FNB Gas
DIE FERNLEITUNGSNETZBETREIBER

Gas Network Development Plan 2020–2030

Scenario Framework

Consultation

Transmission system operators

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FNB Gas
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prognos

Scenario framework

Gas Network Development Plan 2020–2030
commissioned by the German transmission system operators (TSOs)

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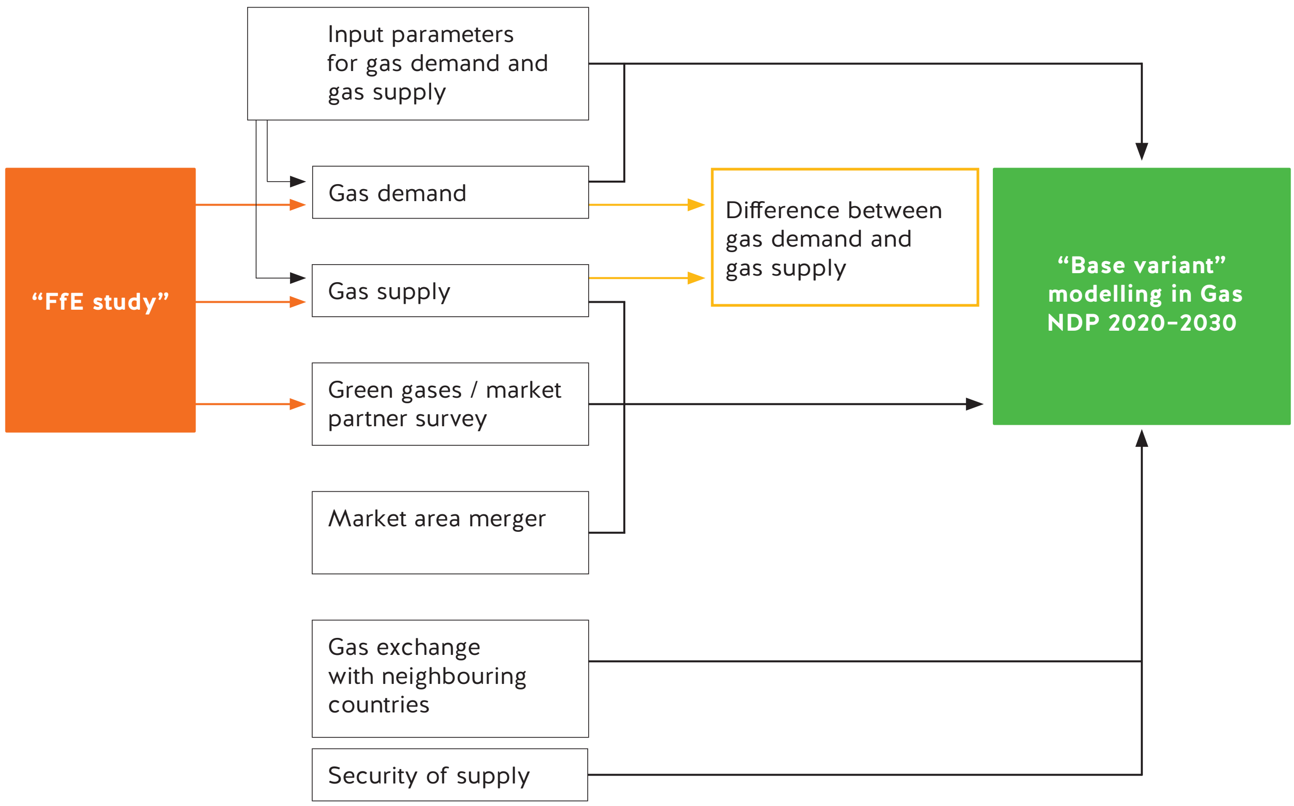
Executive summary

Executive Summary

The transmission system operators present two scenarios with different development paths in the scenario framework for the Gas NDP 2020-2030. For the first time, gas demand up to 2050 is considered in one scenario. The theme of green gases plays a central role. It is important to make the gas infrastructure fit for the future. To this end, the transmission system operators commissioned the Forschungsstelle für Energiewirtschaft (FfE – Research Institute for the Energy Economy) to prepare a study on the regionalisation of power-to-gas services (the "FfE study") and conducted a survey of the market partners about green gas projects. The presentation of the impact of the market area merger on 1 October 2021 in the scenario framework is also new.

The various factors influencing the modelling in the Gas NDP 2020–2030 are discussed in the scenario framework (cf. Figure 1). The proposed "base variant" is, from the perspective of the transmission system operators, based on suitable assumptions for modelling a demand-oriented and forward-looking expansion of the network.

Figure 1: Overview of the scenario framework for the Gas NDP 2020–2030



Source: Prognos AG, transmission system operators

Introduction 1

1 Introduction

“Anyone who does not conform to the market will be punished by the market.”

(Wilhelm Röpke, 1899–1966, German economist and sociologist)

Adopting a wait-and-see approach is not going to work. The world of energy is changing too rapidly for that. When gas was first supplied, it was town gas that was transported. The start of natural gas production in the Netherlands in the 1960s and natural gas imports from Russia at the beginning of the 1970s kept the ball rolling. From that point on, it was natural gas – in two qualities – that flowed through the infrastructure. The ambitious L-to-H-gas conversion project is currently in the process of implementation. Another major transformation has just begun: Other gaseous media, such as green gases, whether this is hydrogen or synthetic methane, are growing in importance and will play an important role in achieving the climate protection targets.

With a network extending approximately 40,000 km in length, the German transmission system operators form the backbone of the entire gas transport system in Germany. The distribution system for natural gas that is fed by the transmission system is more than 470,000 km long. With their gas infrastructure that has been expanded to meet demand, the German transmission system operators thus make an essential contribution to the secure supply of energy to the household, industrial, power plant, commerce, trade and services and mobility sectors.

The existing gas infrastructure can make a significant and economically valuable contribution in the energy system of the future. Gas itself is a climate-friendly source of energy and can become completely climate-neutral. The gas infrastructure opens up the opportunity to transport very large quantities of renewable energy as well as to store it long term. Through the integration of green gases in the existing infrastructure, a significant contribution can be made swiftly and cost-efficiently to the reduction of CO_2 emissions. Green gases represent a flexible, storable and cost-efficient technology for integrating renewable energy in all consumption sectors. The “power-to-gas” procedure (PtG, production of hydrogen or synthetic methane from renewable electricity) in particular offers great and as yet unrealised potential for the intelligent connection of gas, electricity, heating and mobility infrastructure that is called sector coupling. Sector coupling is one of the crucial levers for the successful implementation of the energy transition.

Alongside the generation of hydrogen and synthetic methane with renewable electricity using PtG, hydrogen can also be generated from natural gas in a way that is virtually free of emissions. This hydrogen obtained from natural gas offers the possibility both of ramping up a hydrogen economy quickly and cost-efficiently and of providing large volumes of hydrogen in the long term, partly also through imports.

The addition of hydrogen to the flow of natural gas offers an opportunity to integrate renewable energies into the German energy mix. In return, the needs of the customers who are connected have to be taken into consideration where the proportion of the admixture is increased. The Deutscher Verein des Gas- und Wasserfaches (DVGW – German Technical and Scientific Association for Gas and Water) expressed the following position on this on 9 April 2019: “The future set of rules should initially aim at a target figure for hydrogen injection of around 20 percent by volume. The existing DVGW set of rules already allows admixtures today of just under 10 percent in the existing gas network wherever there are no restrictions resulting from specific applications. By 2030, this value of 10 percent should be binding without restrictions from the set of rules.” [DVGW 2019]

The integration of green gases in the existing gas infrastructure will increasingly gain in importance up to 2030. In addition to the retrofitting of the existing gas infrastructure to increasing proportions of hydrogen, the repurposing of existing gas and storage infrastructure from natural gas to hydrogen is of major importance for enabling this target to be achieved efficiently within the given time frame. The new construction of dedicated hydrogen transmission pipelines is also conceivable within the framework of further consolidation.

In addition, the use of green gases offers the possibility of converting some of the existing gas storage infrastructure and storing efficiently and for longer periods renewable electricity that has not been generated to meet a particular need. Seasonal or short-term production and demand peaks can be securely covered by this process.

The integration of green gases and the expansion of pure hydrogen infrastructure as part of the energy supply network has to be taken into consideration in the Gas NDP 2020-2030 in order to lay today the foundations for the requirements of the energy supply of tomorrow.

“FfE study” [FfE 2019]:

FNB Gas commissioned a “Study on the regionalisation of power-to-gas services for the Gas NDP 2020–2030 scenario framework” from the Forschungsstelle für Energiewirtschaft (FfE – Research Institute for the Energy Economy) [FfE 2019]. This study analyses in particular suitable locations for PtG plants as well as sources of supply and demand regions for green gases [FfE 2019]. Information on the study can be found in Chapters 3.5, 4.3 and 4.4.

From the perspective of the transmission system operators, the conversion of today’s existing gas infrastructure to green gases in general and hydrogen in particular has to be carried out with the close involvement of the market participants. Only in this way can it be ensured that the future production potential of climate-neutral green gases can be optimally combined with the potential applications of today and of the future.

For this reason, the transmission system operators are conducting a market survey of green gas projects from 21 March 2019 to 12 July 2019. This is the first step in systematically and transparently identifying the demand for transporting hydrogen; this consultation process is being continued in the future network development plans with market participants. Based on the hydrogen transportation requirements, it is planned to identify which pipelines can be retrofitted for transporting pure hydrogen and at what time. If the retrofitting processes and times are confirmed by the Bundesnetzagentur (BNetzA – Federal Network Agency), a binding obligation would arise for the transmission system operators to make gas infrastructure available for hydrogen at the time of the conversion. This procedure that has been planned creates a secure planning basis for market participants and opens up a variety of potential uses for hydrogen. Only through this conversion process with the close involvement of the market participants and the BNetzA will it be possible to serve the future applications of hydrogen in the optimal way.

It is the task of the transmission system operators to plan, prepare and carry out any conversion to hydrogen of network areas that are currently operated for natural gas. Various reasons can be cited for this:

- The connection of sources and sinks by pipeline infrastructure is part of the traditional role played by transmission system operators.
- The choice of locations for PtG facilities has to be made by the market participants in consultation with the gas and electricity transmission system operators. In this way, facilities that have a useful function for both the electricity grid and the gas network can be positioned within both of these networks and costs for expanding the network infrastructure can be reduced.

The gas network development plan has proved successful as a central management instrument for L-to-H-gas conversion, especially for the long-term planning of the conversion. The involvement of the relevant market participants is ensured by a variety of public consultation processes. Furthermore, the close connection between L-to-H-gas conversion and network expansion can be taken into account by mapping the L-to-H-gas conversion in the gas network development plan. The aspect relevant for the L-to-H-gas conversion can also be applied in similar fashion to the conversion to hydrogen.

With this document, the transmission system operators (TSOs) fulfil their statutory duty to produce and conduct a consultation on the scenario framework in accordance with Section 15a of the Energiewirtschaftsgesetz (EnWG – German Energy Industry Act). The transmission system operators present two scenarios with different development paths, where current general political conditions are taken into consideration. The development of the demand for gas up to 2050 is considered for the first time here in a scenario.

Building on this, the transmission system operators reviewed the scenario framework produced in 2017 for the Gas Network Development Plan 2018-2028, updated its data base accordingly and took into consideration current developments arising in the political environment. The planned merger of the market area, probably on 1 October 2021, will play a significant role in this connection. With this scenario framework, the transmission system operators create the basis for their modelling of flows and the network expansions measures that will be derived from that.

Input parameters 2

2 Input parameters for gas demand and gas supply

This chapter presents the criteria that have been revised by the transmission system operators from the 2018 scenario framework for considering capacity reservations/capacity expansion claims in accordance with Sections 38/39 of the Gasnetzzugangsverordnung (GasNZV – German Gas Network Access Regulation) (cf. Chapter 2.1). It then explains the consideration of power plants (cf. Chapter 2.2), storage facilities (cf. Chapter 2.3) and LNG facilities (cf. Chapter 2.4). New projects based on the capacity reservations/capacity expansion claims pursuant to Sections 38/39 GasNZV that have been submitted to the transmission system operators are addressed in particular here. The results of the market partner survey on green gas projects as of 15 May 2019 are presented in Chapter 2.5.

2.1 Criteria for capacity reservations/capacity expansion claims pursuant to sections 38/39 GasNZV

Storage, production and LNG facilities and also power plants are taken into consideration based on the capacity reservations/capacity expansion claims pursuant to Sections 38/39 GasNZV that have been submitted to the transmission system operators. The transmission system operators launched a survey on the website of FNB Gas on 28 February 2019 in order to take new projects into consideration in the scenario framework. The reporting date for the considerations in this consultation document is accordingly 31 March 2019. Applications for capacity reservation pursuant to section 38 GasNZV that had not yet been decided by 31 March 2019 are taken into provisional consideration in the consultation document on account of the processing times. The transmission system operators will make the decision on whether to consider them in the Gas NDP 2020–2030 in the draft scenario framework using a number of criteria. The following criteria will be used for including projects with capacity reservations/capacity expansion claims pursuant to Sections 38/39 GasNZV in the scenario framework for the Gas NDP 2020–2030.

- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV had been approved by 17 June 2018 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if a capacity reservation had been made by 31 March 2019. A precondition for an effective capacity reservation is the payment of the annual reservation fee by the connection applicant (Section 38(3) sentence 6 in conjunction with Section 38(4) sentence 2 GasNZV).
- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV has been approved is not taken into consideration in the scenario framework for the Gas NDP 2020–2030 if the applicant has not made use of the option for making a reservation,
- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV had been rejected by 17 June 2018 is not taken into consideration in the scenario framework for the Gas NDP 2020–2030 if a capacity expansion claim pursuant to Section 39 GasNZV had not been asserted by 31 March 2019.
- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV was approved between 17 June 2018 and 31 March 2019 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if a capacity reservation is made by the end of the consultation period on 12 July 2019 and the applicant has verifiably not withdrawn from its connection planning in the meantime. A precondition for an effective capacity reservation is the payment of the annual reservation fee by the connection applicant (Section 38(3) sentence 6 in conjunction with Section 38(4) sentence 2 GasNZV).
- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV has been approved between 31 March 2019 and 12 July 2019 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if a capacity reservation is made by 1 August 2019 and the applicant has verifiably not withdrawn from its connection planning in the meantime. A precondition for an effective capacity reservation is the payment of the annual reservation fee by the connection applicant (Section 38(3) sentence 6 in conjunction with Section 38(4) sentence 2 GasNZV).
- The capacity demand of a project for which the application for capacity reservation pursuant to Section 38 GasNZV has not been decided on by the end of the consultation period on 12 July 2019 on account of the processing times pursuant to Section 38 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if the applicant has verifiably not withdrawn from its connection planning in the meantime.

- A capacity expansion claim pursuant to Section 39 GasNZV that was already included in the Gas NDP 2018–2028 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if the binding implementation schedule pursuant to Section 39(2) GasNZV has been finalised by the end of the consultation period on 12 July 2019 or the payment of the flat-rate planning fee pursuant to Section 39(3) GasNZV has been made by the applicant and the applicant has verifiably not withdrawn from its connection planning in the meantime.

- A capacity expansion claim pursuant to Section 39 GasNZV that was not included in the Gas NDP 2018–2028 is taken into consideration in the scenario framework for the Gas NDP 2020–2030 if the implementation schedule pursuant to Section 39(2) GasNZV has been finalised by the end of the consultation period on 12 July 2019 or the payment of the flat-rate planning fee pursuant to Section 39(3) GasNZV has been made by the applicant and the applicant has verifiably not withdrawn from its connection planning in the meantime. Projects are also taken into consideration in the scenario framework for the Gas NDP 2020–2030 if the applicant and the transmission system operators are conducting concrete negotiations on the implementation schedule and the network connection at least at the present moment and the applicant has furnished proof that their project has made specific planning progress.

- A capacity expansion claim pursuant to Section 39 GasNZV that has been submitted between 31 March 2019 and 12 July 2019 (end of the consultation period for the scenario framework for the Gas NDP 2020–2030) is taken into consideration if the applicant has verifiably not withdrawn from its connection planning in the meantime.

The transmission system operators have had to specify various reporting dates for defining the criteria for including projects with capacity reservations/capacity expansion claims in accordance with Sections 38/39 GasNZV.
The reasons for this are described below:

- 31 March 2019 was selected as the reporting date for compiling the consultation document for the 2020 scenario framework in order to enable the necessary information for the publication to be prepared. This reporting date was published on the FNB Gas website at the end of February.

- 17 June 2018 was selected as the reporting date for defining the criteria in order to identify "old" capacity reservations/capacity expansion claims pursuant to sections 38/39 GasNZV. This reporting date is exactly one year before the start of the consultation for the scenario framework for the Gas NDP 2020–2030 and is necessary in the view of the transmission system operators in order to appropriately assess requests where the project has not recorded any progress.

- The reporting date of 12 July 2019 was selected for the definition of the criteria. The consultation period for the scenario framework for the Gas NDP 2020–2030 ends on this date. On the one hand, capacity reservations/capacity expansion claims pursuant to sections 38/39 GasNZV can still be made up to this reporting date, while, on the other, specific activities have to be carried out by no later than this reporting date depending on the criterion for a project to be taken into consideration in the Draft 2020 Scenario Framework.

- The reporting date of 1 August 2019 was selected for the definition of the criteria. This reporting date applies for current applications for capacity reservation pursuant to Section 38 GasNZV that have been approved between 31 March 2019 and 12 July 2019. This is the last possible time by which the transmission system operators can still incorporate current developments in the Draft 2020 Scenario Framework.

The projects that are currently considered and not considered as of the reporting date of 31 March 2019 are listed in the following Chapters 2.2 to 2.4. The transmission system operators point out that the inclusion of some current capacity reservations/capacity expansion claims pursuant to sections 38/39 GasNZV in the Draft 2020 Scenario Framework is still open on the basis of the criteria that have been formulated. This is flagged accordingly in the tables in the following chapter. Furthermore, there is the possibility that further capacity reservations/capacity expansion claims pursuant to sections 38/39 GasNZV will be received by the transmission system operators by the end of the consultation period for the scenario framework for the Gas NDP 2020–2030.

2.2 Power plants

The systemically important gas power plants on the network of the transmission system operators are presented to begin with in Chapter 2.2.1. Which new gas power plants are taken into consideration in the consultation document for the 2020 scenario framework on the basis of the criteria described above and which are currently not considered are then shown (cf. Chapter 2.2.2). Finally, the planned procedure for the cluster approach for new gas power plants in southern Germany (cf. Chapter 2.2.3), which was used for the first time in the Gas NDP 2016, is outlined.

2.2.1 Systemically important power plants

Table 1 shows the systemically important gas power plants that are connected directly to the network of the transmission system operators. These are unchanged from the scenario framework for the Gas NDP 2018–2028 here. The detailed list of power plants with all systemically important power plants can be found in Appendix 2.

