Risikogruppe „Gasversorgung Ost, Ostsee" (BE, CZ, DK, DE [Koordination], FR, LU, NL, AT, SK, SE):

*1. **Beschreibung des Netzes***

1.1. Geben Sie eine kurze zusammengefasste Beschreibung des regionalen Gasnetzes für jede Risikogruppe (2), an der der Mitgliedstaat teilnimmt, mit folgenden Angaben:
a) die wichtigsten Gasverbrauchszahlen (3): jährlicher Endgasverbrauch (Mrd. m3 und MWh) und Aufschlüsselung nach Art der Kunden (4), Spitzennachfrage (insgesamt und aufgeschlüsselt nach Kategorie der Verbraucher in Mio. m3/Tag),
b) eine Beschreibung der Funktionsweise des/der Gasnetze(s) in den betreffenden Risikogruppen: Hauptgasflüsse (Einspeisung/Ausspeisung/Durchleitung), Kapazität der Infrastruktur der Einspeise-/Ausspeisepunkte für den Transport in die und aus der/den Region(en) der Risikogruppen und je Mitgliedstaat (einschließlich Nutzungsrate), LNG-Anlagen (maximale tägliche Kapazität, Nutzungsrate und Zugangsregelung) usw.,
c) eine prozentuale Aufschlüsselung, soweit möglich, der Gasimportquellen nach Herkunftsland (5),
d)eine Beschreibung der Rolle der für die Risikogruppe relevanten Speicheranlagen, einschließlich des grenzüberschreitenden Zugangs:
i) Speicherkapazität (insgesamt und Arbeitsgas) im Vergleich zur Nachfrage während der Heizperiode, ii) maximale tägliche Entnahmekapazität bei unterschiedlichen Füllständen (idealerweise bei vollen Speichern und bei Füllständen am der am Ende der Heizperiode);
e) eine Beschreibung der Rolle der heimischen Produktion in der/den Risikogruppe(n):
i) Produktionsmenge im Vergleich zum jährlichen Endgasverbrauch,
ii) maximale tägliche Produktionskapazität sowie eine Beschreibung, wie diese den maximalen täglichen Verbrauch decken kann;
f) eine Beschreibung der Rolle von Gas bei der Stromerzeugung (z. B. Bedeutung und Rolle als Ersatz für erneuerbare Energien) unter Einbeziehung der Erzeugungskapazität von Gaskraftwerken (insgesamt (MWe) und als Prozentsatz der gesamten Erzeugungskapazität) und der Kraft-Wärme-Kopplung (insgesamt (MWe) und als Prozentsatz der gesamten Erzeugungskapazität).

Belgium

National consumption

High- and low-calorific gas

Two different types of natural gas, namely H-gas (with high calorific value) and L-gas (with low calorific value) are transported and distributed in Belgium. L-gas is imported from the Netherlands, where it originates from the Groningen gas field, but can also be produced by blending H-gas with nitrogen to reduce its calorific value (quality conversion). The Belgian L- and H-gas networks, markets and balancing zones are distinct, and the two networks are linked through two quality conversion units. A distinction will be made between the figures for L-gas and H-gas to give a reliable overview of the Belgian natural gas market. During the coming years and until the end of 2029, the Belgian L-gas network will progressively be converted to H-gas.

Yearly consumption

The breakdown of the total natural gas consumption for H-gas and L-gas emphasizes the relative importance of natural gas demand per consumer category (for normalised temperatures (for the public distribution, given the strong link between temperatures and consumption, the annual numbers are normalised to represent the consumption in an average year). The main source of demand on the L-gas network stems from the consumers connected to the distribution network (TD) (about 90%). This makes the consumption on the L-gas network particularly sensitive to changes in the outside temperature.

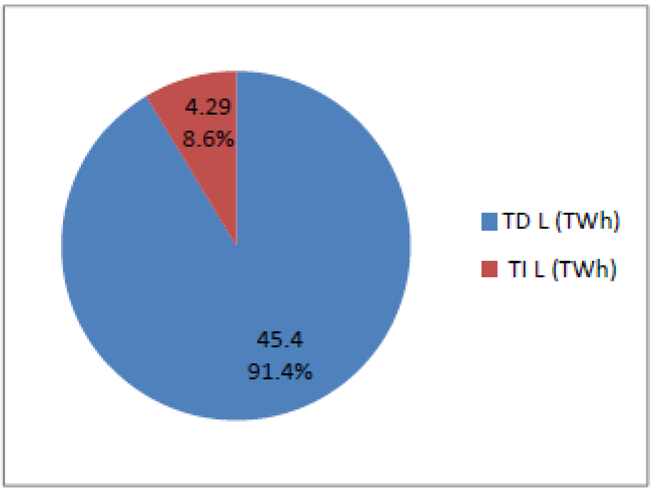

Figure 2: Natural gas consumption (norm.) per consumer on the L-gas network in 2017

On the H-gas network, in 2017 the consumers connected to the distribution network (TD) accounted for about 37% of the natural gas demand after temperature normalisation, while the large industrial consumers (TI) and the electric utilities (TE) took up 29% and 34%, respectively.

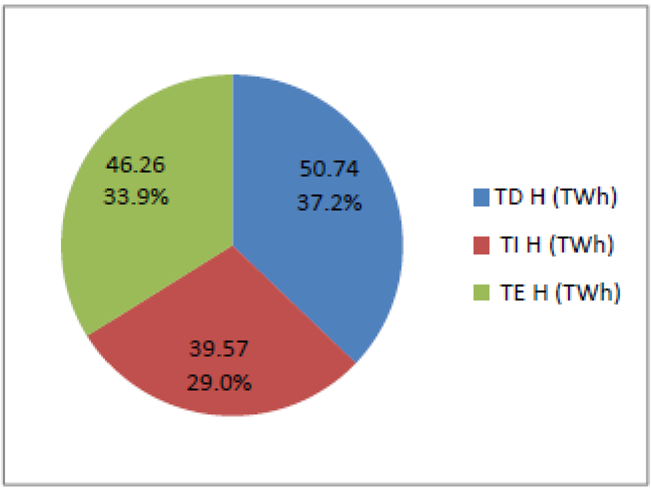

Figure 3: Natural gas (norm.) consumption per consumer on the H-gas network in 2017

Peak consumption

Observed peak

Considering the high dependence between the temperatures and the consumption by the public distribution (and, to a lesser extent, the power plants), there is a large difference between the average daily consumption and the peak consumption that can occur on a cold day. In 2017, the peak day was observed on 18 January, with an equivalent temperature of -2.5°C and total national consumption nearly twice as high as the annual average.

Peak consumption (GWh/d)	L	H	Total L+H	% of annual average
TD	310	341	651	249%
TI	13	118	131	109%
TE	0	206	206	163%
Total	323	665	988	195%

Table 5: Peak day consumption (18/01/2017)

Forecast peak
The historical observed peaks are not sufficient to properly assess the infrastructure (capacity) needed to cover demand on an extremely cold day. The theoretical peak taken into account is one day with extreme temperatures occurring once in 20 years. In Belgium, this corresponds to an equivalent temperature of -11°Ceq.

For the public distribution (TD), based on the daily measured consumption of the distribution network for a given winter period, we can deduce the linear relation between the daily equivalent temperature and the daily consumption. Based on this correlation, we extrapolate the consumption to -11°Ceq to deduce the amount of natural gas that the distribution network will need at -11°Ceq.
For industrial clients (TI) and power plants (TE), the transmission system operator (TSO) determines a default value of the hourly consumption that represents the real gas needs. The calculation of the default value is based on a statistical analysis of the hourly consumption of the three previous years. Non-representative data can be excluded. Therefore, weekends, official holidays, abnormal peaks (test phase, incident) or abnormally low consumption are not taken into consideration.

1-in-20 consumption (GWh/d)	L	H	Total
TD	455	486	941
TI	22	161	183
TE	0	343	343
Total	477	990	1446

Table 6: Forecast 1-in-20 peak demand

Infrastructure

Fluxys Belgium, Belgium's transmission system operator, has a network of about 4 100 km of pipelines with 15 interconnection points and 4 compression stations. Eight cross border pipelines connect the Belgian gas market directly to Norway, the UK, Germany, the Netherlands, France and Luxembourg.

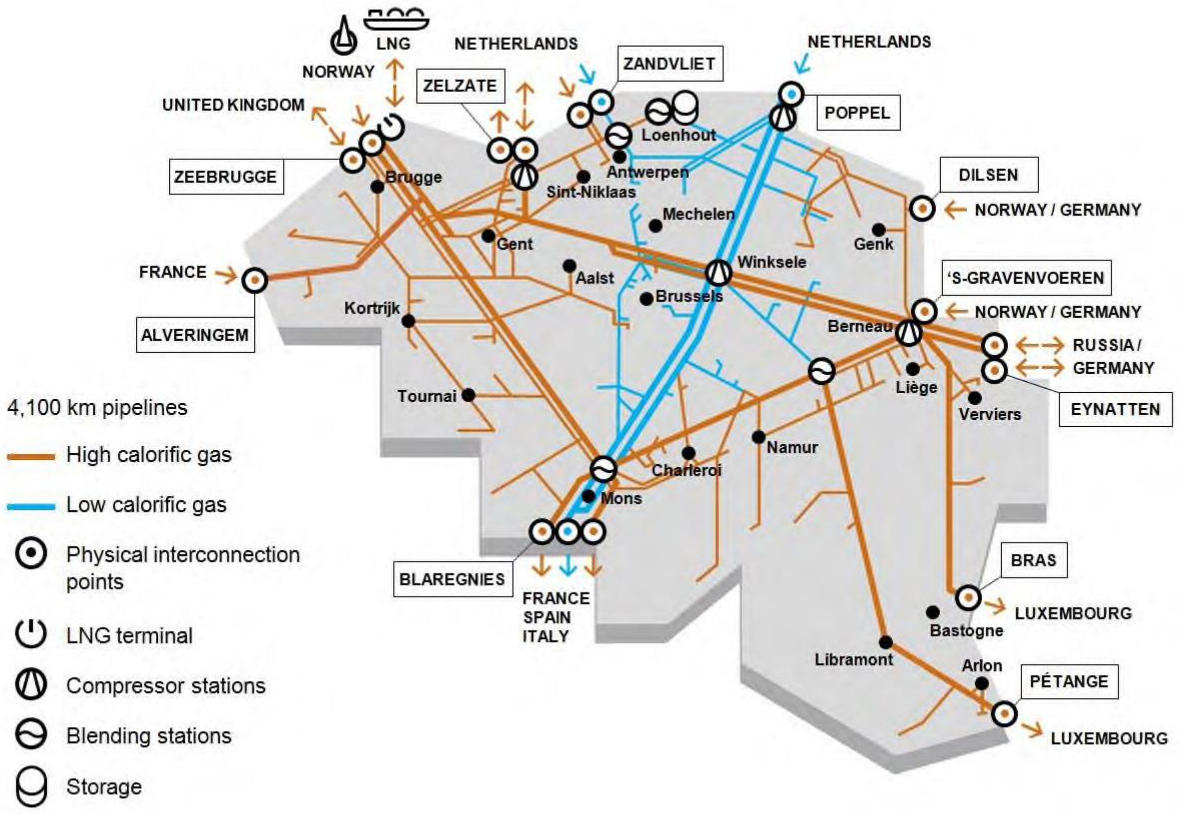

Figure 4: The Belgian transmission network (Source: Fluxys Belgium)

The Fluxys Belgium transmission grid has a high level of interconnectivity with adjacent transmission grids, offering extensive access to north-west European market areas and production facilities.

With 15 interconnection points with neighbouring natural gas transmission systems, the Belgian grid is a central crossroads for gas flows in north-western Europe:

- transmission of Dutch and Norwegian natural gas to France, Spain and Italy
- transmission of British natural gas to continental Europe
- transmission of Russian natural gas to countries including the United Kingdom
- transmission of natural gas to the Grand Duchy of Luxembourg
- natural gas is also passed on to other end-user markets from the LNG terminal in Zeebrugge.

Capacities offered on these interconnection points are summarized in Table 7.

Entry-exit model

The system by which Fluxys Belgium offers transmission services to the grid users is an entry/exit model. Through this entry/exit model, natural gas enters the transmission grid at an interconnection point and can either leave the grid at another interconnection point or be consumed by a Belgian final customer at a domestic exit point or at a public distribution exit point via a distribution system operator.

Transmission services can be subscribed and used independently at interconnection points (entry & exit services) and at domestic exit points (exit services). The model enables parties to freely exchange quantities of gas within the Belgian system. Consequently, this natural gas can be delivered from any interconnection point and taken off towards any interconnection point or any domestic exit point.

The transmission grid is divided into two entry/exit zones: The H-zone and the L-zone.

The H-zone corresponds to the physical H-calorific subgrid and the L-zone to the physical L-calorific subgrid (see Figure 5).

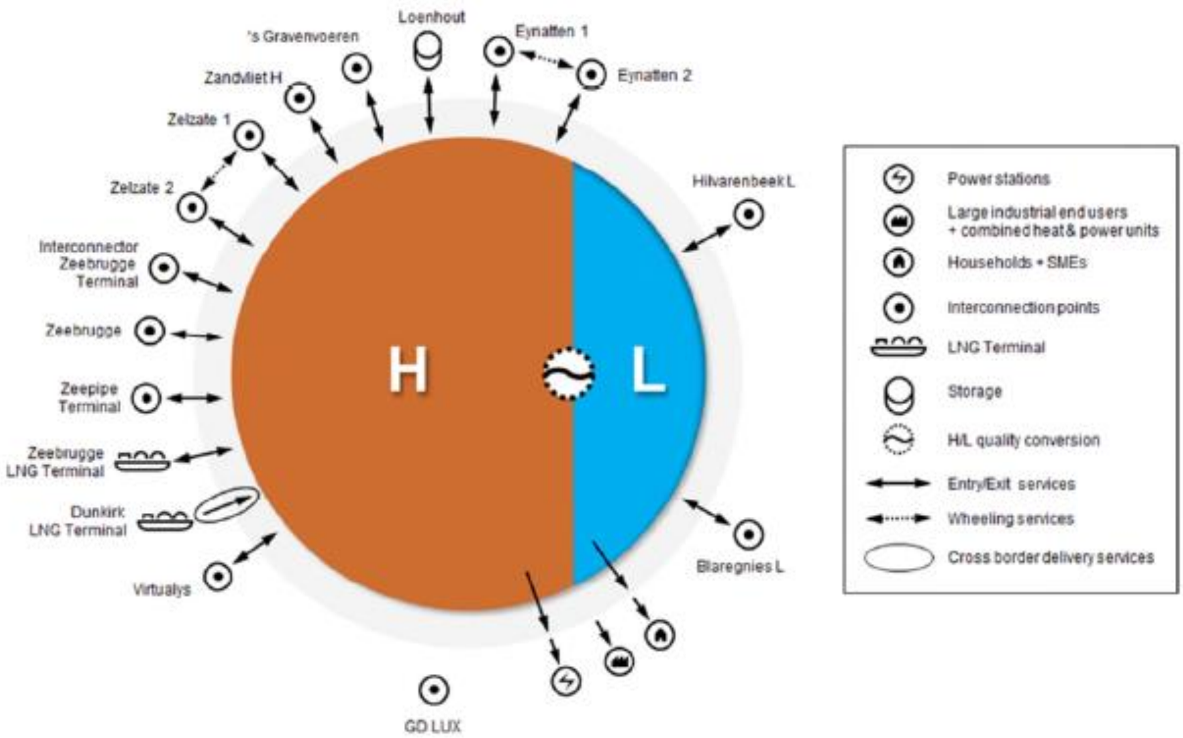

Figure 5: Entry-exit model Belgium (Source: Fluxys Belgium)

Subgrid	Connection point	Type	Connection with	Firm capacity (GWh/d)	
				Entry	Exit
H	Zeebrubge IUK	EP	UK	732.2	881.4
	Zeebrugge Zeepipe	EP	NO	488.2	0.0
	Alveringem	EP	FR	271.2	0.0
	Blaregnies H	EP	FR	0.0	745.8
	Zandvliet H	EP	NL	47.5	0.0
	Zelzate 1	EP	NL	406.8	271.2
	Zelzate 2	EP	NL	0.0	122.0
	's Gravenvoeren + Dilsen	EP	NL	352.6	0.0
	Eynatten 1	EP	DE	203.4	271.2
	Eynatten 2	EP	DE	352.6	271.2
	LNG terminal	LNG		515.3	0.0
	Loenhout Storage	S		169.5	88.1
	Transfo H → L*	EP	BE (L)	0.0	23.5 to 65.2**
L	Transfo H → L*	EP	BE (H)	23.5 to 65.2**	0.0
	Poppel/Zandlviet L	EP	NL	642.1	0.0
	Blaregnies L	EP	FR	0.0	244.6

Table 7: Firm entry and exit capacity offered on the connection points (in GWh/d)

Standard GCV values are used to convert the capacities from volume to energy units (9.8 kWh/m³ for L-gas and 11.3 kWh/m³ for H-gas)
* Transfo H→ L is the entry capacity at the L-gas side and exit at the H-gas side
** Offered capacity in Lillo depends on the temperature.
The Fluxys Belgium network still has an interconnection point at Pétange & Bras (connection point Belgium-Luxemburg) but is not commercialized anymore since the creation of the BeLux balancing zone.

Physical flows and infrastructure utilization

Imports / exports

Belgium has no indigenous gas production and relies entirely on imports for its gas consumption. The current import portfolio is well diversified by origin and type of supply: the Netherlands and Norway are the principal pipeline suppliers, while Qatar is the main source of LNG imports. Most of the gas imports are still based on long-term contracts. This is due to the presence of large shippers on the Belgian market.

