a full fledged, general purpose terminal (e.g. in case of a refinery) is more sophisticated and therefore more expensive. Then the inclusion of jetty costs leads to a 10-40% increase in construction costs. Finally extensive pipelines and security measures as well as a contingency budget of 30% for unforeseen engineering costs led to an estimate for construction costs almost double (USD 50-60/bbl - EUR 250-300/m^3) compared to the figures here calculated (USD 29-37/bbl - EUR 140-180/m^3).

In this paper, the expenses to purchase the stocks are based on 2011 crude import costs across all IEA countries (USD 107.61/bbl). Import costs in IEA Asia Pacific (USD 109.45/bbl) and IEA Europe (USD 110.54/bbl) are above this average, while they are lower in IEA North America (USD 103.05/bbl). In addition, since these are regional averages individual countries might experience higher import costs. Due to the large share represented by the purchase of stocks, differences in import costs can have a significant impact on the level of total costs.[91]

2.5.7 Oil stockholding benefits

Economic benefits consist of reduced GDP losses and reduced import costs. These are derived primarily from offsetting supply losses and thereby reducing significant oil price increases. A computer model simulated thousands of individual scenarios over a time-horizon of 30 years to quantify these benefits. The simulation results show that the use of IEA stocks equals about USD 3.5 trillion of avoided costs to IEA and non-IEA net importing countries. On a yearly basis these benefits amount to about USD 50 per barrel. This value represents an average payoff from the "insurance" provided by stocks. While the results are relatively robust with regard to global crude oil disruptions, the simulation did not attempt to account for benefits derived from the use of stocks in the event of a domestic disruption in or in case of a product supply disruption. Yearly net benefits amount to some USD 40 per barrel. Major non-IEA consumer countries have long recognized the enormous global benefits provided by emergency stocks. China and India have started to set up emergency stocks of their own during the last decade. In conclusion, the tangible economic benefits of holding emergency oil stocks to respond to global supply disruptions are substantial. Under a base case a total gross benefits of about USD 51/bbl/y have to be compared to a yearly cost of USD 7-10/bbl. That leaves a yearly net benefit of at least USD 41/bbl/y even for the most expensive storage option (i.e. newly built above-ground facility).

Table 2.7.1. Benefits versus costs for a variety of sensitivity cases (in USD/bbl/y)

Sensitivity Test	Base Case	Price Elasticity of Demand		Use of Saudi Arabia Spare Capacity (Base Case: 50%)		Drawdown Threshold (Base Case : 2 mb/d)		Availability of Obligated Industry Stocks (Base Case: 100%)	
Variation Compared to Base Case	Base Case	Lower Elasticity (75% of Base Case)	Higher Elasticity (125% of Base Case)	Lower Use (25%)	Higher Use (100%)	Lower Threshold (1 mb/d)	Higher Threshold (3 mb/d)	None Available (0%)	Lower Availability (50%)
Gross Benefits									
Total IEA	21	27	17	26	14	25	15	19	20
Non-IEA Net-Importers	30	38	25	36	18	35	20	26	28
Total Gross Benefits	51	64	42	62	32	60	35	45	48
Costs									
Newly Built Above Ground	10	10	10	10	10	10	10	10	10
Add on Above Ground	9	9	9	9	9	9	9	9	9
Salt Cavern	8	8	8	8	8	8	8	8	8
Rock Cavern	7	7	7	7	7	7	7	7	7
Net Benefits									
Total IEA	11-14	17-20	7-11	16-20	4-7	15-19	5-8	9-12	10-13
Non-IEA Net-Importers	30	38	25	36	18	35	20	26	28
Total Net Benefits	41-44	55-58	32-36	52-55	22-25	40-47	25-28	35-36	38-41

Source: IEA, 2013

91 IEA (Costs, Benefits and Financing of Holding Emergency Oil Stocks, 2013)

Table 2.7.1 shows a sensitivity analysis performed starting from the case base described before and evaluating the impacts of price elasticity of demand, use of Saudi Arabia spare capacity, drawdown threshold and availability of obligated industry stocks on benefits, as variable input parameters.[92]

2.5.8 Financing emergency oil stocks

There are different ways of financing the acquisition and maintenance of emergency stocks as reflected in the distinct practices adopted by IEA countries. Financing mechanisms can generally be divided into two categories: financing of public stocks and financing of obligated industry stocks. The different approaches highlight the flexibility in financing emergency stocks and reflect efforts to keep the burden on state budget, industry and final consumers at a minimum. In many countries, the cost to the final consumer amounts to less than one cent per liter. In conclusion:

- Holding emergency oil stocks provides significant economic benefits
- Benefits vary by country and cannot always be quantified
- Acquisition costs of oil represent the largest share in overall costs
- The financing of emergency oil stocks is highly flexible[93]

2.6 Overview of natural gas emergency response measures in IEA countries[94]

Natural gas plays a large role in the energy balances of IEA countries, making gas security a key element in energy security. However, unlike in the case of oil (see *Section 2.5*), there is no framework for taking collective action in response to a natural gas disruption, and IEA countries do not have the equivalent treaty requirements to establish emergency response mechanisms for natural gas.

IEA countries show a marked diversity in their demand, supply and market conditions with respect to natural gas. These factors will determine how countries perceive the risks associated with a gas disruption and the appropriate emergency response measures required to mitigate such events.

Natural gas has become the fuel of choice for electricity production for several years in Europe, but this role is now declining, whereas in has increased in other OEA . At the same time, the natural gas market is becoming more global, thanks to the development of longer pipelines and inter-regional trade of LNG. The impact of gas supply disruptions could have today a global impact.

2.6.1 Differences between oil and gas emergency response

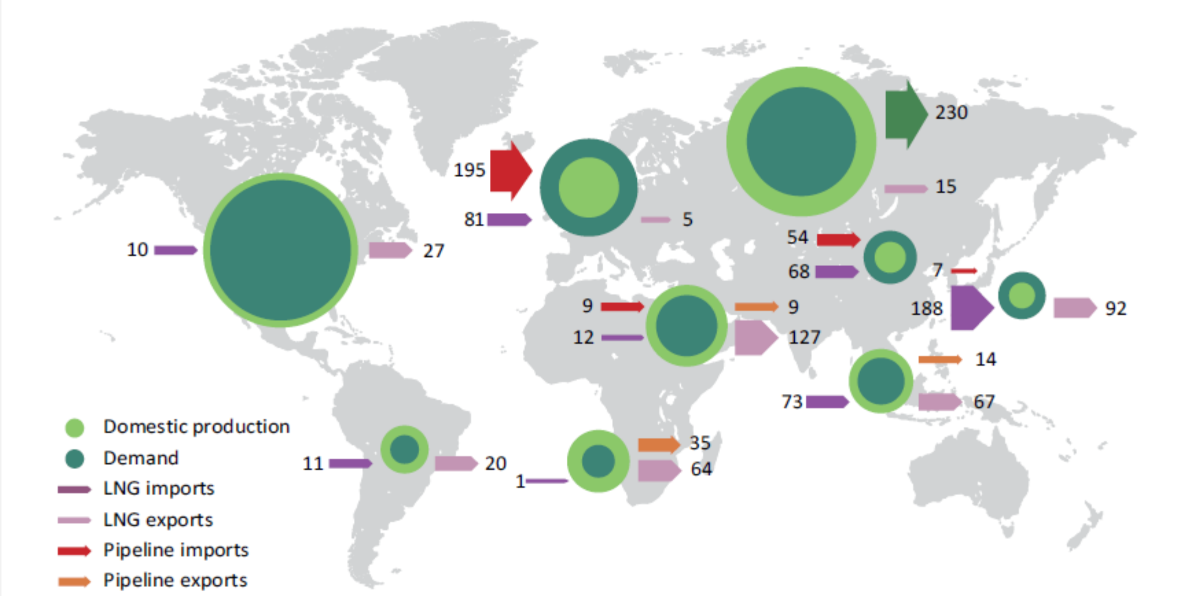
Given the similar features of the two commodities, it is straightforward to think that experience and lessons from emergency response policy for oil can be used as reference point for the case of natural gas. However, emergency response measures can differ substantially due to the unique nature of gas.

Natural gas is bound to a highly capital-intensive transportation and distribution infrastructure, and there is little demand-side response in large consumers sectors like households and space heating. Secondly, natural gas is far less fungible than oil, especially regarding the transportation of the fuel to end users: while downstream gas transport is almost entirely performed by fixed infrastructure (i.e. pipelines), tanker

92 IEA (Costs, Benefits and Financing of Holding Emergency Oil Stocks, 2013)
[93] IEA (Costs, Benefits and Financing of Holding Emergency Oil Stocks, 2013)
[94] Source: IEA, Energy Supply Security 2014.

trucks can be cheaply used to distribute the oil instead. This makes the gas distribution system less resilient, in the sense that where oil tanker trucks are used the loss of one of them will not have large consequences on the oil distribution, but if any part of a gas pipeline is damaged, supply downstream is heavily affected. Furthermore, the available spare capacity, either physically or contractually, is sometimes limited in existing gas pipelines, whereas more oil trucks can deliver more oil to petrol stations via the road system in case of extreme oil demand.

Figure 2.6.1. Inter-regional natural gas trade 2018 (bcm)



Source: IEA, 2013

2.6.2 Natural gas disruptions in the past

A number of gas supply disruptions have occurred over the last decade, arising from weather-related catastrophes (e.g. hurricanes), accidents (e.g. fires, explosions) and contractual disputes. Recent significant gas crises occurred in the United States (2005 and 2008), the United Kingdom, Italy and Ukraine (2006); Turkey, Greece and Australia (2008)[95]. At the beginning of 2009, Europe suffered its worst gas supply disruption to date, with Russian supplies transiting Ukraine interrupted for almost three weeks; in total some 7 bcm of supply was lost, including 2 bcm of supply for Ukraine. Coming at a time of very high demand because of cold weather, this crisis had a far greater impact than even the hurricane-induced shortages in the United States in 2005 and 2008. Some Eastern European countries with heavy reliance on Russian gas and only limited storage capabilities were especially badly affected, with major industrial closures and real hardship in the domestic sector.

2.6.3 Natural Gas emergency measures

Issues related to emergency stockholding that are similar to those in place in the oil market are examined before considering other possible actions for mitigating gas crises.

95 Further information about major gas market shocks and their price implications will be provided in Chapter 4.

Emergency gas stocks

Emergency gas stocks are defined as physical stockpiles of natural gas that are not available to the market under normal conditions. As in the case of oil, emergency gas stocks can be either government owned volumes or consist of stocks held by industry, based on a government-imposed stockholding obligation. In either case, the stocks are held with the aim of protecting consumers against non-market risks, i.e. a risk that cannot be expected to be covered by the market under normal conditions and thus falls outside the reliability standards of a particular market.

Geological or technical barriers, and their entailed costs, are perhaps the greatest impediment to developing sizeable gas storage facilities throughout the IEA countries. Natural gas, like any other gas, needs to be fully contained at all times to prevent it mixing with the air and/or escaping. As well as needing confinement, natural gas has a lower energy density than oil which means that, at standard temperature and pressure, a volume of gas contains much less energy than the same volume of oil. If storage is to be economical, the energy density of gas needs to be increased – gas must therefore be stored either at very high pressures or at low enough temperatures (-160°C) so that it becomes liquid. The operating costs for storing gas either under high pressure or in a liquefied form are well beyond those for oil storage. High pressure environments require specialist materials such as thick steel pipelines and powerful compressors. Storing natural gas under high pressures will typically only be pursued if there is suitable geology for underground storage, such as in depleted oil fields. When using depleted fields for gas storage, the pressure of the field must be maintained at all times, otherwise the geological structure could be altered. This means that even when the field is technically empty of working gas it must have sufficient gas in store to maintain sufficient pressure to maintain the geological structure. The volume of gas left in a gas storage site emptied of useful working gas is referred to as the "cushion gas". The volume of cushion gas required to develop a large underground storage facility can account for up to half the cost of the investment; even if such gas is already available in the site, as it is often the case of depleted fields, it has an opportunity cost, represented by the postponement of a production flow.

In case emergency gas storage is not available, governments can adopt some other measures in order to reduce the impact of a gas disruption.

Emergency gas stock costs

Conceptually, gas stocks are often viewed as the equivalent of "emergency oil stocks"; in fact, gas and gas storage differs markedly from oil. A fundamental difference is cost. Initial capital costs of building gas storage facilities can range from between five to seven times the costs of underground oil storage facilities per ton of oil equivalent (toe) stored. The capital cost of LNG storage facilities can be up to ten times the cost of stocks in oil tanks or approximately 50 times the cost of underground oil storage per toe stored. Furthermore, the volume of gas that is required to be maintained in a gas storage site emptied of useful working gas – referred to as the "cushion gas" – can vary significantly according to the type of storage. Whereas cushion gas can be limited to around 25% of total gas in the case of most salt caverns, it approaches 50% for depleted fields, and can reach up to 80% for aquifers. In certain cases, depending on the market price for gas, cushion gas can account for up to half the cost of the investment. Variable costs for maintaining gas in storage are also significant. Variable costs for gas storage are determined by various economic factors such as interest rates, cost of maintenance and cost of personnel, but also include another factor specific to gas storage – gas leakage. The variable cost of maintaining enough gas in emergency storage to satisfy a 90-day net import standard across the IEA countries is estimated at between 10% and 20% of the capital cost of the facilities per year. Assuming suitable sites within the IEA countries could be found, the cost of developing gas storage in depleted fields is estimated at up to EUR 1.00 per cubic metre of working gas. The cost of developing salt cavern storage is higher, approximately twice the cost per cubic metre of working gas.[96]

However, in the best cases, costs can be in the order of 3-6 €/MWh/year, as shown by the examples of regulated and (negotiated) posted prices shown in section 1.4 above. Operators would not offer storage services if these price levels were not profitable. At such price levels, the costs are of a similar order of magnitude as those of oil, shown above (7-10 $ /bbl/year or about 5-7 €/MWh/year).

Supply response

This is a flexibility source that can only be used in those countries where there is spare import capacity from LNG terminals or unused pipeline or interconnector capacity and contractual circumstances allow. In the pipeline market, this response would rely on there being unused pipeline capacity with associated production flexibility. Some of this import capacity can be used by the capacity owner to increase purchases from upstream suppliers, if supply is available and contractual conditions allow. Alternatively, the capacity could be made available to the market by the system operator if the capacity holder is unable, or unwilling, to secure additional gas supplies. In the LNG market, a supply response would rely on the market's ability to purchase additional LNG tanker cargoes. There are two sources of available LNG cargoes; the "spot" LNG market and LNG cargoes diverted from their original destination by agreement of stakeholders. A combination of reduction in demand in unaffected regions and increased production and cargo diversion could constitute a global LNG response to a supply emergency.

Demand response

Demand response measures are used in some cases to reduce demand in emergency and they refer to a situation where customers decide to modify their consumption depending on the price of gas in a market. Given the increasing use of gas in power generation, similar measures could be used to stimulate demand-side reactions in the electricity sector. One way of allocating natural gas when supply is disrupted is to ration its use through demand restraint, whereby natural gas consumption is restricted. Such a policy goes beyond the voluntary limitation that occurs when customers decide to modify their consumption depending on the price of gas in the market. Governments could impose strict limitations on gas consumption in specific sectors (e.g. industry) in order to assure supplies to predetermined priority customers (e.g. households or vital services such as hospitals). In liberalized markets this is normally an explicit provision in the network code governing the physical operation of the gas system.

Interruptible contracts

Costumers that consume large volumes of gas per year (e.g. industrial costumers) are eligible interruptible users in case they agree to have their gas supply interrupted for a maximum number of days in a year in order to obtain a reduction of gas price. Costumers with this type of contract agree to up to 20 days of zero supply in a year. Generally, large gas consumers on interruptible contracts receive volume-related discounts on wholesale gas costs, in addition to a reduction in transportation costs designed to offset the potential loss of supply. However, the volumes saved through this measure are unlikely to be sufficient to mitigate a large-scale disruption. Nonetheless, this option can be useful as part of a suite of tools for dealing with such interruptions.

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96 Source (IEA, Supply Security, 2014)

Fuel switching

Some gas fired power stations are able to switch to light oil (gasoil) or even burn crude oil if necessary. In addition to the penalty in terms of efficiency and increased maintenance, several other conditions must be met, including adequate stores of oil available at the site. Governments can set specific obligations to maintain minimum stock levels of alternative fuels for use in a gas crisis. The power sector and district heating plants can switch between fuels and power plants regularly in some countries as part of normal (or even abnormal) market functioning. This highlights the importance of having a diverse range of energy sources for power generation, to provide maximum flexibility in the event of a natural gas emergency.

2.7 Conclusions

The Study has analysed other cases of Security of Supply policies outside Europe, however these are hardly comparable. In the U.S., large storages are provided by the private sector, often in order to keep production flows constant and make them more competitive. Yet the issues of a system which – if considered together with Canada – is basically self-sufficient are very different from Europe's and no major policy has been implemented. Yet markets have been heavily affected by major disruptions, notably in the case of the Katrina and Rita hurricanes.

Japan is almost totally dependent on LNG imports. It has substantial LNG storage, built by local utilities also for SoS purposes, yet its gas markets are very fragmented and hardly competitive.

Australia is also a self-sufficient and actually an exporting country. It is a more interesting case than U.S or Japan as the regulator has established a mechanism by which "contingency" gas to be supplied in emergencies is defined by means of auctions. Storage is just one way of providing such gas, which has in fact never been called for yet.

Outside these countries, SoS standards are either much lower, as net importing countries have often resorted to fuel switching in case of lack of gas (e.g. Israel, Turkey, Argentina) or even to load shedding. Net exporters like Russia or Iran can however rely on large production margins or possibly reduce exports, as both have done sometimes. Again, there is little that Europe can learn from such cases.

It is tempting to compare emergency stocks that are accumulated for oil with those of gas. Given the similar features of the two commodities, it is straightforward to think that experience and lessons from emergency response policy for oil can be used as reference point for the case of natural gas. However, emergency response measures can differ substantially due to the unique nature of gas.

However, natural gas uses a highly capital-intensive, mostly fixed transportation and distribution infrastructure, and there is little demand-side response in large consumers sectors like households and space heating. While downstream gas transport is almost entirely performed by fixed infrastructure (i.e. pipelines), tanker trucks can be cheaply used to distribute the oil instead. This makes the gas distribution system less resilient, in the sense that where oil tanker trucks are used the loss of one of them will not have large consequences on the oil distribution, but if any part of a gas pipeline is damaged, supply downstream is heavily affected. Furthermore, the available spare capacity, either physically or contractually, is sometimes limited in existing gas pipelines, whereas more oil trucks can deliver more oil to petrol stations via the road system in case of extreme oil demand.

What is more, holding of oil resources is much cheaper, due to the physical nature of the commodity, which is liquid at common temperature and pressure levels. Holding an equivalent amount of natural gas is far more costly: initial capital costs of building gas storage facilities can range from between five to seven times the costs of underground oil storage facilities per ton of oil equivalent (toe) stored.

3. DESCRIPTION AND EVOLUTION OF THE MAIN STORAGE-RELATED SOS MEASURES[97]

3.1 Overview and comparison of existing SRSMs

In what follows we reviewed storage related security of supply measures (SRSMs) for 11 sample countries, covering nearly 80% of the EU gas market and over 80% of storage working gas capacity[98]. SRSMs include storage obligations and special strategic storage that has to be used only in emergency. Note that the definition of storage obligations and strategic storage may overlap. In the following we categorize as strategic storage only that of Italy and Hungary[99]. We start with a quick overview of analysed countries, aimed at assessing their different situations and how this has led to various Security of Supply (SoS) policies, notably as regards storage.

3.1.1. Austria

Security of supply in Austria is the responsibility of the market parties. Gas storage is a competitive market. There are no particular storage obligations. Nevertheless the N-1 standard is fulfilled (234.59%). According to Austrian legislation the utilities are responsible to secure the supply of protected customers. For this purpose they may book storage capacities voluntarily or procure other flexibilities in order to fulfil this obligation. Only in case of an emergency which cannot be removed by the market parties the legislation defines precise crisis scenarios. In such a scenario the distribution manager[100] defines schedules for storages in order to overcome the emergency. Thereby the storage capacities are allocated pro-rata to the individual balancing accounts.

Even though there is no storage obligation, storage capacities have increased in recent years. In addition it is intended to connect further storage capacities to the Austrian grid, also when these are located abroad[101], in order to increase security level and the level of sustainability in case of interruptions further..

3.1.2. Bulgaria

In Bulgaria a mandatory storage obligation exists in the form of a supplier storage obligation. More precisely, according to the Bulgarian Emergency Plan (EP)[102], the dominant Bulgarian supplier (Bulgargaz, who carries out the activity of public provision of natural gas[103]) shall store gas quantities amounting to 250 mcm, which should be used in the event of an emergency. More specifically, 130 mcm are needed to safeguard supplies, and the remaining 120 mcm are needed to cover seasonal

97 We are very grateful to NRAs who provided valuable contributions for this part.

98 Main data source are Preventive Action and Emergency Plans ex art. 4, Reg. 994/2010, integrated by National legislation and data, interviews and own market knowledge

99 In Spain shippers are required to maintain "strategic stocks" (see Annex 12),in this study we considered these as mandatory storage obligations due to the fact that suppliers are required to maintain these stocks. In this study we classify as strategic stocks those that are taken out of the market, such as in Italy and in Hungary.

100 In Austria the Distribution Manager (VGM) is responsible for the physical network operation, demand of balancing energy, application of load profile.

101 For example the Pozagas storage facility is located on Slovak ground but is directly connected to the Austrian grid too.

102 EP approved by Order № РД-16-1663/30.11.2012 of the Minister of economy and energy.

103 Bulgargaz EAD is the only company in the country who holds the license for public provision of natural gas, that is the supply of gas to consumers who did not freely select their supplier. Bulgargaz is referred as the Public Provider and carries out wholesale gas supply at regulated prices set by the Energy Regulator SEWRC and its share in gas sales in 2013 was 87%. The remaining 13% share is made by two traders (Dexia and Overgas). In compliance with the European directives for full liberalization of electricity and natural gas markets, all gas consumers in Bulgaria have the right to select their natural gas supplier. Practically, in 2013 that right was exercised by one business consumer (District heating-Razgrad EAD) and the five gas distribution companies of the Overgas Inc. AD group. Households have not exercised that right in 2013 (Source: SEWRC Report to ACER 2014).

shortage at the entry of the system. The criteria to determine such amounts are not disclosed; however, the gas volumes that Bulgargaz had to store correspond to about 10% of total yearly gas consumption in 2013.

In addition, in the event of a crisis the use of storage capacity is subject to the rules set in the EP. The storage operator Bulgartransgaz in the event of disruption has the right to limit/interrupt/maximise the level of injections and withdrawals. Bulgartransgaz also has the right to limit/interrupt the level of injections and withdrawals when there is a need to ensure capacity for injection/withdrawal of the natural gas quantities stored to comply with the supplier storage obligation.

3.1.3. Czech Republic

Since April 1st 2013, gas suppliers in Czech Republic are obliged to fulfil at least 20% of supply standards by storing gas in underground storage facilities for their supply of protected customers. The storage capacities do not need to be located within Czech Republic. However, if the storage is located abroad, then suppliers have to procure also the needed transmission capacity. This obligations amounted to about 225 mcm in winter 2014/2015. The storage obligation holds only in the winter and the obligation amount varies depending on the registered temperature of the month. The National Energy Authority calculates the yearly storage obligation and monitors its fulfilment. At the same time suppliers have to report their filling levels at the 15th day of the following month to ERU.

The level of 20% for the computation of the storage obligation was set after a consultation and there is still a debate on whether it is adequate. Czech market operators noticed that the introduction of storage obligations last year did not change substantially storage booking behaviour, as the larger suppliers already owned the needed storage capacity from bookings at the beginning of the unbundling and disintegration of the Czech gas market.

3.1.4 Denmark

Denmark is currently moving from being a net exporter (since 2010) to becoming a partial importer, due to falling North Sea production. The Danish grid has significant levels of interconnection with Germany and Sweden. Most gas consumption is met by internal production, but imports from Sweden and Germany are required to fulfil flexibility requirements.

Denmark has implemented the requirements of the EU Regulation 994/2010, including an Emergency Plan for the Danish gas transmission system.

The current Danish balancing mechanism, introduced in March 2014, gave market mechanisms a much larger role in maintaining SoS.

Denmark has access to two storage facilities that cover a third of its annual consumption requirements. The transposition of the EU Regulation ensures that the TSO (Energinet.dk) is responsible for ensuring SoS, and for dealing with any supply emergency situations. There is no requirement for Energienet.dk to maintain a mandatory specific volume of stored reserves, but it has responsibility for ensuring overall SoS, and is entitled to take measures to maintain emergency reserves; for example, it pays storage customers to maintain storage volumes in winter months, which can be used only in the event of an emergency. The majority of the capacity in Danish storage facilities has been sold because of the commitment of storage customers to maintaining a certain stock volume during the year against a discount (capacity is tendered within market participants). Energinet.dk compensates the two storage companies for this and thus has additional stock volume for emergency situations at its disposal. Each year on 1st March 12% of the shippers' storage capacity must be left in storage.

Energinet.dk also reserves the necessary withdrawal capacity from storage for short term emergency supply incidents, which is normally used for balancing purposes: such reserves are purchased by the TSO in the market at commercial prices.

Currently, Energinet.dk has access to a total of approximately 215 Mcm of Emergency Storage capacity filled with gas. This includes volumes made available from shippers' storage filling requirements and storage volumes reserved by the TSO in order to maintain operational safety.

Energinet.dk can employ market-based tools to achieve its SoS objectives/responsibilities. Non-market based (mandatory) measures can only be used in the event that market-based tools are insufficient to guarantee SoS during emergencies.

The main market-based measures used are the Demand-Side Response mechanism (i.e. annual tenders for interruptibility) and cash-out prices for daily imbalances of the network. Special tools, such as alternative pipe capacity and reserved storage capacity of suppliers, can be used in emergency events.

3.1.5 France

France' gas market growth has been limited by the strong nuclear industry, modest domestic resources and relatively low population density. However, these factors point to reduced alternative flexibility tools and make the SoS problem all the more serious.

An almost total import dependency, notably on long distance pipelines, and reduced power generation flexibility contribute to explain France' SoS policy, which is the toughest in the EU after Hungary. Obligations to store gas are flexible in relation to the expected needs of customers connected to distribution grids, starting from 80% of the estimated seasonal storage requirements at the start of the heating season.

Moreover, the relatively peripheral position of France with respect to the European market may explain why storage capacity and especially its filling rate are high, but decline more rapidly than in neighbouring countries. Therefore, this is a case where any price increase triggered by a crisis may not only lead to early interruption of protected customers, but also to a net cost for the country, hardly offset by gains for producers. These factors are likely at the root of the strict storage obligations that have been enforced.

The current debate is more about ways to make storage obligations less costly than to reduce their size.

3.1.6 Germany

In the German market model there are neither mandatory / strategic storage requirements nor PSO requirements for suppliers. Security of supply is the responsibility of market participants, i.e. the suppliers of final consumers need to book storage capacities in order to ensure the contracted supply. Only in case the supply is in danger TSOs are entitled and obliged to take network related and market related measures to prevent the network users from interferences. Market based measures include the usage of balancing energy, contractual agreements (e.g. interruptible rights) and the utilization of storages.

Nevertheless, there is currently an ongoing discussion to change the market design in order to increase the level of security of supply. The discussion includes at minimum three different models in addition to the current model by which strategic or mandatory gas reserves may be implemented. At the moment no decision has been taken either to change the current market model at all or about the preferred model. The first model foresees a natural gas reserve comparable to the national petroleum stock piling. The second model suggests the allocation of specific gas storages to the assets of the TSO in order to increase its reliability. The third model considers a compulsory storage volume which shall be stored in the storages during the winter period by suppliers of protected customers.

3.1.7 Hungary

Hungary has a very high dependence on natural gas, and particularly on Russian gas. After the 2006 and 2009 Ukrainian crises raised fears of serious supply disruptions, the country has undertaken the most demanding storage related security policy in Europe. It is the only Member State that requires both a strategic storage site as well as minimum storage obligations by market suppliers, totalling about 24% of annual consumption. The almost total privatisation of supply (only recently partly reverted) may have also played a role in this policy choice.

Including commercial storage, Hungary has one of the largest storage endowments in Europe in comparison to its market size. It has also been one of the most active countries in cross-border infrastructure development. Overall, it has a very accurate and comprehensive SoS policy.

After the introduction of the Measures, the N-1 SoS parameter has increased remarkably (to over 1.2) and should further increase after the opening of the new interconnector with Slovakia and reinforcement of existing ones.

Whereas the strategic storage site had certainly improved Hungary’s security of supply, its costs are significant. The peculiar regime of the site may have also somehow affected the commercial storage market, including in interconnected countries.

3.1.8 Italy

As of 2014, in Italy there are no mandatory storage obligations on suppliers.

Mandatory strategic storage reserves were established by law in 2000, with these storage reserves directed to compensate for either the lack/reduction in internal gas supply or gas crisis and hence contributing to the security of supply of the country. The choice to introduce strategic storage volumes may be motivated by the massive use of gas by households. Strategic gas reserves can be used only under authorization by the Ministry and only when the allocated import capacity has been fully used.

Storage companies take out of the market and dedicate to the strategic storage reserves a share of their space capacity. Storage companies should also ensure that such space is filled up with gas volumes they own themselves. SSOs are remunerated for offering this service, which is offered under a regulated regime. Remuneration for such service is done through a fee paid by all importers and domestic producers. It is estimated that the yearly cost of strategic resources is about 60 million euro.

The total volume dedicated to strategic storage is set annually by the Ministry. In storage year 2012/2013 the Ministry reduced[104], for the first time, the total amount of strategic storage by 0.5 bcm, which before amounted to 5.1 bcm. The total amount for 2012, equal to 4.6 bcm, was confirmed for the storage year 2013/2014, storage year 2014/15 and storage year 2015/2016. So far no further reduction in strategic resource has been envisaged, nor their elimination.

3.1.9 Poland

Polish gas supply companies are obliged to hold compulsory stocks in the gas storage capacities if they resale gas to final consumers. The stored gas is an asset of these companies but at the disposal of the Minister of the Economy. The volume shall be equivalent to at least 30 days of the average daily imports of the gas brought in. The gas has to be stored in storage facilities, which provide the opportunity for supplying the entire volume thereof to the gas system within a period of not more than 40 days. Mandatory stocks of natural gas may be maintained outside the territory of Poland, in the territory of another member state of the European Free Trade Association (EFTA) being a party to the European Economic Area Agreement, in storage facilities connected to a gas system and meeting the requirements set out in the Act on stocks. That is to say both the technical parameters and the parameters of the service provision agreements ensure that the total volume of the compulsory stocks of natural gas maintained outside the territory of Poland can be delivered to the national transmission or distribution network within the maximum period of 40 days.

The costs incurred by the enterprises in order to fulfil the obligation to maintain, release and re-establish the compulsory stocks of natural gas shall be included in the justified costs of their operations within their cost calculations of regulated tariffs.

Depending on the assessment of situation and measures necessary for removing the consequences of supply disruptions, it shall be possible to: release mandatory stocks, and subsequently introduce restrictions on natural gas offtake (where it has initially been assessed that the use of mandatory stocks would suffice), or take both actions in parallel.

In the event of having released mandatory stocks, the Minister for the Economy shall immediately inform thereof the European Commission, the Member States of the European Union, and the member states of the European Free Trade Agreement (EFTA) being the parties to the European Economic Area Agreement.

3.1.10 Spain

The Spanish gas market has experienced a vast transformation in the last fifteen years, from an initial position in which the market was controlled by an incumbent to the current fully-liberalized situation. Security reserve requirements applicable on shippers have evolved accordingly.

Mandatory storage obligations are in effect in Spain: shippers are required to maintain strategic stocks, equivalent to 20 days of their firm sales in the previous natural year, located in underground storage facilities and whose utilization is the responsibility of the Spanish Government. Prior to 2011 the mandatory strategic stock requirement was 10 days. The country's strategic stocks can be used to palliate emergency

104 Ministerial Decree 29 March 2012.

situations linked to the failure of infrastructure, the disruption of imports due to geopolitical issues, force majeure and adverse meteorological phenomena.

Suppliers of significant volumes are also required to diversify their supply portfolio if any of the supplying countries accounts for more than 50% of the Spanish aggregated imported gas volume. The Spanish system addresses the possibility for maintaining gas stocks in other EU Member States through bilateral agreements. This option has not, however, been used to date.

All storage products sold in the Spanish gas market have one-year contract duration; that is, underground storage capacity is tendered annually by the TSO (from 1st April of year n to 31st March of year n+1). Storage volumes offered under the tender procedure and which do not become allocated are kept by the TSO who offers them to market participants on a First Come First Served basis. Total underground storage capacity currently amounts to 4.78 Bcm, of which 3.03 Bcm is cushion gas.

Spain is connected to neighbouring countries by means of 6 physical international connections, with total nominal pipeline capacity of 30.19 Bcm/year. Spain has six operative LNG terminals, which together have nominal capacity of 62.3 Bcm/year. Send-out capacity amounts to 60.2 Bcm/year and storage capacity within regasification terminals amounts to 1.96 Bcm/year. Interruptible consumption has limited relevance in terms of SoS and is not forecasted to increase in significance.

3.1.11 United Kingdom

The UK became a net importer of natural gas in 2004, moving from a situation in which its total gas supply was covered by national production (from the United Kingdom's Continental Shelf), to the current situation in which gas imports represent more than half of total gas supply. This was facilitated by a fivefold increase in import capacity.

The UK is served through a diverse set of import routes from Norway, The Netherlands and Belgium, in case of piped gas, and several different international sources through 4 LNG importation terminals. Total import capacity amounts to 156 Bcm/y, divided into the following three sources: the Continent (44.5 Bcm/y); Norway (56.6 Bcm/y); and LNG (53.1 Bcm/y).

Instead of setting absolute mandatory storage indication requirement levels, the UK approach to achieving SoS focuses on the use of market-based mechanisms to provide market participants with signals to increase importing infrastructure and to deliver flexibility. In general terms, storage is an important but relatively small part of the overall supply mix. The natural gas market has to date never experienced a gas deficit emergency and the potential for one to occur is believed to remain low.

The UK gas grid authority has been involved since 2011 in the reform of Cash Out arrangements, the market-based mechanism providing shippers with the incentives to avoid supply disruptions. The main changes brought about by the review included: (1) eliminating the size-priority order of disconnection in case of firm load-shedding; (2) including the possibility of gradual disconnection (instead of a binary on/off mode); and (3) using dynamic prices in case of emergency (instead of freezing prices at the beginning of the emergency).

3.1.12 Overview and comparison

Table 3.1 presents an overview of the existing SRSMs for each country, if any.

Mandatory storage obligations exist in the majority of sample countries: Bulgaria, Denmark, France, Poland, Spain, Czech Republic and Hungary. Only three out of 11 sample countries have no SRSMs: the UK, Germany and Austria. In this respect 56% of totally available storage capacity lies in countries of mandatory storage obligations while 44 % is not restricted by any obligations.

Storage obligations consist mainly in an obligation for gas suppliers[105] to store a given amount of gas to be ready to use during the winter. In France the obligation also concerns withdrawal capacity, as since 2014 suppliers have to ensure they hold a minimum withdrawal capacity, in addition to gas stocks. The total amount of mandatory storage is computed differently in each country and, more specifically, is determined with reference to:

- Protected consumers' winter demand, which generates «storage rights» in France;
- Imported quantity in a given period: in Poland gas suppliers are obliged to maintain compulsory storage stocks equivalent to at least 30 days of the average daily import;
- Past firm sales in a given period: in Spain gas suppliers must store volumes necessary to cover 20 days of their firm sale, computed from the previous year's sales; ;
- Total consumption: 10% of yearly consumption must be stored in Hungary. (It should be mentioned at this stage that besides the storage obligation as share of total consumption Hungary also holds a strategic gas reserve);
- Supply standards: gas suppliers in Czech Republic are obliged to fulfil at least the 20% of supply standards by storing gas in underground storage facilities. Bulgaria and Denmark, to the best of our knowledge, have not disclosed criteria to determine storage obligations.

The amount of mandatory storage obligations is generally determined every year, although principles and criteria usually last more.

Mandatory storage stocks are mostly located within domestic boundaries. In Spain, volumes need to be located on Spanish soil in order to be considered security reserves unless subject to a bilateral agreement. Some countries, such as Czech Republic and Poland, explicitly allow mandatory storage to be located abroad. In the former, volumes can be stored abroad provided that suppliers procure the needed transmission capacity. Poland allows for mandatory stocks of natural gas to be maintained outside the national territory, provided that the volume of the compulsory stocks of natural gas maintained outside the territory of Poland can be delivered to the national transmission or distribution network within the maximum period of 40 days.

Only two sample countries have special strategic storage reserves: Italy and Hungary. The latter is the only country that requires both strategic storage and storage obligations on suppliers. While Italian strategic reserves are spread among existing storage operators and facilities, in Hungary a special facility (Szöreg) is mostly used as strategic reserve, but a smaller part of it can be used for commercial purposes. Hungarian and Italian strategic storages are taken out of the market and can be exclusively used in emergency situations and only to fulfil protected consumers' needs. In particular, Italian strategic gas reserves can be used only under authorization by the Ministry and only when the allocated import capacity have been fully used. While Hungarian reserves had never been used as of April 2015, Italian ones have been used twice: in the winter 2005 and 2006 and in those occasions the

105 In Denmark the obligation is born by storage users, rather than gas suppliers, but the former category includes the latter. In Spain the obligation is born also by direct consumers (users who are connected to the transmission grid, usually big gas consumers)

contribution from strategic resources reached 15% and 24% of the total volumes, respectively.

Table 3.1 Overview of the existing SRSMs in the sample countries	
Member State	Presence of storage obligations and strategic storage, and description
Austria	NO
Bulgaria	YES The dominant Bulgarian supplier shall store gas quantities needed to safeguard supplies and to cover seasonal shortage. The criteria to determine such amount are not disclosed.
Czech Republic	YES Gas suppliers in Czech Republic are obliged to fulfill at least the 20% of supply standards by storing gas in underground storage facilities, not necessarily located within Czech Republic.
Denmark	YES Storage users are paid by TSO to maintain stored volumes in winter time, such volumes can only be used in case of emergency. Criteria not disclosed
Germany	NO
France	YES Gas suppliers have to store not less than 80% of their storage rights by the 1st of November, which in turn depend on the consumers' climate zone and frequency in metering.
Hungary	YES Gas suppliers have to store 10% of total consumption. Moreover, a dedicated storage facility is partly reserved as strategic storage.
Italy	YES Storage companies take out of the market a share of storage capacity and dedicate to the strategic storage reserves amounting to 4.6 bcm.
Poland	YES Gas suppliers that import gas are obliged to maintain compulsory storage stocks: equivalent to at least 30 days of the average daily import, the whole mandatory stored gas has to be injected into the grid within a period of not more than 40 days
Spain	YES Gas suppliers and direct consumers must maintain strategic natural gas reserves to cover 20 days of their firm sale/consumption, computed from the previous year's sales. In addition, suppliers and direct consumers must maintain operative natural gas reserves, computed as: - Volumes equivalent to 2 days of firm sale, computed as the average daily sales from 1 April to 31 March (these volumes can be held also on regas. facilities) - Volumes equivalent to 8 days of firm sale, computed as the average daily sales in October from year n (these volumes cannot be held on regas. Facilities)
UK	NO

The amount of strategic reserves in Italy and Hungary is determined according to criteria set in national legislation and is set every year by the Government. More specifically, in Italy the amount of strategic reserves should be equal to:

- the volume necessary to withdraw from the strategic storage sites, for a period of at least 30 days and during the peak seasons, a gas amount corresponding to the whole technical capacity of the most used import infrastructure.

- the volume necessary to fully cover seasonal swing in consumption in the event of an extremely cold winter, determined as the coldest winter occurred in the last 20 years. The exact criteria to determine the seasonal swing in consumption in the event of an extremely cold winter have not been disclosed).

In Hungary, strategic storage, according to legal provisions, equals the volume of gas necessary to cover 45-day consumption by protected consumers.

As far as the cost of strategic storage is concerned, the current cost[106] of Hungarian strategic storage is estimated at nearly 85 million euro/year, while the yearly cost of strategic resources in Italy is estimated to be about 60 million euro. These values imply a much higher cost in Hungary, as its working gas size is 1.2 bcm vs. 4.6 in Italy. Cushion gas valuation is typically the largest source of divergences in the valuation of storage costs for regulatory purposes. The higher cost of the Hungarian storage site may be related to its geological nature (an oil field with a gas cap).

SRSMs have been introduced in the 2000s in most sample countries: Italy established strategic reserves in 2000, Hungary in 2006; France introduced the storage obligation in 2006, Spain in 1998, Poland in 2007. Czech mandatory storage obligations, however, are relatively more recent, being introduced in 2013. In some cases, storage obligations have evolved since when they were first introduced. Some strategic storage volumes were converted into commercial ones: Italian strategic storage was reduced by 10% compared to the initial level (from 53.6 TWh to 48.3 TWh in 2012). In Hungary the strategic capacity was reduced temporarily to 8.4 TWh (815 mcm) in 2012, but the original level of 12.6 TWh (1.2 bcm) was restored as of mid-2014. In France, the obligation on suppliers was reduced in 2014: from 85% to 80% of storage rights, although it has been extended to all users connected to the low pressure grid. In Spain, responsibility has gradually shifted from TSOs to suppliers (as the market got liberalized) and mandatory reserves for gas suppliers increased in the last ten years: in 2011 strategic security reserves grew from 10 to 20 days of firm sales.

The current amount of total mandatory storage in each country (including both storage obligations and strategic storage) ranges from 3% of national consumption in Czech Republic to 24% in Hungary.

Looking at the Table, three clusters can be identified:

- Countries choosing “tight” SRSMs, where the total mandatory storage amounts to more than 15% of national consumption: France and Hungary.
- Countries choosing “light” SRSMs, where the total mandatory storage amounts to less than 10% of national consumption: Czech Republic, Denmark, Poland, Spain, Italy, Bulgaria.
- Countries with no mandatory storage at all (UK, Germany and Austria).

The current amount of total mandatory storage in each country (including both storage obligations and strategic storage) can be compared to the total consumption of protected consumers. In the absence of precise data on consumption of protected consumers in each sample country and given the difference in the definition of protected consumers across the EU[107], the latter can be estimated using total consumption in 2013 by residential gas users (as provided by Eurostat).

106 Here cost means the cost of holding the stocks, and it therefore does not account for any impact on market prices.
107 See Annexes for a review of definition of protected consumers in each country.

Table 3.2 Amount of total mandatory storage obligations and strategic storage in each country (TWh) and ratio between total mandatory storage and national consumption (%)

Country	Total mandatory storage obligation (Latest available, TWh)	Total strategic storage (Latest available, TWh)	Total mandatory storage (% of 2013 consumption)
Austria	0.0	0.0	0%
Bulgaria	2.6	0.0	9%
Czech Republic	2.3	0.0	3%
Denmark	2.3	0.0	5%
France	85	0.0	18%
Germany	0.0	0.0	0%
Hungary	23.8	12.6	24%
Italy	48.3	48.3	7%
Poland	9.3	0.0	5%
Spain	16.5	0.0	5%
United Kingdom	0.0	0.0	0%

Table 3.3 Amount of total mandatory storage obligations and strategic storage in each country (TWh) and ratio between total mandatory storage and estimate for the consumption of protected consumers(%)

Country	Total mandatory storage obligations (TWh, Latest available value)	Total mandatory storage (% of 2013 total consumption)	Total mandatory storage (% of 2013 protected users' consumption)
Austria	0	0%	0%
Bulgaria	2.63	9%	N.A.
Czech Republic	2.31	3%	9%
Denmark	2.26	5%	27%
France	85.00	18%	52%
Germany	0	0%	0%
Hungary	23.8	24%	73%
Italy	48.30	7%	21%
Poland	9.28	5%	21%
Spain	16.50	5%	40%
United Kingdom	0	0%	0%
Source: Eurostat, case studies			

The current amount of total mandatory storage in each country (including both storage obligations and strategic storage) ranges from 9% of consumption by residential gas users in Czech Republic to over 50% in France and Hungary. As far as Bulgaria is concerned, ratio between total mandatory storage and the consumption of protected consumers could not be obtained due to lack on information on the consumption by Bulgarian district heating companies. Gas consumption by households in this country is very limited (0.6 GWh in 2013 against storage obligations accounting for 2.6 TWh). The amount of mandatory storage in Bulgaria may be related to the fact that in this country district heating facilities running on gas are considered as protected consumers. Bulgarian district heating companies represent an important share of gas consumption but we could not find reliable data on this.

Excluding Bulgaria, France and Hungary have the highest ratio between mandatory storage volumes and protected users' gas consumption, this being above 50%. All the other sample countries have a ratio lower than 40%.

3.2 Choice of SRSMs models

In order to produce an assessment of the impact and cost of existing SRSMs, we analyse the impact of supply disruption scenarios under different SRSM "models":

- Model 1: the gas volumes stored ahead of the winter[108] are those resulting from the existing SRSMs. This is also the "baseline" of our simulations.
- Model 2: the gas volumes stored ahead of the winter are those resulting from the implementation of "tight" SRSMs in all countries, provided that the existing storage capacity is sufficient.
- Model 3: the gas volumes stored ahead of the winter are those resulting from the implementation of "light" SRSMs in all countries, provided that the existing storage capacity is sufficient.
- Model 4: the gas volumes stored ahead of the winter are those resulting from the implementation of the "strategic storage reserves in all countries".
- Model 5: the gas volumes stored ahead of the winter are those resulting from the elimination of the existing strategic storage volumes in Europe (i.e. Italian and Hungarian strategic storage reserves, "market based").
- Model 6: Existing strategic storage and storage obligations are cancelled

Details of model implementation follow. Countries are those included in the ENTSOG Stress Test Assessment.

Note that these models assume that a given amount of gas is in store ahead of the winter and we assume that this amount of stored gas is related to a storage obligation, without differentiating between it being the result of supplier obligation or establishment of strategic reserves. It is worth highlighting that the same amount of gas in storages may also be achieved by other means, for instance through the introduction of incentives for storage accumulation.

Model 2: Tight SRSMs

"Tight" SRSMs are defined as an obligation to store, ahead of the cold season, the maximum between current working gas capacity and the 21% of national consumption. This model could be defined as a situation where we simulate the implementation of French- and Hungarian-like SRSMs to all countries. On average, in fact, the "tight SRSMs cluster" identified in Section 3.12 requires mandatory storage stocks amounting to 21% of national consumption, which is the average over French (18%) and Hungarian (24%) ratio. The implementation of tight SRSMs (Table 3.5) results in an increase in stored gas for 13 out of 21 countries, with very significant increase for some countries, such as Spain and Bulgaria.

From a practical perspective, this model needs not be interpreted as any country having to increase storage capacity in its territory, which could be very costly in several cases. On the contrary, countries may follow the Czech model and allow suppliers to store gas in other countries, possibly subject to transmission capacity holding obligations.

108 We use a reference date 31.08, consistently with ENTSOG Stress Test Assessment, where the supply disruption starts in September.

Table 3.4 SRSM Model 1 (Baseline)

SRSM Model (1)			
Country	Stored gas on 31.8 (TWh)	Stored gas on 31.8 (% tot. Working capacity)	Stored gas on 31.8 (% consumption)
AT	48	56%	53%
BG	4	77%	15%
CZ	31	85%	35%
DK	10	93%	23%
FR	110	81%	23%
DE	216	94%	23%
HU	37	56%	38%
IT	167	96%	23%
PL	26	97%	14%
ES	24	57%	7%
UK	48	93%	6%
BE	8	100%	4%
HR	5	83%	16%
IE	2	100%	5%
LV	17	71%	115%
NL	90	99%	22%
PT	2	86%	4%
RO	28	87%	21%
RS	5	100%	17%
SE	0.1	98%	1%
SK	34	100%	64%

Note: red background indicates that national inventories on 31.08 are less than 80% full, yellow background indicates that national inventories on 31.08 are less than 90% full and more than 80% full; green background indicates that national inventories on 31.08 are more than 90% full.

Source: ENTSOG, GSE, Eurostat

Model 3: Light SRSMs

"Light" SRSMs are defined as an obligation to store, ahead of the cold season, the maximum between current working gas capacity and the 9% of national consumption. This model could be defined as a situation where we simulate the implementation of light SRSMs to all countries. In fact, the "light SRSMs cluster" identified in Section 3.12 requires mandatory storage stocks amounting to maximum 9% of national consumption. In most cases, inventories already account for this percentage of consumption, therefore the application of light measures to all countries do not results in an increase in stored gas for all countries. Only the UK, Portugal, Ireland and Sweden would need to build up storage capacities (Table 3.6).

Model 4: Strategic storage reserves

The implementation of the strategic storage reserves in all countries as foreseen in model 4 is a very extreme scenario that implies that stored gas is above current national working gas capacity. More specifically in this model countries are required to store gas volumes ahead of the winter amounting to 7% of their national consumption. This model could be defined as a situation where we simulate the implementation of an Italian-like strategic reserve obligation to all countries. Italy requires strategic storage stocks amounting to 7% of its national consumption. Under Model 4, only Hungary could decrease stored gas, having a strategic storage obligation accounting for 13% of national consumption; all the other countries experience a significant increase in inventories (Table 3.7).

Again, strategic storage could be located in other Member States to fulfil the obligation more efficiently.

Model 5: Market based

Model 5 assumes the elimination of the existing strategic storage volumes in the Europe and therefore affects only Italian and Hungarian filling levels (Table 3.8).

Table 3.5 SRSM Model 2 (Tight Storage Obligations)

SRSM Model (2)				
Country	Stored gas on 31.8 as it would be applying tight	Change compared to baseline (%)	Stored gas on 31.8 (% tot. Working capacity)	Stored gas on 31.8 (% consumption)
AT	48		56%	53%
BG	**6**	30%	100%	19%
CZ	31		85%	35%
DK	**10**		93%	23%
FR	110		81%	23%
DE	**216**		94%	23%
HU	37		56%	38%
IT	**167**		96%	23%
PL	**27**	3%	100%	15%
ES	**43**	77%	100%	13%
UK	**52**	7%	100%	6%
BE	8		100%	4%
HR	**6**	20%	100%	19%
IE	2	0%	100%	5%
LV	17		71%	115%
NL	**90**		99%	22%
PT	**3**	16%	100%	5%
RO	**28**		87%	21%
RS	5		100%	17%
SE	**0**	2%	100%	1%
SK	34		100%	64%

Note: red background indicates that national inventories on 31.08 are less than 80% full, yellow background indicates that national inventories on 31.08 are less than 90% full and more than 80% full; green background indicates that national inventories on 31.08 are more than 90% full.

Red bold figures indicate where national inventories increase compared to the baseline.

Source: ENTSOG, GSE, Eurostat

Model 6: Existing strategic storage and storage obligations are cancelled

We assume that this models leads to a fall of actual storage amounting to half the size of current obligations. In fact, it is not possible to properly estimate how much storage obligations increase total inventories rather than simply replacing (crowding out) commercial storages. We assume a 50% crowding effect in all countries. See Chapter 4 for more detail on this model.

The implementation of the "Tight" Model (Table 3.5) would impact on a limited number of Member States, as most of them already comply in fact with the model. If MSs were allowed to comply by siting storage in an interconnected country (as in the current Polish and Czech approach), the impact would be even lower. For example, Croatia, Poland, the UK and probably also Bulgaria could comply by booking storage in (respectively (Hungary, Germany, the Netherlands and Romania). On the contrary, it would be difficult for Spain and Portugal to comply, as they have limited geological resources (like depleted fields) and little interconnection (though increasing) with the rest of Europe. Yet the Iberian countries probably do not feel that much more storage is very useful for them given their supply model.

Table 3.6 SRSM Model 3 (Light Storage Obligations)

SRSM Model (3)				
Country	Stored gas on 31.8 as it would be applying light	Change compared to baseline (%)	Stored gas on 31.8 (% tot. Working capacity)	Stored gas on 31.8 (% consumption)
AT	48		56%	53%
BG	4		77%	15%
CZ	31		85%	35%
DK	10		93%	23%
FR	110		81%	23%
DE	216		94%	23%
HU	37		56%	38%
IT	167		96%	23%
PL	26		97%	14%
ES	24		57%	7%
UK	**52**	7%	100%	6%
BE	8		100%	4%
HR	5		83%	16%
IE	2	0.1%	100%	5%
LV	17		71%	115%
NL	90		99%	22%
PT	**3**	16%	100%	5%
RO	28		87%	21%
RS	5		100%	17%
SE	**0**	2%	100%	1%
SK	34		100%	64%

Note: red background indicates that national inventories on 31.08 are less than 80% full, yellow background indicates that national inventories on 31.08 are less than 90% full and more than 80% full; green background indicates that national inventories on 31.08 are more than 90% full.

Red bold figures indicate where national inventories increase compared to the baseline.

Source: ENTSOG, GSE, Eurostat

The "Light" Model (Table 3.6) would have similar, but much lower impacts as the previous one ("Tight" Storage obligations). Probably all MSs except Portugal could easily comply by booking storage in neighbouring countries. The impact of such policy would be very limited indeed.

The reader should also consider that, to some extent, mandatory storage would simply replace commercial ones. Section 4.2 below will discuss this issue in some detail.

Generalised strategic storage would have by far the strongest impact on European storage (Table 3.7). Only part of the obligation could be probably met by booking or investing in other MSs, but a substantial increase of capacity would be necessary anyway.

The "NO strategic" Model (Table 3.8) would have an impact on two MSs only, and release some storage capacity on the market. Any impact we have noticed here may be positive or negative.

The next Chapter is devoted to the assessment of all theidentified SRSM Models, which will be compared with the baseline under the emergency scenarios outlined in some of the ENTSOG's Stress Tests.

Table 3.7 SRSM Model 4 (Generalized Strategic Storage)

SRSM Model (4)				
Country	Stored gas on 31.8 as it would be implementing	Change compared to baseline (%)	Stored gas on 31.8 (% tot. Working capacity)	Stored gas on 31.8 (% consumption)
AT	54	13%	63%	60%
BG	7	47%	113%	22%
CZ	38	20%	103%	42%
DK	13	31%	122%	30%
FR	144	31%	105%	30%
DE	283	31%	123%	30%
HU	32	-15%	48%	32%
IT	171	2%	98%	23%
PL	38	48%	145%	21%
ES	48	97%	111%	14%
UK	107	123%	208%	13%
BE	22	176%	276%	11%
HR	7	43%	119%	23%
IE	6	141%	240%	12%
LV	18	6%	75%	122%
NL	118	32%	131%	29%
PT	6	175%	237%	11%
RO	38	33%	116%	28%
RS	7	41%	141%	24%
SE	1	1139%	1210%	8%
SK	38	11%	111%	71%

Table 3.8 SRSM Model 5 (Zero Strategic Storage)

SRSM Model (5)				
Country	Stored gas on 31.8 in - no existing strategic (TWh)	Change compared to baseline (%)	Stored gas on 31.8 (% tot. Working capacity)	Stored gas on 31.8 (% consumption)
AT	48		56%	53%
BG	4		77%	15%
CZ	31		85%	35%
DK	10		93%	23%
FR	110		81%	23%
DE	216		94%	23%
HU	**25**	-34%	37%	25%
IT	**119**	-29%	68%	16%
PL	26		97%	14%
ES	24		57%	7%
UK	48		93%	6%
BE	8		100%	4%
HR	5		83%	16%
IE	2		100%	5%
LV	17		71%	115%
NL	90		99%	22%
PT	2		86%	4%
RO	28		87%	21%
RS	5		100%	17%
SE	0		98%	1%
SK	34		100%	64%

Note: red background indicates that national inventories on 31.08 are less than 80% full, yellow background indicates that national inventories on 31.08 are less than 90% full and more than 80% full; green background indicates that national inventories on 31.08 are more than 90% full.
Blue bold figures indicate where national inventories decrease compared to the baseline.
Source: ENTSOG, GSE, Eurostat

4. IDENTIFICATION AND ASSESSMENT OF THE COSTS AND IMPACTS OF STORAGE RELATED SECURITY OF SUPPLY MEASURES UNDER COOPERATIVE OR NON-COOPERATIVE SCENARIOS

4.1 The assessment of the impact of measures: methodological introduction

In this Chapter, we try to assess:

- Whether Storage Related Security of Supply Measures (SRSMs) effectively increase gas inventories, or simply sanction gas storage that would be provided by market forces anyway;
- Whether an increase, generalisation, or reduction of existing SRSMs is cost effective.

We perform this analysis, respectively:

- By comparing actual gas holdings with storage obligations and strategic storage;
- By assessing the change in gas supply and storage costs that would arise under several disruption scenarios, if mandatory storage obligations were implemented.

The analysis test the hypothesis that larger gas inventories, triggered by SRSMs, may ease the impact of a disruption, as larger storage holdings can substitute gas bought earlier at lower prices, or (in the worst cases) reduce the resort to fuel switching or the need to reduce gas consumption. Moreover, as in any commodity market, availability of larger storages reduces gas prices in the short term, but increases them later as the storage sites must be refilled. We assess the net balance of these effects, looking at it in a neutral way. We are aware of, but do not consider in this analysis, that consumers and politicians or authorities that represent them, may be risk-averse, or afraid of spikes rather than on higher average prices.

The approach that has been chosen in this Study for the assessment of SRSMs is inspired by the very definition of Security of Supply (SoS). As recalled in many official publications, in Europe "we have come to expect secure energy supplies: uninterrupted access to energy sources at an affordable price".[109] This widely agreed definition shows the double dimension of secure supplies. They must be uninterrupted, but at the same time affordable. To same extent, measures aimed at enhancing SoS help both dimensions: for example a certain improvement of interconnections and/or storage for a market leads to both a probability of interruption reduction and to a more liquid and competitive market, fostering affordability. However, beyond a certain level, a trade-off may emerge: further reductions of the interruption probability may require costs like those related to enhanced supply infrastructure or storage. Such costs - even if affordable - may exceed the expected related benefits in terms of cheaper or more secure supplies. Therefore, it is understandable that Member States may have different attitudes towards such measures.

Differences may also arise from a different view of what "affordability" means. In some cases, a slight cost increase may be seen as acceptable, particularly where the risk of interruption is seen as high – for example, in markets featuring a limited diversity of suppliers and a high dependence on large ones. In these cases, affordability relates to the absolute cost level that must be born to increase the security of physical supply, and it is likely that small price increases, as necessary for example to boost storage or demand side measures, are happily accepted in return for

[109] This example is taken from "In-depth study of European Energy Security" Commission Staff Working Document accompanying the document "Communication from the Commission to the Council and the European Parliament: European energy security strategy, COM(2014) 330 final, p. 3, italics in the original.

more security. It can be said that in such cases, the "quantity" dimension of SoS prevails.

However, in other cases, physical SoS is already quite high, as may be witnessed by the N-1 index[110] or by other supply indicators. High diversity of suppliers, large endowment of more reliable sources (e.g. domestic production, imports from other EU countries or Norway, LNG, large storage capacity or good fuel-switching capabilities may all lead to the SoS issue to be perceived as a matter of affordability (high price) rather than of interruption risk (low quantity). This may even truer for countries with a high import dependence, where a price increase for end users is hardly[111] offset by producers' or suppliers' gains. In these cases, the "price" dimension of SoS dominates.

These rather different perspectives on SoS are possibly at the root of the very different attitudes towards SRSMs , found among EU Member States and analysed in Chapter 3 and related Annexes 3-13. For example, countries like France, Spain and the U.K. are all probably concerned with the price as well as with the quantity dimension of SoS[112]. However given their different resource endowments, they have chosen rather different policies.

- Spain has introduced some storage obligation, but its large LNG as well as pipeline imports from Algeria at partly oil-related prices may significantly protect it from gas price spikes. Hence, it has limited storage and light storage obligations.
- France also has a significant (and increasing) LNG capacity, but smaller than Spain. On the other hand it has a much larger storage capacity: this may explain why it can be reasonable to ensure that this capacity is actually used, as a buffer in case of disruptions and (even more) price spikes. Without such (rather strong) obligations, suppliers may prefer to reduce their stored gas, or to store it in locations that may be more suitable for a flexible use, as their geographically pivotal with respect to several markets[113].
- The United Kingdom is also rather well protected against physical disruptions but less so against price spikes, as its supplies are almost entirely hub-based. The U.K. has a large diversity of supply opportunities, including storage, domestic production, three pipeline import sources and four LNG terminals, and also (for the worse cases) good fuel switching opportunities[114]. However, even though it is a very well developed system, the decline of its own production causes remarkable SoS challenges, which are partly compensated by gas stored on the continent. Therefore, the country has taken the SoS issue seriously, but without imposing storage obligations. On the contrary, a market based approach has been preferred, allowing suppliers to seek the most cost-effective solution but also foreseeing sharp penalties in case of failure.

These are only a few examples of how a similar awareness of SoS risk - including its less explicitly discussed price dimension – is addressed in different ways by countries with different resource endowments. In shorter words, this shows once again that "no one size fits all", notably as storage obligations are concerned. Yet, this often reported sentence does not close the discussion. Before a concrete, quantitative analysis is

[110] As defined by Regulation 994/2010/EC, Article 6.

[111] Please notice that even a country importing all its supplies does not suffer only losses from a price increase, as some of its companies may be active in producing regions elsewhere and enjoy some windfall profit that could be taxed away by the State. Yet in such countries, this compensation is likely to be far smaller than the loss suffered by domestic consumers, so that it is often neglected.

[112] From the Prevention Action and Emergency Plans it is clear that they are concerned with both.

[113] In fact, storage in "central" locations like Austria, Czech Republic, Germany or Slovakia allows suppliers to more easily address disruption risks, as well as market opportunities, which may emerge in more "peripheral" markets, like France, Denmark, Italy, Hungary and the Balkans. This probably explains why the central countries have been more often chosen by market players as venues for storage sites, whereas the storage of peripheral countries appears more related to regulatory provisions. See next section for more on this topic.

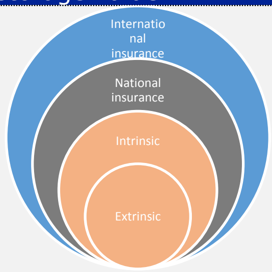
[114] See Annex 15 on power generation switching opportunities.

undertaken, let us outline some general theoretical issues, which may explain why, in a largely integrated gas market like Europe[115], storage decisions taken *individually* by (profit-driven) storage operators, as well as measures taken *individually* by (policy-driven) Member States are not necessarily optimal.

In general, as discussed in detail in *Section 1.3* above, gas market players (including integrated or independent storage operators) see the benefits accruing from "intrinsic" as well as "extrinsic" value of storage. However, they are not likely to fully address the *insurance value* of storage[116], either as a result of disruption or any other source of price spikes. A market based approach like the UK's (see *Chapter 3* and *Annex 13*) addresses only the risk of disruption, but it is not directly concerned with the impact of sustained price increases, which could be (as illustrated in detail below, see *Sub-Section 4.3.3*) the most likely consequences of the disruption for countries with good physical SoS records. In fact, gas suppliers' may be more concerned with being "not worse than competitors" rather than "optimal", and disregard common benefits.

On the other hand, government policies may be affected by consumers rather than suppliers (notably if the latter are based outside the country), and in any case are not likely to consider other countries' (including fellow EU Members') benefits. Some impact of storage improvements is also likely to benefit other countries' consumers, who may not pay for it. For all these reasons, decentralised policies may not yield optimal outcomes (market and /or institutional failure).

Figure 4.1. Components of the storage value



These problems are described in more detail In Annex 16, by means of a numerical example.

The actual outcome and efficiency of choices depends on a number of factual as well as behavioural assumptions. Among them, the following are critical:

- The size of the expected price spikes;
- Their expected probability;
- The market suppliers' attitude towards risk. In fact, they may well be risk averse and prefer the certain outcome of no supernormal profits – as it would happen under the no new storage investment and no SRSM option, provided that increased supply costs can be passed on to end consumers. This is likely unless retail price caps or (at least some) risk-loving players operate,
- The actual impact of more stored gas on market prices;

[115] This general analysis applies to the EU Member States, but broadly to other countries as well, like the Energy Community Contracting Parties, Switzerland and Norway.

[116] It is true that, as seen in section 1.4, official storage prices are often above seasonal spreads, so that at least some insurance value is at least partly considered by several market players. However, industry sources report that such storage costs are now widely seen as too large and regarded among the first items worth cutting, as the European gas and power industry struggles against declining demand and competition from coal and renewables.

- The policy makers' attitude towards price spikes, which is likely to consider consumers' more than suppliers' interests, and to fear the impacts on end user prices but understate suppliers' gains. This may be justified, as specific regulatory provisions may limit or postpone the impacts of price spikes on end users, but these are ultimately expected to bear most of the spike costs.;
- The availability of other, cheaper ways of addressing spikes, including financial hedging opportunities and long term contracts indexed to oil or other commodities.

It is particularly interesting in this Study to consider the risk that policy interventions may be avoided due to the spill over of some benefits towards other markets. As shown in the numerical example, failure to cooperate may well lead so inefficient policies unless a higher level coordination is achieved, or at least a process for benefit and cost trading [117] is implemented.

This outline of issues is purely theoretical and the numerical example of the Box only illustrative, yet they provide an idea of the type of assessment that will be attempted in the rest of this Chapter, by means of modelling exercises that will consider real market conditions.

Current SRSMs that have been outlined for sample EU Member States in Chapter 3 and related Annexes, like storage obligations and strategic stocks can be analysed under three main dimensions:

1. Whether the measures are effective, or their impact is offset by market players' behaviour;

2. What are the main expected benefits of the measures;

3. What are their main costs, both as direct costs and as distortions to market functioning.

The next Sections are devoted to discuss whether and how to analyse, and test, the effectiveness of SRSMs. The following Section will illustrate in some detail the methodology for the analysis of their costs and benefits. The final Sections will provide and comment results at respectively EU and National level (for selected countries).