Table 1: Systemically important power plants connected directly to the network of the transmission system operators

No.	Power plant number	Name of power plant	Scheduled exit capacity in MWh/h	Transmission system operators	Allocation point	2025	2030
1	BNA0172	Dampfkraftwerk BGH – O1	710	bayernets	---	Conditional allocable capacity	Conditional allocable capacity
2	BNA0374	Staudinger 4	1,914	OGE	---	Freely allocable capacity	Freely allocable capacity
3	BNA0514	Rheinhafen-Dampfkraftwerk, Karlsruhe	740	OGE	Wallbach	Firm dynamically allocable capacity	Firm dynamically allocable capacity
4	BNA0614b	Kraftwerk Mitte, Ludwigshafen	---*	GASCADE	---	Freely allocable capacity	Freely allocable capacity
5	BNA0615	Kraftwerk Süd, Ludwigshafen	---*	GASCADE	---	Freely allocable capacity	Freely allocable capacity
6	BNA0626	Kraftwerk Mainz	1,500	OGE	---	Freely allocable capacity	Freely allocable capacity
7	BNA0744	Franken 1 1, Nuremberg	0**	OGE	---	---	---
8	BNA0745	Franken 1 2, Nuremberg	0**	OGE	---	---	---
9	BNA0857	GuD-Anlage Rüsselsheim	445	OGE	---	Freely allocable capacity	Freely allocable capacity
10	BNA0994	Gemeinschaftskraftwerk Irsching 5	1,700	OGE	---	Freely allocable capacity	Freely allocable capacity
11	BNA0995	Ulrich Hartmann (Irsching)	1,100	OGE	Haiming 2-7F, Speicher Bierwang, Speicher Breitbrunn	Firm dynamically allocable capacity	Firm dynamically allocable capacity
12	BNA1078	HKW Wörth	---*	GASCADE	---	Freely allocable capacity	Freely allocable capacity
13	BNA1248a	UPM Schongau	75	bayernets	---	Freely allocable capacity	Freely allocable capacity
			155	bayernets	Überackern/ABG, Überackern 2, Haiming 2-7F/bn, USP Haidach, Haiming 2-RAGES/bn, Wolfersberg, Inzenham	Firm dynamically allocable capacity	Firm dynamically allocable capacity
14	BNA1248b	HKW 3 UPM Schongau	150	bayernets	---	Freely allocable capacity	Freely allocable capacity

* Not published for reasons of third-party trade secrets
**Dual firing

Source: Transmission system operators based on power plant lists and notices relating to systemically important gas power plants from the BNetzA, BNetzA 2019a, BNetzA 2019b

The systemically important power plants connected to the network of the transmission system operators are modelled by the transmission system operators in the Gas NDP 2020–2030 for the target years 2025 and 2030, unless they are expressly included in the decommissioning list of the BNetzA. None of the power plants shown in Table 1 can be found in the currently published power plant decommissioning list.

2.2.2 Consideration of new gas power plants in the consultation document for the scenario framework for the Gas NDP 2020–2030

In accordance with the criteria described in Chapter 2.1, the following power plant requests pursuant to Sections 38/39 GasNZV are taken into consideration in the consultation document for the 2020 scenario framework.

Table 2: Plans for the construction of new gas power plants on the network of the transmission system operators taken into consideration in the consultation document of the 2020 scenario framework (reporting date: 31 March 2019)

TSO	Federal Network Agency number	Project name	Gas type (H-gas/L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/no/open)	Allocation point	Reason/applicable criterion (updated 31 March 2019)
bayernets	BNAP114	GuD Leipheim I	H-gas	1,900	Section 39 GasNZV	yes	yes	Überackern 2, Überackern/ABG, Haiming 2-7F/bn, USP Haidach, Haiming 2-RAGES/bn	– Project included in Gas NDP 2018–2028 – Implementation schedule finalised – Flat-rate planning fee paid – Connection applicant has not withdrawn
OGE		Kraftwerk Scholven	H-gas/L-gas	167	Section 38 GasNZV	yes	yes	Eynatten/Raeren	– Application approved by 17 June 2018 – Capacity reservation made – Payment of the annual reservation fee made – Connection applicant has not withdrawn
OGE		Kraftwerk Scholven	H-gas/L-gas	168	Section 38 GasNZV	yes	yes	Eynatten/Raeren	– Application approved by 17 June 2018 – Capacity reservation made – Payment of the annual reservation fee made – Connection applicant has not withdrawn
OGE		Kraftwerk Irsching	H-gas	1,000	Section 38 GasNZV	yes	yes	will be defined in the course of the modelling	– Application approved between 17 June 2018 and 31 March 2019 – Capacity reservation made – Payment of the annual reservation fee made – Connection applicant has not withdrawn
OGE		Kraftwerk Scholven	H-gas/L-gas	40	Section 38 GasNZV	yes	open	Eynatten/Raeren	– Application not yet approved between 17 June 2018 and 31 March 2019
terranets bw		Gasturbine Heilbronn	H-gas	1,200	Section 39 GasNZV	yes	yes	will be defined in the course of the modelling	– Project included in Gas NDP 2018–2028 – Implementation schedule finalised – Flat-rate planning fee paid – Connection applicant has not withdrawn
terranets bw		GuD-Anlage Altbach	H-gas	1,200	Section 38 GasNZV	yes	open	will be defined in the course of the modelling	– Application not yet approved between 17 June 2018 and 31 March 2019
terranets bw		GuD-Anlage Marbach	H-gas	800	Section 38 GasNZV	yes	open	will be defined in the course of the modelling	– Application not yet approved between 17 June 2018 and 31 March 2019

TSO	Federal Network Agency number	Project name	Gas type (H-gas/L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/no/open)	Allocation point	Reason/applicable criterion (updated 31 March 2019)
Thyssengas	BNAP125	GuD-KW Herne	H-gas	1,600	Section 39 GasNZV	yes	yes	Epe - I (UGE-E), Epe III (UGS-E, Trianel), Gronau Epe 11 (UGS-E; KGE), Gronau Epe 13 (UGS-E; Uniper)	– Project included in Gas NDP 2018–2028 – Implementation schedule finalised – Flat-rate planning fee paid – Connection applicant has not withdrawn
Thyssengas		BHKW Marl M1	H-gas	120	Section 38 GasNZV	yes	yes*	will be defined in the course of the modelling	– Application approved by 17 June 2018 – Capacity reservation made – Payment of the annual reservation fee made – Connection applicant has not withdrawn

* Continuation of the power plant project under review

Note: Changes in status in relation to the criteria pursuant to Chapter 2.1 have resulted for some projects after the reporting date of 31 March 2019. These changes are taken into consideration in the draft scenario framework.

Source: Transmission system operators

In accordance with the criteria described in Chapter 2.1, various power plant requests pursuant to Sections 38/39 GasNZV are not taken into consideration in the consultation document for the 2020 scenario framework. A distinction has to be drawn here, however, between requests that could still be taken into consideration in the Draft 2020 Scenario Framework depending on the criterion (cf. Table 3) and those that can no longer be considered irrespective of any development up to 1 August 2019 (cf. Table 4).

Table 3: Plans for the construction of new gas power plants on the network of the transmission system operators not taken into consideration in the consultation document for the 2020 Scenario Framework, but which could still be included in the draft document (reporting date: 31 March 2019)

TSO	Federal Network Agency number	Project name	Gas type (H-gas/L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/no/open)	Reason/applicable criterion (updated 31 March 2019)
bayernets	BNAP124	GuD Gundremmingen I	H-gas	2,109	Section 39 GasNZV	no	open	– Implementation schedule not finalised and – Planning fee not paid
bayernets	BNAP128	KW Gundelfingen	H-gas	2,109	Section 39 GasNZV	no	open	– Implementation schedule not finalised and – Planning fee not paid
GUD		GHKW VW2	H-gas	920	Section 39 GasNZV	no	open	– Implementation schedule not finalised and – Planning fee not paid
OGE	BNAPXX12	KW Griesheim	H-gas	950	Section 39 GasNZV	no	open	– Implementation schedule not finalised and – Planning fee not paid

Note: Changes in status in relation to the criteria pursuant to Chapter 2.1 have resulted for some projects after the reporting date of 31 March 2019. These changes are taken into consideration in the draft scenario framework.

Source: Transmission system operators

Table 4: Plans for the construction of new gas power plants on the network of the transmission system operators not taken into consideration in the consultation document for the 2020 Scenario Framework which are also not included in the draft document (reporting date: 31 March 2019)

TSO	Federal Network Agency number	Project name	Gas type (H-gas/ L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/no/open)	Reason/applicable criterion (updated 31 March 2019)
bayernets		KW Zolling	H-gas	2,042	Section 38 GasNZV	no	no	– Connection applicant rescinded
OGE		Kraftwerk Karlsruhe (RDK 6S)	H-gas	800	Section 38 GasNZV	no	no	– Application approved by 17 June 2018 – No capacity reserved – No payment of the annual reservation fee made
OGE		Kraftwerk Arzberg	H-gas	888	Section 38 GasNZV	no	no	– Application approved by 17 June 2018 – No capacity reserved – No payment of the annual reservation fee made
OGE		Kraftwerk Karlstein	H-gas	850	Section 38 GasNZV	no	no	– Application rejected by 17 June 2018 – No capacity expansion claim pursuant to section 39 GasNZV asserted
OGE		Kraftwerk Staudinger	H-gas	920	Section 38 GasNZV	no	no	– Application rejected by 17 June 2018 – No capacity expansion claim pursuant to section 39 GasNZV asserted
OGE		Kraftwerk Bischof-sheim	H-gas	943	Section 38 GasNZV	no	no	– Application approved after 17 June 2018 – No capacity reserved – No payment of the annual reservation fee made
OGE		Kraftwerk Wies-baden-Biebrich	H-gas	270	Section 38 GasNZV	no	no	– Application approved after 17 June 2018 – No capacity reserved – No payment of the annual reservation fee made

Source: Transmission system operators

2.2.3 Consideration of the capacity requested for special network operating equipment in southern Germany

The consideration of new gas power plants has been described in Chapter 2.2.2. Half of the new gas power plants taken into consideration in the consultation document are located in southern Germany. It can currently still not be foreseen yet which new gas power plants will ultimately be taken into consideration the Draft 2020 Scenario Framework. As in the Gas NDP 2018–2028, the transmission system operators will, if it can be foreseen that power plant projects for particular network operating equipment will come into competition with each other, provide a cluster approach for these gas power plants in southern Germany. Full consideration of the requested capacity pursuant to Sections 38/39 GasNZV would lead to an oversized and inefficient expansion of the network. A similar procedure to the one provided in the Gas NDP 2018–2028 is planned here.

Demand for new construction on network stability facilities totalling 1.2 GW_e is shown in the report by the BNetzA to identify the demand at network stability facilities in accordance with section 13 k EnWG of 31 May 2017. The transmission system operators TenneT, Amprion and TransnetBW issued a tender for the special network operating equipment for a total of 1.2 GW_e from the end of June 2018. The tender extended across four regions in southern Germany. “The transmission system operator TenneT has awarded the contract for the construction and operation of special network operating equipment to the energy company Uniper. Uniper will therefore build and operate a gas power plant with a capacity of 300 megawatts at the Irsching location.” [TenneT 2019] The other tenders have not yet been concluded at this point in time. [energate 2019]

In this cluster approach, the transmission system operators will implement a regional structuring of the new power plant requests that are in competition with each other. In the clusters that have been created, the estimated electrical power output is capped at a maximum of 1.2 GW_e in each case. In the overall German H-gas balance, however, a total of 1.2 GW_e is taken into consideration in the Gas NDP 2020–2030 for all power plants shown as special network operating equipment. The clustering is carried out using the regional network location of the power plants in relation to the main transmission systems. Power plant projects that can be allocated to the same main transmission systems form a cluster here.

Depending on the special network operating equipment to be taken into consideration in accordance with the criteria in the draft scenario framework for the Gas NDP 2020–2030, the transmission system operators implement the cluster approach on the basis of the procedure that has been described.

2.3 Storage facilities

The role played by the gas storage facilities in the supply of energy is discussed in Chapter 2.3.1. Which storage projects are taken into consideration in the consultation document for the scenario framework on the basis of the criteria described above and which are currently not considered are then shown (cf. Chapter 2.3.2).

2.3.1 Role of the storage facilities

Natural gas storage facilities primarily serve to provide a balance between constant natural gas procurement at the cross-border import points and production as well as consumption of natural gas by end users that fluctuates sharply depending on the temperature.

The use of storage facilities means that the transmission systems can be dimensioned in an economically sensible way and the overall system can be optimised in terms of efficient utilisation. Furthermore, they are technically capable of providing larger gas volumes quickly and locally during peak loads or in the event of a physical bottleneck in the network (balancing energy) and thus play an important role in the security of supply and system stability, whereby storage facilities are also increasingly being marketed from commercial perspectives in the trading sector. A function of the storage facilities that is beneficial for the network can therefore not be guaranteed without further assumptions. Moreover, the transmission system operators support that the general regulatory conditions for securing necessary storage capacity also at the end of a winter period should be further developed.

As in the previous network development plans, the transmission system operators also intend to estimate an average storage capacity of no less than 35% as planning premises in the peak load situation in the Gas NDP 2020–2030.

2.3.2 Consideration of storage projects in the consultation documents for the scenario framework for the Gas NDP 2020–2030

Currently, no storage requests pursuant to Sections 38/39 GasNZV have been submitted to the transmission system operators that are taken into consideration in the consultation document of the scenario framework for the Gas NDP 2020–2030 on the basis of the criteria described in Chapter 2.1.

Table 5: Plans for the construction of storage facilities on the network of the transmission system operators not taken into consideration in the consultation document for the 2020 Scenario Framework, but which could still be included in the draft document (reporting date: 31 March 2019)

TSO	Federal Network Agency number	Project name	Gas type (H-gas/ L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/no/open)	Reason/applicable criterion (updated 31 March 2019)
bayernets		Speicher Nussdorf/ Zagling (7F)	H-gas	648 entry/432 exit	Section 39 GasNZV	no	open	– Implementation schedule not finalised and/or – Planning fee not paid
bayernets		Speicher Nussdorf/ Zagling (7F)	H-gas	346 entry/230 exit	Section 39 GasNZV	no	open	– Implementation schedule not finalised and/or – Planning fee not paid
Nowega		Empelde	L-gas		Section 39 GasNZV	no	open	– Implementation schedule not finalised and/or – Planning fee not paid

Note: Changes in status in relation to the criteria pursuant to Chapter 2.1 have resulted for some projects after the reporting date of 31 March 2019. These changes are taken into consideration in the draft scenario framework.

Source: Transmission system operators

2.4 LNG plants

The current situation involving planned LNG plants in Germany with a connection to the transmission system in Germany is described in Chapter 2.4.1. Chapter 2.4.2 then shows which new LNG facilities are taken into consideration in the consultation document for the 2020 scenario framework for the basis of the criteria described above and which are currently not considered. The planned approach to the LNG plants in the course of the modelling is described in Chapter 2.4.3.

2.4.1 Current situation

The construction of LNG plants in Germany, the connection to the transmission system and the related provision of capacity were already themes in the Gas NDP 2018–2028.

Capacity reservations/capacity expansion claims pursuant to Sections 38/39 GasNZV for planned LNG plants in Brunsbüttel and in Wilhelmshaven are available to the transmission system operators for the Gas NDP 2020–2030.

Brunsbüttel

The Brunsbüttel LNG plant was included in the draft Gas NDP 2018–2028 as the result of an application to expand capacity pursuant to Section 39 GasNZV at GUD. In the request to change the Gas NDP 2018–2028, the BNetzA ordered – on the basis of the existing legal framework – the removal of the resulting network expansion measures, as it is of the opinion that the production of the link is not covered by section 15a EnWG. This decision is not final, because a complaint has been filed about the Federal Network Agency's request to change the Gas NDP 2018–2028.

An ordinance adopted in June 2019 on the enhancement of the general conditions for the expansion of the LNG infrastructure in Germany requires the transmission system operators to connect LNG facilities to the transmission systems at the request of a connectee. The infrastructure required for the network connection is then supposed to become the property of the transmission system operator. It becomes a part of the energy supply network from the time that it is built. These regulations are furthermore intended to guarantee the technical network connection for LNG facilities and a minimum technical entry capacity. As a result, the statutory privileged treatment enjoyed by LNG plant operators is extended beyond the options enabling them to apply for a capacity reservation or a necessary expansion of capacity that already exist by clear regulations governing the network connection. The costs of the transmission system operators associated with the creation of the network connection for LNG plants are classified as an investment measure within the meaning of Section 23 of the Anreizregulierungsverordnung (ARegV – Ordinance governing the incentive regulation for the energy supply network). Coverage of the costs for the transmission system operators is thus ensured.

A capacity expansion claim pursuant to Section 39 GasNZV is still available as before to GUD for the Brunsbüttel LNG project. This project has not yet been confirmed within the framework of the Gas NDP pursuant to Section 39 GasNZV. The project developers continue to assume that the terminal will be implemented, with the result that GUD will continue to pursue the network connection and a corresponding expansion of capacity.

The transmission system operators therefore intend to take the LNG project in Brunsbüttel into consideration again in the Gas NDP 2020–2030.

Wilhelmshaven

A new application of capacity reservation in accordance with Section 38 GasNZV was made to OGE at the beginning of February 2019 for the project involving an LNG plant in Wilhelmshaven. The application had not yet been decided upon by the reporting date of 31 March 2019 on account of the processing times and is therefore included in the consultation document. The transmission system operators will take the decision on whether to include a project in the Gas NDP 2020–2030 in the draft scenario framework for the Gas NDP 2020–2030 using the criteria in Chapter 2.1.

2.4.2 Consideration of LNG facilities in the consultation document for the scenario framework for the Gas NDP 2020–2030

After the criteria described in Chapter 2.1 have been applied and the current situation presented in Chapter 2.4.1 has been taken into consideration, the following requests for LNG facilities pursuant to Sections 38/39 GasNZV are taken into consideration in the consultation document of the scenario framework for the Gas NDP 2020–2030.

Table 6: LNG facilities on the network of the transmission system operators taken into consideration in the consultation document of the 2020 scenario framework (reporting date: 31 March 2019)

TSO	Federal Network Agency number	Project name	Gas type (H-gas/ L-gas)	Gas connection capacity [MW]	Status	Consideration in the consultation document of SF 2020 (yes/no)	Consideration in the draft document of SF 2020 (yes/ no/open)	Reason/applicable criterion (updated 31 March 2019)
GUD		LNG terminal in Brunsbüttel	H-gas	8,700	Section 39 GasNZV	yes	yes	– Project included in Gas NDP 2018–2028 – cf. Chapter 2.4.1 – Connection applicant has not withdrawn
OGE		LNG terminal in Wilhelms-haven	H-gas	12,500	Section 38 GasNZV	yes	open	– Application not yet approved between 17 June 2018 and 31 March 2019

Note: Changes in status in relation to the criteria pursuant to Chapter 2.1 have resulted for some projects after the reporting date of 31 March 2019. These changes are taken into consideration in the draft scenario framework.

Source: Transmission system operators

2.4.3 Planning approach in the modelling

LNG competes on the gas market with gas from other sources that comes into Germany primarily through cross-border interconnection points. LNG also competes with gas from storage facilities in particular in the response to short-term market signals.

LNG terminals do not supply continual injections for the gas networks. Furthermore, in planning LNG volumes, transmission system operators must take into account that at least some volumes are intended for the transport sector (heavy load and shipping traffic). The question therefore has to be asked: what type of capacity can be applied for LNG terminals while complying with the concept of efficiency and fulfilling the obligations pursuant to Sections 38/39 GasNZV.

As already presented in the opinion of FNB Gas on the BMWi's draft bill of 14 March 2019 (ordinance on the enhancement of the general conditions for the expansion of the LNG infrastructure in Germany), an efficient capacity offer for LNG terminals is given only when rival usage of the entry capacity available as a whole (IPs, UGS) is provided at the LNG terminal. The design of the rival marketing should enable capacity that is not nominated or not booked in the short and medium term to be used at the rival points.

In line with the current situation, the transmission system operators propose that the capacity for the LNG terminals is estimated for planning purposes in competition with bookable GUD and OGE entry points yet to be determined.

2.5 Green gas projects from the survey of market partners

In the course of the market partner survey, a total of 22 green gas projects were reported to the transmission system operators by 15 May 2019. Table 7 below shows the reported projects and classifies them based on the parameters of gas quality, source/sink, planned commissioning and connected network level. The transmission system operators have extended the market survey of green gas projects to 12 July 2019 [FNB Gas 2019]. Other projects can be reported up to 12 July 2019. Furthermore, the reports that have already been submitted will be verified in terms of the plausibility and supplemented.