(TWh/y)	IN	BE consumption	OUT
H	389.81	134.38	247.26
L	92.16	47.61	44.72
Total	**481.97**	**181.99**	**291.98**

Table 8: Physical flows into and out of Belgium (2017)

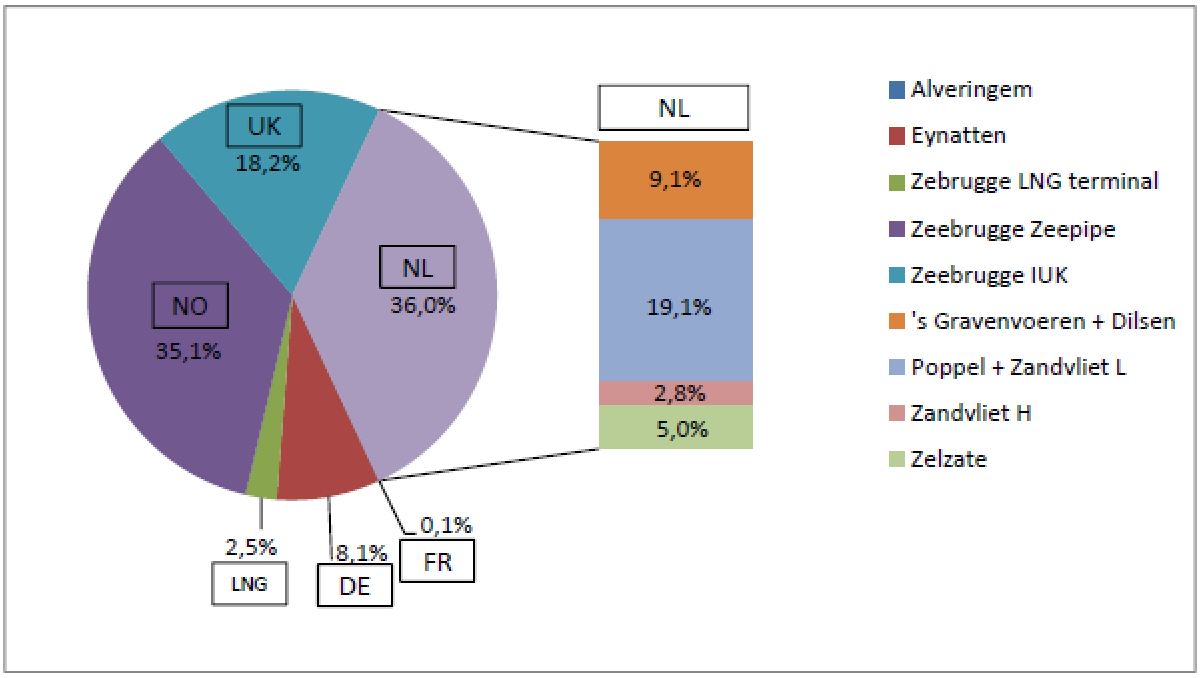

Figure 6 Physical flows into Belgium per entry point (2017)

Storage

Belgium has one underground gas storage installation operated by Fluxys Belgium (available for commercial storage of H-gas), which is the aquifer storage in Loenhout, with a useful storage capacity of 725 mcm. Only high calorific gas (H-gas) may be stored in this facility. Short term LNG storage is also available at the Zeebrugge LNG terminal. Part of the stored natural gas is reserved by Fluxys Belgium for operational balancing of the network. The rest of the storage capacity is sold to the market for dealing e.g. with seasonal swings and situations of peak demand.

If the storage is filled up to its full capacity, the stored natural gas represents theoretically about 45 days send out at the peak output. The effective peak output duration is depending on the realized send out profile. In general, natural gas injection in the storage normally starts in April and ends in October while withdrawal lasts from November until March. The storage capacity in Loenhout allows third party access based on which storage capacity can be booked for the long (from 2 to 10 years), short term (one year or less). The short-term capacity is sold through auctions or on a first committed first served basis during the storage year.

Storage users with subscribed storage capacity in Loenhout are obliged to achieve a gas filling level of at least 90% on the 1st of November according to the booked storage capacity and must still have a level of 30% of gas in storage on the 15th of February.

Location	Type	Working capacity GWh	Peak output GWh/day
Loenhout	Underground	8192.5	169.5

Table 9: Natural Gas storage capacity in Belgium (H-gas)

The Zeebrugge LNG terminal also has storage capacity available (a working capacity of 2576 GWh and a peak send out of 515 GWh/day), but because of the high number of slots that are allocated, the LNG storage must send out almost immediately after the LNG cargos have been unloaded.

Therefore, the LNG storage tanks do not operate as storage as such but more as a very temporary buffer before sending out into the pipelines.

	2016						2017					
	jul	aug	sep	oct	nov	dec	jan	feb	mar	apr	may	june
Gas storage capacity (GWh)	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910
Gas amount in storage[3] (GWh)	3477	5032	6857	7558	7627	7548	7084	4240	2438	1403	1892	2770
Gas stocks change (GWh)												
- withdrawal					-79	-464	-2844	-1802	-1035			
+ injection	1555	1824	702	69						489	878	368
Maximum withdrawal capacity (GWh/d)	68	68	68	68	170	170	170	170	68	68	68	68
Remaining days for using the stored gas	51	74	101	111	45	45	42	25	36	21	28	41

Table 10 Gas in underground storage, winter period 2016-2017

Czech Republic

Structure:

- Transit gas pipelines of the transmission system: total length 2 628 km, DN 500 - DN1 400 pipeline, nominal pressures 6.1 MPa, 7.35 MPa and 8.4 MPa.
- 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.
- Compression stations in the transmission system - Břeclav, Veselí nad Lužnicí, Kralice nad Oslavou, and Kouřim - total installed output for transmission 243 MW
- Border transfer stations in the transmission system: Hora Svaté Kateřiny (DE), Lanžhot (SK), Brandov (DE), Waidhaus (DE) and Cieszyn (PL).
- Transfer stations between the transit and national transmission system - Hrušky, Uherčice, Olešná, Limuzy, Hospozín and Veselí nad Lužnicí.
- Gas pipeline distribution systems: nominal pressures 2.4 MPa - 4 MPa, total length of 73.000 km incl. connections
- Underground gas storages: Tvrdonice, Dolní Dunajovice, Štramberk, Lobodice, Třanov-ice, Háje, Uhřice, Dambořice

Figure 7: Transmission system in Czech Republic (Source: NET4GAS)

Key to the map:
HPS-border transfer station, KS-compressor station

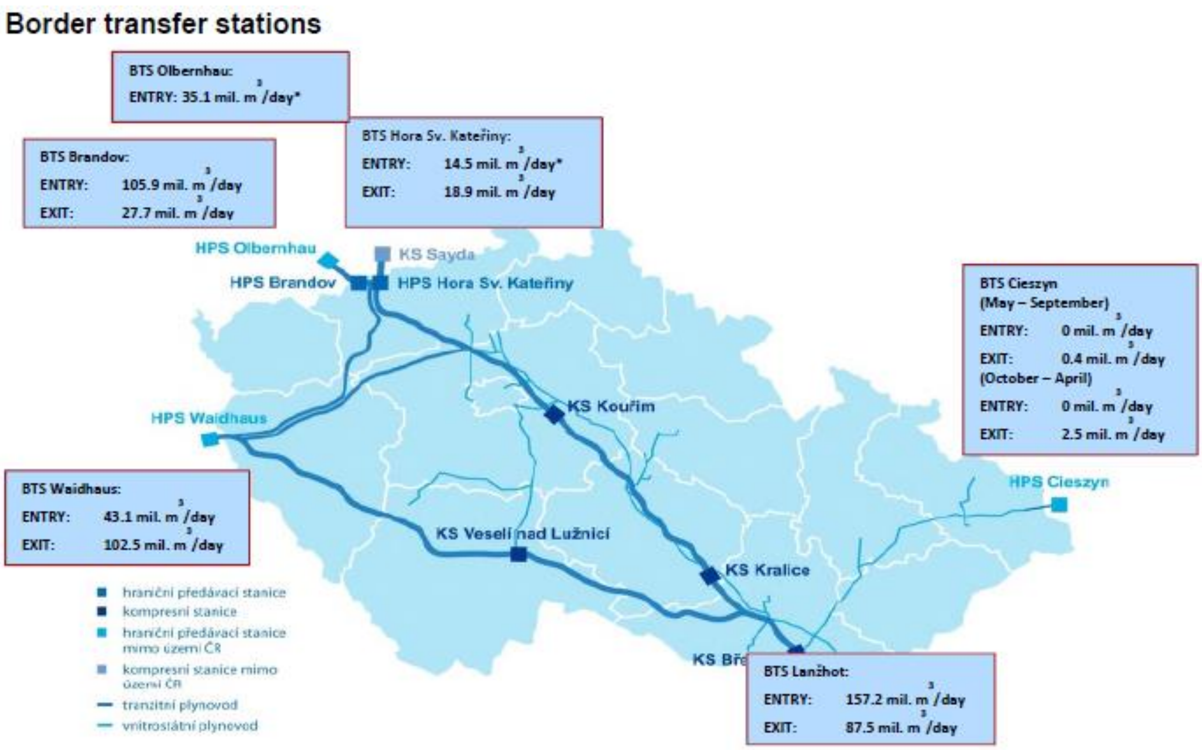

Figure 8: Border transfer stations of Czech Republic

Key to the map:
HPS-border transfer station, KS-compression station

Current reverse gas flows in the transmission system

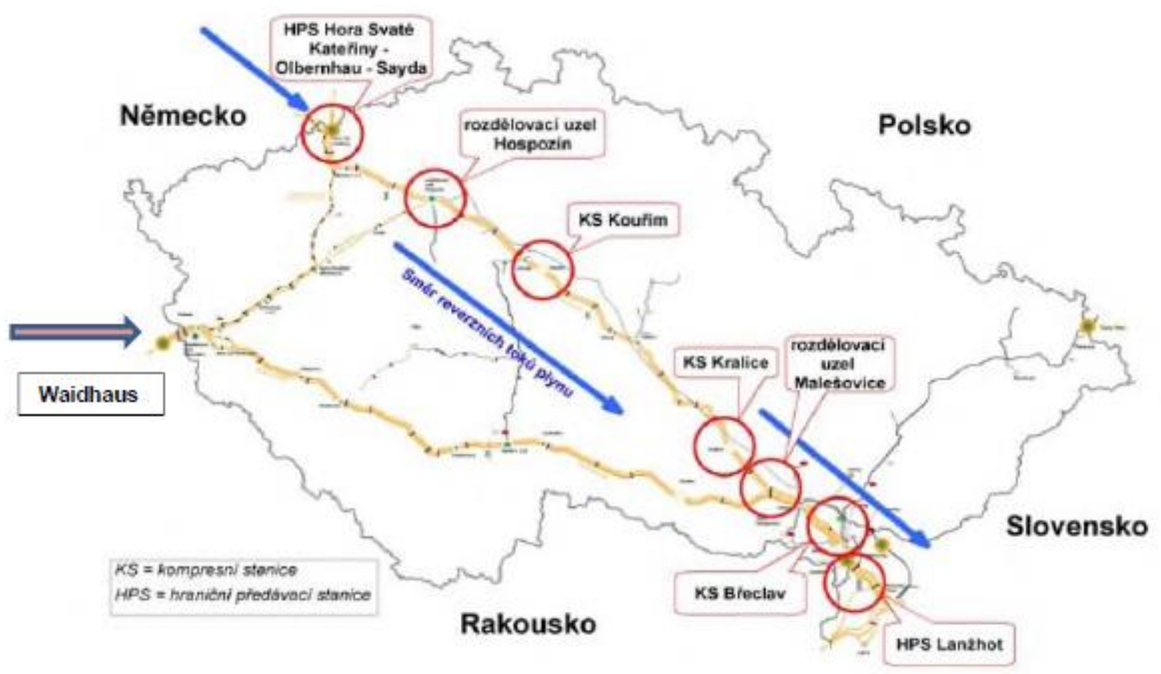

Figure 9: Gas flow system

Total installed output of compressor stations

	Northern branch		Southern branch	
Compression station	Kralice	Kouřim	Břeclav	Veselí nad Lužnicí
Number of turbine sets	5x 6 MW	5x 6 MW	9 x 6 MW	9 x 6 MW
	2x 13 MW	2x 13 MW	1x 23 MW	
Installed output at the compressor stations	56 MW	56 MW	77 MW	54 MW
Total installed output for transmission	243 MW			

Table 11: Output of compressor stations divided in Northern and Southern branch

UGS

The total storage capacity of the underground gas storages in the Czech Republic as of 1 July 2016 is 3.977 billion cubic meters (bcm) (including Dolní Bojanovice underground gas storage which capacity is of 576 million cubic meters (mcm)), which is about 45% of the annual gas consumption of the Czech Republic.

Storage capacities of the individual UGS, maximum daily withdrawal, maximum daily injection output:

Underground gas storage / owner	Storage capacity (mcm)	Maximum daily withdrawal output (mcm/day)	Maximum daily injection output (mcm/day)
Háje / innogy GasStorage	75	6	6
Dolní Dunajovice / dtto	900	16	12
Tvrdonice / dtto	525	8.15	7.87
Lobodice /dtto	177	3.6	2.5
Štramberk /dtto	500	7.3	7.3
Třanovice /dtto	530	8	6.5
The group of these six underground gas storages is operated as a single virtual storage.	Total 2707	Total 49.05	Total 42.17
Uhřice/ MND GasStorage	280	10.1	5.4
Dambořice / Moravia Gas Storage	250	7.5	4.5
Dolní Bojanovice/SPP Storage (SK)	576	eustream net	eustream net

Table 12: Underground storage capacity in Czech Republic

Data in the maps is from PAP 2016.
UGS Damborice is to be increased to 250 mcm in the 2018-19 winter season.

Own gas

Only a negligible part (ca 2% of national consumption = below 170 mcm) comes from domestic sources.

Gas trade

There is a fully liberalised market in the Czech Republic. At the time being the natural gas is imported to the Czech Republic by approximately 20 importers and the number of active traders (with license from ERO) fluctuates around 70-80.

Gas consumption

Consumption of natural gas from 2014 slightly increased on a year-on-year basis and in 2017 it was 8.527 bcm; i.e. 90 996 GWh.

Denmark

Description of the Danish gas system

The Danish gas system (Figure 10) consists of gas production facilities and pipelines in the Danish part of the North Sea, a transmission system, where gas is transported across the country, and a distribution system, where gas is delivered to the gas customers. Moreover, the gas system consists of a gas treatment facility (Nybro), two underground storage facilities (Stenlille aquifer and Lille Torup salt caverns) and a compressor station (Egtved). The compressor station at Egtved has been constructed in order to enable transport of gas from Germany to Denmark.

The Danish gas system has three physical entry/exit points (Nybro, Ellund, Dragor) where gas can be supplied to or from the Danish gas market. Ellund is the only point with physical reverse flow. Furthermore, there are a number of virtual entry/exit points for gas traded within the system (bilateral contracts or gas exchange) and for upgraded biogas (BNG).

From Nybro (landfall of Danish North Sea gas) and Ellund (Germany), the gas is transported to customers in Denmark and Sweden or stored at one of the two underground storage facilities.

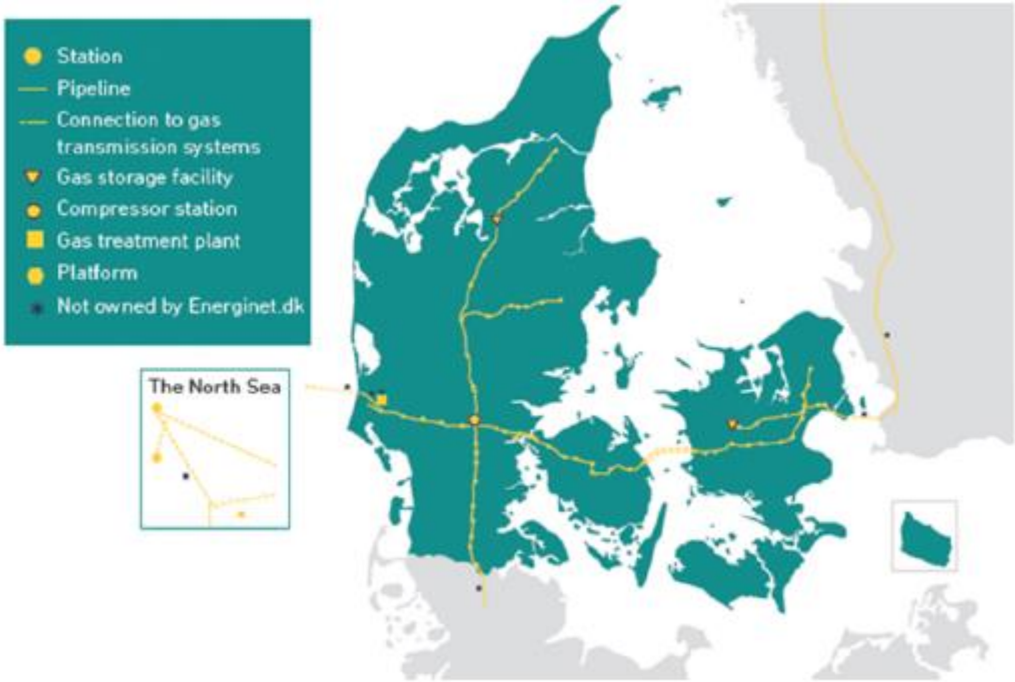

Figure 10: The Danish system

The Danish and Swedish gas market is primarily supplied with gas from the Danish part of the North Sea. Since 1987, the Tyra complex has been the most important source of supply for Danish and Swedish gas consumers. The Tyra complex has sunk approx. 5 meters since its establishment and waves are getting higher and more powerfull. Therefore, the owners of the Tyra complex DUC (Danish Underground Consortium) has decided to reconstruct the platforms in the period november 2019-July 2022 in order to continue to produce gas in the Danish part of the North Sea in the future.

As a consequence, the Danish and Swedish market will not be supplied with gas from the Tyra complex in the reconstruction period. Only a small amount of gas will be supplied from the South Arne field to Nybro. The main supply source will be gas import from Germany via Ellund. Furthermore, Denmark will also be supplied with indigenous production of BNG.

Key infrastructure relevant for the security of supply

Key infrastructure in Denmark with Tyra in production:
- North sea production and the Nybro facility (Nybro Entry)
- Stenlille storage facility

Key infrastructure in Denmark without Tyra in production:
- Ellund Entry
- Stenlille storage facility
- Egtved compressor station
- Lille Torup storage facility
- Pipeline Egtved – Dragør

Descriptions of key infrastructure

Today in 2018 most of the gas on the Danish market comes from the Danish gas fields in the North sea. Furthermore, the Nybro facility ensures the right pressure when the gas enters the system. An interruption at the production facilities or the Nybro facility could lead to a curtailment of the main source of gas in normal years with the Tyra complex in production.

ENTSOG has in their Security of Supply Simulation Report from 2017 pointed at Ellund as critical for the supply in Denmark and Sweden during the reconstruction of the Tyra complex. During the reconstruction period Ellund is the only supply source in the region. The point has also been analyzed in the regional risk assessment for Denmark and Sweden where an interruption of the compressors in Quarnstedt (Northern Germany) could lead to reduced capacity at Ellund.

The Stenlille storage facility is critical for the gas supply east of the Egtved compressor station (East Denmark and Sweden) during periods with extraordinary high demand due to an internal bottleneck. If the Stenlille storage facility is interrupted, it might be necessary to reduce the flow to some of the Danish non-protected customers and to Sweden.

The Egtved compressor station ensures the necessary pressure to transport the gas east of the compressor station (East Denmark and Sweden). During the reconstruction of the Tyra complex the Egtved compressor station becomes essential to ensure the gas supply to the customers. An interruption of the Egtved compressor station can lead to the same consequences as an interruption of the Stenlille storage facility.

The Lille Torup storage facility will be expanded in 2019 prior to the reconstruction of the Tyra complex. This means that the Lille Torup storage facility can ensure a larger withdrawal rate during the reconstruction period. The Lille Torup storage facility can therefore improve the integrity of the system if the supply from Germany should fail. An interruption of the Lille Torup storage facility is not expected to lead to a reduced supply to the Danish customers and Sweden.