To sum up, the main goal of this Chapter is to assess whether SRSMs are *necessary*, *effective* and *useful*. These conditions do not necessarily hold at the same time. For instance, there may be several reasons why markets may not deliver optimal security of supply, yet SRSMs are not necessarily the best solution, as they could be either ineffective (i.e. not achieve their goals) or inefficient (i.e. involve costs higher than their benefits). This section is particularly aimed at assessing the effectiveness of SRSMs.

Before addressing the issue of SRSM effectiveness, it is useful to recall the main arguments that back their introduction, and explain why they may be necessary. In general, as discussed in Section 1.3, market players wish to keep a certain amount of gas in storage for a number of reasons, including:

- as reserve to be able to satisfy customers in case of supply disruptions;
- as a cheaper way of supplying gas for peak periods (typically for the winter season).

[117] As in the co called Cross Border Cross Allocation for process for new transmission infrastructure foreseen by Regulation No 347/2013/EU.

These market opportunities combine with levels of storage required by SRSMs in various ways. Typically, SRSMs aim to ensure that storage inventories are kept even if market signals fail. In fact, SRSMs could simply "legalise" storage levels that suppliers would keep anyway.

In well-functioning market systems like those of North America, prices fluctuate to adjust to seasonal demand, leading to substantial winter-summer spreads that represent an effective market incentive to refill storages: in this way, markets can be very effective also in ensuring SoS.

In a fully market-oriented environment, winter-summer spreads are normally seen as the major market factor that drives gas inventories (*Section 1.3*). In particular, storage facilities with a relatively low deliverability rate (like most depleted fields and aquifers, which include over 70% of European capacity) are mostly driven by such spreads. In turn, high storage inventories (e.g. due to mild winters) depress spot gas prices, curbing price signals for storage replenishment, and the opposite occurs with low inventories[118].

On the other hand, the European market is less perfect than the North-American one. Its design is still affected by lack of harmonisation and reduced transparency on several key issues (e.g. transmission tariffs), as well as by some interoperability problems. Even in its most advanced regions (like the North-West), a small (though declining)[119] part of European supplies is still indexed to oil crude and derivatives, so that it follows oil's rather than natural gas' market logic, and this is still prevailing in Southern and Eastern Europe. In the past, when almost all gas supplies were oil-indexed and gas market competition was very limited, the problem was solved by stipulating a typical 6 month delay in gas prices with respect to oil market indices. Since oil prices tend to peak in the (Northern hemisphere) summer - due to the "driving season" and to power generation demand for air-conditioning - gas prices tended in turn to peak in the winter, maintaining some market incentive for storages[120].

The relevance of this short excursus on the evolution of the European gas markets shows how the problem of SoS may be evolving. Whereas in the past the greatest concern was on physical supply, now - at least in several countries with high import dependency - the concern could also be to protect consumers against market price fluctuations.

In addition to European wholesale prices being often still affected by oil indexation of long term contracts, another factor that may weaken the market incentive to refill European storages is that end user prices in several countries and market sectors (notably for households) are still subject to regulation. Given the generally good level of interconnection[121], such price distortions may indirectly affect even the most competitive and liquid markets, like Britain and the Netherlands. This issue is akin to the "missing money" problem often alleged for power generation markets, where operators are afraid of not being able to fully enjoy the fruits of price spikes, which are

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[118] However, this is not always true. High inventory levels may lead to lower prices for spot deliveries, but not necessarily for the next injection season. Thus, the relationship between hub prices and storage is not always that simple. For example, in the early months of 2014 the W-S spread increased, for after the mild 2013/14 winter storages were half full, which depressed price expectations for Summer 2014. Therefore expected price spreads for the next (2014-15) winter increased, which led to strongly refilling storages in Summer2014. See *Section 1.3* for more on this

[119] See J. Stern, H.-Rogers, *The Dynamics of a Liberalised European Gas Market. Key determinants of hub prices, and roles and risks of major players*, Oxford Institute of Energy Studies, December 2014, http://www.oxfordenergy.org. See in particular p. 18. The 2015 IGU Price Report estimates that gas to gas pricing rules currently cover 61% of the European gas market, which raises to 88% in North-West Europe. This means that in the resat of Europe oil indexation, which is estimated at 32% across all Europe, still prevails. See: http://www.igu.org.

[120] In any case, before market liberalisations storage was either regulated or tightly controlled by incumbent gas suppliers, so that political responsibility was often a more important decision criterion than price signals.

[121] European pipelines' increased viability has led to a substantial price alignment in Western Europe, which is now also significantly spreading to countries like Austria, the Czech Republic and Italy. *Ibidem*, p. 16.

important to recover capacity costs, due to regulatory intervention. This is at the root of the recent, but increasingly common request for capacity support schemes[122].

Whereas the lack of price incentives may put storage refilling at risk, it should be considered that in general suppliers - notably large ones - know that they must ensure high levels of SoS even if this may be against their short term interests. As Chapter 3 has shown, all Member States (and other non EU countries, see Chapter 2) envisage at least generic obligations to ensure supplies, notably for protected customers. Loss of sales revenue and risk of having to pay high damage compensations in case of failure often represent a sufficient threat for suppliers to minimise that risk. Moreover, major supply disruption would damage suppliers' reputation and bring about government measures, which could have even higher costs[123].

Yet in a competitive environment, governments often feel that these incentives may not be enough to provide adequate SoS levels, as documented in the case studies of *Annexes 3-13*. In particular, smaller suppliers and those based in other countries may follow market opportunities and be less sensitive to reputation risks, or speculate that SoS risk may be covered by others, notably market leaders.

This "free riding" risk is certainly a major reason for several governments to mandate gas storage (SRSMs) either in the form of minimum inventories and/or as strategic reserves[124].

The arguments in favour of SRSMs and those in favour of less coercive, more general obligations on suppliers to undertake appropriate actions to ensure SoS measures are well known. In this framework, it is worth mentioning the other points that are often raised in favour of more general obligations. Storage is not the only way of providing SoS: a thorough diversification of supplies, together with an adequate spare capacity of pipelines and (direct or indirect) access to LNG terminals may be also effective. Moreover, spare capacity of production, notably if domestic or in close and allied countries, may be an appropriate tool of both supply flexibility and security. Finally, demand side responses, like market based or incentivised interruptible supplies, may also play an important role in relieving security problems. Discussion of these other SoS options in detail is beyond the scope of this Report.

The case studies of Chapter 3 have shown the role of these alternative tools in a few Member States. Before we turn to the assessment of costs and benefits of SRSMs, this Chapter addresses the issue of SRSMs' effectiveness. In other words, whereas it is clear that light handed obligations and higher reliance on alternative tools may reduce both costs and reliability of Member States' SoS policy, we start from the theoretical and empirical analysis of the effectiveness of SRSMs.

4.2. The effectiveness of storage related security of supply measures

4.2.1 The crowding out effect in storage

The effectiveness of SRSMs is not related to the actual implementation of their legal provisions, even though it cannot be ruled out that violations may occur. In fact, Member States that have introduced SRSMs have also taken care to ensure their

[122] See European Commission, Consultation Paper on generation adequacy, capacity mechanisms and the internal market in electricity, 2012.

[123] This view is akin to the traditional position of most European SSOs, as reflected in GSE's discussion paper "Will strategic stocks increase security of supply?", March 2008, http://www.gie.eu/index.php/publications/gse

[124] As noted in the previous section, the same could happen among countries of an integrated market or region. Governments may feel that some of the policy benefits of SRSMs may spill over borders, and limit their cost-benefit calculation to the domestic market.

implementation by setting up checks and sanctions. For example, France checks storage levels by each gas suppliers twice a year. Since inventories are measured by a rather limited number of SSOs, checks are not too difficult. Italy experienced inappropriate use of inventories (as a sort of storage "smuggling") when some gas suppliers withdrew stored gas reserved for protected customers in order to generate profitable electricity for export in the autumn 2005. Later, the NRA inspected the case and fined several rule breakers. The real risk of ineffectiveness is a different one and is related to market opportunities and moral hazard rather than to unlawful behaviour. It is also known as "crowding out" of commercial storage, which could be (at least partly) replaced by mandatory one so that total stored gas does not increase, or increases less than expected by the SoS authorities.

Box. The Crowding Out of commercial by mandatory storage

The key issue of the effectiveness of SRSMs, in fact , is not the breach of legal obligations, rather, it is a perfectly lawful but practically adverse behaviour, which is known in the economic literature as crowding out effect. Originally, this term was used in macroeconomics in the 1970s, meaning the case where the private sector tended to reduce its own expenditure (notably investments) as a reaction to an increase of public expenditure aimed at stimulating economic activity, thereby partly or totally offsetting the impact of such policy[125]. The term has later been extended to other fields of public intervention, as different as education, health services, and charitable activities.

In the case of SRSMs, a similar effect may occur. As noticed, market players may have a preferred level of storage, which is related to a number of determining factors (gas prices, notably seasonal spreads; storage prices; availability of alternative flexibility tools; gas demand by sector; perceived risk of disruptions etc.). Let us define this preferred level S*(X), where X are the above mentioned explanatory factors of desired storage. Absent any storage obligations, this also coincides with the market-provided storage level S_m and the actual storage level S.

Let us now assume that, fearing that X may be such to yield a too low storage level that would reduce SoS, the Government requires market players to keep a minimum level of storage $\underline{S}$. The Government's desired level of inventories would then be:

$$S_g = S^*(X) + \underline{S}$$

which is higher than what market players would like to have.

The crowding out assumption holds that market players would simply reduce their "free" storage holdings, or "market storage" S_m, offsetting (and hence vanishing) the impact of the measures. In our notation, the actual storage level S that would occur would be:

$$S = S^*(X) = S_m + \underline{S} \qquad \underline{(1)}$$

Or

$$S_m = S^*(X) - \underline{S} \qquad (2)$$

In this way, the measures become ineffective, as the total stored gas would be the same as without the SRSMs. Moreover, checks of the measures and lack of incentives to substitute storage with other (potentially just as effective but less costly) SoS tools

[125] Macroeconomists have long discussed whether, how and when the crowding out effect occurs. See O. J. Blanchard (2008). "Crowding Out," The New Palgrave Dictionary of Economics, 2nd Edition. Abstract.

would lead to unnecessary cost increases.

In fact, the crowding out effect may be less than perfect, with market players reduced storage only partly offsetting that required by the SRSMs. As a rejoinder to the crowding out risk, governments may rely on the crowding out to be only partial, e.g. by setting the required storage level above their desired one.

In our notation, if governments expect crowding out to occur in a certain proportion h ($h<1$), so that:

$$S_m = S^* (X) - h \underline{S} \qquad (3)$$

it may simply raise the storage obligation $\underline{S}$ to a higher level so as to achieve its goal. However, it is far from clear how much crowding out can occur, as the crowding out ratio h may not be stable but it may itself depend on a number of market factors. Therefore, the tendency of the government may be just to increase storage obligations above market desirable levels:

$$\underline{S} > S^* (X)$$

So that all storage is subject to SRSMs and basically no free storage market is allowed. In this way, the government succeeds to achieve a higher level of storage:

$$S > S^* (X) - \underline{S}$$

Italy (section 3.5) can be seen as an example of such approach. In this way, the storage market has long been fully regulated in both prices and quantities[126]. The risks of such policy are not only its possible inefficiency, with storage level (and its related costs) far from the optimal level; but also that – as with any "forbidden" market – a "black" market may emerge, whereas storage users use it for other, more profitable purposes if that is cheaper than providing their own new capacity[127].

In practice, the storage crowding out can take two main different dimensions:

A "short term" dimension, we have just illustrated, where market players reduce (at least partially) their freely chosen inventories in return for the mandatory storage obligation. All these choices occur for a given (working gas and deliverability) existing storage capacity C, which is assumed to be above the desired and mandatory storage levels. In our notation this is the case described by equations (1) and (2) above, provided that enough capacity is available:

$$C > S$$

A "long term" dimension, where private market players do not develop storage capacity because (at least part of) their desired storage capacity is directly provided or mandated by the government, as is the case in Hungary and (again) Italy. The reasoning is similar:

$$C = C^* (Y) = C_m + \underline{C} \qquad (4)$$

Yet determinants of storage capacity (Y) are in fact rather different from those of current storage inventories. Any storage site, whatever the technology, requires

[126] Only recently rules were changed, allowing some capacity to be allocated by auctions.

[127] In the Italian case, some wholesale market players have reported to have purchased retail companies mostly because that entitled them to a share of storage capacity, which in Italy has been until recently almost entirely allocated to protected customers (households, small enterprises and public services) with a view to face emergency supply conditions. Since these conditions rarely occur, the capacity was then effectively used for commercial purposes, though taking the risk that gas could not be available in emergencies. Sanctioning of this behaviour, as for the Autumn 2005 events, has been the exception rather than the rule.

several years to develop (possibly between 3 and 10). The decision can only partly be based on seasonal spreads, even though a reduction of seasonal spreads for several years may well curb storage investment plans.

Researchers only know actual inventory levels S as well as those resulting from mandatory obligations $\underline{S}$. They do not know - but can possibly estimate - market players' desired storage S* (X). Basically, the test about the effectiveness of measures (and hence the lack or extent of crowding out effects) can be done by simulating the implementation of SRSMs of one country to another one with no (or lighter) measures, and comparing the results. The closer the former's storage levels to the actual ones in the latter country, the less effective are the SRSMs of the former country.

More thoroughly, this approach exploits the fact that storage obligations differ in Europe. Assuming that the structural behaviour of market players is similar across countries, which is reasonable given the substantially integrated and continental dimension of the gas market, we can assess whether storage obligations are effective, or (and to what extent) their provisions are eluded by crowding out effects. For example assume that country F (France) has storage obligations $\underline{SF^F}$ but country D (Germany) has none, or only general SoS obligations that do not specify storage holdings. Hence $\underline{SD}$ = 0.

To test whether SRSMs are effective in France, let us see what the market level of storage would be in France without the SRSMs. We estimate that this would the same as chosen in Germany, after allowing for the market differences among the countries. Let us call this level $\underline{SM^F}$. In other words, $\underline{SM^F}$ is the level of storage level that French suppliers would generate if they behaved like their German counterparts (i.e. without being subject to any SRSMs), albeit in a different market.

Likewise, we could also devise what level would be required if French SRSMs were applied (for example) in Germany. Let us call this level $\underline{SD^F}$. In other words, $\underline{SD^F}$ is the level of storage obligations that Germany would require if it applied the same SRSM principles that are enforced in France.

We could now build a matrix:

	France	**Germany**
Storage obligation by French model $\underline{SX^F}$	$\underline{SF^F}$	$\underline{SD^F}$
Actual total storage	S_F	$S_D = \underline{SM^D}$
Market decided storage by German pattern	SM^F	$\underline{SM^D}$

In practice, the difficulty of using this approach is related to the actual specification of SRSMs. For example, in the case of the French model, storage obligations at the beginning of the winter season are assumed to amount to 80% of "storage rights", which are in turn defined (for working gas) as a function of expected consumption of protected customers, specified for each meteorological district in relation to the customer profile and its expected climate (See *Annex 7* for details). Consumption patterns depend on a number of specific conditions, like climate, housing characteristics, role and features of industry and services etc. This could make the estimation of the requirements of the French SRSMs in another country (like Germany) extremely demanding.

Fortunately, the Minister's decree implementing France's storage obligations for winter 2014-15 also estimates the total amount of storage (as working gas and deliverability) that is necessary to fulfil the required measures. This amount (as working gas) is presumably roughly proportional to the total winter consumption, as most of it derives from consumption levels above the summer "baseload". It can be reasonably be assumed that the consumption of protected customers is close to the difference between winter and summer consumption rates.[128]

Using this assumption, we consider that the consumption of protected customers in France amounts to that of the winter months, which is provided by Eurostat. Using the 2008-2013 average of the October-April months, it amounts to 395.6 TWh. This can be compared to a storage obligation at the beginning of winter 2014-15, amounting to 86.6 TWh. Hence, the storage obligation amounts to 21.9% of estimated Oct-April consumption (2008-13 average).

This criterion can now be applied (as an example) to Germany. We assume that the application of a French model of SRSMs in Germany would require 21.9% of the average October-April consumption of that country.

Conversely, the actual storage inventories in Germany could be "adapted" by rescaling them in relation to the presumed consumption of protected customers, estimated as the consumption in excess of the summer "baseload". This holds the SM_F reported in the third line of the following matrix.

Using now average (2010-14) storage inventories as of 31 October as an estimate of total inventories (S) for both countries, we can fill the matrix:

(TWh)	**France**	**Germany**
Storage obligation by French model $\underline{SX}^F$	$\underline{SF}^F = 86.6$	$\underline{SD}^F = 149.4$
Actual total storage	$S_F = 124.6$	$S_D = 229.9$
Market decided storage by German pattern	$SM_F = 133.2$	$SM_D = 229.9$

It is estimated that gas stored in France (using the 2010-2013 filling rate multiplied by the latest space capacity[129]) falls short of Germany's by nearly 6.5% (124.6 vs. 133.2 TWh), if adjusted for the estimated consumption of protected customers.

On the other hand (symmetrically), actual German inventories exceed those which would be generated by a French style SRSMs, by about 53.9% (229.9 vs. 149.4 TWh)..

Hence, French SRSMs in France probably crowd out at least some commercial storage, which would occur anyway.A measure of the crowding out effect could be the ratio between mandatory storage (86.6 TWh) and actual one (124.6) or about 70%. Only if the SRSMs required storage in line or above the estimated market level, we could be sure that SRSMs are effective instead of merely displacing (or sanctioning) a market behaviour that would occur anyway.

In the specific case, it is worth noting that SRSMs have actually been tightened recently, possibly with a view to make them more effective or aimed at permanently increasing gas inventories. Rather, France is willing to ensure a minimum filling level, so that SRSMs become really effective in case markets for some reasons do not adequately Therefore, we can conclude that SRSMs may be partly offset by market

[128] Of course, this is just a preliminary estimation: some consumption of protected customers occurs in summer too, whereas some consumption of non-protected customers also features a winter peak. However experience of the researchers with Italian data show that these mistakes are minor.

[129] The approach of referring to replenishment rates or "%FULL" rather than the reported actual inventory level is recommended by GSE, which is responsible for storage data used in this Project (see *Annex 2*). To compare actual inventories across countries we multiply these filling rates by the latest capacity (DTMTS). For all conversions, the ratio of 11.5 kWh/cm (GCV) is used.

players' behaviour, which would reduce their holdings if they prefer a lower total storage level. The only case where SRSMs certainly increase total storage holdings is when their amount is actually of a similar size as total storage. This does not seem the case In France. Another proof of this SRSM (at least partial) effectiveness has been the increase of storage holdings that has followed the increase of obligations , as was the case between 2013 and 2014.

The exercise could be repeated for a few other countries, comparing those with and without SRSMs. It seems reasonable to try it for countries in a similar situation. Therefore, we compare Germany with France, Italy and Spain, all of which are highly import dependent countries with multiple supply sources and limited excess capacity for transit. Likewise, similar comparisons are performed between Austria, on one side and Poland, Hungary and Bulgaria on the other[130], all of which are smaller local markets with limited diversity of supplies, where transit is very important. On the other hand, none of these countries should be compared with the U.K. or the Netherlands, as both are very important producers with some significant spare capacity, and hence more limited storage capacity requirements.

This approach is simple, but based on rather strong assumptions, namely that the behaviour of suppliers in purchasing gas storage in different countries should be the same. This needs not be the case. Building on the example we have considered, main gas flows in Europe are East to West, and some gas normally flows from Germany towards France. It may well be the case that some suppliers prefer to keep at least part of their inventories in Germany, with a view to supply the French market as well, rather than in France itself. This is a common problem with comparative studies among EU Member States, which may fail to consider that the market is actually integrated so that market players' decisions no longer stop at national borders. In the specific case, supplier's choices are probably affected by the lack of reverse flow from France to Germany (due to odorisation problems)[131], which may also explain why German storage sites are preferred to French ones.

Tables 4.2.1 compares Storage obligations (including strategic storage), as % of total consumption, with maximum working gas in storage as percentage of total winter (October-April) consumption[132]. It seems that SRSMs are at least partly effective in almost all countries, as storage actually exceeds minimum levels. However, it is also clear that countries like Austria and Germany have higher storage use than others in spite of not having any quantitative mandatory SRSM. Another interpretation (not at odds with the previous one) is that in several cases SRSMs are just a minimum requirement for emergency cases but are not actually aimed at boosting storage capacity.

The Table shows that the relationship between SRSM is weak. There are market (as well as technical and geological) reasons that explain how much and where storage is located. If policy makers wish to keep only minimum inventories they may well be successful, but if the goal is to actually increase total stored gas (in view of its insurance value) this can hardly be achieved at national level. Since transmission capacity is widely available and markets as well as gas suppliers are increasingly integrated on a European basis, they tend to locate storage in the most suitable place.

It is likely that, if policy makers wish to increase total storage capacity and /or its filling rates (rather than just ensure minimum levels) they should consider such market integration. Otherwise, market players may simply substitute commercial storage with mandatory ones, and book and /or expand capacity where they find it most appropriate.

[130] Czech data are missing
[131131] This could be solved if the reverse flow project for the TENP pipeline is carried out.
[132] Since the 7Fields and Haidach facilities in Austria are connected to and almost entirely serving the German (NCG) market, thet are included here in Germany and subtracted from Austria.

Table 4.2.1. Relations between mandatory and actual storage and gas consumption (average of 2009-13)					
Member State	**Actual Storage/ Winter consumption**	**Actual Storage/ Annual consumption**	**Mandatory Storage/ Annual consumption**	**Average Transmission Tariff for Storage**	**Average Storage Official WG price[133]**
Austria	97.2%	73.0%	0.0%	0.88	4.86
Bulgaria	26.6%	18.8%	8.8%	0.56	1.45
Czech Republic	51.4%	40.9%	2.6%	NA	NA
Denmark	29.4%	21.3%	5.3%	0.00	4.70
France	34.4%	27.5%	18.0%	0.46	6.47
Germany	36.3%	26.1%	0.0%	0.69	8.89
Hungary	70.3%	54.7%	23.8%	0.86	4.61
Italy	29.4%	20.8%	6.5%	1.21	1.28
Poland	23.1%	16.2%	5.2%	0.34	11.80
Spain	17.5%	10.9%	5.4%	0.00	4.93
United Kingdom	7.5%	5.3%	0.0%	0.30	5.08

4.2.2 On the determinants of storage geographical distribution

This project has tried to analyse by quantitative statistical methods the role of the main determinants of storage capacity and its filling rates, considering and trying to measure the impact of several factors that may explain their location as the evolution of filling rates. Unfortunately, there are many interacting factors to be considered and dataset limitations lead to scant results (see Annex 17 for details).

- Among the potential driving factors of storage capacity we should consider:
- availability of suitable geological sites;
- location with respect to consuming markets: in particular, central location with respect to the European markets, as can be found especially in countries like Germany, Austria, Czech Republic or Slovakia, from where several markets to the North, West and South can be quickly reached if necessary[134];
- transmission tariffs for storage sites;
- the role of residential and other small customers, which require the largest seasonal swings;
- the role of power and steam generation, which could to some extent switch[135] to other fuels and represent therefore a suitable alternative to strategy for flexibility as well as SoS purposes;
- the distance from major production areas, which represent an alternative to storage in providing flexibility resources;

All of these factors play a role alongside that of policy measures in explaining how storage is located across Europe. Moreover, as seen in section 1.3, other factors

[133] The reader is referred to section 1.4 above for a discussion of storage prices. The displayed prices are not probably currently paid but may provide a more appropriate approximation of storage costs, which are relevant for the current analysis.
[134] For example, Russian suppliers have been keen on purchasing and/or booking storage capacity in Germany and Austria, with a view to improve security of their supply in case of disruption of their transit routes.
[135] See *Annex 15* for more on power generation fuel switching opportunities.

(notably seasonal gas price spreads) also contribute to explain the different filling rates of existing capacity among countries and operators, and in the long term may also affect capacity expansion.

As for the role of costs and market prices (discussed in section 1.4 above, see also above Table), it is probably rather uncertain. Historical and official posted (mostly available and known) are certainly heavily affected by regulatory regimes and past limited unbundling. These prices are probably more cost reflective than currently depressed market prices, which are sometimes published after auctions but are often confidential. Low prices may stimulate and attract market players to certain facilities, but location is probably more important than price in many cases. Historical prices may also include a premium for sites with a central location, like German and Austrian ones

As noticed, the large number of driving factors and dataset limitations hamper a quantitative estimation of their relative role. Limited results (presented in *Annex 17*) confirm that storage capacity, which is largely an historical legacy, is definitely related to the type of consumption (residential, industrial, or power generation) and to the local availability of production. However, this is of no great help in the definition of storage SoS policies.

The following Figures provide (for selected countries) a partial analysis of the relationship between storage capacity and transmission tariffs for storage (Figure 4.1.1) and official storage prices (Figure 4.1.2). There are no clear relationships, showing once more the complexity of the storage market determinants.

The main lesson of this section is probably the fact that storage is complex, largely competitive and integrated market, where any policy measure may have only limited effects. This is particularly true for SRSMs, as market players may find it more efficient to locate or book storage in other countries, or simply reduce their commercial inventories if forced to maintain mandatory ones.

On the other hand, national authorities may be discouraged to promote further measures, as they may seem them actually bypassed or, if implemented, they may see benefits spill over borders, with domestic c customers paying for benefits partly appropriated by those of other countries.

For both reasons, it seems that a strong coordination, and possibly common decision, about SRSM should be pursued at regional or European rather than national basis. If national authorities prefer to establish national measures anyway, they should at least foresee the possibility to implement the measures by means of resources located in other countries, which may be less costly and a preferred market choice anyway. A few EU Member states already foresee this possibility under certain conditions, e.g. Poland, the Czech Republic. Collaboration between Slovenia and Austria is another example.

All of these considerations considered whether and how any SRSMs can be effective in boosting gas inventories. It does not however assess whether such storage related measures are an efficient way of providing more security of supply. In other word, we have not discussed yet whether the benefits of SRSMs outweigh their costs. This is the scope of the next sections.

Figure 4.1.1 Transmission tariffs for storage vs. WG capacity

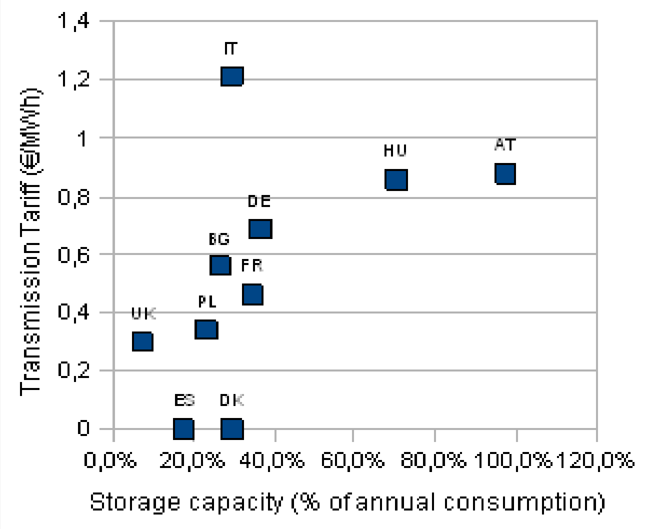
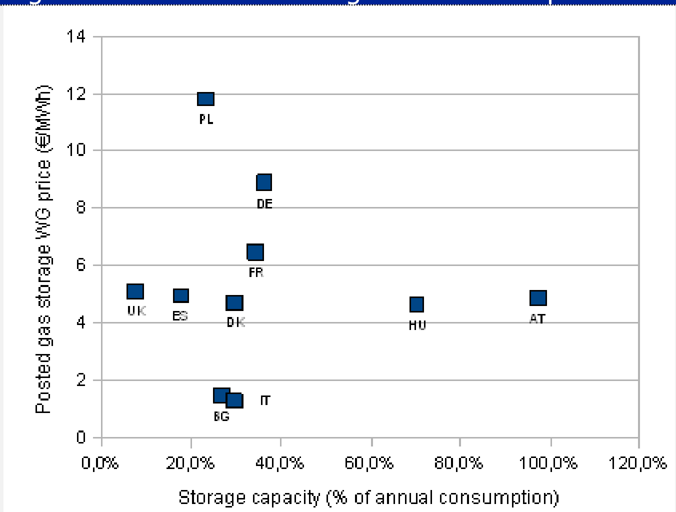


Figure 4.1.2 Official storage WG related prices vs. WG capacity



4.3 Methodology for the assessment of costs and benefits of storage related security of supply measures

4.3.1 General approach

The main benefits of SRSMs in case of supply disruptions consist of the larger availability of stored gas, which reduces the adverse effects of the outage. Hence, the benefits to be estimated actually amount to avoided costs of alternative measures used to replace missing gas in case of supply disruptions. Such alternatives include in principle:

- Increased domestic production;
- Further pipelines supplies from existing and active sources;
- LNG deliveries;
- Interruption of customers if allowed by their contracts,
- Incentivised interruption of customers with non-interruptible (firm) contracts;

- Decrease in gas demand by means of fuel-switching;
- Forced load shedding (interruption) of other customers.

The (related) problems to be solved are: which of these solutions should be chosen, and how to evaluate their costs. These will be discussed in subsection 4.3.2 and 4.3.3. Another potential benefit is related to the effect that a larger availability of stored gas has on reducing gas spot prices' volatility, which will be discussed in subsection 4.3.4.

These avoided costs will then be compared with the costs of providing more storage. This is easier in principle but includes some critical issues, which will be discussed in subsection 4.3.4.

Before illustrating in detail how these costs are estimated, let us briefly recall other possible impacts of SRSMs, often mentioned as market distortions[136], and see how these are related to our analysis. Other adverse effect of SRSM on the market may include:

1. storage obligation may be a barrier to entry of new players as they are costly;

2. storage obligations may damage players having other flexibility sources in their portfolio;

3. SRSMs depress incentive to have commercial storage, as more gas is taken out from storage in the winter and these depress winter prices and in turn this depress W/S spread and incentive to fill storage.

As for point 1, it seems that the costs of SRSMs are in general limited and not such to represent a serious barrier to entry. For example, the cost of the Italian mandatory strategic storage amount to about 0.1 €/MWh or less than 0.5% of average wholesale prices. In relation to the stored amount, the cost is 4.26 €/MWh in Hungary and 1.42 €/MWh in Italy. In both cases the (regulated) price is not very far from the official prices of storages in the countries and in line with official prices in Europe. It is therefore reasonable to think that strategic storage would have costs broadly in line with those of commercial storages.

As for the point 2, these are correct in principle, but can hardly overcome a positive benefit-cost test. However, our Study focuses on SRSMs only and does not therefore analyse other flexibility and SoS tools, which may indeed be more cost effective than storage. This suggests to use wider policy instruments that allow for a broader choice among SoS tools (see the Conclusions).

Point 3 is basically related to the crowding out problem, discussed in section 4.2 above.

ENTSOG has developed a model of European gas networks that allows for adjustment of gas flows in case one or more sources are reduced or are entirely unavailable. This model has been used for the analysis of the Stress Tests underpinning the EC Communication of 16.10.2014 on the short term resilience of the European Gas system[137].

The ENTSOG model has pros and cons. On the positive side:

- the model is able to consider network constraints and capacities so that a technically feasible alternative flow pattern is generated;

[136] See e.g. CEER Final Vision on Regulatory Arrangements for the Gas Storage Market, May 2015, www.energy-regulators.eu, p.13.
[137] COM (2014) 654 final 16.10.2014.

- the model can compare a cooperative scenario, where gas is allowed to flow across borders, with a non-cooperative scenario where gas entering a Member State is not allowed to flow into others unless all demand of the MS is fully satisfied. Hence this model allows estimating the benefits of EU-wide cooperation vis-à-vis a major supply disruption.
- On the other hand, the ENTSOG model:
- does not allocate flows to available sources by an economic merit order, but uses different criteria: in particular, it tries to split loads fairly among available sources, with a partial preference for closer ones;
- only considers alternative natural gas sources, including LNG, but does not provide any information about how gas deficits may be dealt with, e.g. by interrupting end users, requiring those who can to switch fuels, or cut their consumption altogether,
- is limited to quantities and does not include any cost assessment.

These features make the ENTSOG model an excellent tool to assess how a major supply emergency can be addressed (or “cured”). On the other hand, it is less adequate to examine the costs and benefits of any policy aimed at “preventing” the emergency, as is the case of SRSMs, for it does not pursue an inefficient choice of alternatives, and does not evaluate the costs of the various measures and alternatives.

Thus:

- in this Study the ENTSOG model results are used to assess how much different sources of gas (increased domestic production, LNG deliveries, storage flows, increase in pipeline import) will be called upon to face the above outlined emergency scenarios. This choice allows to consider technically consistent and viable solutions to the disruption, under several relevant crisis scenarios;
- a merit order of alternatives (both gas and non-gas) is defined, as outlined in the next sub-section, with costs associated to each of them;
- estimated costs of the alternatives resulting from the ENTSOG model under different scenarios are calculated;
- the benefits of SRSMs fostering higher storage levels are outlined, benefits are assumed to be captured by the reduced resort to alternatives allowed by the larger inventories, starting from the most expensive one, which normally is gas deficit, followed by additional LNG imports.

4.3.2 Costs of replacing missing gas

The cost of each alternative tool to storage for the replacement of missing gas volumes in the event of a supply disruption is discussed below.

Production

The ENTSOG study suggests that, even in the extreme case of a six-month disruption of all Russian supplies, the role of production increases is very limited (about 4% of missing gas). Its cost is normally the lowest of all alternatives, even though their opportunity costs could be seen as not so low, as the resource is limited. In any case, any disruption would results in increase of the (albeit limited) domestic production effort. Therefore, this component is not likely to change if SRSMs were enforced or modified, and its valuation is probably almost irrelevant with respect to different SRSMs models.

For the sake of completeness, increased domestic production will be valued at the marginal cost of gas supplies from other (pipeline or LNG) sources, with a view to consider its opportunity value[138].

Pipeline gas

In ENTSOG's estimates, pipeline gas plays an important role, mostly through increased imports from Norway and (and to a lower extent) Algeria.

In most cases, suppliers can rely on long term contracts that cover almost all technical import capacity from these countries. In the case of Norway, it could be also presumed that further supplies in an emergency would not cost more than usual, even though these exceeded contracted supplies[139]. For these reasons, we assume that this excess pipeline gas would be priced with the same criteria as the current one.

However, these criteria are not the same for all contracts, and are not disclosed. Since actual contracts are confidential, we must resort to estimates of their costs. In the case of Algeria, almost all term supplies are reported to be indexed to oil crude and derivatives. We assume that the disruption does not affect the oil price, hence the price of these supplies is estimated at the average 2014 level, as derived from the Eurostat COMEX database or from estimates provided by specialised magazines (World Gas Intelligence, Platt's International Gas Report).

On the other hand, Norwegian supplies have mixed indexations, with more hub related prices in the North West Europe (where most Norwegian gas is sold) and a mixed status in the rest of Europe. We try to use the best known estimates of indexation, which for Norwegian gas is probably in line with the European average. It is likely that most Norwegian gas is indexed to hub prices, whereas the remaining part will be priced after the best estimates of current contracts, notably for gas delivered to less liquid markets. In any case, estimates provided by specialised magazines and the COMEX database should already consider this fact.

The accuracy of these assumptions must consider that increased Norwegian supplies play a limited role in emergencies: ENTSOG's estimation for the worst case estimates that Norway can cover about 8% of missing Russian supplies, whereas Algeria can cover 2%. Libya is not seen as able to provide further reliable supplies in the current situation.

Annex 14 illustrates in detail the assumptions on which the Study is based.

LNG supply

According to ENTSOG's model, LNG is the largest contributor to SoS, providing over 35% of replacement gas in the worst disruption scenarios. Hence, its valuation is particularly critical.

Part of the replacement LNG supplies may be supported by existing long term contracts, which in recent years have not been widely used. Higher prices in East Asia and Latin America and the European demand slump have attracted most of LNG outside Europe (see Figure 4.3.1, item "Others"), with suppliers and purchasers sharing the benefits wherever deliveries were tied by long term contracts. Whereas some long term contracts may have expired, and more could in the environments of an increasingly flexible LNG market, we assume LNG directed to Southern Europe and Poland is priced at oil-indexed prices, and that the remaining share is imported on a spot basis and hub-indexed.

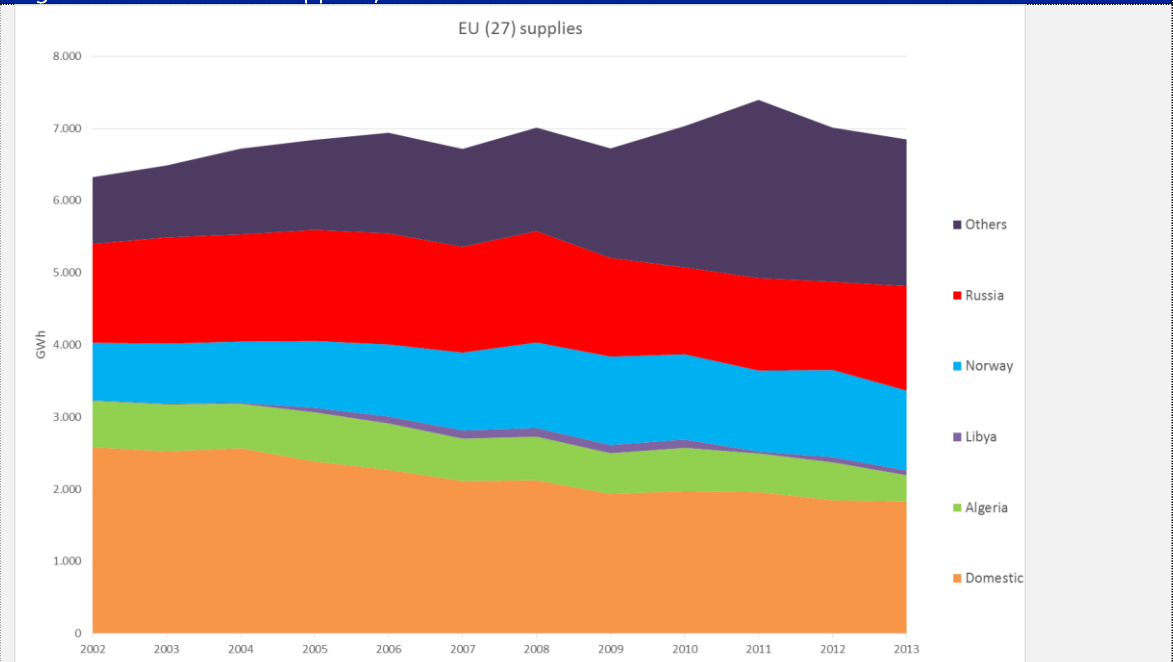
[138] In energy economics, this is also known as *user cost*, representing the cost of using an exhaustible resource.
[139] In the post-Fukushima emergency, Qatar awarded a similar treatment to its Japanese customers, at least for some time.

Spot LNG prices are derived from the model of gas hub price (*Section 4.3.3*) considering that any spot LNG should in any case be competitive in European markets. However, models of the European gas market may not be able to adequately catch the impact of large shocks, like the Fukushima accident and the ensuing closure of all Japanese nuclear capacity.

Fuel switching

Once all chances of replacing missing natural gas supplies have been tapped, consuming countries must resort to other solutions. The most obvious one amounts to fuel switching, which could be induced by price increases, regulatory incentives or by non-market measures like mandatory resort to other energy sources. In some cases (like Finland) almost all gas supplies can be replaced by other sources.

Figure 4.3.1 Main EU supplies, 2002-2013



The estimation of practical possibilities of fuel switching is not easy.

1. Price induced gas demand reductions are likely, but not easily estimated. In several cases, gas demand reduction may simply result in an increase of electricity demand, as consumers try to use electricity to satisfy their needs. In turns this may exacerbate the gas shortage unless the power generation system is substantially independent of gas. This is analysed in detail further on (see also Annex 15);

2. Availability of interruptible supplies, particularly by industrial customers, is common, but its role is usually limited and not well known, due to contractual confidentiality. This option is not valid in most countries as the daily balancing system and the most consumer energy systems cannot support fuel switching options anymore. Fuel switching options where historically used for peak shaving of supply contracts, but, after unbundling, commercial demand management options are located to the suppliers, but the value for fuel

switching in for SoS purposes is known to the TSOs, who have mostly no instruments to purchase such option[140].

3. The simplest and most obvious fuel substitution occurs in the power sector. Whereas most oil-fired generation capacity is no longer operational, several Member States can probably restore a significant contribution from older stations, particularly in the case of longer gas supply disruptions. On the other hand, the current status of coal and carbon prices would make it implausible that a significant capacity of such generation sources could be available – if it was, it would be already dispatched. This holds *a fortiori* for nuclear, hydro and other renewable energy

4. Moreover, a prolonged gas supply disruption threatening protected customers would also lead to an increase of electricity demand, as some heating market demand normally covered by gas could switch to electricity.

In fact, the cost of coal fired-generation is often lower than that of gas fired plants; however, it is often limited on environmental grounds. A similar problem may arise also with oil-fired generation.

Our models do not allow to fully consider the impact of such restrictions. Moreover, it is likely that in case of severe gas supply crises, such restrictions would be often lifted. Related higher costs would then fall on the environment and indirectly on populations, as *external costs*.

Advanced societies including Europe have undertaken studies to estimate such external costs. The following Table 4.3.1 shows some estimates.

For our simulations, we have used the cost of replacing natural gas by oil (actually: light fuel oil, LFO) or coal as:

$LFOg = (P_{LFO} + EXT_{LFO} - EXT_{NG})/EFF_{LFO} * EFF_{NG}$

Where

LFOg is the price of LFO equivalent gas, corrected by the external cost differential. EXT_i and EFF_i are respectively the external costs and transformation efficiency of fuel *i*.

i = LFO, NG (natural gas)

P_{LFO} is the market price of LFO, as average of the last 15 years.

We use the mean point of the EEA external cost estimate and assume that all missing gas can be replaced by LFO. The average net cost of (LFOg) is therefore estimated at 87 €/MWh equivalent.

A similar calculation can be performed for coal. The calculation yields an average equivalent cost of between 97 and 101 €/MWh, with some limited seasonal fluctuations.

[140] E.g. German regulation offers a discount of 5% on grid tariffs for interruptible transmission if a customer offers fuel switching capacities by to a grid company. This is too small, against the cost of such an option for the industrial customer. A cost reduction of 30-50% grid fees would cover the costs for such assets.

Table 4.3.1. External cost estimates for power generation by fuel[141]					
	USA ($c/kWh)			EU (€c/kWh)	
	Non-Carbon	Carbon	Total	Min	Max
Coal	3.4	1.9	5.3	8	26
Oil				7	22
Natural gas	0.2	0.8	1	2	4
	Source: MIT			Source: European Environmental Agency	

Annex 14 provides details of the assumptions and data about the replacement options in Europe and about generation efficiency. However, since ENTSOG's models do not allow to estimate how much of the gas deficit is covered by switching to fuel oil (either directly in end use or in power generation) or by load shedding, we use the conservative assumption than any deficit is covered by LFO.

Load shedding

Although in most cases interruption of protected and other firm customers is a last resort option, this cannot be excluded, particularly in a few Member States with limited supply diversity and under non-cooperative scenarios. Unfortunately, estimates of the value of lost load (VOLL) for gas are scant. There are a few valuations for the U.K. and possibly also for Italy. There are several solutions:

(a) Use of the existing values estimated for the U.K., possibly adjusted in relation to the average purchasing power (or per capita income) of each country. Outcomes of this approach also depend on the climate, as these estimates are related to the willingness to pay for a "heated home" rather than for the energy required to achieve it. Results would span between 200 and 700 €/MWh, including the very high cost of restoring supplies after outing. The best estimate suggested in the UK study is about 600 €/MWh

(b) A floor estimation of the value of (willingness to pay for) gas is given by its end user prices. This is much higher than the wholesale price of gas itself, as it includes also transmission, distribution and retailers' margins. Since the costs of these operators are (almost entirely) not cancelled by the lack of gas, the end user price may represent a reasonable valuation of outages. It would be around 55 €/MWh (European average, according to Eurostat)

(c) Finally, using the "defensive expenditure" approach of cost benefit analysis, the value of gas could be estimated by the value of alternative energy sources even for smaller customers, with a view to considering in particular their typical uses, which are mostly rather standardised. Space and sanitary water heating as well as cooking represent a large share of gas consumption by households, public premises and SMEs, and their valuation can be taken by considering the cost of attaining them by other sources like electricity or LPG, as it happens anyway in areas that are not connected to natural gas grids. This approach would yield prices between 100-300 €/MWh depending on the chosen product and country. Yet this approach is only a minimum and likely underestimated, as it is rarely possible to actually replace pipeline gas supplies by LNG or other gases on a sustained basis and for large amounts.

[141] European Environmental Agency, EN35 External costs of electricity production. M. Greenstone, A. Looney, « Paying too much for energy ? The true cost of our energy choices », Massachusetts Institute of Technology, Department of Economics, Working Paper 12-05 (2012).

The most reliable and accurate valuation seems to be found in the UK study. For any valuation of disruptions at national level, we have adapted this value by attributing it to the value of a "warm house", which requires different amounts of gas in each country. Moreover, the evaluation is adjusted in proportion to per capita income and average household consumption of each country.

4.3.3 The price of gas at hubs

A most likely impact of a supply disruption affecting Europe would be an increase of hub prices. It is estimated that such prices currently affect over 50% of EU supplies, and possibly more for supplies that are not affected by the most feared interruptions. For example, excluding Russian supplies, the share of EU hub priced supplies could be as high as 70%.

Since the average of European Union imported gas in the last five years was 72%, the costs of the disruption would weigh on nearly half of EU gas supplies, net of benefits obtained by European producers. Thus, this is a major source of costs, and a potentially significant benefit of having more storage. Whereas LNG prices could be modelled separately, it is clear that a gas price increase at hubs would also significantly affect the LNG market, particularly if a major shock occurred in Europe - just as the Fukushima events and the entailed closure of all nuclear power generation in Japan led to a sharp increase of LNG prices in East Asia. In the past, limited flexibility of LNG supplies - mostly still tied by long term contracts - and inadequate shipping capacity prevented a full integration of the world LNG market, triggering localised spikes that attract all free supplies. The current LNG glut and expected supply capacity increase in the next two years (notably in Australia and U.S.) have led to a much greater price convergence than in the past. In case of world gas demand recovery and major disruptions like those entailed by the Katrina and Fukushima events, but market swings could restore price differences between hubs, as global shipping capacity has not lately increased more than consumption.

To analyse the impact of storage on prices, we can use the GASP (Gas price) model, developed by REF-E since 2010 as a forecasting tool for the young Italian gas market. It is in fact an adaptation of a model suggested by Brown and Yücel[142] for the analysis of prices in the much more mature US market. Yet the model has been found capable of understanding the Italian market as well, and has been used for short term forecasting. Later as European hubs convergence has improved, the model has been successfully extended to the main European continental market, the Dutch TTF.

The basic idea of the model is simple. Considering that some substitution of gas with fuel oil exists, and that the oil market is far larger and more liquid than the gas market, the main driver of the gas price is still deemed to be the oil price. This is true in North America, and even truer in Europe, as contract indexation to oil crude and derivatives still characterises many long term contracts.

On the other hand, the gas price at hubs has become rather independent of oil in the short term, with gaps explained by:

- Short term demand shocks, mostly consisting of exceptionally high or low winter temperatures, which particularly affect gas demand by households and the commercial sector
- Indicators of economic activity, which affect industrial and power generation demand

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[142] S.P. Brown and M.K. Yücel "What Drives Natural Gas Prices?", *Energy Journal*, 2008, Vol. 2.

- Indicators of inventory level: these tend to depend on the recent history of demand, and are in a sense a stock of recent accumulated short term factors like weather and economic activity. Inventories are a major driver of short term price evolution in many sectors, notably for commodities, not only in energy but also in other minerals and agriculture products. Note that what matters is usually the difference between the current and the expected/past level, rather than the absolute value.

In this Study, the model for the gas hub price has been estimated in the monthly levels of historical variables for the period January 2008 - January 2015. The one month lagged endogenous variable is included. The specification is linear in the levels. The dependent variable is the TTF spot price.

In GASP, a satellite model estimates prices of the Italian market (PSV), which have been largely independent and poorly converging with other European hubs in this period. Similar models could be added to allow for different behaviours of other markets like NBP, PEGN, PEGS, Austrian CEGH and others. However, given the very tight correlation of prices, we have not further implemented this possibility. Instead, we are considering the (small) differences among prices for hub-related supplies (Annex 3) and those of TTF.

The TTF model estimated for this Study includes the following variables:

Variable	**Specification (Unit)**	**Source**
TTF Day Ahead Prices	Monthly average of daily quotes (€/MWh)	Platts
Brent price (lagged 3 months)	Monthly average of daily quotes, in $/bbl, converted at ECB exchange rates and a conversion factor of 7.4 bbl/TOE (€/MT)	Platts, ECB
Ukraine January 2009 crisis	Dummy variable	
12th differences of German storage filling level	Monthly average of daily storage filling levels in the NCG and Gaspool market zones (mcm), the series is corrected for a structural break in May 2009	Gas Storage Europe
Average degree days	Monthly average of heating degree days for the following market zones: NBP, TTF, NCG, Gaspool, PEGN, PEGS, Baumgarten, Zeebrugge; weighted by gas consumption	http://www7.ncdc.noaa.gov/CDO/cdo

To assess the relevance of such estimations, the reader should consider that what matters for the assessment of SRSMs is the variation of prices, as triggered by higher or lower storage endowments, rather than their actual level. Forecasting accuracy is less important for the objectives of this Study.

The impact of a disruption of Russian supplies on TTF - and hence on other hubs and hub-related gas prices in Europe - is a major one. It would nearly double the price, although the pattern would be progressive and swiftly cease as the disruption terminates. This is consistent with the IEA estimate[143] that a major Russian supply disruption would increase LNG prices by about 100%. Figure 4.3.2 shows the prices that would be triggered by a 6-month Russian disruption as described in the Stress

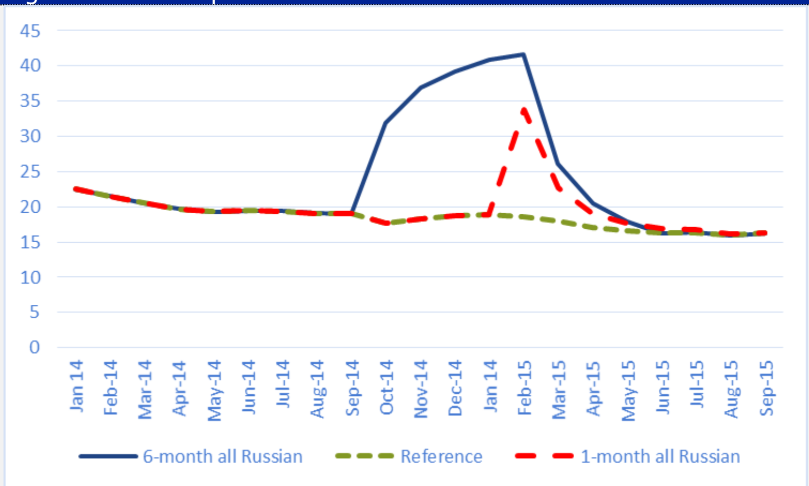
[143] Quoted in the Stress Test Communication (COM(2014) 654 final, p.12), without further details.

tests and fictitiously located in an hypothetical 2014-15 winter, lasting from September until February, with a cold spell affecting half of February; as well as TTF prices estimated for a disruption limited to February, including the cold spell, under the same assumptions about climate and dollar prices. The reference scenario (without disruptions) is also showed.

We assume that oil prices would not be seriously affected by the disruption, and have preferred to use average oil prices rather than those actually occurring in the mentioned period. The actual 2014-15 oil price fall is not a good time to locate a disruption, as delayed impact on long term contract gas prices would confuse the interpretation. Instead, we assume oil prices to follow the monthly averages since 2000. These show only limited seasonal swings, with peaks in July and August. Gas related prices and the TTF equation are simulated in relation to such prices. The average is 66 $/bbl or (at the average euro/dollar exchange rate in the same period) 388.2 €/metric ton.

Temperatures would also follow the average of 2001-2014, with the exception of the cold spell, where a further reduction is envisaged such to trigger the higher consumption foreseen by the ENTSOG scenarios.

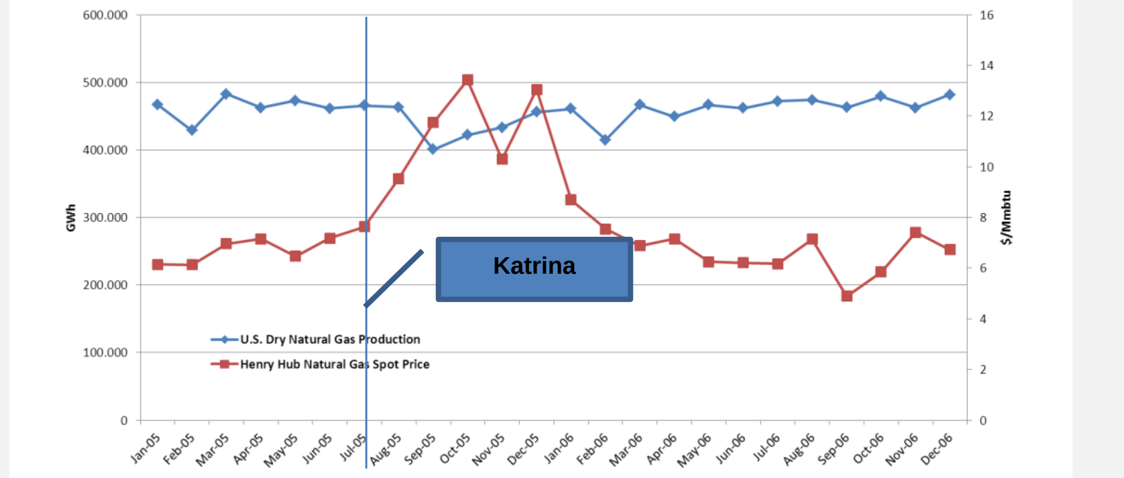
Figure 4.3.2 TTF price scenarios under the Stress Test scenarios



Hurricane Katrina, which hit land in August 2005 in the Gulf of Mexico, caused severe damage to U.S. oil and gas production infrastructures, as a consequence of which U.S. gas production in September dropped by 13% with respect to August and prices briefly spiked to above 13 $/MMbtu in October. Overall, the 2nd half 2005 was higher by 64% than in the first half and by 85% than in the 2nd half of 2004. Later, prices settled back to normal (ahead of the shale gas revolution). A similar, smaller event (not pictured) occurred again in 2008 after another major hurricane.

The disaster of the *Fukushima nuclear power plant* in March 2011 and the following closure of all Japanese nuclear reactors resulted in an increase in gas imports by Japan and a rise in LNG import prices in the entire Pacific basin. In particular, from April 2011 to April 2012, Japanese LNG imports increased by an average of 18% and prices increased by an average of 39%, compared to the same months of the previous year. Annual Japanese imports of LNG in 2012 were up 25% from the 76.4 million tons imported in 2010. As regards LNG spot prices, the average price in Q4 2010 was equal to 9.5 $/Mmbtu, whereas the average price in the same quarter of the 2011 was 17.3, with an increase by 82%.

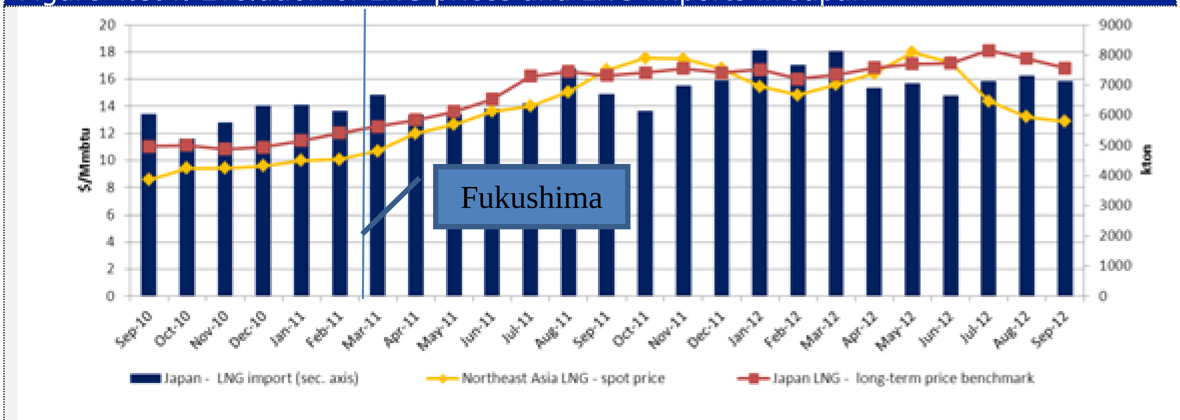
Figure 4.3.3. Evolution of US gas production and Henry Hub spot prices after the Katrina hurricane



Source: EIA

The following Figure 4.3.4 shows the evolution of LNG prices and imports in Japan from September 2010 to September 2012. As regard spot price, we considered North East Asia LNG Price (as estimated by World Gas Intelligence) as indicative of spot prices for LNG delivered in NE Asia. Concerning LNG sold under long-term contract, it is worth noting that long term LNG price is determined as a result of moving averages of historical quotes for selected spot oil products. Indexation on Asian markets is mainly to crudes (Japanese and Korean "cocktails"), often with a less than six month time lag. The graph is based on WGI estimates of the price of long term contracted LNG for the Japanese market.

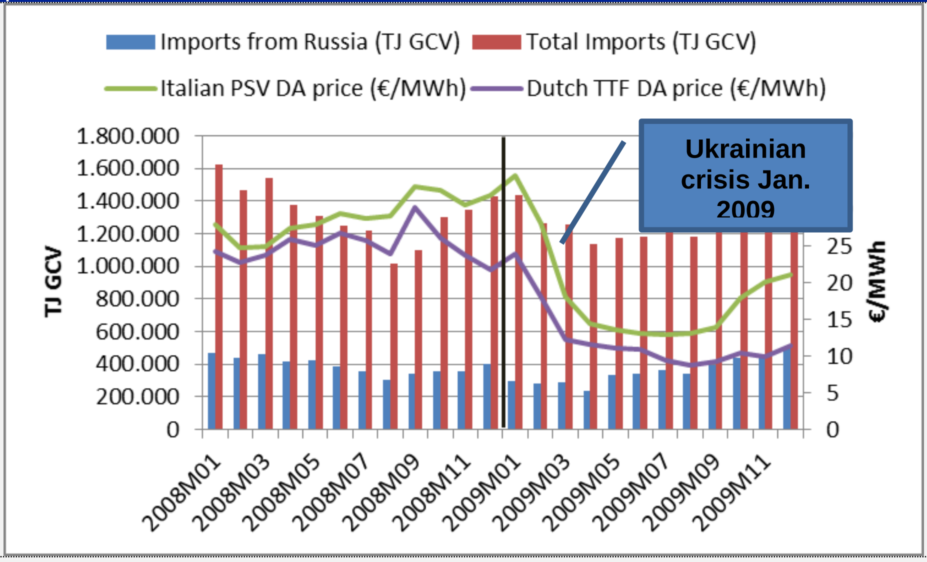
Figure 4.3.4. Evolution of LNG prices and LNG imports in Japan



Source: Analysis on World Gas Intelligence data

These crises can be compared with the Ukrainian case of January 2009. The following Figure 4.3.6 shows the evolution of monthly gas imports in EU27 and the Dutch TTF spot price from January 2008 to December 2009.

Figure 4.3.5. Evolution of monthly gas imports in EU27 and Dutch and Italian spot prices



Source: Platts and Eurostat

The 2009 Russia-Ukraine gas dispute, which caused the stop of the natural gas running to Europe in January 2009, led to a slump in imports from Russia (-25%) and a surge in spot prices (+10%) with respect to the previous month. Disruptions were limited to South-Eastern Europe as most of the continent managed to boost storage withdrawals, substitute imports or implement demand-side measures (*Section 1.3*). Yet the crisis interrupted the downward price trend that had started in October 2008, after the great financial crisis and the related oil price slump. Unlike in the Fukushima case, this was an acute but short event.

It is worth noting that other studies and models expect much lower market price increases than our model[144]. However, these approaches seem to be based on a "rational" market equilibrium of perfectly competitive demand and supply curves rather than on actual crisis cases. As the Katrina case shows, prices started to spike even before the full impact of the supply fall occurred.

Whereas price spikes are clearly a market signal for the restoration of a market equilibrium, the problem is whether this type of adjustment is efficient, or is preferable to prevent (at least partially) to reduce its impacts by accumulating more gas in storages. This problems is addressed in the next two sections.

4.3.4 The costs of Storage Related SoS Measures

For a consistent and sustainable assessment, we consider the gas price impacts that higher resort to storage may generate. In particular, higher availability of stored gas in an emergency will probably reduce the impact of the disruption on spot gas prices as well as LNG spot supplies, however this would be partly offset by the impact of a higher demand of gas once the emergency is over and storages must be replenished. Yet, these two opposite impacts need not offset each other, as price spikes in an emergency can be far larger than those entailed by replenishment in the following summer. What is more, storages may also help to cut resorting to the most expensive alternatives, including outages, which could make them useful. In any case, it is fair to

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[144] e.g. DIW Berlin – German Institute for Economic Research, *Supply Security in Natural Gas Networks: The European Situation, Presentation by* Franziska Holz at the IEB Symposium Barcelona, 03.02.2015.

consider the price increases that are triggered by stronger injection in the summer months, which would be required by tighter SRSMs. Therefore, the positive (in summers) and negative (in winter) impact on prices should be both assessed and included in the calculations[145].

The simulation of summer refilling impacts can be done by the same models that are used to assess the impacts of larger inventories in the winter months. In other words, the gas price models must be run for a whole year, with and without different SRSM models and under several disruption scenarios.

Besides the impact on gas prices, costs of SRSMs basically include the costs of storing more gas. There are several approaches that may be used for this evaluation:

I. The most objective way, notably for countries with negotiated storage prices, would be to use estimated costs of facilities and of their use. This approach also raises some difficulties. The main problem (also affecting regulated pricing regimes) is the valuation of the *cushion gas* that is not annually mobilised and represents in fact an investment cost, even though it may be produced where necessary[146].

II. The simplest way is by using storage prices. Since storage is a market based activity or – where its prices are regulated - it is priced "as if" it was delivered in a competitive market, its prices should in principle reflect its real costs. Difficulties may arise from price fluctuations, which are related to times of high or low demand, and which can be sensible in a highly capital intensive industry. This difficulty can be reduced by using multi-year averages, or regulated prices, which should be more stable. The Project has collected storage prices for bundled services for a large number of operators and sites (see *Section 1.4*)[147].

It has been noticed that the additional storage may not have the same price as existing one. As the cheapest storage sites have probably already been built, more expensive ones would have to come online. However, this is probably offset by the fact that storage technology features remarkable economies of scale. For example, it is often possible to increase storage capacity by boosting compression and slightly increase the pressure of underground cavities and geological traps.

Moreover, if measures entail the increase of filling rates rather than capacity, it may be said that costs are much smaller and limited to those of transmission and the injection / withdrawal process. However, this approach in in our view not acceptable for a long term SoS policy. If capacity costs are not covered, storage operators would eventually lose money (as they cannot depreciate or remunerate capital) or mothball part of their capacity.

The approach of considering only variable costs could be considered for temporary policies. If policy makers feel that disruption risk is temporarily high (e.g. for political reasons) they may for example provide incentives for the expansion of inventories in existing sites at prices that cover variable costs, but possibly fall short of capacity costs. It would be in such case necessary to accurately monitor that such inventories are actually in excess of those that would be provided by markets anyway.

[145] A more complete analysis would also require to address the less likely case of a summer disruption, where storages would have to fill anyway to face the next winter.

[146] In fact, it has been proposed to use part of the cushion gas as emergency inventory, as Serbia did during the Balkan wars of the 1990s. however this may damage the capacity of the site and foster hardly predictable future costs.

[147] This is of course an approximation. The cost of storage itself is a rather difficult concept: it should in principle include the opportunity cost of not selling the stored gas, but that value fluctuates with market prices. Any accounting approach is questionable at best. For regulated storage we take regulated values whatever the approach that has been taken. In negotiated regimes where a market logic prevails, the price should cover that of the marginal unit, therefore prices should be a good approximation of marginal costs, which should be closer to those of new storages (if any).

For these reasons, as an estimation of storage costs for structural SoS purposes, we use these posted prices. In several cases, such prices are regulated and should therefore be generally cost reflective. This concept is not so easily implemented in the case of facilities like a partly deleted gas field, which could still be put into production and has therefore an opportunity value. The hard experience of US regulators in the 1960s and 1970s has shown that it is not easy to estimate the value of an exhaustible resource, which depends on markets conditions as well as on industrial costs. Yet regulators have managed to find some solutions, typically by pricing the "cushion gas" at some long term average value, so as to reflect its value in a way similar to how oil and gas producers assess economic reserves and decide on development plans.

Moreover, cross section analysis of posted prices for selected EU sites shows that posted prices for negotiated regimes are not systematically different from those of regulated regimes, once technical features like the deliverability rate is taken into account. Therefore, we consider that such posted prices may well be cost reflective, and therefore represent an appropriate valuation of the cost to society of developing storage, or of using existing facilities by covering all their lifetime costs. This is without prejudice to the fact that current prices, in a weak market, may well fall below such posted prices, as shown in section 1.4 above. Such situations do not however provide a valuable input for cost-benefit analysis.

On the other hand, the sources for storage development costs are very rare. The best estimation we found is the Clingendael study from 2006, but these costs are now completely out of the market, since the costs have changed significantly in all areas due to technology development and legal and environmental requirements.

In the last ten years, storage developments were usually planned in Europe based on the forecast of a decreasing European gas production and increasing demand. All investment decisions for ongoing projects made in the years 2001 –2006 were made under the assumption of a development time of typically 10-15 years.