Table 7: Green gas projects from the survey of market partners that were reported by 15 May 2019

No.	Designation	Companies involved	Gas quality/ medium	Source/sink	Planned implementation/ commissioning	Competent TSO	Connection to TSO network	Connection to DSO network
1	HySynGas/ARGE Brunsbüttel	ARGE Netz GmbH & Co. KG, MAN, Vattenfall	Hydrogen, synthetic methane	Source	by 2025	GUD	x	x
2	SALCOS	Salzgitter Flachstahl GmbH	Hydrogen	Sink	from 2025	Nowega	x	
3	GET H2	enertrag, Forschungszentrum Jülich, hydrogenious, IKEM, nowega, RWE, SIEMENS, Stadtwerke Lingen	Hydrogen	Source/sink	2023	Nowega	x	
4	Biogas-Anlage InfraServ Wiesbaden	InfraServ GmbH & Co. Wiesbaden KG	Biogas	Source	2020/2021	OGE		x
5	Wasserstoff thyssenkrupp	thyssenkrupp Steel Europe AG	Hydrogen	Sink	from 2020	OGE	x	
6	BW Bürgerwind-park Fehndorf/ Lindloh	BW Bürgerwindpark Fehndorf/Lindloh GmbH & Co. KG	Hydrogen	Source	2021	OGE	x	
7	Salzbergen	H&R Chemisch Pharmazeutische Spezialitäten GmbH	Hydrogen	Sink	2023	OGE	x	
8	hybridge	Amprion, OGE	Hydrogen, synthetic methane	Source	2023	OGE	x	
9	Biogasanlage Stadtwerke Trier	Stadtwerke Trier Versorgungs-GmbH	Biogas	Source	2019	OGE		x
10	PtG-Anlage GVG	Gasversorgungsgesellschaft mbH Rhein-Erft (GVG)	Hydrogen	Source		OGE	x	
11	PtG STEAG	STEAG GmbH	Hydrogen	Source	2024	OGE		x
12	Kreis Steinfurt/ Münster	Kreis Steinfurt/Stadtwerke Münster GmbH/münsterNETZ	Hydrogen	Source/sink		OGE	x	
13	Statkraft Emden	Statkraft Markets GmbH	Hydrogen	Source	2022	OGE	x	
14	Wasserstoffeins-peisung Mainz	Mainzer Netze GmbH	Hydrogen	Source	2018/2021	OGE		x
15	Gazprow		Hydrogen	Source	2022	ONTRAS	x	
16	Energiepark Bad Lauchstädt		Hydrogen	Source/sink	2023	ONTRAS	x	
17	Wasserstoffregion Lausitz		Hydrogen	Source	2021	ONTRAS	x	
18	GASAG/E.dis AG	GASAG/E.dis AG	Hydrogen	Source	2020/2021	ONTRAS		x
19	BGEA Schwarze Pumpe		Biogas	Source	2022	ONTRAS	x	
20	ELEMENT EINS	Thyssengas GmbH (TG), TenneT TSO GmbH, Gasunie Deutschland Transport Services GmbH (GUD)	Hydrogen, synthetic methane	Source		GUD, TG	x	
21	BGEA Krefeld	Thyssengas GmbH/EGK Entsorgungsanlagengesellschaft Krefeld GmbH & Co. KG	Biogas	Source	2021	TG	x	
22	BGEA Coesfeld	Thyssengas GmbH/GFC mbH – Gesellschaft des Kreises Coesfeld zur Förderung regenerativer Energien mbH	Biogas, hydrogen	Source		TG	x	

Source: Transmission system operators

The larger projects, including both sources and sinks, are presented below based on an initial examination. These are content descriptions based on reports from project developers.

GET H2

The GET H2 initiative intends to demonstrate in Lingen, in the district of Emsland, the large-scale generation of green hydrogen (H_2) by means of electrolysis and to build regional hydrogen infrastructure in Emsland. Project partners are here working together along the entire value chain and across all sectors in order to generate H_2 from renewable electricity and use this in an optimal way.

This project is conceived as the nucleus of a nationwide H_2 infrastructure that can be a crucial step forward in achieving the federal government's ambitious climate targets also in the industrial, transport and transmission as well as heating and energy sectors as cost-efficiently as possible.

In order to ensure that this PtG project is economically feasible in the medium term, the project partners have applied for a grant from the BMWi's "Reallabore der Energiewende" funding competition ("Field labs for the energy transition"). The field lab uses electricity from renewable energies as well as existing electricity and gas infrastructure, including a first pipeline storage facility. Two PtG plants (electrolysis) will be added, one of them at the gas power plant in Lingen in combination with a high-temperature heat pump for using the waste heat from the electrolysis process for district heating. The existing liquid fuel infrastructure will also be linked through an LOHC (liquid organic hydrogen carrier) storage and transmission system. The green H_2 will be supplied to consumers in the transport and transmission, industrial as well as heating and energy sectors through the H_2 infrastructure.

Summary of the "GET H2" project:

- Use of renewably generated district heating from central electrolysis
- Conversion of an existing natural gas pipeline at the gas power plant as H_2 pipeline storage
- Repurposing of two transmission pipelines as initial H_2 transmission network
- LOHC (liquid organic hydrogen carrier) storage and transmission system for local applications
- Reconversion of H_2 in existing gas turbine
- Supply of industrial consumers as well as H_2 filling stations for mobility applications

hybridge

Amprion and Open Grid Europe (OGE) are looking to drive sector coupling forward at the system level. The long-term objective of the project partners is to harmonise the electricity and gas systems with each other in an optimal way. The use of a PtG gas plant that is beneficial to the system can thus also help to reduce or prevent bottlenecks in the transmission network. The "hybridge" project is the first step in this direction. The plans are set out below: An electrolyser of 100 MW_e will be built near an electricity substation belonging to Amprion and connected to Amprion's electricity grid. Locations in the vicinity of Hanekenfähr (Lingen area) or Öchtel (Schüttdorf/Salzbergen area) electric power substations are suitable for this. The injection of up to 20,000 m^3/h of hydrogen is possible. Starting out from this, the companies intend to test in the project all the uses that hydrogen can be put to in the future. For efficiency reasons, the direct use of hydrogen is the focus of the "hybridge" sector coupling project. One of the aims is to enable gas shippers, such as refineries, to use elementary hydrogen directly. Adding hydrogen to the natural gas networks represents another possibility that will be tested in the project. As a result, the green gas can also be used for other purposes, including in the heating sector for example. If the options are exhausted, hydrogen can also be methanised with carbon dioxide and injected into the natural gas network. The planned methanisation facility will convert parts of the hydrogen (up to 4,000 m^3/h) into synthetic methane (up to 1,000 m^3/h) by admixing carbon dioxide from a renewable source. Based on what is known about the project at the moment, the Salzbergen industrial park is suitable as the location for the planned methanisation facility. If the regulatory authorities agree to the project, Amprion and OGE will be able to start on the construction shortly after the approval process (planned commissioning in 2023).

Table 8: Data on the "hybridge" project (planning status: May 2019)

	Injection of hydrogen converted from electricity	Out-take of hydrogen converted from electricity for methanisation purposes	Injection of synthetic methane from the methanisation plant
Location of the network connection	Electrolyser in southern Emsland (near the electricity power sub-station at Hanekenfähr or Öchtel)	Methanisation in Salzbergen industrial park	Methanisation in Salzbergen industrial park
Entry in or exit from the gas network	Entry	Exit	Entry
Gas composition	Hydrogen (> 99 %)	Hydrogen (> 99 %)	Synthetic methane (H_2 < 1 %)
Capacity	Approximately 20,000 m^3/h or approximately 70,000 kWh/h	Approximately 4,000 m^3/h or approximately 14,000 kWh/h	Approximately 1,000 m^3/h or approximately 10,000 kWh/h
Pressure	Min. 1–2 bar(a)	Min. 14 bar(a)	Min. 10 bar(a)
Start of entry or exit	2023	2023	2023

Source: Transmission system operators

Lusatia hydrogen region

Project aim

The aim of the project is to convert a city in Lusatia fully to renewable energies (electricity and hydrogen) for the heating, transport, electricity and industrial end-user sectors in the long term.

The conversion involves a complex and elaborate transformation of the regional infrastructure and energy supply.

The project can be divided into two major focal points:

1. Injecting renewable hydrogen from a large-scale electrolyser into the gas network in order to “green” municipal heating and local public transport.

2. Increasing the physical supply of a town with renewable hydrogen until full conversion is completed.

Focal points of the project

With regard to the first focal point, it is planned to equip the “Bahnsdorfer Berg” energy park with a large-scale electrolyser – with an output of 50 MW_e in the first stage and later of up to 100 MW_e – situated at gas pipeline 106 or 11 of ONTRAS Gastransport GmbH. It is intended to establish a hydrogen hub and to inject renewably generated hydrogen into the ONTRAS transmission system. This hydrogen will be used to increase the renewable energy supply of various localities in the region. The first phase of the project will consist in particular in generating heating for households, while further preparation will open up the possibility of use in local public transport.

The planned “Bahnsdorfer Berg” energy park is located in the city of Uebigau-Wahrenbrück, in the west of the existing wind fitness area WEG 33 Oelsig-Buchhain.

The hydrogen production is planned in the vicinity of the ONTRAS 106 or 11 gas pipeline, a few kilometres away from the planned wind farm. The wind turbines and the hydrogen production are connected by 20-kV lines and constitute a combined facility.

The concept provides for the construction of a large-scale hydrogen production facility at the Bahnsdorfer Berg wind farm, which will be supplied by renewable electricity generated on site. The green hydrogen will be produced using electrolysers. Various technologies that have been tested on the market for many years will be employed here. The hydrogen will ultimately be injected into the ONTRAS gas pipeline network and is envisaged for the energy balance marketing of energy suppliers. In the second focal point, it is intended in a staggered process initially to increase to approximately 10% the proportion of renewable hydrogen of a locality that has been supplied with natural gas up to now. In order to realise this goal, it will be necessary in all likelihood to build a local electrolysis unit (or other hydrogen production plant) in the vicinity of the locality, the hydrogen from which will be fed in to the supply network. This locality is subsequently intended to be converted partly or fully to a hydrogen-based energy supply. In addition to the modification of the entire supply infrastructure to hydrogen, all connected technologies, such as domestic heating, industrial customers, filling stations and power plants, will have to be converted in this stage.

Importance

Experience in dealing with permanently increasing proportions of renewable hydrogen will be gained in this project. The project is thus a key building block in the structural transformation in Lusatia and for the renewable energy sector of the future.

ELEMENT EINS

The transmission system operators TG and GUD as well as TenneT as an electricity transmission system operator are aiming to couple electricity and gas networks on an industrial scale for the first time in Germany by converting green electricity to green gas with a large-scale PtG plant that will be expanded in stages.

In order to achieve this, the project partners in ELEMENT EINS plan to construct a 100 MW_e PtG plant in a high-wind region in north-western Germany that will predominantly use renewably generated electricity for conversion into green gas and injection of this in high-pressure gas pipelines.

The plant will be built in the north of Lower Saxony and will be operated by GUD and TG. Diele and Conneforde are currently being evaluated as possible locations.

The foundation for coupling the electricity transmission and the gas transmission networks will be laid In the first phase of the project. For this purpose, a PtG plant with an electrical capacity of up to 40 MW_e will be constructed and connected to the networks to begin with.

A methanisation plant can additionally be built centrally and operated at the PtG facility. This will increase the utilisation of the PtG plant, as synthetic methane from hydrogen and biogenic CO_2 from the area surrounding the PtG plant can be produced centrally in addition to hydrogen. This synthetic methane can be injected into the gas transmission network without restriction. An excess of unused biogenic CO_2 is usually created in the biogas production process, and this can be converted to synthetic methane in combination with the hydrogen supplied.

Following the first phase of the project with input power of up to 40 MW_e it is planned to continue to expand ELEMENT EINS on a gradual and modular basis. A target value of approximately 100 MW_e will be aimed at for the electrolyser input power (electrical).

Table 9: ELEMENT EINS project plan/development path

Year	2019–2022	2022–2024	2024–2028	from 2028
Phase	Planning and initial expansion stage	H_2 injection and second expansion stage	Third expansion stage, expansion by methanisation	Use of free L-gas infrastructure and conversion to 100 % H_2 systems
Subgoals	Planning, approval, tender, construction and commissioning of the first expansion stage of the electrolyser, including network connections	H_2 injection into existing natural gas pipelines (L- and H-gas); use of existing pipelines as pipe storage; potential expansion of the use cases by the option of direct provision of H_2 at the exit point of the electrolyser; second expansion stage	Third expansion stage, expansion of the use cases by the option of methanising H_2 with CO_2 from biogas facilities	Use of the former gas infrastructure that has been fully converted to H_2; connection to existing H_2 infrastructure, use of local and regional storage facilities
Expansion to number of modules (each approximately 20 MW)	2	4	5–6	5–6
Injection quantity m^3/h	up to 5,600	up to 10,500	up to 21,000	up to 21,000

Source: Transmission system operators

thyssenkrupp Steel Europe AG

For the most part, the German steel industry pursues the goal of a low CO_2 production method. To this end, it plans to use all promising technologies, thus both CCU and CDA concepts. Approaches that are being adopted here include exploiting gases generated in steel production as raw materials as well as preventing the formation of CO_2 from the outset. It is clear that gaseous reducing agents and hydrogen in particular represent an integral and essential component in the transformation process of the industry. With regard to the climate targets for 2050, a CO_2 reduction of more than 80% cannot be achieved without the massive utilisation of hydrogen.

Around 1.7 billion tonnes of crude steel was produced globally in 2017. The largest share of this was obtained using the blast furnace process, in which oxide ores are smelted together with coke produced from coal as a reducing agent. The product from this process is molten pig iron. The blast furnace process, which is today operated at least in Western Europe at the technical and thermodynamic optimum, relies on the use of coke and thus produces CO_2 systemically. A further decrease in CO_2 emissions in this conventional blast furnace route is virtually impossible.

A significant reduction in these emissions is possible, however, by using gaseous reducing agents. Natural gas can be used in a transition period, which is later slated to be replaced by hydrogen as a completely carbon-free energy source in order to achieve the ambitious climate targets for 2050. At the same time, however, this step will require a radical and capital-intensive technological transformation from the previous blast furnace route to a direct reduction metallurgy, where solid metallic iron is created in direct reduction plants by the effect of gaseous reducing agents on oxide ore and converted into crude steel using downstream electric arc furnaces. Today, only around 87 million tonnes of crude steel per year is produced using this process globally, primarily in regions with large supplies of natural gas. thyssenkrupp Steel Europe AG intend to invest a total of EUR 10 billion in the construction of new production facilities by 2050 in order to be able to leverage the potential for reducing CO_2 associated with direct reduction metallurgy and increase the proportion of steel production through this route.

thyssenkrupp Steel Europe AG has calculated its own demand for hydrogen for a complete conversion to hydrogen-based direct reduction metallurgy while maintaining the current production volume of approximately 10 million tonnes of crude steel per year at its Duisburg-Nord site. This would be gradually increased over the next three decades – in line with the conversion of the production route – and is currently estimated at 7 billion Nm^3/year in 2050.

SALCOS®

SALCOS® – Direct avoidance of CO_2 formation in steel production (carbon direct avoidance, CDA)

To produce a significant decarbonisation of primary steel production, Salzgitter AG is looking to take advantage of a unique feature of iron metallurgy: hydrogen can replace carbon dioxide in the iron ore reduction process, which results in the creation of water (H_2O) instead of carbon dioxide (CO_2). The process heat that is required in steel production and further processing can additionally be provided by electrical energy instead of carbon-based energy sources. In the final analysis, almost all CO_2 emissions produced in steel production can be directly avoided (carbon direct avoidance, CDA). SALCOS® firmly believes that the direct avoidance of CO_2 in steel production is more sustainable than CCU or CCS. In comparison with other industrial approaches, our approach furthermore offers the best combination of energy efficiency and the potential for CO_2 avoidance. With a view to realising CDA on a large technical scale, Salzgitter SA launch the SALCOS® (Salzgitter Low CO_2 Steelmaking) project in 2015. The project is based on a modular concept that offers the possibility of stage-by-stage implementation. The current energy-efficient steel production in the integrated steelworks in Salzgitter must be extensively modified. In the first expansion step (expansion stage I), which comprises all relevant SALCOS® technologies, a direct reduction plant (DRP), water electrolysis capacity for H_2 production and an electric arc furnace (EAF) would be installed. Some of the direct reduced iron (DRI) would be smelted in the EAF, which is operated as far as possible using renewable energy, and some would be fed into the remaining blast furnaces.

This results in the opportunity to remove from production one of the three blast furnaces currently in operation as well as a converter of Salzgitter AG. CO_2 emissions would be reduced by approximately 26% in this expansion stage. The great strength of SALCOS® is that the approach is based on a large-scale established technology (gas-based direct reduction) that can be further developed in line with the challenges of the future. In technical terms, this produces the possibility of achieving, in a relatively short term, a significant reduction in CO_2 through the use of a plant on an industrial scale. SALCOS® thus differs clearly from many other decarbonisation approaches that are scheduled to be realised on a large scale only from 2035 onwards. The further implementation steps (expansion stages II and III) are based essentially on the same basic module (DRP, electrolysis and EAF) and have the potential to lead in the coming decades to a complete conversion of steel production from the blast furnace-converter route to the direct reduction-EAF route. With a full conversion of production and the use of hydrogen generated 100% by using renewable energy sources in the direct reduction plant, the maximum achievable CO_2 reduction in the SALCOS® concept is 95%. For further details, visit: https://salcos.salzgitter-ag.com/en/index.html.

Energiepark Bad Lauchstädt

The aim of the "Bad Lauchstädt energy park" field lab is to provide renewable electricity for energy and material uses by means of sector coupling. To this end, conditions have to be created with which security of supply can be achieved despite fluctuating energy generation. Large-scale technical storage of hydrogen constitutes the core of the project here. Fluctuating generation capacity for different application pathways can thus be smoothed out and provided based on demand.

The approach used in the "Bad Lauchstädt energy park" is to convert electricity from a wind farm into hydrogen directly through large-scale electrolysis by means of stand-alone operation. This hydrogen will be stored in a salt cavern specially equipped for this purpose. Underground salt caverns are ideally suited for storing hydrogen from renewable fluctuating energy sources safely and efficiently on a large scale. This form of energy storage has not previously been implemented in Germany or continental Europe. The hydrogen that is produced and stored will be provided through a line connection to the H2 network for use as a material at the Leuna chemical industrial park. Other application sectors include mobility and the urban area, where the hydrogen can be used directly for generating heating and electricity.

The "Bad Lauchstädt energy park" project has the goal of demonstrating pioneering technology concepts in sector coupling under real network conditions. The individual system components will be designed in a sufficiently systemically appropriate size here. The capability of extending the system components and the possibilities for later expanding them play a critical role in this process.

An important element in sector coupling is the linking of the generation of renewable electrical energy with the consumers in the chemicals industry and other sectors in order to provide infrastructure that ensures the security of the supply of hydrogen. To this end, the generation of hydrogen in a large electrolysis unit will be coupled directly, outside of the electricity network, with a large local wind and solar farm. The hydrogen will be injected into a sub-network of the gas infrastructure, which enables it to be stored on a seasonal basis and shipped to the consumer. Elements of the natural gas infrastructure, such as underground storage caverns as well as transmission and distribution networks, will be used in this process. This infrastructure will be converted to pure hydrogen. It is planned to analyse the new hydrogen structure in a research operation over several years. In addition to the secure supply of hydrogen for use as a material in the chemicals industry, the utilisation in mobility and the urban energy supply will also be a particular focus here. The Bad Lauchstädt energy park is to be connected for all to the hydrogen network of the Leuna chemical industrial park as well as to an urban area for filling stations and for supplying heating and electricity.