The pipeline Egtved – Dragør is located east of the Egtved compressor station. A breach on the pipeline can have several consequences for the customers in East Denmark and Sweden. However, the probability of a breach is little as the repair time is estimated to be short and there is two pipelines crossing the belts (Little Belt and Great Belt).

Point		Capacity mcm[1]/day	Maximum daily flow 2017 mcm/day
Nybro	Entry	32.4[2]	14.0
Ellund	Entry/Exit	10.8[3][4]/20.0	4.9/5.2
Dragør Border	Exit	7.2[5]	4.7
The Danish Exit zone	Exit	25.5	16.7
Lille Torup Gas Storage Facility[6]	Injection	3.6	
	Withdrawal (100%)	8.0	
	Withdrawal (30%)	8.0	
	Injection/Withdrawal		3.8/7.6
Stenlille Gas Storage Facility[4]	Injection	4.8	
	Withdrawal (100%)	8.2	
	Withdrawal (30%)	8.2	
	Injection/Withdrawal		4.8/6.3

Table 13: Capacities and utilization of the gas transmission system in 2017

Note 1: *mcm = million cubic meters*
Note 2: *Total capacity of the receiving terminals at Nybro. The potential supplies are smaller today as the Tyra-Nybro pipeline is subject to a capacity constraint of approximately 26 mcm/day, and large volumes cannot be supplied from the Syd Arne pipeline.*
Note 3: *At a calorific value of 11.2 kWh/m*^{3}.
Note 4: *Entry capacity in 2018 amounts to 9.0 mcm/day and will be increased to 10.8 mcm/day in 2019*
Note 5: *The Swedish system is not designed to receive these volumes at the assumed minimum pressure at Dragør of 44 bar. The firm capacity is stated at 7.2 mcm/day.*
Note 6: *The Danish storage company dimensions the commercial injection capacity conservatively in relation to the pressure in the gas transmission grid. When the pressure occasionally increases, it is possible to inject more gas into the storage facilities than the specified injection capacity.*

The role of Danish gas storage

The storage facilities are usually filled up during the summer when gas consumption is low. When it gets colder and consumption exceeds the daily gas deliveries from the North Sea, the deliveries are supplemented by gas from the storage facilities. In addition to seasonal leveling, trading in gas may have an effect on gas export and import and consequently on withdrawal from and injection into the storage facilities. The storage facilities are also used for emergency supply.

The withdrawal capacities of the Stenlille and Lille Torup gas storage facilities are today 8.2 mcm/d and 8.0 mcm/d respectively (Table 13) in situations with both full storage levels (100 %) and low storage levels (30 %). The total volume of working gas in the storage facilities is approx. 890 mcm. In 2020 the working volume will be reduced by approx. 12% as the storage facilities are filled with gas from Germany with a lower heat value.

Reconstruction of the Tyra complex 2019-2022

In April 2016, Maersk (today TOTAL) announced that the Tyra complex is sinking and that a solution is to be found which either involved permanent or temporary shutdown to secure Danish gas production for many years to come. DUC (Danish Underground Consortium) and the Danish Government concluded an agreement on 22 March 2017 enabling a reconstruction of the Tyra complex in the North Sea. TOTAL has subsequently announced that Danish gas production will be reduced considerably in the period 2019-2022 during which the reconstruction will take place. The reconstruction will imply considerably reduced production since 90 per cent of Danish gas production passes through the Tyra complex.

During the reconstruction of the Tyra complex, Denmark and Sweden will depend on gas imported from Germany and on supplies from the two Danish gas storage facilities. To secure the supply of gas to the Danish and Swedish consumers it is necessary that the market actors make optimal use of the import and storage volume capacity.

The Danish and Swedish gas consumers will continue to be supplied during the reconstruction of the Tyra complex. Nevertheless, the gas system will get more vulnerable and less flexible if the demand becomes unusually high or a technical incident occurs that may reduce the supply to the consumers.

Different measures to improve the supply situation have been analyzed. The analysis has led to the decision to increase the withdrawal capacity from 8.0 mcm/d to 10.3 mcm/d at the Lille Torup storage facility in 2019 before the start of reconstruction of the Tyra complex.

Further measures will be increased information to and dialogue with the market actors, for instance by regularly publishing system information for them to act on and by facilitating incentive regulating market initiatives.

Gas consumption

Gas is consumed by a number of different sectors in Denmark: households, industry (including service industries), district heating and electricity generation. Furthermore, gas is consumed in oil and gas production in the Danish North Sea. In 2016, the total gas consumption including the gas used for production in the North Sea was approx. 3.1 bcm.

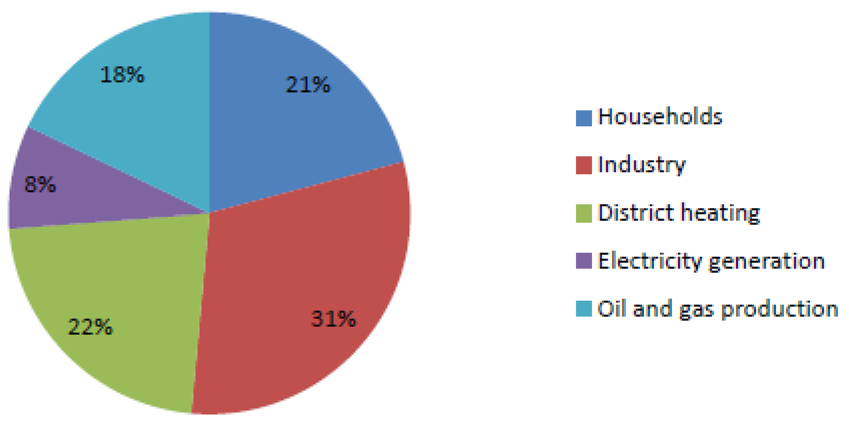

Figure 11: Gas consumption by sector, 2016 (Source: Energinet based on data from the Danish Energy Agency)

The natural gas consumption in Denmark, excluding oil and gas production, in 2017 was 2.5 bcm. After having declined for many years, Danish annual gas consumption has been relatively stable the last couple of years.

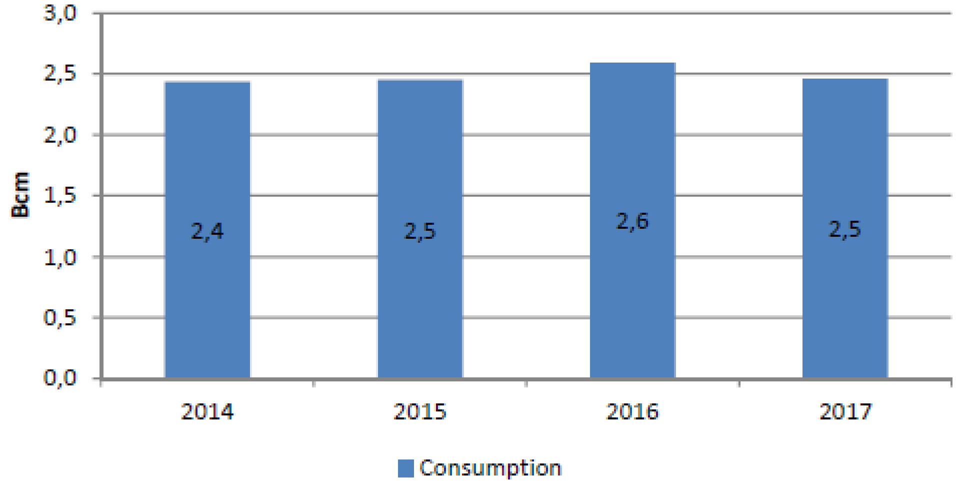

Figure 12: Total Danish gas consumption, 2014-2017(Source: Energinet based on data from Energinet and the Danish Energy Agency)

The total natural gas and BNG consumption in Denmark (Figure 13) is expected to fall to about 1.7 bcm in 2030. The natural gas consumption is expected to fall to about 1.3 bcm in 2030. Consumption of biogas and bio natural gas is expected to grow from the present level of approx. 0.3 bcm to approx. 0.4 bcm in 2030.

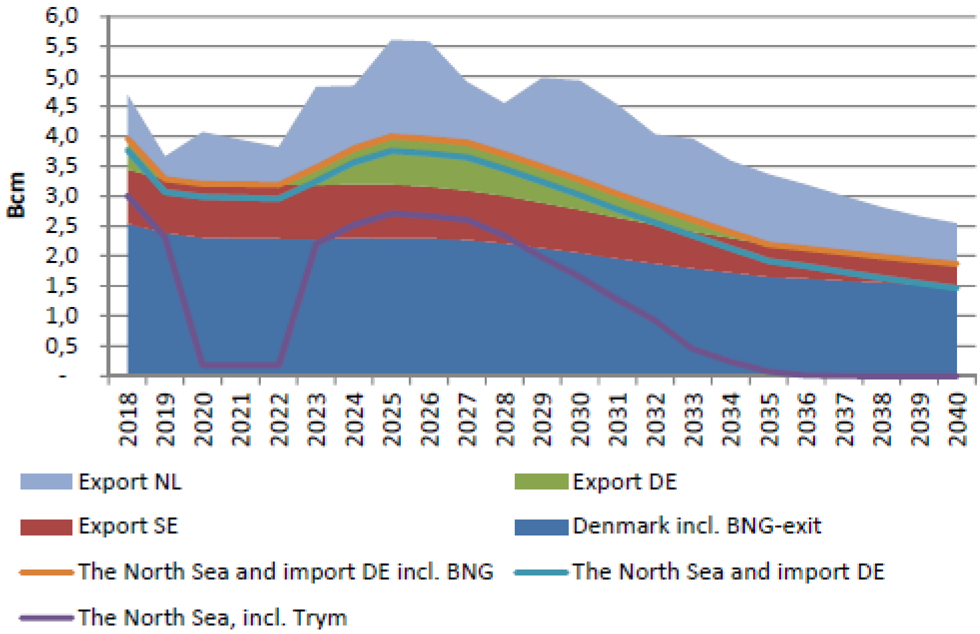

Figure 13: Forecasted demand and supply, 2018-2040 (Source: Energinet based on data from the Danish Energy Agency)

Gas production, import and export

The Danish gas production (Figure 14) is an important part of the Danish and Swedish gas market since it covers the gas demand most of the year. Denmark and Sweden used to be dependent on gas supplied from the North Sea but investments in the Danish gas system have enabled import of large amounts of gas from Germany. This has made the Danish and Swedish gas market less dependent on the Danish gas production.

The Danish gas production has decreased significantly since its peak (9-10 bcm annually 2005-2007). The system is therefore capable of transporting large amounts of gas to the Danish market. The capacity at the entry point for the gas production at Nybro is 32.4 mcm/day. However, the maximum daily flow was 14 mcm/day in 2017.

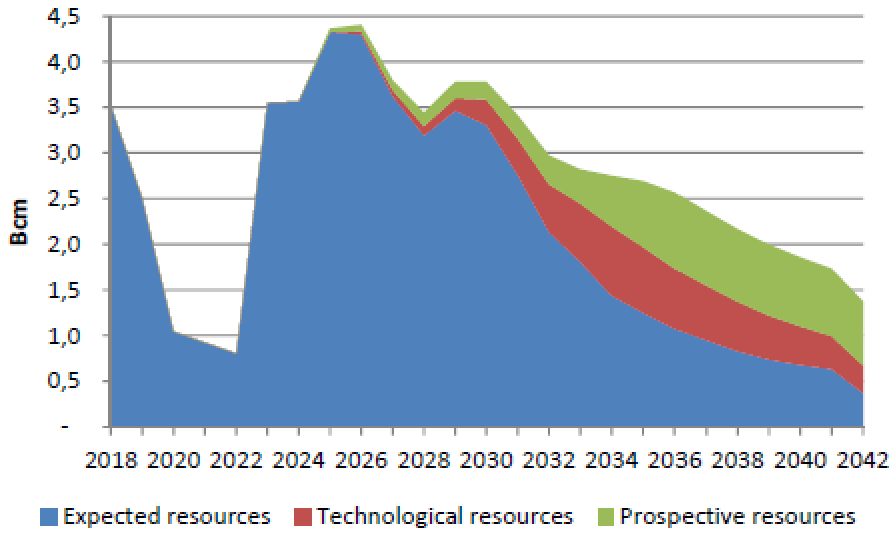

Figure 14: Forecasted Danish North Sea gas production (Source: Energinet based on data from the Danish Energy Agency)

The total reserves in the North Sea are forecasted by the Danish Energy Agency. The total reserves have been generally increased from 2022, due to changed resource assessments on ongoing recovery and several expected developments of existing fields and new discoveries. The expected reserves have been significantly increased but contribution from technological reserves and prospective reserves has been reduced.

The Danish annual production still exceeds the annual Danish and Swedish consumption (except the period of renovation of the Tyra complex). Denmark thus continues to be a net exporter of gas on an annually basis. The Danish production is either exported directly to the Netherlands or transported to Denmark where it is consumed by Danish customers, stored in storages and exported to Sweden and Germany.

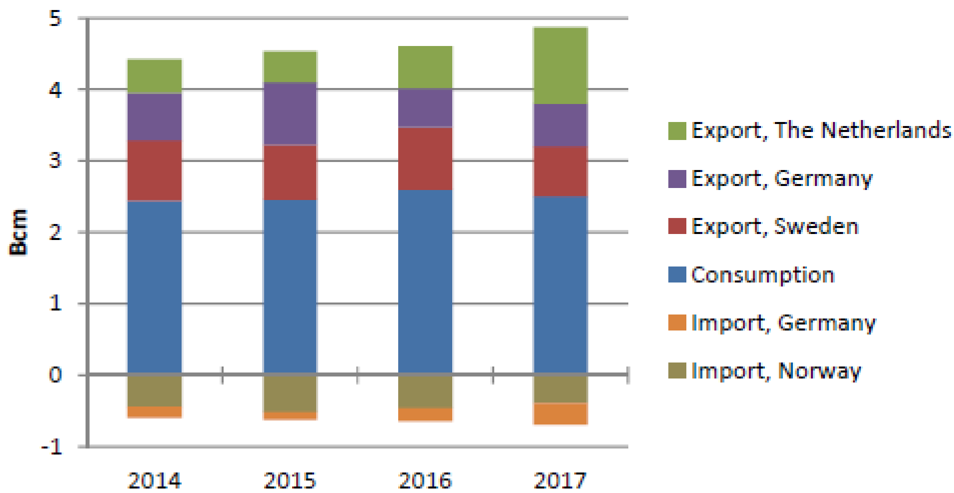

Figure 15: Annual net production distributed on flow, 2014-2017 (Energinet based on data from Energinet and Danish Energy Agency)

The role of gas in electricity production

About a quarter of all thermal power plants in Denmark use natural gas or biogas as the main type of fuel (Figure 16). Several of these units are combined units which can use different kinds of fuel. The actual use of fuel is determined by current fuel prices, electricity prices and also the current taxation scheme. Based on the possibility of gas consumption about 35% of installed capacity is capable of using gas for production of power.

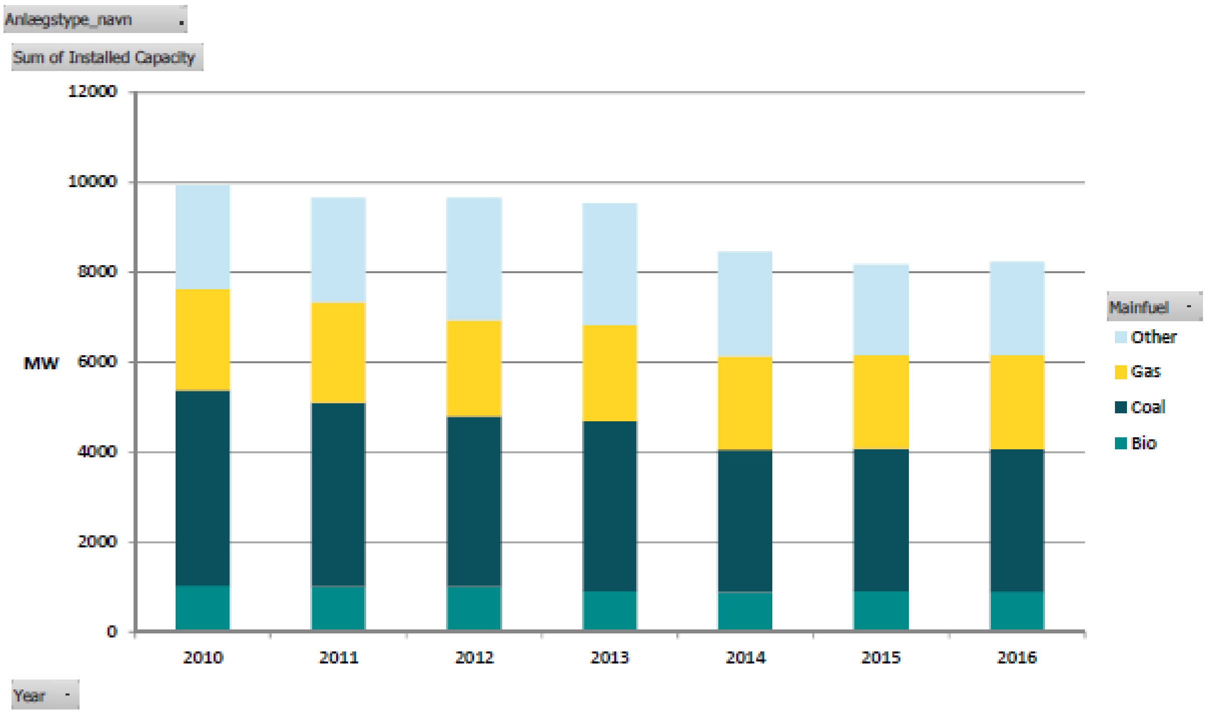

Figure 16: Thermal power installed capacity per main fuel type (Source: Danish Energy Agency statistics, Energiproducenttællingen)

Almost all gas fired power plants are cogeneration units producing power and heat for either district heating or industry. About half the installed gas fired capacity is based on a small scale combined heat and power plants (CHP) producing heat for local communities. There are approximately 460 units with an average size of 2.9 MW.