In this peculiar market conditions, notably regarding storage investment, it seems fair to use existing published prices as estimates for the costs. Such official prices (*Section 1.4*):

- have not significantly declined on average lately, despite several declarations, therefore they should be just as cost reflective as earlier;
- show no systematic difference between regulated and negotiated regimes
- certainly include capital costs in most cases, though with some exceptions, like Bulgaria, as outlined in case studies.

Under these conditions we take storage prices as costs. WG related components are taken as capacity components, whereas injection and withdrawal related tariff components are used depending on the case and month. Transmission tariffs are paid anyway. For few countries where data are missing, we use the EU weighted average instead.

The approach must however be different in case of simulating reduction of storages. For in such cases the existing facilities have already been built and their cost becomes partly stranded. For a precise estimation we should analyse each plant and consider the share of investment costs that have been depreciated, or undertake a full "due diligence" of the value of capacity that is stored or mothballed. Such exercise is clearly beyond the scope of this Report. We assume that 50% of all capacity costs are saved, but the remaining 50% remains. Therefore, in case storage is reduced the related costs savings amount to 50 of capacity (WG related) costs and all variable costs (injection, withdrawal and transmission) for the unused capacity.

Whatever the cost of storage services, a further cost of SRSMs that is worth addressing is the financial cost of keeping gas in the facilities. This cost is rather low in the current situation of low interest rates. We have used typical cost of capital estimates for large European gas and power companies, which are in the 4-5% range according to Damodaran Tables[148]. This is rounded up to 5% and we calculated 0.41% as a monthly equivalent. As *Section 4.5* will show, these costs are of an order di magnitude lower than those of storage services.

4.4 Modelling of the EU gas market

4.4.1 Optimal Modelling strategy

For the assessment of the impact of several SRSMs under SoS scenarios, it is necessary to model the functioning of the EU gas market. Several such models exist in Europe, but most of them are private commercial devices, not for public use. Models are used for several purposes, particularly forecasting of prices and quantities in several national and regional markets, which are in turn used to assess the opportunity of entering or leaving the markets, developing new or expanding / closing existing infrastructure. Models can also be used to simulate the impact and efficiency of several policy measures.

Whereas in principle a single perfect model should describe the market in a way to serve all purposes, in practice this is not feasible. Any model necessarily misses some features, therefore a model may be theoretically less satisfactory but more effective in forecasting, or for policy simulation. Generally speaking, some models try to simulate the behaviour of market players by describing the main demand and supply variables and their determinants (*structural models*), whereas others focus on key variables that are analysed and forecasted by statistical techniques (usually some sort of time series analysis), which do not necessarily specify all underpinning relationships (*reduced form models*).

Our model is based on REF-E's experience in modelling the electricity and gas markets. Yet existing models must be adjusted to be able to test the impact of SRSMs.

Considering limited time and budget resources, we use a modelling strategy based on results obtained by ENTSOG for its Stress Test exercise, which ensures an outcome (allocation of available gas resources, consistent with current (as of Autumn 2014) resources of production, imports and storage, and transmission infrastructure, as well as with the satisfaction of expected gas demand .

This approach is described in the next section.

4.4.2 The costing of ENTSOG results

In its Stress Test exercise, ENTSOG defines values of production, imports and storage use under a baseline (*reference* scenario) as well as simulations of several disruption scenarios. ENTSOG's model accurately considers interconnection and other capacity constraints but does not attempt to achieve cost minimisation. Rather, it is based on keeping all infrastructures working as far as possible and allocating flows to the nearest source where available.

This is a reasonable approach, notably for an analysis of emergency scenarios. Even if no optimisation is pursued, a reasonable containment of costs is presumably achieved. However, the ENTSOG model may not adequately simulate the optimal relocation of

[148] http://people.stern.nyu.edu/adamodar/

flows between market zones. Modelling of such optimal strategies is not easy anyway, notably as it is hard to consider all contractual constraints, like take or pay obligations, make up opportunities and other typical contractual arrangements of gas trade. What is more, contractual prices are not generally known but are usually confidential, therefore any optimisation would be based on estimations of such prices, which may not be precise.

Moreover, the ENTSOG model does not include any assumption about costs of addressing gas deficits that are generated by the model. These will be estimated by defining unit costs for fuel replacement and load shedding [($P_{1,7}$,…, $P_{N,7}$; $P_{1,8}$, …, $P_{N,8}$], with the assumption that the cost of fuel switching is lower than that of load shedding but has a limited capacity. All other costs are also estimated in such a way that a predetermined ranking is envisaged.

We assume that in each market zone, the balance of demand and supply must hold in each time unit. Formally, for each time unit t and market zone h:

$$\sum_{i=1}^{Z} M_{iht} + \sum_{i=1}^{N} F_{jht} = C_{ht} + \Delta S_{ht} \qquad (4.1)$$

where M is import from external source I into zone h, F_{jht} is import from market zone j into market zone h for time unit t, C_{ht} is consumption of market zone h and ΔS_h is the change in inventories of market zone h.

All interconnections as well as primary sources are subject to capacity and non-negativity constraints:

Hence:

$$0 \leq F_{jht} \leq K_{jht}$$

$$0 \leq M_{iht} \leq R_{iht}$$

For i = 1, …, Z=9.

Primary sources include:

I. domestic production;

II. storage withdrawals;

III. further pipeline imports;

IV. further LNG imports;

V. substitution of gas with fuel oil and, in power generation;

VI. substitution of gas with coal and lignite in power generation;

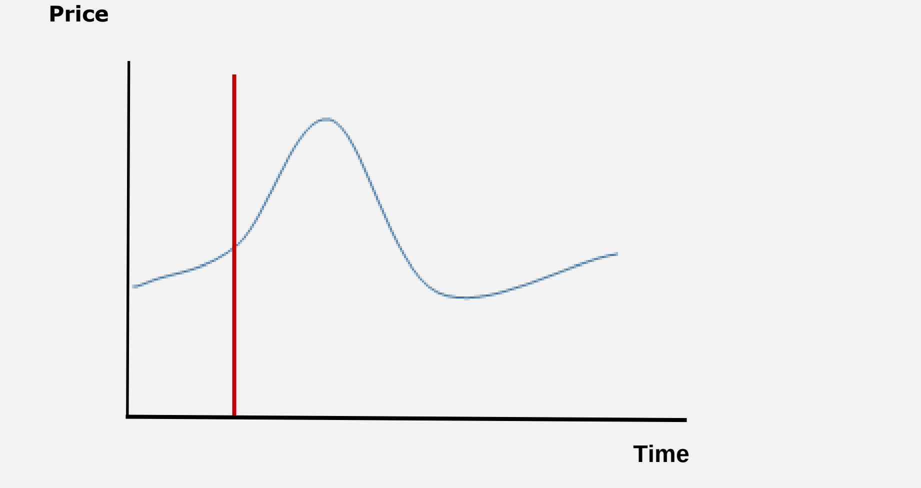
VII. load shedding.

Whereas this list is not exhaustive of all possibilities, it includes the options that can be reasonably modelled. For example, the contribution of some form of interruptible contracts (besides those of power and heat generation stations that can switch to alternative fuels) can hardly be estimated but for few countries.

It is likely that substitution in power generation also encompasses some of the effect that at first sight appears as demand reduction. Whereas in cases like the January 2009 crisis many countries have called for consumers to reduce their demand, this is probably only partly effective and estimations of the size of such demand containment are not available. Yet, in part gas demand containment may be related to a shift of demand towards electricity (e.g. for space heating), which in case of lack of gas may be satisfied mostly by burning more liquid or solid fuels, even with some derogations from environmental limits.

Prices of LNG and hubs are simulated by a reduced form model for the simulation period and not further adjusted. They can therefore be taken as given for any following assessment exercise. These type of models better mirrors the typical price impact of a supply and / or demand shock, which is often similar to that of Figure 4.4.1. Real examples have been provided above (*Sub-Section 4.3.3*).

Figure 4.4.1. A typical price impact of shocks



For pipeline supplies, suppliers are assumed to have spare capacity at current prices, which may be oil and/or hub related depending on the market zones. Matrices of prices

$P_t = [P_{jht}]$

are therefore estimated by using historical values and/or reduced form models. Oil prices are also assumed not to be affected by the events, even though this assumption needs further validation as some prices may in fact be affected. In particular, given the low usage of fuel oil, it cannot be ruled out that its prices may be affected by serious disruption events. Oil strategic stocks may be necessary in the worst cases.

$P_{h,j}$ for any zone h and for any supply source j where j =1,…10, has the following meanings:

- J=1 for Algeria (DZ)
- J=2 for Libya (LY)
- J=3 for Norway (NO)
- J=4 for Russia (RU)
- J=5 for LNG from any source (LNG)
- J=6 for Turkey and its interconnected upstream suppliers
- J=7 for National Production from any European country

In case these sources are not enough, each market zone resorts to

- J=8 for light fuel oil (LFO)
- J=9 for coal or lignite.

Prices of natural gas and of its main alternative (LFO) for supplies have been calculated by the methodology illustrated above (sub sections 4.3.1 – 4.3.3 and Annex 14).

Finally, the cost of load shedding is estimated as explained in section 4.3.1 above, starting from the UK study of the value of lost load and adapting it to each country in relation to climatic conditions, as typical consumption necessary to ensure adequate space heating is geographically determined. This yields the levels of the VOLL or $P_{10,h,t}$, which is articulated by country but constant over time.

In this approach, the simulation proceeds in the following way:

1. ENTSOG's solution by market zone h and month t are taken. These are defined as

$M_{h,t}^{E,B}$ and $F_{h,j,t}^{E,B}$ for the baseline

and

$M_{h,t}^{E,Dl}$ and $F_{h,j,t}^{E,Dl}$ for the disruption (stress) scenario Dl. There are several ENTSOG Stress Test scenarios to be tested, but we have decided to focus on the following:

- Six-month cut of all Russian supplies under a "cooperative" framework, where gas is allowed to flow where necessary, including a 14 day cold spell;
- Six-month cut of all Russian supplies under a "uncooperative" framework, where gas is kept within the country where it is produced or imported until all demand by the country is satisfied, including a 14 day cold spell;
- One-month cut of all Russian supplies under a "cooperative" framework, where gas is allowed to flow where necessary, including a 14 day cold spell.

Other scenarios may be also tested, but have been neglected for simplicity of results. Reader may consider thatUkraine transit disruption scenarios are likely to yield impact that are approximately 40% of the "all Russian" supply disruption, for similar duration and demand conditions, but with worse losses for the Southern part of the Continent.

Gas demand C_{ht} is assumed to be taken from ENTSOG data. Demand side reactions are likely, but their size is supposed to be negligible. Some Preventive Action Plans have estimated their role, but this is not guaranteed. On the other hand, some gas demand side reaction may be partly offset by consumers replacing missing gas with more costly alternatives, like LPG, fuelwood or electricity, with the balance of the latter actually generated by the "replacement fuels". Lack of generalised estimates of short term price elasticity of demand - which is known to be very low indeed - have suggested to ignore both the (negative) gas demand reaction to higher prices and the (positive) transfer of demand to other, more expensive energy sources, notably electricity. In other words, we assume neither a contraction of gas demand nor an increase in the demand for electricity or LPG as replacement for missing gas. We only assume that whenever gas is missing, the next option of each country is to switch power generation to other fuels, as much as possible.

Storage is subject to total volume capacity as well as to maximum withdrawal rates.

$$0 \leq S_h \leq V_h$$

$$W_{ht}^{in} \leq \Delta S_{ht} \leq W_{ht}^{out}$$

Where V_h and W_{ht} are volume and withdrawal/injection capacities for each market zone.

The storage level is assumed to cycle annually, so that no net storage injection or withdrawal is assumed beyond one year. Only underground storage is considered, whereas linepack changes are ignored. This assumption may seem strong, but it is necessary for policy simulation as only sustainable policies are worth simulating. Some limited gaps between injections and withdrawals actually occur every year, but on average these offset each other. A case where the storage level decreases or increases every year is clearly not sustainable, as all stored gas would be depleted and the situation of next year would be dramatic.

In other words, the annual algebraic sum of injections and withdrawals amounts to zero. Formally, for any market zone h:

$$\sum_{t=1}^{T} \Delta S_{ht} = 0 \qquad (4.2)$$

The total cost of supplies is calculated by the formula:

$$Y_{sg} = \sum_{i=1}^{Z} M_{iht}\ P_{iht} + \sum_{i=1}^{N} F_{jht}\ P_{jht} \qquad (4.3)$$

This can be calculated in relation to a defined reference and disruption scenario (s) under a certain SRSM policy.

2.

SRSMs[149] are simulated by requiring that storage levels (as obligations and/or strategic storage) amount to a certain minimum level. For example, if the time granularity was the month and S_{ht} the storage fill of zone h at the end of month t, e.g. :

$$\boldsymbol{S}_h \geq \overline{\boldsymbol{S}}_9$$

where $\overline{\boldsymbol{S}}_h$ is a vector of N minimum required levels of stored gas at the end of September (where N is the number of market zones and T=12).

No optimisation is carried out. However, the choice of fuels as necessary to cover demand after the crisis, including for storage refilling, is adjusted in such a way that the cheapest source is used in each zone, up to the maximum that has been used in "worst" scenario modelled by ENTSOG. These solutions are therefore consistent with constraints of the European gas import, production and transmission system, as well as with storage withdrawal and injection capacities, which are also given in ENTSOG's data (based on GSE). However, we ignore any reduction in storage deliverability as sites get exhausted. This effect may be offset by demand side reactions, e.g. reduced end user consumption as the crisis worsens and awareness emerges among the population. However, this offsetting is not guaranteed.

Thus, the impact of SRSMs is estimated by:

- Using the available storage under the SRSMs that are being simulated
- Resorting to the highest cost source as compensation after that, following a predetermined order.

Given that spare capacity of pipeline supplies from sources other than Russia are limited (EU production, Norway, Algeria) or not reliable (Libya), by far the most

[149] Storage related Security of Supply Measures, like minimum storage obligations.

relevant substitute is LNG. When LNG import and or interconnection capacity[150] are saturated, the system resorts to fuel switching towards LFO and then coal. Only in extreme cases, it could also resort to load shedding.

For example, if more storage was available due to a specific measure, this could reduce the cost of the disruption event by requiring a lower resort to costlier options (LFO, LNG). This cost change variation will be compared to costs of the measures, as assessed in *Sub-Section 4.3.4*.

Results of this simplified tool are outlined in the next section. It is worth noting that, whatever the modelling tool, these results will separately show potential benefits (as reduced supply costs) and costs of SRSMs.

4.5 Policy simulation results

Unfortunately, ENTSOG has not provided simulation results at national or market zone level. This is due to their low reliability, as such results are not based on a market simulation exercise. Results are therefore shown at European level only. In this simulation, all EU Member States are included as well as FYR of Macedonia, Serbia and Switzerland.

Simulation results are shown in the next three Tables. These results are calculated for each scenario and for each SRSM model. Recall that costing of ENTSOG simulations as well as their modification, aimed at testing SRSMs, have been performed for four scenarios:

S=0: Reference scenario: no disruption

S=1: Six-month cut of all Russian supplies under a “cooperative” framework, where gas is allowed to flow where necessary, including a 14-day cold spell;

S=2: Six-month cut of all Russian supplies under a “non-cooperative” framework, where gas is kept within the country where it is produced or imported until all demand by the country is satisfied, including a 14-day cold spell;

S=3: One-month cut of all Russian supplies under a “cooperative” framework, where gas is allowed to flow where necessary, including a 14-day cold spell.

Table 4.5.1 shows the costs that would arise in case the feared event actually happens, calculated by the above formula (4.2). In particular, the Table shows the remarkable increase of LNG and the size of gas deficit in each scenario, as well as the cost of existing storage. These costs are generated under the current pricing scenarios, described in detail in Annex 14. Quantities are not new but are essentially based on ENTSOG’s Stress Tests simulations.

The fifth column of this Table also allows us to provide a preliminary assessment of the costs of a lack of cooperation within Europe in the crisis, with countries “closing the gas borders” unless all national customers can be served. In general, there are substantial costs from such behaviour, as several countries cannot access pipeline gas or LNG landed in other countries and are therefore forced to use substitute fuels earlier. However, these results are preliminary: indeed, it is likely that under a non-cooperative scenario several countries would be forced to disconnect even protected customers, which would trigger far higher costs than fuel switching. Only the availability of a more appropriate modelling device (or at least of resource allocation under the ENTSOG models at national level) would allow a more appropriate

[150] For example, the large Spanish, Portuguese and Greek LNG capacity is not likely to be fully utilised due to limited interconnection capacity with neighbouring countries (France and Bulgaria).

assessment. The current valuation of the costs of a lack of cooperation in a crisis is a very cautious approximation, probably underestimating its real costs.

Table 4.5.1 Disruption scenarios					
Indicator		Reference (no disruption)	-100% Russian supply for 6 months + cold spell in Feb. under current SRSMs cooperative	-100% Russian supply for 6 months + cold spell in Feb. under current SRSMs not cooperative	-100% Russian supply for 1 month + cold spell in Feb. under current SRSMs cooperative
Total imported LNG	(GWH)	582,292	887,406	747 673	796,227
	(% change from reference)		52%	28%	37%
Total deficit	(GWH)	0	-174 051	-198,931	-4,395
Total costs of EU supply	Million €	118,649	154 807	156,014	119,688
	(% change from reference)	-	30%	31%	1%
Total costs of EU supply net of storage	Million €	110,307	146,374	147,595	110,942
	(% change from reference)	-	33%	34%	1%
Total costs of storage	Million €	8,342	8,436	8,419	8,747
	(% change from reference)	-	1%	1%	5%
Note: Totals refer to the whole considered period from September of year to August of year t+1					
Source: REF-E's elaborations based on ENTSOG data					

The above costs would occur under the current storage situation, without any further measures. We now turn to the analysis of different SRSMs.

For each scenario, four models of alternative SRSMs, which have been defined in *Section 3.13*, are tested:

(a) Baseline: No change of current SRSMs;

(b) Tight storage obligations for all: minimum storage obligations as of 1 October in each country must not be lower than 24% of annual consumption;

(c) Light storage obligations for all: minimum storage obligations as of 1 October in each country must not be lower than 9% of annual consumption;

(d) Strategic storage for all: all Member States must ensure that strategic reserves are kept, amounting to % of annual consumption.

(e) Existing strategic storage and storage obligations are cancelled, leading to a fall of actual storage amounting to half the size of current obligations[151].;

[151] In fact, it is not possible to properly estimate how much storage obligations increase total inventories rather than (at least partially) replacing commercial storages (*crowding out*). In all sample countries, actual inventories are clearly above

For each combination of a disruption scenario and a SRSM model, Figure 4.5.1 shows the costs that would arise from each of the three examined scenarios, both as totals and as percentage of the no-disruption (Reference) scenario. These costs are huge, notably in the case of a six month disruption, and are mostly related to the increased costs of alternative supplies. In particular, under the model assumptions, pipeline gas costs would not substantially increase if purely oil-related, but would increase in various ways following the likely price spike of gas hubs during the crisis. LNG prices would also follow hub prices (with some exceptions, as in Spain), and also spike in the emergency.

Next tables show instead whether benefits and costs of various SRSM models, if applied throughout Europe, would mitigate the impacts of the disruption scenarios. In particular, Tables 4.5.2 - 4.5.4. display results for the baseline and the four above suggested SRSM models.

In particular, the last row of these Tables includes the calculation of the net benefits of a certain SRSM model, compared with the current one. For models C, D and E, it can be expected that storage costs increase, but this could be offset by the benefits resulting from a reduced total gas supply cost. The main rationale is that more storage allows to use more gas purchased at cheaper prices, mitigating the impacts of the price spikes in the emergency.

However, such benefits only occur if the disruption event happens. Therefore - as in any risk valuation - the balance between benefits and costs crucially depends on the probability of the adverse event, and the way it is treated or perceived (*risk aversion*). Costs (e.g. increased storage) are firm but benefits are uncertain and linked to the occurrence of the feared event[152].

Any discussion about the inclusion of risk-aversion in cost benefit analysis is beyond the scope of the present Report. We present all results for costs and benefits separately.

Moreover, we calculate the net benefits of each SRSM model in each scenario, by assuming a risk neutral attitude. With this approach, the value of an uncertain event is simply multiplied by its estimated probability. This is an accepted approach in cost benefit analysis for public purposes.

There is no official estimation of probabilities of the adverse events that are described in Stress Tests. Some Member States, like Hungary, have published in their Prevention Plans their estimates of the considered disruptions, but these are only partly comparable to those addressed in ENTSOG's Stress Tests.

Partly based on such estimates, we use the following probabilities:

- Six month cut of all Russian supplies : 2% (1/50)
- One month cut of all Russian supplies: 5% or 10 % (1/20 or 1/10)

Based on these assumptions we calculate, *for each disruption event*, the net benefits of a change in SRSMs to a certain SRSM Model X from the baseline, as follows:

Net Benefits of SRSM Model X = (Gas Supply Costs under Model X - Gas Supply Costs under Baseline) x (Probability of Event) – (Cost of SRSMs).

---

those required by SRSMs (see Table 4.1.1 above). We assume a 50% crowding effect in all countries, meaning that market forces retain 50% of existing storage obligations as commercial storage: for example, if an obligation to store 100 units is cancelled, market forces will actually reduce their inventories by 50. Cost assumptions for this scenario have been discussed in section 4.3 above.

[152] Let us recall that these valuations only consider the consumers' perspective and ignore suppliers' benefits. This is justified by the fact that Europe as a whole is a net importer so that "at the margin" new supplies must come from external sources, and external suppliers are eventually going to appropriate almost all benefits of price increases. Inclusion of the benefit from price increases that would be retained by European companies could slightly change the picture.

Finally, we calculate the *probability break even point*, i.e. the probability that should belong to the event to yield expected benefits that are at least equal to costs. More formally, we calculate the value of the probability that solves the simple equation:

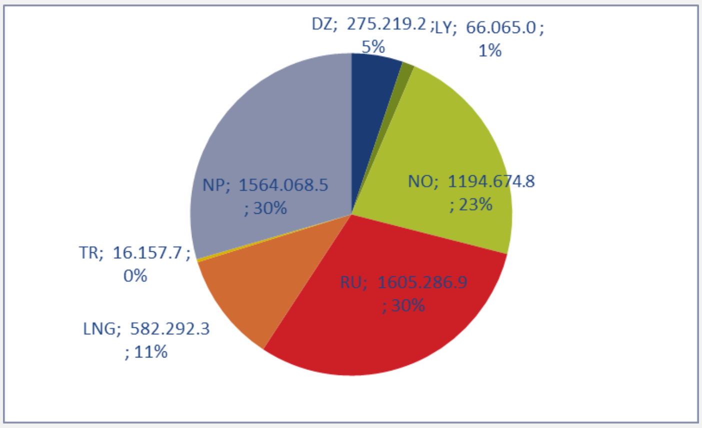
Net Benefits of SRSM Model X = (Gas Supply Costs under Model X - Gas Supply Costs under Baseline) x (Probability of Event) - (Cost of SRSMs) = 0 (zero).

To sum up, in the following Tables we present, for each combination of disruption scenario and SRSM model:

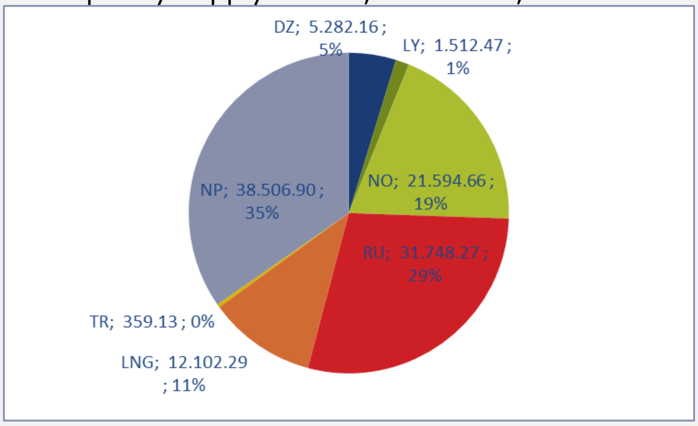
- LNG imports, which are typically the main source tapped to address shortages of pipeline gas;
- Remaining gas deficit that must be covered by other fuels or shed;
- Total cost of gas supplies if the disruption event occurs;
- Storage related costs
- Net Benefits under the above probability assumptions
- Break Even probability.

Figure 4.5.1 Supplies and costs for the Reference ENTSOG scenario

Annual demand matching by supply source, Reference, TWh



Cost split by supply source, Reference, M€



Source: REF-E’s elaborations based on ENTSOG data

Table 4.5.2 Costs and benefits of SRSM models under the 6-month Russian disruption+Cold Spell scenario

Indicator		current SRSM (baseline)	no strategic storage & obligations	light SRSM to all	tight SRSM to all	strategic storage to all
Total costs of EU supply net of storage (k€)	million €	153.261	158.804	153.077	149.780	142.770
	(% change from baseline)	-	4%	-0.1%	-2%	-7%
Total costs of storage (k€)	million €	8.436	7.859	8.466	8.892	11.217
	(% change from baseline)	-	-7%	0.4%	5%	33%
storage benefit	gain compared to baseline (€ million)*	-	-5.543	184	3.481	10.491
storage cost	incremental cost compared to baseline (€ million)**	-	-577	30	456	2.781
Probability-weighted Net Benefits	million €		466.0	-26.1	-386.6	-2571.2
Probability-weighted Net Benefits	% of Baseline costs		0.29%	-0.02%	-0.24%	-1.59%
Probability of event vs. Break-even Probability	2%		10.4%	16.2%	13.1%	26.5%

Source: REF-E’s analysis on ENTSOG data

Details of quantities and costs by source for each disruption scenario and for each SRSM Model are provided in *Annex 18* (Figures A.18.1 – A.18.4).

The reader may notice that benefits definitely exceed costs if the event occurs. However, if the probability of the event is estimated at 2% (or 1/50) then costs of SRSM policies like “tight” or “light” storage obligations for all, as well as strategic storage for all, exceed the benefits.

On the other hand, under such conditions the abolition of existing strategic storages would also supported, as probability weighted savings would exceed costs if the probability of the event was estimated at less than 10.4%. A risk neutral decision maker would support the SRSM models only if the probability of the event was comprised between about 13.1% (tight storage) and 26.5% (Strategic storage for all), with light storage in the middle. However, a risk averse decision maker could support the tighter SRSMs even after these results, but this would be against the traditional (risk-neutral) cost benefit analysis methodology.

It is also appropriate to remind that these results apply to Europe as a whole, as defined at the top of this section (EU+CH+MK+RS). Results may be different at national level (see next section for the one month disruption scenario).

Table 4.5.3 (and Figures A.18:5 – A.18.8 in Annex 18) show the impacts of a less dramatic scenario, a one-month all-Russian disruption in February only, with a cold spell affecting half of that month.

The same general comments apply as for the above scenario. However, it is worth noticing that under this scenario all models even have negative benefits. In other words, under these models, supply costs would be actually larger under enhanced SRSMs than without them. On the other hand (and coherently), the elimination of existing SRSMs would have a net positive impact.

This outcome depends on the need to refill larger storages, which may very demanding and costly. In the case of a one-month (February) disruption, gas used from storages has been bought before the crisis at relatively low (mostly hub-related) prices. However, delays in the market price return to normal levels, as these are typically affected by expectations and the crisis mood, imply that storage refilling requires purchases at higher prices than the gas bought before the crisis (see Figure 4.3.2 above, green line). The impact could be slightly different if the crisis was located at different times, but possibly even worse if it happened earlier in the winter or in the autumn, as it would trigger lower-than-normal storage levels throughout the cold season, which in turn would keep prices up even if the events that originated the crisis was over[153].

Table 4.5.3. Costs and benefits of SRSM models under the one--month Russian supply disruption +Cold Spell scenario

-100% Russian supply for 1 month + cold spell in February						
Indicator		**current SRSM (baseline)**	**no strategic storage & obligations**	**light SRSM to all**	**tight SRSM to all**	**strategic storage to all**
Total costs of EU supply net of storage (k€)	million €	111.093	116.535	111.673	111.618	119.025
	(% change from baseline)	-	5%	0.50%	0%	7%
Total costs of storage (k€)	million €	8.747	5.357	8.774	8.85	11.485
	(% change from baseline)	-	-39%	0.30%	1%	31%
storage benefit	gain compared to baseline (€ million)*	**-**	**-2.052**	**-608**	**-628**	**-10.67**

[153] This type of event is similar to the sustained price levels experienced in the U.S after the Katrina crisis, even though production had been restored to normal levels during the cold season. See Figure 4.2.4.

storage cost	incremental cost compared to baseline (€ million)**	**-**	**-3.39**	**28**	**103**	**2.738**
Probability-weighted Net Benefits	million €		**3184.6**	**-88.6**	**-166.2**	**-3805.5**
Probability-weighted Net Benefits	% of Baseline costs		**2.66%**	**-0.07%**	**-0.14%**	**-3.18%**
Probability of event vs. Break-even Probability	10%		**Always**	**Never**	**Never**	**Never**
**						
Note: Totals refer to the whole considered period from September of year to August of year t+1						
Source: REF-E's analysis on ENTSOG data						

Even with light SRSMs, the benefit-cost would be (unsurprisingly) worse than under the 6-month disruption. In general, it can be noticed that more storage in commodity markets tends to extend in time the impacts of previous situation. Thus, it could extend the impacts of low prices into periods of tight markets, but it could also do the opposite - i.e. prolonging price hikes over time - unless refilling obligations are suspended, with risks transferred to the next winter.

All above analyses are based on European totals. As any sum (or mean) this may hid remarkable national differences between participating countries. It has often been suggested[154] that "no size fits all" in SRSMs, and that in particular SRSMs may be more appropriate for less liquid markets, where fewer opportunities exist to resort to alternative sources.

In the next section, we adopt a simplified approach to test this hypothesis, and more generally to test whether SRSMs, though not efficient at EU level, may pass the cot-benefit test at least for some countries.

4.6 Country –based analysis

As a further check of the net benefits of the proposed SRSM models, it would be most appropriate to dispose of a full simulation model of the European gas market, with a view to analyze in detail how benefits and costs of policies are spread among countries and stakeholders. Since no such model is available, we implement again a simplified approach, consisting of the following steps:

1. For each country, we analyse the structure of supplies and, based on available public evidence, estimate which is (are) the marginal gas supplies sources, i.e. the sources that would be increased in case gas demand increases or an existing, cheaper source is not available.

2. In case storage and alternative gas sources do not satisfy demand, we assume fuel switching in power generation, provided the required capacity is available. This assessment is based on data published by ENTSO-E, the electricity TSOs' official body, on power generation capacity and production by fuels. Assuming the presence of adequate fuel reserves, which is also part of ENTSO-E's

[154] E.g. recently in CEER's Position Paper on storage…

assessment, spare capacity could be used for fuel switching if necessary. Details are provided in Annex 1. Replacement of gas by oil-fired capacity is the most common and relevant way, but coal and lignite also play a role. Only in case these sources are not enough, systems resort to load shedding, which is prices as described in section 4.3 above.

3. We assume that current gas storage capacity (as working gas, deliverability and injection) in each country is increased by a certain proportion (10% or 20%). This can be interpreted as the impact of a storage obligation, but need not be necessarily the case. It may also be an independent decision of a SSO expanding storage at its own risk, or fostered by appropriate incentives.

4. We evaluate the costs that the country would bear if all Russian supplies were interrupted for one month (February), including a 14-day cold spell. This is scenario 3 that was examined above. Storage costs are assumed to increase linearly.

5. The net benefits of the storage increase are estimated for each country, using a 5% or 10% probability of this event, as in the previous section.

Given the complexity of the analysis, even in this simplified form, the exercise is limited to the 11 countries that were included in the original sample. France and Germany are both split in two balancing zones (respectively PEGN and PEGN, Gaspool and NetConnect). However, considering the strict interconnection between the markets of Spain and Portugal and between those of the UK and Ireland, we prefer to pool these two couples of countries. In this way, the analysis effectively applies to about 80% of the EU gas market.

In principle, this analysis could be extended to the other scenarios analysed in ENTSOG Stress Tests. However, this would require heroic assumptions, as the complex and interconnected structure of the European gas transmission network does not allow analysing each country independently if no proper model is used to deal with interconnection constraints. However, for limited variation of supplies these constraints can be deemed as not relevant.

In most cases, the source that is used to meet demand in the disruption (beyond storage) is LNG, possibly with limited increases of Norwegian and Algerian supplies. In no case we found any gas deficit to occur anywhere under this scenario[155]. The typical impact of having more storage is that it must be refilled after the disruption. Since we assume such refilling to occur, often the cheapest sources (including Russian gas, in our pricing scenarios) are overly requested in the aftermath of the event.

Table 4.6.1 shows results, as net benefits of the 10% and 20% storage increases. For an easier comparability results are provided as percentages of original supply costs of the baseline costs. Two probability assumptions are included.

[155] Thus, this test is robust towards our assumptions about the cost of replacing gas by other fuels and about the costs of load shedding.

Table 4.6.1 Net benefits of an increase of storage use with a one month all Russian supply disruption in February, including a 14-day cold spell						
	Gas supply cost variation (%)		Net Benefits of Storage Enhancement			
Storage:	Enhanced +10%	Enhanced +20%	Enhanced +10%		Enhanced +20%	
Probability of disruption			10%	5%	10%	5%
AT	-0.7%	-1.3%	-2.5%	-2.5%	-5.0%	-5.0%
BGn	3.2%	7.7%	-0.5%	-0.4%	-1.1%	-0.7%
CZ	-0.7%	-1.3%	-2.3%	-2.3%	-4.6%	-4.7%
Deg	1.3%	2.6%	-4.8%	-4.8%	-9.6%	-9.5%
Den	0.0%	-1.4%	-3.6%	-3.6%	-7.1%	-7.2%
DK	-3.3%	-5.1%	-0.9%	-1.0%	-2.0%	-2.2%
ES&PT	0.0%	0.0%	-0.2%	-0.2%	-0.4%	-0.4%
FRn	-0.6%	-1.3%	-1.0%	-1.0%	-1.9%	-2.0%
FRs	1.0%	2.0%	-1.0%	-0.9%	-1.9%	-1.8%
HU	-3.9%	0.0%	-1.4%	-1.6%	-3.0%	-3.4%
IT	-0.1%	-0.3%	-0.8%	-0.8%	-1.6%	-1.6%
PL	-4.4%	-8.5%	-0.7%	-0.9%	-1.5%	-2.0%
UK&IE	-2.3%	-3.2%	0.0%	-0.1%	-0.1%	-0.3%
Source: REF-E's elaboration based on ENTSOG data and WGI price estimates						

Readers can notice that, in general, an increase of storage endowment and use reduces the supply cost in case the disruption event occurs. However, there are a few exceptions, notably Bulgaria, France's PEG-S and the Gaspool area of Germany. These cases may be related to the fact that these regions can rely only partly on cheaper LNG supplies to refill their storages after the larger use in the crisis.

In general, countries that already have a relatively high storage capacity, like Austria, France's PEG-N, Germany, Italy, enjoy lower gas supply cost reductions. The interpretation could be that, if storage capacity is already large, lower benefits can obtain from its further enhancement. In such cases we could say that the only impact may be a substitution of commercially stored gas by gas stored due to SRSMs.

However, considering the (assumed) probabilities of the event, net benefits of increasing storage capacity are almost always negative. Of course, markets which do not even feature supply cost reductions have the lowest net benefits (e.g. Austria, Gaspool).

On the other hand, the only Market where the impact is almost neutral, with a very small positive net benefit appearing in one case but slightly negative in others, is the British Isles. This may be surprising, but it is not if we consider that this market has a relatively low storage capacity (compared to its market size) and that it is very exposed to price swings due to its strong market liquidity. Even in this case, mandatory increased storage does not seem supported by the analysis.

These results do consider the benefits that may arise to markets where prices are more stable due to (at least partial) oil indexation, which involves a different sharing of price swing burdens between consumers and suppliers. On the other hand, it ignores the extent to which other forms of risk hedging (like those found in financial markets) may help reduce supply costs in a crisis. However, since such mechanisms are ultimately based on physical resources, it may be expected that their costs will eventually fall on consumers, sooner or later.

Moreover, these evaluations (like those of the previous section) do not consider the benefits that may accrue to suppliers. This is justified by the fact that Europe as a whole is a net importer so that "at the margin" new supplies must come from external sources, and external suppliers are expected to eventually grasp almost all benefits of price increases. However, involvement of European companies in upstream production may lead to some shares of such benefits being returned to Europe. Such estimation lies beyond the scope of this analysis. In particular, this may affect the benefit-cost balance of countries that more involved in domestic activities, both at home and abroad. These arguments may lead to net benefits for countries to be actually lower than our estimate.

Finally, what we show is only part of the benefits of a storage enhancement. For example, larger storage capacity may allow to extract a higher extrinsic value, and if seasonal spreads recover (for any reason) also some intrinsic value[156.] This argument leads in the opposite direction than the previous one: even if net benefits of a storage enhancement are small, or slightly negative, adding the benefits of other uses of storage (not valuated in this exercise) in some case may well lead to positive total net benefits. This would justify storage enhancement decisions at company or national level, which could be facilitated if appropriate incentives allow operators to factor the insurance value of storage into their investment decisions.

4.7 Concluding remarks

In this Chapter, we have found that from a theoretical perspective, it is not sure that companies will fully consider the insurance value of storage in their private investment and capacity booking decisions. Likewise, it is not even sure that Member States belonging to an integrated market will make the right choices, as some not all benefits are likely to be internalised at country but some benefits arising from storage investments may spill over to other countries,. Some regional or European coordination is therefore probably appropriate.

Analysis of actual storage data in comparison with SRSM requirements show that storage measures are probably at least partly effective, but it is not guaranteed that some crowding out by mandatory storage at the expense of private one is also likely. In fact, countries with no storage obligations like Austria and Germany have higher storage endowments than most Member States with mandatory storage, even though this is probably due to geological reasons (availability of suitable sites), and particularly to their focal position in the market, which helps sites located there to offer services to several other, more peripheral European markets[157]. It is likely that most European storage would have been developed anyway, but SRSMs may have boosted capacities in countries like France, Hungary and Italy.

We have estimated the impacts, benefits and costs of extending some existing SRSM Models across all Europe. Benefits are mostly the reduced supply costs that would arise from using more storage resources instead of external sources (mostly LNG), whose prices are likely to spike in case of a serious crisis. Even higher are the benefits of not resorting to other sources that are much more costly for Europe, like oil and coal, notably if their environmental costs are factored in. Even larger would be the costs of load shedding, but this appears as a very minor and remote case in almost all of Europe, expected only in very limited areas under the worse disruption scenarios like a 6-month all Russian outage.

[156] See *Section 1.3* for definitions of extrinsic and intrinsic value.
[157] These and other determinants of storage development and of its distribution throughout Europe have been discussed in sub-*Section 4.2.1* above.

On the other hand, costs of storage are certain and have been estimated by official posted prices or by regulated prices, which are assumed to be cost reflective, rather than by currently depressed market prices.

Despite the benefits of having more storage, cost benefit analysis requires that the benefits of generalised SRSMs are weighted by the probabilities of the adverse event (assumed at 10% for a one-.month or 2% for a six-month all Russian disruption, including a two-week extreme cold spell).

If calculated in this way, if netted of certain storage costs, the benefits of generalised SRSMs are negative in all examined scenarios. In other words, costs normally exceed benefits, if the latter are multiplied by reasonable probabilities of the expected disruption. In fact, even the record of current strategic storage is dubious.

This conclusion does not hold at European level only. Country by country analysis covering 13 Member States, or about 80% of the gas market, has shown that in no country are net benefits positive, with only few countries that are barely neutral.

The lessons of these simulations are not obvious. In fact, it is shown that in most cases storage could indeed have an insurance value, which is not necessarily considered by market forces, and perhaps not even by individual Member States. If the insurance value was properly considered and added to the other components of the storage value, like those arising from seasonal (intrinsic) and short term (extrinsic) gas price swings, it is possible that the room of storage in the European gas industry may still be remarkable.

Somehow surprisingly, the insurance value does not arise much from physical disruption requiring costly fuel switching or even load shedding, but rather derive from an growing feature of liberalised markets, i.e. their tendency to spike as a response to disruptive events that unexpectedly affect either the supply or demand side of the market. Since this insurance value may not be fully captured by private companies, which are likely to be able to transfer related costs to end users, there may be room for some policy measures.

On the other hand, it is clear that storage obligations and strategic storage, the traditional SRSMs, are not likely to be the most efficient way of addressing the insurance and SoS value of storage. Rather, it would be preferable to internalise this value, either as a penalty in case of disruptions (provided that their costs are not eventually passed through to end users), or as incentives and premiums offered for physical or virtual storage or other market driven tools, which may deliver to gas consumers the expected benefits of levelling price spikes, as well as reducing their size. This is indeed the typical role of inventories in almost all commodity markets.

ANNEX 1 - DESCRIPTION OF AVAILABLE DATA: GSE GAS STORAGE MAP

Data evidence on storage in Europe is made available by Gas Storage Europe (GSE). GSE data that are available on the GSE website include:

- the Aggregated Gas Storage Inventory database (AGSI+ database)
- GSE Storage Capacity Map.

GSE data are disclosed on a voluntary basis by storage companies that are GSE members.

The GSE Gas storage map is available at: http://www.gie.eu/index.php/maps-data/gse-storage-map

Years available: 2006, 2011, 2013 and 2014

The GSE Gas storage map includes the following variables

- Working gas volume - TPA (million m3). Commercially offered firm capacities (sold or unsold) in the meaning of GGPSSO: "the maximum available storage capacity (i.e. technical storage capacity), apart from that part of the storage capacity used for operational needs related to transmission and/or production...". This includes TPA exempted capacities as far as they are not defined as Non-TPA below.
- Withdrawal capacity (million m3 per day) - TPA. Technical withdrawal rate related to TPA Working gas volume.
- Injection capacity (million m3 per day) - TPA. Technical injection rate related to TPA Working gas volume
- Working gas volume - Non-TPA (million m3). Capacities reserved for operational needs related to transmission and/or production including strategic stocks (only technical capacitites).
- Withdrawal/Injection capacity (million m3 per day) - Non-TPA. Technical injection rate related to TPA Working gas volume

ANNEX 2 - AGGREGATED GAS STORAGE INVENTORY DATABASE (AGSI+)

Data evidence on storage in Europe is made available by Gas Storage Europe (GSE). GSE data that are available on the GSE website include:

- the Aggregated Gas Storage Inventory database (AGSI+ database)
- GSE Storage Capacity Map.

GSE data are disclosed on a voluntary basis by storage companies that are GSE members.

AGSI+ database includes the following variables:

- Stored gas: current inventory level of gas in storage at 06:00 pm, in mcm[158]. Stored gas as reported in the AGSI database includes all working gas, irrespectively of its legal status (e.g. whether it is available for TPA, or strategic gas, or reserved for producers)
- Injection into storage site: storage increase at 06:00 pm compared to 06:00 pm on previous day, in mcm (only starting from January 2010)[159]
- Withdrawal into storage site: storage decrease at 06:00 pm compared to 06:00 pm on previous day, in mcm (only starting from January 2010)
- Percentage of filling: % of maximum available storage in use (storage level compared with Declared Total Maximum Technical Storage, namely: Stored gas/DTMTS)
- DTMTS: Declared Total Maximum Technical Storage in mcm, that is the maximum technical storage space capacity
- DTMTI: Declared Total Maximum Technical Injection / day in mcm (only starting from January 2010)
- DTMTW: Declared Total Maximum Technical Withdrawal / day in mcm (only starting from January 2010)
- Accuracy/Status: signaling the degree of accuracy of each data point.

AGSI+ has been first launched in 2007 and has evolved quite a lot since it started.

The AGSI+ spatial coverage has enlarged over time: the number of storage facilities/SSOs covered by the database constantly increased over the whole period. Data granularity also improved: data are published daily for the period January 2010-to date, weekly for the period January 2007-September 2010; data are disaggregated at storage facility level since 2014, at country level since January 2010 and hub region level since 2007.

More precisely, the database went through different phases:

1. For the period from the 08/01/2007 to 22/10/2007, regional aggregated weekly data on storage levels and filling rate were published for four regions:

- North West Europe including Germany, Denmark and Sweden
- North Europe including UK, France (excluding PEG TIGF) , Ireland, Netherlands, Belgium
- South Europe including Portugal, Spain, PEG TIGF

[158] There are no official GCV values for stored gas. The EU average is 11.6 kWh/Nmc but 11 is typically used by GIE.
[159] Note that in the AGSI+ data set the difference between gas stored in d+1 and gas stored in d, do not necessary coincide with net movements from storage (-withdrawal + injection).

- South East Europe including Italy, Greece, Austria, Cz, Rep, Slovakia, Hungary, Poland

2. For the period starting from September 2007 up to 31 December 2009, only weekly data was provided by a limited set of SSOs, with accuracy generally lower than in the most recent data. Explicit information on the declared total technical maximum space capacity (DTMTS) started to be included in the dataset. Data were aggregated by 7 hub regions. Hub regions are defined as follow:

- TTF (Eurohub): Denmark, Netherlands
- NBP&ZEE: Belgium, Great Britain. Starting from the 18th of May 2009 the hub region NBP&ZEE was split up into two separate hubs 'NBP' (corresponding to GB storage) and 'ZEE' (corresponding to Belgium storage)
- PSV: Italy
- Germany: NCG, Gaspool
- PEG: including storage groups Sediane, Sediane Multi, Sediane B, Sediane Littoral, Serene Nord and Serene Sud[160].
- Baumgarten: Austria, Czech Republic, Hungary, Poland, Slovakia
- Iberian: Spain, Portugal

3. Starting from 1 January 2010 up to 31st of December 2013, daily data were provided and data were aggregated by country as well as by hub region. Explicit information on the declared total technical maximum injection and withdrawal capacity (DTMTI, DTMTW), as well as on daily stock change, started to be included in the dataset.

4. Starting from 1st January 2014 data were provided on a daily basis at facility level. As of February 2015 the 48 SSOs report data to the AGSI+ dataset:

As far as sample countries are concerned, data available on AGSI+ are summarized below.

Country	Hub region in AGSI+	Country daily data on stored gas and DTMTS available since	Country weekly data on stored gas and DTMTS available since
Germany	Germany	1-Jan-10	8-Oct-07
France	France	1-Jan-10	17-Sep-07
Italy	PSV	1-Jan-10	17-Sep-07
UK	NBP&ZEE	1-Jan-10	18-May-09
Austria	Baumgarten	4-Mar-12	N/A
Poland	Baumgarten	4-Mar-12	N/A
Slovakia	Baumgarten	4-Mar-12	N/A
Hungary	Baumgarten	4-Mar-12	N/A
Bulgaria	South East	12-Dec-12	N/A
Denmark	TTF	1-Jun-12	N/A
Spain	Iberian	15-Mar-11	N/A

[160] As of April 2010, a re-allocation of Storengy storage groups has been made between the PEG and Iberian hub areas, as a result of which the storage group Serene Sud has been allocated to the hub Iberian. As of 15 March 2011 other re-allocation for storage capacity between PEG region and Iberian region was made.

Additionally, AGSI provides hub-level aggregated data for regions where sample countries are included.

Hub region in AGSI+	Countries included	Hub region daily data on stored gas and DTMTS available since	Hub region weekly data on stored gas and DTMTS available since
TTF	Denmark, Netherlands	1-Jan-10	17-Sep-07
PSV	Italy	1-Jan-10	17-Sep-07
Italy	PSV	1-Jan-10	17-Sep-07
NBP&ZEE	Great Britain	1-Jan-10	17-Sep-07
Baumgarten	Austria, Czech Republic, Hungary, Poland, Slovakia	1-Jan-10	17-Sep-07
PEG	France	1-Jan-10	17-Sep-07
Iberian	Spain, Portugal	1-Jan-10	17-Sep-07
South East	Bulgaria	12-Dec-12	N/A

Due to progressive enlargement of the dataset and occasional re-arrangement of region boundaries, it is not straightforward to identify whether the increase in space capacity included in the AGSI+ is due to either the enlargement of the dataset coverage (e.g. due to an existing facility/SSO which began to report data to GSE), or to data re-arrangement (e.g. France region including sites previously accounted for in Iberian region), or to an actual increase in European storage capacity due to a new project coming online. Actually the period 2007-2014 saw also an important increase of storage capacity due to many projects coming online.

We identified the following important breaks in the dataset, limiting the feasibility of a comparison over time:

- In December 2009 NBP coverage enlarged from 2 SSOs (Centrica, National Grid) to 6 SSOs and data for all UK storage facilities were included for the first time.
- More precisely, in December 2009, National Grid started its reporting to the AGSI publication and data for all UK storage facilities were included for the first time. Before that date, data for NBP hub region included only 2 SSOs: Centrica (Rough site) and National Grid LNG sites. Therefore starting from December 2009, NBP included 6 SSOs: Centrica (Rough site), National Grid LNG (Glenmavis LNG, Avonmouth LNG, Partington LNG sites), Scottish Power (Hatfield Moor), Scottish and Southern Energy Ltd (Hornsea, Aldbrough), EDF Trading Gas Storage Ltd (Hole House Farm), Star Energy (Humbley Grove)
- In June 2009, PSV storage levels were revised as they previously did not include 5100 mcm of strategic stocks.
- More precisely, on the 6th of June 2009, PSV storage levels were recalculated to include strategic stocks. As a result of this, Italian SSOs Stogit and Edison Stoccaggio also updated their DTMTS (Declared Total Maximum Technical Storage). Storage covered by hub region PSV increased by 5100 mcm, from 9235 mcm to 14335 mcm
- Over the period, the Germany coverage was updated several times, possibly due to existing German SSOs or storage associations starting their reporting to the AGSI publication or revising data.
- More precisely, the difference in DTMTS between the beginning of October 2007 and the end of 2008 accounted for over 1.7 bcm. The most important break in the stock level time series however occurred on the 18th of May 2009

when Wingas joined the Germany hub region and as a result of the maximum storage capacity of the Germany hub increased by 4.6 bcm, going from 12.936 up to 17.536 bcm[161].

- Over the period, the Baumgarten hub region coverage was progressively updated, mainly due to existing SSOs, starting their reporting to the AGSI publication or revising provided information on DTMTS. The most important break in the stock level time series in June 2009 when the Hungarian storage operator MMBF (accounting for 1.9 bcm working gas including 1.2 bcm strategic stocks) and Austrian RAG (accounting for 0.7 bcm working gas) joined the AGSI dataset.
- The definitions for the Iberian and France (former PEG) hub regions changed over time. As of 15th March 2011 AGSI+ eventually redefined the allocation of storage capacity between the Iberian and France regions. Since then France region contain three sub-regions: PEG SUD containing the Storengy data previously in IBERIAN; PEG NORD containing the Storengy data previously in PEG; TIGF containing the TIGF data previously in IBERIAN. Data before that date have not been revised accordingly, not allowing for consistent comparison.

Based on the data available on AGSI+, and taking into account the above mentioned breaks, we combine the AGSI+ weekly dataset for the period 2007-2009 and the daily dataset for data after 2010, in order to get consistent time series[162], relevant to describe the evolution of storage use for sample countries. We prefer daily data to weekly data when available, but for when weekly data took into account for data coverage enlargement earlier than daily[163].

More specifically we create daily time series presented in Table A.1.1 below.

[161] Stock levels data provided by Wingas to AGSI cover the company's storage capacity located in both Germany and Austria, the latter of which serves exclusively the German market. The total stock values for Wingas are attributed to the hub GERMANY in the AGSI dataset.
[162] Outlaying data points which were clearly spurious were eliminated, and corrected when possible.
[163] For instance daily Germany data include Wingas data only starting from 1/04/2010, while weekly data include Wingas starting from 18/05/2009. Further daily data for Baumgarten include MMBF data only starting from April 2010, while weekly data include Wingas starting from June 2009.

Table A.1.1 Time series created from AGSI+

Country/ Region	Time span	Input data	Comment
Germany	Oct 2008–Dec 2014	weekly data for Oct 2008 to Mar 2010 and daily data for Apr 2010-Dec 2014	WINGAS data are included since the 18/05/2009
France	Mar 2011–Dec 2014	daily data from March 2011	before Mar-2011 re-arrangement of storage capacity between PEG and Iberian region prevent any consistent comparison
Italy	Sep 2007–Dec 2014	weekly data for Sep 2007 to Dec 2009, daily data for Jan 2010-Dec 2014.	Strategic stored gas is always included within DTMTS and stored gas volumes.
UK	May 2009–Dec 2014	weekly data for May 2009 to Dec 2009, daily data for Jan 2010-Dec 2014	all UK storage facilities included since Dec 2009
Austria	Mar 2012-Dec 2014	daily data for Mar 2012-Dec2014	
Poland	Mar 2012-Dec 2014	daily data for Mar 2012-Dec2014	
Slovakia	Mar 2012-Dec 2014	daily data for Mar 2012-Dec2014	
Hungary	Mar 2012-Dec 2014	daily data for Mar 2012-Dec2014	
Bulgaria	Dec 2012-Dec 2014	Weekly data for Dec 2012-11/3/13, daily data for 3/3/2013 to Dec 2014	
Denmark	Jun 2012-Dec2014	Daily data for Jun 2012-Dec2014	Before that date aggregated with NL within the region TTF(Eurohub)
Spain	Mar 2011–Dec 2014	daily data from March 2011	before Mar-2011 re-arrangement of storage capacity between PEG and Iberian region prevent any consistent comparison
Baumgarten	Sep 2007–Dec 2014	weekly data for Sep 2007 to Mar 2010, daily data for Apr 2010-Dec 2014.	MMBF and RAG data included in June 2009

ANNEX 3. CASE STUDY: AUSTRIA

A.3.1 Austrian security of supply related measures

A.3.1.1 Illustrate and discuss the main storage related SoS measures of the country

Gas is an important energy source for the Austrian energy market (about 21% of total energy consumption 2013. The total gas consumption amounted to 7.6 bn m3 in 2013 which can be spread to the various sectors: [164]

- Industry: 43%
- Power stations, heat: 28%
- Households, agricultural: 19%
- Transport and services: 10%

In order to secure the gas supply the Austrian gas market relies on a mixture of imports, gas storage facilities and diversification of gas supplying countries. Although the Austrian gas market relies on imports there was no supply crisis in last decades which caused any damages to final consumers even though gas imports were interrupted for almost two weeks during the Ukraine crisis in 2009. The gas imports (about 88% of gas supply or 41.8 Bcm in 2014) come from Slovakia[165] (74%) and Germany (26%). In addition to gas imports the Austrian gas market consists of reasonable gas underground storage capacities. The storages capacities may store about one third of the Austrian annual gas consumption (7.373 Bcm in 2014). Finally, Austria has own gas fields which accounted for 16.8% of Austrian gas consumption in 2014 (total of 1.179 Bcm).[166]

Table A.3.1. Gas storage capacities in Austria

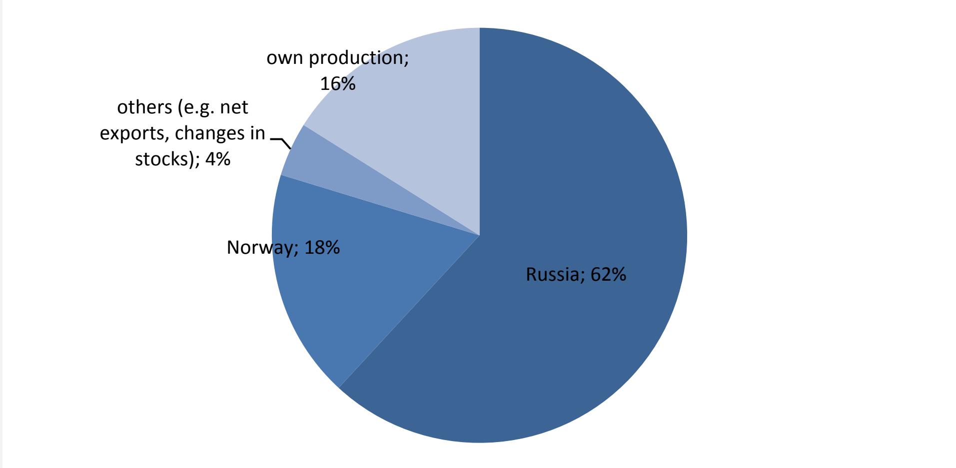
Name	Company	Maximal injection capacity [m3/h]	Maximal exit capacity [m3/h]	Working gas [Mio. m^3]
Schönkirchen/ Reyersdorf	OMV Gas Storage	650,000	960,00	1.780
Tallesbrunn	OMV Gas Storage	125,000	160,000	400
Thann	OMV Gas Storage	115,000	130,000	250
Puchkirchen/Haag	RAG	520,000	520,000	1.080
Aigelsbrunn	RAG	50,000	50,000	100
Haidach 5	RAG	20,000	20,000	16
Nussdorf/ Zagling	RAG			
Haidach	RAG/astora/Gaz prom Export	1,000,000	1,100,000	2.640
7Fields	RAG/ E.ON Gas Storage	662,600	963,600	1.850
Austria total		3,142,600	3,903,600	8.116

Source : Austrian National Emergency Plan 2014

[164] See Natural gas and district heating – numbers 2014.
[165] The share of gas from Russia entering Austria via Slovakia is more than 90%
[166] See E-Control: Erdgasstatistik: Betriebsstatistik 2014. .

In general Austria relies on market forces to manage potential supply crisis and has not implemented any specific supply obligations. That is to say due to the market opening in recent years various supply companies appeared by which the sources have been further diversified. In addition to this there are further projects ongoing to connect additional gas storage capacities also internationally inter alia in order to increase security level in case of supply interruption in winter times..

Figure A.3.1. Sources of Austrian gas consumption 2014 [%]



Source: own calculations, E-Control Erdgasbilanz 2014

The market parties - Distribution Area Manager and Market Area Manager - are responsible for coordinating the Long Term Planning (*Section 2.2*. of the Natural Gas Act) and the Coordinated Network Development Plan (*Section 63* of the Natural Gas Act) by implementing the projects in the respective plans..

According to Art. 121 (5) GWG the utilities supplying final consumers are responsible to secure the supply of protected customers. Protected customers in Austria are only households[167].

However, in addition there exist an emergency legislation (Energielenkungsgesetz 2012, EnLG) which defines precise crisis scenarios. Market interventions are allowed in order to avert an immediately foreseen interruption or to remove an already existing interruption, if the interruption

- is not the result of seasonal shortage in gas supply or
- cannot be removed by market based measures at all or in due time or only with exceptional expenses[168].

The difference between market responsibilities and measures according to EnLG and Gas Law (Gaswirtschaftsgesetzt, GWG) and other market obligation are summarized in Figure A.3.2. The measures under EnLG are limited for a period of 6 months, however, it can be prolonged.

[167] See Austrian Prevention Plan Gas (2014), p 8.
[168] See Art. 4 (1), 1 Energielenkungsgesetz 2012.

Figure A.3.2. Difference between market based and regulatory measures

Market based	Public intervention
•GWG 2011, GMM-VO, market rules •Daily business: operation management, market based measures (negotiated storage access) •Responsibility: market participants	•Energielenkungsgesetz •Emergency supply: Avoidance of an emergency or emergency management •Responsilities: public authorities (Federal Minister of Science, Research and Economy) in cooperation with market parties (inter alia E-Control, Distribution and Market Area Manager)

In case of a regulatory intervention the distribution market manager defines schedules for storage in order to overcome the emergency. Thereby the storage capacities are allocated pro-rata to the individual balancing accounts.

In addition to this intervention on storage capacities the EnLG foresees reporting obligations for large gas consumers: CHP operators (with a maximum thermal capacity of at least 50 MW or an annual heat output of at least 300 GW) and district heating companies (with a total maximum thermal output of at least 50 MW or an annual heat output of at least 300 GW)[169] .

Instead of interrupting individual consumers there is inter alia the opportunity to ask the market parties to voluntarily reduce their consumption ("Sparaufrufe"). In this case the final consumers, large consumers and consumers of district heating are appealed to consume the energy most economically.

A.3.2 Other SoS information

Before continuing with other SoS measures it should be noted that the Austrian gas market is split into three separated market areas: market area East, market area Tirol, market area Vorarlberg. The zones are physically not interconnected to each. The core market area of Austria is the market area East. The market areas Tirol and Vorarlberg are closely connected to the German gas market by implementing respective market rules as the only possibility to transport gas in these market areas is via Germany. For those consumers the German NCG ist used used as the VTP.

With respect to the market area East the impact of a default of gas supply routes (from SK, GER, ITA, and CZ) and an interruption of major infrastructures (e.g. storages) were investigated. The evaluation of the different scenarios showed that only 15 cases (3.8%) imply high risk. However, any of these incidents are not covered by SoS-regulation as the analysis also included distribution grids. The only relevant scenario which is addressed in the SoS-regulation is the interruption of supply via Slovakia to Baumgarten. This scenario is judged as low risk. The proposed measures to compensate the default are the utilization of storage facilities and a higher gas supply via Oberkappel. However, any of these measures should be market based as it was done in 2009, when this emergency occurred in reality.

[169] See section 27(5) and 26 (5)

A.3.2.1 N-1 standard level, pursuant to art. 6 of Regulation 994/2010/ec

The N-1 standard for the market area is fulfilled. The relevant parameter N-1 results in 234,59%. The two other market areas are distribution network which are not considered by the SoS-regulation. Due to their connection to Germany their peak demand (Tirol: 2.1 million m^3/d and Vorarlberg: 1.8 million m^3/d) have been included in the German calculations. Even in this case the German N-1 standard is fulfilled.

Table A.3.2. N-1 standard Austria 2014		
		mcm/day
Technical capacity of entry points	EP_m	275.1
Maximum daily technical storage withdrawal capacity	S_m	47.75
Maximum daily technical production capacity	P_m	4.1
Maximum daily technical LNG send-out capacity	LNG_m	0
Technical capacity of single largest gas infrastructure	I_m	205.2
Daily gas demand (once in 20 years)	D_{max}	51.9
N-1		234.59%
Source: National Prevention Plan Austria Version 2, December 2014 [170]		

The individual parameters are also shown in the National Emergency Plan 2014 and are presented in following table.

Table A.3.4. Individual parameters of N-1 criterion		
Asset class	**Technical capacity [Mio. m3/d]**	
EPm	275.10	
- Baumgarten	205.20	
- Oberkappel	21.80	
- Überackern	10.10	
- Arnodstein	37.10	
- Freilassung & Laa	0.90	
Pm	4,10	
- Production OMV	3.36	
- Production RAG	0.74	
Sm	47.75	
- Storage OMV	31.09	
- Storage RAG	13.39	
- Storage E.ON Gas storage	3.27	
- Storage astora (Haidach)	0.0	
- Storage Gazprom Export (Haidach)	0.0	
LNGm	0.0	
Im	205.20	Baumgarten
Dmax	51.90	
Source: Austrian Emergency Prevention Plan 2014		

170 http://www.bmwfw.gv.at/EnergieUndBergbau/Energieeffizienz/Documents/Nationaler%20%C3%B6sterreichischer%20Pr%C3%A4ventionsplan%20zur%20Gew%C3%A4hrleistung%20der%20sicheren%20Gasversorgung_2014_final_DE_korr.pdf

The analysis for the different cases assumed in SoS-regulation[171] showed that all cases are fulfilled. Suppliers of protected customers are obliged to report how they intend to fulfil the supply standard annually ex ante. This monitoring differentiates three cases:

- case a: extreme temperature: the gas storage capacities cover at the necessary volumes by 21-60 times
- case b: extreme gas consumption: volumes in gas storage cover about 4-14 times the necessary demand
- case c: interruption of the largest gas infrastructure for at least 30 days: gas storage volumes cover about 5-15 times of the necessary demand.

The required gas volumes according to the different cases are shown in Table A.3.5.

Table A.3.5. Required gas volumes per measure point to fulfill different cases

	Oct. 2014	**Nov. 2014**	**Dec. 2014**	**Jan. 2015**	**Feb. 2015**	**Mar. 2015**
Case a: [kWh/d]	52	78	104	94	117	79
Case b: [kWh]	33	62	93	82	92	65
Case c: [kWh]	28	47	76	76	78	50

Source: Austrian National prevention plan 2014

[171] See Regulation EC No. 994/2010

ANNEX 4. CASE STUDY: BULGARIA

A.4.1 Main storage related SoS measures of the country

A.4.1.1 Mandatory Storage Obligations

Storage in Bulgaria

Bulgaria has a single underground gas storage facility, Chiren, managed by the Bulgarian TSO Bulgartransgaz and located in the north-west of the country. Chiren has a working gas capacity equal to 550 mcm[172] (6400 GWh), which corresponds to about 20% of total annual domestic gas consumption in 2013[173], and a maximum declared withdrawal capacity amounting to 4.2 mcm/d[174] (49 GWh/d) corresponding to 23% of estimated daily peak demand[175]. Access to storage is regulated.

Supplier storage obligation

In Bulgaria a mandatory storage obligation exists in the form of supplier storage obligation.

More precisely, according to the Bulgarian Emergency Plan (EP)[176], the dominant Bulgarian supplier (Bulgargaz, who carries out the activity of public provision of natural gas[177]) shall store gas quantities amounting to 250 mcm. More specifically, 130 mcm are needed to safeguard supplies, and the remaining 120 mcm are needed to cover seasonal shortage at the entry of the system.

The criteria to determine such amount are not disclosed, however the gas volumes that Bulgargaz had to store correspond to about 10% of total yearly gas consumption in 2013.

Mandatory use of storage in the event of disruption

In addition, in the event of a crisis the use of storage capacity is subject to the rules set in the EP. The storage operator Bulgartransgaz in the event of disruption has the right to limit/interrupt/maximise the level of injections and withdrawals.
More specifically, when the "early warning level" or the "alert" level is notified, additional gas quantities shall be injected in Chiren storage by the TSO, either physically of virtually (by reducing withdrawals), provided that this is technically and commercially feasible.
When emergency level is declared, enforced storage withdrawals are foreseen and the whole amount of gas stored in Chiren facility is used to meet the needs of protected consumers.