Trends in gas demand 3

3 Trends in gas demand

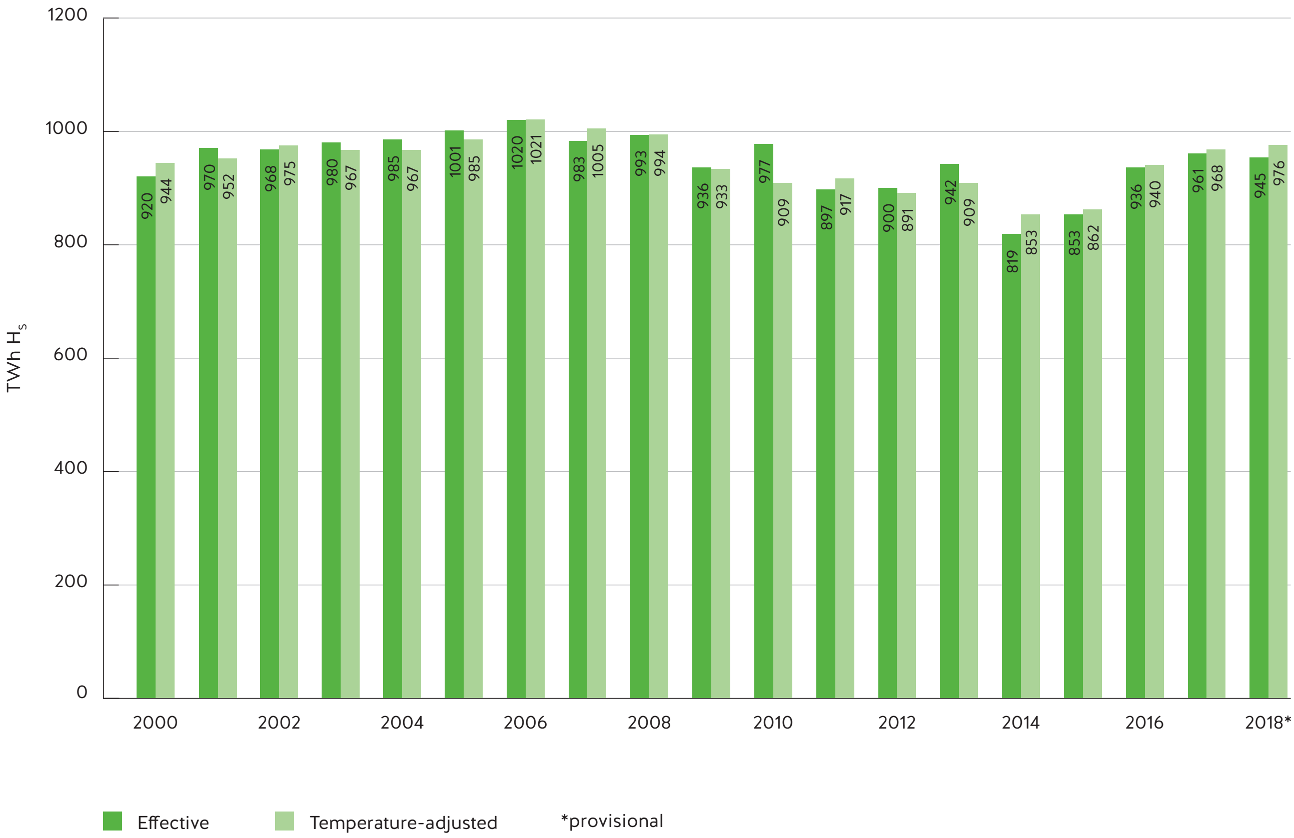
This chapter deals with the trends in gas demand in Germany. Following the state analysis of gas consumption since 2000 (cf. Chapter 3.1), various future gas demand scenarios for Germany will subsequently be examined and specific gas demand scenarios will be defined for this scenario framework (cf. Chapter 3.2). Chapters 3.3 and 3.4 describe the trends in gas demand in the final energy demand and the transformation sector. Chapter 3.5 deals specifically with the trends in demand for green gases. The overall trends in demand, including regionalisation, are summarised in Chapter 3.6. Chapter 3.7 deals with the development in demand in Baden-Wuerttemberg.

3.1 State analysis

Germany's gas demand is compiled from the individual results of the development paths related to the final energy consumption, gas usage in the transformation sector (generation of electricity and heating) and non-energy consumption.

To be able to present the trends in natural gas consumption independently of the influence of variations in temperatures, it is necessary to adjust the annual natural gas consumption by the temperature effect with the help of degree day figures and reference it to a year with average temperatures.

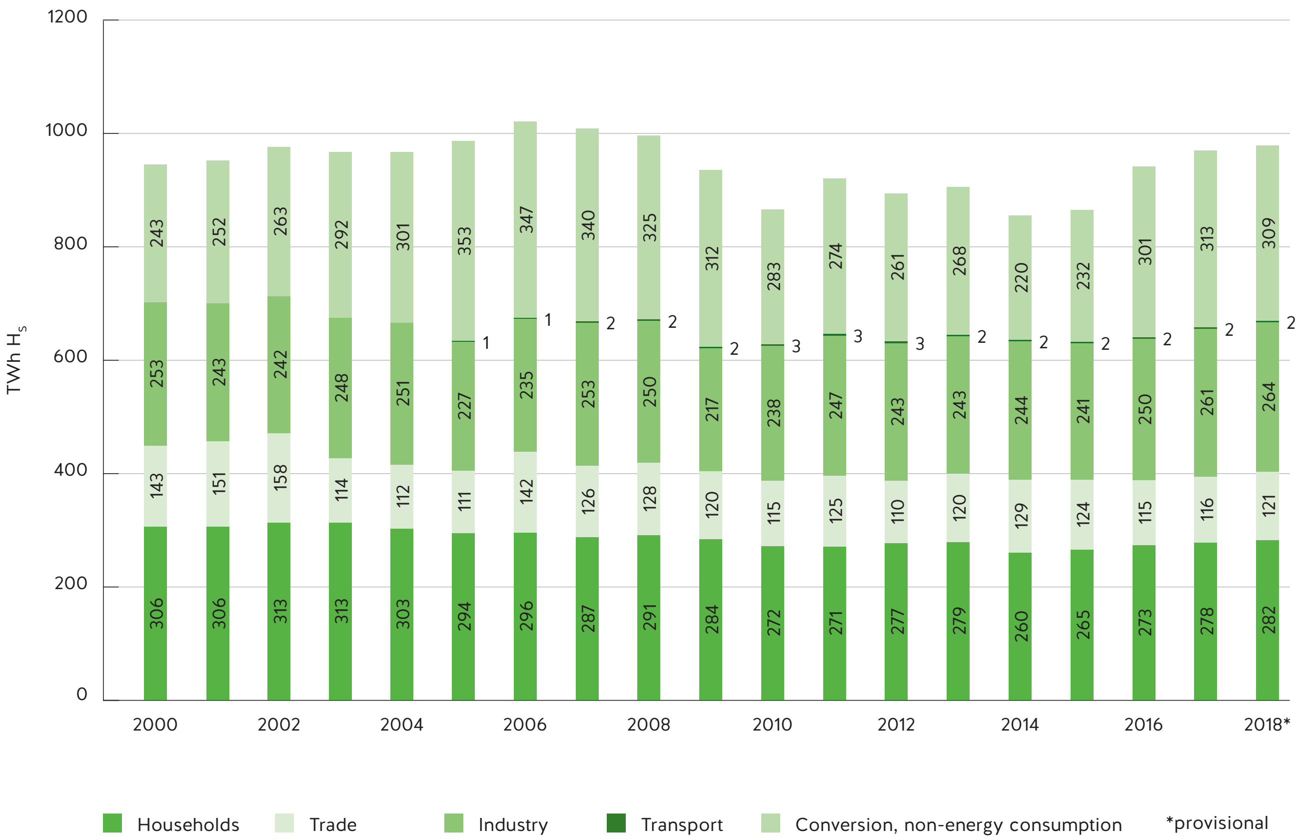
Figure 2: Development of consumption of natural gas (primary energy consumption) in Germany in TWh (H_s)



Source: BDEW 2019a/AG Energiebilanzen 2019 (primary energy consumption, natural gas), calculation by the transmission system operators (temperature-adjusted values)

The trend in the consumption of natural gas in Germany presented in Figure 2 shows that consumption – adjusted by the temperature effect – initially increased from the base year of 2000 up to 2006, subsequently declined from 2006 to 2014, but has grown again significantly in the last three years.

Figure 3: Development of temperature-adjusted consumption of natural gas in Germany by sector (final energy, other consumption) in TWh (H_s)



Note: NEV – Nichtenergetischer Verbrauch – non-energy consumption, part of the energy source not used for energy (e.g. as raw material for chemical processes)

Source: BDEW 2019a/AG Energiebilanzen 2019 (final energy consumption, natural gas), calculation by the transmission system operators (temperature-adjusted values)

The trend in the temperature-adjusted consumption of natural gas in Germany by sector presented in Figure 3 shows that the transformation sector, i.e. in particular the gas-based generation of electricity and heating, accounted for a considerable proportion of the fluctuating consumption trends and increased significantly in the years from 2016 to 2018.

In contrast, the consumption of natural gas in private households and the commerce, trade and services sector have stayed at a relatively constant level since 2011 following declines in the years from 2000 to 2010, as has the consumption of natural gas in industry, which is influenced by economic fluctuations.

The relatively high new construction activity of the last few years continued in 2018 with around 305,000 approved apartments. However, the market share of natural gas in new builds fell in the same period from previously around 77 % in 2000 to around 39 % now. Electric heat pumps and district heating, on the other hand, have continually gained market shares in new builds in the last few years (cf. Table 10).

Natural gas heating has been able to increase its market share in the housing stock consistently since 2000, where the percentage growth has got continually smaller. The market share of apartments heated using natural gas has remained constant at around 49.4 % since 2016. (cf. Table 11).

Table 10: Market shares of energy sources in new builds

Year	Number of apartments[1]	Natural gas[2]	Electric heat pumps	District heating	Electricity	Fuel oil	Wood, wood pellets	Others[3]
		Share in %						
2000	304,248	76.7	0.8	7.0	1.3	13.4	–	0.8
2001	256,530	75.9	2.0	7.5	1.7	11.3	–	1.6
2002	243,248	75.8	2.1	7.2	1.7	11.0	–	2.2
2003	263,348	74.3	2.8	7.0	1.2	12.0	–	2.7
2004	236,352	74.9	3.1	7.3	1.2	10.7	1.2	1.6
2005	211,659	74.0	5.4	8.6	1.2	6.4	3.0	1.4
2006	216,519	66.9	11.2	9.0	1.0	4.3	6.0	1.6
2007	157,148	65.6	14.3	10.2	1.3	3.2	3.0	2.4
2008	148,300	58.4	19.8	12.0	1.0	2.3	4.0	2.5
2009	153,701	50.9	23.9	13.1	0.8	1.9	5.0	4.4
2010	164,540	50.2	23.5	14.6	1.0	1.8	5.0	4.1
2011	200,061	50.1	22.6	16.3	0.9	1.5	5.6	2.5
2012	211,155	48.5	23.8	18.6	0.6	0.9	6.3	1.4
2013	254,250	48.3	22.5	19.8	0.7	0.8	6.4	1.5
2014	264,332	49.9	19.9	21.5	0.6	0.7	6.1	1.3
2015	285,282	50.3	20.7	20.8	0.7	0.7	5.3	1.5
2016	329,000	44.4	23.4	23.8	0.9	0.7	5.3	1.5
2017	300,349	39.3	27.2	25.2	0.7	0.6	5.5	1.6
2018*	305,000	39.0	28.9	24.9	0.9	0.5	4.4	1.4

* provisional

1) New residential units approved for construction; up to 2012 in new buildings to be constructed, from 2013 additionally in existing buildings
2) Including bio natural gas
3) Up to 2003 including wood

Source: BDEW 2019a on the basis of the Statistisches Bundesamt (German Federal Statistical Office), state statistical offices, updated February 2019

Table 11: Heating structure of the housing stock

Year	Number of apartments[1] in millions	Gas[2]	District heating	Electricity	Electric heat pumps	Fuel oil	Others[3]
		Share in %					
2000	38.2	44.5	12.3	4.8	–	32.6	5.8
2001	38.5	45.3	12.4	4.6	–	32.2	5.5
2002	38.7	46.0	12.4	4.5	–	31.9	5.2
2003	39.0	46.6	12.4	4.4	0.1	31.6	4.9
2004	39.2	47.2	12.4	4.3	0.1	31.2	4.8
2005	39.4	47.6	12.5	4.2	0.2	30.9	4.6
2006	39.6	48.0	12.5	4.1	0.3	30.5	4.6
2007	39.7	48.3	12.6	4.0	0.5	30.1	4.5
2008	39.9	48.5	12.6	3.8	0.7	29.8	4.6
2009	39.9	48.9	12.7	3.6	0.8	29.3	4.7
2010	40.3	49.0	12.8	3.4	1.0	28.9	4.9
2011	40.4	49.1	12.9	3.2	1.1	28.3	5.4
2012	40.6	49.2	13.1	3.1	1.2	27.8	5.6

Year	Number of apartments[1] in millions	Gas[2]	District heating	Electricity	Electric heat pumps	Fuel oil	Others[3]
		Share in %					
2013	40.8	49.2	13.3	3.0	1.4	27.2	5.9
2014	41.0	49.3	13.5	2.9	1.5	26.8	6.0
2015	41.3	49.3	13.6	2.8	1.7	26.5	6.1
2016	41.5	49.4	13.7	2.7	1.8	26.3	6.1
2017	41.7	49.4	13.8	2.6	2.0	26.1	6.1
2018*	42.0	49.4	13.9	2.5	2.2	25.9	6.1

* provisional

1) Number of apartments in buildings with living area; heating present
2) Including bio natural gas and liquefied gas
3) Wood, wood pellets, other biomass, coke/coal, other heating energy

Source: BDEW 2019a, updated February 2019

3.2 Gas demand scenarios

The reduction of greenhouse gas emissions, the expansion of renewable energy sources and the increase in energy efficiency are key targets of European and German energy and climate policy. The long-term goal is a major reduction in greenhouse gas emissions by 80 % to 95 % by 2050 in comparison with emissions in 1990. These general conditions of energy and climate policy form an important foundation for the large number of the existing scenarios for energy and gas demand.

Prognos AG analysed renowned studies and publications on the future development of gas demand and gas supply in Germany on behalf of the transmission system operators for this scenario framework. Target scenarios that fulfil the targets of energy and climate policy are focused on here. In the following, gas demand is understood to be the demand for natural gas, biogas and synthetic gases (hydrogen and methane that has been produced using renewable electricity).

Table 12 below contains a list of the gas demand scenarios for Germany that have been analysed.

Table 12: Studies and scenarios considered

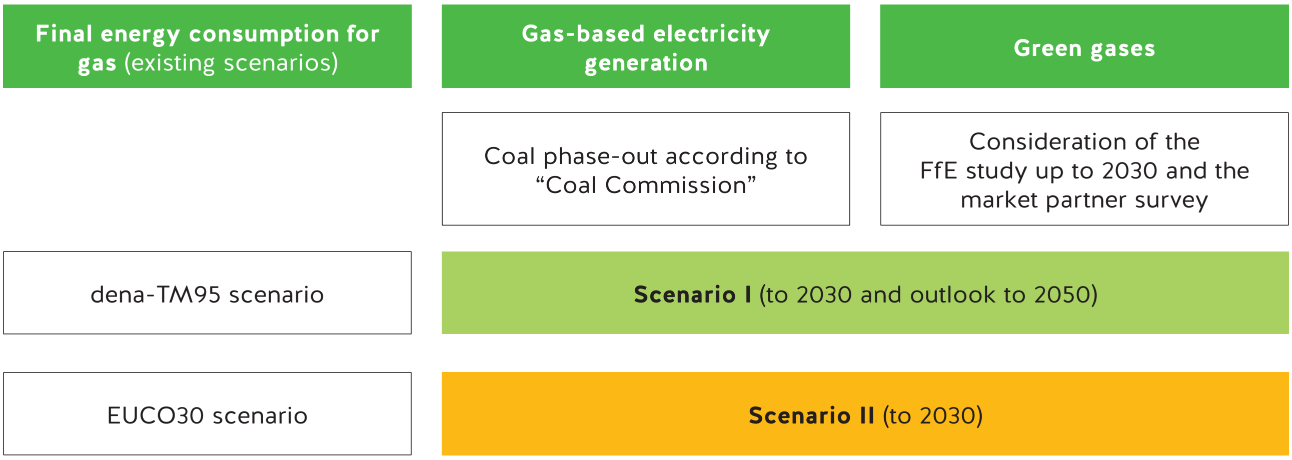
Study	Scenarios
BDI study (2018) “Klimapfade für Deutschland” (“Climate paths for Germany”) [BDI 2018]	Reference scenario (BDI-REF)
	Target scenario Global climate protection −95 % (BDI-G95)
	Target scenario Unilateral national efforts −80 % (BDI-N80)
dena study (2018) “dena-Leitstudie Integrierte Energiewende” (“dena study on the integrated energy transition”) [dena 2018]	Reference scenario (dena-REF)
	Electrification scenario −80 % (dena-EL80)
	Electrification scenario −95 % (dena-EL95)
	Technology mix scenario −80 % (dena-TM80)
	Technology mix scenario −95 % (dena-TM95)
EUCO scenarios (2017) “Technical report on Member State results of the EUCO policy scenarios” [EUCO 2017]	EUCO30 scenario (EUCO30)
	EUCO+40 scenario (EUCO+40)
	Other European scenarios*
Frontier (2017) “Der Wert der Gasinfrastruktur für die Energiewende in Deutschland” (“The value of the gas infrastructure for the energy transition in Germany”) [Frontier 2017]	“Only electricity” scenario −95 % (Frontier-NS95)
	“Electricity and gas storage” scenario −95 % (Frontier-SG95)
	“Electricity and green gas” scenario −95 % (Frontier-SGG95)
Öko-Institut (2015) “Climate protection scenario 2050” [Öko-Institut 2015]	Current measures scenario (Öko-AMS)
	Climate protection scenario −80 % (Öko-KS80)
	Climate protection scenario −95 % (Öko-KS95)

* https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en.pdf [EC 2018]

Source: BDI 2018, dena 2018, EUCO 2017, Frontier 2017, Öko-Institut/Fraunhofer ISI 2015, Prognos AG

For the scenario framework for the Gas NDP 2020–2030, the transmission system operators decided to take the dena-TM95 and EUCO40 scenarios into more detailed consideration (cf. Figure 4). The dena-TM95 scenario focuses on green gases. By using the EUCO30 scenario as a basis for consideration, the consistency with the previous scenario framework is retained. The two selected scenarios look ahead to 2030, and in both of them the coal phase-out path, as recommended by the "Commission on Growth, Structural Change and Employment" ("Coal Commission") [BMWi 2019], is also mapped. For the dena-TM95 scenario, the "Study on the regionalisation of power-to-gas services for the scenario framework for the Gas NDP 2020–2030" of the Forschungsstelle für Energiewirtschaft (FfE – Research Institute for the Energy Economy) [FfE 2019] is also used in 2030 concerning the development of green gases. The dena-TM95 scenario additionally provides a possible outlook for gas demand in 2050, and the specific results of the selected scenarios are presented here. The transmission system operators prefer Scenario I.

Figure 4: Scenarios for the development of German gas demand

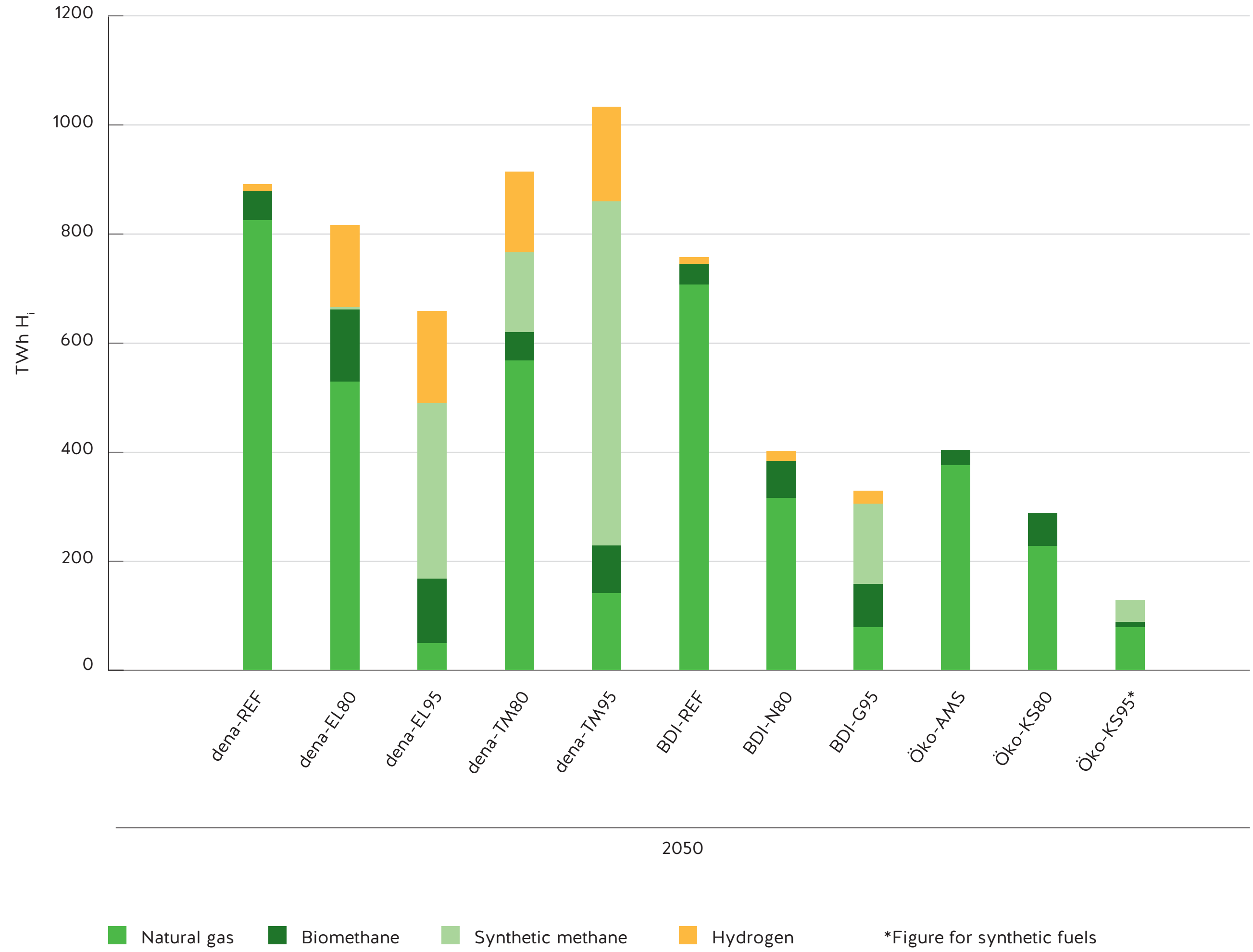


Source: Prognos AG

A distinction has to be drawn in principle between the terms scenario and modelling variant. Two scenarios for the development of gas demand in Germany (cf. Figure 4) are presented in the scenario framework. The individual elements of the gas demand scenarios are described in Chapters 3.3 and 3.4. The modelling variants, which are described in Chapter 9, form the basis for the modelling in the Gas NDP 2020–2030. These modelling variants essentially build on the scenarios.