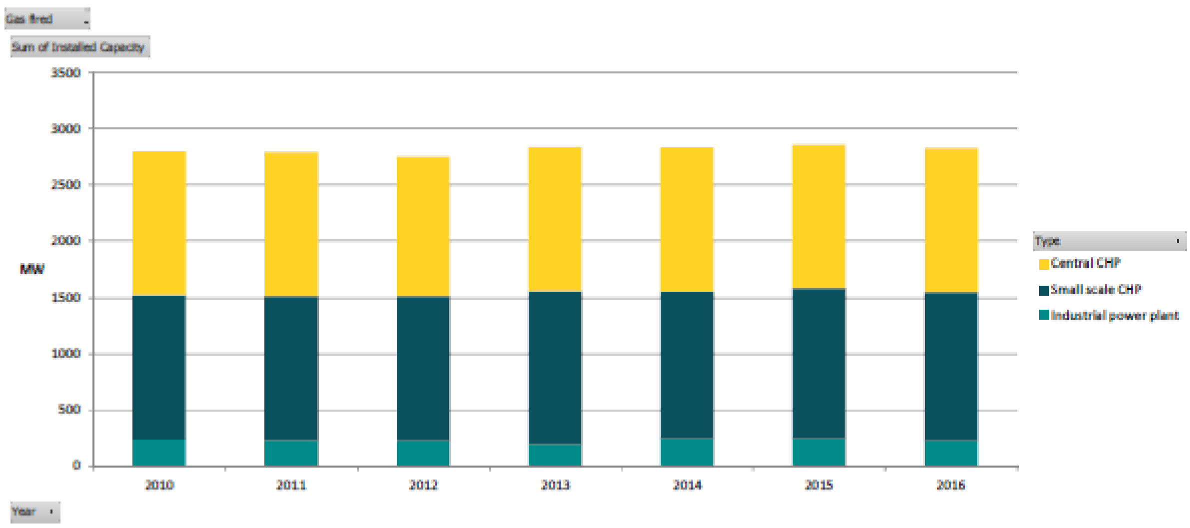

Figure 17: Power plants which can use natural gas in DK (Source: Danish Energy Agency statistics, Energiproducenttællingen)

All gas fired power plants, except for some industrial and very small units sell the electricity production on the day-ahead electricity spot market. Power prices vary through the day and the year depending on electricity demand, availability of renewable energy and many other parameters. The gas fired power plants optimize revenue by mainly producing electricity when prices are above a certain level. Small scale CHP units use a large heat accumulator in order to produce electricity independent of demand for heat. The small CHP units are able to start, stop and regulate power production very quickly. In addition to a heat accumulator, the large CHP units are also equipped with a condensation turbine which allows them to produce electricity without heat production. This gives the large units a larger degree of flexibility compared to the smaller CHP units. However, the larger units are slower to regulate and start and stop production compared to the small scale CHP units.

The current outlook for the gas fired capacity is a reduction in capacity. The larger units are being supplemented or converted to biomass. The capacity to use gas as a fuel will remain, but the expectation is a reduced demand for natural gas. A large share of the small scale CHP units are expected to be shut down and replaced with other heat producing units: mainly biomass, heat pumps and solar heating. The capacity for producing electricity using gas is thus expected to decline significantly the next years. The drivers for this development are: low electricity prices and a relative higher taxation on heat based on fossil fuels compared to heat from biomass or electricity. This is a general trend in the Danish electricity system, power plant capacity is expected to be reduced and other sources of flexibility are used to balance load and production. The role for power plants gas fired and others is expected to decrease significantly.

France

Gas consumption

Consumption in the French gas market is around 490 TWh/year. Gas represents a much smaller share (15%) of total primary energy consumption than the EU average (23%).

Natural gas is primarily used for heating in the residential and industrial sectors. Power generation from natural gas is limited.

Due to the important share of heating in gas use, there is a strong link between climate and demand for gas. Thus demand is highly modulated during the year. Average consumption increases almost fivefold between August (530 GWh/d) and February (2 370 GWh/d).

Considering a cold spell with an occurrence of once every fifty years, daily peak demand is 4 300 GWh/d.

Since 2003, a slight decrease in gas demand has been observed. In the residential sector, energy efficiency efforts combined with the stagnation in the number of customers led to a decline in demand. Conversely, industrial demand has remained stable with an increase in fuel conversion (from heavy fuel oil) and increasing demand in the commercial and service sectors.

For the coming years, the drivers of the natural gas demand evolution are:

- The effectiveness of energy efficiency measures, which should result in lower demand in the residential and tertiary sectors;

- The economic situation and the competitiveness of natural gas compared to other fuels, which will determine the use of gas by the industry;
- The potential development of gas demand in new sectors such as power generation and mobility.

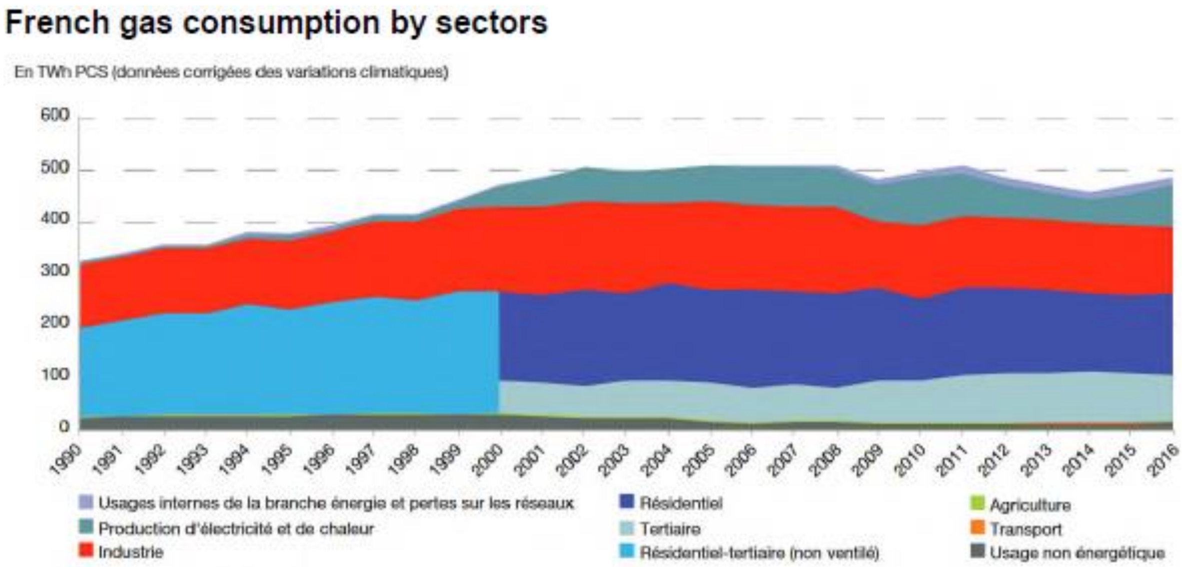

Figure 18: Gas consumption by sectors (Sources: enquête annuelle sur les statistiques gaziéres (SDES), enquête annuelle sur la production d'électricité (SDES), enquête annuelle sur les consommations d'énergie dans l'industrie (Insee))

Gas system

The gas system in France is composed of:

- 12 500 km of transmission network operated by two TSOs (GRTgaz and TIGF).
- 7 major interconnection points (2285 GWh/d of technical entry capacity)
- LNG terminal (1 330 GWh/d of technical entry capacity)
- 12 storages sites in operation (2 400 GWh/d of withdrawal capacity).
-

The daily import capacity on the French territory amounts to around 3 600 GWh/d, 65% of which is pipeline gas and 35% LNG.

French gas network

Figure 19: Map of Gas infrastructure in France

Interconnection

The French gas system has eight major interconnection points.

Interconnection point	From/to	Capacity (GWh/d)		Flows	
		Entry	Exit	2016	2017
Dunkerque	*Norway*	*570*	*-*	*500*	*525*
Alveringem	*Belgium*	*-*	*270*	*0*	*8*
Taisnières B	*Belgium*	*230*	*-*	*135*	*122*
Taisnières H	*Belgium*	*640*	*-*	*367*	*351*
Obergailbach	*Germany*	*570*	*-*	*240*	*229*
Oltingue	*Switzerland*	*-*	*223*	*-37*	*-81*
Jura	*Switzerland*	*-*	*37*	*-6*	*-6*
Pirineos	*Spain*	*225*	*170*	*-84*	*-118*
		2 235	*700*		

Table 14: Interconnection points in France

Underground gas storage

France has 15 gas storage facilities. Storengy operates 100 TWh of storage capacity, or around three-quarters of the country's total. TIGF operates two aquifers with a total capacity of 32 TWh or 20% of the gas storage.

Since 2012, three storage facilities (Trois-Fontaines, Soings-en-Sologne and Saint-Clair-sur-Epte) have been mothballed, reflecting worsening economics for storage operators.

Storage	Working gas [TWh]	Maximal daily withdrawal capacity for 45% filling level [GWh/d]
Beynes	5.5	125
Céré-la-Ronde	6.5	105
Cerville-Velaine	7.3	70
Chemery	42.4	420
Etrez	7.9	360
Germigny-Sous-Coulomb	9.4	60
Gournay (gaz B)	13.4	245
Lussagneet / Izaute	32.6	544
Monasque	3.3	170
Saint-Illiers-la-Ville	7.8	1 335
Tersanne	1.8	140
Total	**137.9**	**3 574**

Table 15: Gas storage capacities in France

LNG terminal

France has four operating LNG terminals. The country's total regasification capacity stands at around 35 bcm/y. Since 2011, the utilization of the French LNG infrastructure has been low (25% in 2017) because of the significant fall in Europe's gas demand and the diversion of LNG cargoes to higher-priced markets in Asia (re-export).

The facilities at Fos-Tonkin, Fos-Cavaou and Montoir-de-Bretagne follow a regulated third-party access (TPA) regime and tariffs for capacity used at these facilities are set in a fashion similar to that for network tariffs.

LNG Terminal	State	Startup	Capacity [GWh/d]	Capacity [Bcm/y]	Storage capacity (LNG m³)	Max capacity of LNG cargoes (m³ GNL)
Dunkerque	Exemption	2016	350	13.0	570 000	266 000
Montoir	Exemption	1980	400	10.0	360 000	266 000
Fos Tonkin	Exemption	1972	410	3.0	80 000	75 000
Fos Cavaou	Exemption	2010		8.3	330 000	266 000
			1 160	**34.3**	**1 340 000**	

Table 16: Capacities of LNG terminals in France

Dunkirk LNG terminal was granted full exemption from third-party access (TPA) and tariff regulation. These exemptions apply to all the capacity of the terminal for a period of 20 years from the date of commissioning (2016). Exemptions were granted by the European Commission under the European Directive 2009/73/EC Article 36.

Gas supply

French natural gas security of supply relies on a gas system with numerous entry points that allows diversified imports and extensive gas storage facilities.

French supply is based on diversified imports. Norway, Russia, the Netherlands and Algeria are the major suppliers with a 43%, 21%, 11% and 10% share of imports, respectively. Norway is the only supplier representing more than 20% of total imports.

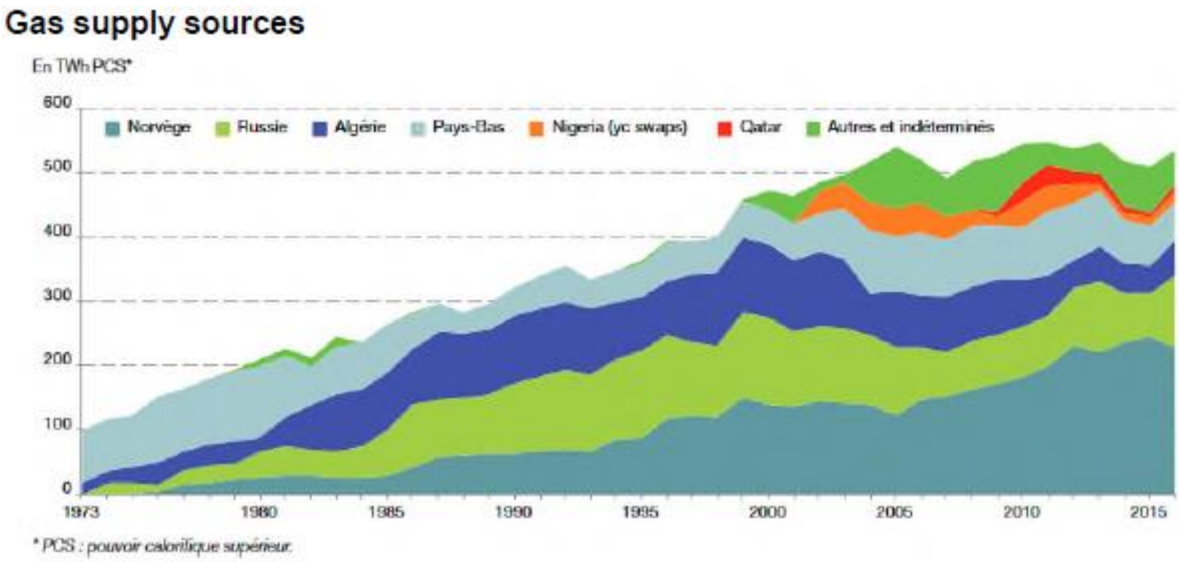

Figure 20: Gas supply sources (Source: calculs SDES, enquête annuelle et mensuelle sur la statistique gaziére)

In 2017, 80% of imports were made by pipeline and 20% by LNG terminal.

In addition to pipeline imports (55%) and LNG terminal dispatch (15%), storage covers an average of 30% of winter demand. During peak demand, or supply issues, the role of storage is even more important. It reached 55% on a daily basis during a cold spell in February 2012.

French gas production represents a small share of gas consumption. In 2016, 0.2 TWh were produced accounting for 0.04% of French gas consumption.
Since 2012, biogas can be injected into the gas network. Volumes are very limited but grow every year (0.4 TWh in 2017). There is strong potential for production based on agricultural waste. The TECV Act set an objective of 10% of renewable gas in gas consumption for 2030. Several measures have been taken to support biogas production.

Germany

In 2017 Germany had gas consumption of 897.5 TWh but the amount of gas that has been transported over the German infrastructure is approximately twice as much. The German gas infrastructure is highly suitable for and capable of meeting the demands of gas transportation through and within Germany.

Germany has an extensive transmission system. The network of the transmission system operators (TSOs) is about 38 000 km long, has more than 110 compressor stations and is connected to the systems of neighbouring countries via a large number (>25) of cross-border interconnection points. The transport infrastructure was essential for Germany's natural gas market, situated as it is in the centre of Europe, to develop into an important trading hub for the continent. The German gas transmission system is divided into an H-gas area and an L-gas area.

In the past, gas consumed in the northern part of the supply area in Schleswig-Holstein and Hamburg largely came from Danish reserves. For some years now Denmark has been stepping up preparations for supply from German imports via the Ellund station.

The network stretches from the import points at the North Sea and the supply systems from the direction of Schleswig-Holstein, Saxony-Anhalt and Thuringia, as well as from the import points and some export points in the south from the direction of the Czech Republic and Austria, and in the west from the direction of the Netherlands and Belgium through to the export points to France and Switzerland.

The import of large volumes plays an important role in the north-west of Germany. Equally large volumes also enter the area via the pipeline networks from an eastern and northeastern direction, so the principal flow of gas is from the north-east to the south-west. There are further import points for the western transmission system around Aachen, allowing gas to be transported to Germany from the Netherlands/Belgium via Eynatten/Raeren, and Bocholtz. Eynatten/Raeren can also be used as an export point.

In the southern part there are significant import points on the borders of the Czech Republic and Austria. The major export points are on the borders to France, Switzerland and Austria. The transmission system is thus used for both transit and supply services.

The eastern part of the supply area covers Mecklenburg-Western Pomerania, Brandenburg, Saxony-Anhalt, Saxony, Thuringia and Berlin. Gas for this part comes from import points in the east via Poland, in the north-east via the Baltic Sea and in the south from the Czech Republic. Some of the gas needed is fed in from the west of Germany, so the available transmission system provides both transit and supply services.

The Nord Stream and Baltic Sea Pipeline Link (OPAL) pipelines were put into operation at the end of 2011. The OPAL can transport up to 35 bcm of natural gas a year from Nord Stream. This means that Nord Stream and the OPAL, together with pipelines in the Czech Republic (Gazelle), ensure supply volumes for the Waidhaus import point and strengthen the security of supply for Germany, France and the Czech Republic.

The North German Gas Pipeline (NEL), which started full commercial operation on 1 November 2013, runs from where Nord Stream comes on shore in Lubmin near Greifswald towards the west through Mecklenburg-Western Pomerania to Lower Saxony. Over 20 bcm of natural gas a year can flow through the NEL.

Table 17 lists the German cross-border interconnection points and gives the available, fixed entry and exit capacity for each. This shows that there are relatively many import routes to supply the German market ("diversification of supply routes"), while adjacent markets can also source gas from Germany using various routes. There is therefore a reduced risk to the security of supply for both the German and neighbouring markets.

Cross-border interconnection point	Gas quality	Import [GWh/d]	Export [GWh/d]	Bidirectional
Eynatten/Lichtenbusch/Raeren	H	321.1	310.9	Yes
Remich	H	0.0	38.7	No
Bocholtz	H	426.5	0.0	No
Zevenaar	L	456.0	0.0	No
Winterswijk	L	178.6	0.0	No
Bunde/Oude Statenzijl	H	135.7	506.5	Yes
Bunde/Oude Statenzijl	L	268.7	0.0	No
Oberkappel	H	159.9	199.4	Yes
Medelsheim/Obergailbach	H	0.0	587.3	No
Überackern/Burghausen	H	237.1	216.4	Yes
Kiefersfelden	H	0.0	28.3	No
Wallbach	H	0.0	319.7	No
Ellund	H	91.1	101.2	Yes
Mallnow	H	931.5	184.8	Yes
Lasów	H	0.087	48.7	No
Brandov/Stegal	H	0.0[16]	0.0	Yes
Olbernhau/Hora Svaté Kateřiny	H	0.0	319.7	Yes
Hora Svaté Kateřiny/Deutschneudorf	H	198.3	105.6	Yes
Opal/Brandov	H	0.0	951.9	No
Waidhaus	H	906.9	0.0	No
Haanrade	L	4.9	0.0	No
Dornum/NETRA	H	721.2	0.0	No
Emden	H	470.6	0.0	No
Greifswald	H	618.18	0.0	No
Total		**6 127.0**	**3 919.0**	

Table 17: Cross-border interconnection points of Germany

In the following figure the size and the spread of the German H-Gas network is shown. The H-Gas network covers the entire territory from the North to the South and from the West to the East.