The storage operator Bulgartransgaz also has the right to limit/interrupt the level of injections and withdrawals when there is a need to ensure capacity for

[172] Source: GSE Storage Map.
[173] Source. Eurostat.
[174] Source: GSE Storage Map. According to Bulgarian Preventive Action Plan (PAP) Chiren storage facility's withdrawal capacity ranges from 1 mcm/d to 4,2 mcm/d depending on the pressure layers and other factors; injection capacity into storage ranges from 1.5 mcm/d to 3.5 mcm/d for injection.
[175] Source: EP, p.8. PAP p.7.
[176] EP approved by Order № РД-16-1663/30.11.2012 of the Minister of economy and energy.
[177] Bulgargaz EAD is the only company in the country who holds the license for public provision of natural gas, that is the supply of gas to consumers who did not freely select their supplier. Bulgargaz is referred as the Public Provider and carries out wholesale gas supply at regulated prices set by the Energy Regulator SEWRC and its share in gas sales in 2013 was 87%. The remaining 13% share is made by two traders (Dexia and Overgas). In compliance with the European directives for full liberalization of electricity and natural gas markets, all gas consumers in Bulgaria have the right to select their natural gas supplier. Practically, in 2013 that right was exercised by one business consumer (District heating-Razgrad EAD) and the five gas distribution companies of the Overgas Inc. AD group. Households have not exercised that right in 2013 (Source: SEWRC Report to ACER 2014).

injection/withdrawal of the natural gas quantities stored in Chiren by Bulgargaz to comply with the supplier storage obligation, which are equal to 250 mcm (see above)

A.4.2 Special Mandatory strategic Storage

No special mandatory strategic storage exists in Bulgaria, although gas volumes stored by Bulgargaz can be considered strategic storage, as they should be used in the event of an emergency.

A.4.3 Any other existing storage related measures

A.4.3.1 Tariffs for transmission to/from storage

Tariff for transmission to/from storage equals to 19.73 BGN/mc[178]. These tariffs are 100% commodity tariffs.

A.4.3.2 Incentives for storage accumulation and investments

To the best of our knowledge no national incentives scheme for storage accumulation and investments in storage is foreseen. However, projects for expansion of Bulgarian storage capacity qualified for the status of Project of Common Interests (see below), so they may benefit from grants and regulatory incentives, as well as from a stream-lined authorization procedure. Investment in storage capacity is mainly regarded as a security of supply issue (see below).

A.4.3.3 Drivers for investment decisions in storage

In the EP, the expansion of Chiren storage facility is presented as an important measure to improve security of supply in the country. According to the Bulgarian Preventive Action Plan (PAP)[179], a project for the expansion of Chiren facilty shall be implemented to foster security of supply[180]. The first stage of expansion was expected in 2014, consisting in new drills aimed at upgrading withdrawal capacity from 4.2 to 5.5 mcm/d and working gas from 550 mcm to 650 mcm by 2017. The expansion of Chiren storage facility is a project that obtained Project of Common Interest (PCI)[181] status, according to the list published in October 2013. Similarly PCI status was obtained by a project aiming to the construction of new storage facility on the territory of Bulgaria.

A.4.3.4 Information on long term allocation of storage capacity

As of 2014, two storage services are available in Bulgaria

[178] http://www.bulgartransgaz.bg/en/pages/transstorge-110.html
[179] PAP approved by an Order №РД-16-1662/30.11.2012 of the Bulgarian Minister of economy and energy
[180] Note that Chiren storage facility planned expansion is not indicated in the GSE Storage Map.
[181] On 14 October 2013, the European Commission has adopted a list of 248 key energy infrastructure projects. These projects have been selected by twelve regional groups established by the new guidelines for trans-European energy infrastructure (TEN-E). Carrying the label "projects of common interest" (PCI) they will benefit from faster and more efficient permit granting procedures and improved regulatory treatment.

- Short-term storage bundled services: contracted storage capacity where the schedule of injection and withdrawal is within one gas year
- Long-term storage bundled services: contracted storage capacity where the period between the schedule of injection and withdrawal is more than one gas year.

For storage year 2014/15 (SY 2014/15) the SSO Bulgartransgaz offered most of the capacity for the short term service (Table A.4.1). As of SY 2014/15 total available commercial storage capacity was equal to 300 mcm.

Table A.4.1. Available commercial storage capacity for SY 2014/15 at Chiren facility	
Service	Firm Capacity (mcm)
Short-term storage	273
Long-term storage	27
Total available commercial storage capacity	300

As of 2014, storage capacity is allocated according to a "merit order" and priority is given to storage users who supply protected consumers and to protected consumers themselves[182]. Therefore the top priority in allocating storage is given to: district heating companies supplying customers in Bulgaria with heat energy and end suppliers supplying households in Bulgaria. The rationale behind the priority is guaranteeing the security of supply in the winter season, as peak consumption in winter months is mainly caused by increased natural gas consumption in this period for space heating purposes.

Storage capacity that can be allocated to a storage user is proportional to the gas quantities the user supplies, under signed contracts, to protected consumers.

The storage capacity that is available after priority allocation is allocated pro-rata between users who do not supply protected consumers. Then, any available capacity is allocated following the principle "First come, first served" and if more than one application has been received on the same working day, the available capacity is allocated pro rata to the applications received[183].

As of 2013 there was no storage capacity trade on the secondary market[184], although the transfer of storage capacity is allowed[185].

A.4.4 Other SoS info

Pursuant to SoS Regulation (Art. 6 of Regulation 994/2010/EC), the "Prevention Action Plan" (PAP) and the "Emergency action plan" (EP) were published by the Bulgarian Ministry of Economy, Energy and Tourism (MEET)[186] in 2012[187].

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[182] Rules for access to Chiren Underground Gas Storage, effective as of 29.04.2014. Adopted by Decision under item 4.1 of Protocol No 120/28.03.2012 of Bulgartransgaz EAD Board of Directors and amended and supplemented by Decision under Minutes № 40/29.04.2014 of meeting of Bulgartransgaz EAD Management Board.

[183] http://www.bulgartransgaz.bg/en/news/available_natural_gas_storage_capacity_at_ugs_chiren_for_gas_year_2014_2015-168-c15.html

[184] SEWRC Report to ACER 2014, p.49.

[185] Rules for access to Chiren Underground Gas Storage, effective as of 29.04.2014. Adopted by Decision under item 4.1 of Protocol No 120/28.03.2012 of Bulgartransgaz EAD Board of Directors and amended and supplemented by Decision under Minutes № 40/29.04.2014 of meeting of Bulgartransgaz EAD Management Board.

[186] The competent Authority is the Bulgarian Ministry of Economy, Energy and Tourism pursuant to art. 4, para. 2, item 4a of Energy Act.

[187] PAP approved by an Order №РД-16-1662/30.11.2012 of the Bulgarian Minister of economy and energy and EP approved by Order № РД-16-1663/30.11.2012 of the Minister of economy and energy.

As of 2014, Bulgaria remains highly dependent on gas imported via the Trans-Balkan pipeline coming from Russia and passing through Ukraine, Moldova, Romania and eventually entering Bulgaria at the Negru Voda I (RO) / Kardam (BG) Interconnection Point (IP). As of March 2015, Russian gas is supplied pursuant to a 10-year contract signed between Bulgargaz and Gazprom Export in November 2012. Total annual quantity is estimated to be 2.9 bcm[188]. The former contract, under which Gazprom supplied up to 3.1 bcm of gas to Bulgaria, expired at the end of 2012.

Investments in reverse flow and interconnectors with neighboring countries (Greece, Romania, Turkey and Serbia) have been planned to improve security of supply.

In particular, pursuant to SoS Regulation (Art. 6 of Regulation 994/2010/EC), the Bulgarian gas TSO Bulgartransgaz as of 1 January 2014 made available reverse physical flow from Greece. The transmission technical capability from Greece to Bulgaria, at IP Kulata (BG) / Sidirokastron (GR) ranges from 1 mcm/d to 3 mcm/d (11-34 GWh/d), depending on the Greek gas transmission network capabilities[189]. The reverse flows at the interconnection between Greece and Bulgaria, according to Commission Staff Working Document SWD (2014) 325[190], could in principle be used to a level of 3 mcm/d of which 1 mcm/day is firm capacity while another 2 mcm/d is interruptible capacity, while Bulgaria sets out in its national Stress Test report that the capacity could even be 4.2-6 mcm/d depending on pressure conditions.

The Bulgaria-Romenia interconnector (IBR) with a technical capacity of 0.5 bcm/y (1.4 mcm/d) was commissioned in 2014[191]. The construction of the Interconnector Bulgaria - Romania faced a series of technical problems resulting in delay of its commissioning, originally expected for May 2013[192]. According to according to Commission Staff Working Document SWD (2014) 325[193], the interconnector between Bulgaria and Romania was initially foreseen to be operational by the end of 2013 but was not finalized yet as of October 2014. In addition, the same document points out that the low pressure in the Romanian system remains problematic with respect to enabling more substantial cross-border flows to Bulgaria.

The other projects that have been put forward to improve security of supply in Bulgaria are:

- the Greece-Bulgaria interconnector (IGB) with a technical capacity of 3 bcm/y was expected to be commissioned in 2014, but experienced delays and it is now more likely to be completed by 2016[194]. IGB will provide a direct link between Greece and Bulgaria with an Entry Point in the vicinity of Komotini (GR). IGB was given the status of Project of Common Interest (PCI) and also receives EU financial support under the European Energy Program for Recovery
- the interconnection Bulgaria-Turkey (ITB) having a capacity of 3-5 bcm/year and with expansion possibility on subsequent stage; ITB was given the status of Project of Common Interest (PCI). Presently, Turkey does not have the available capacity to supply gas for Bulgaria, even for reverse flow in the event of a crisis, due to fast growing consumption in Turkey
- the interconnection Bulgaria-Serbia (IBS) with a 1.8 bcm/y capacity in both directions and expected to be commissioned in 2015.

[188] World Gas Intellingence , 21/11/2012.
[189] SEWRC Annual Report to ACER, 2013, p.51. According to ENTSO-G data technical physical capacity at IP Kulata (BG) / Sidirokastron (GR) amounts to 108 GWh/d and Bulgartransgaz offers firm capacity in one direction, and virtual backhaul capacity in the other, whereas DESFA offers firm capacity in one direction.
[190] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.
[191] http://www.bulgartransgaz.bg/en/news/forthcoming_commissioning_of_interconnection_bulgaria_romania-134-c15.html.
[192] PAP, p. 11.
[193] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.
[194] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.

A.4.4.1 N-1 rule

For the purpose of computing the N-1 rule, the major import infrastructure is the Trans-Balkan pipeline coming from Russia and passing through Ukraine, Moldova, Romania, and entering Bulgaria at Negru Voda I entry point. Its daily technical capacity amounts to 20.3 mcm/d (227 GWh/d), according to EP.

Daily peak domestic demand, originating from gas end users and distribution companies connected to the grid, according to EP equals 18 mcm/d (209 GWh/d)[195].

Bulgaria is an important transit country (natural gas is transported from Russia through Bulgaria to Turkey, Greece and FYRM) and total Bulgarian exports, intended for transit to Turkey, Greece and FYRM, as well as for transmission to consumers in South-western Bulgaria, equals 24 mcm/d (278 GWh/d)[196].

Based on import capacity available as of the end of 2014, maximum withdrawal capacity from storage as published by GSE, PAP estimates for peak domestic demand and maximum deliverability from domestic production, Bulgaria does not fulfil N-1 rule (Table A.4.2), as, assuming the maximum contribution from reverse flow from Greece, the N-1 formula returns 70% if the IBR is considered and 62% if not. In the calculation transit volumes are fully disrupted. If reverse flow from Greece is at the minimum level, then the N-1 formula returns 49% if the IBR is considered and 41% if not.

Table A.4.2. N-1 analysis (actual values as of 2014)

Main inputs in the N-1 analysis for 2014 (actual values)	**Technical capacity mcm/d (actual as of 2014)**
Pipeline imports from Negru Voda I (RO) (Largest infrastructure)	20.3
Pipeline imports from Sidirokastro (GR) (reverse flow)	From 1 to 3.5
Pipeline imports through the interconnector BG-RO (IBR)	1.4
Pipeline imports through the interconnector GR-BG (IGB pipeline)	0 (not yet commissioned)
Pipeline imports from Malkoclar (TR) (reverse flow)	0 (not yet commissioned)
Pipeline imports through the interconnector TR-BG	0 (not yet commissioned)
Pipeline imports through the interconnector BG-RS	0 (not yet commissioned)
Domestic production	2.2
Storage withdrawal (Chiren facility)	4.2
National peak demand	18
Note: reverse flow from Greece ranges from 1 to 3.5 mcm/d. 3.5 mcm/d is assumed in the PAP	
Source: estimates based on PAP, ENTSOG capacity map, SEWRC Report to ACER	

The result is different from what presented in the PAP, issued in 2012. In 2012, in fact, a N-1 supply exceeding peak demand by 15% was expected for 2014, thanks to

[195] EP, 6.7.3.
[196] EP, 6.7.4.

the expected commissioning of IGB, which did not occurred as explained above (Table A.4.3).

Table A.4.3. N-1 Analysis (for 2014 as expected in 2012)	
Main inputs in the N-1 analysis for 2014, as expected in 2012	**Technical capacity mcm/d, as expected in 2012**
Pipeline imports from Negru Voda I (RO) (Largest infrastructure)	20.3
Pipeline imports from Sidirokastro (GR) (reverse flow)	3.5
Pipeline imports through the interconnector BG-RO (IGR)	1.4
Pipeline imports through the interconnector GR-BG (IGB pipeline)	8.2
Pipeline imports from Malkoclar (TR) (reverse flow)	0 (not yet commissioned)
Pipeline imports through the interconnector TR-BG	0 (not yet commissioned)
Pipeline imports through the interconnector BG-RS	0 (not yet commissioned)
Domestic production	2.2
Storage withdrawal (Chiren facility)	5.5
National peak demand	18
Source: PAP	

In 2012 it was expected that in the event of disruption of the single largest gas infrastructure (the pipeline bringing gas from Russia through Ukraine), the capacity of the remaining infrastructure (the reverse flow from Greece, domestic gas production, reverse interconnectors with Greece and Romania) was able to meet daily peak demand.

A.4.4.2 Definition of supply standards for protected consumers

Pursuant to SoS Regulation (Art. 8 of Regulation 994/2010/EC), supply standards for protected customers are defined.

According to Bulgarian EP protected consumers consist of all the categories foreseen by SoS Regulation. More specifically, in Bulgaria, protected consumers are:

- All household consumers connected to a gas distribution (low pressure) network
- Small and medium-sized enterprises, provided that they are connected to a gas distribution network, and essential social services, provided that they are connected to a gas distribution network or to a gas transmission network, and provided that these additional consumers do not represent more than 20% of total end-user demand of gas
- Central heating installations to the extent that they deliver heating to household consumers and to the other protected consumers, provided that these installations are not able to switch to other fuels and are connected to a gas distribution network or to a gas transmission network

Gas supplies shall provide for guaranteeing the supply to protected customers, defined as specified above, in case of:

- extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
- any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years;
- for a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions.

The daily direct consumption of natural gas in a cold winter day by public, administrative and household clients connected to the gas distribution network totals around 0.5 mcm; while, in a typical winter day, the total consumption of gas by all protected customers, including district heating companies, is around 5 mcm[197].

The PAP assesses the quantitative requirements to fulfill supply standards for protected customers in Bulgaria and explain how these standards are met[198]. Supply to protected customers for a period of 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions can be met by storage withdrawals and domestic production, which are able to supply 5.5 mcm/d. In particular, Chiren storage facility can deliver 3.7 mcm for a period of 30 days.

In the event of extreme temperatures and exceptionally high gas demand, the excess demand can be covered by domestic production, resort to storage and higher import of gas.

No explicit mechanism for enforcing the implementation of supply standards is foreseen.

A.4.4.3 Cross border agreement or regional decisions in the field

Reverse flow from Greece was realized at the end of January 2009 gas crisis, based on signed agreement[199].

A cooperation scheme between Greece and Bulgaria has been discussed by which Greece could exchange around 3 mcm/d of gas (through the reverse flow) for its equivalent in electricity produced, thus helping to keep both sectors stable in the two Member States[200]. Bulgaria objected that for such an exchange-based scheme to function effectively, it needs the additional electricity generation capacity of the Varna coal-fired power plant which is to be closed down on 31 December 2014 in line with the Large Combustion Plant Directive[201]; the Commission states that it will consider granting a temporary exemption to alleviate a possible supply crisis[202].

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[197] PAP, P.8

[198] In order to quantify supply standards, the MEET requires information on:
historical gas demand levels
forecasts for the impact of abnormally low temperature on gas demand
gas quantities required to cover protected consumers' consumption needs (annual, monthly, maximum daily and maximum hourly value; the information about household consumers must be provided separately from information on non-household consumers)
time required for district heating companies to switch to an alternative fuel and supply heat to protected consumers
Such information has to be updated at least once in two years.

[199] SEWRC Report to ACER, 2014, p.52

[200] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.

[201] Varna power plant, owned by the CEZ Group, is situated in south-eastern Bulgaria and its generating capacity is of 1260 MW, consisting of 6 units of 210 MW each (Source: www.cez.cz). Unit 6 of the Varna power plant is to be shut down end 2014 on the basis of EU environmental rules set by Large Combustion Plant Directive (Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.) However, although units 1, 2 and 3 have a derogation to continue production until end 2015, due to running hour limitations of 700h/year for each, the plant owner (CEZ Group) is planning to shut down the entire plant by end 2014 (Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5).

[202] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.

No cross border agreements with FYRM have been signed to ensure gas transit to FYRM in the event of disruption, although this was suggested by the European Commission[203].

A.4.4.4 Quantitative estimate of Domestic Production

Domestic production, originating from the Galata field in the Black Sea, in 2013 amounted to 0.2 bcm[204]. There has been a decline in Bulgarian domestic gas production in the last three years: in 2013 production decrease by 43%[205] compared to 2011.

Pursuant to EP, domestic gas producers shall maximise production in the event of an emergency.
Maximum daily rate of domestic production is estimated at 2.2 mcm/d.

Quantitative estimate of LNG import capacity

No LNG facility in Bulgaria, however reverse flow from Greece to Bulgaria may allow imported LNG volumes, regasified at Greek Revithoussa terminal, to flow into Bulgaria.

Quantitative estimate of Pipeline import capacity

Gas suppliers must maximise imports in the event of an emergency[206].

In particular, pursuant to EP, importers of natural gas to Bulgaria[207] shall include flexible clauses in their gas procurement contracts such that the imported gas quantity can be increase above the contractual ones in the event of a gas crisis. However, information is not available on the implementation of such obligation.

Contractual maximum daily import volumes at the Negru Voda entry point are estimated at 10 mcm/d during the winter period[208]. In the event of an emergency, additional pipeline imports to Bulgaria are available thanks to reverse flow from Greece and to the Romania-Bulgaria interconnector. The maximum daily imported volumes coming from infrastructures are presented in Table A.4.4.

The reverse flows at the interconnection between Greece and Bulgaria, according to Commission Staff Working Document SWD (2014) 325[209], remain quite restricted and could in principle be used to a level of 3 mcm/d of which 1 mcm/day is firm capacity while another 2 mcm/d is interruptible capacity, while Bulgaria sets out in its national Stress Test report that the capacity could even be 4.2-6 mcm/d depending on pressure conditions.

[203] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.6.
[204] Eurostat.
[205] According to SEWRC Report to ACER 2014 domestic production in 2011 accounted for 406 mcm and in 2013 it accounted for 176 mcm. Data on domestic production provided by Eurostat for 2011 do not match the figure indicated by SEWRC, possibly for missing value in Eurostat dataset.
[206] In Bulgaria market players concluding or amending contracts for wholesale suppliers from third countries shall notify MEET the contract duration, annual total contracted quantities, agreed delivery point and, in the event of an alert or emergency, the contractual maximum daily volumes.
[207] The main importer is Bulgargaz, who has an import contract with Gazprom Export . In 2013, a second trader entered the Bulgarian natural gas market carrying out imports and at the same time selling natural gas to gas distribution companies and end consumers (SEWRC Report to ACER, p.10 and p.11).
[208] EP, 9.12.3.
[209] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.5.

Table A.4.4. Pipeline imports to Bulgaria		
	maximum daily imported volumes	Notes
Pipeline import volumes at the Negru Voda IP (Russian gas)	10	Contractual maximum daily imported volumes in winter(EP estimate)
Pipeline imports from Sidirokastro (GR) (reverse flow)	3.5	We assume that the whole technical capacity is used. However this may imply cooperative approach
Pipeline imports through the interconnector BG-RO (IGR)	1.4	We assume that the whole technical capacity is used
Note that reverse flow from Greece may happen at the expense of Greece. In other words, some disruption scenarios, ensuring gas imports from Greece may occur only provided that Greece accepts burden-sharing with Bulgaria. In fact, according to ENTSOG Stress Test exercise, in the event of all Russian supplies disruption, Greece experience smaller shortfalls and is the only Member State in the focus group South East Europe whose position deteriorates in the "cooperative" scenario due to a relative burden sharing with Bulgaria, whose position would otherwise be more precarious[210]		
Source: PAP		

A.4.4.5 Estimated demand response and fuel switching

Domestic household consumers

Household sector gas consumption is very low: less than 2% of the total consumption and the expected growth for the period 2014-2017 is from 1.4 to 2.3% of the total natural gas consumption in the country[211]. Domestic household consumers cannot provide any demand side response measure.

Transit

Pursuant to EP, when emergency level is declared, transit shall be restricted or disrupted.

According to European Commission[212], while not mentioned specifically in the report of Bulgaria, the demand in the former Yugoslav Republic of Macedonia is so small (1 mcm/d in February) that sending minimal necessary volumes to that country from Bulgaria will likely be possible even if Bulgaria experiences a shortfall; European Commission highlighted that this would be an important signal of cooperation that would need to be prepared in advance by way of an agreement between the two countries. However, No agreement was signed as mentioned above.

Industrial consumers and Heating sector

District heating companies and industrial consumers provide for the major demand-side measure in Bulgaria. First because they make it for the most of Bulgarian gas consumption, secondly because some district heating companies and industrial consumers are capable of switching from gas to alternative fuels.

[210] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.3.
[211] SEWRC Report to ACER, p.52.
[212] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.6.

In Bulgaria industrial consumers account for an important share of gas consumption: in 2013 industries represented 54% of total gas consumption in the country, amounting to 1.4 bcm[213]. This share is not expected to decrease[214].

District heating running on gas is well-established in Bulgaria. District heating companies represent an important share of winter gas consumption and on average consume 4.4 mcm/d during the winter[215] (representing 24% of peak demand). Bulgarian district heating facilities supply between 14-19% of total space and water heating requirement in the country and a share between 10-40% of domestic consumers have their house heated by district heating[216]. Up to 80% of district heating runs on gas in Bulgaria[217].

The PAP and the EP do not provide an assessment on the amount of price-elastic gas demand (for the industrial or heating sector) that may be removed from the market as a result of the likely price increases in the case of a serious disruption scenario, either through voluntary switching or voluntary load shedding. According to Stress Test Communication, in any event it is unlikely that demand response is higher than 10% in any Member State[218].

The PAP and the EP do not provide an assessment for existing interruptible contracts and the potential decrease in demand consumption in the industrial sector due to interruptible contracts.

This said, Bulgaria ruled for enforced fuel switching. In fact, Bulgaria foresees obligations for on-site stocking of alternative fuels (heavy fuel oil) for district heating plants and industrial consumers, which should allow fuel switching to take place in the event of a gas disruption. Pursuant to EP, when emergency level is declared, after that industrial consumption is limited according to contract provisions (i.e. interruptible contracts are activated, whose scope is not quantified as mentioned above), and there is voluntary switching to other fuels/load shedding(presumably driven by price increase, whose scope is not quantified as mentioned above), then forced use of alternative fuels stocks is foreseen.

More specifically, in Bulgaria suppliers to gas end-users require their final consumers, excluding households and industrial consumers without alternative fuels, to maintain stocks of alternative fuels. This obligation actually applies to the district heating plants and the auto-producers who are obliged to maintain reserves of heavy fuel oil, which they can use to continue production in the event of disruption in the gas supply.

According to Stress Test communication, fuel switching obligations apply to less than 20% of gas-fired heating plants[219].

The necessary heavy fuel oil reserves are estimated at about 4 thousand tones daily[220]. The PAP does not provide an estimate for the potential fuel switching in the event of a supply disruption. According to Stress Test communication, in Bulgaria alternative fuel stocks usually provide for continuing industrial and heat production for 5 days[221].

[213] SEWRC Report to ACER, p.48.
[214] PAP, p.2.
[215] PAP, p.8.
[216] Stress Test Communication COM (2014) 654 final, p.9.
[217] Stress Test Communication COM (2014) 654 final, p.9.
[218] Stress Test Communication COM (2014) 654 final,p.12.
[219] Stress Test Communication COM (2014) 654 final, p.9.
[220] PAP, p.10.
[221] Source: SWD 326 (2014) accompanying the Stress Test Communication COM (2014) 654, P.10.

Power generation

Pursuant to EP, when emergency level is declared, on top of voluntary switching to other fuels (which are not quantified), enforced shut-down of gas-fired power generation as well as enforced use of alternative fuels reserves are foreseen.

In 2014 total Bulgarian electricity consumption was equal to 31221 GWh, according to data published by ENTSOE[222].

ENTSO-E publishes data about Bulgarian power generating capacity and power production (Table A.4.5).

Table A.4.5.				
Source	**Electricity PRODUCTION in 2014 (GWh)**	**Electricity PRODUCTION in 2014 (% over total)**	**NET GENERATING CAPACITY ON DECEMBER 31st 2013 (MW)**	**Average load factor**
Nuclear	14,708		2,000	84%
Fossil fuels	19,582	47%	6,704	33%
-of which gas	*1,563*	*4%*	N/A	N/A
-of which lignite	*15,587*	*37%*	N/A	N/A
-of which hard coal	*2,432*	*6%*	N/A	N/A
-of which oil	*0*	*0%*	N/A	N/A
Hydro	4,698	11%	3,184	17%
Renewables (excl. hydro)	2,669	6%	1,757	17%
Total	**41,657**		**13,645**	**35%**
Total wo RES (incl. hydro)	**38,998**		**11,888**	**37%**
Source: ENTSO-E				

Low average load factor of fossil fuel fired generation capacity (33% on average in 2014 according to ENTSOE) may suggest that Bulgaria has some idle fossil fuel fired generation capacity, which may be ready to be used should gas fired plants be forced to shut down.

In 2014 on average only about 4% of consumed electricity (1,563 GWh) was generated by gas fired power plants[223], ranging from 5.4% in January to 2.2% in August and September.

The relative low importance of gas power generation translates into a limited weight of the power sector in total national gas demand: power plants consumed only 15% of total annual gas demand in 2012 according to PAP[224]. More precisely, consumption of natural gas from gas-fired power plants in 2012 was equal to 0.442 bcm (against a total annual gas demand of 2.9 bcm), with an average daily consumption of 1.2 mcm[225], representing about 41% of total gas demand of the Bulgarian energy sector. More recent historical consumption data for the power generation sector in Bulgaria are not available in the PAP (which was issued in 2012). In the SEWRC annual report to ACER, published in July 2014, it is reported that the total gas consumption of the Bulgaria energy sector, which includes both heating and electricity production,

[222] ENTSO-E data on DETAILED MONTHLY PRODUCTION (IN GWh) (Database: 09.03.2015)
[223] ENTSO-E data on detailed monthly production (IN GWh) (Database: 09.03.2015)
[224] Source: PAP, Table on p. 4.
[225] Source: PAP, Table on p. 4.

equalled 980 mcm in 2013[226]. Therefore, if we assume that electricity production is 41% of total energy sector (same share as in 2012), total annual gas consumption from power generation sector in 2013 can be estimated at about 0.4 bcm. If we assume that the efficiency rate of Bulgarian gas-fired power plants is 50%, then consumption by gas-fired plants in Bulgaria in 2014 was equal to 0.3 mcm.

Due to the limited role of gas fired plants (which, as noticed above, produce only about 4% of total consumed electricity) and to the likely existence of spare fossil fuel fired generation capacity, electricity generation would not be significantly affected by a gas supply disruption and the scope for replacing missing gas by fuel switching in power generation is limited (gas power plant consume less than 0.5 bcm/y, equal to about 1.2 mcm/d).

It may be reasonable to assume that in the case all the gas-fired thermal generation was shut down, then all the missing electricity may be generated by a greater use of lignite and hard coal power plants. Lignite fired and hard coal fired power plants are hence expected to fully replace gas to power generation. The costs of generating electricity with lignite fired and hard coal fired power plants are not estimated in the EP.

A.4.5 Conclusions on the main flexibility and emergency tools available in the country

Summing up the options for maintaining gas demand balance in the event of disruption of the major gas supply source (Trans-Balkan pipeline bringing Russian gas into Bulgaria) are the following (Table A.4.6).

Table A.4.6. Role of main Gas security of supply measures in Bulgaria

Measure	Type of measure	Estimated max contribution in the event of disruption of major infrastructure mcm/d	Source
Storage	Supply-side	5.5	PAP
Domestic gas production	Supply-side	2.2	PAP
Pipeline import	Supply-side	4.9	PAP
LNG	Supply-side	0	PAP
Fuel switching	Demand-side	-5.9	
of which power generation		*-1.2*	*HP all missing electricity is generated by a greater use of lignite and hard coal power plants*
of which heating		*-0.9*	*HP fuel switching obligations apply to less than 20% of gas-tired heating plants*
of which industrial consumers		*-3.8*	*HP all industrial users switch*

[226] SEWRC Report to ACER 201, p.48.

ANNEX 5. CASE STUDY: CZECH REPUBLIC

A.5.1 Main storage related SoS measures of the country

A.5.1.1 Mandatory Storage Obligations

With the decree on the State of Emergency in the Gas Industry (No. 344/2012) from Oct 10th 2012, which was effective as of April 1st 2013, gas suppliers in Czech Republic are obliged to fullfill at least the 20% of supply standards by storing gas in underground storage facilities for their supply of protected customers, not necessarily located within Czech Republic. If the storage is located abroad, then suppliers have to procure also the needed transmission capacity. In total Czech supplier storage obligations should amount to about 225 mcm (2014/15). The storage obligation holds only in the winter and the obligation amount varies depending on the registered temperature of the month. The National Energy Authority checks whether storage obligation is properly fulfilled and calculate the yearly storage obligation. Suppliers have to report their fulfilment of the obligations at the 15th day of the following month to ERU.

The 20% percentage for the computation of the storage obligation was set after a consultation and there is still a debate on whether it is adequate. Czech market operators noticed that the introduction of storage obligations last year did not change substantially storage booking behaviour, as the larger suppliers already owned the needed storage capacity.

In addition to this mandatorily stored gas there is still a large share of storage capacities which has been allocated through competitive open auctions and long term bookings of storage capacities exist in Czech Republic before the introduction of the decree. These capacities are held by old incumbents which have concluded long term contracts at the beginning of the unbundling of the Czech gas market.

A.5.1.2 Special mandatory "strategic" storage

As of 2014, in Czech Republic there is no mandatory strategic storage.

A.5.2 Any other existing storage related measures

A.5.2.1 Special tariffs for transmission to/from storage sites

The transmission tariff to/from storages sites are set annually by the national regulator ERU.

For all storage operators in the Czech Republic, including the major provider RWE Gas Storage who has aggregated his six physical sites to one virtual storage for Czech Republic with direct access to the virtual trading point, transmission tariffs are as follows.

Table A.5.1. Calculated tariffs for storage products with access to the VTP			
TOTAL (EUR/MWh)	Seasonal (IR, WR= 100 days*)	Cavern, fast product (IR, WR=20 DAYS**)	Mid-range facility (IR, WR=60 DAYS**)
Transportation of 1 MWh from VTP to UGS (charge for exit to UGS + variable charge for transported volume)	0.03	0.17	0.06
Transportation of 1 MWh from UGS to VTP (charge for entry from UGS)	0.11	0.79	0.26
TOTAL (EUR/MWh)	0.13	0.97	0.32

A.5.2.2 Drivers and incentives for storage investment and storage accumulation

In Czech Republic two main gas storage providers invest in gas storages. RWE Gas storage has taken the last storage expansions in operation in 2011. The investment decision for this storage increase was taken before the storage company was unbundled in a separate entity. Currently RWE Gas storage plans to increase injection and withdrawal capacity in 2016, 2017 and 2019[227]. A further capacity increase is currently not planned.

The other storage service provider, MND Gas Storage, develops their provided capacity from 180 mcm operating volume in 2010 to 245 mcm operating volume in 2015. A further increase is under development, the planned and sold operation volume for 2019 is 280 mcm. The last tranche was fully auctioned in March 2015 to a strategic customer.

A.5.2.3 Information on long term allocation of storage capacity

Currently some long term bookings of storage capacities exist in Czech republic, on hand by old incumbents which have concluded long term contracts at the beginning of the unbundling of the Czech gas market on the other hand by strategic investors like Gazprom (at the MND Storage facilities) which have booked in auctions long term capacities inclusive cushion gas. However the yearly auctions volumes in Czech Republic are bigger than the total demand of storage capacity to fullfill the storage obligations mentioned in 2.8.1.1. Expansion of underground gas storage Uhřice to the final capacity of 280 mcm of withdrawal capacity of 7 mcm/day to be completed in 2016.

Currently, the construction of a new underground gas storage Moravia Gas Storage in Dambořice is in place with a total capacity of 580 mcm and a withdrawal capacity of 17 mcm/day.

[227] http://www.rwe-gasstorage.cz/en/capacity-development/

A.5.3 Other SoS Information

A.5.3.1 Overview of the Czech gas market

Supplies of natural gas are available from abroad for the needs of the Czech Republic and a negligible part (1.5 % of national consumption) comes from domestic resources. The total volume of imported natural gas was 7,249 in 2014[228].

The gas system of the Czech Republic consists of:

(a) Transit gas pipelines of the transmission system: total length 2.628,6 km, DN 500 - DN 1400 pipeline, nominal pressures 6.1 MPa, 7.35 MPa and 8.4 MPa.

(b) National gas pipelines of the transmission system: total length 1.188,6 km, DN 80 - DN 700 pipeline, nominal pressures from 4 MPa to 6.3 MPa.

(c) Compressor stations in the transmission system: Břeclav, Veselí nad Lužnicí, Kralice nad Oslavou, and Kouřim (Hostim out).

(d) Border transfer stations in the transmission system: Hora Svaté Kateřiny, Lanžhot, Brandov, Waidhaus (DE) and Cieszyn (PL).

(e) Transfer stations between the transit and national transmission system: Hrušky, Uherčice, Olešná, Limuzy, Hospozín and Veselí nad Lužnicí.

(f) Gas pipelines distribution systems: nominal pressures 2.5 MPa - 4 MPa, total length 65,000 km.

The required gas pressure in the gas pipelines is provided by compression stations built at intervals of about 100 km. Each compression stations permit bi-directional flow in the transmission system of the Czech Republic. Table A.5.2 shows the individual technical capacities at the entry and exit points of the transmission system. These capacities represent the possibility of reverse flow at the given entrances and exits.

Table A.5.2. Entry and Exit capacities of Czech gas system (Source: Preventive Action Plan 2014)

	Entry [mcm/d]	Exit [mcm/d]
BTS Brandov (entry OPAL, Olbernhau; exit STEGAL)	104.2 27.7	27.3
BTS Hora St. Katherine	14.3	18.6
Cieszyn	0.0*	2.6
Waidhaus	43.3	102.5
Lanžhot	157.0	70.0

*10MWh/day in case of interruption of the gas flow from the Czech Republic to Poland and the reverse of the flow - emergency supply for Moravian region would be ensured only in case of decreasing of pressure level.

In 2014, natural gas was imported from Russia (70 %), Norway (9,6 %) and the European Union + Germany (20,4 %).

[228] Source: Annual Report ERU 2013

Table A.5.3. Imports of natural gas by sources (source: ERU – Energy Regulatory Office 2014)							
Gas imports [mio. m3]	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Russia	6,680.9	4,974.3	5,464	5,863.1	4,845	5,408	5,071
Norway	2,073.4	2,999.6	1,057.3	273.3	3	4	699
Germany + EU	218.1	571	1,988.6	3105	2,467	3,067	1,480
Total	8,972.4	8,544.9	8,509.9	9,241.4	7,315	8,479	7,249

The drop in imports from Norway and the steep increase of imports from Germany and EU, especially in 2011, were caused by the increase of gas traders purchasing natural gas on the spot market with lower natural gas prices. Gas from long term contracts were primarily used to cover high winter demand.

In addition 35,069.5 mio. m3 gas was transported through the Czech transmission for other countries in 2013.

Table A.5.4. Gas balance in the Czech gas system (Source: Annual Report ERU 2013)								
Year [Mio m3]	**Transit**	**Imports**	**Expor ts**	**With-drawal from UGS facilities**	**Injectio n into UGS facilities**	**Indig enous produ c-tion**	**Balan cing differ-ence**	**Gas consump tion**
2009	25,780.2	8,669.8	-28.3	2,224.70	-2,805.8	111	-10.1	8,161.30
2010	31,903.30	8,510.10	-159.3	2,255.30	-1,529.1	134.9	-232.6	8,979.20
2011	29,675.30	9,321.3	-167.3	877.5	-1,818.8	135.2	-262	8,085.80
2012	32,267	7,471.20	-7.4	2,247.10	-1,543.2	155.8	-165.2	8,158.20
2013	35,069.50	8,479.20	-7.9	2,231.30	-2,477.4	151.9	-100	8,277.10

The utilisation of the storages in Czech Republic shows a common utilisation of the facilities, i.e. the withdrawal period lasts from November until April.

Table A.5.5. Gas balance of gas storage (Source: Annual Report ERU 2013)					
Storage operators [1000 m3]	**Withdrawal**	**Injection**	**Balancing difference**	**Level of stores**	
				End of 2012	**End of 2013**
RWE Gas Storage	2,031,148	-2,262,942	5,124	1,763,773	1,990,443
MND Gas Storage	200,200	-214,474	-5,653	157,753	177,679
Total	2,231,349	-2,477,417	-528	1,921,526	2,168,122

The total storage capacity of the underground gas storages in the Czech Republic is 2.931 billion m3 (2014, excl. Dolní Bojanovice) which are about 37 % of the annual gas consumption of the Czech Republic. Doni Bojanovice accounts for additional 576 mcm, whereas this storage is only interconnected with the gas system of Slovakia.

The gas storage facilities in Czech Republic are all connected to the transmission grid of NET4GAS and partially to the distribution system.

Table A.5.6. Capabilities of Czech storage facilities (Source: GSE Storage Map 2014)				
Underground gas storage / owner	**Owner**	**Storage capacity (million m3)**	**Maximum daily withdrawal (million m3/day)**	**Maximum daily injection (million m3/day)**
Háje	RWE GasStorage	2,696	49.05	42.17
Dolní Dunajovice				
Tvrdonice				
Lobodice				
Štramberk				
Třanovice				
The group of these six underground gas storages is operated as a single virtual storage.		**2,696**	**49.05**	**42.17**
Uhřice	MND Gas Storage	225	6 (12 from 2017)	2.6
Dolní Bojanovice	SPP Storage (Slovakia)	576	9	7

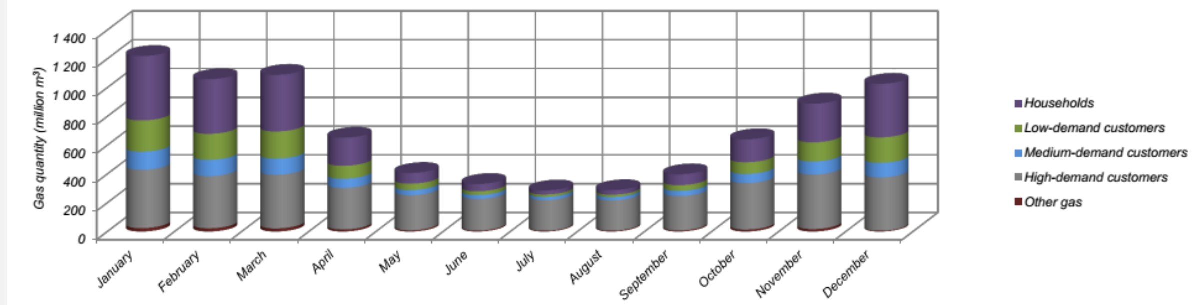
Gas demand in Czech Republic is split into five categories of consumer groups: High demand customers, medium demand customers, low demand customers, household customer and others.

Table A.5.7. Categories of gas consumption in Czech Republic (Source: Gas Annual Report ERU 2013)						
[miom3]	**High demand customers**	**Medium demand customers**	**Low demand customers**	**Households**	**Other gas**	**Total CR**
2005	4,298.0	989.0	1,257.2	2,832.1	186.5	9,562.8
2006	4,210.2	902.1	1,189.0	2,796.1	172.0	9,269.4
2007	4,003.4	864.4	1,119.4	2,494.7	170.7	8,652.6
2008	3,984.7	854.1	1,157.9	2,508.5	180.0	8,685.2
2009	3,421.5	821.7	1,186.2	2,514.5	217.4	8,161.3
2010	3,650.0	881.0	1,365.5	2,905.5	177.2	8,979.2
2011	3,544.5	782.9	1,159.8	2,443.9	154.6	8,085.8
2012	3,542.7	801.4	1,196.7	2,469.0	148.4	8,158.2
2013	3,627.3	819.1	1,204.2	2,473.7	152.6	8,277.1

Table A.5.8. Monthly gas consumption by customer groups (Source: Gas Annual Report ERU 2013)						
[million m3]	**High-demand customers**	**Medium-demand customers**	**Low-demand customers**	**Households**	**Other gas**	**Total Consumption**
January	405.3	126.3	216.6	447.2	23.4	1,218.9
February	363.2	113.0	180.6	379.2	21.8	1,057.9
March	373.2	112.1	188.7	393.3	21.1	1,088.4
April	289.1	64.4	89.2	194.8	13.8	651.2
May	243.8	36.3	43.6	74.1	8.8	406.5
June	219.3	27.5	25.5	50.6	7.2	330.0
July	212.0	22.7	16.3	27.9	6.1	285.0
August	209.8	23.9	15.7	31.1	6.6	287.1
September	238.1	36.8	39.0	75.5	8.0	397.4
October	323.5	64.1	80.3	159.6	13.2	640.6
November	379.4	91.2	132.3	268.4	16.8	888.0
December	370.7	100.8	176.5	372.2	5.9	1,026.1

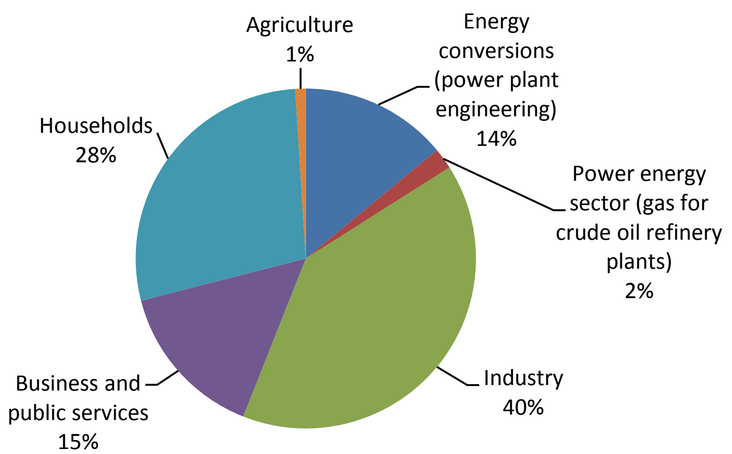
During the year the gas consumption of large and medium consumers is rather constant while in particular the consumption of household customers varies as it is primarily used for heating. Storages are used for seasonal variations.

Figure A.5.1. Customer categories' share of total natural gas consumption (Source: Gas Annual Report ERU 2013)



The largest sector of gas consumption is the industry with 40 % followed by households with a share of 28 %.

Figure A.5.2. Share of energy consumption by sector in 2011



Source: Annual Report ERU

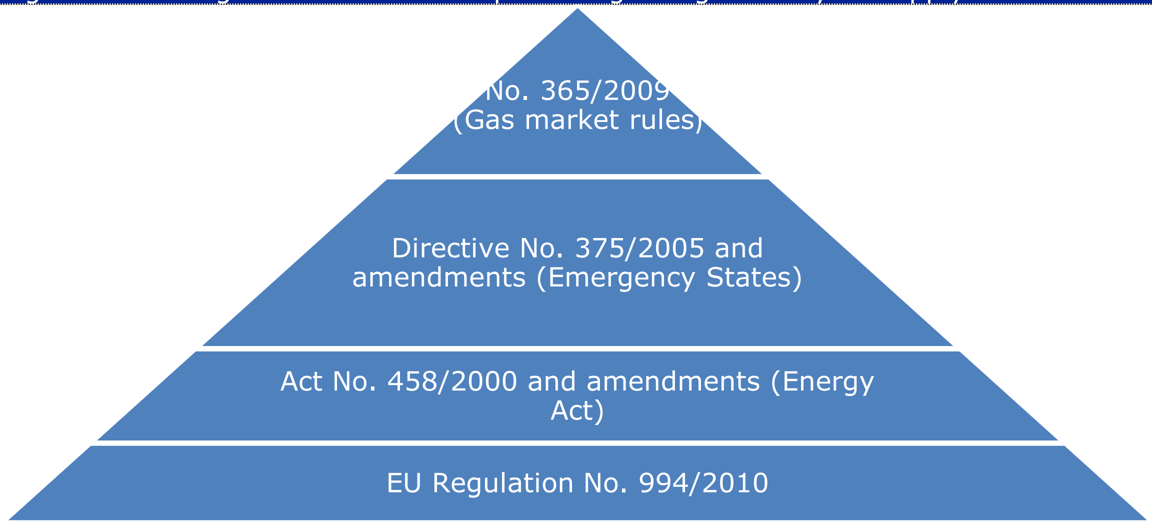
Law and Regulation on security of supply

The European legislation in particular Regulation (EU) No 994/2010 has already been implemented into national legislation and regulation. The basic legislation for power engineering in the Czech Republic is Act No. 458/2000 Coll. on business conditions and public administration in the energy sectors and on amendments to other laws (the "Energy Act").[229] In the amendment to Act No. 670/2004 Coll. the obligations applicable to all gas industry undertakings were laid down for a state of emergency.

[229] The latest amendment of the power engineering act No. 221/2011, effective from 18 August 2011, also implements the requirements of Regulation No. 994/2010 of the European Parliament and of the Councilanchoring of which in national legislation was required.

Finally, all requirements from EU regulation have been integrated in the amendment in Act No. 211/2010.

Figure A.5.3. Legislation in Czech Republic regarding Security of Supply



The obligations of gas undertakings were further detailed in the implementing directive of the Ministry of Industry and Trade No. 375/2005 Coll. (Emergency States in gas industry). This directive has been amended by decree No. 344/2012 Coll., which divides customers into seven groups (later increased to eight) depending on gas consumption type and determines five consumption levels for restricting gas supplies and five consumption levels for interrupting supplies to individual groups of customers.

Decree No. 365/2009 Coll. of the Energy Regulatory Office on gas market rules determines, among others the settling of balancing gas in an emergency and in emergency prevention.

In general critical market situation are managed by market based measures. In particular the gas traders are obliged to maintain the balance between the volume of gas entering the gas system and the volume of gas withdrawals at the same time[230]. The TSO is responsible for securitization of a safe and reliable transmission system[231]. Only if these measures were not sufficient, the transmission system operator would limit gas supplies to a group of customers according to the decree on gas industry emergencies (so called non-market measures).

The national legislation distinguishes three crisis levels:

1.Prompt warning

The prompt warning level occurs if there is specific, serious and reliable information about a potential and probable situation by which a substantial deterioration of the gas supplies and the declaration of a warning or emergency levels may occur. This can result from:

- an extraordinary event with an immediate impact on the gas industry (e.g. a natural disaster)

[230] See Article 61 Gas Act.
[231] See Article 58 (8) a).

- an extraordinary event in the gas industry (e.g. technical or technological accident, particularly in another area than the Czech Republic)
- deterioration of the political situation at the international level
- deterioration of the internal political and security situation in states producing or transiting natural gas
- receiving intelligence information about a potential terrorist attack threat
- necessity to control gas consumption and supply, in order to avoid a state of emergency.

2.Alert

The alert level results in market situations when supplies were disrupted or exceptionally high gas demand would result in a substantial deterioration in natural gas supplies, but the market remains capable using available market measures to deal with the disruption of supplies or increased demand. Potential situations of alert level are:

- limited or suspended natural gas supplies in part of the country during long-term extreme temperature conditions in winter
- occurrence of secondary crisis situations
- escalation of the political situation at the international level
- escalation of the internal political and security situation in states producing or transiting natural gas
- receiving intelligence information confirming a real terrorist attack.

3.State of emergency

The emergency level is if market measures are not sufficient to manage a serious disruption of natural gas supplies or another substantial deterioration of the situation of natural gas supplies and the natural gas supplies are not sufficient to cover the remaining natural gas demand. In this case other than market measures must be applied in addition particularly to secure natural gas supplies to protected customers. Situations resulting in emergency level are:

- declaration of a state of emergency in the gas industry
- limited or suspended natural gas supplies to the vast majority or all the state
- the expected term required to restore normal operation exceeds several days up to weeks
- prevailed or deteriorated temperature conditions
- occurrence of other secondary crisis situations, threat to the fundamental functions of the state and critical infrastructure
- limited or suspended natural gas supplies due to the international political situation in states producing or transiting natural gas.

In case of an emergency the central emergency committee was established to handle this situation. The members of this committee are members of the TSO, DSOs, SSOs, gas producers and the Ministry of Industry and Trade. Each member of the committee has decision making authority in their undertakings. They are together responsible to restore natural gas supplies by analyzing the situation and reviewing the developments of the measures being implemented if necessary.

A.5.4 SoS measures available in the country: market Measures

The basic assumption for preventing a crisis in the gas market is a reliable, safe, economic and thoroughly maintained gas system. Thereby each market participants has specific rights and obligations which are specified in the Energy Act (Act No. 458/2000 Coll. and on amendments).

The Act defines the liability of the operators to provide the Ministry of Trade and Industry and the Energy Regulatory Office with an annual report on the quality and maintenance level and to prepare, send to the Ministry and annually review the emergency response plan.

The TSO has the right to access gas storages under the conditions stipulated further in the Energy Act for arranging equilibrium in the gas system (Article 58 (1) a) of Act No. 458/2000 Coll.). The storage operators are obliged to share relevant information with the connected system operators to secure the interoperability of their systems and facilities (Article 60 of Act No. 458/2000 Coll.). The gas traders must ensure a reliable and safe gas supply (Article 61 of Act No. 458/2000 Coll.).

In case of the alert the national gas market differentiates between market measures on the supply and the demand side. On the supply side the market participants intend to increase import flexibility to secure additional gas supplies from other virtual trading points in the EU. Furthermore withdrawals from storages can be increased or reverse flows can be used. Finally, on a rather long term perspective the Czech gas market may increase the diversification of the supply routes.

By these measures any crisis situation could have been passed in the past. In addition due to the commissioning of the Gazela pipeline in January 2013 the effect of a serious supply breach will further decrease. The Gazela pipeline will supply natural gas from NordStream and OPAL. Furthermore the reverse flow of the northern branch of the gas transmission system can be used in emergencies to supply Slovakia with a daily capacity of up to 70 million m3. Finally, there is a project for constructing a north-south gas pipeline corridor, connecting LNG terminals in Swinoujscie (Poland) and Krk (Croatia) and a project interconnecting the Břeclav compression station with the virtual trade point Baumgarten in Austria.

On the demand side the available tools are limited as only a limited number of customers are able to switch to an alternative fuel other than gas. According to the PAP, in fact, customers with the possibility of fully or partially switching to an alternative fuel (so called Level A customers, see below) represents 1.2% of the Czech gas consumption (3 consumers) and their switch would take approximately 2 days. Concluding a contract with optional termination as well as an agreement on voluntarily reducing consumption of some customers may be used on the demand side depending on the season and term of the alert situation.

In addition to this, additional measures can be taken in an emergency as defined in Section 3 of the emergencies decree (Decree 344/2012 Coll.). The responsibilities are differentiated for the alternative market roles - transmission system operators, distribution system operators, underground gas storage operators, gas traders and the market operator – as well as the two phases (prompt warning and warning):

1. Preventing a state of emergency in the prompt warning phase:
   (a) TSO/DSO: use of an accumulation of the transmission/ distribution system,
   (b) SSO: check of the preparedness of underground gas storage facilities for the maximum extraction value,
   (c) Gas producers: check of the preparedness for a maximized operation of gas production and inform the transmission system operator of the results of the check results without undue delay,

(d) Gas traders: check of their possibilities of increasing gas imports and submit a report on the results of the check to the transmission system operator without undue delay.

Based on instructions from the transmission system operator, the market operator will immediately notify electronically all entities and registered gas market participants that on the next gas day a business settlement of deviations in the Czech balancing system will be launched to prevent an emergency.

2. When preventing an emergency state in the warning phase:

(e) the agreed gas volume transmission or distribution as well as the agreed gas supply to all consumer points of customer group A to the extent of their possibilities of switching to an alternative fuel via consumption level 1 are limited,

(f) the agreed gas volume transmission or distribution and the agreed gas volume to all consumer points of customer groups B1, B2, C2 and E, which the trader notified about preventing a state of emergency due to no gas supply or substantial gas supply variations are suspended.

A.5.4.1. SoS measures available in the country: non-market measures in case of an emergency

In order to manage an emergency situation the above mentioned measures can also be applied. In addition as the Czech Republic has no strategic reserves of natural gas only a mandatory withdrawal of natural gas from underground storages would be possible besides the restrictions on natural gas offtake. According to Section 4 of Decree 344/2012 Coll. the consumption level is declared in an emergency situation in order to limit the overall gas consumption level. Thereby the emergency activities are carried out in the following order:

- Step 1: the consumption levels for *limiting* the natural gas supply are declared,
- Step 2: the consumption levels for *suspending* the natural gas supply are declared,
- Step 3: the emergency consumption level is declared, which *suspends* the natural gas supply to *all customers*.

The consumption levels are further defined in Article 5 of Decree 344/2012 Coll. In general the market participants try to ensure that consumption can be fulfilled as contracted (basic level).

Step 1: Limited gas supply

However, in case of limited gas supplies the consumption may be restricted according to the defined consumption levels:

- Consumption level 1: limited gas supply to consumption points of customer group A to the extent of their possibilities of switching to an alternative fuel,
- Consumption level 2: Consumption level 1 plus limited daily gas consumption on consumption points of customer group B1 to value of permitted daily consumption,
- Consumption level 3: Consumption level 2 plus customer group B2 to value of permitted daily consumption,
- Consumption level 4: Consumption level 3 plus a 70 % reduction of the daily gas consumption on the consumption points of customer group C2 compared to the daily value of the previous business day,

- Consumption level 5: Consumption level 4 plus a 20 % reduction of the daily gas consumption on the consumption points of customer group E compared to the value specified in the gas distribution contract.

Step 2: Suspended gas supply

- Consumption level 1: suspended natural gas supply to the consumption points of customer group B1, limited daily gas consumption to the consumption points of customer group B2 to the value of the permitted daily consumption, limited gas supply for the consumption points of customer group A to the extent of their possibilities of switching to an alternative fuel and reduced daily gas consumption on the consumption points of customer group C2 by 70 % compared to the daily value of the previous business day, and reduced daily gas consumption on the consumption points of customer group E by 20 % compared to the value specified in the gas distribution contract,
- Consumption level 2: suspended gas supply for the consumption points of customer groups B1 and B2, reduced daily gas consumption on the consumption points of customer group C2 by 70 % compared to the daily value of the previous business day, reduced gas supply to the consumption points of customer group A to the extent of their possibilities of switching to an alternative fuel and reduced daily gas consumption on the consumption points of customer group E by 20 % compared to the value specified in the gas distribution contract,
- Consumption level 3: i.e. suspended gas supply for the consumption points of customer groups A, B1, B2, C2 and reduced daily gas consumption on the consumption points of customer group C1 by 20 % compared to the daily value of the previous business day and reduced daily gas consumption on the consumption points of customer group E by 20 % compared to the value specified in the gas distribution contract,
- Consumption level 4: i.e. suspended gas supply for the consumption points of customer groups A, B1, B2, C2 and E and reduced daily gas consumption on the consumption points of customer group C1 by 20 % compared to the daily value of the previous business day,
- Consumption level 5, i.e. suspended transmission, distribution and supply of natural gas to the consumption points of customer groups A, B1, B2, C1, C2, D and E.

Step 3: Suspended gas supply to all customers

In case of an emergency consumption level also natural gas supply customer group F is suspended.

Evolution and debate on security of supply measures

The reliability and secure operation of the gas system in the Czech Republic was demonstrated both during the gas crisis in January 2009 as well as during the very cold weather of February 2012. In both cases, it was not necessary to limit supplies to customers and increased demand was covered by higher gas withdrawals from gas storages. The supply was ensured even without any common preventive action with neighbouring countries. A similar situation happened in year 2014 when during the Ukrainian-Russian crisis the simulation of stress tests for several cases of gas disruption from Russian Federation was carried out. Results of Stress tests (without higher problems) in the Czech Republic were passed forward to the European Commission.

Definition of protected customers

According to Article 2 (1), a) and b) the ERO has defined different customer groups A-F:

- group A is the consumption points of customers with a predicted annual consumption of more than 630 MWh with the possibility of fully or partially switching to an alternative fuel;
- group B1 is the consumption points of customers mainly with technological consumption up to a predicted annual consumption of more than 52,500 MWh not included in groups A or D; these consumption points are included in this group if the sum of actual needs in the last quarter of the previous year and the first quarter of this year is less than 70 % of the total consumption for the period from 1 April of the previous year to 31 March of this year; if no actual consumption is available, it will be replaced by the planned monthly consumption specified in the distribution contract;
- group B2 is the consumption points of customers mainly with technological consumption up to a predicted annual consumption of 4,200 MWh to 52 500 MWh not included in groups A or D; these consumption points are included in this group if the sum of needs in the last quarter of the previous year and the first quarter of this year is less than 70 % of the total consumption for the period from 1 April of the previous year to 31 March of this year; if no actual consumption is available, it will be replaced by the planned monthly consumption specified in the distribution contract;
- group C1 is the consumption points of customers mainly with consumption for heating up to a predicted annual consumption of more than 4,200 MWh not included in groups A or D; these consumption points are included in this group if the total consumption for the last quarter of the previous year and the first quarter of this year is 70 % or more of the total consumption for the period from 1 April of the previous year to 31 March of this year and if the customers in this group provide more than 20 % of their total produced thermal energy to households, health care facilities and social service facilities; if no actual consumption is available, it will be replaced by the planned monthly consumption specified in the distribution contract;
- group C2 is the consumption points of customers mainly with consumption for heating up to a predicted annual consumption of more than 4,200 MWh not included in groups A or D; these consumption points are included in this group if the total consumption in the last quarter of the previous year and the first quarter of this year is 70 % or more of the total consumption for the period from 1 April of the previous year to 31 March of this year and they are not classified in group C1; if no actual consumption is available, it will be replaced by the planned monthly consumption specified in the distribution contract;
- group D is the consumption points of customers with a predicted annual consumption per year of more than 630 MWh producing foods for daily consumption, including but not limited to perishable food processing, animal production operations with animal death hazard, producing fuels, communal incinerator plant waste, power for public transport vehicles, health care facilities, social service facilities2), basic elements of the Integrated Emergency Response system, reconstruction facilities, crematoriums as well as the Czech National Bank; specific customers are classified by the transmission system operator for the consumption points of the customers connected directly to the transmission system or distribution system operator for the consumption points of the customers connected directly to the distribution system (hereinafter the "competent operator") for informing the local and competent regional authority or the Prague Municipality Office.

- group E is the consumption points of customers with a predicted annual consumption of 630 MWh to 4,200 MWh not included in groups A or D;
- group F is the consumption points of customers with a predicted annual consumption per year of up to 630 MWh and households.

Based on the decision of the Competent Authority mentioned in § 2 of the decree on emergencies in the gas industry, the protected customers includes the groups **C1, D** and **F.**

The supply security standard was provided for the winter months of 2013 according to § 73a of the Energy Act at a daily volume of 189,334 - 459,907 GWh.

The way of safeguarding the security standard of supplies for protected customers is laid down in § 11 of Directive No. 375/2005 Coll. Thereby from 30 September to 1 April, the security standard is at least 20 % of the stored gas in the underground gas storages in the European Union. A gas trader and gas producer, who deliver gas to protected customers, must inform the market operator and the Energy Regulatory Office of the extent of the security standard specified and explained above according to the Preventive Action Plan.

Definition of supply standards for protected customers

The relevant input parameters for the supplies security standard in Czech Republic are:

(a) Under extraordinary temperature conditions over a seven-day period of peak demand occurring with a statistical probability of once in 20 years:

(b) Because switching from town gas to natural gas took place in the Czech Republic from 1990 to 1995, natural gas consumption statistics are only available from 1995. The daily value for a seven-day period of peak demand at -14°C, according to the security standard of supplies for the Czech Republic, is 47,982 thousand m3.

(c) During an extraordinary high gas demand period of at least 30 days occurring with a statistical probability of once in 20 years:

(d) A period of extraordinary high gas demand only occurs for a short time and has never lasted for more than 10 days; during this period, the daily consumption was about 50 - 57 million m3 for approx. 10 days in January 2009.

(e) As the consumption of protected customers (see above) accounts for about 35 % of the total natural gas consumption during winter, the security standard would have to be 19.95 million m3/day. This can be secured for 30 days even if all cross-border supplies are interrupted by extraction from underground gas storages.

(f) During a breach of the single largest gas infrastructure for at least 30 days under average winter conditions:

(g) No such period has occurred in the Czech Republic, however, the experience of the interruption of the natural gas supply in January 2009 followed by the simulation drill [232]at November, 12th 2009, see above, has shown that supplies from underground gas storages would be sufficient to supply the natural gas to protected customers under average winter conditions, see also clause b).

In order to fulfill the security of supply standard the Preventive Action Plan describes various measures to be taken:

(a) Diversification of gas supply sources

[232] Source: PAP.

The original scheme of 75% natural gas supplies from Russia and 25% natural gas supplies from Norway significantly changed after liberalization. Short-term contracts on the EU spot market are used to a great extent and were 33.59 % in 2011, whereas Russian and Norwegian shares were 63.44 % and 2.95 %, respectively primarily because of the NordStream and OPAL gas pipelines which has been connected to the Gazela pipeline in January 2013.

(b) Availability of stored gas

About 37 % of annual gas consumption (2,931 bn m3) can be stored in underground gas storage facilities. Suppliers of protected customers have to prove for the gas stored in underground storages and the arrangements of fixed transmission capacities to the Czech markets (as described above). In case the gas is stored in storages other in the Czech Republic the confirmation has to be provided for both storage and transmission capacities from the foreign storage operator and border transmission network operator and must be reported to the Czech Regulator.

(c) Long term gas supply contracts

Gas traders from the Czech Republic have concluded long-term contracts for natural gas supplies with Russian gas producers of 8 billion m3/year until 2035 and Norwegian gas producers of 2 billion m3/year until 2017. These quantities have to be reported to the Energy market operator and Energy Regulatory Office together with the confirmation of booked firm capacities.

(d) Domestic gas production

National gas production's share is just 1.5 % of the annual natural gas consumption such that its impact is minor.

(e) Use of alternative fuels and termination rights for gas supply

Because of the reliable natural gas supply to date, this possibility is not widely used in the Czech Republic. However, the number of protected customers being involved in the possibility of using alternative fuels or the contract based on which the supply can be interrupted have to be provided to the Energy market operator and Energy Regulatory Office.

Given these parameters the Ministry of Industry and Trade of the Czech Republic has calculated the actual and future N-1 standard.

A.5.5 N-1 rule

Czech Republic fulfils the N-1 standard today and in the future by more than 150%:

$$N-1\,[\%] = \frac{EPm + Pm + Sm - Im}{Dmax} * 100$$

Dmax (1 in 20 years)

The day of highest consumption was identified as 23 January 2006 with a value of 67.639 Mcm/day (at -16.9 °C). The forecasted values have been recalculated based on the future expected annual consumption of natural gas in the Czech Republic.

Supply side parameters: EPm,Pm, Sm, Im

The EPm parameter is the sum of all border entry transfer capacities, i.e. Hora Svaté Kateřiny - Olbernhau, Hora Svaté Kateřiny – Sayda, Brandov, Waidhaus, Český Těšín and Lanžhot.

The Pm parameter has been specified based on data from the biggest producers of natural gas in the Czech Republic.

Individual Sm parameters represent the maximum daily technical and applicable capacities for the underground gas storages in the Czech Republic of the following companies: RWE GasStorage and MND GasStorage.

The Im parameter is the infrastructure with the highest capacity for gas supplies i.e. the Lanžhot entry point: 157 Mcm/day.

Table A.5.9. Security of Supply in the Czech Republic in 2012-20121 (in mio. m3/day, 0°C)

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Pm	0.4	0.4	0.4	0.5	0.6	0.6	0.6	0.4	0.3	0.3
Sm RWE GS	47.4	47.8	49.3	53.1	55.9	57.8	60.6	61.6	63.5	63.5
Sm MND GS	7.5	8.0	8.5	9.0	10.0	12.0	12.0	12.0	12.0	12.0
Sm ČNS	-	-	-	-	0.9	0.9	2.0	2.0	2.0	2.0
EPm	292.1	292.1	319.8	319.8	319.8	319.8	319.8	319.8	319.8	319.8
Im Lanžhot	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4
Dmax	66.2	71.3	75.2	75.2	79.3	82.3	82.3	82.3	82.3	82.3
N-1 [%]	**288.4**	**269.3**	**294.5**	**300.3**	**291.0**	**285.2**	**290.0**	**290.9**	**293.1**	**293.1**

The national prevention plan also calculated scenarios on exceptionally high gas demand and on gas supply interruption.