Figure 5 below shows the trend in gas demand in the various target scenarios up to 2050. The large range of possible trends in the gas demand in Germany can be observed here. A transformation of the gas infrastructure towards green gases takes place in the scenarios with a reduction in greenhouse gas emissions of 95 % by 2050. It would be possible to use fossil natural gas here only for non-energy consumption.

Figure 5: Trends in gas demand in the scenarios under review up to 2050 in TWh (low calorific value)



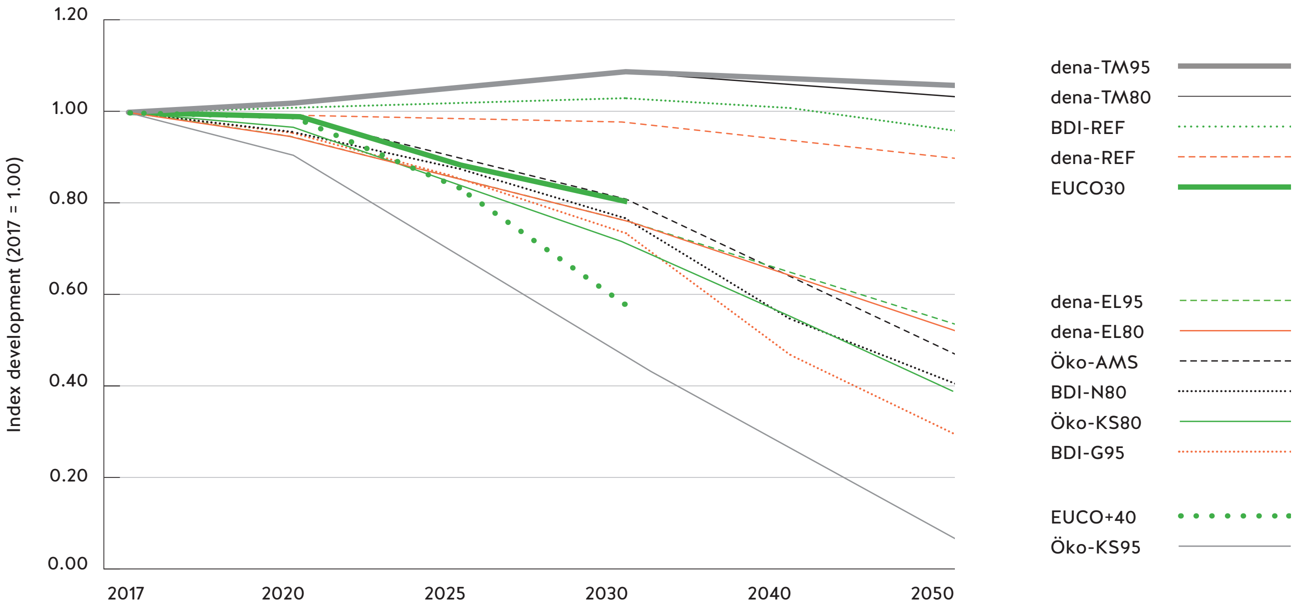
Source: BDI 2018, dena 2018, Öko-Institut/Fraunhofer ISI 2015, Prognos AG

The trends in gas demand in the areas of final energy consumption (cf. Chapter 3.3), power plants (cf. Chapter 3.4) and hydrogen (cf. Chapter 3.5) are presented below. The overall development of the gas demand in Germany is subsequently summarised in Chapter 3.6. Chapter 3.7 deals with the particular situation regarding additional demand in Baden-Wuerttemberg.

3.3 Final energy demand for gas

Figure 6 below shows the relative trend in the final energy demand for gas in Germany in various scenarios up to 2050 (also cf. Table 12 on this). The figure reveals very different expectations for the development of the final energy consumption for gas in Germany. An extensively constant final energy demand for gas can be attributed in particular in the dena target scenarios (dena-TM80/95) to increased use of gases in the industrial and transport sectors.
In contrast, the final energy consumption for gas declines in many scenarios on account of increasing efficiency assumptions and substitution effects.

Figure 6: Development of German final energy consumption for gas in the various scenarios up to 2050 [index development]



Note: not all interim years are reported in the scenarios. Where necessary, an interpolation has been made between available values.

Source: BDI 2018, dena 2018, EUCO 2017, Öko-Institut/Fraunhofer ISI 2015, Prognos AG

The development of the final energy consumption for gas in the selected scenarios dena-TM95 [dena 2019] and EUCO30 [EUCO 2017] are looked at in more detail in the following. Figure 6 shows how these gas demand scenarios can be classified in comparison with the large number of other existing reference and target scenarios. The two selected scenarios cover the broad range of possible developments.

For the final energy consumption of gas, the base year 2017 was analysed to begin with. The results of the scenarios for 2020, 2025 and 2030 are presented for the forecast. The scenario results also up to 2050 are shown for the dena-TM95 scenario. The final energy requirement for gas is based on the following selected scenarios:

- Scenario I: this scenario is based on the final energy consumption of gas of the dena-TM 95 scenario. The technology mix scenario assumes a broad variation in the technologies and energy sources used. The achievement of the cross-sector targets for reductions in greenhouse gas are modelled in line with the climate protection plan in this scenario. The results of the FfE study [FfE 2019] are also used with regard to the trends in green gases up to 2030 as part of this scenario.
- Scenario II: this scenario is based on the final energy consumption of gas of the EUCO30 scenario [EUCO 2017]. The achievement of the European climate and energy targets for 2030 are modelled in this scenario. The 30 % efficiency target (decline in primary energy consumption by 30 % in comparison with the 2007 baseline development) is realised in this scenario. Furthermore, the EU targets for the reduction of greenhouse gases (at least –40 % in comparison with 1990) and for the share of renewables (share of renewables in final energy consumption of at least 27 %) are achieved. For Germany, the reduction in greenhouse gas emissions (excluding LULUCF[1]) in 2030 in comparison with 1990 is around 43 % in this scenario.

The final energy demand, the non-energy consumption and indirectly also the gas demand for the generation of district heating in Germany are taken from the presented scenarios up to 2030. Gas demand in the transformation sector (including own consumption), on the other hand, has been derived from the power plant modelling described below.

[1] LULUCF: Land use, land-use change and forestry

Table 13 shows the results of the final energy consumption for gas of the two scenarios broken down by the consumption sectors of households/commerce/trade/services, industry and transport up to 2030. For the dena-TM95 scenario, an outlook going all the way to 2050 is provided on the basis of the dena results.

In sum, a decline in the entire final energy consumption for gas between 2017 and 2030 of around 1 % results in Scenario I (dena-TM95). The final energy consumption for gas subsequently rises up to 2050. This can be attributed to increased use of gas in industry and in the transport sector (CNG, LNG, hydrogen). In Scenario II (EUCO30), the decline in the 2017–2030 period under review comes to around 20 %. Efficiency increases are not compensated for by new applications to any extent here.

Table 13: Development of the final energy consumption (FEC) for gas by sector in the dena-TM95 and EUCO30 scenarios

	Unit	2017	2020	2025	2030	2040	2050	Change 2030 from 2017	Change 2050 from 2017
Scenario I Gas demand FEC dena-TM95									
Gas demand FEC, total	TWh H_s	656	650	639	652	687	722	−1 %	10 %
Industry	TWh H_s	261	274	297	319	337	355	22 %	36 %
Households/commerce, trade and services	TWh H_s	394	371	333	296	225	155	−25 %	−61 %
Transport	TWh H_s	2	4	9	37	125	212	1,757 %	10,498 %
Scenario II Gas demand FEC EUCO30									
Gas demand FEC, total	TWh H_s	656	656	580	525	---	---	−20 %	---
Industry	TWh H_s	261	261	222	204	---	---	−22 %	---
Households/commerce, trade and services	TWh H_s	394	393	354	313	---	---	−21 %	---
Transport	TWh H_s	2	3	4	8	---	---	276 %	---

Note: the values of the final energy demand for gas are not available for all interim years. Where necessary, an interpolation has been made between available values. To update the final energy consumption for gas, the actual value that has been calculated is generally updated by the relative development in the sectors up to 2030 taking the FfE study into consideration. For the dena-TM95 scenario, the original values of the study are reported for 2040 and 2050.

Source: dena 2018, EUCO 2017, Prognos AG

3.4 Gas usage in power plants

As described in Chapter 3.2, a coal phase-out path as proposed by the "Commission on Growth, Structural Change and Employment" ("Coal Commission") in January 2019 [BMWi 2019] is assumed in both scenarios. The most important recommendations of the coal commission for phasing out coal-fired power generation in Germany are:

- Reducing the capacity of lignite and hard coal-fired power plants to 15 GW each by 2022;
- Reducing the capacity of lignite coal-fired power plants to 9 GW and the capacity of hard coal-fired power plants to 8 GW by 2030, where coal-fired power generation is intended to decline continually between 2022 and 2030;
- Ending coal-fired power generation by no later than 2038, whereby a review is intended in 2032 of whether ending this form of generation can be brought forward to 2035.

Intensive expansion of renewable energy sources is closely associated with the phase-out of coal. The current coalition agreement [CDU/CSU/SPD 2018] states in this connection: "We will continue the energy transition in a clean, safe and affordable way: a determined, efficient, mains-synchronous and increasingly market-oriented expansion of renewable energy sources. Under these conditions: increase of the share of renewable energies to 65 percent by 2030."

The restructuring of the energy system faces a large number of challenges. The issues of grid reserves, grid stability equipment and systemically important power plants, among other things, are of particular relevance here for the power plant park when it comes to guaranteeing the stability of the electricity supply system. These factors exert a significant influence on the gas power plants.

Among other things, there is an obligation on the part of the power plant operators to notify the electricity transmission system operator and the BNetzA of planned temporary and final closures at least 12 months in advance. A review is subsequently carried out by the electricity transmission system operator whether the power plant is systemically important. The BNetzA finally approves the systemic importance if proof of this has been furnished beforehand by the electricity transmission system operator. The systemic importance is determined in each case for the following period of up to 24 months [BNetzA 2019b].

For the gas demand of the power plants, the development path of gas-fired power generation has been analysed using the power plant model of Prognos AG. The starting points for the modelling are the list of power plants, i.e. the BNetzA list of the current stock of power plants and of additional and decommissioned capacity in Germany [BNetzA 2019a], and the current capacity reservations pursuant to Section 38 GasNZV submitted to the transmission system operators as well as capacity expansion claims pursuant to Section 39 GasNZV. Information from the BDEW's list of power plants is additionally used [BDEW 2019b].

This data also includes the location of the plants, so that these can be geographically assigned directly for the modelling. Furthermore, the findings from the recently approved scenario framework for the Electricity Network Development Plan 2019–2030 are used as a data basis (e.g. development of renewable energy sources) [BNetzA 2018]. To model the electricity market, the following fuel price assumptions have been made for the two scenarios.

Table 14: Assumptions on the costs for fuels and CO_2 in the scenarios

Scenarios I and II, fuel prices and certificate costs						
	Unit*	**2017**	**2020**	**2025**	**2030**	**Change 2030 from 2017**
International prices						
Crude oil	USD_{2017}/bbl	52	70	83	96	85 %
CO_2	$Euro_{2017}$/t	5	22	28	34	600 %
Cross-border prices, Germany						
Crude oil	$Euro_{2017}$/t	358	417	520	623	74 %
Natural gas	$Cent_{2017}$/kWh	1.7	2.0	2.2	2.3	36 %
Hard coal for power plants	$Euro_{2017}$/tce	92	85	87	89	–4 %

* The table shows the real, i.e. inflation-adjusted, price trends up to 2030. The price base for the real prices presented is 2017.

Source: Prognos AG

The existing gas power plants and those under construction today are taken into consideration for the future gas-fired power generation. The statements in Chapter 2.2.2 apply for the addition of new gas power plants on the network of the transmission system operators on the one hand. On the other, new gas power plants in the distribution network are taken into consideration based on the BDEW's list of power plants [BDEW 2019b]. However, the BDEW's list also includes several planned gas power plants that are not taken into consideration in accordance with the criteria formulated in Chapter 2.1. As in the previous scenario frameworks, an unspecified addition of local CHP plants is made in line with the 2019–2030 electricity scenario framework.

Power plants listed by the BNetzA as systemically important continue to be listed up to 2030, unless they are slated for decommissioning in accordance with the BNetzA power plant decommissioning list (final notification of closure pursuant to Section 13a EnWG). Plants that will reach the end of their life of 45 years by 2028 are replaced in principle on a structurally identical basis only if direct heating supply is present at the location. The following overview shows the installed power plant capacity for the modelling of the electricity markets in the scenarios (excluding power plants that have been mothballed or finally closed).

Table 15: Scenarios for electricity generation

	2017 Reference	**Scenarios I and II, 2030*** Prognos
Installed net capacity [GW$_e$]		
Nuclear power	9.5	0.0
Lignite	21.2	9.0
Hard coal	25.0	8.0
Natural gas	29.6	33.7
Petroleum products	4.4	0.9
Pumped storage	9.5	11.6
Others	4.3	4.1
Total conventional generation	**103.5**	**67.3**
Wind, onshore	50.5	85.5
Wind, offshore	5.4	17.0
Photovoltaics	42.4	104.5
Biomass	7.6	6.0
Hydroelectric power	5.6	5.6
Other renewable generation	1.3	1.3
Total renewable generation	**112.8**	**219.9**
Total generation capacity	**216.3**	**287.2**
Electricity consumption [TWh$_e$]		
Net electricity consumption**	530	577

* The values presented for 2030 (exception: natural gas) refer to Scenario C 2030 in accordance with the approval of the 2019–2030 Electricity Scenario Framework.
** including the sum of the network losses in TWh in the distribution network

Source: BNetzA 2018, Prognos AG

In accordance with the procedure described for considering (new) gas power plants, the following installed capacity of gas power plants in Germany up to 2030 is produced. The results of the dena-TM95 scenario are again used for 2050.

Table 16: Electrical power plant capacity (net) installed in gas power plants in Germany

Installed net capacity of gas power plants in GW$_e$	**2017**	**2020**	**2025**	**2030**	**2040**	**2050**	**Change 2030 from 2020**	**Change 2050 from 2020**
Scenario I	27	28	33	34	63	57	20 %	102 %
Scenario II	27	28	33	34	---	---	20 %	---

Source: Prognos AG

The necessary secured power plant capacity is a frequent topic of discussion in the course of the coal phase-out. In this connection, the Coal Commission addresses the following measures in its final report:

- further development of the monitoring of the security of supply;
- review of a systematic investment framework;
- use of the existing reserve instruments for safeguarding the electricity market;
- further development and continuation of the promotion of combined heat and power production;
- acceleration of the approval process for new gas power plants;
- adequate replacement of coal power plants that have been closed from the network reserve.

Up to 2030, the guarantee of a continued high level of security of supply in the electricity network will depend in particular on the creation of additional capacity to cover the residual load peaks, e.g. from new gas power plants, demand flexibility or storage systems [Öko-Institut 2019]. Demand of up to 10 GW_e in additional secured capacity has been calculated up to 2030 for example in the impact assessment related to the 2050 Climate Protection Plan [Öko-Institut et al. 2019]. The measures mentioned above for ensuring the security of supply (e.g. intensified monitoring of the security of supply in the electricity network, creation of a systematic investment framework) have to be taken here in order to bring about the modifications of the market design that may be necessary. For example, the installed gas power plant capacity in 2030 lies between 48 GW_e and 75 GW_e in the dena scenarios and between 46 GW_e and 60 GW_e in the BDI scenarios.

The transmission system operators take the new gas power plants connected directly to the TSO network into consideration in the modelling of the Gas NDP 2020–2030 in accordance with the criteria described in Chapter 2.1. The studies that have been examined assume a higher gas power plant capacity over the long term. The transmission system operators will take additional power plant capacity into consideration using the established processes (e.g. sections 38/39 GasNZV, internal orders/long-term forecasts, BNetzA power plant list).

The gas demand of the power plants (in TWh_{th}) is produced in the modelling of the electricity markets under the given general conditions from their generation of electricity (in TWh_e) using the efficiency levels of the individual power plants.

Table 17: Results of gas usage in the transformation sector

Results of the electricity market modelling	Unit	2017	2020	2025	2030	2040	2050	Change 2030 from 2020	Change 2050 from 2020
Scenario I									
Gas demand, transformation sector	TWh H_s	274	285	302	319	299	280	12 %	−2 %
Scenario II									
Gas demand, transformation sector	TWh H_s	274	284	297	315	---	---	11 %	---

* Gas consumption in the transformation sector comprises power plants, district heating plants and the internal gas consumption in the sector.

Source: Prognos AG

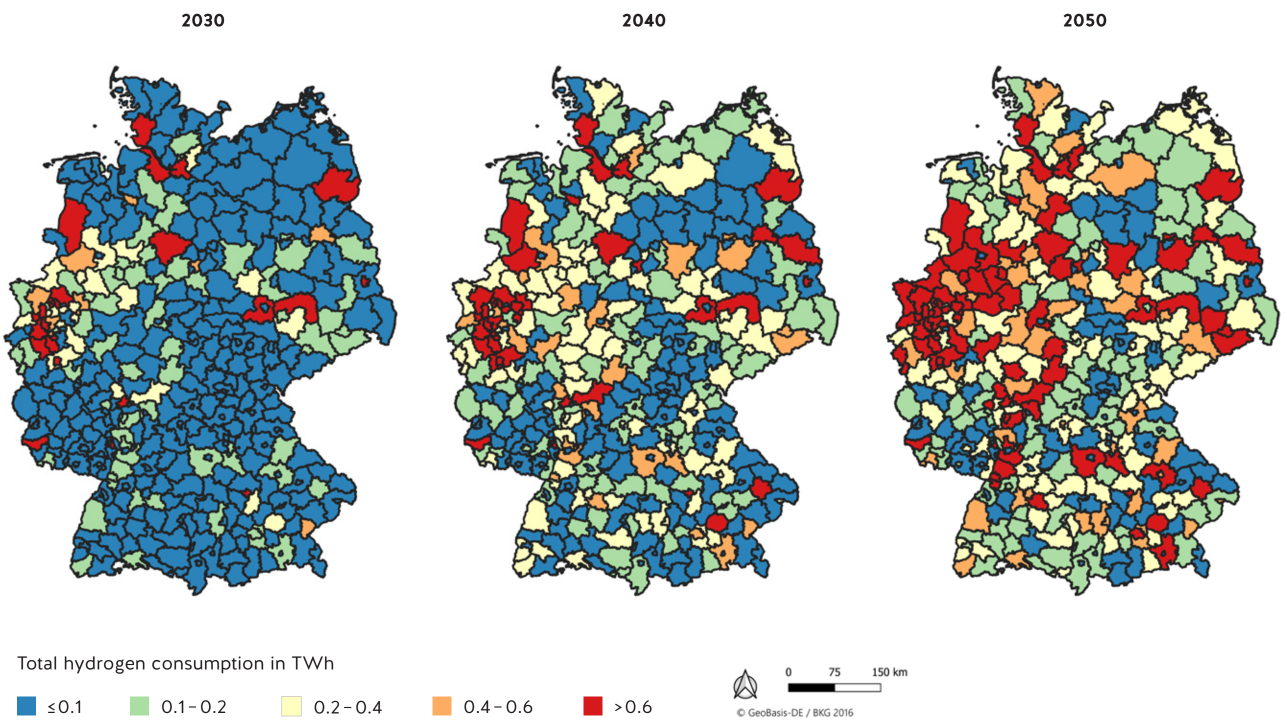
3.5 Trends in the demand for hydrogen

Green gases include biomethane, hydrogen and synthetic methane, which is generated from hydrogen. While biomethane and synthetic methane can be used like natural gas, special conditions apply to pure hydrogen. For this reason, this chapter explicitly addresses the possible development in demand for hydrogen in Germany.