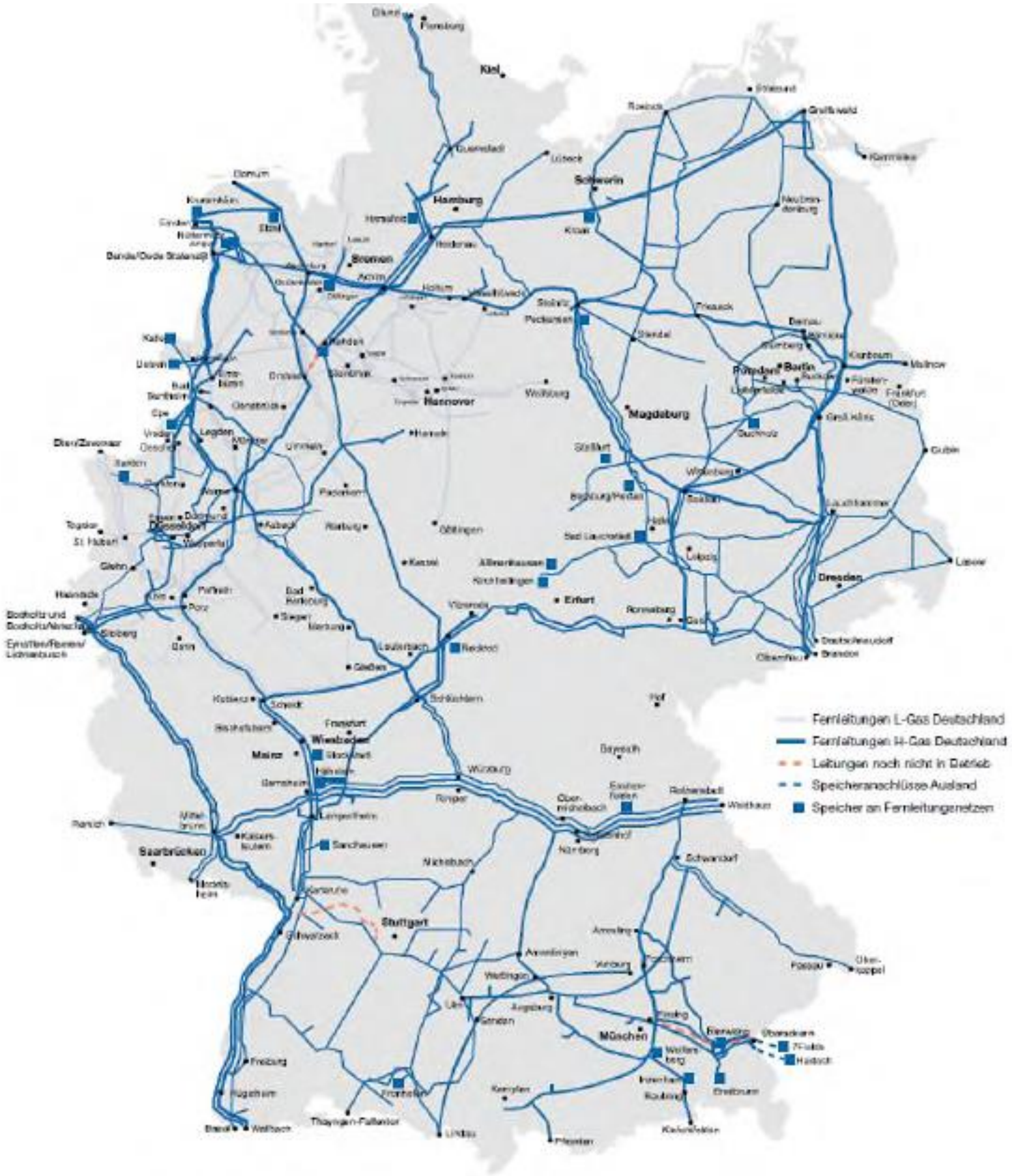

Figure 21: H-gas transmission network (Source: Transmission system operators)

Parallel and partly overlapping to the H-Gas network in the following figure the size and the location of the L-Gas network is displayed. The L-Gas network concentrates in the northwestern part of the German territory.

Historically, the L-gas networks in the north grew up around the existing reserves, i.e. the large areas around the Elbe/Weser and Weser/Ems in Germany and the Groningen gas field in the Netherlands, from which gas is imported via the Oude Statenzijl station. These are still the only sources today. Storage facilities to allow resources to be structured and cover peak loads are located in Nüttermoor, Huntorf, Lesum and Empelde. The network is designed to be supplied from the abovementioned reserves and offers only limited flexibility.

The L-gas network in the west primarily supplies final consumers across the network levels. The high proportion of household customers makes gas sales heavily dependent on temperature. Situations that put the system under strain occur not just under normal circumstances but also in intermediate or weak load situations when there is a lot of flexibility on the entry side. The system is supplied partly by imports from the Netherlands and partly by volumes from German production through the northern subsystem. Storage facilities to allow resources to be structured and cover peaks are located in Epe.

Figure 22: L-Gas Transmission system (Source: Transmission system operators)

In north-west Germany, the L-gas area expands over the two market areas, NetConnect Germany (NCG) and GASPOOL. Five TSOs operate L-gas transmission systems: Open Grid Europe and Thyssengas in NCG and Gasunie Deutschland (GUD), GTG Nord and Nowega in GASPOOL.

German L-gas is produced only in the GASPOOL market area. One of the aims of the current conversion plants is for the remaining domestic L-gas production to remain usable until the time when production ends completely.

The two market areas are affected by the decline in L-gas production in the Groningen field in the Netherlands to different extents. The GASPOOL network area receives L-gas imports from the Netherlands only via the cross-border interconnection point in Oude Statenzijl. GTG Nord and GUD are directly affected, whereas Nowega does not have its own L-gas crossborder interconnection point. Only gas from the Groningen field, which has been affected by the earthquake issue, is transported via Oude Statenzijl.

Current planning for production from the Groningen field has a decisive influence on German L-gas imports from the Netherlands.

The L-gas system operators in the NCG market area, Open Grid Europe and Thyssengas, can also be supplied with gas converted from H-gas to L-gas in the Netherlands via the cross-border interconnection points at Winterswijk/Vreden, Elten/Zevenaar, Tegelen and Haanrade, so NCG is less directly affected by the decline in production caused by earthquakes. It should be noted, however, that around 75% of Dutch conversion capacity is already in use as planned. If the L-gas production is restricted, therefore, conversion will be able to provide relatively little additional capacity. The NCG market area accesses further L-gas capacity from market area interconnection points to the GASPOOL market area.

In view of the reductions in German L-gas production and L-gas imports from the Netherlands, the relevant companies are already taking action to prevent any decline in the availability of L-gas negatively affecting security of supply. German L-gas producers, the network operators affected and storage system operators have set up a joint working group to develop a plan for the coordinated conversion from L-gas to H-gas. The companies involved are drafting a conversion plan that will include a schedule for converting the supply areas affected from L-gas to H-gas.

The conversion plan is included in the national network development plan as an input parameter. The investment measures at the transmission system level that are necessary for the conversion from L-gas to H-gas arise out of the gas network development plan and are subject to assessment by the regulatory authority. As part of the national network development plan, these investment measures are legally binding, but if there is a need to adjust the conversion plan, changes can be introduced when the network development plan is drawn up.

Gas storage facilities

Some 34 underground storage facilities are operated in Germany at the present time, but because some of them are used by more than one operator, 50 facilities are marketed. The maximum usable working gas volume in these underground storage facilities amounts to some 280.1 TWh,19 giving Germany the largest storage capacity in the European Union.

Of the total usable working gas volume, 132.22 TWh are accounted for by cavern and 125.86 TWh by pore storage facilities. Reflecting the structure of the German natural gas market, the majority of the storage facilities are used for the storage of H-gas (259.86 TWh for H-gas compared to 20.24 TWh for L-gas).

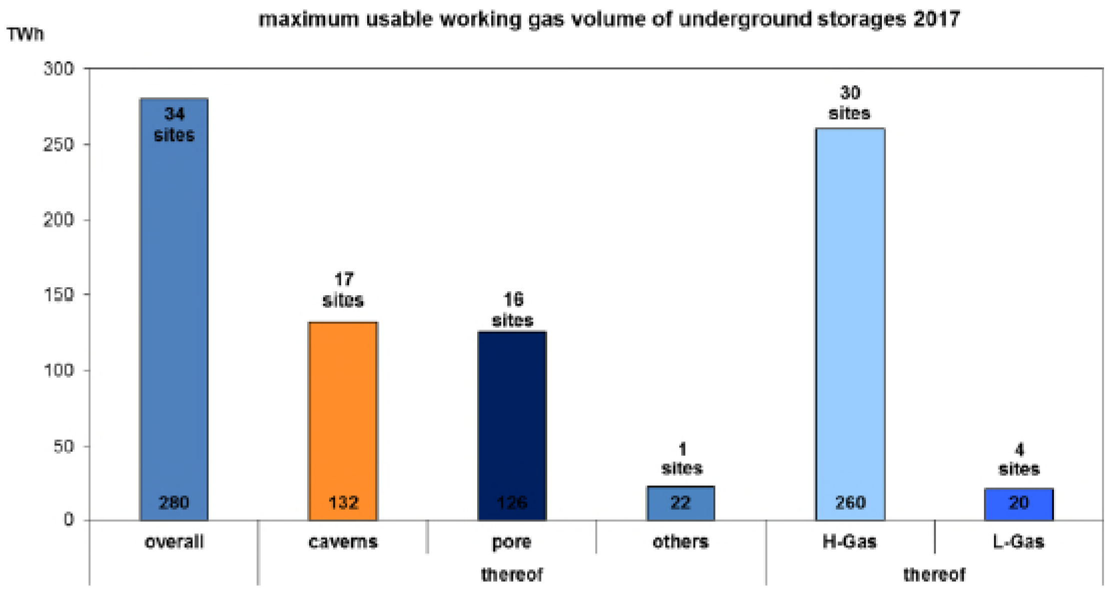

Figure 23: Distribution of working gas volume in German natural gas storage facilities (Bundesnetzagentur, Monitoring Report 2018)

The storage facilities are located across nearly the whole of Germany, although for geological reasons there are regional clusters in the north-west and south-east.

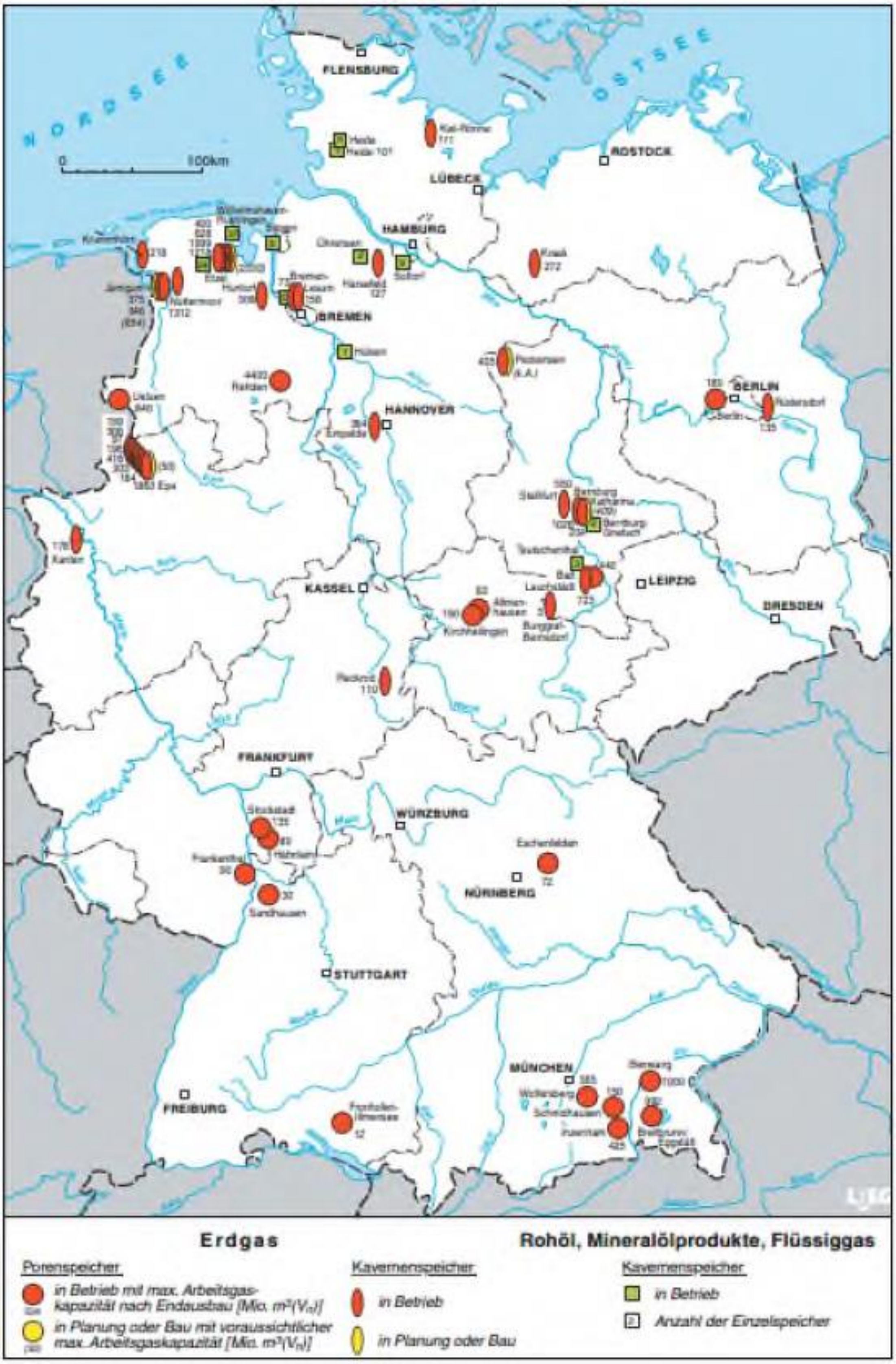

Figure 24: Map of German natural gas underground storage facilities (Source: LBEG, 2016)

Major investments in the expansion of transmission systems

An overview is given below of the most important expansion measures in the gas network that contribute to security of supply and have been implemented since 2013 or are planned for implementation by winter 2019-2020.

Nordschwarzwald pipeline

The 71 km Nordschwarzwald pipeline lies in the area of network operators Fluxys TENP, Open Grid Europe and terranets bw in southern Germany. It increases transport capacity in the south of the country and was completed by terranets bw in 2016. In Baden-Württemberg, the Nordschwarzwald pipeline connects to the existing Trans Europa Naturgas Pipeline (TENP), which transports gas from the Netherlands through to Switzerland and Italy and, in future, will also take it in the other direction. The Nordschwarzwald pipeline considerably increases capacity for gas-fired power plants and distribution networks located in southern Germany.

Monaco I

The Monaco I pipeline is helping to reduce transportation congestion in southern Germany from winter 2017-2018. It is 86.7 km long and runs from Burghausen on the Austrian border to Finsing. It increases transfer capacity between Open Grid Europe and bayernets as well transport capacity to the 7Fields and Haidach storage facilities and exit capacities for downstream network operators. Moreover, Monaco I also helps to ensure that demand for natural gas in Germany can be met by linking international pipelines.

Schwandorf-Forchheim pipeline and Forchheim-Finsing pipeline

Alongside the existing pipeline network in Bavaria, Open Grid Europe planned to build two new pipelines, one of them from Schwandorf to Forchheim (62 km, under operation since the end of 2017) and the other from Forchheim to Finsing (79 km, start of operation planned for the end of 2018). These pipelines will help to improve the capacity situation in Bavaria and the connection of the 7Fields and Haidach storage facilities.

Werne compressor station

The Werne compressor station is a central hub in the German transmission system where pipelines come together from various directions. Open Grid Europe worked on reversing the compressor station so that gas can flow from south to north. Work has finished and the compressor station is under operation since the end of 2017. It improves transfer capacity in the direction of Denmark and between the network operators Open Grid Europe and Thyssengas, with the result that security of supply will be increased. It plays an important role in the conversion of network areas from L-gas to H-gas.

Rehden conversion plant

In early 2016 TSO Nowega put a plant in Rehden into operation that can convert H-gas to L-gas. Key German L-gas reserves are located in Nowega's network area. The German TSOs' plan for the conversion from L-gas to H-gas provides for these German reserves to be fully utilised, so it is planned for network areas in Nowega's region to be supplied with L-gas beyond 2030. However, production there is not sufficient to cover all consumption peaks throughout the year. The conversion plant allows H-gas to be imported into these network areas, converted to L-gas and then used to cover peak loads.

Wertingen compressor station

Network operator bayernets plans to construct a new compressor station with three compressor units at its Wertingen site. The station is to improve the supply situation in southern Germany from the end of 2019 onwards. This measure will increase the transfer capacity between Open

Grid Europe, bayernets and terranets bw. As a result, the existing storage facilities, 7Fields and Haidach, will be better connected and the capacity situation for distribution system operators will also be improved.

TENP reverse flow

The TENP runs for about 500 km through Germany and directly connects the Dutch and Belgian gas markets with the Swiss one. It was originally designed to transport gas south from trading points in the Netherlands and Belgium. It is also connected to the MEGAL pipeline system that brings Russian gas to Germany.

The liberalisation of the gas markets and the opening up of southern transport routes have created an increased need to be able to transport gas in the other direction as well, leading Open Grid Europe and Fluxys TENP to plan to reverse the flow of the pipeline. This means that, in future, as the southern gas corridor is expanded, it will also be possible to transport gas from Italy through Switzerland towards Germany and beyond, as required. Transport routes will be diversified and the security of supply in Europe strengthened.

To reverse the pipeline, it is necessary to reverse the compressor station at Hügelheim and install a deodorisation plant on the Swiss-German border. These are due to be operational by the end of 2020.

NOWAL

The north-west pipeline link (NOWAL) is 26 km long and runs from Rehden to Drohne. It transports gas from the north – from the Netherlands or Nord Stream, for example – to the main German consumption areas. This enables the transfer capacity from the GASPOOL to the NCG market area to be increased. The pipeline was set into operation at the end of 2017.

Reversal of Waidhaus compressor station

The Waidhaus compressor station, which is located on the German-Czech border, has up to now been used to feed gas coming from the Czech Republic into the MEGAL pipeline and transport it west to the NCG market area. Open Grid Europe and GRTgaz Deutschland plan to expand and convert the compressor station so that gas can also be transported in the opposite direction, from Germany to the Czech Republic. This will make it possible to use the Waidhaus cross-border interconnection point bidirectional in future, allowing, for example, gas from the Netherlands or from the storage facilities on the German-Austrian border to be transported towards central and Eastern Europe, improving security of supply there. Start of operation is planned for the end of 2018.

North European Natural Gas Pipeline (NEL)

The NEL pipeline started operating fully in November 2013. It and the OPAL pipeline, which was already in operation, connect Siberian natural gas reserves with the supply network in Western Europe. The NEL takes gas from Nord Stream in Lubmin, near Greifswald, and transports it through Mecklenburg-Western Pomerania and Lower Saxony to the Rehden interconnection point, from where it is taken on to the German and western European consumption centres in the MIDAL pipeline or injected directly into the Rehden storage facility. The NEL is about 440 km long and can transport up to 20 bcm of gas a year, equivalent to around a fifth of Germany's annual consumption. It therefore improves Germany's security of supply.

EUGAL

EUGAL is to run from Lubmin near Greifswald by the Baltic Sea in Mecklenburg-Western Pomerania southward to Deutschneudorf in Saxony and from there to the Czech Republic. It has a total length of some 480 kilometres and large parts of it are to be laid parallel to the Baltic Sea Pipeline Link (OPAL). That means it will run through the German federal states of Mecklenburg-Western Pomerania (approx. 102 kilometres), Brandenburg (approx. 272 kilometres) and the Free State of Saxony (approx. 106 kilometres). Much of EUGAL will be built with two parallel strings in order to cater for the capacities required long term, especially in Southeastern Europe. Just one string is planned from Weißack in Brandenburg to the German/Czech border, since existing capacities can be used for further transportation. The fact that the new pipeline is to run in existing corridors will minimize the impact on people and nature. A new compressor station is also planned in Brandenburg, to ensure that the gas can be transported with sufficient pressure. Start of operation is planned for the end of 2019.