Scenarios of exceptionally high gas demand

For calculating the scenarios, the last two years have been considered because, after liberalization of the market in 2007, new licenses for gas trading issued and new gas traders started their gas supplies in particular in 2009.

Natural gas consumption in the Czech Republic:

Table A.5.10. Gas consumption in Czech Republic (Source: Preventive Action Plan 2014 and ERÚ 2014)

[bn m3]	2009	2010	2011	2012	2013	2014
Gas consumption	8.161	8.979	8.058	8.158	8.277	7.280

For these three years the maximum historical daily consumption appeared on 23 February 2011 at the average daily temperature of -10.1°C. Applying the maximum daily consumption on 2006 of 67.6 million m³ at – 16.9°C this results in a calculated consumption of 52.816 million m3.

Scenarios of gas consumption in household categories

Natural gas consumption in the Czech Republic for the household customer category in the relevant last three years were:

Table A.5.11 Household gas consumption in Czech Republic (Source: Preventive Action Plan 2012)

[bn m3]	2009	2010	2011	2012	2013	2014
Household gas consumption	2.514	2.905	2.443	2.469	1.204	1.999

Thus the maximum daily consumption of household customer category over the last two years amounts to 20.3 million m3 and historical 23.7 million m3.

In the Stress tests carried out in 2014 various alternatives of infrastructure interruptions have been analysed. The impact on consumption was marked by the variance of disruption of supply from Russian Federation to the whole EU for time period February 2015 and by the variance of disruption of gas supply from RF to EU for period September – February 2015.

For 2012 the N-1 coefficient for the Czech Republic was 288 %, that is to say the failure of any individual transmission infrastructure would not substantially affect the supply of natural gas to end customers.

Table A.5.12 Interruptions of the infrastructure and the consequences

Interruptions of the infrastructure	**Consequence**
BTS Lanžhot	No danger to the natural gas supply in the Czech Republic even in winter
BTS Hora Svaté Kateřiny	No affect on the natural gas supply in the Czech Republic
BTS Brandov	No affect on the natural gas supply in the Czech Republic, affect on natural gas transit to Germany only
BTS Waidhaus	No affect on the natural gas supply in the Czech Republic, affect on natural gas transit to Germany only
BTS Český Těšín	No affect on the natural gas supply in the Czech Republic, affect on natural gas transit to Poland only
UGS Uhřice	No affect on the natural gas supply in the Czech Republic
UGS Dolní Dunajovice	No affect on the natural gas supply in the Czech Republic
UGS Háje	No affect on the natural gas supply in the Czech Republic
UGS Lobodice	No affect on the natural gas supply in the Czech Republic
UGS Štramberk	No affect on the natural gas supply in the Czech Republic
UGS Třanovice	No affect on the natural gas supply in the Czech Republic
UGS Tvrdonice	No affect on the natural gas supply in the Czech Republic

However, none of the investigated individual interruptions will have an effect on the gas supply in the Czech Republic. In some cases there will be restrictions for the transit to Germany or Poland. Only if the supplies via Lanzhot and Hora Svaté Kateriny fail concurrently the supply in Czech Republic may be interrupted. However, this scenario is highly unlikely[233].

Quantitative estimate of pipeline import capacity

The total technical pipeline import capacity (i.e. the sum of all border entry capacities) in 2014 equals 319.8 mcm/d[234].The single largest import infrastructure is the pipeline that is interconnected to the national pipeline system at the entry point of Lanžhot, having a technical import capacity into the Czech system of 157 mcm/d[235].

Gas traders from the Czech Republic have concluded long-term contracts for natural gas supplies with Russian gas producers of 8 billion m3/year until 2035 and Norwegian gas producers of 2 billion m3/year until 2017.

Quantitative estimate of domestic production

The Czech Republic has a domestic gas production amounting to approximately to 150 Mio. m^3/a from the South Moravian Region and from hard coal mines in the North Moravian Region. This production is only maximum 2% of the national demand. According to PAP, the maximum daily contribution from national production in 2014 is 0.4 mcm/d.

Estimated demand response and fuel switching

In Czech Republic demand side measures are limited as only a limited number of customers (and in particular only 3 consumers) are able to switch to an alternative fuel other than gas. According to the PAP, in fact, customers with the possibility of fully or partially switching to an alternative fuel (so called Level A customers, see above) represents 1.2% of the Czech gas consumption and their switch would take approximately 2 days.

[233] See Preventive Action Plan 2012, p. 30.
[234] Source: PAP.
[235] Source: PAP.

ANNEX 6. CASE STUDY: DENMARK

A.6.1 Main storage related sos measures of the country

Denmark is currently involved in a transition from being a net exporter (until 2010) to becoming a partial importer, as production from the North Sea fields decreases. Danish network is characterized by a high degree of interconnection with Sweden and Germany, with most of consumption still covered by domestic production although imports from neighbouring countries are required to fulfil flexibility requirements. Regarding storage, Denmark relies on two facilities that can cover around one third of its total annual consumption.

Currently, there are neither mandatory/strategic storage requirements nor PSO requirements for suppliers; the responsibility falls on the side of TSO (Energinet.dk) who must maintain Security of Supply (SoS) and will manage any emergency situation that may arise in the Danish market. Energinet.dk can use both market-based and mandatory tools, but only in cases where market based measures are not sufficient to guarantee gas supplies during emergencies, will Energinet.dk apply non-market measures.

Main market-based measures are the Demand Side Response mechanism (annual tenders for interruptibility) and cash-out prices for daily imbalances of the network, as a way to incentivize investments on flexibility (such as storage capacity).

A complete definition of the tools available to the TSO can be found under the non-storage related SoS measures section below.

A.6.1.1 Emergency situations

Hence, in case supplies from the North Sea are disrupted, gas will be delivered to the Danish market from the two national gas storage facilities and from the north of Germany, while consumption will be reduced by means of disconnecting those major gas consumers who have concluded commercial interruptibility agreements with Energinet.dk.

In cases of abnormal operation of the Danish gas market, Energinet.dk can activate three different levels of alarm: Early Warning, Alert and Emergency.

Figure A.6.1. The Danish Emergency Supply Model

Source: Energienet.dk

During the two first levels of alarm (Early Warning and Alert), gas will be normally transported and distributed, although Energinet.dk, on its role as responsible for security of supply, may increase the prices of imbalances (by means of increasing up to 100% adjustment steps 1 and 2 described in the Cash-out prices section below) and removing maximum and minimum prices for the balancing actions taken, in order to give suppliers the right incentives to avoid emergency escalation.

In case of an Emergency, Energinet.dk is not forced to fulfil its contractual obligations towards shippers, which remain suspended for as long as the Emergency lasts. In the event of Emergency, imbalances are not allowed unless otherwise instructed by Energinet.dk.

In an emergency supply situation Energinet.dk would take over the supplies to the Danish gas market from market players. To this end, Energinet.dk purchases alternative transport capacity in the South Arne pipeline, reserves capacity at storage facilities and enters into interruptibility agreements with a number of major consumers. Every year Energinet.dk determines the gas volumes to be covered by each of these emergency measures.

The TSO can also give direct instructions to shippers regarding nominations at Entry, Exit and Storage points, as well as in the Gas Transfer Facility (Danish gas exchange). In case a shipper does not comply with the instructions given, Energinet.dk is entitled to altering its nominations or even to excluding that shipper from the market.[236]

Regarding storage, Energinet.dk can contract gas quantities subject to filling requirements with shippers and storage customers. In case of emergency, the gas contracted under those agreements will be made available to Energinet.dk.[237]

A.6.2. Mandatory Storage Obligations

There are no mandatory storage obligations in Denmark, since transposition of EU regulation was made by the introduction of market-based mechanisms and by relying in the TSO for the maintenance of SoS in case of gas emergencies. This was made possible partly due to the large amount of storage capacity available and the high degree of interconnection of the Danish market.

Energinet.dk has access to special tools that can only be used in case of gas emergencies (alternative pipe capacity, reserved storage capacity from suppliers, etc.) while the market participates in two ways: consumers, by means of interruptible contracts (DSR annual tender) and cash-out prices for un-balanced suppliers.

A.6.3 Special mandatory "strategic" storage

There are no obligations for Energinet.dk to maintain a certain amount of reserves, but as the responsible for maintaining SoS, it is entitled to maintain emergency storage reserves which can be only mobilized in situations of emergency (see Emergency Storage below).

Energinet.dk also reserves the necessary withdrawal capacity for short term emergency supply incidents, which is normally used for balancing purposes (see System Operator Storage below).[238]

- Evolution of the measures in the last ten years

Denmark implemented the requirements of the EU Regulation 994/2010 in October 2012, including an Emergency Plan for the Danish gas transmission system. The

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[236] Energinet.dk (2014), Rules for Gas Transportation, version 14, p.70.
[237] Energinet.dk (2014), Rules for Gas Transportation, version 14, p.71.
[238] Energinet.dk (2014), Gas in Danmark 2015, p.40.

Danish executive order on maintaining security of natural gas supply 962/2012[239] is intended to define the responsibilities and tasks for the safeguarding of the country's natural gas supply.

In January 2014 the Danish market became fully liberalized. Prior to that, customers covered under public service obligation were forced to obtain supplies from the local distributor of the area in which they lived (only four DNO in Denmark).

In March 2014, the Balancing Network Code was introduced into Danish regulation, which introduced current balancing mechanism into the Danish market. Such modification, and the new security of supply model, which was prepared on the basis of the EU regulation, give the market a much larger role in maintaining security of supply (instead of leaving all the burden for the TSO).

Regarding cross-border cooperation, the new transmission rules included Swedish customers on the Danish DSR mechanism, with the aims to facilitating operation of the Danish market and supply to Swedish protected customers.

On January 2015 Energinet.dk took over Dong in the Stenlille facility (Energienet.dk acquired 100% ownership of Dong Storage, previously owned by Dong Energy), to facilitate the management of stored stocks in emergency situations and increase its ability to optimize flows. Dong Energy had already divested its share in Lille Torup in 2007 following the same optimization goal.

New changes are forecasted for October 1st 2015, the official deadline for Energinet.dk to implement the complete Balancing Network Code (currently, there are still no reverse flows on the interconnection with Sweden).

A.6.4 Any other existing storage related measures

There are currently four different storage-related tools Energinet.dk can use to mitigate the effects of gas emergencies on the Danish system. Two of them are normal balancing tools while the latter two can only be used if emergency has been declared.

- Swap between volumes stored and capacities in gas storage facilities, to optimize operation efficiency of the network. As of 1 January 2015, both stocks will be owned by Energinet.dk, and the introduction of a virtual storage point is forecasted;
- Usage of System Operator Storage, including withdrawal capacity, employed to maintain operational safety. Such reserves are purchased by the TSO in the market at commercial prices;
- Introduction of filling restrictions: storage customers are paid by Energinet.dk to maintain stored volumes in winter time (1st November-31st of March). Those volumes can only be used by Energinet.dk in case of emergency.
- Use of Emergency Storage: Energinet.dk can buy and maintain stored quantities to be used at emergencies (not equivalent to SO storage, destined to operational safety instead of supplying protected customers).

Currently, Energinet.dk has access to a total of approximately 215 Mcm of Emergency Storage capacity filled with gas. This includes amounts reserved directly by Energinet.dk ((2) and (4), the amount is determined each year) and volumes made available from shippers' storage filling requirements (individual filling requirements, (3)).

[239] Available at : https://www.retsinformation.dk/forms/R0710.aspx?id=143284

The majority of the capacity in Stenlille and Lille Torup has been sold under filling requirements such that the storage customers commit themselves to maintaining a certain stock volume during the year against a discount (capacity is tendered within market participants). Energinet.dk compensates the two storage companies for this and thus has additional stock volume for emergency situations at its disposal. Each year on 1st March 12% of the shippers' storage capacity must be left in storage.

A.6.4.1 Winter and Emergency Plans

The responsibility for Denmark's security of supply lies with the Danish Energy Agency (DEA) on behalf of the Minister for Climate Change and Energy. Within this framework Energinet.dk has responsibilities for operational matters.

This consists of observing minimum standards and preparing National Preventive Action Plans and emergency plans to accomplish the Regulation (EU) no. 994/2010 concerning measures to safeguard security of gas supply. The plan must describe how security of supply is ensured during the period under review and how it will be ensured in the coming year and next ten years.

In addition, the plan must account for the means used to maintain security of supply in emergency supply situations.

Energinet.dk calculates both off-take in Denmark (exit zone) and in transit and the supplies from the North Sea, from Germany and from storage facilities based on a winter's day with an average temperature of -13°C. The calculations for the winter 2014-15 are shown in this figure:

Figure A.6.2. Danish Transmission System[240]

[240]Available at (danish only) http://www.energinet.dk/EN/GAS/Hvad-sker-der-i-2014-2015/Winter-Outlook-2014-2015/Sider/default.aspx

- Total transport: Total net transport has been estimated at 29.5 Mcm/day
- Exit Denmark: Consumption in Denmark is 21.7 Mcm/day
- Ellund: Ellund has net imports of 3.0 Mcm /day
- Dragør: Dragør has exports of 7.8 Mcm /day
- Storage facilities: Total withdrawal of gas is estimated at 16.2 Mcm/day, with 8.2 Mcm/day coming from Stenlille and 8.0 Mcm/day from Lille Torup. Distribution of withdrawals is optimised to achieve highest possible network pressure
- Nybro: Supplies at Nybro are estimated at 10.3 Mcm /day.[241]

For Denmark, it is assessed that both protected and non-protected consumers, in part due to the high stocks, could be supplied for a minimum of five months, and that all consumers could possibly be supplied throughout the period if consumption is simultaneously reduced in the period due to rising prices, and the entire North Sea production is supplied to the Danish and Swedish markets.

Energinet.dk has an emergency supply agreement which paves the way in emergency supply situations for supplies of 7.4 Mcm/day to be redirected from Tyra to the South Arne pipeline, also connected to Nybro (hence, North Sea supplies would be secured despite a long-term disruption of its main route).

According to the prevention plan, Tyra pipeline will only use 40-50% of its full capacity (26 Mcm/day), while the South Arne pipeline will only transport 1 Mcm/day (out of a full capacity of 13 Mcm/d). In case of emergency, full capacity could be reached using the procedure previously described[242].

In cases of emergencies, commodity charges for transmission of gas are reduced. In a normal situation, all consumers face the same transmission charges, but in case of emergency, protected customers receive a smaller discount than non-protected ones (since they face a certain risk of disconnection). Currently, emergency commodity charge for protected customers is 91% lower than the normal charge, whereas for non-protected customers reductions amounts to -94%[243].

Estimations of withdrawal under normal conditions for year 2015 are expected to range between 10 and 16 Mcm/d, while total stored volume is forecasted at 400 Mcm (against a total capacity of 1 Bcm). In emergency situations, withdrawal capacity reaches 20 Mcm/d[244].

Energinet.dk has also estimated the commercial storing needs destined to system balance purposes, to be in a range between 300 and 800 Mcm/year for the period 2015-2030[245].

- Agreements for cross-border storage utilization

Sweden is supplied 100% from the Danish market. Such an unusual situation implies that each improvement in Denmark's Security of Supply leads to improvements in the Swedish market.

Hence, both TSOs (Energinet.dk and Swedegas) work together on the elaboration of Emergency plans. Swedish consumption is included in the N-1 analysis, since Swedish protected consumers need to be supplied in cases of emergency as well. Currently,

[241] Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p. 5.
[242] Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p. 11.
[243] Energinet.dk (2014), Prices for transport in the gas trasmission system, effective as of 1st January 2015, p.2.
[244] Energinet.dk (2014), Gas in Danmark 2015, p. 41-42.
[245] Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p. 11.

Swedish large customers can enter into interruptibility contracts, and for the first time in Winter 2014/2015, Swedish actors could participate on interruptibility services offered by Energinet.dk[246].

Regarding the obligation to implement bi-directional flows on interconnections, an exception was granted to both Danish and Swedish energy authorities on 21st December 2012 for the Dragør interconnection on their common border[247].

A.6.5 Other SoS information

A.6.5.1 Definition of supply standards for protected customers pursuant to Art. 8 of Regulation 994/2010/EC

All household customers are protected consumers. In order to offer gas consumers the best possible protection, the Danish Energy Agency (DEA) has also decided to classify small and medium-sized enterprises, district heating systems, schools and hospitals as protected consumers[248].

Which consumers are protected is determined by the 'cubic metre limit' determined and published each year by DEA on the basis of a recommendation from Energinet.dk. Such recommendation is based on the criteria set by DEA in Executive Order no. 962 of 27 September 2012. The assessment will be conducted on the basis of the distribution companies' consumption data from the last three years.

For 2014/2015, the limit was set at 6.3 Mcm/year[249]. In practice, this means that all industrial enterprises with an annual gas consumption of less than 6.3 Mcm and most gas-fired CHP[250] plants will be protected. Last year's number was 4.7 Mcm/y, while two years ago the threshold stood at 2 Mcm/y[251]. Currently, protected gas consumers in Denmark amount to 80% of total consumption.

On its 2014-2015 Plan, Energinet.dk foresees the following peak demands, in case the coldest temperature conditions in the last 20 years were to occur, which account for points a) and b) of Article 8 of Regulation 994/2010/EC.

Table A.6.1. Protected Consumers' Consumption during peak conditions

	Protected consumers (GWh)		
	Normal Condition	**Peak Condition**	**Increase**
1 Week[252]	1,455	1,823	368 (25.2%)
1 Month[253]	5,872	7,359	1,487 (25.3 %)
Source: Energinet.dk[254]			

Denmark uses an increased supply standard in Article 8.1.c) from at least 30 days to 60 days in the event of a disruption of the largest single supply infrastructure at the average winter conditions[255].

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[246] Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p. 14.
[247] Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p. 16.
[248] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.7.
[249] Limits are valid from the 1st October of year n to 30th September of year n+1.
[250] Co-generation of heat and power.
[251] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.7.
[252] Average temperature for the period is -9.5 ° C.
[253] Average temperature for period is -6.0 ° C.
[254] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.16-17.
[255] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.8.

A.6.5.2 N-1 standard level, pursuant to Art. 6 of Regulation 994/2010/EC

In case the largest supply sources are interrupted (N-1), the emergency supply covers the protected Danish gas market for a period of up to 60 days during a normal winter. In an emergency-supply situation, the non-protected Danish market remains covered for up to three days.

Table A.6.2. Protected Consumers' Consumption in case of N-1 disruption			
	Protected consumers (GWh)		
	Normal Condition	**Peak Condition**	**Increase**
1 Month	4,866	6,098	1,232 (25.1 %)
Source: Energinet.dk[256]			

In Denmark, it is not possible to identify only one single gas supply infrastructure responsible for gas supplies to the Danish transmission network. The gas supply to the Danish transmission grid is largely equally divided between the four sources of supply, and risk assessment processes such managed supply failure from all delivery points

Table A.6.3 Infrastructures considered in the N-1 disruption	
Facility	**Emergency Description**
North Sea (Nybro).	North Sea (Tyra pipeline) gas supply outages for several months,
Germany (Ellund)	Ellund delivery point outages due to supply crisis in Europe
Stenlille Gas Storage (Zealand)	Stenlille Gas Storage outage without notice
Lille Torup Gas Storage (Jutland)	Lille Torup Gas Storage outage without notice
Source: Energinet.dk[257]	

Depending on actual supply conditions on a given day, each of these sources could be the main source of supply.

The following calculation is made for all four feed points, Nybro from the North Sea, Ellund from Germany, Lille Torup Gas Storage in North Jutland and Stenlille Gas in Zealand.

Regarding Sweden, which is currently uniquely supplied by Denmark, they are not subject to the N-1 rule but are required to maintain supply for protected consumers. Protected consumers amount to only 2% of total Swedish gas demand, and those are the volumes included on the N-1 simulation.

For winter 2014/2015, protected gas consumers amount to 2 GWh/d, with a peak of 13 GWh and 52 GWh in case of especially cold week and month. Hence, flows to the

[256] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.17.
[257] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.19.

Swedish market can be quickly reduced from 94 to 2 GWh, allowing for increased flexibility to the Danish market[258].

Table A.6.4. Demand Coverange in case of N-1 disruption	
Calculation of N-1 formula	Mcm/d
Daily gas demand	23.1
Technical input capacity (excl. production, storage and LNG)	10.8
Max. Technical capacity (North Sea)	12
Max. Technical withdrawal capacity of all storage facilities	21.7
LNG	0
Technical capacity of the single largest infrastructure North Sea (Nybro) Germany (Ellund) Stenlille Gas Storage Lille Torup Gas Storage	N-1 12 Mcm → 141% 10.8 Mcm → 146% 10.8 Mcm → 146% 10.8 Mcm → 146%
Source: Energinet.dk[259]	

If the N-1 rule is applied, transmission capacity is still capable of covering the whole market in all scenarios.

Apart from the N-1 rule, Energinet.dk also implemented two additional SoS analysis[260]:

- A 60-day disruption under normal winter conditions; and
- A longer-than-a-year disruption from North Sea supplies.

In both cases, the situation will be solved by means of increased imports from Germany (especially after commissioning of infrastructure enlargement in North Germany by the end of 2015) and stored volumes.

A.6.5.3 Other (non-storage) related SoS measures and main flexibility and emergency tools available in the country

In the event of major interruptions of the North Sea supplies, a number of measures will be initiated to ensure supplies to the Danish gas market. The primary tools comprise:[261]

- Remove buffering limits on interconnections and storage facilities
- Use of interruptible capacity in exit and entry points
- Declare reduced capacity: shippers will see their nominations reduced or cancelled on a pro-rata basis. It can affect only certain parts of the network, and reduced capacity to the Swedish market is also considered (down to serving Swedish protected customers only)

[258] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.18.
[259] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.21.
[260] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.23.
[261] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, Annex A, p.10.

- Balancing: shippers shall maintain a balanced position each day or be subject to a cash-out regime, depending on tolerance levels (Green and Yellow Zones). The risk of facing a high marginal price for balancing provides incentive for the market itself to keep the balance. In any of the three levels of emergency, Energinet.dk may increase the price to be unbalanced from an additional 0.5 % up to a maximum of 100%. The rate can be increased in each direction (buying and selling balance gas), or isolated in one direction (buy or sell), depending on the specific situation[262]
- Increased incentive payments: in situations of emergency, Energinet.dk buys and sells excess gas at incentive-based prices. High prices will send shippers the right signal to avoid an escalation of the emergency (this measure is a continuation of the balancing mechanisms, although only applies in case of emergency)
- Disconnection from commercially interruptible consumers (Hyper Severability)
- Use of South Arne's pipeline: in case flows in the Tyra-Nybro pipeline cannot be delivered, gas from Tyra field will be transported in the opposite direction to Harald pipeline and then transported to Denmark by means of the South Arne pipeline
- Disconnection from the rest of non-protected customers (those who didn't engage in interruptibility contracts).

The first four measures, together with SO storage and swapping of storage nominations, are labelled as balancing tools and can be used under both normal operation and emergency situations. The remaining 4 can only be used in emergencies. The following section offers an overview of the two main market based mechanisms.

A.6.5.4 Cash-out Mechanism

Energinet.dk is responsible for the ongoing balancing of the Danish Gas System. Shippers are responsible for balancing their deliveries and off-take in order to minimize the need for Energinet.dk to undertake balancing actions. If, for any given shipper, the sum of its deliveries is not equal to the sum of his off-take, then it's deemed imbalanced for that Gas Day and will be subject to imbalance charges.[263]

The commercial balancing model involves a daily full cash-out of the Shippers' imbalances end-of-day.

Payments depend on the aggregated imbalanced volume: Energinet.dk computes two different levels of tolerance, based on physical conditions of the network, called the Green and Yellow Zones.

The Green Zone functions as a tolerance level for total commercial balance position. Energinet.dk shall publish it one day ahead. Its size is based on accepted nominations for Entry and Exit Points, Energinet.dk's forecast for off-take in the Exit Zone and accepted nominations for direct sites. Moreover, each day Energinet.dk publishes an expected gas balance for the end of that day no later than 14:00. If this balance lies outside tolerance levels, Energinet.dk must intervene in the commercial market. During the rest of gas day, expected aggregated balanced position will be computed

[262] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, Annex A, p.14.
[263] Energinet.dk (2014), Rules for Gas Transport, version 14.0, article 9.1.

each hour on the basis of nominations and forecasts. This position is called Expected System Commercial Balance and is published until 02.45 on the gas day.[264]

If the Expected Balance moves into the Yellow reaction Zones, this will be a signal to the market that Energinet.dk will intervene in the market. Energinet.dk will only react on expected balance if it is in the yellow zone at five specific times during the day, and Energinet.dk will start trading 20 minutes immediately after on Gaspoint Nordic.

The product to be traded will be the within-day product and the quantities traded will be equal to the difference between the latest estimate of the Expected Balance and the border between Yellow and Green zones. The pricing of the trade will be included in the daily settlement of imbalances. At the end of the day, total imbalance will be allocated among imbalanced shippers. Those with a positive position will be granted a credit for imbalance charges by Energinet.dk[265].

A.6.5.5 Imbalance charges

If total imbalance for any given day falls within the Green Zone, settlement will be made using the Neutral Gas Price (NGP). NGP is calculated as half of the weighted average of all the within-day product trades on Gaspoint Nordic on the gas day plus half of the Gaspoint Nordic Spot Index for the gas day. [266]

If imbalance falls on the Yellow zones, settlement price will depend on whether there was trading by Energinet.dk or not (Energinet.dk only trades if Expected Balance lies on the Yellow Zones five times during a given day).

(a) There was balancing trading by Energinet.dk

In case Energinet.dk traded in order to correct imbalances, four different situations appear and settlement prices will be the following:

Table A.6.5. Settlement prices if Energinet.dk engaged in balancing actions

Shipper's Position	Expected Balance sign	
	Positive	Negative
Positive	Lowest between: • NGP plus step 1 adjustment • Mg Trade Price for Within-day Imbalance operations Lower Limit : 65% NGP	NGP – adjustmet step 1
Negative	NGP + adjustment step 1	Highest between: • NGP plus step 1 adjustment • Mg Trade Price for Within-day Imbalance operations Upper Limit : 135% NGP

Source: Energienet.dk[267]

[264] Gas days expand from 6 :00 a.m. of day N to 6 :00 a.m. of day N+1.
[265] Energinet.dk (2014), Rules for Transportation of Gas, Article 9.2.3. and 17.2.d.
[266] Energinet.dk (2014), Prices for transport in the gas transmission system, effective as of 1st January 2015, p.2.
[267] Energinet.dk (2014), Prices for transport in the gas transmission system, effective as of 1st January 2015, p.2. ; and Energinet.dk (2014), Rules for Transportation of Gas, Article 17.2.d.

If Expected Balances changed signs within-day (i.e. the actions of shippers and Energienet.dk combined overestimated the necessary reaction), settlement prices will be the highest of the four prices proposed above for shippers with a negative balance, and the lowest of the four prices proposed above for shippers with positive balances.

(b) There was no balancing trading by Energinet.dk

Settlement prices would be the following:

Table A.6.6. Settlement prices if Energinet.dk did not engage in balancing actions		
Shipper's Position	Expected Balance sign	
	Positive	Negative
Positive	NGP - adjustment step 2	NGP - adjustment step 1
Negative	NGP + adjustment step 1	NGP + adjustment step 2
Note that in this case upper and lower limits have been removed.		
Source: Energienet.dk[268]		

Currently, adjustment steps 1 and 2 amount to 0.5% and 2.0%. However, in situations of emergency, Energinet.dk can increase the adjustment percentages up to 100 %, for both adjustment step 1 and 2, and can remove the minimum and maximum price levels [269].

A.6.6 DSR

In the commercial interruptibility concept, Energinet.dk buys the right to disconnect a customer's gas supply under special circumstances in order to lower aggregated Danish demand.

Current interruptibility agreements provide for the possibility of partial disconnection of customers (instead of a binary on/off schedule) and it also allows Swedish gas consumers to participate (in collaboration with Swedish TSO Swedegas).

Energinet.dk entered into agreements with Denmark's largest gas consumers concerning the interruption of supplies during an emergency situation, what amounts to approximately 20% of the total Danish gas consumption during winter.

The terms of the agreement can cover either an interruption of gas delivery after three hours or after three days, or a combination of these. Some consumers have agreed to a 100% interruption of their consumption while others reduce their consumption only partly. Thus, most of the CHPs, in such situations, plan to temporarily stop their electricity production and reduce their gas consumption to cover heat production only. In general, the interruptible end users plan to reduce their consumption by as much as 75% in case of such an emergency supply situation.

Interruptibility contracts are set by means of annual auctions for commercial interruptibility, where Energinet.dk purchases the right to interrupt large consumers' gas supply whenever the supply situation is under pressure. The trigger point for interruptibility contracts is the alert level (of the three degrees of emergency considered in Danish regulation).

[268] See Foonote 267.
[269] Energinet.dk (2014), Prices for transport in the gas transmission system, effective as of 1st January 2015, p.2.

In order to be eligible, consumers shall have an annual consumption level of at least 2 Mcm/y. If a consumer wishes to choose interruptible supply for a given point, it shall inform Energinet.dk and participate in that year's tender for interruptible supply.[270]

The following interruptible products are currently offered:

- Hyper3-interruptibility: means that the Consumer must interrupt his off-take from the relevant Consumption Site within 3 hours and be interrupted for up to 69 hours.
- Hyper72-interruptibility: means that the Consumer must interrupt his off-take from the relevant Consumption Site within 72 hours and be interrupted for up to 72 hours.[271]

The interaction between the two products ensures that no jump in demand appears after 72 hours (since Hyper 72 starts disconnection when Hyper 3 got re-connected to the grid).

A.6.7 Production capacity

The following table presents the evolution of production, imports, exports and consumption from 2006 to 2014. As it can be see, Denmark remained as a net exporter of natural gas until 2010.

2014 consumption levels reached around 3 Bcm, which is almost a 1 Bcm reduction if compared to 2011 levels. Such a decrease has been mostly caused by the reduction of gas-fired power generation in the country[272].

All figures shown are expressed in Mcm.

Table A.6.7. Production, Exports, Imports and Consumption in the Danish Gas System

Year	Production	Imports	Exports	Consumption
2006	9,872.2	0.0	4,964.0	4,823.9
2007	8,743.3	0.0	4,282.4	4,318.3
2008	9,565.5	0.0	5,228.9	4,351.0
2009	7,988.9	0.0	3,797.9	4,181.0
2010	7 787.5	144.3	3,350.4	4 729.4
2011	6,247.9	796.5	2,962.6	3,961.2
2012	5,453.7	870.0	2,829.9	3,696.0
2013	4,592.4	1 292.3	2,119.6	3,536.3
2014	4,371.7	592.5	1,984.2	2,995.5

Source: Danish Energy Regulatory Authority[273]

Regarding import origins, in 2014, 75% came from Norway and 25% from Germany. As for exports, 24% were destined to The Netherlands, 43% to Sweden and 34% to Germany.

A.6.8 LNG import capacity

[270] Energinet.dk (2014), Rules for Gas Transport, version 14.0, p. 72.
[271] Energinet.dk (2014), Rules for Gas Transport, version 14.0, p. 16.
[272] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, p.10.
[273] Available at (danish only) : http://www.ens.dk/info/tal-kort/statistik-nogletal/manedsstatistik

Denmark has no LNG facilities and no plans to develop any. However, a plan for small-scale LNG fuelling of vessels in the Baltic Sea is currently being developed. Such plan envisages small scale LNG supplies as fuel for vessels and relies heavily on LNG facilities from neighbouring countries (facilities located in Rotterdam, Goteborg, Hamburg and Tallin). However, this project is not meant to increase import capacity.

The project foresees the installation of a 200 tons LNG tank and filling facility at the port of Hirtshals (North of Denmark) for fuelling of passenger/cargo vessels with a view to later establishment of a larger tank at the port274.

A.6.9 Pipeline Import Capacity

For a detailed description of Danish pipeline capacity, see "Calculation of the N-1 formula's" Table above.

Future Projects

The expansion of the gas infrastructure in the Southern part of Jutland was completed in October 2013. The expansion includes establishment of a new compressor station at Egtved and looping of the existing transmission pipeline from the German border to Egtved.

The first phase of expansion in the Northern part of Germany is completed and the next phase is planned to come into operation in October 2015. It will allow Denmark (and Sweden) to increase imports of gas from Germany in order to compensate for the decreasing Danish North Sea production.

The bi-directional flow on this interconnection allows Denmark to export gas to Germany during the summer time and import gas from Germany during winter time, where gas consumption in Denmark (and Sweden) is high due to need for gas for heating purposes.

Current capacity of 7.44 Mcm/d will be increased to 10.8 Mcm/day [275].

A.6.10 Interruptible consumption

Approximately 20% of the total Danish gas consumption during winter can be interrupted through these agreements.

The following tables show interruptible consumption volumes contracted for the last two winters. First table presents clearing prices for interruptible consumption while the second and third present the volumes contracted of the two products currently available. Figures are expressed in KWh/h.

Table A.6.8. Clearing prices for Interruptibility contracts 2013-2015

Product	**Clearing Prices (dkk/KWh/h)**	
	2014/2015	**2013/2014**
Hyper 3	8.210	12.93
Hyper 72	1.112	1.26
Source: Energinet.dk		

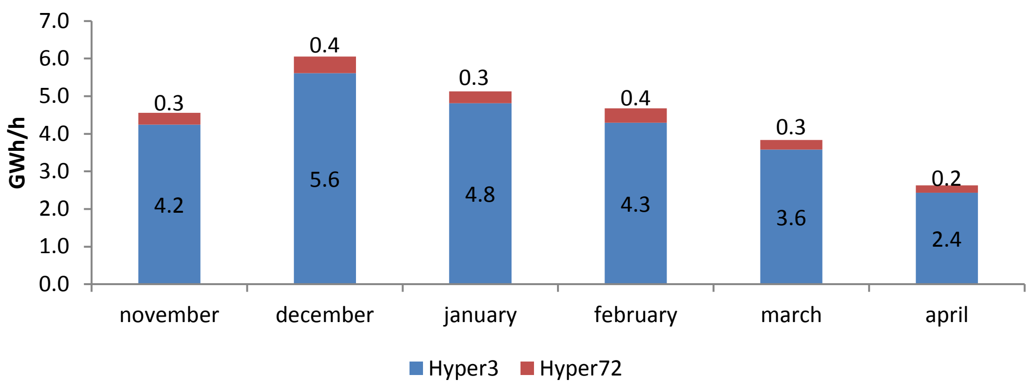
[274] Available at :http://inea.ec.europa.eu/download/project_fiches/denmark/fichenew_2013dk92060s_final.pdf
[275] Energinet.dk (2014), Security of Supply Regulation - Risk Assessment, Annex A, p.20. Danish Energy Authority (DEA) (2014), Preventive Action 2014/2016, p.12.

Table A.6.9. Hyper 3 monthly contracted quantities 2013-2015						
Hyper 3	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
2014/2015	516,492	683 219	586,226	523,158	435,898	296,622
2013/2014	-	302 309	358,984	364,476	296,254	241,537
Source: Energinet.dk						

Table A.6.10. Hyper 72 monthly contracted quantities 2013-2015						
Hyper 72	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
2014/2015	286,300	401,869	283,064	339,963	232,457	175,997
2013/2014	-	304,706	363,759	423,265	329,228	285,001
Hence, Danish suppliers valued the cost of interruption announced with short advance (3h) at around 1.1 €/KWh/h, while the cost of interruption on a longer time horizon (up to 72 hours) was valued at 0.15 €/KWh/h[276]						
Source:Energinet.dk						

The following graph represents total interruptible capacity for each of the months for winter 2014/2015 (figures expressed in GWh/h).

Figure A.6.3. Evolution of interruptible consumption in winter 2014-2015



Source: own elaboration

The total cost for Winter2014/2015, as obtained from the results of each of the tenders carried out by Energinet.dk, amounts to 26.8 million DKK (3.6 € million)[277].

A.6.11 Estimated fuel switching

There are no estimations available for fuel switching potential.

A.6.12 Available Cost Estimations

Regarding winter 2014/2015, apart from the interruptible consumption contracts described above, Energinet.dk engaged in the following market based activities in order to guarantee Security of Supply. [278]

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[276] Conversion was computed using an exchange rate of 1 DKK= 0,13422 €.
[277] Energinet.dk (2014), The Danish Gas Market, Market Based activities.

- Purchase of emergency withdrawal capacity on Lille Torup storage facility (4.85 GWh/h)
- Purchase of storage standard bundled units (SBUs) on both storage facilities (1,887 GWh)
- Signing of three individual filling requirements contracts (2,255 GWh)
- Sale of 288 GWh of stored gas from May 2015 onwards[279]
- Purchase of additional import capacity from the pipelines from the North Sea.

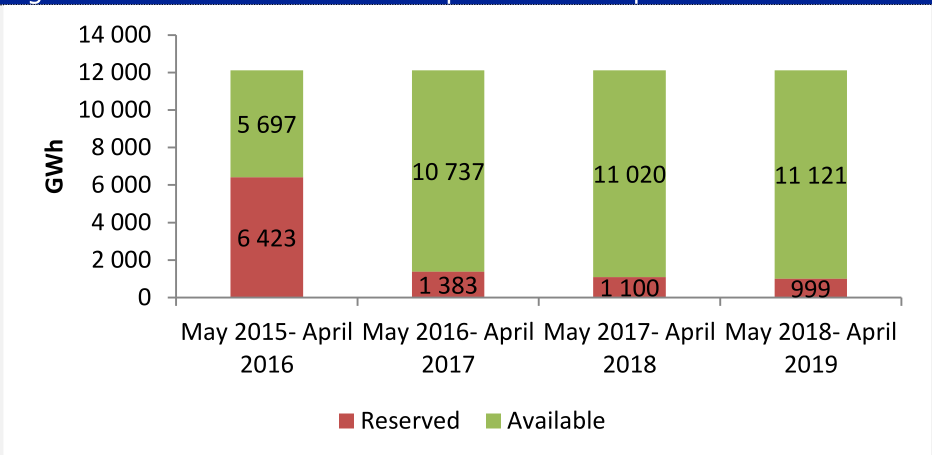
All these interventions by Energinet.dk resulted in a cost of 22.1 DKK millions (2.97 € million).

A.6.13 Long-term Contracting

Energinet.dk offers multiyear products for both storage sites, but there are no public data on historical sales of each type of product (data exists but aggregated for both yearly and multiyear products). As regards to its future evolution, Energinet.dk, on its website offers all the information on available capacity.

As it can be seen, only for the immediately following year (2015/16), reserved capacities are dominant (53%; 13.3% belonging to the TSO). For the rest of years, reserved capacity ranges around 10% of total available capacity. Hence, it can be concluded that multiyear (l/t) products represent a significant amount but 1-year and shorter-term-products represent most of Danish gas storage the market.

Figure A.6.4. Evolution of interruptible consumption in winter 2014-2015



Source: Energinet.dk[280]

[278] Energinet.dk (2014), The Danish Gas Market, Market Based activities.
[279] Energinet.dk (2015), The Danish Gas Market, Market Based activities.
[280] Available at http://www.gaslager.dk/GSMSPUB_WEB/dsp/dspGraf.do?aktGraf=TOT_VOL_KAP&aktAar=2018

ANNEX 7. CASE STUDY: FRANCE

A.7.1 Market overview

The French market is the 4th national largest in the EU, after Germany, the UK and Italy. Yet gas represents a much smaller share (15%) of total primary energy consumption that the EU average (23%). There are several reasons for this. First, France has a historically strong nuclear power industry triggering relatively low electricity prices: as a consequence of this, nuclear-made electricity made its way even in markets where it is not usually competitive, like space heating, and prevented natural gas from significantly entering the power generation market. Second, domestic production in France has always been limited and is now covering less than 1 % of requirements, hence a very high import dependence. Third, the country's population density is lower than the EU average, therefore gasification is relatively costly.

The fact that gas represents a relatively small share of French primary energy does not make its security of supply easier. On the contrary, there are fewer flexibility tools that in other countries: in particular, little gas gas-fired power generation that could be substituted by other fuels in emergency. On the other hand, France can rely on abundant LNG regas capacity; excellent diversification of suppliers; limited pipeline imports from outside the European Economic Area (less than 15%, from Russia).

The French gas market has long been dominated by the former state owned monopolist, Gaz De France. However after its partial privatisation and the merger that has created GdF-Suez, the market has been substantially opened and several large and small competitors have entered it, including the former electricity monopolist (EDF). Moreover, the South-West of the country (where most domestic production was available) had been dominated by the largest French oil & gas major, TOTAL. Thus, the market is now rather competitive.

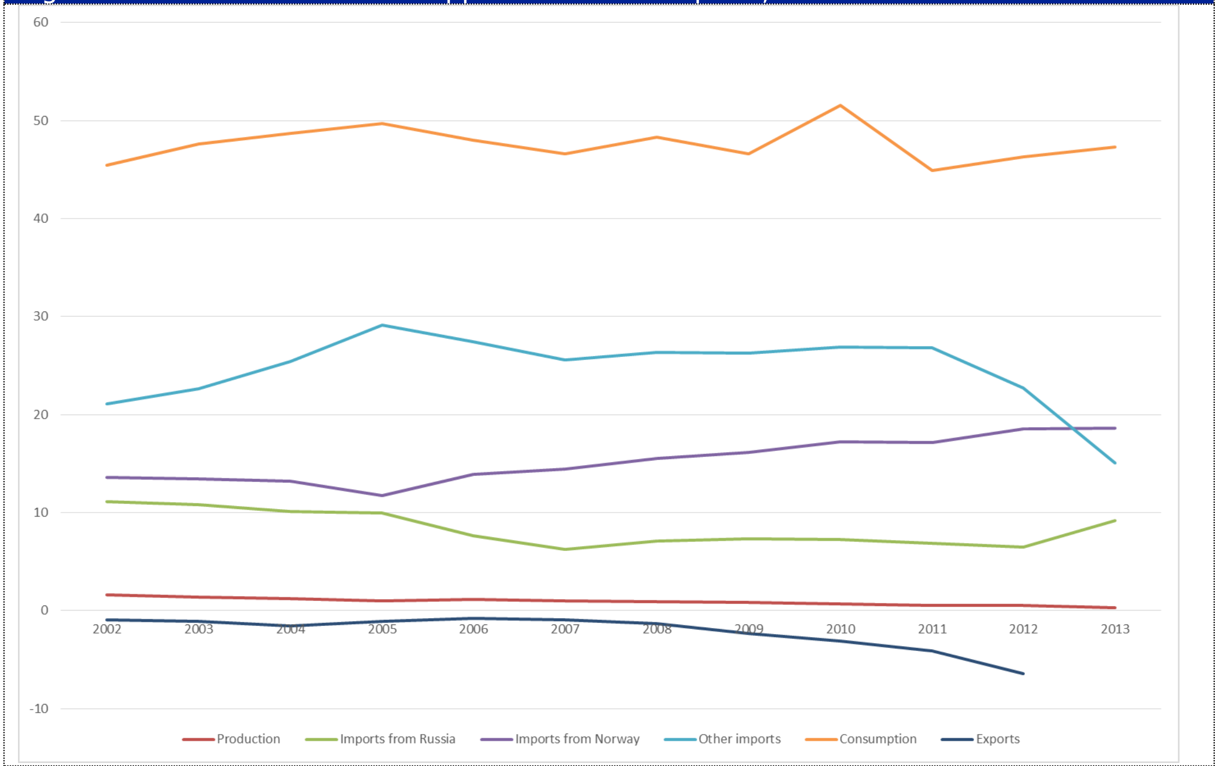
The main national TSO (GRTgaz) covers the area originally supplied by the GdF monopoly whereas TIGF covers the smaller former TOTAL area in the South-West.

The main difficulty, also affecting SoS, is the limited transmission infrastructure development, which has prevented the fast creation of a single national entry-exit system. After starting around 2007 with five national hubs, limited liquidity development has shown the need to merge them into a single virtual point. The three Northern areas (*Point d'Exchange du Gaz Nord* or PEGN)have been merged in 2011 and recently the Southern areas of TIGF and the Southern GRTgaz area have been also merged (*Point d'Exchange du Gaz Sud* or PEGS). However, the limited North-South interconnection has so far prevented the formation of a single French market. This also affects SoS, partly because of reduced market liquidity compared to neighbouring markets, and partly because (in particular) the Southern zones are heavily exposed to LNG supplies and their swings. Despite an attempt to link the market by a "coupling" mechanism, Southern France has often seen higher prices than the North. The latter instead has been mostly aligned with neighbouring markets in Germany, Belgium and the Netherlands (see Figure A.7.3.1 above).

These developments help explaining the peculiar attitude of French authorities towards SoS. The policy (outlined in detail in the following sections) may be aimed at curbing price fluctuations, notably in the South of the country, which has a lower supply diversity and a high exposure towards LNG market fluctuations. Yet, the South has also the highest endowment of storage sites.

French plans are now aimed at reducing the South's relative isolation. In particular, reinforcement of the North-South link (notably through the construction of the *Arc de Dierrey and the Val de Saone projects*) and enhanced interconnection with Spain should ease the disconnection of Southern France from the rest of the country and Europe.

Figure A.7.1.1 France's main supplies and consumption, 2002-2013



A.7.2 France's main storage related SoS measures

The French Prevention Action Plan explicitly rejects the opinion that spot markets can represent a sufficient tool to address situations of gas supply stress, and advocates Public service Obligations involving storage. In Section 6.3, Frances's PAP explains that:

"Suppliers and infrastructure managers must be able to ensure continuity of supply for all customers (except industrial customers with interruptible contract) in circumstances previously defined:

- a cold winter as it produces one every fifty years;
- an exceptional cold spell for three successive days such as occurs once every fifty years;
- the disappearance, for a given provider, of its main source of supply for six months."

These requirements are clearly and explicitly tighter than those required by the SoS Regulation.

In general, "storage rights" are attributed to protected customers. Storage obligations in turn are proportional to such storage rights.

In particular, they are implemented by Decree 2006-1034 of 21 August 2006 relating to third party access to storage. This decree provided for:

- a reporting requirement that permits competent authorities to verify that suppliers have sufficient recourse to natural gas stocks taken into account their other means of action, which authorizes in the case of failure, the imposition of additional stocks;

- an obligation of stockpiling at the beginning of the winter for suppliers of domestic customers or those conducting missions of general interest, up to 85% of the storage rights of these customers.

Lately (March 2014) these obligations have been modified. They have been extended to all customers connected to distribution grids (except interruptible ones), but the obligation on suppliers has been reduced to 80% of the storage rights that are attached to these customers.

The Decree of the Minister for Industry of 7 February 2007 defines in chapter 1 the unitary storage rights by consumer classes. There are nine classes, which are related to the reading frequency (twice yearly, monthly or daily) and to the consumption level. For all classes but the smallest one (customers with annual consumption of more than 6000 kWh/year), rights depend on climate parameters of the nearest meteorological station (out of 32 in France).

Storage obligations during the course of winter amount to 80% of such rights. To fulfil its obligations of supply in the case of a cold winter, as occurs statistically every fifty years , the supplier must be capable, every first day of the month between November 1 and March 31, to cover the consumption, to the 2% risk, of all its customers who have not accepted a supply contract subject to interruption, over the residual period until 31 March. However, the value of this hazard cannot be greater than the difference between the expected consumption of a once in fifty years cold winter and the consumption recorded over the period from November 1, up to the date concerned[281].

Providers are responsible for estimating the additional consumption of their customer in their portfolio in case of a 1/50 cold winter for the remaining part of the heating season.

To fulfil its obligations of supply in the case of an extremely low (1/50) temperature during three days, also called *peak cold 2% risk*, all suppliers must be capable to serve their customers who have not accepted a supply contract that may interrupt with an additional daily consumption calculated:

- for the period from November 1 to February 1, from the temperature of the peak cold 2% risk;
- for the period from 1 February to 31 March, from the temperature linearly interpolated between the temperature of the peak cold 2% risk, positioned at February 1st, and of the temperature of the peak cold 2% risk of a month of April, positioned on April 15.

Storage rights and the related storage obligations include both a working gas and a withdrawal capacity, which are expressed as a share of the yearly reference consumption. These rights (as percentage ranges related to the meteorological stations where applicable) are shown in Table A.7.1.

In the whole of France, such storage obligations for the current year (between 1.4.2014 and 31.3.2015) amount to 86.6 TWh of WG and to a withdrawal capacity of 1,836 GWh/day.

Since congestion problems within the country may also emerge, storage operators are required to grant priority to suppliers of users located within the balancing zone where they are located. In France there were until recently three trading regions (PEG Nord, PEG Sud and TIGF), but the last two have been merged since 1 April 2015. Congestion is much more likely to occur between rather than within zones.

[281] For this reason, the obligation changes over the winter in relation to actual consumption. It has been compared to a “tunnel”, which looks wide at beginning but appears to be narrowing near its end.

A.7.3 Evolution and debate

Storage obligations have been operational in France for a rather long time, basically dating back to Decree No. 2006-1034 of 31 August 2006, which specified that:

- Priority for storage use is awarded to Transmission and Storage Operators for the implementation of their duties;
- Remaining capacity is allocated by a merit order, listing:

1. Residential customers and buildings;
2. Other customers pursuing missions of general interest;
3. Other customers with firm supply contracts;
4. Last resort suppliers;
5. Interruptible customers;
6. Transit contracts subscribed before July 2004;
7. Beneficiaries of international bilateral agreements with other EU or EEA Member States.

These obligations have not basically changed. The Decision of the Minister in charge of energy of 7 February 2007 has specified the storage rights, which have been only slightly modified later. The minimum amount of storage to be kept by suppliers has been reduced by a Minster's Decision of 11 March 2014 from 85 to 80% of storage rights, but the plateau has been extended to all end users connected to distribution grids. This was decided for the difficulty of implementing selective disconnections within distribution systems.

Any further capacity beyond the merit order list is regarded as commercial storage. Such capacity may be claimed whenever necessary for the satisfaction of primary needs of the merit order list. In these cases, commercial capacity rights are reduced on a pro-rata basis.

Further rules specify how capacity must be split among sites, with a view to ensure that suppliers are granted the capacity in the sites that are closer to the areas where they are more active. This also considers the risk of transmission congestion, which is still remarkable in France. The country is still divided in three trading regions known as PEG-Nord, PEG-Sud and TIGF (in the South-West).

However, the main new feature that has been introduced in March 2014 is a further obligation on minimum withdrawal capacity rights, which did not exist earlier (see Table A.7.1, last column). Minimum withdrawal capacity rights are defined as the largest of:

- The available withdrawal capacity available on 1 February of a cold winter as it happens once in five (1/5) years;
- The available withdrawal capacity after depletion of 55% of the working gas.

As noticed, whereas storage prices in France are negotiated, the sector is actually heavily regulated. Capacity allocation is mostly governed by merit orders and (where necessary) prorating criteria within them. Auctions are rarely used and only for limited amounts.

Table A.7.3.1. Storage rights by consumer classes in France			
Customer Profile	Consumer type	Storage Working Gas Right / 1000 kWh	Storage Withdrawal daily Capacity Right / 1000 kWh
P11	Bi-annually metered customer with yearly consumption < 6000 kWh	94	2.35
P12	Bi-annually metered customer with yearly consumption > 6000 kWh	210 - 500	9.2
P13	Monthly metered customer with load factor ≤ 39 %	0	0
P14	Monthly metered customer with load factor 39 ÷ 50 %	18.5	1.55
P15	Monthly metered customer with load factor 50 ÷ 58 %	41.5 - 190	5.05
P16	Monthly metered customer with load factor 58 ÷ 69 %	125 - 405	8.4
P17	Monthly / daily metered customer with load factor 69 ÷ 75 %	160 – 515	10.5
P18	Monthly / daily metered customer with load factor 75 ÷ 81 %	220 – 630	13
P19	Monthly / daily metered customer with load factor > 81 %	235 – 780	17.5
Source: Minister's Decision of 7 February 2007, consolidated version as of 23 January 2015			

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As noticed in the previous section 3.4.1, the tight rules and high requirements are justified by the heavy reliance of France on imports, which is close to 99%, and by the large role that storage plays in the coverage of daily peak consumption, estimated at over 60%.

Almost all (95%) of storage capacity is allocated on a yearly basis. There is very little long term capacity booking. Therefore, filling rates and capacity bookings may be very sensible to gas market prices in case no formal storage obligations were in place.

Obligations are verified twice a year, in May and early December.

Public discussion on the SRSMs in France is ongoing. Shippers are aware that these obligations are among the heaviest in Europe and are complaining about their costs. Proposals have been put forward for mechanisms based on auctions. The benefits of having substantial storage in a country like France are widely acknowledged, as well as the risk of (particularly smaller) market players "free riding" by not subscribing enough storage, particularly in areas that are still inadequately connected to the rest of the European market. Such proposals do not exclude a move towards regulated storage, so that the income of SSOs and their role may be acknowledged.

Stakeholders as well as government authorities have also explained why this issue may be hotter in countries that are located farther away from the main gas flows, so that the (private) interest in storing gas in the location is much lower than (e.g.) in Germany, Slovakia or Austria. At the same time, France does not have the same strong alternatives as other countries, like Netherlands and the U.K.'s domestic production; even its LNG capacity is remarkable but not as strong as in Spain or Belgium (as a share of national consumption) and is exposed to LNG market fluctuations. All of these factors explain why, even though the search for cheaper models continues, French stakeholders mostly agree with the need to retain a large storage as a major SoS tool. However, suppliers tend to regard the current regime as rather costly and are suggesting ways to reduce its cost, like a larger resort to auctions.

A.7.4 Other SoS information

In France, tariffs for transmission to/from storage sites are differentiated from those applying to other entry/exit points. Entries from imports vary between 88,82 (Taisnières B) and 114,19€/MWh/d/year (Taisnières H, Obergailbach, Dunkerque). For domestic intra-zone crossings they vary between 50 €/MWh/d/year from South to North trading regions, and 208.04 €/MWh/d/year from North to South trading region. However storages tariffs for transmission are the lowest and vary only between 8.17 and 11.96 €/MWh/d/year for entries to storage and between 18.39 and 26.92 €/MWh/d/year for exits from storage.

Until 2013, France's major import infrastructure is the MEGAL, carrying flows coming from Germany, including Russian imports, transit and arrives in the country at the Obergailbach IP. Since 2014, firm capacity offered at IP with Belgium (Taisnières) slightly overcome Obergailbach IP. In any case, the calculation made for France yields an N-1 supply score that exceeds demand by 30% in Gas Year 2014.

As for alternatives in case of major disruptions, the Emergency Plan duly considers and outlines measures to be taken to face them, including[282]:

- Recommendation to moderate energy consumption. For this purpose, announcements are disseminated at the national and/or local level in the media by the Competent Authority (television, radio, newspapers);
- Strict application of the temperature limits in the premises of some establishments receiving the public;
- Stopping of the supply of interruptible customers;
- Switching of industrial customers able to use an alternative energy source and not having taken out an interruptible contract;
- Reducing or stopping consumption in the premises of public establishments not receiving the public in a period of emergency;
- Limiting the period of heating in the premises of establishments receiving the public.

Moreover, the EP envisages further measures including those of last resort (load shedding) and the procedures, priorities and conditions for them. However, no information is provided about how the energy system could deal with such provisions, e.g. by fuel switching in heat and power generation.

As for substitution potential of gas uses, it is interesting to notice that the French electricity TSO (RTE) publishes detailed data about the country's capacity and its use. These will be used for the estimation of the costs of a possible supply disruption,

[282] Ministry of Ecology, Sustainable Development and Energy, Director-General for Energy and Climate, Emergency Plan carried out under the implementation of EU Regulation 994/2010 of the European Parliament and of the Council concerning measures to safeguard the supply of natural gas and repealing Council Directive 2004/67/EU, April 2013, English version, p.[ADD PAGE]

which is however extremely unlikely for France according to ENTSOG's Stress Test model (see *Section 4.1 and Annex 4*).

Table A.7.4.1 Generation capacity by source in France and its usage

	Installed capacity as of 31.12.2013	Generation in 2013	Average Load Factor
	MW	GWh	
Nuclear	63.130	403.756	73,0%
Fossil Thermal	25.707	44.653	19,8%
of which: Coal	6.359	19.829	35,6%
of which: Oil	8.948	4.872	6,2%
of which: Gas	10.400	19.952	21,9%
Fhydro	25.434	75.432	33,9%
Other renewable	14.018	26.819	21,8%
of which: Thermal	1.487	6.218	47,7%
of which: Photovoltaics	4.366	4.660	12,2%
of which: Wind	8.157	15.941	22,3%
Total	**128.282**	**550.660**	**49,0%**

Source: RTE

ANNEX 8. CASE STUDY: GERMANY

A.8.1 Main storage related SoS measures of the country

Currently, there are neither mandatory / strategic storage requirements nor PSO requirements for suppliers.

The German market design relies on market forces to secure gas supply. There is no particular regulation regarding storing gases for an emergency. In principle, this concept is widely accepted by market participants. However, there are discussions about potential adoptions of the current market model for storages, by which the role of storages in respect to security of supply may be increased. Until now no decision has been taken for any adoption at all. Consequently the following presents the actually published information about potential changes.

A.8.1.1 Current discussions on storage obligations

Security of supply is currently intensively discussed in the German gas market and the German Bundesrat (Federal Council of Germany) has asked the Federal government in a resolution from July 2014 to ensure a sufficient level of stored gas in order to improve the security of supply.

In this respect the Federal Ministry of Economic Affairs and Energy has issued a study to evaluate the possibilities to improve the level of security and strengthen the preventive measures. The backgrounds of this study were market observations that the liberalization process has changed the role of the market participants by which inter alia the economic incentives to do preventive actions have been reduced.. Finally, the high import dependencies of Germany increased the sensitivity for security of supply. In this respect alternative options shall be investigated, e.g. strategic reserves and storage obligations. The study will last until May 2015; however, the models which will be further investigated were presented in a workshop.

As the discussion about the implementation of the reserve in Germany is ongoing it is not possible to give any direction which model might be implemented if any at all. However, it is agreed by the most market participants that some changes in the market design are necessary. Consultations showed that most market participants agree with the current market model by which they are responsible for securing the supply individually. Nevertheless in the mentioned study tree models have been presented for adoption in the current regime.

1) National gas reserve

This approach follows a decision of the German Bundestag. It is foreseen that the gas reserve shall be sufficient to cover the national gas consumption of about 45 days which equals approximately 10 bcm. The application of the strategic gas reserve should be comparable to the application of the petroleum stockpiling.

The petroleum stock is financed by membership fees of importers and producers of gas which are obliged to become members in the German National Petroleum Stockpiling Agency (EBV). The costs can then be added to the sales prices. The stock is regionally allocated and is used in an emergency by decree of the Federal Ministry of Economics. Applied to the gas market the implementation of such national natural gas reserve would mean that the capacities for the natural gas reserve are taken out of the market and reserved for the national reserve.

2) Allocation of specific storage capacities to the TSO

The second model intends to compensate for reduced gas reserves by the market in particular for extreme winter seasons. This volume equals the difference between the gas stored in regular winter and the required gas reserves in an extreme winter. In the market area of NCG this volume was estimated by Open Grid Europe (one of the participating TSOs) at ca. 2 bcm. These storage capacities shall be allocated to the TSO and financed by the network tariffs. The stored gas should then be used as internal balancing energy by the TSO. In an emergency this gas is allocated to the market (trader) by balancing energy at balancing costs. After the emergency the TSO will refill the stock from external balancing market.

3) Traders obligation to hold storage capacities

The third model has been developed by the association of storage operators in Germany (INES). The model considers the compulsory storage volume to secure three scenarios of the regulation of security of supply. The estimated volume amounts to about 7 bcm in total and 4 bcm for protected customers. This compulsory volume shall be available in the winter period whereas the compulsory stock shall reduce until end of March. The storage volumes can be booked by the market operator or the individual traders/ sellers according to their share of the market volume and will be made available to the market after a decree of the TSO in cooperation with the competent authority (Bundesnetzagentur or Federal Ministry of Economic Affairs and Energy).

Figure A.8.1. Level-dependent performance of the German gas storages

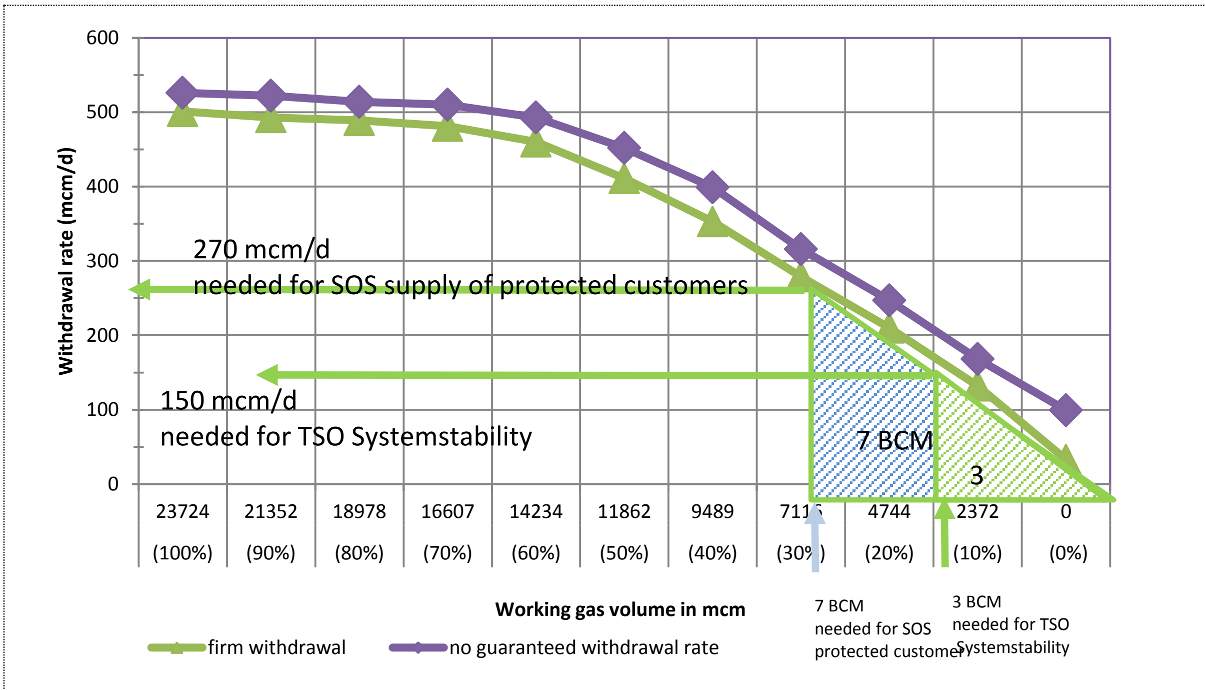


Figure A.8.1 shows the dependencies between the withdrawal rates for SOS measures and working gas volumes for system stability and SOS supplies for protected customers. If Germany decides to supply all customers additional 4 BCM WGV would be needed. But these are in total less than 50% of the available storage capacity needed for SOS measures.

A.8.1.2 Tariffs for transmission to/from storage sites

At March 24th the German regulator has published a new fee structure for short term capacities which enters to force at 1 January 2016. Currently the German TSO fee structure is a daily fee which is multiplied with the number of days for longer term product, e.g. with 365 for a yearly product. In future the yearly product is the calculation basis and short term products will be calculated with a multiplier of:

Daily product	Yearly product / 365* 1.4
Monthly product	Yearly product / 12 * 1.25
Quarterly product	Yearly product / 4 * 1.1

For storages the TSO’s have to discount the entry- and exit fees by 50% of the regulatory fee. In special cases the TSO can request a higher discount up to 90% at the NRA for special storage sites. For storages which have access points with multi national or international market areas this discounts can only be offered if the SSO and the storage customer guarantee that the gas will not be transported to the neighbouring market area via the storage site. With this regulation a misuse of storages as a market transfer point between grids shut be prevented. In a first review with the existing capacity fees and their usage profiles the new legislation will increase network access fees for storage users by 6% as current storage user book normally seasonal products and daily or monthly products for trading purposes.

A.8.2 SoS-measures of the country

The current system of securing energy supply in Germany and in particular of gas is basically regulated in three pieces of national legislation: Energy Act (Energiewirtschaftsgesetz, EnWG), Law of Energy Security (*Energiesicherungsgesetz*, EnSiG) and Regulation of Gas Supply (Gassicherungsverordnung, GasSV). In addition to this the European Regulation EC 994/2010 applies in Germany. This legislation describes the framework for measures to be taken in case of an emergency. However, as shown above there is a consultation ongoing which may result in a reform of the current regulation.

A.8.2.1 National legislation: Energy Act (EnWG)

According to Articles 1 and 2 EnWG security of supply of any network related supply of energy (power and gas) is the responsibility of all market participants in Germany (Article 1 and 2 Energy Act, EnWG). This general obligation of all market participants is further detailed in Articles 11, 15, 16, 16a, 49, 53a, and 65 EnWG:

- Article 11: Operators of Energy-grid are required for a safely and reliable grid with non-discriminatory access.
- Article 15: TSOs are responsible for the transport of gas via their network. By this they shall operate and interconnect to other networks in such a way that the supply of gas is secured. In this respect TSOs, storage operators and operators of LNG terminals are obliged to provide necessary information to any third party with which their asset is technically connected.
- Article 16: In case the supply is in danger TSOs are entitled and obliged to take network related and market related measures to prevent the network users from interferences. Market based measures include the usage of balancing energy, contractual agreements (e.g. interruptible rights) and the utilization of storages.
- Article 16a addresses regulation for DSOs.
- Article 49: Energy equipment is to build and to operate with technical security.

- Article 53a: Utilities supplying protected customers (i.e. households and district heating plant operators) must ensure supply of gas according to Art. 8 (1) EC 994/2010. By this they are entitled to use the instruments mentioned in appendix II of this regulation.
- Article 65: The National Regulatory Authority (Bundesnetzagentur) is the responsible entity to supervise this regulation.

Following unbundling regulation both network operators and storage operators act independently from other market activities. The separation of roles and responsibilities also applies in case of interruptions, that is to say any communication in an emergency has to be consistent with competition law.