Looking forward, existing hydrogen consumption must be converted to hydrogen that is generated in a climate-neutral way. While consumption is concentrated primarily in the material-based use in industry, especially the chemical industry and refineries, its use as an energy source for industrial and private heating purposes, for transport and, potentially, in the generation of electricity will increasingly emerge in the future. A significant increase in the demand for hydrogen will similarly arise in the area of steel production as the industry converts to direct reduction.

There are currently three major industrial hydrogen communities in Germany, which are referred to as the Unterelbe, Weser, Ems cluster, the central Germany cluster and the Ruhr cluster in the FfE study. Based on this existing state of affairs, the FfE study delivers the demand for hydrogen in the transport sector and in industry in TWh per district (3 regions defined as NUTS[2]) for 2030, 2040 and 2050. The calculation was made essentially using the electricity NDP 2030 and the dena study. Total hydrogen demand in 2030 is estimated at 94.4 TWh. Set against the annual demand in 2017 of 69.0 TWh, this means that annual demand will have increased by 25.4 TWh.

Figure 7: Combined hydrogen demand in the industrial and traffic sectors on a regional basis



Source: FfE 2019

17.9 TWh of this increase can be attributed to the growing demand in the transport sector. Featuring a concentration in densely populated regions and along major transport routes, every administrative district shows demand for hydrogen in the transport section in 2030.

[2]NUTS (Nomenclature des unités territoriales statistiques – Nomenclature of Territorial Units for Statistics) regions are geographical reference units that have been developed by Eurostat, the statistical office of the European Union in Luxembourg. NUTS3 corresponds to administrative districts in Germany.

An additional annual demand for hydrogen of overall 7.5 TWh can be attributed to the industrial sector. Strong growth in demand is shown in particular for industry in the Ruhr region.

For example, the Ruhr region is an attractive target area for hydrogen thanks to its high population density, high volume of traffic and high density of relevant industrial installations. The FfE study assesses the development to be sustainable and continuous throughout Germany. Compared with 2030, the demand for hydrogen is expected to double by 2050.

The results of the market partner survey on green gas projects are presented in Chapter 2.5. Projects that have reported demand for green gases can also be found here. These projects are taken into consideration in the Gas NDP 2020–2030.

3.6 Trends in the total gas demand and regionalisation

The tables below show the total German gas usage in the examined scenarios presented in terms of high calorific value (H_s) in each case and is based on the results presented in the previous chapter.

Table 18: Development of German gas demand in Scenario I, temperature-adjusted, presentation as high calorific value (H_s)

Gas demand in Germany – Scenario I Presentation as high calorific value (H_s)	Unit	2017	2020	2025	2030	2040	2050	Change 2030 from 2017	Change 2030 from 2020	Change 2050 from 2020
Gas demand, total	TWh H_s	968	980	998	1,039	1,087	1,159	7 %	6 %	18 %
Final energy demand for gas	TWh H_s	656	650	639	652	687	722	–1 %	0 %	11 %
Industry	TWh H_s	261	274	297	319	337	355	22 %	16 %	29 %
Households/commerce, trade and services	TWh H_s	394	371	333	296	225	155	–25 %	–20 %	–58 %
Transport	TWh H_s	2	4	9	37	125	212	1,757 %	734 %	4,657 %
Non-energy consumption of gas	TWh H_s	38	45	57	69	101	157	81 %	53 %	247 %
Gas usage in the transformation sector*	TWh H_s	274	285	302	319	299	280	16 %	12 %	–2 %

* Gas consumption in the transformation sector comprises power plants, district heating plants and the internal gas consumption in the sector.

Source: BDEW/AG Energiebilanzen (final energy consumption of natural gas), calculation of the transmission system operators (temperature-adjusted values), dena 2018, Prognos AG

Table 19: Development of German gas demand in Scenario II, temperature-adjusted, presentation as high calorific value (H_s)

Gas demand in Germany – Scenario II, presentation as high calorific value (H_s)	Unit	2017	2020	2025	2030	2040	2050	Change 2030 from 2017	Change 2030 from 2020	Change 2050 from 2020
Gas demand, total	TWh H_s	968	980	917	880	---	---	–9 %	–10 %	---
Final energy demand for gas	TWh H_s	656	656	580	525	---	---	–20 %	–20 %	---
Industry	TWh H_s	261	261	222	204	---	---	–22 %	–22 %	---
Households/commerce, trade and services	TWh H_s	394	393	354	313	---	---	–20 %	–20 %	---
Transport	TWh H_s	2	3	4	8	---	---	276 %	185 %	---
Non-energy consumption of gas	TWh H_s	38	39	40	40	---	---	5 %	2 %	---
Gas usage in the transformation sector*	TWh H_s	274	284	297	315	---	---	15 %	11 %	---

* Gas consumption in the transformation sector comprises power plants, district heating plants and the internal gas consumption in the sector.

Source: BDEW/AG Energiebilanzen (final energy consumption of natural gas), calculation of the transmission system operators (temperature-adjusted values), EUCO 2017, Prognos AG

The results of the determination of the gas demand for Germany are broken down on a regional basis for the calculations in the Gas NDP 2020–2030, i.e. the gas demand is allocated down to the individual district. The following distribution factors are used here:

- To identify the final energy consumption, the non-energy consumption, the gas demand of the district heating plants and the private consumption in the transformation sector on a regional level, the databases of Prognos AG, in which demand has been analysed at the district level using a regional model, will be taken into account.
- To identify the electricity and heat generation from gas on a regional level, the modelling findings of the European electricity market model of Prognos AG will be applied. The location of the power plants included in the list of power plants serves as a basis for the regional breakdown.

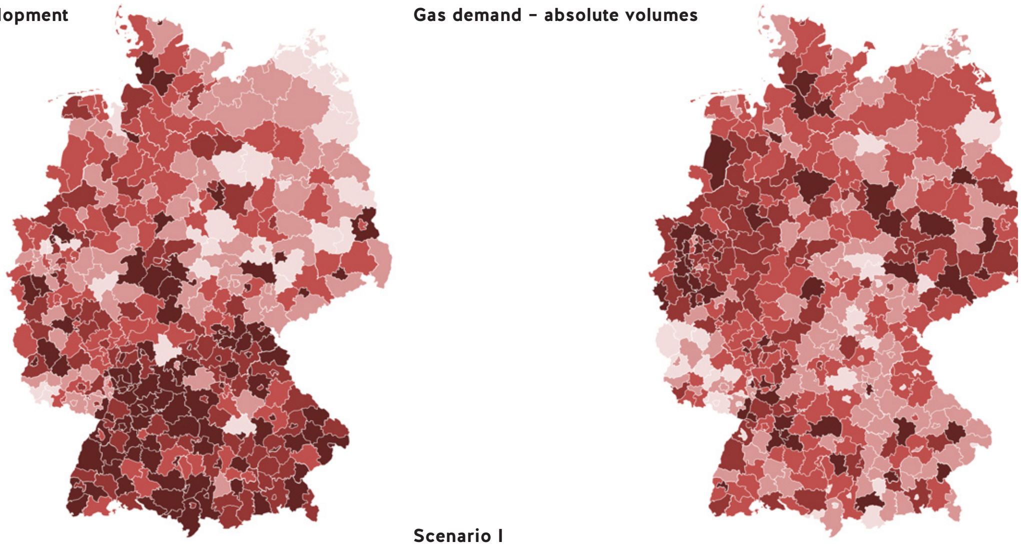
Note on the map view below

The changing demands at the district level are presented in the map below as an index development (cf. Figure 8 on the left) for the period from 2020 to 2030. An index of 1.00 in 2030 is thus equivalent to a constant gas demand. The selected colour scale additionally illustrates how the trends in the individual districts are developing relative to each other.

The figures below illustrate the trends in the entire gas demand in the consumption sectors private households, commerce, trade and services and industry/power plants. The map on the right in Figure 8 illustrates the absolute gas demand in Scenario I, while the map on the left illustrates the relative development in the period under review up to 2030.

Gas demand at the district level is heavily dependent on regional characteristics, such as the establishment of industrial and power plant locations and the connection rate for apartments to the gas network. Overall development up to 2030 foresees trends such as a more positive demographic and economic growth in southern Germany.

Figure 8: Scenario I: Regional gas demand for 2030 in total (absolute in GWh, temperature-adjusted, presentation as high calorific value H_s) and change in the regional gas demand from 2020 to 2030 in total; index development for gas demand 2020 = 1.00



Gas demand – index development

Scenario I

Change in regional gas demand 2020 to 2030
Index development at district level (2020 = 1.00)

Index: gas demand 2030 is ...
- smaller than 0.8
- from 0.8 to under 0.9
- from 0.9 to under 1.0
- from 1.0 to under 1.1
- at least 1.1

Gas demand – absolute volumes

Scenario I

Regional gas demand 2030
Absolute volumes at district level in GWh

Gas demand 2030 is ...
- lower than 500 GWh
- from 500 to under 1,000 GWh
- from 1,000 to under 2,000 GWh
- from 2,000 to under 4,000 GWh
- higher than 4,000 GWh

Source: Prognos AG

3.7 Development in demand in Baden-Wuerttemberg

In view of the continually rising demand for capacity in Baden-Wuerttemberg and the extremely high utilisation of the network, terranets bw carried out a comprehensive forecast of demand together with its distribution system operators, final consumers and power plant operators and involving the state of Baden-Wuerttemberg at the suggestion of the BNetzA. Special attention was paid here to new connections and storage facilities in the distribution networks as well as power plant demand. The trend towards increasing demand for capacity was also confirmed for the years to come in this process. The results were discussed at workshops with the network customers of terranets bw in the presence of the BNetzA and the state of Baden-Wuerttemberg.

The result of the demand forecast is that the energy transition, fuel switch and the CO_2 savings potential of gas in the heating market are continuing to produce a continually growing demand for gas both in the power plant sector and in the heating market. It can moreover be expected that the trend to decommission storage facilities in the distribution networks, which have traditionally been used to cap peak loads, will also continue for reasons of economic viability. The demand forecast suggests capacity demand of at least 33 GWh/h for 2025, while capacity demand of up to 38 GWh/h seems plausible for 2030. This corresponds to an increase of 35 % over today's capacity demand. In addition to the pure capacity level, it is important to consider that a lower base load and considerably more dynamic and higher capacity peaks can increasingly be expected.

On top of that is the experience of terranets bw that the forecast relevant for the calculation year in the past network development plans was actually around 20 % too low when compared with the internal orders that were then placed and long-term forecasts for the corresponding year.

The limits of transport capacity have currently been met in the terranets bw network. This means that even in the base variant, the construction of large new transport systems will be necessary for which the corresponding entry capacity has to be provided. Given the very strong demand forecast beyond 2025 as well, the network expansion to be defined for the 2025 calculation year will have to be able to meet demand of potentially 38 GWh/h by adding further modules.

Gas supply 4

4 Gas supply

This chapter deals with past and future trends in the gas supply in Germany. The procedure for analysing the gas supply is described in Chapter 4.1. The following chapters present the trends in conventional natural gas production (cf. Chapter 4.2), in biomethane injection (cf. Chapter 4.3) and the supply trends in green gases (cf. Chapter 4.4). A summary presentation of the Germany-wide gas supply, including a regional breakdown, is subsequently provided in Chapter 4.5.

4.1 Procedure

Domestic production of natural gas and petroleum gas, the generation and injection of biogas/biomethane as well as green gases are taken into consideration for the trends in the gas supply in Germany up to 2030. The following sources are available for this:

- Domestic production of natural gas: The development path is taken from a current investigation by the Bundesverband Erdgas, Erdöl und Geoenergie e.V. (BVEG – German Federal Association of Natural gas, Petroleum and Geoenergy) [BVEG 2019].
- Injection of biomethane: The basis for the assessment is provided by the FfE study [FfE 2019]. The Germany-wide regionalisation of the use of biomethane for providing electricity and heating is based on the assessment of the Federal Network Agency's current 2018 monitoring report [BNetzA/BKartA Monitoringbericht 2019] and the project list for biomethane injection published by Deutsche Energie-Agentur GmbH (dena – German Energy Agency) [dena 2019].
- Green gases (hydrogen, synthetic methane):
  An assessment is made on the basis of the FfE study [FfE 2019] and other assumptions of how the gas supply from green gases is developing in Germany.

4.2 Natural gas production

The forecast of the regional natural gas production up to 2030 is based on the current projection of the BVEG for the two most important production regions (Elbe-Weser excluding “Altmark” and Weser-Ems excluding “Ostfriesland”) as well as for Germany as a whole.

Table 20: Projection of natural gas production and capacity

Natural gas production in Germany and the main extraction regions – Scenario I and II								
Germany as a whole*, of which			... Elbe-Weser region (excluding Altmark)			... Weser-Ems region (excluding Ostfriesland)		
	Production	Capacity	Production	Capacity based on planning	Capacity with safety margin	Production	Capacity based on planning	Capacity with safety margin
Year	Billion m³	Million m³/h	Billion m³	Million m³/h	Million m³/h	Billion m³	Million m³/h	Million m³/h
2019	6.26	0.80	2.65	0.33	0.31	3.30	0.41	0.38
2020	5.82	0.74	2.47	0.31	0.29	2.98	0.37	0.35
2021	5.72	0.73	2.25	0.28	0.26	3.16	0.40	0.37
2022	5.38	0.68	2.20	0.28	0.25	2.85	0.36	0.33
2023	5.11	0.65	2.13	0.27	0.24	2.55	0.32	0.29
2024	5.76	0.72	1.91	0.24	0.22	2.43	0.30	0.28
2025	5.44	0.68	1.75	0.22	0.20	2.22	0.28	0.25
2026	5.02	0.63	1.60	0.20	0.18	1.97	0.25	0.22
2027	4.61	0.57	1.49	0.19	0.16	1.72	0.21	0.19
2028	4.23	0.52	1.34	0.17	0.14	1.50	0.19	0.16
2029	3.99	0.49	1.22	0.15	0.13	1.35	0.17	0.14
2030	3.73	0.46	1.08	0.14	0.11	1.23	0.15	0.13

*Germany as a whole contains the two main production areas Elbe-Weser (excluding Altmark) and Weser-Ems (excluding Ostfriesland) as well as the production and capacity of other small regions.

Source: BVEG 2019

The data on production and on "capacity according to planning" are based on the data from the BVEG. As the planned capacity was not reached in the last few years, the table produced by the BVEG for the Elbe-Weser (excluding Altmark) and Weser-Ems (excluding Ostfriesland) regions additionally represents the "capacity with safety margin".

The supply of natural gas in Germany is low outside of the two main production regions. The other production regions include "Between Oder/Neisse and Elbe", "North of the Elbe", "West of the Ems", "Thuringian Basin", "Upper Rhine Valley" and "Pre-Alps". All the future gas production of these regions is calculated from the total German production less the production of the "Elbe-Weser" and "Weser-Ems" regions. This remaining sum is distributed to the smaller production regions up to 2030 based on their current share of production (as of 2018). Natural gas production is usually presented in cubic metres in the gas industry. To make it easier to compare values, they have been converted into TWh in the scenario framework.

Table 21: German natural gas production in various units

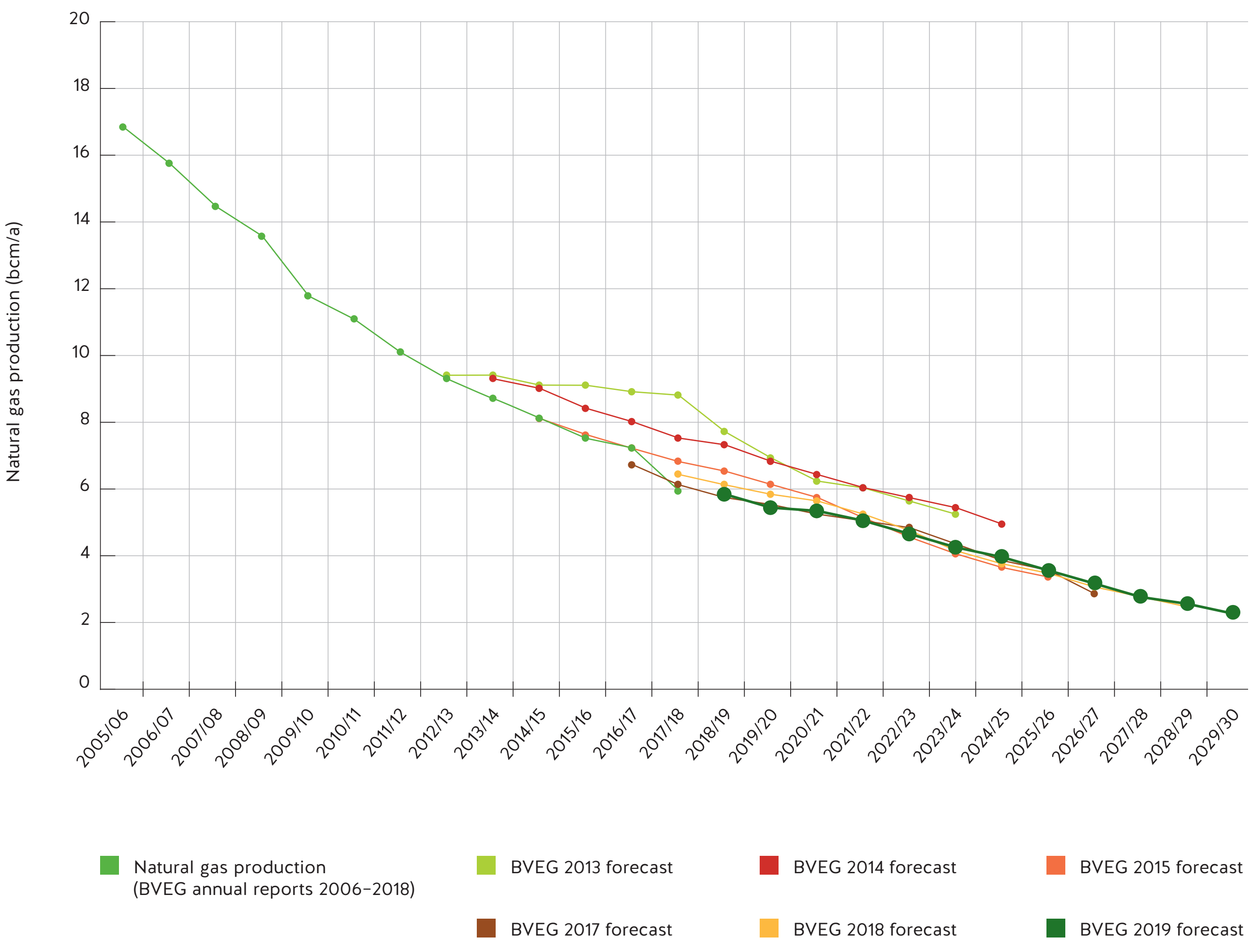
Natural gas production in Germany Scenario I and II	Unit	**2017**	**2020**	**2025**	**2030**	**Change 2030 from 2017**	**Change 2030 from 2020**	**Change 2030 from 2025**
Conventional gas	billion m³*	7.25	5.82	5.44	3.73	-49%	-36%	-32%
Conventional gas	TWh H_s**	71	57	53	36			

* Quantities relate to natural gas with a uniform high calorific value (H_S) of 9.7692 kWh/m³.
** Quantities converted into TWh (9.7692 kWh/m³), high calorific value (H_S)

Source: Prognos AG, BVEG 2019

Figure 9 shows the historical and forecast development of German natural gas production in the period from 2006 to 2030 for the Elbe-Weser and Weser-Ems regions.