Luxembourg

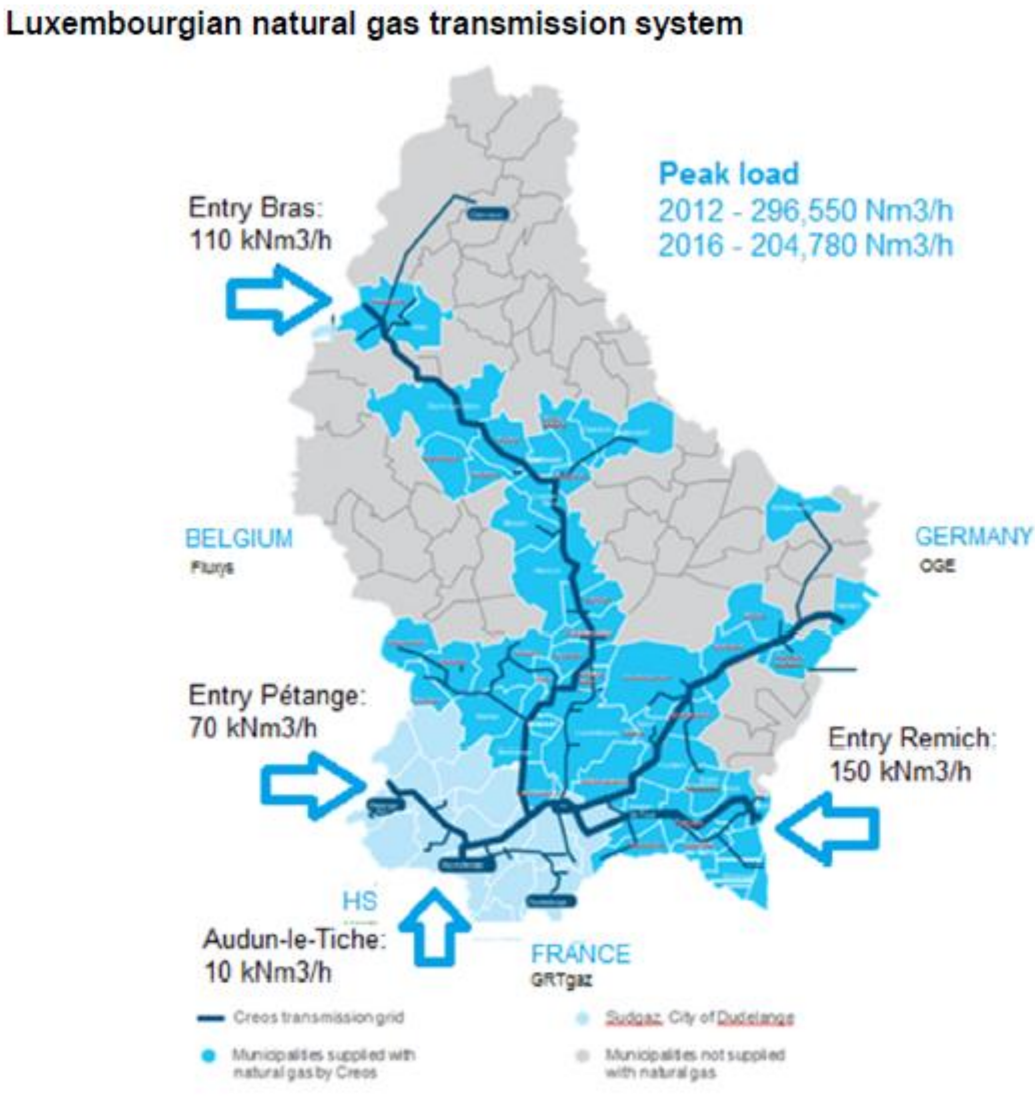

Figure 25: Natural gas transmission system of Luxembourg

The natural gas transmission system of Luxembourg comprises 281.8 km of PN 67.5 high pressure pipeline (DN500/DN400). The transmission gas infrastructure is owned and operated by Creos Luxembourg. The Luxembourg gas supply is ensured mainly by three physical entry points, two to Belgium and one to Germany. A small connection to France has not been in operation since

2016. The two entry points to Belgium ensure a total capacity of 180 000 m3/h. The capacity at the German interconnection point (IP) is limited to 150 000 m3/h and a minimum of 90 000 m3/h is necessary to fulfil the N-1 obligation.

The total capacity of the transmission system amounts to 330000 m3/h.

The transmission system transports natural gas to 59 pressure-reduction substations (distribution system and customers). No transit is currently possible due to operational constraints and gas odorization at the German and Belgian border. No infeed or storage entities are connected to the transmission system.

The main peak load registered in the last ten years dates from 2012 and amounts to 296 550 m3/h. However due to the decommissioning in July 2016 of a CCGT gas power plant with a capacity of 375 MWel, the peak load decreased significantly to 204780 m3/h in 2016.

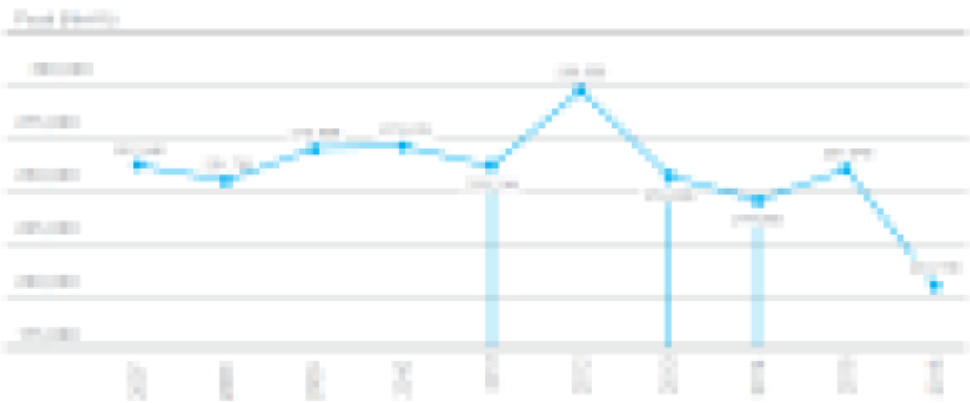

Figure 26: Main peak loads in Luxembourg

Since 2016 the two TSOs Fluxys Belgium and Creos Luxembourg have launched the first cross border market integration. With the removal of the Bras/Pétange interconnection point from the commercial offer, grid users will no longer have to reserve capacity at that point (which disappeared from the commercial offer) to transmit gas between Belgium and Luxembourg. The commitment to increase firm capacity from 110 000 m3/h at 27 bar up to 180 000 at 40 bar in Bras and at 32 bar in Pétange is part of the integration project and insures significant security of supply for Luxembourg.

Due to the market integration and the shutdown of the CCGT in Luxembourg, more gas volumes are currently delivered from Belgium than from Germany to Luxembourg.

In 2016 70.7% of the flow was delivered from the Belgium entry points.

Breakdown of flow per point of interconnection

		2015	2016	Variation
Remich	German network	3693 GWh	2682 GWh	-27.4 %
Bras	Belgian network	5387 GWh	5701 GWh	+6.0 %
Pétanger	Belgian network	858 GWh	782 GWh	-9 %
Total		9938 GWh	9165 GWh	-7.8 %

Table 18: Breakdown of flow on Luxembourg's interconnections points

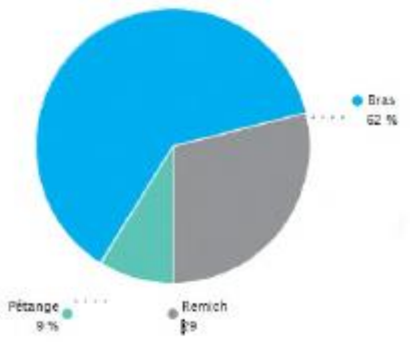

Figure 27: Chart of breakdowns of flow in Luxembourg in 2016

Netherlands

The gas system in the Netherlands

Gas network in the Netherlands

Configuration of regional grids

In the Netherlands there is a total of 135 000 km of gas pipelines (Netbeheer Nederland, http://www.netbeheernederland.nl/branchegegevens/infrastructuur/). At the time of writing there were 8 Local Distribution Companies for gas in the Netherlands (https://www.acm.nl/), of which there are 7 operating gas transmission grids for L-gas and 1 for H-gas (ZEBRA Gasnetwerk B.V. operates a high calorific gas transmission grid in Zeeland and Brabant). On the map, Figure 28, the service areas of the different distribution companies for L-gas are indicated.

Figure 28: Service areas of the Dutch Local Distribution Companies for L-Gas in 2018 (Source: http://www.energieleveranciers.nl/netbeheerders/gas)

Configuration of national grid

Of the 135 000 km, 11000 km is high pressure pipelines, operated by GTS. The high pressure gas network is shown on the map, Figure 29. The Dutch high pressure network is directly connected to Belgium, Germany, Norway and the United Kingdom. Through over 1 000 gas custody transfer stations gas is distributed to the Dutch domestic market to for example large industries, power plants and to local distribution companies.

Dutch gas market size

A good illustration of the size of the Dutch gas demand is the fact that peak demand for gas is almost 10 times the size of peak demand for electricity. The Dutch network of gas pipelines, storage facilities and an LNG terminal can supply 10 times as much energy to the domestic market as compared to the existing Dutch electricity grid. This is illustrated by the figure below, where the gas demand is compared to the electricity demand.

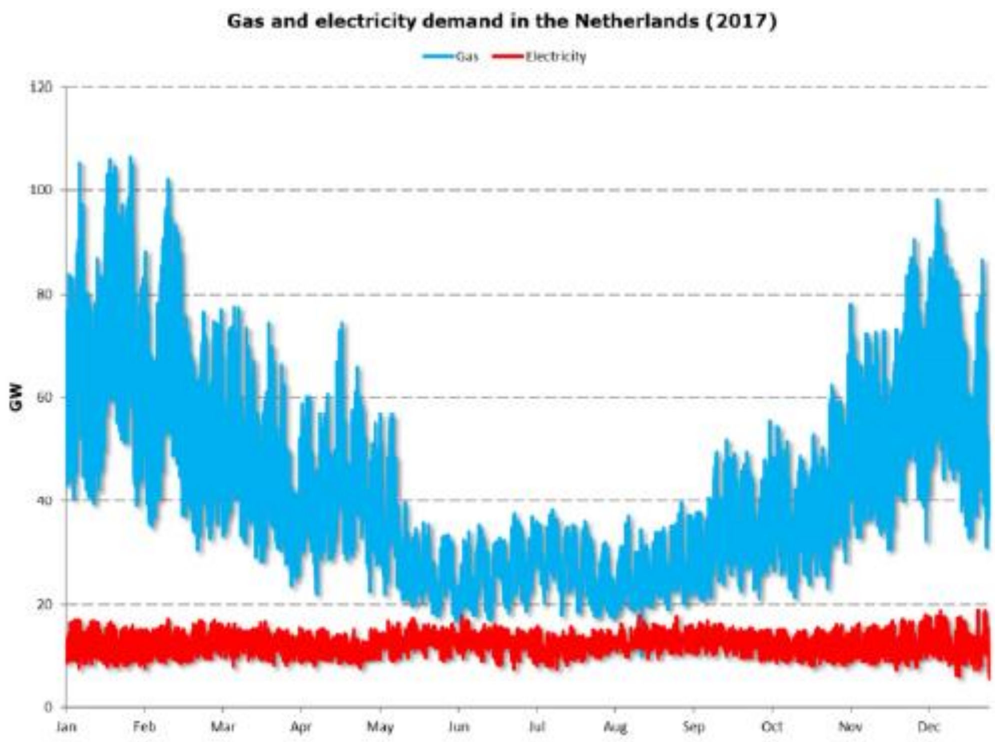

Figure 29: Gas and electricity demand in the Netherlands in 2017 (Source GTS, TenneT)

In 2017 GTS transported about 959 TWh. This means that the average Dutch annual gas consumption of 374 TWh is less than half of the total volume of gas that annually is transported through the country. This is due to export of indigenous gas and the role of the Netherlands as a transit country. Depending on climatic conditions, the share of L-gas in the domestic gas demand varies from year to year. In 2017, the L-gas demand was 243 TWh, roughly 65% of the total gas demand.

While on average national demand slightly decreases, domestic production is on the longer term in strong decline. As a result more volumes have to be imported. Infrastructure has been and will be adjusted to facilitate this. According to the National Development Plan of GTS, the Netherlands will become a net importer of gas between 2020 and 2035, depending on considered scenario (https://www.gasunietransportservices.nl/netwerk-operations/onderhoud-transportsysteem/netwerk-ontwikkelingsplan-2017-nop2017).

	2015		2016		2017	
	Yearly TWh	Peak GWh/d	Yearly TWh	Peak GWh/d	Yearly TWh	Peak GWh/d
Build environment	112	2 226	119	2 191	115	2 238
Industry and power generation	127	943	128	943	128	872
Total	**239**	**3 169**	**247**	**3 134**	**243**	**3 110**

Table 19: Historic L-gas demand in the Netherlands

Sources of gas

Gas flows through the Netherlands

The sources of the gas that flows through the Netherlands are indigenous production, LNG, Norwegian gas and Russian gas. The figures below show the gas flow from and to neighbouring countries and the yearly utilisation rates of the infrastructure that were observed in 2017.

Actual cross border flows in TWh in 2017		L	H	Total
Belgium:	to Belgium	91	86	177
	from Belgium	0	45	45
Germany:	to Germany	185	88	273
	from Germany	0	104	104
Norway:	to Norway	0	0	0
	from Norway	0	230	230
United Kingdom:	to the UK	0	21	21
	from the UK	0	0	0

Table 20: Actual cross border flows in 2017[28]

[28] The actual flows do not include Zebra pipeline or the flows related to cross-border connections to German storages.

Utilisation in 2017	Entry	Exit
Hilvarenbeek	n.a.	37%
OSZ-G	n.a.	33%
Winterswijk-Zevenaar	n.a.	40%
Tegelen	n.a.	12%
Haanrade	n.a.	48%
Emden-OSZ-H	49%	5%
Limburg	n.a.	38%
Zandvliet H (Fluxys)	n.a.	77%
Vlieghuis	n.a.	33%
Julianadorp-Zelzate	29%	18%
Dinxperlo	n.a.	9%
Zandvliet Wingas	n.a.	39%
OSZ UGS	16%	13%
Caverns Epe	7%	10%
GATE LNG Terminal	6%	0%

Table 21: Yearly utilisation rates[29]

[29] Source: GTS

Security of supply supported by a liquid gas hub

The TTF (Title Transfer Facility) is the virtual gas trading platform in the Netherlands where gas can be traded. Trade on the TTF continues to grow steadily, further strengthening its leading position on the European continent. In January 2018 148 traders were active on the platform, compared to 114 in June 2014. The volume of gas traded on the TTF in 2017 was 20 962 TWh, compared to 13.216 billion TWh in 2014. This is more than three times the volume of all other continental exchanges put together, making it the most liquid continental hub.

Figure 30 shows the strong growth in the number of parties on the TTF, the increase in traded volumes and the net volume between January 2013 and January 2018. The increasing liquidity of TTF helps to lower costs for consumers through efficient resource use and investment decisions and provides confidence for suppliers and investors, enhancing security of supply.

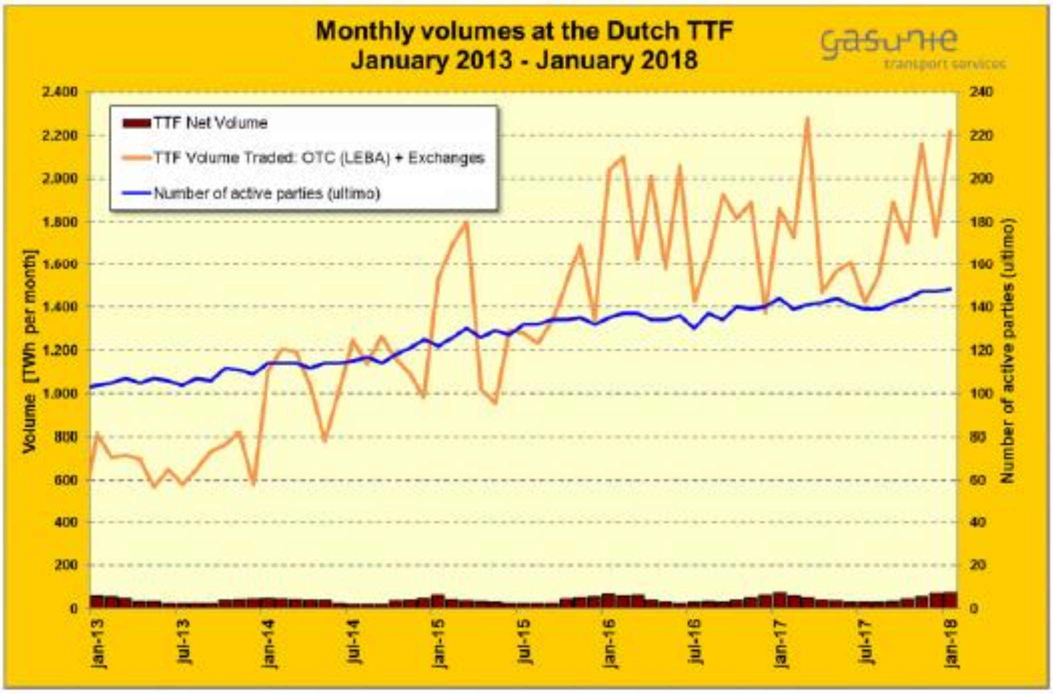

Figure 30: Monthly volumes and number of active participants TTF 2009 - 2017[30]

[30] Source: Source: https://www.gasunietransportservices.nl/over-gts/publicaties

Gas production in the Netherlands

History of production

In 1959 one of the world's largest gas fields was discovered in The Netherlands. This Groningen gas field is a giant natural gas field located near Slochteren in Groningen province in the north eastern part of the Netherlands. The Groningen gas field is owned and operated by the Nederlandse Aardolie Maatschappij BV (NAM), a joint venture between Royal Dutch Shell and ExxonMobil with each company owning a 50% share. The Groningen field produces gas of so-called G-gas quality.
The Groningen field has been producing natural gas for more than 50 years. It had an estimated total production volume of 2800 BCM of which around 25% is in theory still available. In order to save this field, the Netherlands has been dedicated since the 1970s to extracting gas from smaller fields, and the Groningen field is used to provide stability in the provision of energy, the so-called small fields policy. Since then, over 466 small gas fields have already been discovered in the Netherlands, of which the larger part (236) have already been taken into production. Altogether, these small fields provide about a third of the total gas production in the Netherlands.

For many years total annual production in The Netherlands was about 80 BCM. This has already decreased in the past year and will continue to decrease in the coming years due to production limitations set on the Groningen field and lower production levels of the small fields.