In case of extreme situations of emergency of supply the NRA is obliged to regulatory interventions which are ruled in Law of Energy Security (EnSIG) and Regulation of Gas Supply (GasSV).

A.8.2.2 Law of Energy Security (EnSiG)

In case of an emergency i.e. energy supply is endangered or disrupted and it cannot be removed by market based measures (either economically or in due time) the rules of Law of Energy Security are applied. Before the German government declares that an emergency case exists by which non-market based measures can be taken in order to ensure the supply of energy at least to the protected customers. The measures available under EnSiG comprise regulations for the production, transport, storage, distribution, delivery, acquisition, usage and maximum prices as well as the accounting, certification and notification obligations regarding quantities and prices and additional market conditions of gas products (Art. 1 (1) EnSiG). In particular, the delivery, acquisition or usage of gas can be restricted in time, location and quantity or assign to specific ways of utilization. However, the maximum duration of these measures is limited to 6 months but can be extended by Federal Council (Art. 3 (2) EnSiG).

Based on the EnSiG the regulation for gas supply has been developed.

A.8.2.3 Regulation of Gas Supply (GasSV)

This regulation transfers the responsibility of gas distribution to the responsible governmental bodies, which are the NRA and the federal states. They are responsible to allocate the spare gas in case of an emergency to the most essential resources. In addition, the producer, acquirer and supplier and consumer can be forced to change their general market behaviour in particular to sign new contracts. In return, the market parties are paid a market based compensation fee.

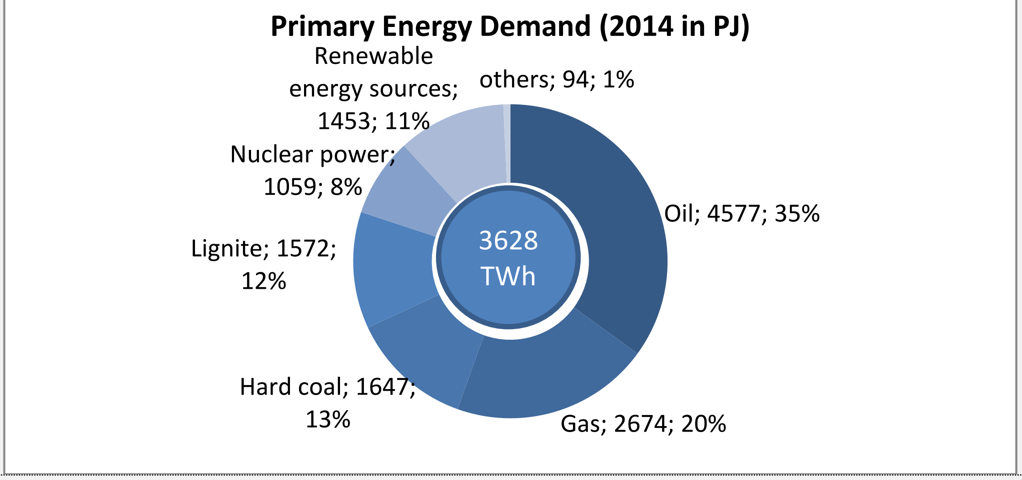
These measures include the possibility to increase exit capacities from storage facilities.

According to Article 53a EnWG protected customers are households and operators of district heating plants which supply household with thermal energy.

A.8.2.4 Market based measures to ensure security of gas supply in Germany

In total the German energy demand amounts to 3,863 TWh in 2013. Almost 22 % is contributed by natural gas.

Figure A.8.2. Primary energy demand in Germany (preliminary results)



Source: AG Energiebilanzen e. V. , Jahresbericht Energieverbrauch 2014, 03/2015, preliminary data

The gas supply is secured by a variety of different measures:

- National production
- Diversified sources and transportation routes
- Long-term supply contracts
- High reliability of gas infrastructure and
- Availability of underground gas storage facilities.

However, neither of these measures is regulated. They are rather market based meaning that security of supply is the responsibility of all market parties.

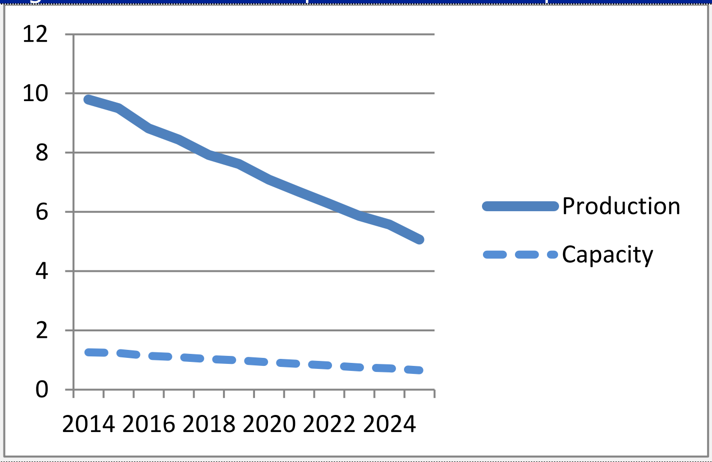
A.8.2.5 National gas production

The national production of natural gas further reduced from 12.28 bn. m3 in 2012 to 11.9 bn. m3 2013. This trend continued due to accelerating exhaustion and dilution of national gas fields. Instead of generating gas from national gas deposits biogas is increasingly produced. In 2013 about 602 mn. m3 biogas has been injected into the national gas grid (2012: 413 mn. m3).

A.8.2.6 Diversification of supply sources and transportation routes

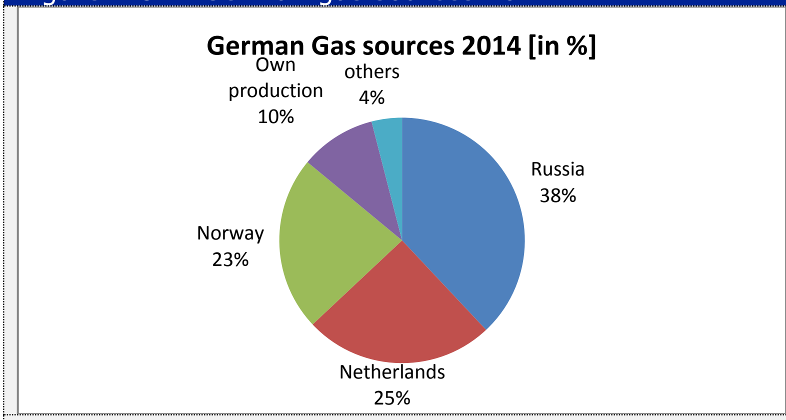
Gas imports to Germany in 2014 sourced mainly from Russia, The Netherlands and Norway. While the peak of European gas production has already been passed the largest gas reserves are located in Russia (almost ¼ of the gas reserves worldwide), by which Russia will keep a remarkable role in gas supply in Europe as a whole and Germany in particular.

Figure A.8.3. German production development 2014 - 2025[283]



The imports are further distributed via a widely meshed and connected pipeline system. In addition there are multiple interconnection points to neighbouring countries. From Norway gas is transported to Germany via three pipelines (Norpipe, Europipe I and II) to the national entry points Emden/Dorum. The total capacity of these entry points is 54 bn m³. Russian gas is transported directly through the Nord-Stream Pipeline (55 bn m³) or indirectly via Jamal Europe (33 bn m³) and the Ukraine rout (120 bn m³) to the entry points Greifswald, Mallnow, Olbernhau/Deutschneudorf (Sayda) and Waidhaus respectively. Gas from the Netherlands primarily comes from the Groningen gas field via the entry points Oude, Bochholtz/Vreden, Zevenaar and Winterswijk.

Figure A.8.4. German gas sources 2014



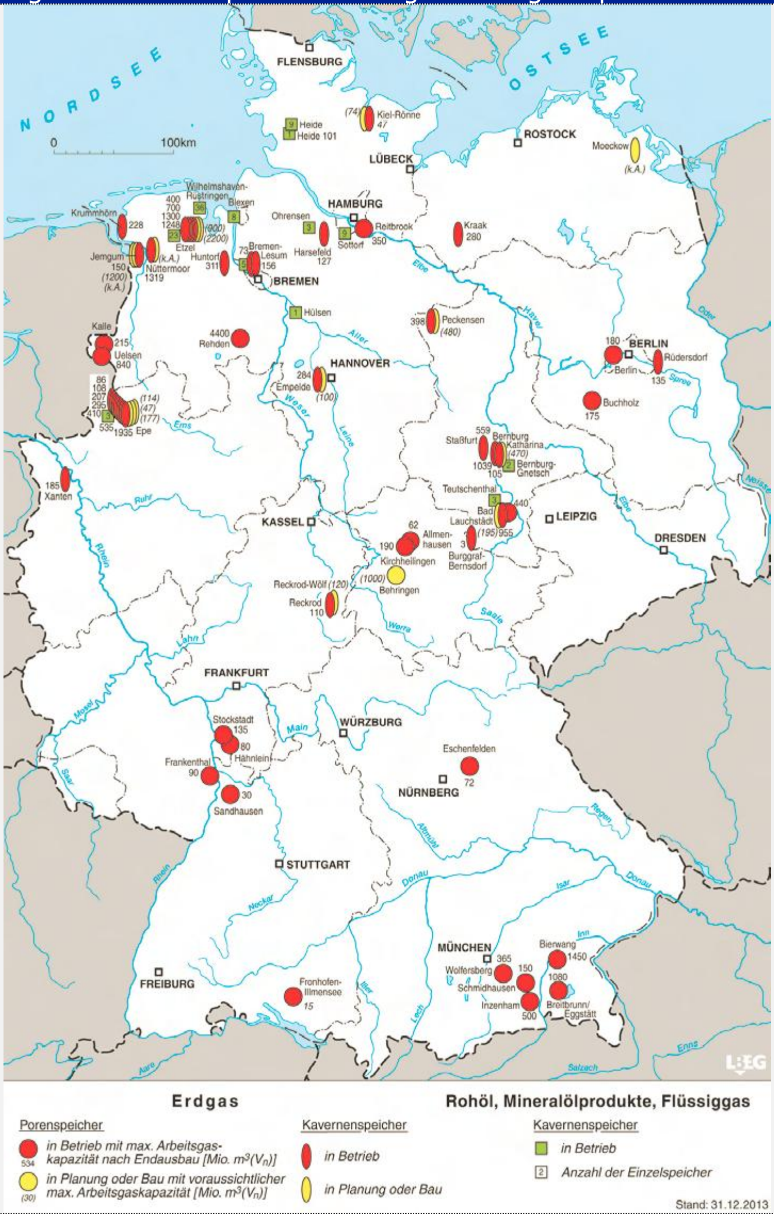
Source: AG Energiebilanzen e.V., Jahresbericht Energieverbrauch, 03/2015, preliminary dataEB

A.8.2.7 Storage capacities

Besides the diversified transportation system for gas supply Germany has a remarkable level of gas storage capacities of pore, cavern and aquifer storage facilities. Due to the geological requirements for the different types of storages they are located primarily in the North-west, Mideast and South of Germany.

[283] WEG : Prognosis 2014

Figure A.8.5. Map of German gas storage capacities



Source: LBEG

Storages take two roles in the German market. On the one hand they help to equalize variations between constant supply and a more flexible demand. On the other hand they support the availability of gas in cases of interruptions of the national and international gas transportation.

By end of 2013 there were 30 cavern storages and 21 aquifer storages and depleted gas fields.[284] The working gas capacity amounted to 13.2 bn m³ and 10.6 bn m³ respectively. Consequently Germany is number four in storage capacities worldwide and is the largest storage country in the EU.

The maximum storage capacity lasts statistically for 80 days on average.

[284] In 2014 storages in Dötlingen (Storengy Deutschland) and Hamburg Reitbrook (Storengy (owner) / ExxonMobil (owner)) were decommissioned. Further storage facility in Kalle (RWE) will be decommissioned in 2016.

Figure A.8.6. Ranking of German storage capacities world and europe

Source: http://www.bmwi.de/DE/Themen/Energie/Konventionelle-Energietraeger/gas,did=292330.html

Table A.8.1 .Storage capacities world

	Storage capacities	Working gas (Mio. m³)	Number of storage operators
1	USA	121,400	419
2	Russia	65,620	22
3	Ukraine	32,780	13
4	**Germany**	**23,800**	**51**
5	Italy	17,440	12
6	Canada	16,680	56
7	France	12,600	16
8	Austria	7,450	10
9	Hungary	6,280	6
10	Uzbekistan	5,400	3
	World total	**362,499**	**698**

Source: forecasted data of igu 2010 for 2013

Besides the existing storage capacities there had been several additional projects in the past by which the total working gas capacity in Germany could increase by up to 7 bcm. However, due to changes in market conditions most of the project have been cancelled or are on hold (*see* Table A.8.2). Some storages have even been shut down (Dötlingen and Hamburg-Reitbrook) such that the effective storage capacities reduced first time in 2011 an 2012. In addition RWE explained that storage in "Kalle" will be closed in April 2016.

Traditionally the German DSOs had a large number of regional storage capacities[285] (more than spherical gas tanks, pipe storage facilities and gasometer). A large number of these regionally important storage facilities are out of service now as the current daily balancing system in Germany doesn't grant revenues for local SSO's for the maintenance of operation.

The development works for some storages were stopped due to the persistently difficult market environment for storage. Other storage developments were postponed to an indefinite period.

[285] DVGW Study « Korrelationsanalyse Versorgungsicherheit und Gasmarkt », DVGW 2013, page 91

Table A.8.2 Storage capacities in Germany (planned/ under construction)					
Site location	**Company**	**Number of storages**	**Total volume [Mio. m3]**	**Working gas [Mio. m3]**	**Status**
Behringen	Storenegy	(1)	(2300)	(1000)	stopped
Bad Lauchstaedt	VNG Gasstorage	3	250	195	One cavern ongoing
Empelde	GHG Gasstorage Hannover	1	125	100	Finalization 2015
Epe-ZES	Zechstein Energy Storage	3	292	177	
Epe-E.ON	E.ON Gas Storage	1	n/a	47	Finalization 2015
Epe-KGE	Kommunale Gasspeichergesellschaft Epe	2	152	114	commissioning Q4/2015
Etzel-ESE	E.ON Gas Storage/ IVG Caverns	8	1,300	900	
Etzel-IVG	IVG Caverns	26	3,300	2,200	
Jemgum-EWE	EWE Gas Storage	4	n/a	n/a	Ongoing
Jemgum-WINGAS	astora / VNG Storage / WINGAS	18	1,620	1,200	Ongoing
Katharina	Erdgasspeicher Peissen	10	574	470	ongoing
Kiel-Rönne	Stadtwerke Kiel	1	114	74	postponed
Moeckow	EWE Vertrieb	24	n/a	n/a	Approved 2012. Build stopped
Peckensen	Storengy Germany	6	720	480	Postponed
Reckrod-Wölf	Wintershall	3	150	120	
Stassfurt	RWE Gas Storage	(6)	(620)	(500)	stopped
Total		**111***	**8,597***	**6,077***	
Source: Underground Gas Storage in Germany (Erdöl Erdgas Kohle (2014), No. 11, p. 402 ff.) *without stopped projects					

A.8.2.8 LNG - Liquefied Natural Gas

Even so there is no national LNG-terminal yet LNG plays an increasing role in the gas supply in the world and in Germany. By this it contributes to the diversification of the German gas supply. The closest terminals to Germany are located in the Netherland Gate and Belgium Zeebrugge. In addition there are plans to construct another terminal in Swinoujscie (Poland, planned operation after 2015).

A.8.3 Other SoS-information

Pursuant to SoS-regulation (Art. 6 of Regulation 994/2010/EC), the "Prevention plan Gas"[286] (PAP) and the "Emergency Plan Gas for Germany"[287] (EP) were published in December 2012 and updated in December 2014 by the German Ministry of Economics Affairs and Energy (BMWi).

In total six scenarios were evaluated in order to analyse the impact of interruptions of gas supply. In particular, partial or total interruptions of interconnection transport from Russia, Norway and the Netherlands were simulated. The gas demand also included the demand of systemically sensitive gas power stations, which were nominated according to Art. 13 EnWG. Further the demand of some areas of Austria (Tirol and Vorarlberg) and Liechtenstein were considered, as they are almost exclusively delivered via the German network. Finally, it was assumed that about 50 % of storage exit capacities of Seven Fields were available and the filling levels of German storage capacities were also 50 %.

N-1 calculation for Germany

The largest single German entry point is the entry point of Nord Stream in Greifswald. In total the entry capacity amounts of 1,678 GWh/d.

$$\mathbf{N-1}\,[\%] = \frac{\mathbf{654,5+30,3+400,0+0-151,2}}{\mathbf{490,7}} \times \mathbf{100} = \mathbf{190}$$

$$\mathbf{N-1} \geq \mathbf{100}\%$$

Consequently the security standard of SoS-regulation is fulfilled for Greifswald. Critics of the done SoS-evaluation argue that this only applies on a national basis while regionally there exist some rather critical situations. Additionally via the German TSO transport system nearly 50% of the capacity are booked for international transports to Czech Republic, Austria, Switzerland, France, Luxembourg, Belgium, The Netherlands, Denmark and Poland. A rather huge part of the storage capacity is also booked by international traders to secure their international supply portfolio.

A.8.3.1 Emergency scenarios

According to the supply standards of Art. 8 (1) SoS-regulation network operators have to be able to supply protected customers even in situations of high demand. The different scenarios to be considered in the analysis are

(a) extreme temperature on seven consecutive gas days with peak demand

(b) extraordinary gas demand of at least 30 day and

(c) failure of largest single infrastructure given average weather conditions in winter period for at least 30 days.

Protected customers are defined in Germany as the group of households and district heating facilities which provide heating to household customers and are connected to the distribution or transmission grid and are not able to switch to alternative fuels.[288]

[286] Präventionsplan Gas http://www.bmwi.de/BMWi/Redaktion/PDF/P-R/praeventionsplan-gas-fuer-die-bundesrepublik-deutschland,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf
[287] Notfallplan Gas für die Bundesrepublik Deutschland http://www.bmwi.de/BMWi/Redaktion/PDF/M-O/notfallplan-gas-bundesrepublik-eutschland,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf
[288] See Art. 53 (a) EnWG.

Scenario A

The relevant period of the last 20 years is between 27. December 1996 and 2. January 1997 when daily average temperature reached minus 13.4 to minus 9.6° Celcius. The corresponding gas demand amounts 33 TWh out of which 17.8 TWh account to protected customers. The total gas consumption which has to secured under SoS-regulation is 21.5 TWh. Besides the above mentioned German protected customers this includes 0.3 TWh for the supply of the Austrian areas and 3.4 TWh maximal demand of systemic gas power stations.

Scenario B

The total gas demand in such an emergency situation was calculated at 130 TWh that is to say 64.6 TWh protected customers (54.4 TWh household customers). The Austrian area and the systemic power stations account for additional 1.1. TWh and 14.4 TWh respectively but are in principle not covered by Energy Law (Art. 53 a EnWG).

Scenario C

In total, almost 55.1 TWh (39.8 TWh protected customer, 0.8 TWh Austrian areas and 14.4 TWh systemic power stations) needs to be secured. The largest entry point (Greifswald) has a daily capacity of 1,678 GWh/d which results in a maximal gas supply at risk for the relevant period of 30 days of 50 TWh. The border entry points exclusive Greifswald have a total capacity of 5,587 GWh/d or 168 TWh for the period of 30 days.

As can be seen all scenarios are fulfilled in the German gas market even if the gas volumes of the Austrian market areas and the systemic power stations are not covered by Energy Law (Art. 53 a EnWG) in scenarios b and c.

The risk analysis stated that Germany fulfils the requirements of the SoS-regulation with the given SoS-standards. Nevertheless, the experience shows in February 2012, that there may be, depending on the supply situation in other Member States and utilization of the north-south transport axis (not least by transits), even in total sufficient amounts of gas in Germany to regional shortages of failure of delivery quantities of certain IGPs. The shortages in gas supply may threaten the stability and safety of the electricity networks. This previously unknown situation counterfactual situation has become particularly evident during the tight supply situation in February 2012. As a result the SoS-requirements for power and gas are linked now in the German energy law. System relevant powerplants need to book firm capacities in the gas grid and are not allowed to be curtailed by TSO in SoS-situations. System relevant power plants have a nearly similar status as the are ranked first within the group of non-protected customers.

ANNEX 9. CASE STUDY: HUNGARY[289]

A.9.1 The Hungarian Gas market before the 2009 crisis

Landlocked Hungary's gas market history is closely related to that of other Central-Eastern European countries that have been under the influence of the Soviet Union. The natural gas industry has been developed rather early thanks to reservoirs located mostly in the South of the country, but has boomed thanks to imports from the Soviet Union and (later) from Russia through Ukraine. Seen as a less reliable ally then neighbouring Slovakia, Hungary has not been chosen as a major transit route towards Western markets, but has only served limited flows towards Serbia and Bosnia-Herzegovina. On the other hand, the country has become very reliant on natural gas, with a capillary gasification of its territory, also due to poor endowment of other domestic fossil fuels. Currently, about 37% of primary energy requirements are covered by natural gas, far more than the EU average of 23%. Domestic production has long been fluctuating between 2 and 2.5 bcm/ year, covering between 15 and 25% of demand.

Consumption has peaked at 13.4 bcm in 2005 before declining to 9.3 in 2013 (Eurostat data) and 8.6 in 2014 (latest Eurogas estimate). Dependence on Russian supplies through Ukraine has also peaked at 84% in 2003 before declining, as reinforcement of interconnection capacity from Austria has allowed an increased resort to alternative supplies. However, it has recovered in the last few years, back to 83%.

Thus, Hungary features, if not the highest gas dependence from Russia, probably the highest share of Russian gas within the energy balances, alongside Slovakia. On the other hand, it has a smaller transit role than other former Soviet satellites (like Slovakia, Czech Republic, Poland, Romania and Bulgaria), as well as former Soviet Republics like Lithuania, Belarus and Ukraine. Control of significant transit would represent a bargaining tool towards the big Eastern supplier.

This peculiar situation of high dependence and low bargaining power towards Russia is probably at the root of the radical Hungarian choices towards security of supply.

The Hungarian gas industry organisation has also had a rather peculiar history. As Central and Eastern European countries were cash stripped in the middle of its economic transition towards market economy, sale of energy interests to large Western corporation was a tempting opportunity. Hungary had MOL, a state controlled monopoly rooted in the country's oil and gas upstream, with a significant oil downstream business: a company model similar to Austria's OMV, Italy's ENI, France's TOTAL and Spain's REPSOL. Yet it went its own way, by promoting an early unbundling and selling MOL's wholesale gas supply business to German EON and distribution companies to several Western competitors (GDF, ENI, RWE). On the other hand, the state retained MOL's control over the high pressure network, placed into a subsidiary acting as national TSO (FGSZ); imports, domestic production and storage, were also left under MOL's control. At the same time, MOL was being partly privatised and is now a substantially public company.

In 2004, as the country entered the European Union, the market started to be liberalised, but lack of entry capacity and supply concentration led to very limited effective competition.

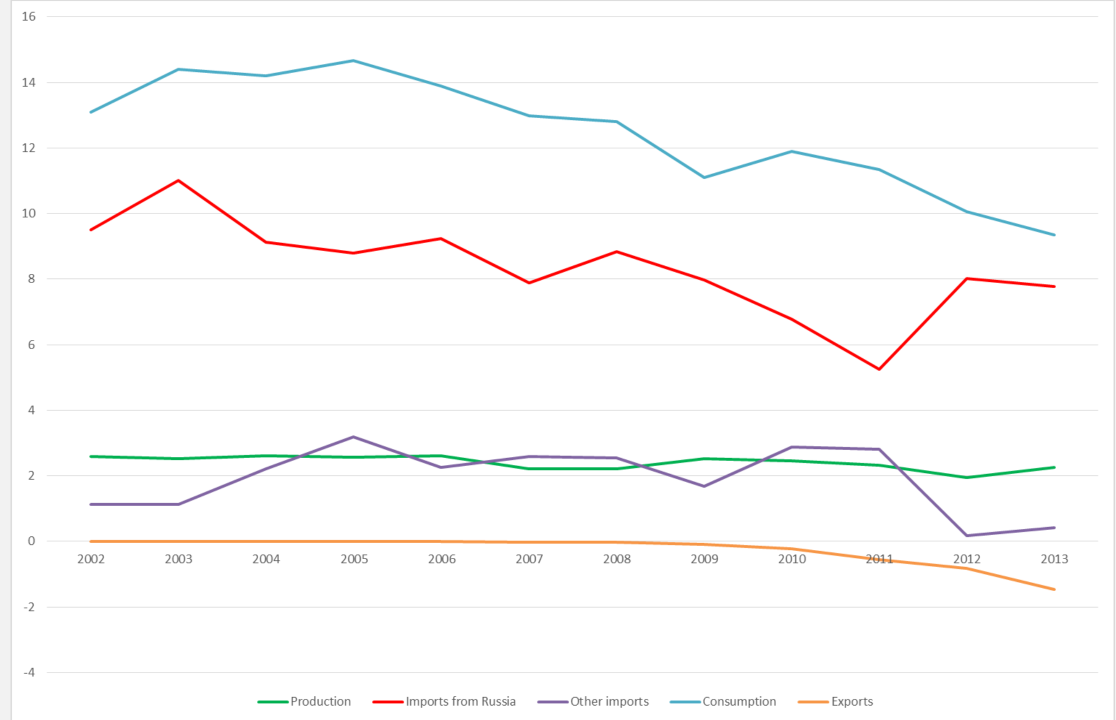
In 2006, import contracts were also transferred to EON and a limited gas and contract release programme (1.5-2 Bcm/year) was undertaken at the request of the European Commission. Storage was also transferred to EON under a regulated regime. Its

[289] For this Annex the authors gratefully acknowledge contributions provided by REKK' Peder Kaderjak and Palma Szolnoki during courses and workshops of the Florence School of Regulation. Any responsibility remains with the authors.

capacity was substantial compared to the market: 3.74 Bcm WG, about one third of annual consumption, a share overcome only by Latvia and Austria in Europe.

Around 2008-9, competition started to take off, boosted by the release programme and some improvement of import capacity from the West, as well as by companies based on Russian supplies. Whereas storage was a monopoly, it faced some increasing flexibility competition from Western, and later even Eastern pipeline supplies. Yet demand for flexibility was high and MOL had a remarkable depleted field at Szöreg, which could be turned into a new facility.

Figure A.9.1. Hungary's gas production, imports, exports and gross consumption



Source: Eurostat

Meanwhile, in January 2006 the first major Russian-Ukrainian dispute had triggered no curtailment, but was enough to generate a strong consensus in the country on the need for a strategic storage site. Parliament approved Act XXVI/2006 on security stockpiling of natural gas 4. § (1) requiring the construction of a 1,200 Mcm working gas and 20 Mcm/day withdrawal capacity facility, mainly for securing household consumption. It had to be built by January 2010 (during the 2009 gas crisis it was not in operation. The task was given to the Hungarian Hydrocarbon Stockpiling Association (MSZKSZ), who launched a tender: MOL won and established MMBF as a vehicle for the facility construction and operation, of which MSZKSZ is a minority shareholder (38%), but the majority belongs to MOL (62%). Since the Szöreg site was actually larger than necessary, a facility of 1900 Mcm with withdrawal capacity of 25 Mcm/day was built, with 700 Mcm/5 Mcm/day retained by MOL for commercial services. The 1,200/20 strategic reserve capacity was instead subject to a long term capacity contracting between MSZKSZ and MMBF, with yearly capacity costs covered from the membership fee that suppliers pay in proportion of the energy they deliver to final consumers. In 2010 this cost amounted to about 85 M€/year involving a fee of 0.64 €/MWh ultimately born by end users.

A.9.2 THE 2009 crisis

With its 3-week disruption, the January 2009 event remains the largest gas crisis in Europe's history. It entailed a total loss of over 5 bcm for Europe and some 2 bcm for Ukraine.

Hungary was heavily affected, but barely managed to avoid the serious disruption of protected customers that affected countries further south, like Serbia, Bosnia-Herzegovina, Bulgaria and Macedonia.

Besides the high dependence on gas, specific preconditions help to understand Hungary's vulnerability to the 2009 crisis, compared with other countries of Central and Eastern Europe.

Demand was relatively low due to the economic crisis, and the mild December 2008 had helped to maintain high storage fill levels. Yet other factors help to explain how each country achieved a rather different degree of success in terms of short term impact of the disruption (Table A.9.1)

Table A.9.1. SoS relevant factors of Central and Easter Europe countries before the 2009 Ukrainian crisis

	DIVERSIFICATION (non Russian import / total import, year)	DOMESTIC PRODUCTION (as % of load winter peak)	STORAGE (withdrawal/load winter peak %)
Austria	**36%**	**16%**	**104%**
Bulgaria	**0%**	**8%**	**35%**
Bosnia-Herzegovina	**0%**	**0%**	**0%**
Czech Republic	**25%**	**0%**	**96%**
Croatia	**0%**	**38%**	**45%**
Hungary	**25%**	**13%**	**69%**
Romania	**0%**	**54%**	**43%**
Serbia	**0%**	**6%**	**0%**
Slovakia	**0%**	**0%**	**73%**
Slovenia	**48%**	**0%**	**0%**

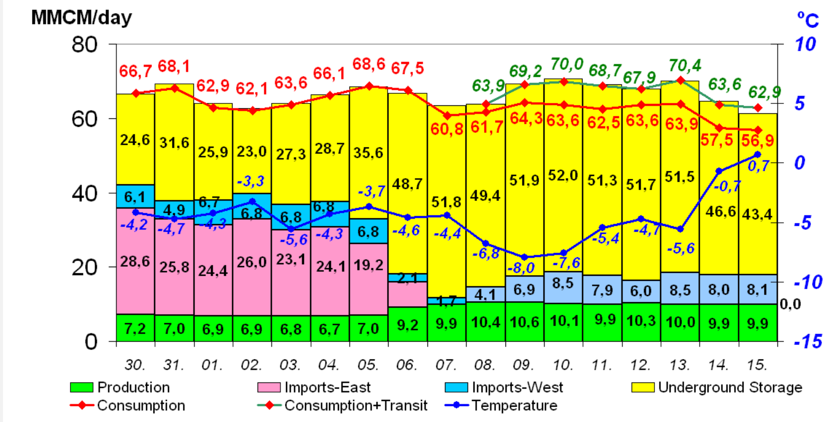
On the supply side, import diversification, at contractual as well as infrastructure level, and the closer integration with the large German market minimised the impacts on countries like Austria, the Czech Republic and Slovenia. They managed to achieve a successful system reconfiguration, using reverse flows. Austria and the Czech Republic (as well as Romania) also benefited from local production and storage. Last but not least, Austria had already established an efficient balancing market where its huge transit flows could be traded.

The most dramatic phases of the crisis are depicted in Figure A.9.2. The gradual disappearance of imports from Ukraine was initially addressed mostly by a storage boost. Later, this was also helped by enhanced production and by reverse flow supplies from the West (through Austria), which were mostly organised by Western companies (EON and GDF-Suez), who provided a contribution of 7-8 MCM/day in the second week of the crisis. Hungary's demand side contributions are estimated to 6-7 MCM/d in the first week and 7-9 in the second week. Despite lower than normal temperatures in the worst week of the crisis, Hungary did not curtail any protected customers and helped to transfer about half of the reverse flow supplies from the West on to Serbia and Bosnia-Herzegovina.

Reduction of demand was limited to "Category I and II" restrictions, involving fuel switching in electricity generation and interruptible customers' restriction. Public announcements called on people to save gas.

The supply increase was achieved by maximum withdrawal from storage. Contractual diversification of foreign suppliers (GdF-Suez, EON) also proved to work after the first hit, as they managed to arrange emergency supplies from the West.

Figure A.9.2. Hungarian demand and supplies between 30.12.2008 and 15.1.2009



Source: Hungarian Energy Office

A.9.3 Security of supply scenarios and their impact

The current situation of storage site in Hungary, as reported by GSE at mid-2014, is as reported in Table A.9.2. This capacity remains very large at over 50% of annual gas consumption. Moreover, Hungary has been very active in developing interconnections. Besides existing ones with Ukraine (bi-directional) Austria and Serbia (exit only), new pipelines have been opened connecting Romania (mostly exit, but with expected larger reverse flow) and Croatia (bi-directional). What is more, a large interconnection with Slovakia - mostly on Hungarian territory) is under construction expected to be commissioned in 2015, with a daily capacity of 13.9 MCM. This will further reinforce the connection of Hungary with Western markets, which already contribute almost 50% of Hungarian imports. In this way, Hungary is becoming a crucial hub that will be in a position to provide gas to Ukraine, Romania, Croatia and Serbia.

From a SoS perspective, this should significantly improve reliability with respect to the 2009 situation. Yet, the official Preventive Action Plan is very accurate. It features several disruption scenarios and outlines the ways to cope with them. In fact, Hungary's PAP is one of the few that estimate the probability of the considered disruption cases (see Table A.9.3)

Moreover, the N-1 indicator as envisaged by EC Regulation 994/2010 is calculated under four different combinations, featuring expected capacity in 2012, 2015 and 2020. This includes the market based SoS measures, like the (very limited) production and storage enhancements.

Demand side measures play an important role in Hungary's PAP and are thoroughly assessed. Their potential contribution in a major crisis is estimated at 22-24 MCM/d without restrictions. And up to 18 from restrictions of not protected customers.

Power plants over 50 MW are required by the law to be able to switch to alternative fuels and to stock pile the fuels they would need in such cases for 16 days. The State controls the strategic oil reserve amounting to 90 days of liquid fuels consumption.

Table A.9.2. Hungary's storage endowment

Map #	Site	Owner	Type	Working Gas (Mcm)	Withdrawal Capacity (Mcm/d)	Injection Capacity (Mcm/d)
5	Szöreg-1	MMBF	Oil Field with Gas Cap	1,900	25.00	12.70
5	Of which: strategic reserve	MMBF	Oil Field with Gas Cap	1,200	20	10
3	Pusztaederics	Magyar Földgáztároló Zrt.	Depleted Field	340	3.10	2.90
2	Zsana-Nord	Magyar Földgáztároló Zrt.	Depleted Field	2,170	28.00	17.00
4	Kardoskút-Pusztaszolos	Magyar Földgáztároló Zrt.	Depleted Field	280	3.20	2.35
1	Hajdúszoboszló	Magyar Földgáztároló Zrt.	Depleted Field	1,640	20.80	11.50
Source: GSE						

Figure A.9.3. Hungarian gas transmission network and storage sites

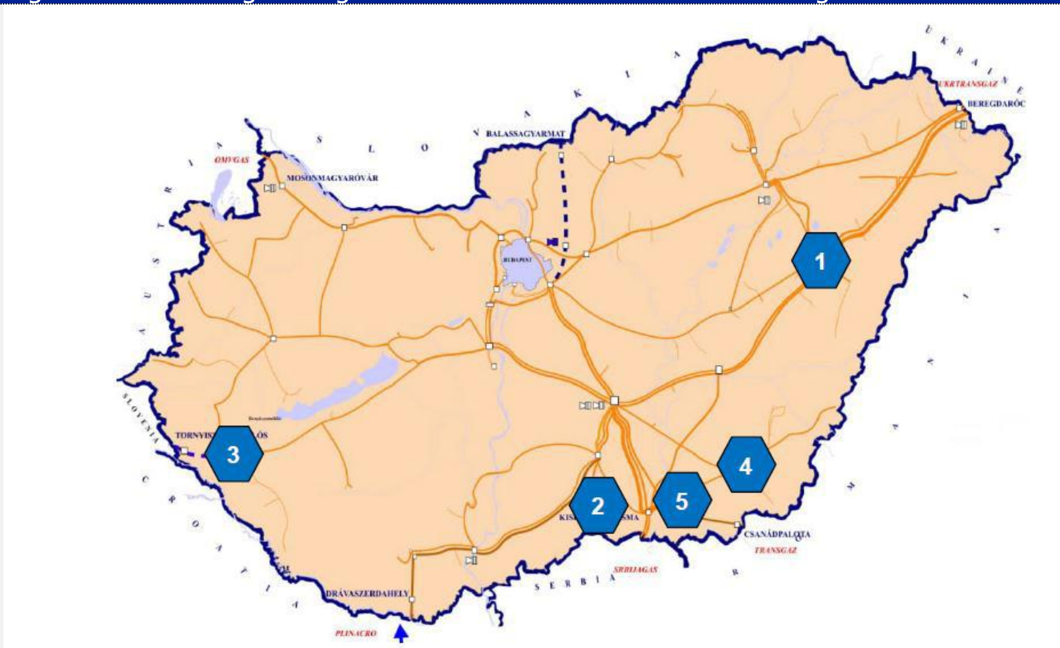


Table A.9.3. Emergency scenarios for Hungary			
Scenario #	Definitions of risk scenario items	Annual estimated probability	Missing gas (Mcm/d)
SC1	Extreme daily consumption, supply sources are less by min. 10 % than likely consumption.	0.2	30
SC2	Extreme daily consumption, at least one primary *transmission network component* out of operation for more than 24 hours.	0.1	10
SC3.	Extreme daily consumption, at least one primary *distribution network component* out of operation for more than 24 hours.	1	1
SC4.	Extreme daily consumption, supply at the Ukrainian-Hungarian cross-border point interrupted for more than 24 hours.	0.1	20
SC5.	Supply at the Ukrainian-Hungarian cross-border point interrupted for more than 48 hours.	0.05	40
SC6.	Working gas in the storage below 20 %, extreme daily consumption and supply sources are less by minimum 10 % than likely consumption.	0.05	40
SC7.	Working gas in the storage below 20 % and at least one primary *transmission network component* out of operation for more than 24 hours.	0.05	30
SC8.	Working gas in the storage below 20 %, extreme daily consumption and at least one primary *distribution network component* out of operation for more than 24 hours.	0.15	15
SC9	Working gas in the storage below 20 %, and supply at the Ukrainian-Hungarian cross-border point interrupted for more than 48 hours	0.05	50
SC10	Working gas in the storage below 20 %, extreme daily consumption and supply at the Ukrainian-Hungarian cross-border point interrupted for more than 48 hours	0.02	60
Source: preventive action plan for hungary, 2012			

A.9.4 main storage related SoS measures of the country

Hungary is currently the only EU Member State to require both suppliers' storage obligations and strategic storage.

Every universal supplier has to store the 60 % of their consumers' winter period consumption.

As regards strategic storage, Ministerial Decree 3/2011 (IV.7) has restored the original provision to 1.2 Bcm as from mid 2014. The deadline for having the above volumes stored was September 30th 2014.

Overall, it can be estimated that storage obligations and strategic storage represent about 24% of annual domestic consumption of the country.

Table A.9.4. N-1 Calculation for Hungary						
			2012	**2015**	**2020**	
			A	**B**	**Ca**	**Cb**
Epm1=Im	Beregdaróc (maximum import capacity Im)	mcm/d	56.3	56.3	56.3	56.3
Epm2	Mosonmagyaróvár	mcm/d	14.4	14.4	14.4	14.4
Epm3	from Slovakia	mcm/d	0.0	12.0	12.0	12.0
Epm4	from Romania	mcm/d	0.0	4.8	4.8	4.8
Epm5	from Croatia	mcm/d	0.0	19.2	19.2	19.2
Epm6	from AGRI	mcm/d	0.0	0.0	0.0	1.5
Epm7	from South Stream	mcm/d	0.0	0.0	0.0	18.9
Epm8	Other (not planned)	mcm/d	0.0	0.0	0.0	0.0
Epm summa	Total import	mcm/d	70.7	106.7	106.7	127.1
Epmsum-Im	**Total import less Maximum (Im)import capacity**	**mcm/d**	**14.4**	**50.4**	**50.4**	**70.8**
Pm	Technical production capacity	mcm/d	7.6	6.9	3.3	3.3
Sm	Technical withdrawal capacity (security storage incl.)	mcm/d	72.8	72.8	72.8	72.8
LNGm	LNG capacity	mcm/d	0,0	0.0	0.0	0,0
Grand total		**mcm/d**	**94.8**	**130.1**	**126.5**	**146.9**
Dmax	Daily maximum demand	mcm/d	90.4	104.5	103.7	103.7
N-1			1.05	1.24	1,22	1.42

A.9.4.1 Evolution and debate

The 2009 crisis brought several lessons that were highlighted in Hungary. Storage had provided an excellent performance, and there was a potential regional demand for its services in Hungary. Hence an increased interest in storage investment, which triggered the evolution towards an "hybrid" regime envisaging negotiated TPA for new entrants into the UGS market, while maintaining regulated TPA for existing ones. Discussions also flourished about the role of strategic storage and the access regime and nomination rights during crisis, as well as about the related liability regarding commercial contracts.

The after-crisis discussions triggered significant developments. In 2010, the strategic site started the market alongside its 700 Mcm commercial part, while E.ON also finished the expansion of the Zsana site (1.6 Bcm working gas).

The strategic site has had a remarkable impact on the commercial storage market: MOL as a "new" entrant in such market controlled nearly 15% of working gas capacity, but with a higher speed, as in fact it uses the withdrawal and injection capacities of the strategic storage part of the site. Moreover, it sells for negotiated prices, which reduces its transparency. From a commercial perspective, the site has been very successful.

However, the new availability of WG capacity approaching (including strategic storage) 60% of total annual consumption at end 2010, has prompted the Government to reverse the policy direction by converting some strategic capacities into commercial ones. The current cost of strategic storage at nearly €85 million /year even exceeds the Hungarian government's own estimation that the 2009 crisis had had a cost of around €76.5 million.

Act CXXXIV/2010 reduced the size of strategic storage to "at least 600 mcm and at most 1,200 mcm" with a Ministerial decree in charge of deciding on the actual value. Decree 13 and 14 (April 2011) of the Ministry of Development temporarily reduced the strategic size to 915 mcm from July 2011, stipulating that MVM (the state owned power incumbent, a new entrant to the gas market) and EON would get the freed gas to serve the producers of district heating and the universal suppliers.

Moreover, both suppliers were also awarded by the law - as a further Sos measure aimed at ensuring reverse flow availability - 1/3 each of the Western cross border capacity. As a results of which Western cross border capacities were underutilised while for the remaining 1/3 part there was oversubscription and therefore auction.

A further Ministry of Development Decree of March 2012 reduced the strategic size to 815 mcm but envisaged its return to the original level of 1,200 mcm.

These changes have been accused of fostering further distortions to the commercial storage and wholesale market, as well as uncertainty and gas price increases for final consumers. The impact may have extended abroad, e.g. by lowering the interest of developing the Serbian site of Banatsky Dvor, which is located not far from Szöreg.

The discussion in Hungary about the peculiar SoS policy of the country has been significant. According to REKK, no doubt a large strategic storage site provides a comfortable security feeling, but costs are remarkable so that it may not be the most cost-efficient solution. Moreover, it provides additional conflicts of cross-subsidizing, distorts the commercial storage market and allows for non-transparent negotiations and support.

Although it allowed for a new entrant, however the circumstances of the investment and the regulatory evolution have been non-transparent. Finally, usage of the strategic site’s injection and withdrawal capacities did not cause reduction in the strategic fee borne by all market players. The lowering of its size did not also result in the reduction of the strategic fee.

Changes of the strategic/commercial size have provided an uncertain environment and may have distorted the wholesale market as well. Previous investment plans have been cancelled - but this has not happened in Hungary only and may be related with developments discussed in sections 1.2 and 1.3 of the present Report.

ANNEX 10. CASE STUDY: ITALY

A.10.1 Main storage related SoS measures of the country

A.10.1.1 Mandatory Storage Obligations

As of 2014, in Italy there are no mandatory storage obligations on suppliers.

In Italy a large share of storage capacity[290] is allocated through competitive open auctions since storage year 2013/14[291], and the priority access to storage for suppliers who served protected customers is not yet in place[292].

A.10.1.2 Special mandatory "strategic" storage

Legislative Decree No. 164/2000 establishes mandatory strategic storage reserves, being the storage directed to compensate for either the lack/reduction in internal gas supply or gas crisis and hence contributing to the security of supply of the country.

Strategic gas reserved can be used only under authorization by the Ministry and only when the allocated import capacity have been fully used, exceptions are possible but have to be justified due to force majeure[293].

Responsibility

To comply with provisions concerning strategic storage service, storage companies take out of the market and dedicate to the strategic storage reserves a share of their space capacity. Storage companies should also ensure that such space is filled up with gas volumes they own themselves[294]. The responsibility of strategic gas volumes is on the SSOs and SSOs are remunerated for offering this service, which is offered under a regulated regime. Remuneration for such service is dome through a fee paid by all importers and domestic producers: in particular SSOs are allowed to receive a regulatory rate of return on the value of the capital they invested in strategic storage volumes, exactly in the same fashion they receive a regulatory rate of return on other investments related to their regulated storage activity. Storage companies should mutually agree on the allocation of strategic storage obligations among them. In case the agreement fails, then the AEEG decides for the allocation of the strategic storage service among companies. New storage operators may be exempted from strategic storage obligations in so far there is uncertainty on the technical feasibility of providing strategic volumes on requests.

[290] In storage year 2014/15, half of the existing storage capacity was allocated through auctions, amounting to about 8 bcm, out of a total storage capacity of about 17 bcm. Note that this represents over 90% of the storage space available for annual allocation at the beginning of the storage year (amounting to 8.8 bcm). Storage capacity reserved for the needs of domestic gas producers (0.026 bcm), for the needs of TSO for the balancing of the grid (0.2 bcm) as well as storage capacity reserved for LNG import for industrial users (0.5 bcm) were not allocated through auctions; 2.7 bcm were already allocated for long term storage contracts, 4.8 are reserved for strategic resources (see below)

[291] Law Decree n.1/2012, article 14.

[292] It is worth noticing that, according the legislation in force (Legislative Decree 164/2000, art. 12, as modified by Legislative Decree 93/2011, art. 27), the standard seasonal storage service ("swing storage" or "peak storage") shall be allocated with priority to suppliers supplying protected consumers. However, due to the fact that the seasonal storage service is fully allocated through auctions and consequently any supplier/trader can access to it, this provision is de-facto outdated. Recent provisions (Ministerial Decree 6 February 2015) established that there is not priority access to auctions, nor special reserved auction, for suppliers who served protected customers. See below for more detailed discussion.

[293] Legislative Decree 164/2000, article 12.

[294] Italian Energy Authority resolutions 119/05 and 149/12.

Criteria

Total volume dedicated to strategic storage is set yearly by the Ministry in consultation with the Emergency and Monitoring Committee of the natural gas system. Total strategic storage reserves should not be lower than certain volumes set by law[295]:

- Volume necessary to withdrawal from the strategic storage sites, for a period of at least 30 days and during the peak seasons, a gas amount corresponding to the whole technical capacity of the most used import infrastructure.
- Volume necessary to fully cover seasonal swing in consumption in the event of an extremely cold winter, determined as the coldest winter occurred in the last 20 years

The exact criteria to determine the seasonal swing in consumption in the event of an extremely cold winter have not been disclosed.

In storage year 2012/2013 the Ministry reduced[296], for the first time, the total amount of strategic storage by 0.5 bcm, which before amounted to 5.1 bcm. The total amount for 2012, equal to 4.6 bcm, was confirmed for the storage year 2013/2014, storage year 2014/15 and storage year 2015/2016

Cost allocation

Pursuant to the law[297] all importers and domestic producers[298] bear the costs of the strategic gas reserve.

Charges to be applied to producers and importers are defined by the Italian Energy Authority[299], through a variable component called CST that is paid by the above parties to storage operators (Table A.10.1) for each imported and produced[300] gas volume unit.

Table A.10.1. Values for strategic storage fee

Period	CST (€c/cm)	CST (€c/MWh)
2014	0.0967	0.9137
Source: Italian Energy Authority resolution 350/2013/R/gas		

Cost estimation

The total annual cost of Italian strategic storage may be estimated by multiplying the variable component CST times the volumes subjected to the payment of such component in a year. Assuming that the latter ones are equal to about 62 bcm[301], it follows that the yearly cost of strategic resources is about 60 million euro.

[295] Legislative Decree No. 164/2000, art.12.
[296] Ministerial Decree 29 March 2012.
[297] According to Article 12, paragraph 11-bis of the above mentioned Decree, as amended by the Legislative Decree No. 93/11, and Article 1, paragraph 1, of the Ministerial Decree of 29 March 2012.
[298] domestic producers whose production exceed a threshold defined by the Ministry.
[299] Italian Energy Authority Resolution No. 149/2012/R/gas.
[300] Excluding volumes exempted from the payment of royalties.
[301] Sum of Total volume imported in 2014 and total domestic production in 2014, based on Snam Rete Gas data.

Evolution and debate

In 2012 the Ministry decided for a reduction in the amount of strategic storage resources[302]. The capacity resulting from the reduction storage capacity was intended to be allocated to new storage services for industrial users and the LNG operators.

So far no further reduction in strategic resource has been envisaged, nor their elimination.

The Italian gas system resorted to strategic storage resources in the winter 2004/05 and in the winter 2005/06 and in those occasion the contribution from strategic resources equalled to 0.8 and 1.2 bcm[303] respectively.

Recently the performance of strategic resources in terms of withdrawal rate has not been tested.

A.10.2 Any other existing storage related measures

A.10.2.1 Swing storage service

Accordingly to the provisions of Legislative Decree 164/00[304], the Italian Ministry for Economic Development establishes every year the storage amount reserved to the seasonal storage bundled service (also known as "swing storage service" or "peak storage"), whose withdrawal performance is fit for fulfilling seasonal consumption swing of protected consumers.

Swing storage is fully allocated on an auction basis since storage year 2014/2015[305], where, since storage year 2014/2015, suppliers of protected consumers have no priority access.

More specifically, according the legislation in force (Legislative Decree 164/2000, art. 12, as modified by Legislative Decree 93/2011, art. 27), the swing storage shall be allocated with priority to suppliers supplying protected consumers. However, as mentioned above, due to the fact that the seasonal storage service is fully allocated through auctions and consequently any supplier/trader can access to it, this provision is de-facto outdated. In particular, although, until 2014/15 storage year, suppliers having in their supply basket protected customers had priority in the auction for the seasonal storage bundled service[306], the priority was de facto neutralized by the fact that they had anyway to "conquer" their share of seasonal storage by participating successfully in the auctions. This priority is not foreseen anymore for the 2015/16 storage year[307].

Amount and criteria

Volumes dedicated to swing storage are set every year by the Ministry and should be equal to the seasonal consumption swing of protected consumers in an extremely cold winter[308]. The exact criteria to determine the seasonal swing in consumption of protected consumers in the event of an extremely cold winter have not been disclosed.

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302 Ministerial Decree 29 March 212.
303 Italian Energy Authority and Italian Antitrust Authority Inquiry on Storage, 2009.
304 Article 12.7.
305 Law Decree n.1/2012, article 14.
306 According to Ministerial Decree 19 February 2014, Art.2, half of the seasonal storage capacity on auction is reserve to suppliers serving protected consumers.
307 Ministerial Decree 6 February 2015.
308 Legislative Decree 164/2000, article 12.7.

Pursuant to ministerial provisions[309], swing storage amount for storage years 2013/2014, 2014/15 and 2015/16 was determined taking into account:

- Italian gas consumption in the October- March period over the last 10 years
- the sum of domestic production and total maximum potential imports in the October- March period considering an import infrastructure load factor not greater than 65% and net of exports

The amount of swing storage was equal to 6.4 bcm in SY 2013/14, 6.95 bcm in SY 2014/15 and 6.843 in SY15/16[310].

According to Italian legislation[311], if at the end of the storage allocation season, the seasonal storage bundled service is not fully booked, then the Ministry for Economic Development may rule on “further action” to be taken to guarantee the “optimal re-fill of storage sites” with the aim to ensure security of supply and safe functioning of the gas system. However, the gas volumes needed for ensuring the optimal re-fill of storage sites are not quantified, nor are the “further actions” better defined. Such provision was never implemented.

Swing obligation

Pursuant to Legislative Decree No. 164/2000 (art.18), in Italy each supplier has to ensure the full coverage of the seasonal consumption swings of its residential[312] and commercial customers as well as of its non-residential consumers consuming less than 50,000 cm/year[313] (protected consumers). Such obligation is known as “swing obligation” and in the past gave priority access to storage to suppliers serving protected consumers.

Evolution

Since 2014 the swing obligation generated a right to get priority access to storage for those who bore such obligation, as storage was considered the primary tool to meet seasonal consumption swings. Storage allocated to them on a priority basis was meant to be used as the main tool to fulfil the "swing” obligation and therefore had to be used for the needs of protected consumers only. Such provision was motivated by the fact that when gas market liberalization started in Italy storage was perceived as a scarce resource.

The quantity of storage each supplier of protected consumers was entitled to have (the share of storage capacity that allowed him to fulfil his “swing obligation”) was computed as a function of the consumption of its residential and commercial customers in 2001. More specifically each supplier was entitled to have priority access to a storage space capacity equal to a percentage ranging from 33% to 42% of the consumption of its small residential and commercial consumers in 2001.

In the past, storage space available in Italy was just sufficient to cover supplier swing obligations, with little or no space for other possible uses. According to the Italian Energy Authority[314] this fact distorted market competition considerably since the storage allocation criteria, based on merit order, acted as a barrier to entry for new

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[309] Ministerial Decree 6 February 2015, art.2; Ministerial Decree 19 February 2014, art.2; Ministerial Decree 15 February 2013, art.1.
[310] Ministerial Decree 6 February 2015, art.2; Ministerial Decree 19 February 2014, art.2; Ministerial Decree 15 February 2013, art.1.
[311] Ministerial Decree 6 February 2015, article 5.
[312] Including households and essential social services, such as hospitals, schools.
[313] INITIALLY THIS THRESHOLD WAS SET AT 200,000 CM/YEAR THEN IN 2011 IT WAS LOWERED DOWN TO 50,000 CM/YEAR PURSUANT TO LEGISLATIVE DECREE 93/2011.
[314] Italian Energy Authority and Italian Antitrust Authority Inquiry, 2009, Attachment A in the Italian Energy Authority resolution VIS 51/09.

market players not equipped with a portfolio of residential and commercial customers, therefore not allowed to have priority in the storage allocation criteria.

The numerous changes which have occurred in the gas market over the last year as well as the introduction of competitive allocation mechanisms for storage since storage year 2013/2014[315] have resulted in storage contractual congestion being solved and for the first time storage allocations for the storage year 2013-2014 have recorded allocations of quantities smaller than the available capacity.

A.10.2.3 TSO storage

Transmission System Operators (TSOs) have priority access to storage capacity, in order to have resources for the hourly balancing of the network. The TSO sets each year the amount of storage he requires and storage operators have to fulfil the TSO needs. Such storage capacity is remunerated through a regulated tariff.

The storage capacity allocated to the TSO is small in terms of space, but higher in terms of withdrawal and injection capacity compared to the total one (Table A.10.2).

Table A.10.2. Storage allocated to the TSO in storage year 2014/15

Storage allocated to the TSO in storage year 2014/15	Quantity	As a percentage of total capacity
Space capacity	200 mcm	2% (excluding strategic storage)
Withdrawal capacity	64 mcm/d	22% (based on declared maximum technical withdrawal capacity)
Injection capacity	14 mcm/d	10% (based on declared maximum technical injection capacity)

Source: Stogit, Edison Stoccaggio and Gas Storage Europe Storage Map July 2014

TSO storage is a balancing service according to the European Network Code on Balancing[316].

The reform in the balancing system that introduced an emergency day-ahead balancing session, concerned also the use of TSO storage. In particular it provided that, when the TSO resorts to the emergency day-ahead balancing session to balance the grid, the TSO has to offer to shippers the share of storage capacity which it does not use.

Provisions on the withdrawal curve of the seasonal storage bundled product

Since 2013, the monthly withdrawal capacity included in the seasonal storage bundled product (swing storage) should guarantee that the maximum withdrawal performance is reached in January and February. The indicative withdrawal curve of the standard seasonal bundled storage product is set by the Italian Ministry for Economic Development every year, before the storage allocation procedures starts.

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[315] Law Decree n.1/2012, article 14.

[316] EU Regulation 312/2014. According to Network Code Balancing, TSO storage may be considered as 'balancing service', meaning a service provided to a TSO via a contract for gas required to meet short term fluctuations in gas demand or supply, which is not a short term standardised product (art. 1 EU Regulation 312/2014). Pursuant to article 8 EU Regulation 312/2014 "The transmission system operator is entitled to procure balancing services for those situations in which short term standardised products will not or are not likely to provide the response necessary to keep the transmission network within its operational limits or in the absence of liquidity of trade in short term standardised products.[…] Balancing services shall be procured in a market-based manner, through a transparent and non-discriminatory public tender procedure in accordance with the applicable national rules".

The indicative withdrawal curve was introduced for the first time for storage year 2013/14[317]. Maximum daily withdrawal rate in storage year 2014/15 for the seasonal product offered by the main storage operator Stogit is presented in Table A.10.3 below.

Table A.10.3. Maximum daily withdrawal rate from storage							
mcm/d	**Nov**	**1-24 Dec**	**25-31 Dec**	**1-7 Jan**	**8-31 Jan**	**Feb**	**Mar**
Maximum daily withdrawal rate from storage (main storage operator, Storage Year 2014/15)	25.9	36	25.6	52.5	86.5	63.9	19.1
Source: Italian Ministry for Economic Development							

The possibility of using the withdrawal capacity was reduced compared to technical withdrawal capacity for the beginning of the winter seasons, in order to maximise withdrawal performance in January and February. Consequently, while in the past the maximum capacity allocated could be used at the beginning of the winter season (at least until storage space started to empty below the level which allows maximum performance), since winter 2013/14 the maximum capacity may only be used in the coldest months.

Evolution

According to the Ministry[318] these provisions are necessary for security reasons and will be set until new storage capacity is implemented.

Special tariffs for transmission to/from storage sites

In Italy tariffs for transmission to/from storage sites are differentiated from those applying to other entry/exit points.

Different storage sites are considered as a single entry/exit point, hence in Italy there is a single entry tariff to storage and a single exit tariff from storage, notwithstanding which storage facility the gas handling takes place.

Differently to the other entry points, entry transmission tariff from storage to the grid consists only of a fixed "capacity" component[319]; similarly to the other exit points the exit transmission tariff from grid to storage consist of a fixed "capacity" component only. Capacity components differ depending on the point.

Entry capacity transmission tariffs (Table A.10.4) from storage to the grid are similar to those applying to entry points from gas production sites located in the area where most storage facilities are located (Northern Italy).

Exit tariffs from the grid to storage (Table A.10.5) are lower than those for the points located in Northern Italy.

[317] Ministerial Decree 15 February 2013. Withdrawal curves for SY 2014/15 and SY 2015/16 are set by Ministerial Decree 19 February 2014 and Ministerial Decree 6 February 2015, accordingly.
[318] Ministerial Decree 19 February 2014.
[319] Tariffs at other entry points include a variable "commodity" component as well.

Table A.10.4. Entry transmission tariffs, fixed component, 2015 (€/year/MWh/day)	
Entry point	**Value in 2015**
Pipeline in Northern Italy (average)	84.2
LNG regasification terminals in Northern Italy (average)	38.2
Production sites in Northern Italy (average)	14.8
Storage sites	16.4
Source: Italian Energy Regulator	

Table A.10.5. Exit transmission tariffs, fixed component, 2015 (€/year/MWh/day)	
Exit point	**Value in 2015**
Average for Northern Italy	155
Storage sites	47.9
Source: Italian Energy Regulator	

Drivers and incentives for storage investment and storage accumulation

In Italy storage business is regulated and subject to concession regime.

The Government shall list which are the new storage infrastructures that are classified as strategic ones[320] according to a government decision that is expected in 2015.

The tariff regulation of the storage business envisages the following incentives for investment in storage infrastructures:

- Income guarantee factor
- Output based incentive mechanism, starting in 2015
- Special incentive for new storage infrastructure contributing to the improvement of the peak withdrawal rate
- Incentive scheme of the development of new storage capacity exempted from TPA, created in 2010.

First of all, the application of an income correction factor for storage operators who run regulated storage sites ensures partial cover of allowed revenues relating to fixed costs (approximately 90% of the total), even if the infrastructure is not used or if it is used through competitive procedures for the allocation of capacity at a price less than the regulated tariff. However the revenue compensation mechanism applies to existing storage companies and only to new storage infrastructures that are classified as strategic ones according to a government decision which is expected in 2015.

The costs resulting from the application of an income guarantee factor for the storage service until September 2015 are recovered through the CV_{OS} component of the gas transport entry tariff which is charged on volumes injected into the Italian network (Table A.10.6). Starting from October 2015[321] the costs resulting from the application of an income guarantee factor for the storage service are recovered through the CVRos component of the gas transport exit tariff which is charged on off-takes from the Italian network.

[320] Legislative Decree 93/2011, article 3.
[321] Italian Energy Authority Resolution 60/2015/R/gas.

Based on the new regulation for the storage sector[322], an output based incentive mechanism is in place and replaces a premium on the regulated rate of return that was previously provided for new investments in storage.

Table A.10.6. CVos component financing storage operators' revenues

€c/cm	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1
CVOS	0	0	0	0	0.095	0.095	0.095	0.9	0.9
Source: Italian Energy Authority									

Pursuant to Legislative Decree 133/2014, an additional incentive mechanism for new storage infrastructures that improve the peak withdrawal rate has to be implemented.

The decree n.130/2010 (so called "storage decree") introduced a possible exemption from TPA[323] for new storage facilities, aiming to foster the development of new storage capacity. Storage facilities developed pursuant to this decree are reserved only to industrial and power generation gas consumers who participate in the financing of these new storage capacities. Storage services are allocated to these particular storage clients for a period longer than one year and a share of this storage capacity has to be made available to the market through competitive procedures. Investments pursuant to the storage decree are remunerated through a specific regulated regime. As of now, the storage decree regime applies only to investments accounting for 4 bcm carried out by the main storage operator Stogit. Due to the storage decree implementation, storage capacity offered by the main Italian SSO Stogit actually increased year-on-year starting from 2011 and the storage decree was the main driver of storage space expansion in the 2011-2014 period.

Information on long term allocation of storage capacity

The decree n.130/2010 (so called "storage decree", see above) introduced for the first time a long-term allocation mechanism for storage: storage was allocated for a 5 year period.

Pursuant to recent provisions, a long term storage service was introduced amounting to 0.5 bcm offered by the main storage operator, Stogit. Such service was intended to be allocated for a two year period, with an option for renewing the contract for additional two years. This long term service was auctioned in March 2015 but no bids were received.

Table A.10.7. Available long term storage products in Italy

Service	SSO offering the service	Duration	Total Offered Capacity (mcm)	When it was offered	Allocated as of March 2015 (mcm)	Allocated as of March 2015 (as % of Total available commercial storage capacity in the country)
Long-term	Stogit	2 years	500	March	0	0%

[322] Italian Energy Authority Resolution 531/2014/R/gas.
[323] The exemption consists in the fact that such storage facilities are not required to provide access to third parties: these facilities are for the exclusive use by pre-selected industrial and power generation clients.

storage				2015		
Long-term storage according to Dlgs 130/10	Stogit	5 years	4000	2011	2642	22%
Source: Stogit						

A.10.3 Other SoS information

Pursuant to SoS Regulation[324], the "Prevention Action Plan" (PAP) and the "Emergency plan to deal with unfavourable events for the natural gas system" (EP) were published by the Italian Ministry for Economic Development in April 2013[325] and updated in December 2013[326].

A.10.3.1 N-1 rule

In the case of Italy the major import infrastructures is the TAG pipeline, through which gas flows coming from Austria, including Russian imports, transit and arrive in Italy at Tarvisio Interconnection Point. The calculation made for Italy gives an N-1 supply that exceeds demand by 8% in GY14 (Table A.10.8).

Table A.10.8. Main inputs in the N-1 analysis (GY 2014/15)	
Daily storage withdrawal rate	242.5 mcm/d
Peak demand	490.7 mcm/d
Demand side response	5 mcm/d
Pipeline supply	328.6 mcm/d
LNG Supply	52.8 mcm/d
Domestic Production	19.7 mcm/d
Total Supply	643.6 mcm/d
N-1 Supply (absence of TAG)	524.8 mcm/d
Source: PAP	

It is worth noticing the TSO Snam Rete Gas itself declares a capacity for injection into the network from storage of 229 mcm/d. Further, according to Gas Storage Europe (GSE), the Declared Total Maximum Technical Withdrawal in Italy equals 230 mcm/d as of January 2015.

With regard to demand, the peak demand considered probable is approximately 491 mcm/d, compared to a historical maximum of 464 mcm/d. This is reduced by the demand side response (interruptible consumption) in the formula for calculating N-1, estimated at 5 mcm/d, a level considered "prudential".

A.10.3.2 Definition of supply standards for protected customers

Pursuant to SoS Regulation (Art. 8 of Regulation 994/2010/EC), supply standards for protected customers are defined.

[324] Art. 6 of Regulation 994/2010/EC
[325] Ministerial Decree of 19th April 2013.
[326] Ministerial Decree of 27th December 2013.

According to Legislative Decree 164/2000 (art.22) protected consumers are defined as residential[327] (households) and commercial customers as well as non-residential consumers consuming less than 50,000 cm/year[328]. In the EP, the Ministry states that the gas demand related to low pressure network is considered to be entirely coincident with the protected customers' demand.

Gas supplies shall provide for guaranteeing the supply to protected customers, defined as specified above, in case of:

- Extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
- any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years;
- for a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions.

No explicit mechanism for controlling and enforcing the implementation of supply standards is foreseen. Information on the methodology for controlling and enforcing the supply standard is missing in the PAP. However, the swing obligations outlined in *Section 2.5.2* are most likely sufficient to cope with these requirements.

A first estimate of the quantitative requirement to fulfill supply standards for protected customers in Italy is about 7 bcm.

A.10.3.3 Other non-storage related SoS measures and main flexibility and emergency tools available in the country

In the event of a gas emergency, Italy resorts to supply and demand management measures.

DSR measures include interruptible consumption and enforced fuel switching; the recourse to interruptible consumption contracts and enforced fuel switching is set every year by the Ministry. For the winter 2014/15 no recourse to interruptible consumption and enforced fuel switching is foreseen.