Figure 9: Natural gas production in the Elbe-Weser and Weser-Ems production regions



Source: Transmission system operators on the basis of BVEG 2007–2019, BVEG 2019

The production data for the years from 2006 to 2018 is based on the figures published by the BVEG for the two most important production regions Elbe-Weser and Weser-Ems [BVEG 2007–2019]. For the period from 2019 onwards, the values are based on the BVEG's projections of regional natural gas production up to 2030.

German production was taken into account in the L-gas quantity balances of the previously published network development plans using the BVEG's forecasts for natural gas production in the Elbe-Weser and Weser-Ems supply region, even if a proportion of the forecast production volumes was provided as H-gas in the past.

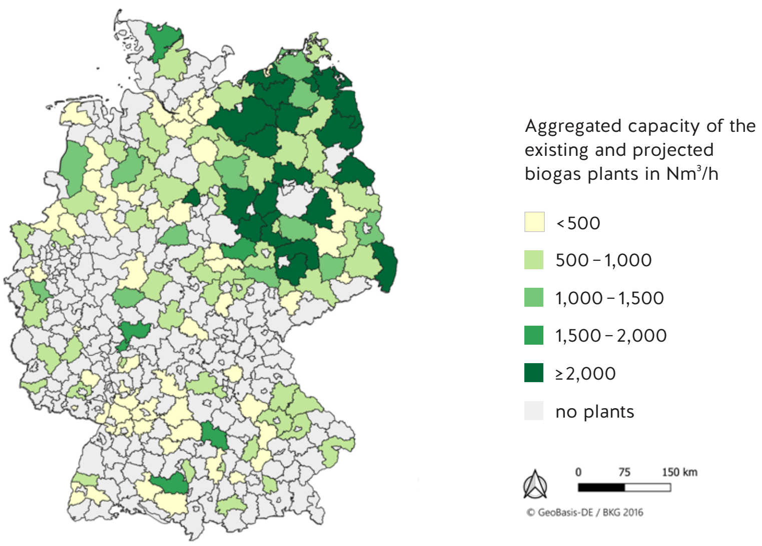
The effects of the BVEG's new production forecast are analysed by the transmission system operators in the course of the modelling of the Gas NDP 2020–2030. Furthermore, the reduction of 22% on the forecast production volumes that is made in the 2019 implementation report for the production provided as H-gas in the past is reviewed, among other things.

With a view to ensuring sustainable use of L-gas resources, as high a share of German production as possible should be provided as L-gas. Achieving this goal does not lie within the transmission system operators' immediate sphere of influence. From the perspective of the transmission system operators, there is a need for action to create appropriate additional instruments and market incentives. The transmission system operators consider prompt discussions at the political and regulatory level to be necessary and will be happy to make themselves available for this.

4.3 Injection of biomethane

The current state of affairs and the development of biogas plants with preparation and injection into the gas grid were additionally taken into consideration for the development of the supply of green gases. Biogas plants injecting into the gas grid are primarily found in the north-east of Germany. Due to great uncertainty regarding the development of biomethane injections, only the projected plants that can be found in dena's injection atlas are taken into consideration. Potential injection increases by 15,820 Nm^3/h (up to 149,274 Nm^3/h) as a result of the projected plants [36 plants in total]. Typical full load hours of approximately 6,000 h/a will result in an injection volume of 94.92 million Nm^3/a (0.9 TWh). This result corresponds to growth of 0.18 TWh/a and thus to a slightly greater increase compared to the Gas NDP 2018–2028.

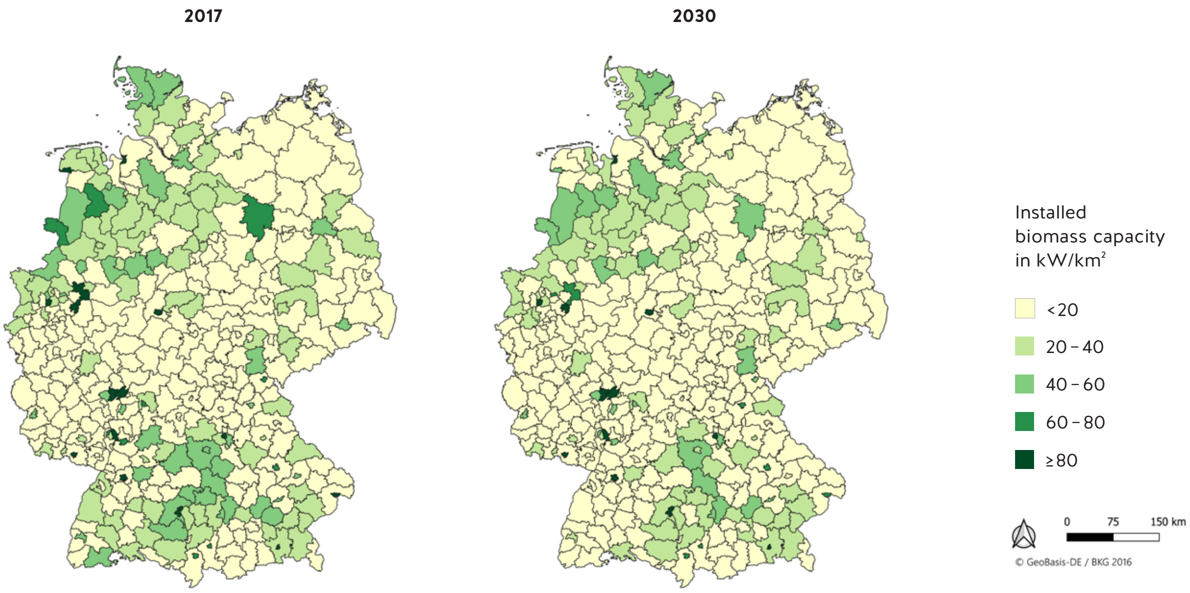
Figure 10: Projected and existing biomethane production plants in Germany



Source: FfE 2019

A large number of biogas plants generate electricity directly on site nowadays. In this context the transmission system operators see future injection potential for biomethane. The majority of these plants can be found in the north-west and in the south of Germany. This distribution develops contrary to the biomethane injection sites, which are primarily located in the north-east.

Figure 11: Electricity-generating biogas plants, 2017 and 2030



Source: FfE 2019

4.4 Trends in supplies of green gases

PtG technology offers great potential for storing large volumes of energy and using it in a flexible way due to the large storage capacity of the natural gas network and the connected natural gas storage facilities. Upon request, cogeneration plants and CCGTs can convert hydrogen or synthetic methane back into electrical energy to supply the electricity market. Together with gas power plants, this creates the necessary security of supply in the event of a "Dunkelflaute", when neither sun nor wind are contributing a sufficient amount to electricity generation.

Currently, hydrogen can only be injected into the existing gas infrastructure up to a certain limit [DVGW 2019], because fuel characteristics of the gas mix change as a result of its injection, which impacts connected critical gas applications. The repurposing of existing transport systems to hydrogen transport systems is additionally conceivable.

The transmission system operators constructively support the injection of hydrogen while taking into consideration the compatibility with the entire gas network infrastructure. They are cooperating in associations and committees to find further solutions for the compatibility of hydrogen injections into the gas networks. Furthermore, they are investigating and testing the feasibility of repurposing existing pipelines.

Excursus: Conversion of existing systems

As a result of the conversion from L-gas to H-gas, the transmission system operators have gained experience in successfully converting network areas. This concerns both the long-term planning, technical design, coordination with distribution system operators and consumers with a direct connection as well as the actual execution of the conversion.

Various factors that are key for the planning of the L-to-H-gas conversion can also be used for any conversion to hydrogen:

- L-gas and H-gas have to be transported independently of each other in separate systems for technical reasons.
- Existing L-gas transmission pipelines can often not be used directly for transporting H-gas after areas have been converted to H-gas, since remaining L-gas areas have to be supplied further using these pipelines until their final conversion.
- As most end user equipment cannot be operated with H-gas without further measures, each individual item of end-use equipment has to be checked and, based on the test result, either modified to the change in gas quality or replaced. The large number of appliances and the limited number of technicians qualified to carry out such a conversion result in a gradual implementation and a well-defined conversion rate.

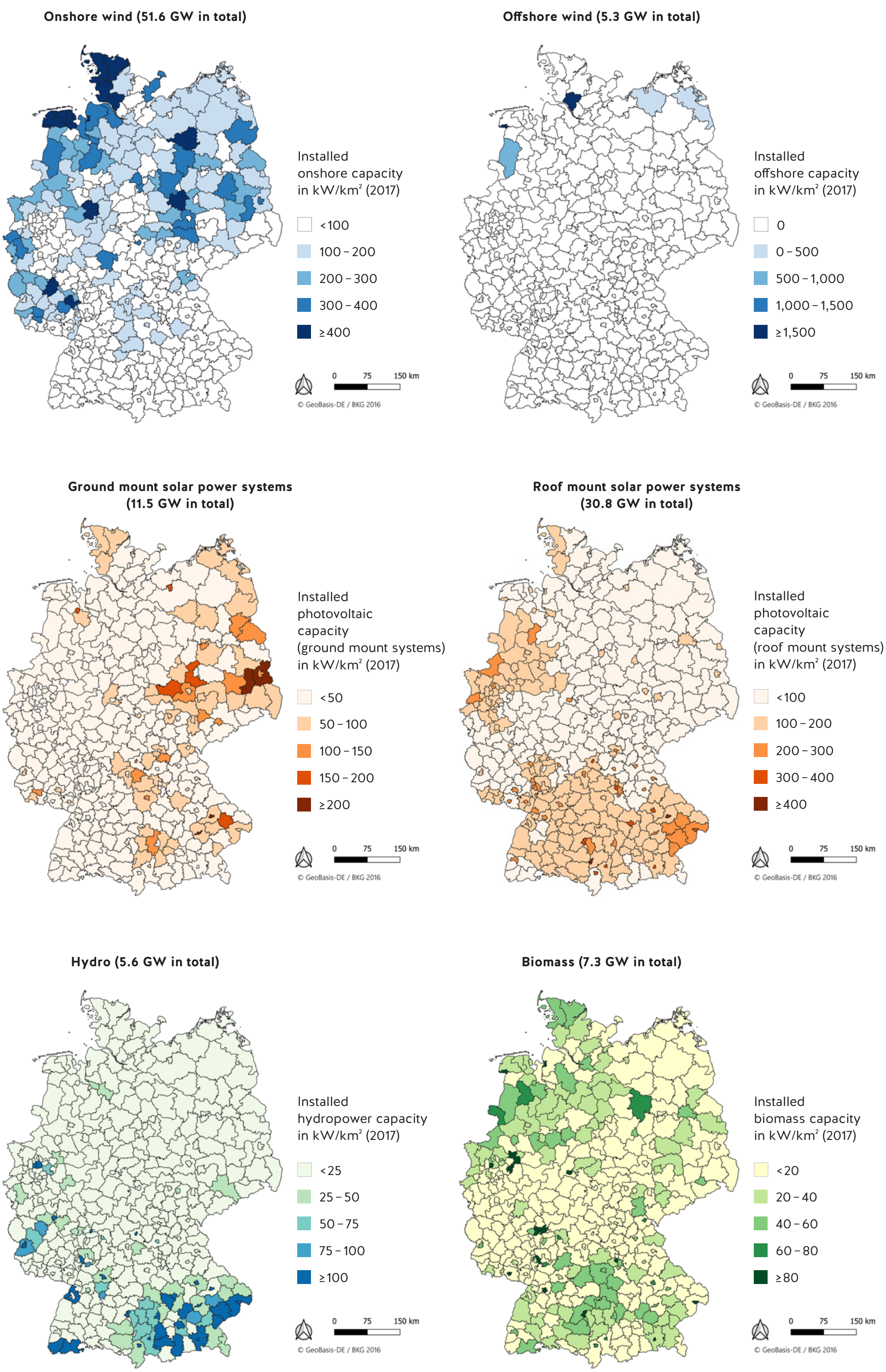
It is precisely the above-mentioned needs of the gradual conversion as well as the parallel supply of regions with L-gas and H-gas during the conversion process that have led to a significant demand for network expansion. The Gas NDP 2018–2028 includes around 90 network expansion measures costing around EUR 2 billion in connection with the conversion from L-gas to H-gas. These investments will already have been made in any case at the time of a potential conversion to hydrogen, but could generate an additional benefit in the course of a hydrogen conversion. The former L-gas areas will have been prepared network-wise to be operated with two different types of gas for a transitional period and to enable a step-by-step conversion.

FNB Gas commissioned a study from the Forschungsstelle für Energiewirtschaft e.V. (FfE – Research Institute for the Energy Economy) to analyse possible sources of supply and demand regions for hydrogen and synthetic methane. One aim of the study is to ascertain the current state of affairs in PtG as well as regionalised factors that successfully determine the attractiveness of possible locations for PtG in Germany. The changing needs for hydrogen are considered in Chapter 3.5 of the scenario framework for the Gas NDP 2020–2030.

The scenario considered is based on the developments in PtG capacity, the total electrical consumption and the generation of renewable energies derived from the Electricity Network Development Plan 2030 and the dena study (technology mix with 95% reduction in GHG emissions).

The study defines regions with a surplus of electrical injection volumes from sustainable sources. The regional distribution of the various technologies (onshore wind, offshore wind, hydro, ground mount solar power systems, roof-mount solar power systems and biomass) can be presented by regionalising the installed capacity from sustainable sources at the administrative district level.

Figure 12: Status quo, regionalised installed capacity derived from sustainable sources 2017

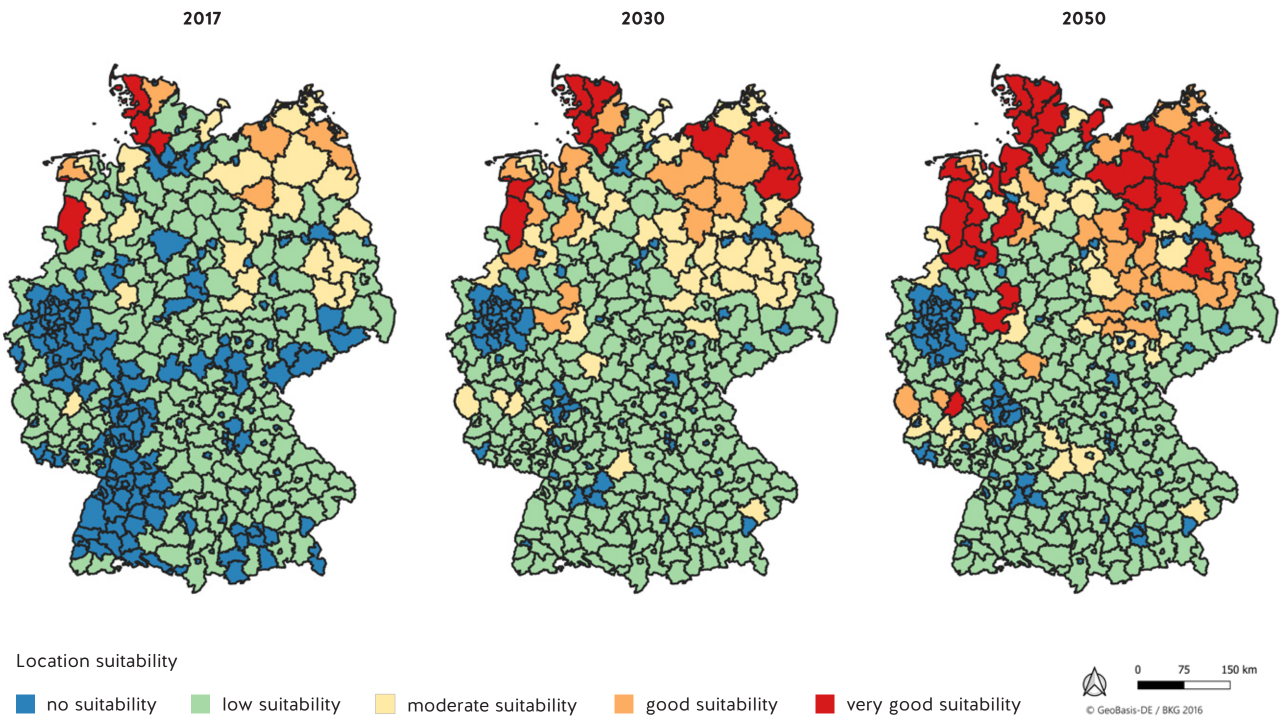


Source: FfE 2019

Initially, the development of the installed capacity of renewable energies was analysed, and in a second step the surplus feed-in potential was examined to see whether there was any critical impact on the electricity network.

Key performance indicators were generated taking into consideration technical as well as economic perspectives in order to determine the suitability of locations for PtG plants. In this process, the surplus energy potential of renewable injections was recorded at hourly intervals and correlated with an economically meaningful life of the PtG plants of 3,000 full load hours per year. The result of this correlation was broken down to the administrative district level in order to identify the suitability of locations on a regional basis. The identification of the suitability of locations was projected through to 2050 on the basis of the TM-95 scenario from the dena study “Integrated energy transition” [dena 2018].

Figure 13: Suitability of locations for PtG plants up to 2050

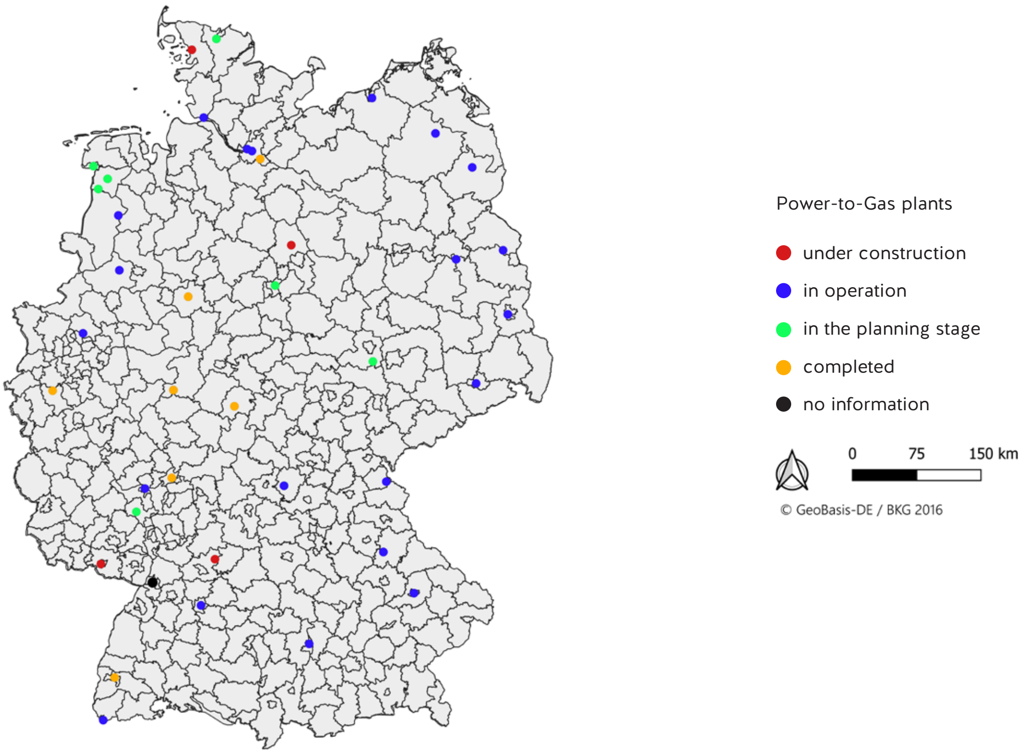


Source: FfE 2019

The study predicted PtG potential primarily in the north and the north-west of Germany. This will also increasingly extend to the north-east over the years. Significant local differences between the individual administrative districts can be identified, which is why the north cannot be seen as a homogeneous region.