Forecasted indigenous production

Figure 31 below details long term Dutch small fields gas production estimates (https://www.gasunietransportservices.nl/netwerk-operations/onderhoud-transportsysteem/netwerk-ontwikkelingsplan-2017-nop2017). For the graph the most recent information, dating back to 2017, was used.

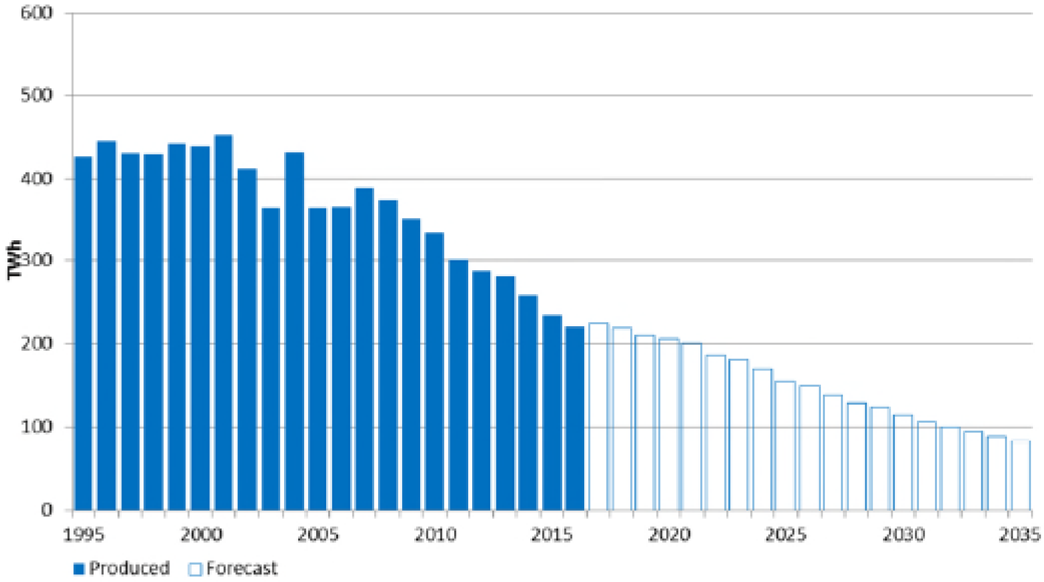

Figure 31: Historic and estimated production of Dutch small fields[32]

[32] Source: GTS

Due to the earthquakes related to the gas production in Groningen the volume allowed to be produced has been restricted in the past years. This has resulted in a reduction of production level from the Groningen field from 54 BCM in 2013 to 23.98 BCM in gas year 2017 (https://www.nam.nl/feiten-en-cijfers/gaswinning.html#iframe=L2VtYmVkL2NvbXBvbmV-udC8/aWQ9Z2Fzd2lubmluZw==).

On the 8th of January 2018 a gas production induced earthquake occurred at Zeerijp in the province of Groningen. Following the advice of the State Supervision of the Mines, the Dutch Minister has decided to reduce the Groningen production as fast as possible to 12 bcm/year and then continue to 0 bcm i.e. terminate the production from the Groningen field.

To achieve this, GTS will invest in a new nitrogen plant at Zuidbroek which can produce up to 7 bcm of pseudo L-gas in a cold year. In addition, GTS will purchase additional nitrogen which can produce 1 to 1.5 bcm of pseudo L-gas. Furthermore industrial clients will be converted from L-gas to H-gas. Possibilities to accelerate the market conversion in Germany, Belgium and France will also be investigated.

In the meantime, the production from the Groningen field will never be more than is required from a security of supply perspective. This means that the blending stations of GTS will produce baseload (on average 85% of blending stations Ommen and Wieringermeer) and the Groningen field with the other sources (storages) will cover the rest of the market.

In addition to these volume reducing measures, the Minister also decided to close the production clusters in the Loppersum region. This decision will reduce the capacity of the Groningen field by approximately 25%.

Because these new circumstances were not known at the time the Security of Supply simulations were performed (https://entsog.eu/publications/security-of-gas-supply#UNION-WIDE-SIMULATION-OF-SUPPLY-AND-INFRASTRUCTUREDISRUPTION-SCENARIOS), the disruption scenarios have been recalculated with the latest decisions of the Dutch Minister. In addition to a Norg disruption (Peak and two week) a disruption of blending station Wieringermeer (Peak and two week) has also been considered.

Gas storage in the Netherlands

Indigenous gas production plays an important role in compensating for fluctuations in North West European market demand. The decline in gas production in North West Europe is causing a decrease in the availability of this natural flexibility. Storage facilities are playing an increasingly greater part in order to compensate for this declining production flexibility. To this end, it is important to make a distinction between storage facilities that can provide supplies for summer-winter variations and those that can absorb relatively short peaks in the gas demand. Depleted gas fields (DGF) are extremely suitable for absorbing seasonal fluctuations or to satisfy peak demand. Salt caverns are often used for shorter peaks, but can, when having a large storage volume, also be used to balance out seasonal supply and demand.

The following table (Table 22) was taken from the database underlying the Gas Storage Europe (GSE) map 2016. It lists the storages in the Netherlands. The storage operators provided this data to GSE.

Facility/ Location	Type	Operator	Working gas TWh	Withdrawal 100% GWh/day	Withdrawal 30% GWh/day	Injection GWh/day
EnergyStock	SC	EnergyStock BV	2.7740	252.0	252.0	21.,0
Grijpskerk	DGF	NAM	27.6667	719.3	630.0	172.9
Norg	DGF	NAM	69.8056	758.9	698.0	448.8
Alkmaar	DGF	TAQA Energy BV	4.9514	356.5	356.5	39.6
Bergermeer	DGF	TAQA Energy BV	45.6000	634.5	425.1	467.8

Table 22: Storage facilities in the Netherlands[35]

[35] Source: http://www.gie.eu/index.php/maps-data/gse-storage-map (Norg, Alkmaar and EnergyStock store G-gas, the other storages store H-gas)

The gas storage Bergermeer started operations at 1 April 2015. This storage has a capacity of 46 TWh or 4.1 BCM. With the start of operations at gas storage Bergermeer the total capacity of gas storages in the Netherlands has almost doubled. Norg UGS is connected to the Groningen field via the so called NorGron pipeline. As such, the Norg storage facility is considered to be part of the Groningen gas production system.

Besides access to storages located on Dutch territory, the Dutch gas network has access to German storage facilities. The figure below shows the capacities at Interconnection Points connecting these storages and the GTS grid.

Location	Network point	Entry capacity (GW)	Exit capacity (GW)
Cluster Enschede/Epe storages	Cluster	13.1	7.0
Enschede (Eneco-UGS Epe)	301397	3.9	2.0
Enschede (Innogy-UGS Epe)	301198	4.3	2.2
Enschede (Nuon-UGS Epe)	301309	4.9	3.5
Cluster Oude Statenzijl storages (H)	Cluster	34.0	24.6
Oude Statenzijl (Astora Jemgum)	301391	23.5	23.5
Oude Statenzijl (Etzel-Crystal-H)	301400	15.1	10.8
Oude Statenzijl (Etzel-EKB-H)	301360	16.5	11.6
Oude Statenzijl (Etzel-Freya-H)	301401	10.8	10.2
Oude Statenzijl (EWE Jemgum)	301453	23.5	23.5
Oude Statenzijl (EWE-H)	301361	9.0	8.7
Oude Statenzijl Renato (OGE)	301185	11.9	11.3

Table 23: Capacity at IPs connecting German storage facilities to the GTS grid[36]

[36] Source: NOP Appendix VI, https://www.gasunietransportservices.nl/netwerk-operations/onderhoudtransportsysteem/netwerk-ontwikkelingsplan-2017-nop2017

LNG in the Netherlands

On the Maasvlakte in Rotterdam, Gate terminal has built the first H-gas LNG import terminal in the Netherlands. The terminal currently has a throughput capacity of 12 bcm per annum and consists of three storage tanks, two jetties and a process area where the LNG will be regassified. Annual throughput capacity can be increased to 16 bcm in the future. The terminal dovetails with Dutch and European energy policies, built on the pillars of strategic diversification of LNG supplies, sustainability, safety and environmental awareness. The initiators and partners in Gate terminal are N.V. Nederlandse Gasunie (Gasunie) and Koninklijke Vopak N.V. (Vopak). Gate terminal is an important factor in importing gas from other countries and sources into Europe. It increases the security of supplies and also enables new players to enter the European gas market. Moreover, the terminal's direct connection to the national natural gas transmission network supports the Netherlands' position as a major European hub for gas trade and distribution.

The NW European L-gas market

The NW European L-gas system

Gas produced from the Dutch Groningen field is called G-gas. Low calorific gas (L-gas) is a combination of gas originating from the Groningen field, blended with high calorific gas (H-gas) or H-gas blended with nitrogen. All Dutch blending stations are indicated on the map below, Figure 32. L-gas is consumed in the Netherlands and exported to Germany, Belgium and France.

Figure 32: The high pressure gas network in the Netherlands 2015

The current market demand for all these L-gas consuming countries is shown in the overview below (Figure 33, based on 2017 data). The Netherlands is the largest consumer and main supplier of L-gas in the region. Germany, the second largest market, does also have L-gas production but this is insufficient to meet its domestic demand. Demand in Belgium and France is entirely supplied by imports from The Netherlands. L-gas is exclusively supplied from within the L-gas region. As a consequence there is no import from or export to other regions.

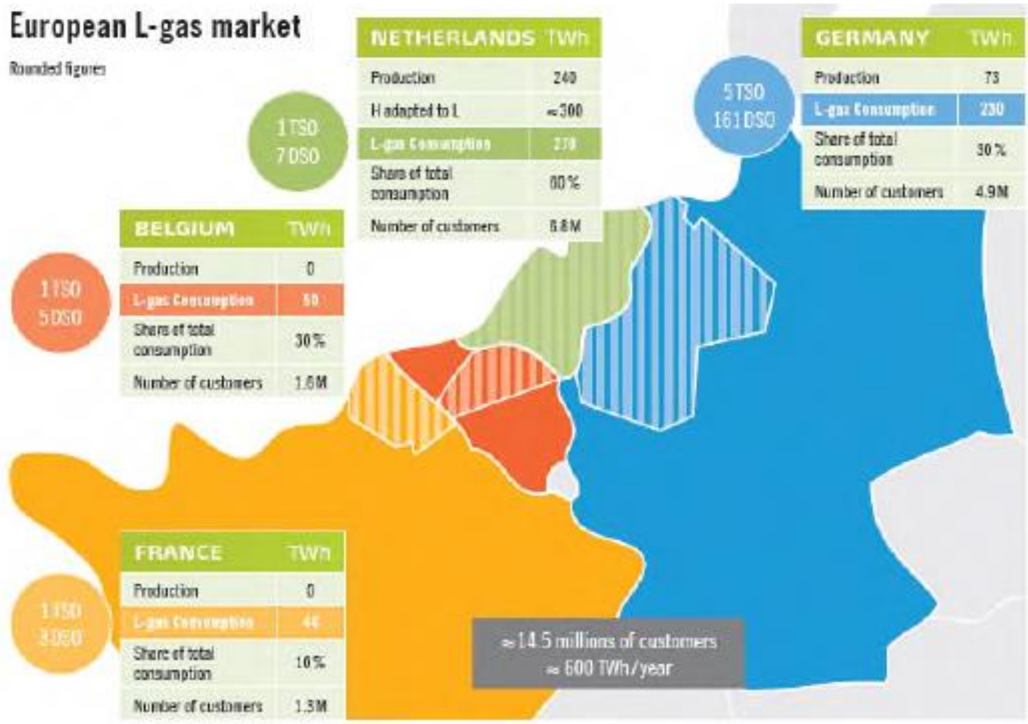

Figure 33: Overview of the L-gas market[37]

[37] Source: GRIP North West 2017

Table 24 gives an overview of the L-gas consumption observed in the last three years. The build environment accounts for more than half of total L-gas consumption, making the demand sensitive to climatic conditions.

Year (unit=TWh)	2015	2016	2017
Build environment	288	306	297
Industry and power generation	263	276	272
Total	**551**	**583**	**569**

Table 24: Historic L-gas demand

The L-gas networks are physically separated from the H-gas networks, as L-gas and H-gas differ in gas quality. The all four countries two separated networks are connected through blending stations. These can blend the different gasses and/or use nitrogen/ ambient air to produce the required Wobbe-index for low calorific gas.

Although there is a clear physical distinction between L-gas and H-gas there is no need for shippers to be in balance in both qualities. Gas on the TTF is traded in energy content and not in a specific quality. The entries and exits of the Gasunie Transport Systems (GTS) (Gasunie Transport Services B.V. (GTS) is owner and operator of the national transmission network in the Netherlands. GTS is responsible for the management, operation and development of the gas transport system in the Netherlands) system have a designated quality range labelled L-gas or H-gas. Operators of gas production grids and storages have to comply with this quality range when feeding into the system and GTS will arrange for the right quality for the exits. The same applies to the two German market areas GASPOOL and Net Connect Germany where transactions at the VTP can be done independently of the gas quality.

Conversion of L-gas markets

It has become clear that, due to decreasing G-gas and L-gas production (related to both a natural decrease in production and political decisions related to Groningen production related earthquakes), the current L-gas market demand cannot be sustained. Other sources of gas will, in due course, replace the L-gas sources gradually in the coming years. This topic is being discussed in the Gas Platform with representatives of the involved Member States. Due to a gradual decrease of L-gas coming from the Netherlands, L-gas capacities towards Belgium and Germany will gradually decrease after 2020 as it is agreed between the adjacent TSOs and detailed in GTS' Network Development Plan 2017 (NOP). The market in Germany is foreseen to be gradually converted to H-gas during the 2020-30 decade. The market in Belgium and France is foreseen to be converted during the period between 2024 and 2030. The conversion of the domestic market in the Netherlands will primarily focus on large industries which are directly connected to the L-gas transmission network of GTS. Next to that a start will be made with conversion of households and other so-called small consumer in the residential area. Large scale conversion of these small-consumers is not likely to start before 2030, because the current appliances are not suited to switch between different gas qualities.

Conversion of the markets will take several years since all appliances have to be checked and adapted to a different gas quality range and adaptation of infrastructure is also required. To plan for the required future market conversion, the German Netzentwicklungsplan (NEP) takes into account a reduction of L-gas import capacities from the Netherlands, with 10% per year starting in 2020. To reach the reduction from 2020 ongoing, conversion of German L-gas areas has already started in 2015.

The ENTSOG TYNDP currently does not model the conversion of L-gas markets because the future need for L-gas substitution is neither a matter of resilience of the system nor can L-gas be imported from somewhere else, which is the core focus of the TYNDP. However, the topic of L-gas is considered highly relevant for the North West region, therefore is being explored in the Gas Regional Investment Plan (GRIP NW) 2017.

The conversion of the L-gas markets into H-gas markets will be the result of on-going intensive interaction between governments, TSOs and suppliers. Currently, evaluations are carried out regarding the substitution of L-gas; the exact impact this may have on infrastructures has not yet been fully determined.

A further description of the NW European L-gas system is given on a country level in de paragraphs below.

Slovakia

Transmission network is defined by the relevant legislation as: "the network of compressor stations and the network foremost of high pressure gas pipelines that are interconnected and which serve primarily for transporting gas in the defined territory, excluding the upstream network, storage and high-pressure gas pipelines that serve primarily for transporting gas to part of the defined territory".

In the field of gas transmission one company is active in Slovakia - Eustream - which is the operator of the national transmission network. Based on the decision of the Government of the Slovak Republic from 28 November 2012 it was determined that unbundling required by European legislation will be carried out by using the model of an independent transmission operator (ITO).

In 2016 the total gas transmission amounted to 60.6 bcm. Due to the amount of transported gas Eustream remains one of the most important TSOs based on the volume of gas transported within the EU.

The transmission network is made up of parallel pipes DN 1 200 and DN 1 400 in four to five lines, the total length of the gas transmission network is almost 2 270 km. Four compressor stations are part of the transmission network – Veľké Kapušany, Jablonov nad Turňou, Veľké Zlievce and Ivanka pri Nitre – which provide a pressure differential needed for the flow of gas with a total output of 600 MW. They are situated at a distance of about 110 km apart. The total transmission capacity of the network is more than 90 bcm per year. Natural gas from the transmission network in the defined territory passes through intrastate stations into the distribution networks and is transported to the final customers.

Figure 34: Transmission system of eustream (Source: eustream, a.s.)

On 30 November 2011 implementing measures were completed that allow reverse flow within the transmission network in Slovakia. In this mode it is possible to transport in the west – east direction the amount of gas that is higher than the highest consumption in Slovakia in the winter months. This project was funded under Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Community financial assistance to projects in the field of energy (hereinafter "Regulation No 663/2009").

Slovakia interconnection with neighbouring countries on the level of transmission networks currently exists with Austria [border point Baumgarten], Czech Republic [border point Lanžhot], Hungary [border point Veľké Zlievce] and Ukraine [border point Veľké Kapušany and border point Budince].

Interconnection with the Czech Republic since 2009 and with Austria since 2010 have been prepared so that it will be possible in a crisis situation (emergency level respectively) to ensure a physical reverse flow of gas to Slovakia.

Technical firm capacity at interconnection points of transmission system with systems of neighbouring countries

Border point	Exit firm capacity (GWh/day)	Entry firm capacity (GWh/day)
Veľké Kapušany [SK/UA]	0	2 028.0
Budince [SK/UA]	280.8	176.8
Baumgarten [AT/SK]	1 570.4	247.5
Lanžhot [CZ/SK]	400.4	696.8
Veľké Zlievce [SK/HU]	126.9	0

Table 25: Cross border points in Slovakia[40]

[40] Source: eustream, a.s., data

The distribution system is defined by the legislation as: the gas distribution equipment within part of the defined territory, including high-pressure gas pipelines that serve primarily for the transportation of gas to part of the defined territory, except for gas pipelines that are part of other networks".

Over 40 companies are active in the field of gas distribution in Slovakia. SPP - distribúcia, a.s. is the largest operator with nationwide coverage to more than 1.5 million connected customers (including more than 1.4 million household customers). The distribution system of SPP - distribúcia, a.s. is made up of about 33 000 km of gas pipelines, its total distribution capacity is nearly 10 bcm per year. Slovakia is one of the most gasified EU countries.

Distribution system of SPP – distribúcia

Figure 35: Distribution system of SPP[41]

[41] Source: SPP – distribúcia, a.s.

Slovakia has in its territory several geological formations which are suitable for the construction of underground gas storage facilities. Currently there are two companies active on the market that are storage system operators - NAFTA a.s., Bratislava and POZAGAS a.s., Malacky. Total storage capacity in Slovakia is 3.35 bcm, which represents more than 65% of total consumption. The facilities are located in the southwestern part of the country near the border with Austria and the Czech Republic.

The storage facility at Dolní Bojanovice located in the Czech Republic is used solely for the Slovak market. It is operated by SPP Storage, s.r.o., Praha, Czech Republic and its storage capacity is 0.57 bcm. The facility is directly connected to the Slovak gas network and is used by SPP - distribúcia, a.s. primarily to ensure the balancing of the distribution system and losses in the distribution system as well as to ensure security of supply standard for household gas customers.