Supply side management consists of maximization of gas imports and a LNG peak shaving emergency service.

A.10.3.4 Interruptible consumption and enforced fuel switching

Main operational rules

Demand side management aims to contain gas consumption through:

- Voluntary agreements with industrial consumers who agree to interrupt their own gas consumption in the event of an emergency[329]
- Enforced fuel switching by turning on oil-fired power plants (and other non-gas fired plants) with dispatching priority who are usually idle but agree to be ready to operate on demand[330].

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[327] Including essential social services, such as hospitals, schools.

328Initially this threshold was set at 200,000 cm/year then in 2011 it was lowered down to 50,000 cm/year pursuant to Legislative Decree 93/2011.

[329] Ministerial Decree 11 September 2007.

In the latter case, gas power plants do not sign any agreement to interrupt their consumption, but as marginal resource on the system they are “forced” to shut down as the power plants that are turned on have a dispatching priority. In theory, all non-gas fired power plants can participate, however based on Ministerial statements[331] it can be said that all of them are old oil-fired power plants.

Selection procedures for industrial interruptible contracts are set by the Italian Energy Authority[332]. Selection procedures power plants willing to participate in the enforced fuel switching mechanism are set by the Ministry, eligible power plants should have a nominal net power greater than 300 MW.

Industrial plants willing to be disconnected and oil-fired power plants willing to be turned back on receive a fixed payment for their availability and a variable payment if advantage is actually taken of it. Power plants participating in the enforced fuel switching mechanism are remunerated also for maintaining oil stocks to be ready to use in the case are they requested to turn on.

Amount and criteria

The recourse to interruptible consumption contracts and enforced fuel switching is set every year by the Ministry (Table A.10.9 shows estimated reduction in gas consumption for each demand side measures, in the event they were actually used). The latter should be set by the end of July. As of March 2015 no recourse to interruptible consumption contracts and enforced fuel switching is foreseen.

Table A.10.9. Recourse to interruptible consumption contracts and enforced fuel switching

Period	Potential reduction due to concluded interruptible contracts with industrial consumers	Potential reduction due to resort to dispatching oil-fired power plants
Winter 2012/13	12 mcm/d	18 mcm/d
Winter 2013/14	0	13 mcm/d
Winter 2014/15	0	0
Source: PAP		

More specifically, demand-side management for industrial demand was eliminated for the winter 2013/14 and winter 2014/15 (see below for a discussion), while for the winter 2012/13 interruptible consumption contracts signed with industrial gas users were such to reduce gas consumption by 12 mcm/d[333].

The amount of contracted capacity of oil-fired power plants was reduced in the winter 2013/14 compared with the previous year: the list of plants under contract has never been published, but the availability is sufficient to reduce gas consumption by up to 13 mcm/d[334], down from 18 mcm/d[335] in previous winter. The number of oil-fired power plants under contract for winter 2013/14 has been defined on the basis of a cost benefit analysis[336]. Recourse to oil-fired power dispatching for the winter 2014-2015 should have been quantified by the end of 2014 but it was not, arguably indicating that no oil-fired power plants were asked to provide this service.

[330] Introduced by art. 38bis, Law Decree 83/2012.
[331] http://www.sviluppoeconomico.gov.it/images/stories/documenti/competitivita_ver21.pdf
[332] Italian Energy Authority Resolution 498/2012/R/gas
[333] Italian Energy Authority Resolution 498/2012/R/gas, Ministry for Economic Development Decree of 23 November 2012
[334] Italian Energy Authority Opinion No. 439/I/R/gas
[335] Ministry for Economic Development Decree of 23rd November 2012.
[336] Ministerial Decree of 13th of September 2013 and Resolution No. 439/2013/I/gas

Cost estimation

According to the Italian Energy Authority[337], industrial interruptible contracts signed for the winter 2012/13, leading to a potential reduction in consumption of 12 mcm/d, had a cost of 40 million euro. Based on this, it may be concluded that reducing 1 mcm/d of gas demand by using interruptible contracts signed by industrial consumers costs about 3 million euro.

According to Ministerial statements, the cost of enforced fuel switching in 2013 was equal to 40 million euro. Based on this, it may be concluded that reducing 1 mcm/d of gas demand by using enforced fuel switching costs about 3 million euro.

Cost allocation

The expenses for demand side management and dispatching of oil-fired plants are recovered until September 2015 through the CVi component of the gas transport entry tariff, which is charged on volumes injected into the Italian network[338] (Table A.10.10). Such component, if passed on to the cost of the commodity delivered to the PSV, can increase the premium paid on the Italian market compared with the rest of Europe. Starting from October 2015, the expenses for demand side management and dispatching of oil-fired plants are recovered through the CVRi component of the gas transport exit tariff which is charged on off-takes from the Italian network.

Table A.10.10. CVi component financing expenses for demand side management and dispatching of oil-fired plants

€c/cm	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1
CVi	0.04	0.04	0.057	0.057	0.057	0.057	0.1	0.1	0.1

Source: Italian Energy Authority

Evolution and debate

In the PAP, the Italian Ministry states that the use of demand side SoS measures should fall in the next years, thanks to:

- the creation of market instruments to address situations of supply difficulties (a new emergency session of the balancing market)
- improvement in infrastructures, which would improve the margin of system security and therefore reduce recourse to administrated emergency measures.

The choice of gradually giving up demand side SoS measures is also backed by efforts to reduce the costs of the energy system and improve competitiveness. More specifically, demand-side management for industrial demand was eliminated since the winter 2013/14. The decision to stop resorting to demand side management in industry was motivated by the entry into service of the new OLT regasification terminal, which increases the diversification of the supply and increases system entry capacity. Moreover, two further measures have been introduced:

(i) a G-1 emergency balancing session, which should allow greater co-ordination between Snam Rete Gas and importers when the system is under pressure; (ii) the introduction of a peak shaving service at partially used regasification terminals (see below). The PAP suggests that new contractual structures aimed to incentivize a wider

[337] Italian Energy Authority Resolution 281/2013/R/gas
[338] Italian Energy Authority Resolution No. 277/07

participation of industrial customers may be included as further measures for risk prevention, to be undertaken in the short – medium run.

According to the PAP, the dispatch of oil-fired plants will also cease just as soon as the new storage capacity comes into service. According to the EP, new storage capacity was expected to increase peak withdrawal performance from the end of 2015. However, the forecast contained in the emergency plan, which states that a storage withdrawal capacity of over 350 mcm/d will be reached from gas year 2015, appears to be over optimistic in view of the market difficulties that are slowing many projects. In fact, only 2.7 bcm of the 4 bcm of new space that must be made available by Stogit by 2015 pursuant to the storage decree (see above) has been offered in April 2014 due to shippers that decided not to apply for the remaining project capacity.

The Italian gas system actually resorted to enforced fuel switching and interruptible gas contracts in February 2012.

A.10.3.5 LNG Peak Shaving emergency service

Main operational rules

In 2013, the Italian Ministry for Economic Development introduced an emergency peak shaving service at regasification terminals[339]. The service was introduced to supplement the original preventive action plan[340]. It involves using currently partially used terminals to store LNG, to be regasified when needed in emergencies.

More specifically, the liquefied gas to be stored in terminals with slots that are not booked should be made available to Snam Rete Gas for balancing in emergencies and should be purchased on the market through auctions. Terms and conditions of the mechanism are set by the Ministry for Economic Development. The auction criteria set a maximum bid price, whose determination criteria and level have not been disclosed.

Regasification terminals voluntary decide whether to offer this service and arrange the tender. Shippers having access to regasification capacity may participate in such tender.

Amount

No bids were received at the auctions for the winter 2013/14, while in 2014 the tender was run by three LNG terminals, three successful bids have been received and the service eventually launched for deliveries to be made in the winter 2014/15. As of March 2015, the system has not activated to this emergency measure.

Table A.10.12. Emergency peak shaving service at regasification terminals: total volume stored and successful bids

Period	**LNG stored**	**N.successful bids**
Winter 2013/14	0	0
Winter 2014/15	100,000 cm at OLT terminal 165,000 cm at Panigaglia terminal 65,000 cm at the Adriatic LNG terminal	3
Source: OLT offshore, GNL Italia		

[339] Ministerial Decree 13 September 2013
[340] Ministerial Decrees of 13th September 2013

Estimated cost

Details on the reserve price have not been published, nor have the results of the auctions ever disclosed. So a precise estimate for the cost of this emergency service is not possible. However the cost of this service may be linked to the price of spot LNG delivered to Italy in the 4th quarter of 2014 (around 9 $/MMbtu, equal to around 27 €/MWh) plus the cost of the use of regasification terminals. It has to be taken into account that the rational for introducing this service was to avoid to resort to other costly measures for managing the demand side.

Cost allocation

Until September 2015, the expenses for emergency peak shaving service are recovered through the CVBL component of the gas transport entry tariff which is charged on volumes injected into the Italian network[341]. Such component, if passed on to the cost of the commodity delivered to the PSV, can increase the premium paid on the Italian market compared with the rest of Europe. Starting from October 2015[342] the expenses for emergency peak shaving service are recovered through the CVRBL component of the gas transport exit tariff which is charged on off-takes from the Italian network. The amount of CVBL / CVRBL aimed at financing the emergency peak shaving service has not being quantified jet.

A.10.3.6 Quantitative estimate of domestic production

Maximum technical production daily capacity, intended as the sum of maximum technical production daily capacities of all of the production facilities interconnected with the national pipeline network, is 19.7 according to PAP.

A.10.3.6.1 Quantitative estimate of LNG import capacity

There are 3 LNG regasification terminals in Italy:

- Panigaglia (operated by GNL Italia), with a maximum send out capacity of 11.4 mcm/d
- Rovigo terminal (operated by Adriatic LNG), with a maximum send out capacity of 26.4 mcm/d
- OLT Offshore terminal (operated by OLT offshore), with a maximum send out capacity of 15 mcm/d.

A.10.3.7 Quantitative estimate of pipeline import capacity

In the event of a gas crisis Italy resorts to the maximization of gas imports.

The total technical import capacity equals 328.6 mcm/d in GY14[343]. The single largest import infrastructure is TAG, the import pipeline from Russia, passing through Austria, Slovakia and Ukraine, which is interconnected to the national pipeline system at the

[341] Italian Energy Authority Resolution 466/2014/R/gas.
[342] Italian Energy Authority Resolution 60/2015/R/gas.
[343] Source: PAP.

entry point of Tarvisio. TAG has a technical import capacity into the Italian system of 118.8 mcm/d[344].

In the event of disruption of Russian flows, which may zero out the flows from Tarvisio and Gorizia entry points, the remaining potential import capacity would be equal to 207.4 mcm/d, based on data published in the PAP.

A.10.3.8 Estimated demand response

No estimate for price-driven demand response are provided. Estimated contribution from interruptible consumption contracts and enforced fuel switching is 5 mcm/d according to PAP. As of GY14 the contribution from interruptible consumption contracts for is 0, based on the decision by the Ministry to discontinue the recourse to this measure.

A.10.3.8.1 Estimated fuel switching

No estimate for price-driven fuel switching are provided. Estimated contribution from interruptible consumption contracts and enforced fuel switching is 5 mcm/d according to PAP. As of GY13 the maximum contribution from enforced fuel switching was 13 mcm/d, but it is likely to decrease in the next years, even if demand conditions did not change. In fact, increased renewable energy generation capacity has reduced Italy’s dependence on natural gas.

[344] Source: PAP.

ANNEX 11. CASE STUDY: POLAND

A.11.1 The Polish gas market

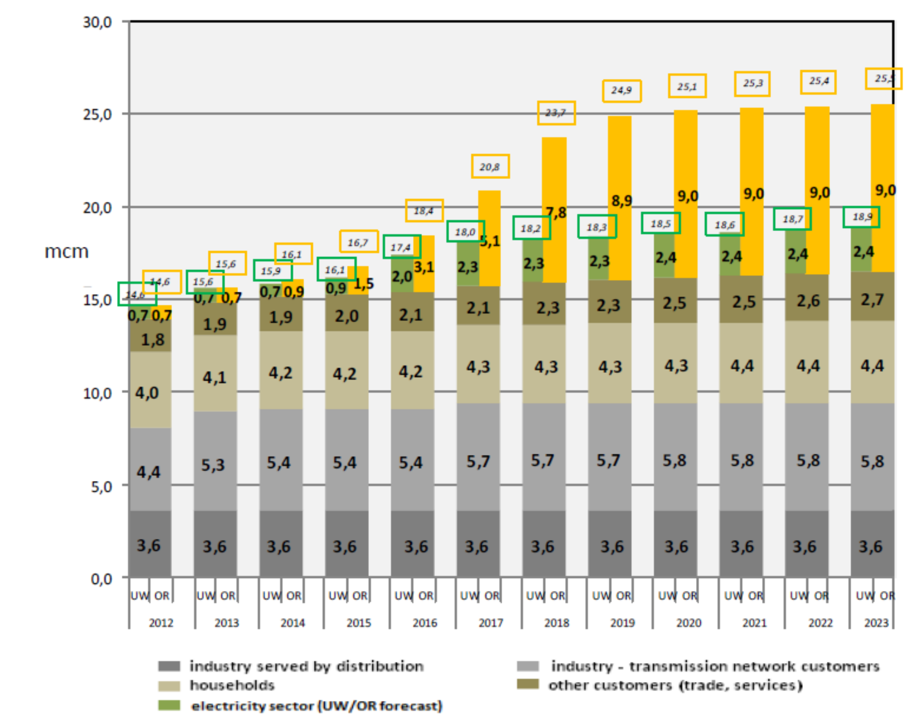
The gas balance in Poland shows that about 75.8% of gas is imported from outside Europe. Storage capacities account for 2.4% of gas supplied to the system in 2013.

Table A.11.1. Balance of high-methane and nitrogen gas flows in the transmission system (including Transit Gas Pipeline System) in 2013 [TWh] (Source: ERO on the basis of data of OGP Gaz-System SA and SGT EuRoPol GAZ SA.)

	TWh	Share
Entry to the system in total	**524.8**	**100%**
Mines and denitriding plants	38.6	7.4%
Storage facilities	12.7	2.4%
Supplies from outside the EU	433.2	82.5%
Supplies from the UE	39.9	7.6%
Other (entry points from distribution system)	0.3	0.001%
Exit from the system in total	**524.8**	
Blending stations and denitriding plants	4.5	
Storage facilities	16.4	
To the distribution network	103.5	
To the end users connected to the transmission network	53.4	
Supplies from outside the EU	331.3	
Supplies from the UE	10.3	
Operator’s own needs	5.3	

Gas consumption in Poland amounted to 14,818 mcm in 2014. About 3.7 mcm of gas consumption belongs to households. The largest increase is seen in the electricity sector from 2014 onwards.

Figure A.11.1. Forecast of demand for the transmission service, broken down by customers (Source: URE Activity Report 2014, p. 80)



Gas supplied to Poland is transported via different routes from Belarus (Wysokoje entry point, TGPS entry points (Wloclawek, Lwowek), Tietierowka), Ukraine (Drozdowicze), Germany (Lasow) and Czech Republic (Ciezsyn)

A.11.2 Law and Regulation

Besides the European legislation (Regulation (EU) No 994/2010) there are additional national legislations which define procedures in emergency cases.

- Energy Law (Act of 10 April 1997, Journal of Laws of 2012, item 1059)
  - Lays down the obligation for any energy enterprise whose activity consists in the transmission and distribution of fuels or energy, storage of gaseous fuels, including liquefied natural gas, natural gas liquefaction or regasification of liquefied natural gas to maintain the operability of equipment, installations and grids to provide supply in a continuous and reliable manner, with the observance of binding quality requirements
  - obligation to provide public services related to the security of natural gas supply
- Stocks Act (Act of 16 February 2007, Journal of Laws 2012, item 1190)
  - Lays down the basic public service obligations related to the security of natural gas supply.
  - Definition of principles for proceeding in circumstances of a threat to the fuel security of the state and disruption on the petroleum market.
- Regulation of the Minister for the Economy of 2 July 2010 on the detailed terms and conditions for the operation of the gas system (Journal of Laws No 133, item 891, as amended);
- Regulation of the Council of Ministers of 19 September 2007 on the method and procedure for the introduction of restrictions on natural gas offtake (Journal of Laws No 178, item 1252)

In case of an emergency the Minister for Economy is supported by a Team for Security of Natural Gas Supply.

The Energy Law lays down the obligation for any energy enterprise whose activity consists in the transmission and distribution of fuels or energy, storage of gaseous fuels, including liquefied natural gas, natural gas liquefaction or regasification of liquefied natural gas to maintain the operability of equipment, installations and grids to provide supply in a continuous and reliable manner, with the observance of binding quality requirements[345].

The Stocks Act lays down the basic public service obligations related to security of natural gas supply. That is to say in order to secure the gas supply to Poland and to minimize the consequences of threats to the fuel security of the state, an emergency situation arising in the gas grid or an unforeseen increase in natural gas consumption, retail companies are obliged to maintain compulsory stocks of natural gas. Besides such non-market based obligations there exists market based obligations for gas companies operating in the gas supply business which are further elaborated below. Such obligation does not apply to residential natural gas consumers[346].

[345] See Article 4 of the Energy Law.
[346] See Article 49 (3) of the Act on stocks.

Table A.11.2. Functioning of the transmission network in the periods of failure-free system operation (Source: Preventive Action Plan 2013)		
Location	**Maximal technical capacity of individual infrastructure**	**Assumed network operation parameters in failure-free conditions**
RIO Odolanów	2.0	2.0
Grodzisk nitrogen removal	1.1	1.1
Plant Mines	4.0	4.0
Mines and nitrogen removal plants in total	7.1	7.1
Storages		
UGS Swarzów	1.0	0.6
UGS Brzeźnica	0.9	0.3
UGS Strachocina	2.9	2.9
UGS Husów	5.8	5.1
UGS Wierzchowice	9.6	6.3
UGS Mogilno	18.0	10.8
Total storage facilities	38.1	25.9
Total POLISH SOURCES	45.2	33.2
IMPORT		
Lasów	4.3	4.3
Lwówek	6.5	6.5
Włocławek	8.4	6.5
Drozdowicze	12.0	12.0
Wysokoje	15.0	9.3
Cieszyn	2.5	2.4
Tietierowka	0.6	0.6
Total import	**49.3**	**41.6**
TOTAL	**94.5**	**74.8**

A.11.3 Market Measures

Energy companies engaged in gas business are required to have operational measures in place for emergency cases, i.e.[347]:

- the occurrence of disruptions of natural gas supply to the gas system;
- an unexpected increase in natural gas consumption by customers.

Operational procedures shall specify, in particular, the manner of:

- initiation of additional natural gas supplies from other sources or directions;
  - relocation of imported gas supply from selected entry points to other, according to their technical capacities, as well as increased workload for the remaining gas compressor stations within the system (supply side)
- diversification of directions and sources of gas supply to Poland through the development of intersystem connections in contact points with the German, Czech and Slovakian transmission systems (supply side) (gas junctions)
- reducing the offtake of natural gas by customers, in accordance with contracts concluded with them (trade restrictions).

[347] See Article 49 (1) of the Act on stocks.

- introduction of gas fuel supply contracts which would allow for interruptions (total or partial interruptions) (demand side)

Operational procedures shall also include guaranteeing supplies of natural gas to protected customers being supplied from natural gas re-gasification facilities. Operational procedures shall be agreed upon with entities responsible for their implementation, including, respectively, operators of other gas systems, and subsequently submitted to the transmission system operator.

In addition to this the TSO shall draw up the "Transmission Network Operator's National Plan for Crisis Situations in the Natural Gas Sector". The National Plan shall integrate the procedures developed and the plans (including plans for the introduction of restrictions)4 of other operators and undertakings, and shall be based on information provided by distribution system operators, the storage system operator, the liquefaction and re-gasification system operator, energy undertakings engaged in business activities in the field of natural gas import for subsequent resale to customers, and customers connected to the transmission network or distribution network. By this the plan shall integrate market and non-market based measures. Energy undertakings shall be required to agree on the procedures and plans (including plans for the introduction of restrictions) with the transmission system operator. The transmission system operator shall check the procedures submitted by natural gas market participants for technical capacities of the gas system. The Transmission Network Operator's National Plan for Crisis Situations in the Natural Gas Sector shall be submitted to the Minister for the Economy for approval.

The National Plan shall, inter alia, include:

1. Operational procedure to be followed in the event of disturbances to gaseous fuel supply, in particular an unexpected increase in the gaseous fuel consumption by customers, thereby causing disruptions to gaseous fuel supply, or in the event of an emergency in the installation of the transmission service shipper's (ZUP) customer or supplier
2. accurate estimation of natural gas volumes consumed by protected customers
3. the possibilities for transition to alternative fuels by a certain number of customers connected to the transmission network and distribution networks
4. preparation of a detailed safety net for identified hazards
5. analysis of the network operation in the event of particular crisis scenarios
6. estimation of the volumes of natural gas necessary to ensure supply only to protected customers in accordance with the supply standard (Article 8(1) of Regulation 994/2010)
7. estimation of the volumes of natural gas not supplied to end users, with particular regard to protected customers in the event of a crisis situation.

In the event of a threat of disruption of natural gas supply to the gas system, or an unexpected increase in the consumption thereof by customers, the trading undertaking and entities contracting the provision of natural gas transmission or distribution services shall implement market measures set out in the above-mentioned procedures, in accordance with the Transmission Network Operator's National Plan for Crisis Situations in the Natural Gas Sector.

After having implemented all measures which allow meeting their customers' demand for natural gas, energy undertakings engaged in business activities in the field of natural gas import for subsequent resale to customers (hereinafter referred to as trading undertakings), and entities contracting the provision of natural gas transmission services, shall notify:

- the gas system operator of the occurrence of disruptions of natural gas supply to the gas system, or an unexpected increase in consumption, and of the measures implemented in order to ensure natural gas supply to their customers, or of the absence of possibility for safeguarding that security in good time.
- the customers being subject to the measures set out in procedures, with whom natural gas sales contracts have been concluded, through available means, of the occurrence of the above-mentioned events and their impact on the security of gas supply, and of the measures implemented in order to remove the consequences of those events.

The emergency plan distinguishes supply and demand side measures as market based measures. Thereby storage capacities are defined as part of the supply side measures with a total working gas capacity of 2.67 billion m3 out of which 1.84 billion m3 were available in 2014 and 836 mcm accounted for mandatory stocks.

A.11.4 Non-market measures

The non-market based measures foresee holding of mandatory stocks of natural gas on the one hand and restrictions on natural gas offtake on the other.

A.11.4.1 Mandatory stocks of natural gas

The obligation to hold mandatory stocks concerns gas importing companies which resale the gas to customers. The stored gas is an asset of these companies[348] but at the disposal of the Minister of the Economy. The volume shall be equivalent to at least 30 days of the average daily imports of the gas brought in. The gas has to be stored in storage facilities which provide the opportunity for supplying the entire volume thereof to the gas system within a period of not more than 40 days.

The costs incurred by the enterprises in order to fulfil the obligation to maintain, release and re-establish the compulsory stocks of natural gas shall be included in the justified costs of their operations within their cost calculations of regulated tariffs.[349]

Mandatory stocks of natural gas may be maintained outside the territory of Poland, in the territory of another member state of the European Free Trade Association (EFTA) being a party to the European Economic Area Agreement, in storage facilities connected to a gas system and meeting the requirements set out in the Act on stocks. That is to say both the technical parameters and the parameters of the service provision agreements ensure that the total volume of the compulsory stocks of natural gas maintained outside the territory of Poland can be delivered to the national transmission or distribution network within the maximum period of 40 days.[350]

Depending on the assessment of situation and measures necessary for removing the consequences of supply disruptions, it shall be possible to:

1. release mandatory stocks, and subsequently introduce restrictions on natural gas offtake (where it has initially been assessed that the use of mandatory stocks would suffice), or

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[348] See Article 28 of the Act on stocks.

[349] See Article 3, Section 21 of the Energy Law.

[350] See Article 24a, of the Act on stocks.

2. release mandatory stocks and introduce restrictions on natural gas offtake in parallel (where it is immediately apparent that the use of mandatory stocks will not suffice).

In the event of having released mandatory stocks, the Minister for the Economy shall immediately inform thereof the European Commission, the Member States of the European Union, and the member states of the European Free Trade Agreement (EFTA) being the parties to the European Economic Area Agreement.

In 2012/2013 season mandatory stocks of natural gas amounted to 883.7 million m3 in order to cover a volume equivalent to at least the 30-day average daily import of gas to the territory of Poland.

A.11.4.2 Restrictions on natural gas offtake

Restrictions on natural gas offtake shall involve restricting the maximum hourly and 24-hour offtake of natural gas in the territory of Poland or a part thereof, and may be introduced for a specified period of time. Energy undertakings shall not be held responsible for the consequences of restrictions introduced.[351] The restrictions shall be introduced in accordance with plans for the introduction of restrictions, and shall not affect household gas customers. Restrictions on natural gas offtake may be introduced in the event of:[352]

1. a threat to the fuel security of the State,
2. an unexpected increase in natural gas consumption by customers,
3. the occurrence of disruptions to natural gas imports,
4. a failure in gas system operators' networks,
5. a threat to the security of operation of gas networks,
6. a threat to the safety of individuals,
7. a threat of significant material losses,
8. the need for Poland to fulfil international obligations.

However, there are limitations for the restrictions as they shall not result in:

1. a threat to the safety of individuals, and damage to or destruction of process facilities;
2. disruptions to the operation of institutions, enterprises and facilities as regards the performance of tasks associated with:
   (a) security and defence of the State,
   (b) healthcare,
   (c) education,
   (d) generation and supply of electricity and heat to household customers,
   (e) environmental protection.

The transmission system operator and distribution system operators shall be required to draw up plans for the introduction of restrictions on natural gas offtake according to the following procedure:

[351] See Article 57 of the Act on stocks.
[352] See Article 54 of the Act on stocks.

1. These plans shall set out the maximum hourly and 24-hour volumes of natural gas offtake by individual customers connected to their network, for particular gas rationing levels.
2. The operators (TSO and DSO) shall inform customers of the maximum volumes of natural gas offtake at particular gas rationing levels, as determined for them in the plan. The volumes in question shall become an integral part of sales contracts, contracts for the provision of natural gas transmission or distribution services, and comprehensive contracts;
3. Customers covered by the plans shall inform the relevant operator, to whose network they are connected, by 31 July of each year, of the minimum volume of natural gas the offtake of which does not result in a threat to the safety of individuals, and damage to or destruction of process facilities, and is equivalent to the maximum permissible natural gas offtake at a gas rationing level of 10. The volume of natural gas specified in the information provided may be verified by operators on the basis of data on the consumption to date;
4. The plans shall include data on natural gas consumption by customers, including protected customers, and the manner of supplying gaseous fuel in accordance with the existing "Assessment of Risks Associated with the Security of Gas Supply to Poland", and the existing "Preventive Action Plan";
5. Based on the plans of operators and trading undertakings, the transmission system operator shall draw up the Transmission Network Operator's National Plan for Crisis Situations in the Natural Gas Sector, which shall include the obligation to supply natural gas to protected customers. In case of the absence of possibility for supplying gas to a certain number of protected customers after the occurrence of a scenario identified in the existing Assessment of Risks, the transmission system operator shall communicate to the Competent Authority recommendations concerning the "Preventive Action Plan" being cyclically drawn up;
6. Operators shall annually update the plans for the introduction of restrictions, and submit them, by 15 November of each year, to the President of the Energy Regulatory Office (ERO) for approval by way of Decision.

In the event of a crisis situation when the foreseen market measures (i.e. operational procedures) were not sufficient the TSO may upon permission of the Minister of Economy release gas from mandatory stocks or besides releasing gas from mandatory stocks introduce restrictions on gas offtake. The restrictions on gas offtake are applied to the Regulation of the Council of Ministers. If the restrictions were also not sufficient to terminate the event the Council of Ministers would be entitled to introduce the state of natural disaster or the state of emergency.

A.11.5 Other SoS information

A.11.5.1 N-1 Standard level

While calculating the infrastructure standard for the Risk Assessment submitted in 2011, the technical capacity of all entry points to the Polish transmission system was taken into account while the contractual conditions were excluded from the analysis. The risk assessment considers as scenarios of infrastructural damages the following events:

1. failures of natural gas compressor stations
2. failures of gas junctions.

The quantity of methane-rich gas extracted in 2010, as well as the gas brought into the system from nitrogen removal plants, were adopted as the maximum technical capacity for production. The maximum technical capacity for reception from storage installations is calculated without taking into account the variable quantity of reception capacity depending on the level of storage exploitation.

The N-1 infrastructure standard for Poland comes to 97.3%.

However, it is noted in the Preventive action plan that the N-1 formula cannot be deemed reliable in the case of Poland as a tool for evaluating the condition of the transmission network. The phrase "maximum technical capacity" applied in the definition results in the imprecise and unreliable outcome of the calculation.

According to the Competent Authority, the product of the calculation does not mean that the network security that has been provided, as other factors - such as contractual arrangements - must be taken into account as well. Poland has at its disposal free transmission capacities only at the Eastern entry points to the gas system (at the Belarusian border). Entry points at the Western and Southern borders of Poland have been already used nearly in 100% of their capacities. Due to the lack of TPA on the gas transmission pipelines on the Eastern side of the Polish border, purchasing gas from alternative providers is almost impossible. The real N-1 formula for Poland should therefore be calculated in relation to the technical capacities of connections with EU countries and contractual arrangements for Eastern entry points.

Table A.11.3. N-1 formula calculated for the purposes of the Risk Assessment

		mcm/day
Technical capacity of entry points	EP_m	49.1
Maximum daily technical storage withdrawal capacity	S^1_m	30.8
Maximum daily technical production capacity	P_m	6.2
Maximum daily technical LNG send-out capacity	LNG_m	0
Technical capacity of single largest gas infrastructure	I_m	18
Daily gas demand (once in 20 years)	D_{max}	70
N-1		97.3%

([1]) technical capacity of UGS (Sm) identified for the fully filled-in active capacity. The maximum gas deliverability from the CUGS Mogilno amounts to 28.80 mcm/day, although the deliverability of the transmission network from this storage point amounts only to 18 mcm/day.

Source: Prevention Action Plan 2013, p. 15

According to the latest data provided by the OGP GAZ- SYSTEM SA on 13th April 2012, the N-1 formula - having taken the latest investment activities (e.g. new entry point Cieszyn, expansion of entry point Lasów, and increased gas supply capacity of storage facilities Wierzchowice and Strachocina) into account - currently amounts to 102.3%. However, this formula does not take into account the aforementioned contractual limitations nor the possibility of distributing natural gas within the national gas system; it also assumes the complete utilisation of natural gas storage facilities.

It should be mentioned that, in order to obtain the maximum technical deliverability of gas from UGS (Sm), the compulsory stocks of natural gas would have to be released. This would constitute a non-market based measure and would be possible only in the event of supplies to protected customers being threatened. Moreover, it would require the completion of the extension works of the UGS and storage of the required quantity of natural gas. In the event of an emergency at the end of the winter period, the deliverability of natural gas from storage facilities would be decreased, resulting in the decrease in the N-1 formula to the level of approx. 92%.

Table A.11.4. N-1 formula calculated for the purposes of the Risk Assessment incl. latest investment activities		
		mcm/day
Technical capacity of entry points	EP_m	49.3
Maximum daily technical storage withdrawal capacity	S_m	38.1
Maximum daily technical production capacity	P_m	7.1
Maximum daily technical LNG send-out capacity	LNG_m	0
Technical capacity of single largest gas infrastructure	I_m	18
Daily gas demand (once in 20 years)	D_{max}	75
N-1		102.3%
Source: Prevention Action Plan 2013, p. 17		

A.11.5.2 Protected Customers

The definition of protected customers5 as adopted by the Polish state includes the customers in households connected to the distribution network of natural gas, entities which provide basic social services and installations of heating systems which provide thermal energy to the aforementioned entities (Table A.11.5).

Table A.11.5. Supply standard for protected customers pursuant to Article 8, Section 1 of Regulation 994/2010				
Energy Enterprise	**Type of gas**	**Standard: extreme temperatures during a 7- day peak period of gas demand**	**Standard: 30 days of exceptionally high gas demand**	**Standard: 30 days of disruption of the single largest gas infrastructure**
		statistical probability of once in 20 years [m3]		average winter conditions [m3]
Supplier 1	E	187.366.716	803.000.215	6.603.821.292
	Lw	9.619.244	41.225.335	26.568.887
	Ls	3.410.328	14.615.692	9.010.368
Supplier 2	E	2.650.000	8.830.000	1.090.000
Supplier 3	E	800.000	3.500.000	2.500.000
Source: Prevention Action Plan, 2013				

ANNEX 12. CASE STUDY: SPAIN

Storage of natural gas in Spain has grown substantially during the last decade and a half, mainly in order to keep in-step with the remarkable increase in importance of natural gas in the Spanish energy sector generally. It is observable that Spanish storage facilities are typically amongst the fullest (in terms of the proportion of total storage capacity that contains gas) in comparison with other EU countries. Various factors have contributed to this situation.

Firstly, Spain is entirely dependent on imported gas and achieved greater import-export flexibility only very recently. It must also be understood that the impact of economic recession in Spain in the late 2000s and years following had a very substantial negative impact on total gas demand. The Spanish gas market is therefore substantially over-contracted. Storage capacity was developed in-line with forecasted gas requirements, which, as a consequence of supressed demand/growth caused by the economic recession, were substantially higher than actual requirements.

It is also important to note that Spanish underground storage capacity is not high (in volumetric terms) compared with other EU countries, or even when compared with total Spanish gas demand. However, Spain has a binding requirement to maintain a minimum 20 days' worth of gas reserves. Consequently, the combination of having significant minimum storage reserve requirements and relatively limited storage space means that Spain's storage facilities are generally relatively 'full' when compared with those of other EU countries.

A.12.1 Main storage related SoS measures of the country

Main responsibilities for agents in the natural gas market were established by Law 34/1998[353] and were afterwards developed by Royal Decree 1716/2004, and its subsequent modification Royal Decree 1766/2007, Natural gas suppliers must implement two different measures in order to guarantee security of supply:

- They must diversify their supply portfolio. Suppliers of a significant volume will be forced to diversify their supply portfolio if any of the supplying countries accounts for more than 50% of the Spanish aggregated imported volume[354].
- Shippers shall keep permanently in underground storage facilities (UGS) an amount of gas (20 days of their firm sales in the previous year).

A.12.1.1 Mandatory Storage Obligations

Article 98 regarding Security of Supply of Law 34/1998 of the Hydrocarbons Sector establishes that shippers and direct consumers in the market shall keep minimum security stocks expressed in equivalent days of their firm sales in the Spanish territory.

Royal Decree 1716/2004 which regulated the obligation to maintain minimum security stocks, diversification of gas supply and established the Corporation for Strategic Reserves of Petroleum Products (CORES), amended by Royal Decree 1766/2007 and by Order ITC/3128/2011, establishes that shippers shall keep strategic stocks,

[353] "Ley 34/1998, de 7 de octubre, del sector de hidrocarburos" «BOE» n. 241, 8th October 1998, Ref: BOE-A-1998-23284, consolidated version.
[354] Article 17 of RD 1716/2004, Ref: BOE-A-2004-15457, with the provisions included in Article 10 of Order ITC/3128/2011, November 17th.

equivalent to 20 days of their firm sales in the previous natural year, located in UGS and whose utilization is a responsibility of the Government[355].

Such stocks can be used to palliate emergency situations linked to infrastructure's failure, cease of imports due to geopolitical issues, force majeure, adverse meteorological phenomena etc.

A.12.1.1.1 Winter Outlook

Detailed regulation "NGTS-09" Normal Operation of the System, foresees the possibility for Enagás (in its role as Technical Manager of the System) to elaborate a Winter Outlook, in collaboration with agents involved, in order to guarantee natural gas security of supply in view of an increasing demand, as a consequence of the seasonality of the domestic/commercial market and due to sudden cold spells

Since the first Winter Outlook 2005-2006, the plan has included measures to ensure operative and available natural gas stocks, in order to guarantee demand coverage under adverse winter conditions.

Rule 1 of the Winter Outlook in force (Resolution of 8 October 2013 of the General Directorate of Energy and Mines Policy) foresees:

- Storage in LNG tanks of at least two days of capacity booked for send out and LNG truck loading.
- Storage in LNG tanks and/or UGS, of at least two days of the booked entry capacity in cross border Interconnection Points and national production fields, to supply the national market.

For Winter 2014/2015, such stocks have been appraised to range between 1.900 and 2.400 GWh (they were 1.900 when the report was issued, but were expected to increase until 2.400 as winter went by).[356]

A.12.1.2 Special mandatory "strategic" storage

All agents subject to security reserves (suppliers and direct customers) shall, at all times, maintain security minimum reserves of strategic nature equivalent to 20 days of firm sales (computed from last year's sales)[357].

Such stocks will be held on storage facilities belonging to the basic gas network. Cushion gas extractible by mechanical means can be included in such volumes[358].

Usage of such minimum security stocks of natural gas in case of necessity depends uniquely on the Government[359].

Regarding strategic gas reserves, computation of the required security reserves will be implemented yearly, after the end of the natural year, and will be applicable between the 1st of April and the 31st of March of the following year. Natural gas stocks can be held in property or leased, as long as the agent has complete availability of them.

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[355] The Hydrocarbon's Law 34/1998 is currently under revision. Provisions regarding security of supply might be modified.
[356] Initial forecast of august 2014. The stock level increases in accordance with short-term contracts.
[357]Article 17 of RD 1716/2004, Ref: BOE-A-2004-15457, with the provisions included in Article 10 of Order ITC/3128/2011, November 17th.
[358] Article 10 of Order ITC/3128/2011, 17th of November 2011.
[359] Article 17 of RD 1716/2004.

The following quantities cannot be included as security reserves:

- Natural gas reserves located on the fields of origin.
- Volumes maintained on pipelines belonging to the gas transmission system.
- Existing gas kept on underground storage facilities that cannot be technically extracted.
- Volumes held as cargoes on LNG ships.

In any case, volumes need to be located on Spanish soil in order to be considered security reserves unless subject to a bilateral agreement (see the following section).

If any company has just started its activities, the quantities required will be determined using a sales/consumption forecast approved by the Ministry of Industry[360].

Sales within suppliers or exported volumes to other Member States are not included in the computation of last year's sales for each agent. Nor will volumes subject to interruptible transmission fees or supplies under contracts in which commercial interruptible clauses have been included.

Under authorization of the Ministry of Industry, those agents subject to minimum reserve obligations belonging to the same industrial group can abide their mandatory requirements as a group[361].

For the period 1 April 2015–31 March 2016 the strategic stocks have been fixed at 16.460 GWh[362].

The evolution of the measures in the last ten years

The Spanish gas market has experienced a vast transformation in the last fifteen years, from an initial position in which the market was controlled by an incumbent to the current, fully liberalized situation. Security reserves' requirements for shippers have evolved accordingly.

Spanish regulation has increased mandatory reserves for gas suppliers and diversifying requirements in the last ten years. Responsibility has gradually shifted from TSOs to suppliers (as the market got liberalized). Until 2007, no discrimination between strategic and mandatory reserves was included. The responsibility for maintaining gas reserves switched from TSOs to suppliers because the TSOs were originally the suppliers of last resort, at the time before there were independent gas suppliers operating. Later, the market was liberalised, independent suppliers entered the market and assumed the responsibilities of being suppliers of last resort.

As outlined at the beginning of this country analysis, mandatory reserve requirements increased in Spain in line with the substantial increase in the role of gas in meeting the country's total final energy needs. Spain is also entirely dependent on gas imports and has limited interconnection capacity that would allow gas trade with neighbouring countries to help meet gas security needs. Therefore, as the role and importance of gas grew it became increasingly necessary to increase mandatory storage requirements in order to maintain an adequate level of security of supply.

[360] Article 19 of RD 1716/2004.
[361] Article 20 of RD 1716/2004.
[362] Resolución de 19 de enero de 2015, de la Dirección General de Política Energética y Minas, por la que se publica la capacidad asignada y disponible en los almacenamientos subterráneos básicos de gas natural para el período comprendido entre el 1 de abril de 2015 y el 31 de marzo de 2016.

Initially, Law 34/1998 and Royal Decree 1716/2004 envisaged security reserves for natural gas equivalent to 35 days of firm sales. Regarding diversification of the supplying portfolio, the threshold level was first established at 60% of the Spanish yearly gas consumption.

Regarding the computation of required reserves, initially, volumes stored in LNG cargoes directed to Spain and with delivery dates close to the time of computation, were also included[363].

Also, since at that time regulated customers were still supplied by distributors instead of by suppliers, the TSO had the responsibility to ensure both diversification of supply and to maintain security reserves (of the same amount as suppliers and direct consumers)[364].

In 2007 a new law (Law 12/2007)[365] was passed in Spain to adapt Spanish regulation to the dispositions included in Directive 2003/55/CE. The law envisaged that as from 1 January 2012, minimum security stocks would not include operational reserves.[366] The law was later further developed by a complementary Royal Decree (1766/2007)[367]. Both pieces of regulation introduced a basic change in the structure of mandatory storage for gas suppliers.

Royal Decree 1766/2007, reformed RD 1716/2004 to give it its current structure. Given that TSO did no longer have a supplying role on the Spanish market, its obligations to maintain security reserves were extinguished. A transitional period (until July 1st 2008) was established, in which TSO still had the obligation to maintain security reserves for their sales to tariff consumers[368].

Moreover, the level of security reserves was modified to 20 days of firm sales and current structure (strategic and operative reserves) was introduced; the quantities that could be included were reduced (volumes on LNG ships were ruled out) and the threshold level for portfolio diversification was lowered (from 60 to 50%). It also shifted responsibility of monitoring: from CORES to the Ministry of Industry, while the former still acted as the receiver of all required information[369].

Regarding interruptibility of supply, it imposed a maximum level of sales/consumption that could be considered interruptible (25%). Hence, it imposed a more restrictive approach to the treatment of interruptibility[370].

Order ITC/3128/2011[371] increased strategic security reserves from 10 to 20 days of firm sales. It also provided for a transition period (until the first of November 2012) in which suppliers only needed to maintain reserves for ten days if they had already booked storage capacity at any underground facility for the required 20 days.[372]

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[363] Article 17 of RD 1716/2004, non-consolidated version.
[364] Article 15 of RD 1716/2004, non-consolidated version.
[365] *Transitory Provision 19ª of Law 12/2007.*
[366] Directive 2003/55/CE of the European Parliament and of the Council of 26 June 2003, concerning common rules for the internal market.
[367] Royal Decree 1766/2007, de 28th December 2007, Ref. BOE-A-2007-22455.
[368] Article 2 and Third Transitory Disposition of RD 1766/2007. 2007, de 28th December 2007, Ref. BOE-A-2007-22455.
[369] Article 1.3 and 1.4 of RD 1766/2007.
[370] Article 2.2 of RD 1766/2007.
[371] Order ITC/3128/2011, November 17th 2011, «BOE» núm. 278, Ref. BOE-A-2011-18065.
[372] Article 10 and Second Transitory Disposition, Order ITC/3128 (17th November 2011).

A.12.2 Any other existing storage related measures

A.12.2.1 Agreements for cross-border storage utilization (by/for other countries)

The Spanish legislation considers the possibility of maintaining gas reserves on other Member States.[373] According to Spanish legislation, the existence of a bilateral agreement is required to be able to maintain security reserves outside the Spanish national territory, and the agent shall receive authorization from the Ministry of Industry[374].

However, so far Spain has developed no such bilateral agreements with any country (despite being engaged in similar agreements for oil and oil products with France, Ireland, Italy, Malta, Portugal and New Zealand)[375].

Long-term contracting of storage capacity

Currently, all storage products sold in the Spanish gas market have duration of one year. Hence, no gas supplier possesses long-term contracting. Every year, underground storage capacity is tendered by the TSO in annual terms (from 1st April of year n to 31st March of year n+1). Those volumes offered under the tender procedure which do not become allocated, are kept by the TSO who offers them to market participants on a First Come First Served basis.

A.12.3 Other SoS information

A.12.3.1 Definition of supply standards pursuant to Art. 8 of Regulation 994/2010/EC

On its 2014-2015 Winter Plan[376], Enagás foresees the following peak demands, in case the coldest temperature conditions in the last 20 years were to occur, which account for points a) and b) of Article 8 of Regulation 994/2010/EC.

Table A.12.1 Peak expected demand (1/20)

	Conventional Segment			Power Generation Segment		
	Normal Condition	**Peak Condition**	**Increase**	**Normal Condition**	**Peak Condition**	**Increase**
1 Week	7.250	8,620	1,370 (18.9%)	1,365	7,970	800 (58.6%)
1 Month	31,070	34,150	3,080 (9.9%)	6,525	7,970	1,445 (22.1%)

Source:Enagás

Apart from the coldest temperature in 20 years, both scenarios include low wind production levels and unavailability of one nuclear plant. Figures are expressed in GWh.

[373] COUNCIL DIRECTIVE 2009/119/EC of 14 September 2009, imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products.
[374] Article 18 of RD 1716/2004, non-consolidated version.
[375] See http://www.cores.es/es/seguridad-suministro/internacional
[376] Enagás (2014) Winter Outlook 2014-2015, Gestión del Sistema Gasista, Sept. 2014; slide 24.

N-1 standard level, pursuant to Art. 6 of Regulation 994/2010/EC

The following table presents Enagas estimates for winter 2014-2015. Probable and Extreme peaks represent the conditions described in Art. 8 of regulation 994/2010/EC. Maximum transmission demand has been computed as total forecasted demand plus export nominal capacity (i.e. as if exports were at their maximum).

Table A.12.2. N-1 calculation		
	Probable Peak	**Extreme Peak**
Maximum Transport Capacity (GWh/day)	3,080	3,080
Maximum Transmission demand (GWh/day)	1,800	2,160
Security Margin (%)	71%	43%
Security Margin using N-1	40%	17%
Source:Enagás[377]		

Security margin represents spare capacity when all infrastructures are working according to the conditions defined for Winter 2014-2015, while the N-1 rule margin, as included in the base case scenario for Indicative Infrastructure Planning, represents the same margin in case the largest entry infrastructure fails (i.e. the regasification plant of Barcelona).

Regarding storage (considering both LNG and UGS, as established in the Winter Plan currently in force), stocks would allow to cover 1 week of extreme temperatures, while additional gas would be needed to cover a whole month.

Table A.12.3. LNG N-1 calculation		
	1 Week	**1 Month**
Forecasted Increase in Consumption	2,170	4,525
Security Existences (GWh)	1,900-2,400	1,900-2,400
Coverage (%)	88%	42%
Source:Enagás		

Total send-out capacity from LNG storage to the system amounted to 1,916 GWh/day and was contracted below 20%[378] when the Winter Outlook was developed.[379]

Other (non-storage) related SoS measures and main flexibility and emergency tools available in the country

In case of an emergency situation in the Spanish gas market (if firm sales' supply is threatened), the Spanish Government, apart from usage of strategic reserves, can apply the following measures:

- Temporarily limit or modify the gas market

[377] Enagás (2014) Winter Outlook 2014-2015, Gestión del Sistema Gasista, Sept. 2014; slide 34.
[378] Booked capacity in august 2014 for Winter 2014-2015. Within the winter period, booked capacity can considerably increase due to short term contracts.
[379] Enagás (2014) Winter Outlook 2014-2015, Gestión del Sistema Gasista, Sept. 2014; slides 43-44.

- Establish special (additional) mandatory reserves for natural gas (as they did according to current Winter Plan)
- Temporarily limit or modify third party access to gas infrastructures
- Modify general conditions of regularity of supply for all or some customers' categories
- Impose administrative authorizations on sales to foreign countries
- Any other measure recommended by either bilateral agreements or international organizations in which Spain takes part[380].

Besides, both direct consumers and gas suppliers are required to develop emergency plans to be sent to the TSO. Such plans shall include:

- Description of interruptible gas supplies contracted
- Description of firm gas supplies contracted, including a customer priority order (following a minimum cost criteria and prioritizing essential services)
- Management plan for own existences (operative reserves)
- Management plan for other existences (non-mandatory reserves that suppliers may maintain)
- Time schedule and instruments required to re-establish affected supplies
- Proposed measures in cases of emergency.

Using all individual emergency plans, the TSO will develop a global emergency plan to be approved by the Ministry of Industry. The Government will allocate the costs of emergency measures among natural gas agents in the most balanced way possible[381].

Production capacity

Spain produces very small amounts of natural gas and will continue to do so in the future. Currently, four fields are active[382], whose production in 2014 amounted to 508 GWh. There are no official estimates for 2015, but production will remain within a range between 400 and 1,000 GWh.

LNG import capacity

Spain has 6 operative LNG terminals (Barcelona, Sagunto, Cartagena, Huelva, Mugardos and Bilbao) while a 7th terminal is mothballed[383] (El Musel, in Gijon, with a total nominal capacity of 7 Bcm).

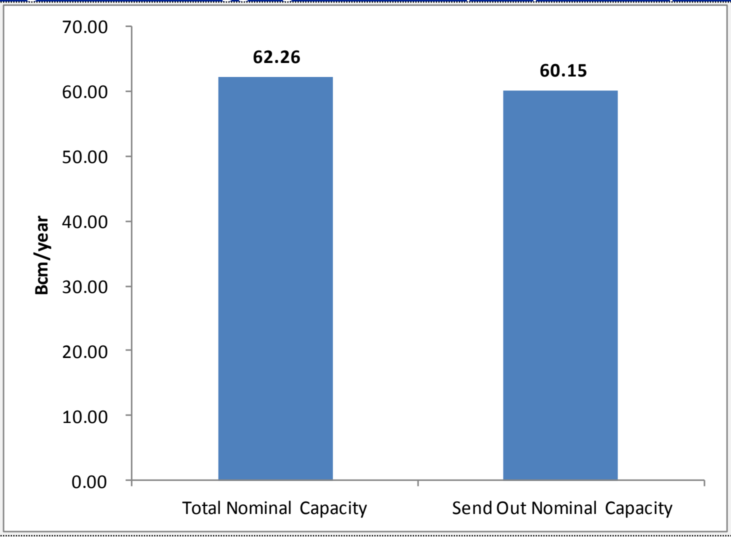
Considered all together, Spanish nominal capacity amounts to 62.3 Bcm/year, to be increased up to 69 Bcm when El Musel facility becomes operational. Send-out capacity amounts to 60.2 Bcm/year (67.2 bcm with el Musel) and storage capacity within regasification terminals amounts to 1.96 Bcm (2.13 bcm with el Musel). The total heel of the Spanish regasification terminals amounts to 0.15 bcm[384].

Despite the great capacity available (or caused by it), in 2014 utilization of the terminals remained low: utilization ranges between15% at Barcelona terminal and 29% at Mugardos terminal[385].

[380] Article 40 of RD 1716/2004.
[381] Ibidem.
[382] The four fields include Poseidon, Marismas, Aznalcázar and Biogas according to "Infrastructures capacity of Enagás Transporte". There is an additional field "Viura" which will start operating in 2015.
[383] RD-Ley 13/2012.
[384] Enagás (2015), Spanish Gas System Report 2014, p. 81.
[385] Enagás (2015), Spanish Gas System Report 2014, p. 75.

Total LNG Storage capacity amounts to 3,316 mcm of LNG[386].

Figure A.12.1. Aggregated LNG Capacity on the Spanish System

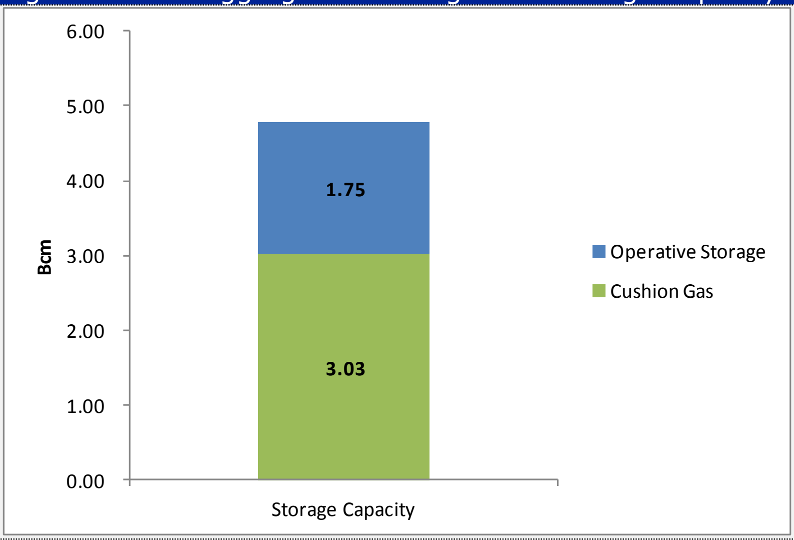


Source: Enagás[387]

Underground Storage Capacity

The following figure presents total underground storage capacity in the Spanish gas system. Total underground storage (UGS) capacity amounts to 4.78 Bcm, 0.71 Bcm of which is cushion gas extractible by mechanical means. Total Cushion gas amounts to 3.03 Bcm (including that extractible by mechanical means.

Figure A.12.2. Aggregated Underground Storage Capacity on the Spanish System



Source: Enagás[388]

[386] Enagas (TSO), Statistic Bulletin December 2014, slides 19-24.
[387] Enagás (2015), Spanish Gas System Report 2014, p. 75.
[388] Enagás (2015), Spanish Gas System Report 2014, pp. 108-109.

Pipeline Import Capacity

Spain is connected to its neighbouring countries by means of 6 physical International Connections (Larrau and Biriatou in France and Tuy and Badajoz in Portugal). Their capacities are commercialized in VIP Pirineos and VIP Iberico. Additionally, Spain counts with two international links (non-EU) with Algeria. Both pipelines link the Hassi R'mel with Spain. The Maghreb–Europe Gas Pipeline (MEGP) links the Hassi R'mel field in Algeria through Morocco and MEDGAZ connects Beni Saf on the Algerian coast, to Almería in the Spanish coast. MEDGAZ, started operating in March 2011.Total nominal capacity of the six interconnections, as of March 2015, amounts to 30.19 bcm/y.

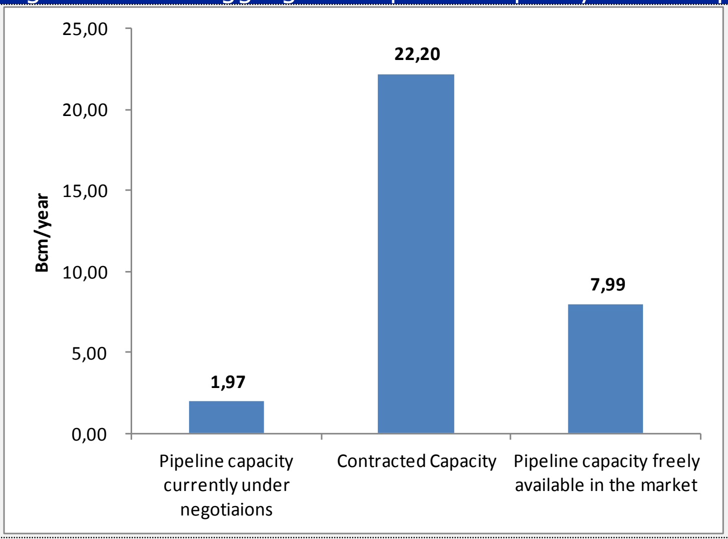
Interruptible consumption

In Spain interruptible consumption has a limited relevance and is not forecasted to increase its significance. According to the estimates elaborated by the Ministry of Industry, for 2014-2015 only one client has chosen the interruptible supply option, amounting to 0.575 GWh/d. However, under this type of agreements, customers can only be disconnected 5 days/year (2.875 GWh/year)[389].

Estimated fuel switching

According to CORES, the body responsible for the monitoring of security of supply measures with respect to natural gas, in 2013 there were 21,295 GWh (1.832 Bcm) of natural gas served to customers with technical capability to switch to alternative fuels[390].

Figure A.12.3. Aggregated Pipeline Capacity on the Spanish System for 2014/2015



Source: Enagás[391]

Available cost estimations

Currently there are no updated cost estimations available for LNG, pipeline or transport future infrastructure. The only estimation available can be found on the Indicative Infrastructure Planning 2008-2016.[392] However, those estimations only offer aggregated figures and include projects which have been delayed/mothballed (El

[389] MINETUR (2015), Spanish Gas System Preventive Action Plan, p. 11.
[390] Available at http://www.cores.es/es/seguridad-suministro/gas-natural/control-de-diversificacion
[391] Enagás (2015), "Capacidad de transporte existente y reservada", obtained in March 2015, available at http://www.Enagás.es/Enagás/es/Transporte_de_Gas/CapacidadesTransporte/CapacidadDeInstalaciones
[392] MNETUR (2008) "Planificación de los sectores de electricidad y gas 2008-2016", p. 446.

Musel LNG plant has been mothballed and LNG facilities on the Canary Islands have suffered a delay).

Available information on capital and operational costs of storage facilities

Regarding underground storage, operational cost estimations are available for two facilities (Gaviota and Serrablo).

Table A.12.4. Forecasted Operational Costs for Storage Facilities

	Forecasted Stored gas in 2015 (MWh)	O&M provisional forecast (Euros)	O&M forecast (Euros c/kWh)
Serrablo	9,730,000.0	7,772,345.3	7.98802
Gaviota	18,340,000.0	17,698,735.3	9.65035
Source: MINETUR[393]			

Regarding capital costs, the unique estimation available was implemented by the Ministry of Industry in 2006.

In their estimation they distinguish between capital costs for the facility and capital costs for cushion gas.

However, this last part should be taken cautiously, since estimations for cushion gas relied largely on gas prices at that time (2006).

Table A.12.5. Forecasted Capital Costs for Storage Facilities

Facility/Concept		**Estimated cost (€)**
Serrablo		
	Cushion Gas	23,776,376
	Facilities	59,344,239
Gaviota		
	Cushion Gas	106,676,673
	Facilities	84,165,513
Source:MINETUR[394]		

[393] Order IET/2445/2014, 19th December 2014. Annex II, point 4. Ref : BOE-A-2014-13476 and DGPEM Resolution 19 January 2015, setting assigned and available capacity on UGS facilities for 01/04/2015-31/03/2016.
[394] Order ITC/3995/2006, 29th December 2006, Annex III. Ref: BOE-A-2006-22967.

ANNEX 13. CASE STUDY: UNITED KINGDOM

A.13.1 Main storage related SoS measures of the country

Regulatory measures in the UK regarding Security of Supply (SoS) do not include storage-related indications.

- On one side, they largely rely on their import infrastructure plus national production (with capacity enough to cover twice its current peak demand). Storage is an important but relatively small part of the overall supply mix.
- On the other, they prefer the use of market-based mechanisms as the Cash-Out procedures explained below. Both Ofgem and the Government agree that efficient price signals are necessary to enhance SoS[395].

A.13.2 Any other existing storage related measures

A.13.2.1. Obligation to provide transmission support gas

Shippers booking the LNG constrained storage facility located in Avonmouth undertake an obligation to provide transmission support gas to National Grid in cases of very high demand. In exchange, suppliers receive a credit in respect of minimum booked storage deliverability. Such credit is then deducted from the charge for storage services. However, current credit, until the end of winter 2014/2015 (31st April 2015), is equal to zero[396] and the facility is programmed to be phased out by 30 April 2016.

A.13.2.2 Special tariffs for transmission to/from storage sites

A variable charge, called NTS commodity charges, is payable for exit and entry of gas to the system. However, these commodity charges on gas flows at NTS Storage facilities are zero (other than on the amount of gas utilised as part of the operation of any NTS Storage facility, known as storage "own use" gas)[397].

A.13.2.3 Incentives for storage investment and storage accumulation

Recently, the Government (by means of DECC)[398] declined the introduction of further support schemes to incentivize investment on storage facilities. Main reasons are stated below:

- UK gas supply is resilient with supplies outstripping demand
- Government and Ofgem are already taking action to boost resilience
- Study finds no case for Government to subsidise investment in new storage[399].

As stated above, cash-out prices are the only incentives for investment in storage that gas shippers receive.

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[395] Ofgem (2014), Gas Security of Supply Significant Code Review: Final Policy Decision, p.2.
[396] National Grid (2014), The Statement of Gas Transmission Transportation Charges, p. 11.
[397] National Grid (2014), The Statement of Gas Transmission Transportation Charges, p. 17.
[398] Department of Energy and Climate Change.
[399] DECC (2013) « Fallon: no new subsidy needed for gas storage - decision saves bill payers up to £750 million », Press Note, issued on 4th September 2013.

Recently, DECC announced that no subsidies would be provided for new gas storage, what has led to a number of projects being put on hold indefinitely or cancelled.

According to NGG development plan, there are projects for a total capacity of 7 Bcm. However, in the last ten years, despite numerous proposals, only 1 Bcm was added to total storage capacity, to reach a level of around 4.6 Bcm[400].

Ofgem maintains this skeptical view: on the report by Pöyry (January 2014)[401], natural gas storage capacity amounts to slightly more than 5 Bcm by 2020 and remains on a similar level in 2030. Hence, according to the views approved by the regulator, storage capacity is not likely to increase significantly during the following fifteen years.

A.13.2.4 Information on long term allocation of storage capacity

Regarding Rough's UGS (the unique long-term gas storage facility in the UK), for gas year 2014/2015, 30,300 GWh were sold as part of the SBUs, which cover one year and are sold on a FCFS basis every year (prices are agreed bilaterally, using NBP price spread between summer and winter as the reference price for bids). Additional 1,530 GWh were sold as additional capacity (tendered). These two quantities represent the minimum quantities that shall be annually offered by SCL, who actually increased sales up to 41,000 GWh of capacity last year, using a mix of bundled and unbundled products, with duration from 1 year to multiple years or just a part of the storage year.

Regarding Hornsea facility, operated SSEHL, SBUs are currently sold for a minimum period of one storage year[402], by means of annual auction processes, to all those who signed the Storage Service Contract (SSC). Non employed capacity is then also offered to those who signed SSC on a interruptible basis (irrespective of whether they were able to secure capacity by means of SBUs or not).

A.13.3 Other SoS information

A.13.3.1 UK security of supply measures

The UK became a net importer of natural gas in 2004, moving from a situation in which total supply was covered by national production coming from the United Kingdom's Continental Shelf (UKCS), to a situation in which imports represent currently more than half of total supply, made possible by a fivefold increase of import capacity[403].

SoS related measures have focused on creating market-based mechanisms to provide market participants with the right incentives to increase importing infrastructure and to deliver the required levels of flexibility. In this sense, during the past four years a Gas Security of Supply Significant Code Review has taken place, with the aims to review current cash-out agreements and to include demand-side mechanisms to respond to potential gas deficits on the grid.

To illustrate the first point above, see the table below that shows winter gas supply by source of origin for 2014/15.

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[400] National Grid (2013), 2013 Gas Ten Year Statement, p. 140.
[401] Pöyry (2014), Gas SCR- Cost Benefit Analysis for a demand-side response mechanism, p.15.
[402] SSEHL, Application for an Exemption under Section 8S of the Gas Act 1986
[403] DECC (2014), UKCS Oil and Gas Production Projections, p.4.

However, the British natural gas market has, so far, never experienced a gas deficit emergency and the probability of it remains low[404].

There are three different types of gas storage[405]:

- Long range (LRS): only one facility (Rough, operated by Centrica). Usually stores gas during the summer and pours it to the system during winter time.
- Medium range (MRS): these commercially operated sites have shorter injection/withdrawal times. Hence, they are mostly used for balancing the grid when required.
- Short range (SRS): only one site, located at Avonmouth near Bristol. It contains LNG that has been condensed from the grid (not delivered by ship). If needed, is then re-vaporised and injected to the network. It can respond quickly to changes in demand but has limited storage capacity. However, National Grid intends to shut down this facility by 30 April 2016.

Table 3.11.1. Winter Consumption by Source of Origin 2011-2015						
	2011/12		2012/13		2014/15	
	Bcm	%	Bcm	%	Bcm	%
UKCS	21	39	16	30	17	37
Norway	16	31	18	34	17	37
Continent	4	8	9	17	6	13
LNG	8	15	4	8		7
Storage	3	6	6	11	3	7
Total	53	53			46	
Source: National Grid[406]						

If full, it takes more than three months to deplete Rough storage site (since gas can only be withdrawn at a certain rate). Regarding MRS sites, they have a variable injection/withdrawal scheme which allows them to deliver gas to the system one morning and refill that afternoon. Operation of MRS sites relies on price/demand conditions.

Based on assessments of current storage sites, deliverability for 2014/15 winter is approximately 129

Mcm/d (1,420 GWh/d). The table below shows storage capacity and deliverability levels assumed for winter 2014/15.

Table A.13.2. Forecasted Capacity and Deliverability of Storage Facilities					
	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (Mcm/d)	Duration (days)
Short (SRS)	677	3	143	13	5
Medium (MRS)	12,572	709	824	75	15
Long (Rough)	40,700	420	455	41	89
Total	53,949	1,132	1,422	129	
Source: National Grid[407]					

[404] Ofgem (2014), Gas Security of Supply Significant Code Review: Final Policy Decisions, p.5.
[405] Definitions given by National Grid gas at their website.
[406] National Grid (2014), Winter Consultation Report 2014/15, Table g1.
[407] National Grid (2014), Winter Outlook Report 2014/15, p. 26. National Grid (2014), Winter Outlook Report 2014/15, p. 26.

A.13.3.2 Agreements for cross-border storage utilization (by/for other countries)

Currently, there are no agreements for cross border utilization of storage capacity, nor there is any restriction to their development.

A.13.4 The evolution of the measures in the last (10) years

In 2009, Gas Balancing Alerts were replaced by Gas Deficit Emergencies while the level of the security monitor stopped being facility-type specific to become an aggregate goal.

A Gas Security of Supply Significant Code Review started in 2011[408] in order to re-arrange Cash-out proceedings with the aim to give gas suppliers the correct incentives for investments in SoS-related infrastructures.

Main changes consisted in:

- eliminating the size-priority order of disconnection in case of firm load-shedding (which proved inefficient)
- including the possibility of gradual disconnection (instead of binary on/off mode)[409]
- dynamic prices in case of emergency (instead of freezing prices at the beginning of the emergency).

Ofgem has emphasized that the Gas SCR is intended to provide incentives for shippers to secure supply, but it is suppliers who must determine how to mitigate the risks they face to cause a GDE. The following list present the main measures proposed by Ofgem:

- Negotiating for commercial interruption
- Diversifying supplies
- Holding more storage capacity or altering the usage of existing capacity
- Investing in new infrastructure[410].

Such mechanism has already been approved and will be in force by winter 2015/16.

At the same time, a Demand Side Response (DSR) mechanism is to be developed by NGG (forced by

Ofgem's decision). It should be approved by Ofgem this year and be in force by winter 2016/17.

A.13.5 The possible evolution of the measures

Currently, NGG is developing a methodology to implement a Demand Side Response (DSR) mechanism which should be effective by Winter 2016/17. In the studies implemented by Ofgem, the main discussion focused on the following three topics:

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[408] A complete chronology of the SCR can be found at Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p. 9.
[409] Ofgem (2014), Gas Security of Supply Significant Code Review Conclusions, p. 32.
[410] Ofgem (2014), Gas Security of Supply Significant Code Review Conclusions, p. 24.

- whether a market based or a centralized mechanism should be imposed
- whether gas-fired generators should be included or excluded from an eventual DSR mechanism
- whether additional measures should be imposed to guarantee Security of Supply.

The second question remains unsolved, while initial mechanism will be centralized and ruled by NGG (see the Demand Side Response section below) and further measures have been disregarded.

A.13.5.1 N-1 rule

Every year, NGG elaborates a winter outlook (November 1st to March 31st) in which a security supply level is computed. According to this year's set of forecast for the winter outlook, there is a positive gas security of supply position, with gas supplies, storage and network capacity well in excess of maximum expected demand.

The following table shows peak demand considerations included by NGG in its Winter Outlook for 2014/15 (according to EU Regulation 994/2010/EC).

Table A.13.3. Assumed flow in N-1 Computation		
Situation	Concept	Flow (Mcm/d)
All	Non-Storage Supply Capacity	488
Cold Day Demand	Cold Day Storage Deliverability	129
	Cold Day Demand	400
	Surplus	217
1 in 20 Demand	1 in 20 Storage Deliverability	129
	1 in 20 Peak Gas Demand Forecast	499
	Surplus	118
Source: National Grid Gas[411]		

Demand for winter 2014/15 is expected to be similar to last year, at 47.5 Bcm (October - March). Average cold day demand is forecasted at 400 Mcm/d with an exceptionally cold (1 in 20 years) peak demand forecasted at 499 Mcm/d.

The maximum potential non-storage supply (NSS) is 488 Mcm/d which when combined with current storage deliverability of 129 Mcm/d gives a maximum supply potential of 617 Mcm/d, significantly higher than the forecast peak day and 1 in 20 years demand[412].

A.13.5.2 Potential Disruption due to Russia/Ukraine Dispute

NGG has envisaged an additional supply disruption concerning Russian supplies (due to tensions with Ukraine). Two Scenarios have been considered:

- Pipelines crossing Ukraine stop receiving gas

[411] National Grid (2014), Winter Outlook Report 2014/15, p.7.
[412] National Grid (2014), Winter Outlook Report 2014/15, p.4.

- All pipelines coming from Russia stop delivering gas (Nord Stream and Yamal included)[413].

Both these cases were tested against average winter and very cold conditions. Under average winter conditions, both low and high levels of disruptions can be met as normal, with most of replacement gas coming from LNG imports. Only in case total disruption and cold winter conditions were in place would disruption from Russia require further market actions, which would be: reduced exports to the continent combined with maximized LNG imports and/or demand side reduction[414].

A.13.5.3 Definition of supply standards for protected customers pursuant to Art. 8 of Regulation 994/2010/EC

In order to assess security of the system, NGG included the following weather conditions into the analysis, both for normal supply conditions and in case of a supply disruption. These extreme weather conditions represent 1-in-50 demand conditions over four different time periods:

- the peak day (average -5°C)
- the coldest week (average -3°C)
- the coldest month (average -1°C); and
- the coldest three months (average 1.5°C).

Supply disruptions are represented by the failure of the pipeline between Milford Haven and Felindre, the biggest single piece of gas supply infrastructure. Such disruption would result in a supply loss of 86 Mcm/d and the test is consistent with the N-1 rule introduced by the EU.

Demand is split into the following three categories:

- Light Green: 'Protected demand'. All customers protected by National Grid's Safety Monitor
- Dark Green: 'Other large loads'. Large loads that are not expected to respond to a short-term increase in gas price
- Orange: 'Large loads DSR'. Large loads that are expected to respond to a short-term increase in the gas price and therefore provide a demand side response (DSR).

Under protected demand, NGG includes all non-daily metered loads up to 5,860 MWh/year (including all residential and small business consumers), non daily metered flows to Ireland and priority load. Priority load is then divided into three categories:

- Category A, which includes cases in which disruption could lead to loss of life (e.g. medical services)
- Category B, which includes agents in Category A who signed interruptible contracts (because they have access to alternative generation)
- Category C, customers for which disruption would lead to losses in excess of 50 £ million.

In case no disruption appears, there is no need to increase Non Storage Supplies (NSS) for both the peak day and for a cold week. For the longer duration cold spells additional NSS would be required to meet demand.

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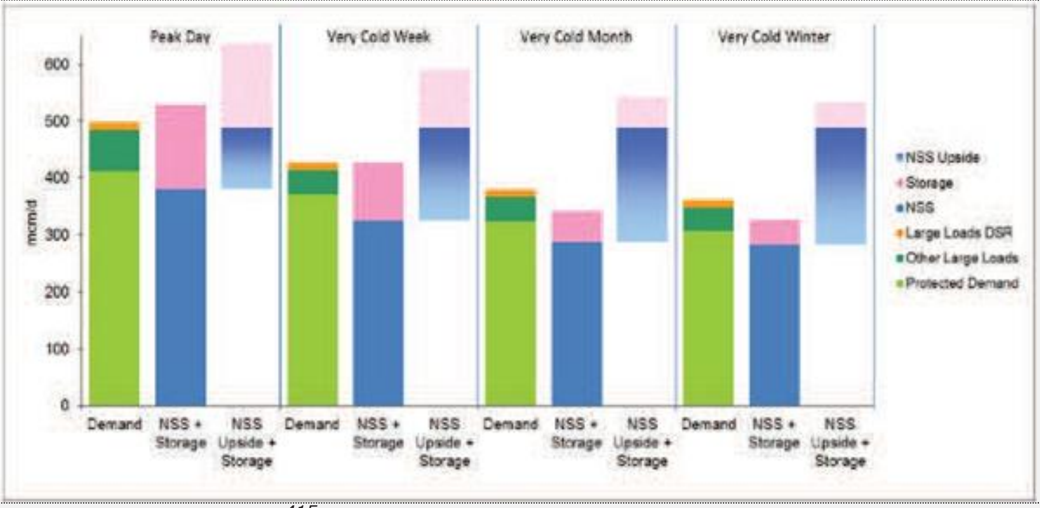
[413] National Grid (2014), Winter Outlook Report 2014/15, p. 28-31.
[414] National Grid (2014), Winter Outlook Report 2014/15, p. 5.

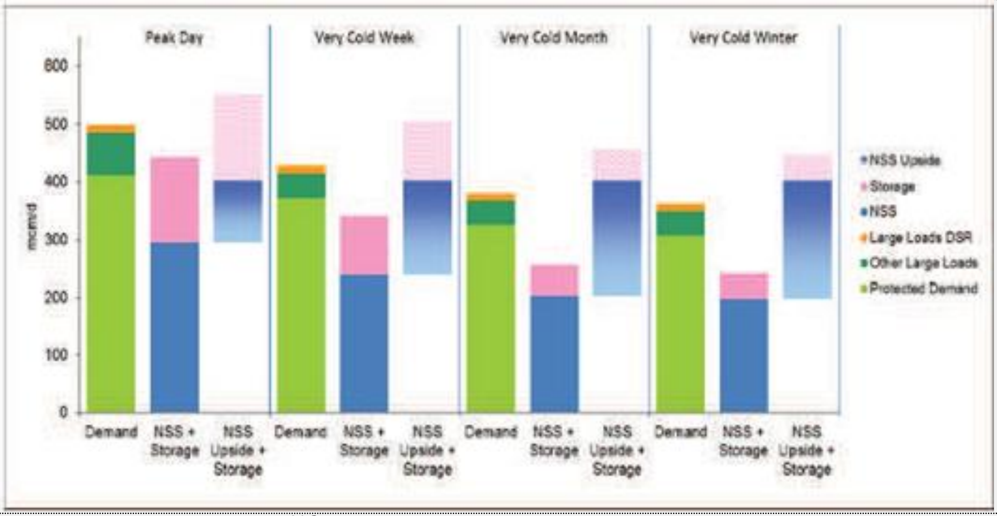
Figure A.13.1. Supply in Peak Conditions by Source of Origin



Source: National Grid[415]

In case of supply disruptions, for all the situations considered, some additional Non Storage Supply would be required to meet demand, but NGG considers that there are sufficient potential supplies available to cover the gap.

Figure A.13.2. Supply in Peak Conditions with Supply Disruption



Source: National Grid[416]

Given that the British market presents a wide range of supplying sources, main concerns in the NTS are related to daily operation of the network.

[415] National Grid (2014), Winter Outlook Report 2014/15, p. 38.
[416] National Grid (2014), Winter Outlook Report 2014/15, p. 39.

A.13.6 Operational safety

NGG has three different tools to ensure operational safety of the NTS: one related to maintaining pressure (the Safety Monitor), and two related to system balancing (the Margins Notice and the Gas Deficit Warning).

The Safety Monitor tries to ensure that there are sufficient gas volumes kept in storage facilities to support those consumers whose premises cannot be physically disconnected (isolated) from the NTS within a reasonable time period (see previous section). Hence, its main goal is to ensure safe operation of the gas transmission system. Current level, since 2009, is computed on an aggregated level.

According to NGG, safety monitor levels for winter 2014/15 amount to 958 GWh[417].

NGG acts as the residual balancer of the system: if suppliers are not balanced, NGG will carry out balancing trades if there is a risk for system balance at the end of the day. Such actions, as historical data suggest, are required approximately on 1 day in 3[418].

If imbalances become important, NGG can issue a Margins Notice or a Gas Deficit Warning to inform the market of its needs for balancing gas. Market participants will then take the required steps (there is no formal obligation, but un-balanced shippers will be subject to cash-out prices as a penalty). A brief description of both tools can be found below:

- Margins Notice: if forecasted demand exceeds forecasted National Transmission System supply capability (not in terms of capacity, but of actual flows), this tool provides the industry with a day-ahead notification of the deficit
- Gas Deficit Warning: NGG can issue a warning if it perceives a significant risk of not achieving a balanced position by the end of the day. It can be issued day-ahead or during the same gas day[419].

The system faces an increasing need for *linepack*[420] flexibility, with frequent changes to operational and compressor strategies in order to maintain adequate levels of pressure in the system, plus a need for frequent and rapid storage site transitions between injection and withdrawal. Hence, NGG is currently undertaking a project to appraise future flexibility requirements of the system[421].

A.13.7 Cash out arrangements

NGG has been involved since 2011 in the reform of the Cash out arrangements, the market based mechanism that tried to offer shippers the right incentives to avoid disruptions of supply. The goals of the Security of Supply Significant Code Review (SCR) are to:

- Minimise risk and severity of a Gas Deficit Emergency (GDE)
- Ensure that the market provides incentives for shippers to maintain Security of Supply (SoS)

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[417] National Grid (2014), Winter Outlook Report 2014/15, p. 40.
[418] National Grid (2014), Winter Outlook Report 2014/15, p.33.
[419] National Grid (2014), Winter Outlook Report 2014/15, p.34.
[420] The volume of gas within the National Transmission System (NTS) pipelines at any time. Definition obtained from National Grid's Winter Outlook Report Glossary.
[421] National Grid (2014), Winter Outlook Report 2014/15, p.24.

- Compensate end customers in case disconnection of loads in required[422].

NGG is responsible for residual balancing of the NTS. If, by the end of the day, the system faces an imbalance risk, NGG enters into contracts with suppliers to balance the system and the prices it pays are then transferred to long and short shippers (those who created the imbalance). Long shippers are paid for their positive imbalance while short shippers pay a different rate for their negative imbalance. Those payments are known as cash-out prices[423].

The reform seeks to transfer risk from customers to suppliers and also to improve the efficiency of price signals. It is based on the following four points:

- Dynamic cash-out prices during a GDE, with no cap on prices
- Incorporate the cost of supply interruption to customers, which will be considered as balancing actions and will be priced at:
  - For NDM consumers: VoLL or £14/therm (about 65 €c/kWh) on the first day that they are subject to network isolation, with no further payment (Ofgem's estimate of the costs of this interruption)[424]
  - For DM consumers: 30-day System Average Price (SAP) for each day that they are subject to firm-load shedding.
- Use the funds recovered from cash-out charges to make payments to consumers for the involuntary balancing service they provide when disconnected during a GDE[425].

A.13.7.1 Any available information on valuation of lost load (lost supplies)

To ensure that involuntarily interrupting consumers is incorporated into cash-out prices, the Valuation of Lost Load (VoLL) will be used. This is the theoretical price at which a consumer would rather have their gas supply disconnected than continue to pay for a firm supply[426].

The approach has been different for NDM and DM customers since having a daily-read meter allows for direct engagement with the gas wholesale market by means of indexed prices or commercial interruption contracts. Hence, market prices are used to value interruption costs for large I&C customers.

For Domestics customers, the cost was obtained from a study from London Economics[427], that allocated a cost of 30 £/day for interruption for domestic customers. Such figure was then divided by the average winter domestic consumption (2.2 Therms/day) to reach a final value of 14 £/therm[428].

Regarding the payment limitation to the first day of network isolation, Ofgem believes that VoLL for NDM consumers should not reflect the full cost of network isolation since duration of interruptions is not within control of suppliers: isolated consumers need to be visited by an engineer from the Distribution Network Operator (DNO) in order to be safely reconnected to the grid (which could take weeks). Hence, the pricing-in of NDM VoLL was limited to the first day in which isolation was initiated[429].

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[422] National Grid (2014), 0504 -Development of a Demand Side Response Methodology, PPT, sl.4.
[423] Ofgem (2014), Gas Security of Supply Significant Code Review Conclusions, p. 47.
[424] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.18.
[425] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.5.
[426] Ofgem (2014), Gas Security of Supply Significant Code Review : Final Policy Decisions, p.54.
[427] London Economics (2011), Estimating Value of Lost Load (VoLL) , Final Report to Ofgem..
[428] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.16.
[429] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.17.

Moreover, the volumes associated with NDM consumer interruptions will be included into shippers' imbalance. Specifically, this measure ensures that costs of a GDE will fall more directly on the shippers that caused it (those who were short)[430].

A.13.8 Demand side response

Ofgem instructed NGG to develop a Demand Side Response (DSR) mechanism to be applied in winter 2016/17. Its main mandatory features can be consulted on conditions 8I.4 (a-h) of the transporter licence[431]. They focus on not foreclosing the development of a commercial market for DSR.

The main target for the commercial DSR mechanism are DM customers, since their size and daily- read meters make it easier to assess the cost of interruption. After consultations with industry stakeholders, the preferred option was to set up a centralized mechanism, given the potential lack of trust between shippers and customers that could prevent the creation of commercial DSR contracts[432].

NGG shall present the methodology for its approval before 1st March 2015[433].

The methodology shall be guided by the following principles (included in the licence modification under section 8I.4)[434]:

- 8I.4 (a) Shippers will submit offers on behalf of consumers
- 8I.4 (b) The methodology will specify which end consumers are eligible to participate
- 8I.4 (c) The mechanism is intended to avert an emergency. Hence, a GDW (gas deficit warning) will be the trigger point
- 8I.4 (d) Exercised DSR bids should be factored into the cash-out price and if it is the highest balancing action it should set the short cash-out price
- 8I.4 (e) The mechanism should widen the range of consumers that currently access the market
- 8I.4 (f) The DSR mechanism must not foreclose the market for commercial interruption products, or penalise self-interruption by consumers
- 8I.4 (g) The DSR mechanism should be designed to ensure no harm to operation of normal traded markets (effects over power market included)
- 8I.4 (h) NGG must procure DSR in an economic and efficient manner.

A.13.8.1 Quantitative estimate of domestic production

Last estimations available for natural gas production coming from the UKCS show a stable path for the future, around 34 Bcm/year. In all cases, the figure represents the central scenario for production, while the low and high scenarios cover the range between 25 and 40 Bcm for all the years considered. As for 2014, actual production numbers are still not available (in 2013, production reached 34.2).

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[430] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.19.
[431] Special Condition 8I: Development and implementation of a Demand Side Response methodology for use after a Gas Deficit Warning.
[432] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.30.
[433] Ofgem (2014), Modification of the Gas Transport Licence held by National Grid Gas, p. 3.
[434] Ofgem (2014), Gas Security of Supply Significant Code Review : Conclusions, p.31.

Table A.13.4. UKCS Aggregated Forecasted Production	
Year	**Production (Bcm)**
2014	34.2
2015	34.1
2016	34.1
2017	34.1
2018	34.1
2019	32.4
Source: DECC[435]	

The following table shows national production forecasts for winter 2014/15 (all coming from UKCS). National Grid foresees a provisional UKCS maximum supply forecast of 109 Mcm/d for this winter (marginally below the equivalent forecast for winter 2013/14).

Table A.13.5 UKCS Individual Forecasted Production	
Facility	**2014/15 Forecast (Mcm/d)**
Bacton	27
Barrow	9
Burton Point	1
Easington	9
St. Fergus	37
Teeside	15
Theddlethorpe	11
TOTAL	109
Source: National Grid [436]	

Although during winter 2014/15 some new fields are forecasted to come on-stream (like the West of Shetland fields), its contribution won't be able to offset the decline in existing fields at Bacton and Burton Point.

A.13.8.2 Quantitative estimate of import capacity

The UK is served through a diverse set of import routes from Norway, The Netherlands and Belgium, in case of piped gas, and several different international sources through 4 LNG importation terminals.

Currently, no new importation project is under construction. Total import capacity amounts to 156 Bcm/y, divided into the following three sources:

- the Continent (44.5 Bcm/y)
- Norway (56.6 Bcm/y); and
- LNG (53.1 Bcm/y)[437].

[435] DECC (2014), Oil and Gas Production Projections, p. 2-3.
[436] National Grid (2014), Winter Outlook Report 2014/15, p. 23.
[437] National Grid (2013), 2013 Gas Ten Year Statement, p. 138.

A.13.8.3 Quantitative estimate of LNG import capacity

Table A.13.6 UK LNG Infrastructure			
Name	**Developper/ Operator**	**Location**	**Capacity**
Isle of Grain	National Grid	Kent	20.4
Gasport	Excelerate Energy	Teeside	4.1
South Hook 1-2	Qatar Petroleum and ExxonMobile	Milford Haven	21
Dragon 1	BG Group/ Petronas	Milford Haven	7.6
TOTAL			53.1
Source: National Grid[438]			

According to NGG's views, for this winter, flows could range between 8 and 130 Mcm/d (the former is near the minimum boil-off level of plants). A concern was raised regarding the capacity of the British market to attract additional LNG imports given higher demand and increased prices on Asian markets[439].

A.13.8.4 Quantitative estimate of pipeline import capacity

Pipelines from Norway: Norwegian imports to GB flow through two dedicated import pipelines, Langeled to Easington and Vesterled to St Fergus and two additional offshore connections, Gjøa and the Tampen Link, both linked to the UKCS FLAGS pipeline to St Fergus.

Pipelines from the Continent: the UK is connected to Belgium and The Netherlands by means of two separate pipelines, called the Interconnector (IUK) and the Balgzand-Bacton Line (BBL).

The following table shows actual pipeline import capacities for the UK.

Table A.13.7 UK Pipeline Infrastructure			
Name	**Developer/Operator**	**Location**	**Capacity (Bcm/y)**
Interconnector	**IUK**	**Bacton**	**26.9**
BBL Pipeline	BBL Company	Bacton	17.6
Langeled	Gassco	Easington	26.3
Vesterled	Gassco	St. Fergus	14.2
Tampen	Gassco	St. Fergus	9.8
Gjøa	Gassco	St. Fergus	6.2
		TOTAL	101.0
Note: IUK and BBL values were adjusted for UK standard conditions (original values are 25.5 and 20.6 Bcm/y at normal conditions)			
Source: National Grid[440]			

Pipeline Import Forecasts for winter 2014/15.

- According to NGG, flows from Norwegian Exports are forecasted to be 95 Mcm/day on its central scenario (could range between 82 and 115 Mcm/d

[438] National Grid (2013), 2013 Gas Ten Year Statement, p. 138.
[439] National Grid (2014), Winter Outlook Report 2014/15, p. 25.
[440] National Grid (2013), 2013 Gas Ten Year Statement, p. 138.

depending on the flow directed to the Continent). On a especially cold day, NGG forecasts a flow of 110 Mcm/d[441].

- Interconnection flows from Continental Europe[442];
  - Pipeline BBL is forecasted to work at 40 Mcm/d
  - Flows for IUK are forecasted at 45 Mcm/d.

A.13.8.5 Estimated demand response

Current interruptible consumption (or DSR) was estimated by NGG as 13 Mcm/d. Most of it (10 Mcm/d) is provided by gas-fired power generators. They also consider a potential upside in case other technologies for power generation present higher availability rates: 4.5 additional Mcm/d for each additional GW available of non-gas fired capacity[443].

Regarding future potential interruptible consumption, Pöyry, who was required by Ofgem to perform a cost-benefit analysis (CBA) on the relative merits of a demand-side response mechanism, assessed the volumes of Industrial and Commercial customers that could be eligible for DSR mechanisms. On its appraisal, DSR quantities amounted to 2.94 million therms/day that stands for 22.5% of total daily consumption)[444].

A.13.8.6 Estimated fuel switching

Pöyry estimated total volumes for Industrial and Commercial customers of gas consumption backed- up by distillates (i.e. alternative fuels) to be 1.158 million therms/day[445]. Such figure can be expressed as Mcm/day using the average Calorific Value for the NTS:[446] 3.31 Mcm/day.

Costs of fuel switching for I&C customers have been appraised by Pöyry at 160 p/therm for 2016 (costs vary in terms of fuel and carbon costs)[447].

Regarding CCGTs, the total capacity of distillate back-up amounts to 10 Mcm/d according to Pöyry. Another 5 Mcm/d of capacity have been mothballed, but are not expected to be re-commissioned[448].

The costs of fuel switching for CCGTs has been estimated by Pöyry at 148p/therm. In other costs (such as carbon costs, reduced efficiency or shut down time before running o distillate), according to Pöyry's view it would only be worth switching when the gas price is in excess of approximately 190p/therm in 2016 [449].

A.13.9 Available cost estimations of the measures above

Ofgem instructed Pöyry to conduct a cost-benefit analysis of two of the options initially proposed by Ofgem [450] plus an alternative method proposed by NGG. This last method

[441] 225 National Grid (2014), Winter Outlook Report 2014/15, p. 24.
[442] Ibíd.
[443] National Grid (2014), Winter Outlook Report 2014/15, paragraph 112.
[444] Pöyry (2014), Gas SCR – Cost-Benefit Analysis for a demand side response mechanism, p.97.
[445] Pöyry (2014), Gas SCR – Cost-Benefit Analysis for a demand side response mechanism, p.37, Table 11.
[446] 36.9 MJ/m3, as used in National Grid 2013 Ten Year Gas Statement, and the conversion factor provided by IEA of 1 therm=105.505585 MJ.
[447] Pöyry (2014), Gas SCR – Cost-Benefit Analysis for a demand side response mechanism, p.39.
[448] Pöyry (2014), Gas SCR – Cost-Benefit Analysis for a demand side response mechanism, p.43.
[449] Pöyry (2014), Gas SCR – Cost-Benefit Analysis for a demand side response mechanism, p.46.
[450] Ofgem (2013), Gas Security of Supply Significant Code Review: Demand-Side Response Tender Consultation, p. 31.

was the option finally preferred by Ofgem (centralized DSR mechanism, explained in the sections above).

The two additional mechanisms are based on SO-run tenders for annual disconnection products. Tenders are run by NGG and shippers bid the price at which they accept disconnecting their own customers in case of a GDE. If accepted, those prices will be incorporated into Cash-out prices. Shippers who do not participate remain in the firm load-shedding (i.e. they won't receive any payment but will be subject to compensating the disconnected consumers they represent). In both cases, bids are ordered by prices and a volume cap (set by NGG) is established[451].

Differences between options:

- Strawman 2: pay-as-cleared method; exercise fee only.
- Strawman 3: pas-as-bid method; both exercise and fixed option fees. Fixed-option fees are payments made on a regular basis to the bidder for the right to call on them to provide DSR.

For each of them, two scenarios have been analyzed: Gone Green and High Demand, both of them included by NGG on its 2012 Gas Ten Year Statement[452].

- Slow Progression – deployment on low carbon energy is slow and the renewable energy target for 2020 is not met. The carbon reduction target is met but not the indicative target for 2030. There is an overall increase on gas demand
- Gone Green – all renewable and emission targets for 2020 and 2030 are met. Demand reduces due to energy efficiency improvements while medium prices foster some reduction on industry consumption.

The High Demand scenario corresponds to the Slow Progression scenario.

The following table shows Pöyry's assessment for the Net Present Value of each of the options considered in the analysis (figures represent £ millions until 2030)[453]:

Table A.13.8 NPV Estimation for each proposed reform

Policy Scenario	Current	Cash out reform	Cash out ref.+NGG platform	Cash out ref.+ Strawman 2 (exercise only)		Cash out ref.+Strawman 3 (inc option fees)	
Gas-fired power station eligibility	N/A	N/A	N/A*	Inc.	Exc.	Inc.	Exc.
Gone Green	0.0	0.0	-34.3	- 41.0	- 41.0	- 91.3	- 162.3
High Demand	0.0	2.7	37.5	30.8	20.5	- 35.5	- 89.3

*N/A for modelling purposes only

Source: Ofgem[454]

Figures are only positive in case gas demand is high, given that, with low demand figures, GDE are even more unlikely to occur and any money spent on preventing them will be a cost for the system.

[451] Ofgem (2013), Gas Security of Supply Significant Code Review: Demand-Side Response Tender Consultation, p. 33-36.
[452] National Grid (2012), 2012 Gas Ten Year Statement, p. 17.
[453] GB Pounds Sterling in 2012 real prices.
[454] Ofgem (2014), Gas Security of Supply Significant Code Review: Conclusions, p.34.

The analysis from Pöyry supports the idea of Ofgem that a commercial DSR mechanism is preferred to a centralised, SO-run mechanism (whose costs can be high).

ANNEX 14 - ASSUMPTIONS ON GAS PRICING

We model a European gas system including the following nodes.

Table A.14.1 List of Nodes and corresponding extra-EU sources of gas supply

	Supplier1	Supplier2	Supplier3	Supplier4	Supplier5	Supplier6	Supplier7
AT							
BE	**NO**	**LNG**					
BG	**LNGGT**	**TRGR**					
CH							
CZ							
DEg	**RU**	**NO**	**RUYam**				
DEn	**NO**						
DK							
ES	**LGN**	**DZ**					
FRn	**LNG**	**NO**					
FRs	**LNG**						
HU	**RU**						
IT	**DZ**	**LY**	**LNG**				
NL	**NO**	**LNG**					
PL	**RU**	**RUYam**	**LNG**				
PT	**LNG**						
RO	**RU**	**RUTRA**					
SK	**RU**						
UK	**NO**	**LNGUK**					

Legend

- TRGR supply from Turkey via Greece
- RUTRA Supply from Russia via Trans Balkan Pipeline
- RUYam Supply from Russia via Yamal
- NO supply from Norway
- DZ supply from Algeria
- LY supply from Lybia
- RU supply from Russia
- LNGGR LNG regasified in Greece
- LNG LNG domestically regasified

We model the following extra-EU sources of gas supply.

Table A.14.2 List of extra-EU supply sources, assumed max import capacity and pricing rule, by import point

	Max. capacity in the model (GWh/d)	Max capacity in ENTSOG stress test worst scenario	Our Assumption (if different from ENTSOG worst scenario)	Pricing rule (€/MWh)
DZ	817	817	-	
to ES	481	481	-	Algeria - 5.8
to IT	336	336	-	Algeria
LY	181	181	-	
to IT	181	181	-	Algeria
NO	3 615	3 615	-	
to UK	1 398	1 398	-	TTF
to FR North	570	570	-	80%(TTF+0.4) + 20% (Norwey-1.6)
to BE	464	464	-	80%(TTF) + 20% (Norwey-1.4)
to NL	335	335	-	TTF
to DE NCG	552	552	-	80%(TTF+0.2) + 20% (Norwey -3.2)
to DE Gaspool	761	761	-	80%(TTF+0.2) + 20% (Norwey -3.2)
RU	4 457	4 457	-	
to EE	not modelled	18	-	not modelled
to FI	not modelled	131	-	not modelled
to LV	not modelled	80	-	not modelled
to LT	not modelled	118	-	not modelled
to DE Gaspool	1 421	1 421	-	80%(TTF+0.2) + 20% (Russia+1.7)
to PL	312	312	-	50% (TTF+1.3) + 50% (Russia -2.5)
to PL via Yamal	410	410	-	50% (TTF+1.3) + 50% (Russia -2.5)
to HU	311	311	-	50% (TTF+1.3) + 50% (Russia -2.5)
to RO	137	137	-	Russia
to RO via Trans Balkan Pipeline	385	385	-	Russia
to SK	1 134	1 134	-	50% (TTF+1.3) + 50% (Russia -2.5)
LNG	3 700	3 700	-	
to BE	369	369	-	TTF+ spread
to ES	1 029	1 029	-	Oil indexed formula
to FR North	296	296	-	TTF+ spread
to FR South	328	328	-	Oil indexed formula
to BG via GR	11	135	11	Oil indexed formula
to IT	473	473	-	Oil indexed formula
to LT	not modelled	47	-	not modelled
to NL	137	137	-	TTF+ spread
to PL	-	-	-	Oil indexed formula
to PT	139	139	-	Oil indexed formula
to UK	1 131	1 131	-	TTF+ spread
TR	61	61	-	
to BG via GR	11	61	11	Russia

Legend

- Algeria estimate for an oil-linked formula for gas imported from Algeria
- Norwey estimate for an oil-linked formula for gas imported from Norwey
- Russia estimate for an oil-linked formula for gas imported from Russia
- Spread estimate for a spot LNG price differential depending on LNG transportation costs
- TTF estimate for hub price in North West Continental Europe
- Oil indexed formula estimate for an oil-linked formula adopted for the pricing of LNG long term deliveries in Southern Europe

Assumption for Russian supply to Hungary, Poland, Slovakia

According to International Gas Union (2014)[455] in Central Europe (Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland) hub indexation has increased from almost zero in 2005 to over 50% in 2013. Our estimate for the oil indexed component is based on our estimate of Russian gas price to Italy minus the observed difference between the price of Russian gas to Italy according to WGI in 2014 and the average price for imported gas to Hungary, Czech Rep. and Slovakia in 2014 according to COMEX database. Our estimated for the hub component is the TTF plus the observed average difference between TTF day ahead price and CEGH day ahead price in 2014.

Assumption for Russian supply to Germany

According to IGU (2014) Northwest Europe (Belgium, Denmark, France, Germany, Ireland, Netherlands, UK) the ratio in price formation mechanisms in 2013 was 20% oil indexation and 80% hub indexation. Oil indexed component is the formula estimate for deliveries from Russia to Italy plus the average difference between Russian gas price to Germany minus Russian gas price to Italy in 2014 according to WGI.

Assumption for Norwegian supply to Germany

We considered the 10-year contract for 4.5 bcm/year negotiated in November 2012 between Statoil and Germany's Wintershall (100% owned by BASF) for which supplies began in January 2013 which is 100% hub-indexed, which could be some combination of Germany's NCG and Gaspool. For the remaining supplies, being mostly Statoil sales to EON, we assume a 60-40 split between oil and gas-hub pricing. Oil indexed formula is the formula estimate for deliveries from Norway to Italy minus the average discount in 2014 between the price of Norwegian supply to Germany according to WGI and the price of Norwegian supply to Italy according to WGI. Hub component is the TTF plus the average difference between TTF and NCG in 2014.

Assumption for Norwegian supply to France/Belgium/Netherlands

According to IGU (2014) Northwest Europe (Belgium, Denmark, France, Germany, Ireland, Netherlands, UK) the ratio in price formation mechanisms in 2013 was 20% oil indexation and 80% hub indexation. Oil indexed formula is the formula estimate for deliveries from Norway to Italy minus the average difference between Norwegian gas price to France/Belgium/Netherlands and Norwegian gas price to Italy in 2014 according to WGI. For France, hub component is the TTF plus the average difference between TTF and PEGN in 2014; for Belgium and Netherlands is the TTF.

Assumption for Norwegian supply to UK

Supply to UK is assumed to be 100% hub indexed. Difference between TTF and NBP assumed to be zero.

Assumption for Algerian supply to Spain

According to IGU (2014) in the Mediterranean Europe (Greece, Italy, Portugal, Spain, Turkey), oil indexation is prevalent. The Oil-linked formula from Algeria to ES is our estimate for oil formula from Algeria to Italy minus 5.8, where 5.8 is the average difference between WGI price of Algerian gas to Spain and WGI price of Algerian gas to Italy in 2014.

[455] International Gas Union "Wholesale Gas Price Survey - 2014 Edition, A global review of price formation mechanisms 2005 -2013", hereafter referred as IGU (2014).

Assumption for Algerian and Libyan supply to Italy

According to IGU (2014) in the Mediterranean Europe (Greece, Italy, Portugal, Spain, Turkey), oil indexation is prevalent. The Oil-linked formula from Algeria to Italy is our estimate for oil formula from Algeria to Italy, based on WGI border price data. Libyan gas priced at the same price as Algerian gas.

Assumption for Russian supply to Romania

According to IGU (2014) there is no oil indexation in South East Europe. No information available on average import price from Russia to Romania, the price is estimated using Russia price to Italy based on WGI database on border price.

Assumption for LNG supply

For Northern Europe, excluding Poland, LNG spot price is TTF minus an estimate of the difference between the cost of shipping LNG from Qatar to NL and that of shipping LNG from Qatar to the relevant destination country.

For Southern Europe and Poland LNG is priced using an oil-indexed formula, based on a three month moving average of Brent prices. The price is corrected for different shipping costs according to the destination country.

ANNEX 15 - METHODOLOGICAL NOTE ON POTENTIAL FUEL SWITCHING IN POWER GENERATION

The potential fuel switching in power generation in each Country is estimated by REF-E based on the following data and assumptions (Table A.15.1)

1. REF-E collected and elaborated the 2013 statistical data on generation and installed capacity per technology (fuel)[456] and per Country reported in ENTSO-E "Yearly Statistics & Adequacy Retrospect (YS&AR) 2013", in order to calculate the 2013 yearly load factors per technology.
2. Where necessary (incomplete data) ENTSO-E data were integrated with Eurostat data on power generation (Bulgaria and Netherlands)
3. The ENTSO-E technologies/fuels considered for potential fuel switching from gas were: lignite, coal and oil
4. Based Italian thermal plants historical market results and considering the technology specific reference unavailability rates (both accidental and planned maintenance – based on REF-E data on Italian thermal units), REF-E calculated a potential yearly load factor per technology: 80% for lignite and coal units (7000 h/y) and 34% for oil units (3000 h/y).
5. The potential load factors were applied to the ENTSO-E 2013 total capacity installed per technology, obtaining the total yearly potential generation per each technology and Country
6. The difference between the total yearly potential generation per each technology/Country and the ENTSO-E 2013 actual electricity generation per technology/Country is the value of the extra potential fuel switching from gas to lignite, coal and oil
7. Considering each Country individually, the actual fuel switching corresponds to the minimum between the ENTSO-E 2013 natural gas electricity generation and the extra potential fuel switching from gas to lignite, coal and oil (final column of each Country row in Table A.15.1)
8. Considering the selected Countries as a whole, the actual fuel switching corresponds to the minimum between the sum of each Country extra potential fuel switching from gas to lignite, coal and oil, and the sum of each Country ENTSO-E 2013 natural gas electricity generation (final column of row "TOTAL" in Table A.15.1); the sum of each individual Country actual fuel switching is lower than the whole actual fuel switching.
9. The costs related to the fuel switching from gas to lignite, coal and oil were calculated assuming for all Countries the average reference efficiency of Italian thermal units: coal (and lignite) 35%; oil 35%; gas 53%.

[456] ENTSO-E fuels : lignite, coal, gas , oil, other fossil fuel

Table A.15.1 Data on potential fuel switching in power generation

Country	Country Code	2013 generation, GWh/y		Total potential generation, GWh/y		Extra potential generation, GWh/y		2013 generation, GWh/y	Fuel switching, GWh/y
		Coal&Lignite	Oil	Coal&Lignite	Oil	Coal&Lignite	Oil	Natural gas	Gas > Coal+Lignite+Oil
Austria	AT	4203	683	8197	1080	3994	397	6416	4391
Belgium	BE	2352	0	2870	630	518	630	19985	1148
Bulgaria	BG	19392	0	41305	0	21913	0	2338	2338
Switzerland	CH	0	0	0	0	0	0	0	0
Czech Republic	CZ	37190	0	69028	0	31838	0	4414	4414
Germany	DE	256613	2048	327524	11640	70911	9592	39003	39003
Denmark	DK	13447	84	34278	3133	20831	3049	5113	5113
Spain	ES	40236	10189	73867	10189	33631	0	54460	33631
France	FR	19829	4872	52013	27969	32184	23097	19952	19952
Great Britain	GB	129247	19	154771	7575	25524	7556	80556	33079
Hungary	HU	6384	46	8309	1230	1925	1184	4695	3109
Italy	IT	42662	17940	63063	47513	20401	29573	93977	49975
Netherlands	NL	24614	140	28963	780	4349	640	55164	4989
Poland	PL	132687	0	198868	0	66181	0	3047	3047
Portugal	PT	10951	191	12292	1077	1341	886	6910	2227
Romania	RO	14949	0	35448	0	20499	0	3649	3649
Slovakia	SK	2737	3	7204	815	4467	812	2189	2189
TOTAL		**757493**	**36215**	**1118000**	**113631**	**360507**	**77416**	**401868**	**401868**

Sources: ENTSO-E (YS&AR 2013); Eurostat; REF-E elaborations

ANNEX 16. STORAGE IMPROVEMENT DECISIONS: AN EXAMPLE OF COST-BENEFIT ANALYSIS AT COMPANY, COUNTRY, AND MULTI-COUNTRY LEVEL

Let us imagine a not too large Market Player (MP) serving 30% of a market (assume a share of 30 TWh out of a 100 TWh/year market). In this example we explicitly ignore extrinsic and intrinsic value of storage, or assume that some storage is already booked with a view to exploit price short term volatility and seasonal spreads.

Now, the MP could decide whether to invest and further increase its storage endowment (or to book more of existing capacity), with a view to insure against a price spike. Suppose that.

- The typical expected spike, triggered by upstream market disturbances, leads to a price increase from 20 to 30 €/MWh for three months (on average).
- The probability of such event is estimated at 10%;
- The very existence of the new storage site (or more stored gas in existing sites) is expected to reduce the spike by 4 €/MWh, so that the average price hits 26 rather than 30 €/MWh. Section 4.3.3 below illustrates a few cases from real markets.
- The (levelized) cost of storage is 1 €/MWh and the new Working Gas (WG) envisaged by the MP covers three months of his supplies, or 7.5 TWh, so that the MP can sell some gas, previously purchased at 20 €/MWh, for the market price of 26 €/MWh;
- Other suppliers purchase and sell at the market price (neglecting normal margins for simplicity);

In such case, the net benefits (NB) for the MP of investing in the storage capacity would be:

NB = (Reduced gas procurement cost) x (MP sales) x Spike Probability – Storage cost =

= (26-20) x 30 TWh x 3/12 x 10% - (1 x 30 TWh x 3/12) = - 3 (MEUR).

Net expected benefits are negative Therefore, the MP is not likely to undertake the investment (or to purchase the same capacity in an existing storage facility, priced at full cost).

However, what if the same storage capacity was required for the whole market, by means of a SRSM? In such case, the policy maker could at first consider the consumers' perspective. In their view, net benefits of the new storage would be given by the difference of the price in the spike, with or without the new storage capacity, or:

NB of Consumers = (30-26) x 100 TWh x 3/12 – 1 x 7.5 TWh = 2.5 MEUR

Thus, if policy makers followed consumer interests only, they would support the SRSM allowing to enhance storage capacity by 7.5 TWh. This shows how, under certain plausible conditions, market players may not pursue the best consumers' interests.

However, consumers are only one side of the coin. Suppliers would clearly lose some of the gains if the price spike was smaller than expected. Let us assume that the policy maker is:

- Neutral between national suppliers and consumers, e.g. it considers the same value wherever it goes (within the country);

- Neutral towards risk, like consumers and suppliers, so that probability weighted benefits are simply calculated by multiplying benefits by their expected probability.

Under such assumption, the sign of the net benefit crucially depend on how much of the suppliers' benefits remain within the country. To see this, consider two identical countries (A) and (B), where consumption and markets are the same except as regards domestic producers. Country A has a substantial domestic production and/or control of overseas equity gas (after producer country's taxation) so that it can retain within the country 25% of the gains from the price hike. On the other hand, country B can only control 5%. It can be easily calculated that the net benefits of expanding storage to face a price spike would be positive for country B but negative for country A. Assumptions and results are summarised in the Table below.

The same numerical example can be used to show how policy makers could react to different supply conditions. For example countries with a substantial domestic production (like the Netherlands the U.K and Romania) are more likely to see negative net benefits from a storage obligation and to undertake policies aimed at ensuring the physical delivery of gas rather than its low cost. On the other hand, countries that are almost entirely based on imports, like France, Spain or Italy, are more likely to see net benefits from some type of SRSMs if this helps reduce supply costs.

Last but not least, the numerical example shows how the nationally preferred policy of each country is not necessarily the best policy for the "Union" of both countries. In the numerical example, let us assume that country A&B's total net benefits would be positive, but country A does not support the SRSM so that with only B developing a new storage site of 7.5 Bcm the market price would hit 28 €/MWh. In such case, the net benefits would be negative even for country B, hence no SRSM would be undertaken and the market price would be 30€/MWh. On the other hand, if a common) SRSM was approved, this would drive the price in the spike down to 26€. In this case, consumers from both countries would be better off and even total net benefits of the whole Union's suppliers and consumers would be positive (see Table A.16.1). This is a version of the classical "prisoner's dilemma", showing the costs of non-cooperation.

It is worth highlighting that this example is purely hypothetical and not based on real cases. It only serves the purpose of illustrating how a nationally based policy in an integrated multinational market may be ineffective. This does not mean that such case actually occurs in Europe. Efficiency of SRSMs in the avtual European market are analysed in the main text.

Table A.16.1 A numerical example of benefits and costs of storage expansion by private companies or national SRSMs

		MP	Consumers	All suppliers	National suppliers	National B-C Balance
Market scenario	Price before spike	€/MWh	20	20	20	20
	Price in spike, no new storage	€/MWh	30	30	30	30
	Price in spike, with new storage	€/MWh	26	26	26	26
	Spike time	Years	0.25	0.25	0.25	0.25
	Prob	%	0.1	0.1	0.1	0.1
Country A	Sales/Year	TWh	30	100	100	25
	New storage cost	€/MWh	1	1	0	0
	New storage WG	TWh	7.5	7.5	7.5	7.5
	Benefits	MEUR	45	100	150	37.5
	Costs	MEUR	7.5	7.5	0	0

	Net Benefits (Prob. Weighted)	MEUR	-3	2.5	15	3.75
	Country A: National Net Benefits			MEUR		-1.25
Country B	Sales/Year	TWh	30	100	100	5
	New storage cost	€/MWh	1	1	0	0
	New storage WG	TWh	7.5	7.5	7.5	7.5
	Benefits	MEUR	45	100	150	7.5
	Costs	MEUR	7.5	7.5	0	0
	Net Benefits (Prob. Weighted)	MEUR	-3	2.5	15	0.75
	Country B: National Net Benefits			MEUR		1.75

ANNEX 17 - ECONOMETRIC ANALYSIS OF STORAGE CAPACITY DETERMINANTS

In principle, researchers could try to estimate how the most relevant variables affect actual storage levels. With this approach, researchers should estimate an econometric equation like (3) above:

$S = (1-h)\ S^*\ (X) + h\ \underline{S}$

c

where X is a matrix of relevant factors, measured over some time and across jurisdictions. SRSMs are just one factor, which should increase actual inventories unless perfect crowding out occurs. The main other factors have been described in Section 1.3 and are summarised below.

Testing that SRSMs are at least partly effective amounts to testing whether the level of mandatory storage obligations $\underline{S}$ is a significant factor in the explanation of observed inventories. This approach is less simple than the previous one, but it may better understand storing patterns of market players. Further, it carries remarkable implementation difficulties.

First of all, the significant inventory levels that can be tested are probably only those observed at the beginning of each winter season. Data do exist for inventories at different dates, with daily granularity in recent years (see *Annex 2*), but actual levels heavily depend on the actual meteorological factors that affect the winter months[457], as illustrated in *Section 1.2*. This includes significant complications.

Explanatory variables would include:

- Expected seasonal spreads, which can be estimated by means of spot and forward prices in the main European hubs[458]
- Expected requirements for space heating, which could be related to winter consumption and / or to the consumption of the residential and commercial sector, which largely overlaps with protected customers;
- Cost distance from storage demand centres[459];
- Availability of alternative gas sources, which could be estimated by the jurisdictions' excess entry capacity, including (possibly as a separate factor) domestic production and LNG imports;
- Storage prices;Special events that may have affected storage accumulation;
- SRSMs.

From a theoretical perspective (subject to confirmation), the expectation is that the locational dimension of storage demand is very important. This is related both to the existence of relevant transportation costs and to the availability of transportation capacity in different directions. Storage that is located in "focal" positions along major supply routes may be more attractive, as it can be used to cope with market opportunities and/or disruptions in several markets that are (normally) located downstream. The typical example in Europe are the countries located along the main

[457] Generally speaking, the desired level of inventories at the beginning of the winter season should be independent of weather factors. However, if the previous winter had been very tough, it could have some late impact on the next winter season, as it has happened in 2013 (*Section 1.2*).
[458] This assumes that at least a remarkable share of market players hedge in the most liquid hubs like NBP or TTF.
[459] It may be thought that In Entry/Exit regimes transmission costs do not really depend on the distance, howver this depends on the chosen tariff calculation criteria. Unllike with postage stamp, distance is normally the main driving factor of transmission tariffs even in Entry/Exit regimes. Moreover, if users wish to use a farther storage site, they may have to cross several TSOs and hence to to pay higher total transmission tariffs.

Russian supply routes (Poland, Slovakia, Czech Republic, Germany, Austria) from where gas coming (mainly) from the East can not only be consumed locally but also quickly transferred to several different consumption areas (like Belgium, UK, Ireland, Netherlands, Denmark, Sweden, France, Italy, Slovenia, Croatia, Hungary). On the other hand, any storage site located in the latter group of countries has a more "peripheral" location and a shorter range of action, therefore may be less commercially attractive. Observers of the market and its regulation may notice that the latter group of countries is more likely to issue storage obligations as substitute for lower commercial storage[460] unless high domestic production or international connection to safe sources reduces their appeal.

On the other hand, using only observed level at the start of winter leaves only 3-5 observation for about 10-15 jurisdictions (countries or reference hubs), which are few for a statistical analysis that should combine the effects of geographical as well as time related variables. This may be the reason why our estimation attempts have not been successful. Data show some mild correlation with consumption demand as well as with seasonal spreads in spot markets, but there are too few observations for a reliable econometric model. Some more insights are provided by an analysis of storage capacity determinants (see Box, but this does not provide insights on whether storage sites are filled, and why.

Dependent Variable: Working Gas TPA Capacity 2012 (GSE data, Mcm)

Method: Least Squares

Included observations: 17

Variable	***Coefficient***	***Std. Error***	***t-Statistic***
Constant	*887.6332*	*912.5033*	*0.97274*[461]
Residential & Commercial Consumption (bcm)	*400.5773*	*119.0896*	*3.36366*
Industrial Consumption (bcm)	*360.0108*	*147.4379*	*2.44178*
Power Generation Consumption (bcm)	*-228.7392*	*101.2321*	*-2.2595*
% Domestic Production / Total Consumption	*-118.7248*	*37.23628*	*-3.188417*

R-squared	*0.880358*	*Mean of dependent variable*	*5354.188*
Adjusted R-squared	*0.840477*	*St. Dev. of dependent var.*	*6560.180*
S.E. of regression	*2620.154*	*Sum of squared residuals.*	*82382486*

All consumption values in Bcm/year.

Measures like strategic storage and obligations were no significant explaining variables of storage levels in this Study. Gaps between the values forecasted by this model and reality (as shown in the Chart below) are clearly not related to the presence of SRSMs in the country. For example, countries with storage obligations or strategic stocks like Italy and Poland have less capacity than expected, whereas countries without SRSMs like Austria and Germany have more. However, abundant storage in Austria, Germany, Czech Republic and Slovakia may be explained by their focal position within the European network. The above shown model lacks an adequate variable to reflect this impact: it may be provided by the "attraction" of consumer markets, as in the well

[460] In fact France and Hungary, which are the countries providing for the tightest SRSMs (*Section 3.12*) are located in peripheral locations and do not feature much transit. As opposed, transit countries, such as Czech Republic and Slovakia, envisage lighter SRSMs.
[461] Since this t-ratio is below significance level, the regression equation should in principle be run again without a constant term. However, it is common in econometric practice to leave the constant in the specification anyway. The lack of significance only shows that the estimated value of the constant is not significantly different from zero.

known “gravitational” models used in marketing sciences.

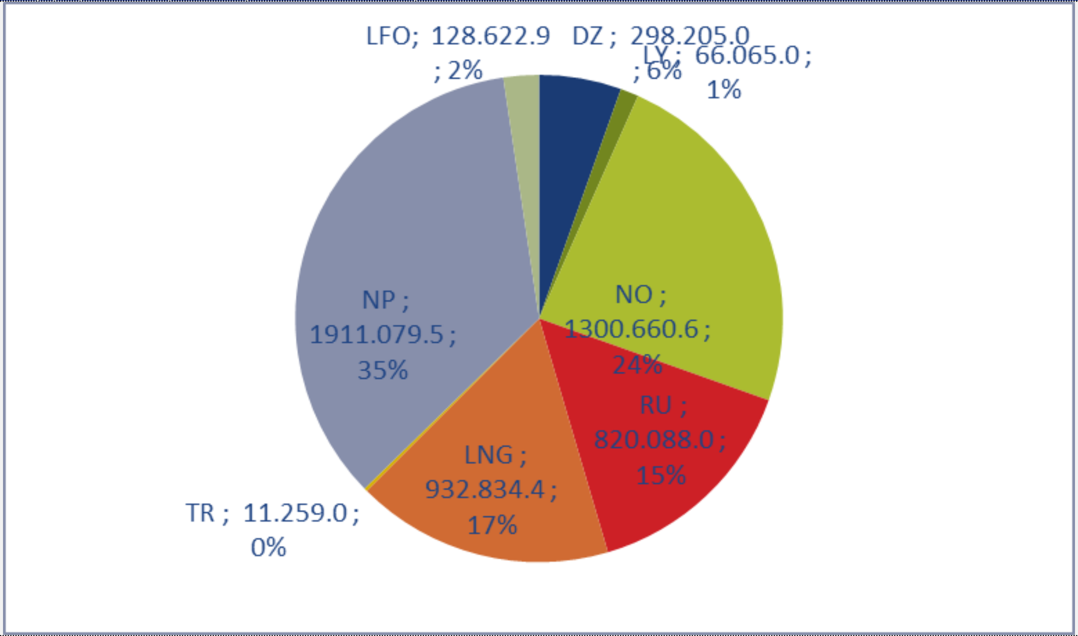
Statistical analysis performed by various researchers has shown that the main drivers of storage capacity development in a cross country analysis for Europe include levels of residential/commercial and of industrial consumption, with the former playing a stronger role. On the opposite side, availability of domestic production leads (unsurprisingly) to lower storage development, as it represents itself a source of security (from a physical consumption perspective) and an insurance policy against price increases (from an economic perspective).

More uncertain is the role of consumption for power generation, which seemed to be positively related to storage (WG) capacity in the Ramboll (2008) study but appeared negatively related in Ascari’s 2013 study (see Box). The evolution may be related to the increase that has occurred in spare gas fired generation capacity, which has turned it into a flexibility tool rather than a main consuming sector whose needs must be covered.

This analysis may be updated with current data at a later stage, and the role of other factors like the prevailing access regime (regulated or negotiated), proximity to production or cross border storage, supply mix as well as SRSMs, will be tested.

ANNEX 18. SIMULATION RESULTS

Figure A.18.1 - Tight SRSM for all: annual demand matching by supply source (above, TWh) and cost split by supply source (below, M€), under a six-month all-Russian supply disruption plus February cold spell



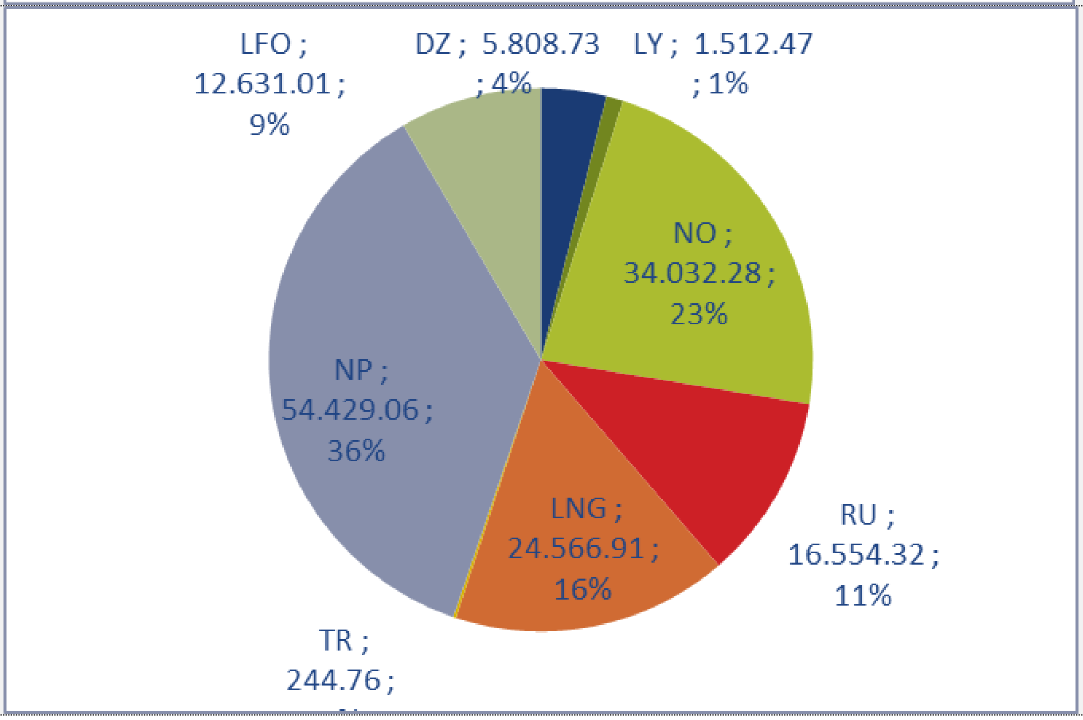
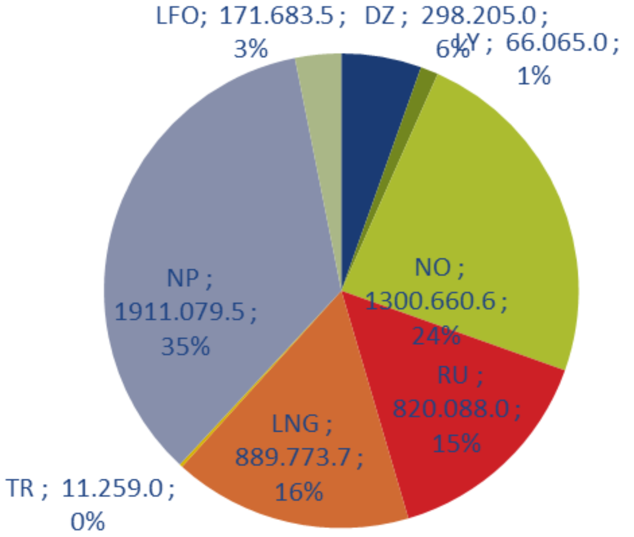


Figure A.18.2 - Light SRSM for all: annual demand matching by supply source (above, TWh) and cost split by supply source (below, M€), under a six-month all-Russian supply disruption plus February cold spell



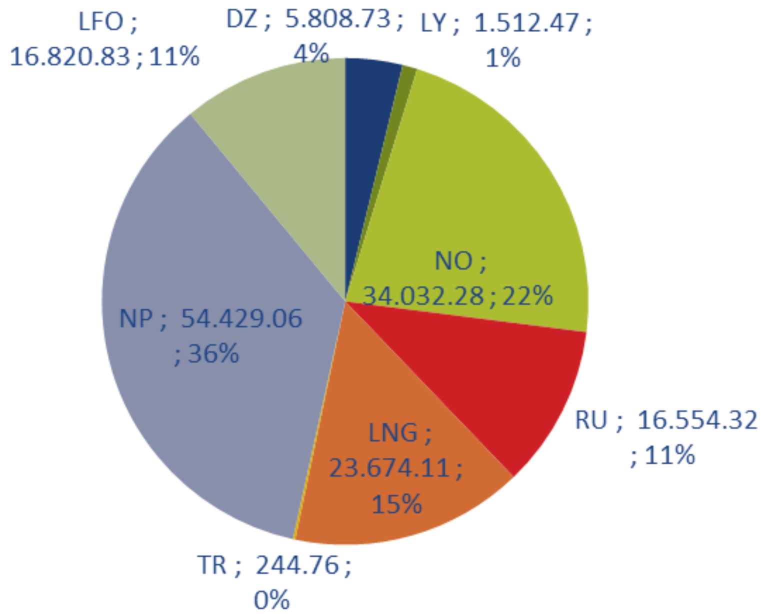
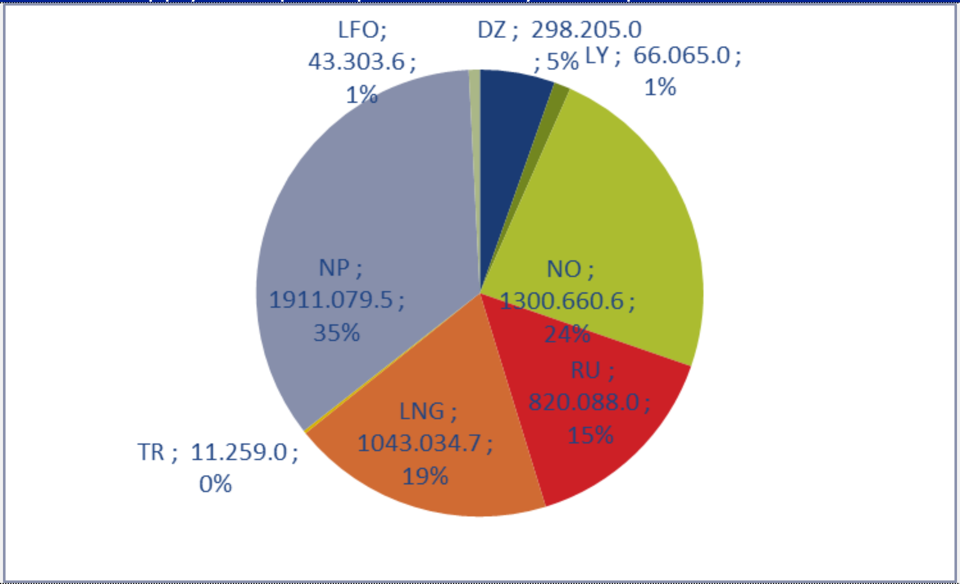


Figure A.18.3 - Strategic storage for all: annual demand matching by supply source (above, TWh) and cost split by supply source (below, M€), under a six-month all-Russian supply disruption plus February cold spell



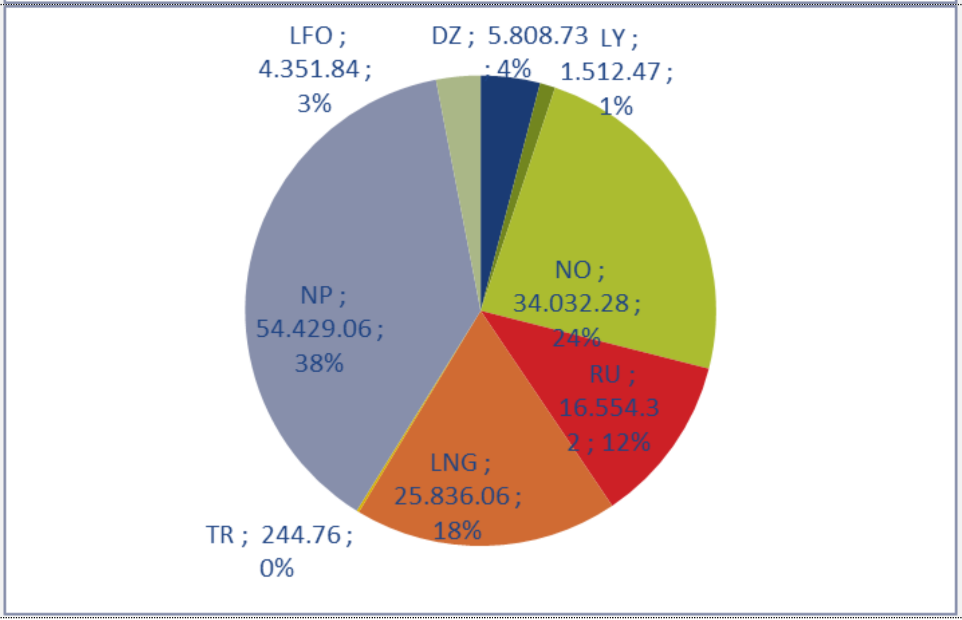


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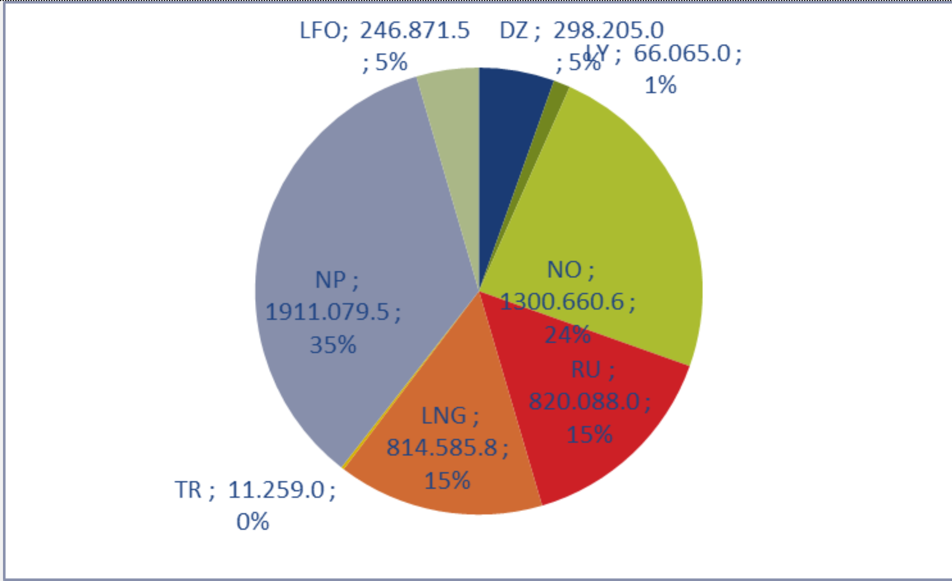
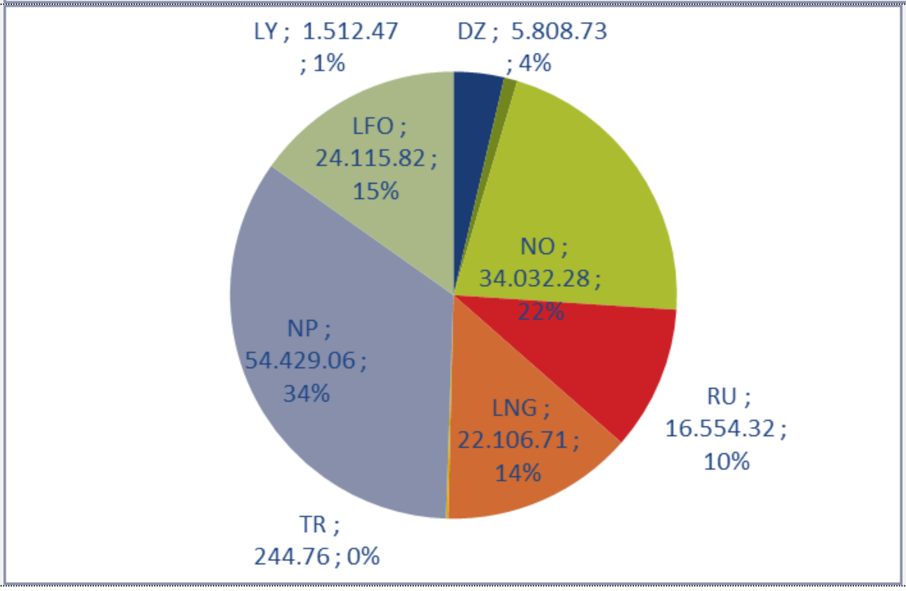
Figure A.18.4 – Elimination of current strategic storage and obligations: annual demand matching by supply source (above, TWh) and cost split by supply source (below, M€), under a six-month all-Russian supply disruption plus February cold spell





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