Technical specifications of storage facilities

Underground storage facility/region	Operator	Working gas volume (storage capacity) (bcm)	Maximum firm withdrawal capacity (mcm/day)	Maximum firm injection capacity (mcm/day)
Láb 1,2,3 a 5	NAFTA a.s., Bratislava	2.70	38.25	31.9
Láb 4	POZAGAS a.s., Malacky	0.65	6.85	6.85
Total SK		3.35	45.1	38.75
Dolní Bojanovice (CZ)	SPP Storage, s.r.o., Praha	0.57	8.8	8.8
Total CZ		0.57	8.8	8.8
Total (SK+CZ)		**3.92**	**53.9**	**47.55**

Table 26: Figures of unterground storage in Slovakia[42]

Note: All Figures at 101.325 kPa and 15°C.

[42] Source: storage systems operators

Sweden

There is no extraction of natural gas in Sweden and the entire volume of consumed natural gas is imported from Denmark via pipeline. The Swedish transmission system for natural gas begins in Dragør in Denmark, crosses the Öresund strait via the Öresund pipeline to Klagshamn south of Malmö, from where the trunk pipeline heads northward to Stenungsund. The technical capacity of the Öresund trunk line is 8.6 mcm/d and the technical capacity of the entry point of Dragør (in Denmark) is 8.6 mcm/d. The natural gas network consists of approximately 620 km of transmission lines and roughly 2 700 km of distribution lines. Branch pipes lead off from the trunk pipeline to various consumption areas.

Swedish gas mainly comes from the Tyra gas fields in Denmark which will be closed for facilities' maintenance between 1 December 2019 and 1 of March 2022. However, the production will gradually be reduced until final closure 1 December 2019 and this process will commence in March 2018. During the reconstruction of Tyra the Danish and Swedish market will be completely dependent on natural gas from Germany via Ellund. This will cause increased vulnerability of the Swedish natural gas supply as there will be no secondary pipeline route option during this time.

Sweden has a biogas production which increased by 4 percent during 2016 and small volumes of biogas with a quality equal to natural gas is injected into the distribution systems. The total production of biogas in Sweden is around 2 TWh per year. The amount of biogas upgraded to natural gas quality and fed directly into the network in Sweden rose by 9 percent in 2016 compared to the previous year, and biogas represented 5 percent of the gas in the southwest Swedish network in 2016. The produced biogas is mainly consumed in transportation where over half of used. Sweden is also a world leader in liquefied biogas technology (LBG), although this is still represented by very low figures of production in pilot plants.

The gas flow in the Öresund pipeline is one-way from Denmark to Sweden. Today it is not technically possible to reverse the flow so that gas flows from Sweden to Denmark. Sweden has no natural gas production or any significant gas storage, nor is biogas production significant, although biogas production will gradually increase according to decisions and plans.

Sweden has an exemption from the N-1 infrastructure criteria in the regulation as well as from the criteria for reverse flows. The western Swedish natural gas system is exclusively connected to the Danish natural gas system.

Furthermore, Sweden has been granted an exemption from the criteria for reverse flows as Sweden does not have any natural gas production or any significant storage, nor is the internal/domestic biogas production significant in volume although production is gradually increasing. This means that Sweden cannot contribute to the security of supply in the Danish or European gas system, therefore, there is no need to establish reverse flows between Sweden and Denmark.

Figure 36: The Swedish gas system

The Swedish natural gas market is relatively small when compared to other European markets. In 2015 the total Swedish natural gas demand was about 1 bcm. Industry is the biggest consumer of natural gas and consumed 40 percent of the total in 2015. The power sector consumed 26 percent, 16 percent was consumed in the commercial and residential sector, 5 percent in transportation and 13 percent was used for non-energy purposes. The power generated by natural gas amounted to 0.3 percent of Sweden's total electricity generated in 2015. The IEA forecasts Swedish gas demand to remain stable until 2020 and decline slightly by 2030.

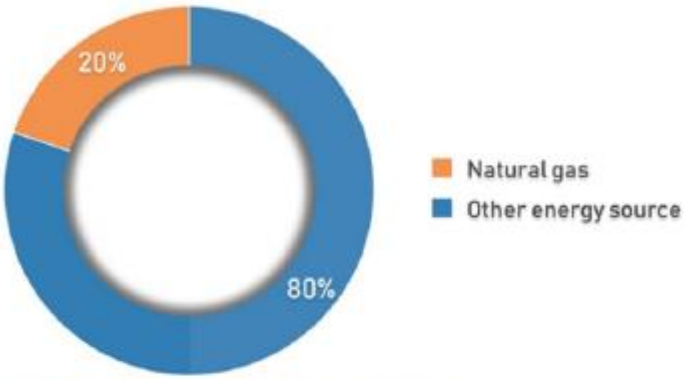

Figure 37: The role of gas in Southwest Sweden

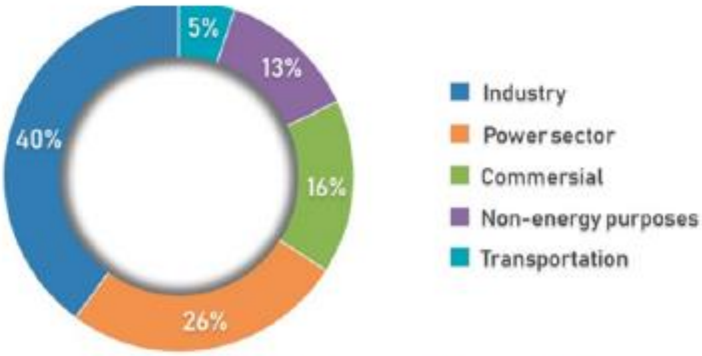

Figure 38: Total Gas Consumption in percentages

2. Infrastrukturstandard (Artikel 5)

viii) Falls mit den zuständigen Behörden der betreffenden Risikogruppen(n) oder mit direkt verbundenen Mitgliedstaaten vereinbart, gemeinsame Berechnung(en) des N – 1-Formel:
— Berechnung der N – 1-Formel gemäß Anhang II Nummer 5,
— Beschreibung der Werte, die für alle Elemente in der N – 1 Formel verwendet werden, einschließlich der für ihre Berechnung verwendeten Zwischenwerte (falls diese von den unter Nummer 2 Buchstabe a Unternummer iii beschriebenen Werten abweichen),
— Angabe der für die Berechnung der Parameter in der N – 1 Formel (z. B. Dmax) zugrunde gelegten Methodologien und etwaigen Annahmen (Verwendung von Anhängen zwecks ausführlicher Erläuterungen)
— Erläuterung der Vereinbarungen, die getroffen wurden, um die Einhaltung der N – 1-Formel sicherzustellen;

Calculation of the infrastructure standard

For the calculation of the N-1 standard it is assumed that the entire region is seen as one "calculated area". This means that only the entry points connecting the region with countries outside the region are taken into account. Cross-border capacity points inside the region are not included.

N-1 formula:

$$N-1\,[\%] = \frac{EP_m + P_m + S_m + LNG_m - I_m}{D_{max} - D_{eff}} \times 100,\; N-1 \geq 100\,\%$$

Where:

- EP_m: technical capacity of entry points that are other than production, LNG and storage facilities covered by PM, LNG, and Sm
- P_m: maximal technical production capacity
- S_m: maximal technical storage deliverability
- LNG_m: maximal technical LNG facility capacity
- I_m: technical capacity largest gas infrastructure
- D_{max}: 1 in 20 gas demand
- D_{eff}: market-based demand-side response

The single largest infrastructure in this region is the Slovakian entry point Velke Kapusany. The analysis we will conduct further focuses on the Greifswald entry point, which is slightly smaller than Velke Kapusany. The calculation of N-1 will be performed for both entry points.

Member State	EP_m [GWh/d]	P_m [GWh/d]	S_m [GWh/d]	LNG_m [GWh/d]	I_m [GWh/d]	D_{max} [GWh/d]	D_{eff} [GWh/d]
Austria	0.0	40.4	470.6	0.0		595.2	0.0
Belgium	1 247.5	0.0	169.5	461.6		1 356.8	0.0
Czech Republic	0.0	4.3	754.9	0.0		709.4	0.0
Denmark	0.0	12.1	196.0	0.0		236.0	0.6
Germany	3 915.3	272.5	7 453.0	0.0	1 776.0	5 202.0	0.0
France	795.0	0.0	2 400.0	1 330.0		4 020.0	0.0
Luxembourg	0.0	0.0	0.0	0.0		52.0	0.0
Netherlands	2 266.0	2 156.0	3 421.0	399.0		3 678.0	0.0
Slovakia	2 204.8	2.1	560.2	0.0	2 028.0	470.9	0.0
Sweden	0.0	1.9	0.0	0.0		78.0	0.0
∑ Sum	**10 428.6**	**2 489.3**	**15 425.2**	**2 190.6**	**3 804.0**	**16 398.3**	**0.6**

Table 27: Entries for the N - 1 formula by each Member State

N – 1: Single largest infrastructure

N-1 for region with failure of:	EP_{VK} [GWh/d]	P_m [GWh/d]	S_m [GWh/d]	LNG_m [GWh/d]	I_m [GWh/d]	D_{max} [GWh/d]	D_{eff} [GWh/d]
Velke Kapusany (SLO)	10 428.6	2 489.3	15 425.2	2 190.6	3 804.0	16 398.3	0.6

$$N-1\,[\%] = \frac{10\,428.6 + 2\,489.3 + 15\,425.2 + 2\,190.6 - 2\,028.0}{16\,398.3 - 0.6} * 100 = 174\%$$

N – 1: Second single largest infrastructure

N-1 for region with failure of:	EP_G [GWh/d]	P_m [GWh/d]	S_m [GWh/d]	LNG_m [GWh/d]	I_m [GWh/d]	D_{max} [GWh/d]	D_{eff} [GWh/d]
Greifswald (D)	10 428.6	2 489.3	15 425.2	2 190.6	3 804.0	16 398.3	0.6

$$N-1\,[\%] = \frac{10\,428.6 + 2\,489.3 + 15\,425.2 + 2\,190.6 - 1\,776.0}{16\,398.3 - 0.6} * 100 = 175\%$$

N – 2: the two single largest infrastructures

N-1 for region with failure of:	EP_{VK+G} [GWh/d]	P_m [GWh/d]	S_m [GWh/d]	LNG_m [GWh/d]	I_m [GWh/d]	D_{max} [GWh/d]	D_{eff} [GWh/d]
Velke Kapusany (SLO) + Greifswald (D)	10 428.6	2 489.3	15 425.2	2 190.6	3 804.0	16 398.3	0.6

$$N-2\ [\%] = \frac{10\,428.6 + 2\,489.3 + 15\,425.2 + 2\,190.6 - (2\,028.0 + 1\,776.0)}{16\,398.3 - 0.6} * 100 = 163\%$$

The common risk group infrastructure consists of several operational facilities. Even with the failure of the two largest infrastructures, the resulting figure from the N-1 formula remains distinctly above 100%. This proves that the security of gas supply does not depend on a few large facilities because the extensive infrastructure offers more possibilities to transport and distribute gas.

Cooperation mechanism for the *Eastern gas supply risk group Baltic Sea* under the Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply

Preamble

Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 establishes in its recitals:

"*Natural gas remains an essential component of the energy supply of the Union. A large proportion of such gas is imported into the Union from third countries.*
A major disruption of the gas supply can affect all Member States. It can also severely damage the Union economy and can have a major social impact, in particular *on vulnerable groups of customers.*
The Regulation aims to ensure that all the necessary measures are taken to safeguard an uninterrupted supply of gas throughout the Union, in particular to protected customers in the event of difficult severe weather conditions or disruptions of the gas supply.
In a spirit of solidarity, risk associated cooperation, involving both public authorities and natural gas undertakings, should be the guiding principle of the Regulation, to mitigate the identified risks and optimise the benefits of coordinated measures and to implement the most cost-effective measures for Union consumers. Risk associated cooperation should gradually be complemented with a stronger Union perspective, allowing recourse to all available supplies and tools in the entire internal gas market. Union-level assessment of the emergency supply corridors should be incorporated into the risk associated cooperation.
In order to make the risk associated cooperation feasible, Member States should establish a cooperation mechanism within each risk group. Such mechanism or mechanisms should be developed sufficiently in time to allow for conducting the common risk assessment and discussing and agreeing on appropriate and effective cross-border measures, which will require the agreement of each Member States concerned, to be included in the risk associated chapters of the preventive action plans and emergency plans, after consulting the Commission.
Member States are free to agree on a cooperation mechanism best suited for a given risk group."

Regulation (EU) 2017/1938 was published in the Official Journal of the European Union on 28 of October 2017 and is applicable from 1 November 2017.

I Principles

1. Subject matter

The aim of this document is to *establish a cooperation mechanism for the risk group "1.(c) Eastern gas supply risk groups: Baltic Sea"* as defined in Annex I of the Regulation (EU) 2017/1938, in order to facilitate:

a) Preparation and notification of the common risk assessment, according to Article 7
b) Preparation of the regional chapters for national preventive action plans and emergency plans, according to Article 8 Coordination in case of declaration of any crisis level in the emergency plans, according to Annex VII.
c) Any coordination task to be addressed within the group of risk.

This document shall be modified and new chapters may be added when necessary by consensus.

2. Coordination

Germany is prepared to take the lead of the Eastern gas supply risk group *Baltic Sea* according to Annex I of regulation (EU) 2017/1938

- The Federal Network Agency – the German Regulator - holds the pen for the common risk assessment, according to Article 7 of this respective regulation.
- The German Federal Ministry for Economy and Energy holds the pen for the national preventive action plans and emergency plans according to Article 8 of this respective regulation.

3. Members of the risk groups

Members of the Group are the Competent Authorities from Members states defined in Annex I of the regulation:

- Austria
- Belgium
- Czech Republic
- Denmark
- France
- Germany
- Luxembourg
- Netherlands
- Slovakia
- Sweden.

Further, observation and participation in the risk group by the European Commission, Governments, Regulators, and/or Transmission System Operators of the Member States above shall be welcomed in as far as that observation or participation is necessary for the achievement of the goals listed at point 1, above.

4. Role of the coordinator

The coordinator shall organise the tasks and, in particular:

a) Identify key project milestones and deadlines;

b) Make initial proposals concerning:
    i. Cooperation mechanisms
    ii. Scope for assessments
    iii. Chapters of plans
c) Propose timing, location, and agendas of meetings;
d) Chair meetings;
e) Request of information and contributions to Member States within the risk group;
f) Coordination of exchange of information;
g) Submission of documents to the Commission.
h)

5. Commitment

All the Member States commit to submit information necessary for the preparation of the risk assessment and to support work carried out to prepare assessments, plans and other documents as far as possible.

6. Meetings

Meetings can be arranged as web-conferences, telephone-conferences or ordinary meetings or back to back of GCG-meetings by using EU-Commissions facilities. The format of the meetings, and any agendas, will be proposed by the Coordinator, and agreed by consensus.

Each competent authority may request to convene a meeting

If requested by a Member State, meetings can be restricted to competent authorities only.

7. Working Language

English shall be the working language without prejudice of using other languages in communications with gas undertakings and other national stakeholders.

8. Decisions

All the decisions and documents shall be adopted by consensus.

9. External assistance

Whether Member States individually so decide, experts not belonging to Competent Authorities, such as Transport System Operators or National Regulatory Authorities (if they are not the Competent Authority) shall be authorised to attend meetings and to develop certain tasks under their surveillance.

10. Professional secrecy

Professional secrecy principles shall be guaranteed by Competent Authorities at the same level than in the Gas Coordination Group.

11. Costs
Each member of the risk group is overtaking his own travel expenses.

II Common Risk Assessment

1. Objective

A Common Risk Assessment shall be prepared according to Article 7 of Regulation and notified to the Commission by 1 October 2018. Member States and their competent authorities involved shall support the development and finalisation of the common risk assessment.

The competent authorities shall take into account the results of the EU-wide simulation carried out by ENTSO-G for the preparation of the document.

2. Coordinator

The Federal Network Agency – the German Regulator - will play the role described in point I.2 for coordinating the preparation of the first risk assessment

III Preparation of the regional chapters for national preventive action plans and emergency plans, according to Article 8

Germany, The Federal Ministry for Economic Affairs and Energy will hold the pen for the preparation of the regional chapters for the national preventive action plans and the emergency plans as described in point I.2.

The work for the preparation the regional chapters for the preventive action plans and emergency plans will start as soon as the first results of the risk assessment are available.
The composition of the group as well as the way of cooperation will be the same as listed in I.

Contact list

Member State	*Competent Authority*	*Persons*	*Email*	*Phone*
Austria	Bundesministerium für Wissenschaft, Forschung und Wirtschaft	Klaus Jenny Ronald Farmer	klaus.jenny@bmwfw.gv.at Ronald.farmer@e-control.at	+43 171100 3088
Belgium	FOD Economie	Pierre Paladin Benjamin Heylen Bernard Picron	Pierre.Paladin@economie.fgov.be Benjamin.Heylen@economie.fgov.be Bernard.Picron@economie.fgov.be	+32 2277 6253 +32 2277 6424 +32 2277 8101
Czech Republic	Ministry of Industry and Trade	Jan Zaplatilek Lubomir Pesák Martin Pejrimovsky	zaplatilek@mpo.cz pesak@mpo.cz pejrimovsky@mpo.cz	+420 224 853 482 +420 224 853 442 +420 224 854 116
Denmark	Energistyrelsen	Per Stokholm	pst@ens.dk	+45 3392 6654
France	Ministère de l'Environnement, de l'Energie et de la Mer	Alban Liegeard	alban.liegeard@developpement-durable.gouv.fr	+33 140 819 549
Germany	Bundesnetzagentur Federal Ministry for Economic Affairs and Energy	Jürgen Dengel Ursula Mumpro	Juergen.dengel@bnetza.de Ursula.Mumpro@bmwi.bund.de	+49 228 14 5723 +49 30 18615 7294
Luxembourg	Ministry of the Economy	Tom Eischen Marco Hoffmann Gérard Meyer	tom.eischen@eco.etat.lu marco.hoffmann@eco.etat.lu gerard.meyer@eco.etat.lu	+352 247 84322 +352 247 84324 +352 247 84326
Netherlands	Ministerie van Economische Zaken	Wim van't Hof	W.R.J.L.vantHof@minez.nl	+31 70 3696618
Slovakia	Ministry of Economy	Lubomír Čačaný Peter Dvorák	cacany@economy.gov.sk dvorak@economy.gov.sk	+421 2 4854 1908 +421 2 4854 3905
Sweden	Swedish Energy Agency	Elin Akinci	elin.akinci@energimyndigheten.se	+46 16 544 22 84
European Commission	DG ENER	Beatriz Sinobas Monika Zsigri	Beatriz.Sinobas@ec.europa.eu Monika.Zsigri@ec.europa.eu	+32 229 68753