Current PtG projects are currently very widely dispersed in Germany, as their construction is driven for political or research purposes and not on an economic basis or even in way that is useful for the network. Any attractiveness of a location can be derived from this only to a limited extent today.

Figure 14: Locations of PtG projects in Germany



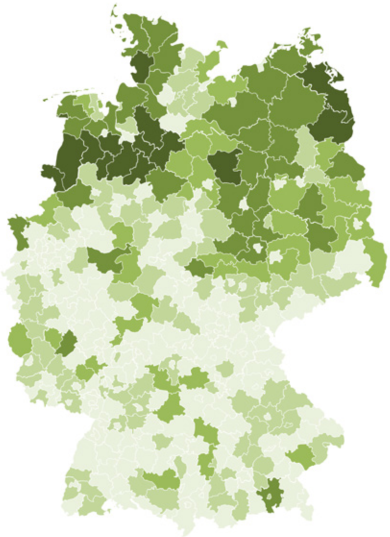
Source: FfE 2019

4.5 Total gas supply

The total regional gas supply from domestic production, biomethane and green gas production in 2030 and its change from 2018 is presented in the following illustration. The decline in the production of natural gas in Germany can clearly be seen in the map on the right in Figure 15, in which the absolute change in gas supplies is presented.

Figure 15: Scenarios I and II: Regional gas supply in 2030 and change from 2020 (absolute in GWh)

Gas supply – absolute volumes



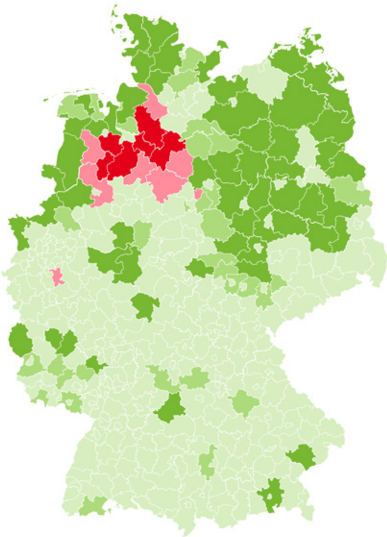
Scenarios I and II

Regional gas supply 2030
Absolute volumes at district level in GWh

Gas supply 2030 is …

- less than 25 GWh
- from 25 to under 100 GWh
- from 100 to under 250 GWh
- from 250 to under 1,000 GWh
- more than 1,000 GWh

Gas supply – change



Scenarios I and II

Change in regional gas supply 2020 to 2030
Absolute volumes at district level in GWh

Gas supply to 2030 …

- falls by more than –1,500 GWh
- falls by up to –1,500 GWh
- increases by less than 50 GWh
- increases by 50 to under 100 GWh
- increases by at least 100 GWh

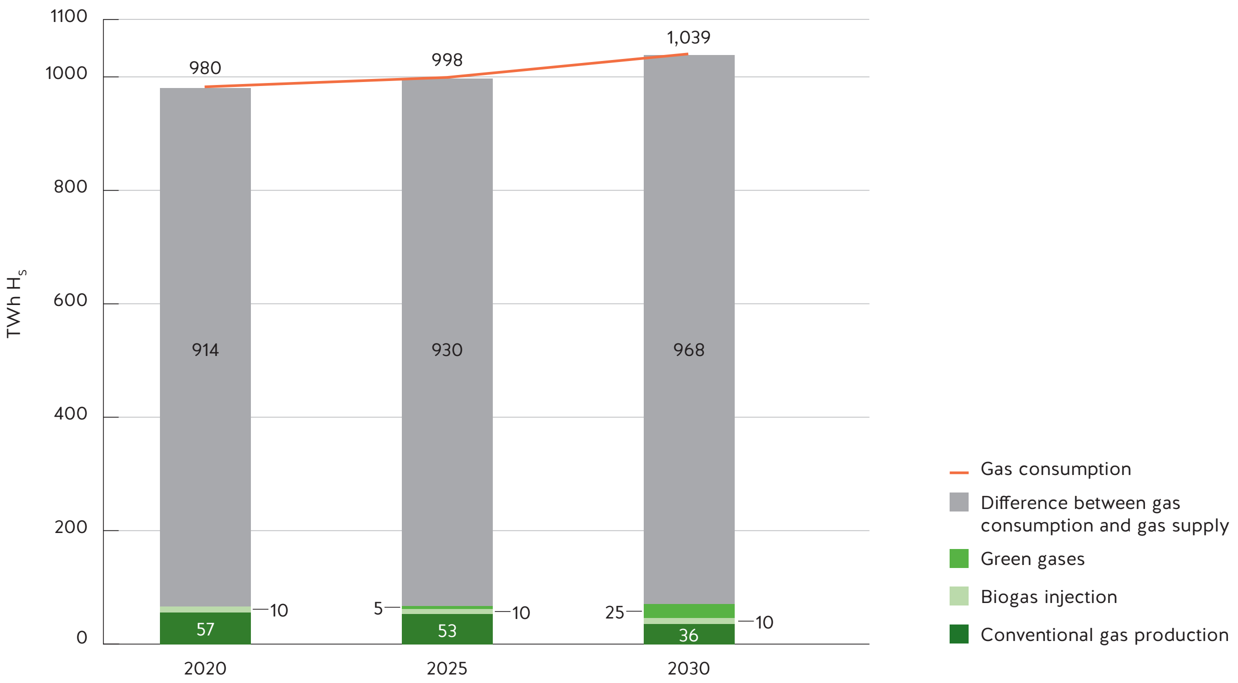
Source: Prognos AG

5 Comparison of gas demand and gas supply

5 Comparison between gas demand and gas supply in Germany

Based on the gas demand scenarios presented, a difference arises between gas demand and gas supply (excluding transit quantities). This difference is shown in Figure 16 below and in Table 22. This consideration involves a simple quantity balance based on the detailed gas demand scenarios considered, for example without differentiating between L-gas and H-gas volumes. The balances relevant for the network modelling are first presented in the Gas NDP 2020–2030.

Figure 16: Development of the difference between gas demand and gas supply in Germany according to Scenario I (presentation as high calorific value)



Source: Prognos AG, FfE 2019

Table 22: Development of the difference between gas demand and gas supply in Germany according to Scenario I (presentation as high calorific value)

	Results of Scenario I [figures in TWh, presentation as high calorific value (H_s)]		
	2020	**2025**	**2030**
Gas consumption	980	998	1,039
Gas supply	67	68	71
Conventional gas production	57	53	36
Biogas injection	10	10	10
Green gases	0	5	25
Difference between gas consumption and gas supply	**914**	**930**	**968**

Source: Prognos AG, FfE 2019

Market area merger 6

6 Market area merger

6.1 Background

In accordance with the Gas Network Access Regulation, the two German market areas NCG and GASPOOL have to be combined into one market area no later than 1 April 2022. The transmission system operators are planning to carry out the integration on 1 October 2021.

With the new combined market area, one of the most attractive and, in future, most liquid gas hubs in Europe will be created. The German transmission system operators are currently working intensively with the market area managers as well as the market participants and the BNetzA on the structure of this new market area.

The market dialogues (cf. Chapter 6.7) have shown that the various stakeholder groups, comprising producers, traders, platform operators and associations among others, can establish and shape the new combined German market area only in cooperation with each other and in agreement with the BNetzA.

Further general information on the market area merger can be found on the website at http://www.marktgebietszusammenlegung.de/en.

6.2 Capacities for the Gas NDP 2020–2030

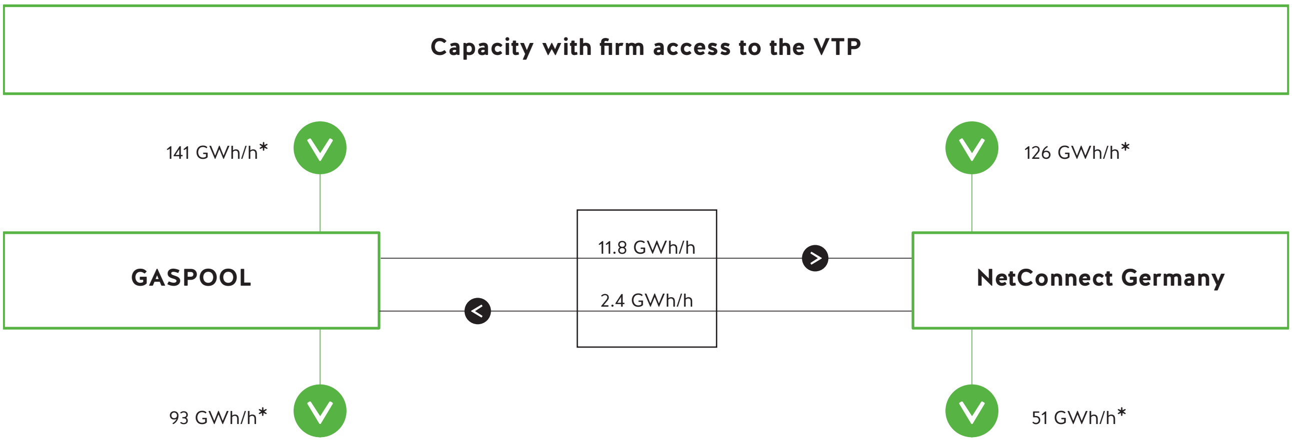
The goal of Section 21 GasNZV is “to increase the liquidity of the gas market” by combining the two existing market areas. In fulfilment of this statutory requirement, the TSOs should aim to transfer the capacity existing in the two separate market areas of GASPOOL and NCG (e.g. capacity in the Gas NDP 2018–2028) in terms of quantity and quality into capacity in a Germany-wide market area as far as possible.

As the most recently published opinions expressed in the course of the market dialogue on the draft of the capacity model of the transmission system operators show, a future offer of capacity that is comparable with the current capacity level is of central importance for the market. Only by guaranteeing sufficient liquidity of the gas market can the security of supply and the competitive intensity/competitiveness of the German gas market be ensured. Against this background, the transmission system operators are endeavouring, where this is possible in terms of quantity and quantity, to provide today’s capacity in the separate market areas – taken from the Gas NDP 2018–2028 – in one Germany-wide market area.

On account of the considerable enlargement of the market area, however, this significant upgrading of capacity cannot be guaranteed without investment measures or the use of other instruments. As significant investment measures cannot be realised until the market area merger is implemented and, moreover, seem inefficient, the transmission system operators are currently examining to what extent and in what quality capacity could be offered even without further structural measures. The guarantee of a secure and, at the same time, cost-efficient energy supply is the focus here.

A particular challenge in the establishing of a new capacity model for the combined market area is the relatively low exchange capacity between the NCG and GASPOOL market areas that currently exist. This makes it difficult to offer freely allocable capacities in the combined market area.

Figure 17: Exchange capacity between NCG and GASPOOL according to the Gas NDP 2018–2028



* Conditionally firm freely allocable capacity and free allocable capacity for cross-border interconnection points, storage and production

Source: Transmission system operators

In order to meet this challenge, a new capacity model is currently being developed, with which possible restrictions in the combined market area will be identified and analysed to begin with and the capacity framework will subsequently be determined in line with the premises mentioned above. A large number of different use cases for the execution of future transport functions are simulated using this model – on the basis of historical flow data and information on the planned network and capacity developments. Consequences for the market area merger are subsequently derived from the results of the simulation.

6.3 New capacity model – "NewCap"

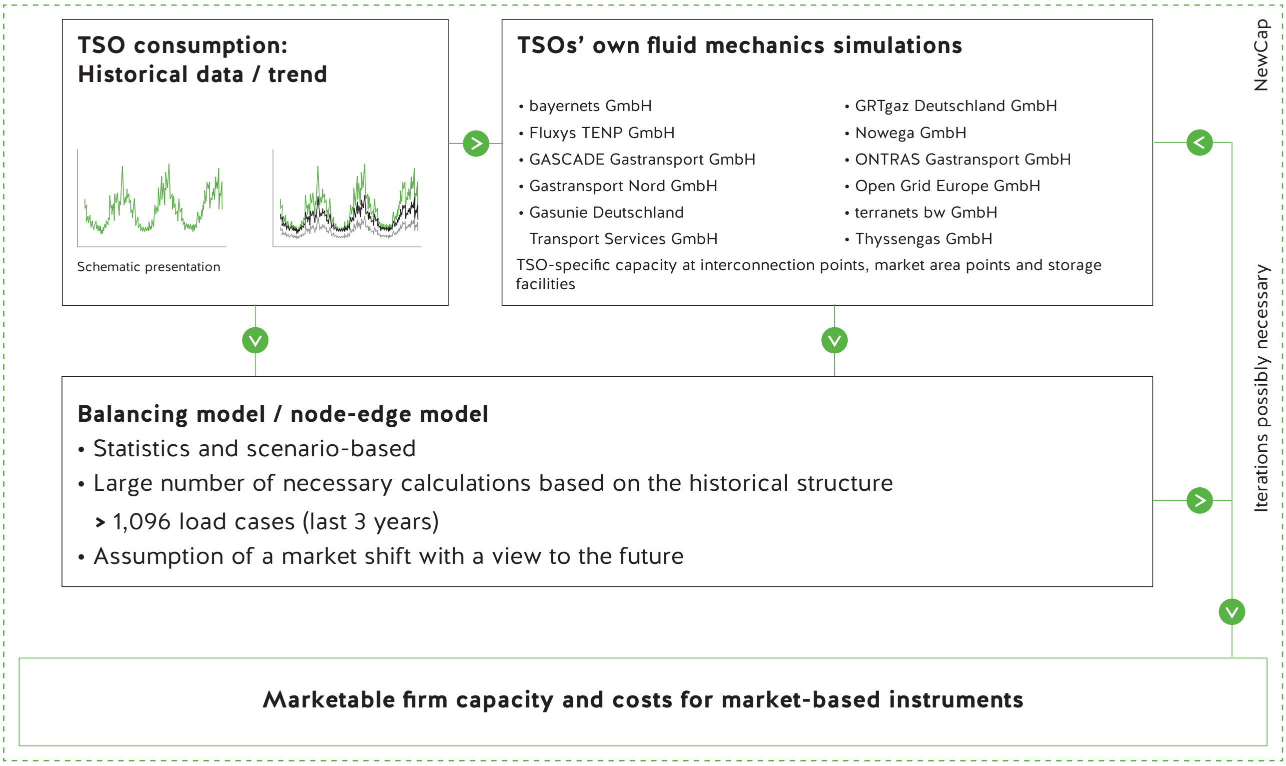
Based on the existing technical conditions in the networks, the transmission system operators in the two market areas currently use different approaches to identify available capacity. These different approaches have to be harmonised upon the merger of the two German market areas.

The experience gained from ten years of operating the market areas using different models has been incorporated in the development of the new capacity model. In this process, the combination of a statistical model with the use of Germany-wide load scenarios has emerged as the preferred approach for processing future transport functions.

The basis of the model is provided by data comprising historical flow data, the result of the TSOs' own network simulations and the capacities at TSO-specific network points. The statistical approach includes (for each scenario, see below) the calculation of numerous network use cases based on a historical load structure. The determination of consumption is based on daily consumption values in the period from 1 April 2015 to 1 April 2018. Daily consumption is scaled in accordance with capacity changes based on the Gas NDP 2018–2028, and the market area conversion is taken into consideration in line with the conversion plan in accordance with the Gas NDP 2018–2028. A statistical approach allows the consideration of how frequently certain load situations have arisen in the past, which can be used as the basis for estimating their occurrence in the future. In a capacity model based on statistical evaluations and assumptions, assumptions and decisions can thus also be made for rare load situations. In the rare network use cases in which the physical network would be unable to provide transport, marketing of the capacities can be carried out by using additional market-based instruments.

The scenario-based approach consists in loading the network using various assumed (extreme) (load) scenarios. In combination with the statistical approach, the demand for market-based instruments (MBIs), such as wheeling, third-party network use and exchange-based spread products, is estimated for the various scenarios here.

Figure 18: Capacity model – NewCap in a nutshell



Source: Transmission system operators

6.3.1 Scenarios in NewCap

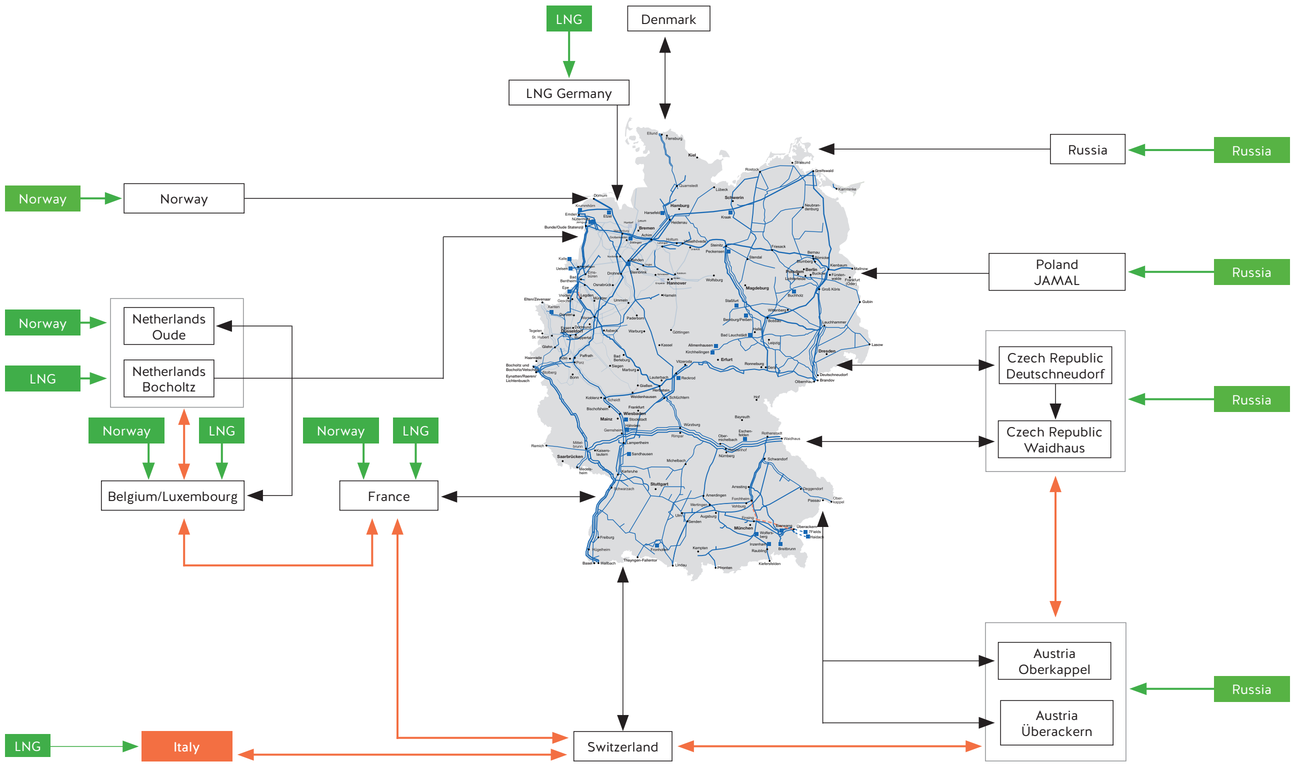
Similar to the modelling of consumption, the consideration of interconnection points, storage and production is based on historical usage in the period from 1 April 2015 to 1 April 2018. The usage profiles of the interconnection points are increased or reduced on a daily basis in the course of the scenarios investigated. The technical capacities taken from the Gas NDP 2018–2028 form the limit here.

The scenarios map a variation of the Russia, Norway and LNG sources and taken into particular consideration planned expansion measures based on the previous network development plans and expected changes in entry and exit volumes (e.g. market area conversion) for the future. The scenarios can be divided into two categories:

- Redistribution variants (diversified supply Germany)
  - > A percentage increase in the netted entry volume in an import zone (source) and a corresponding reduction in the netted entry volume in another zone.
- Transit variants (transit Germany – supply Europe)
  - > A simultaneous increase in the entry volume in an import zone and an increase in the exit volume in another zone. An increase in the transit volume is intended to be simulated in this way.

The variation between the entry and exit flows takes place up to the maximum use of the technical capacity or up to when a market shift of 10 % is reached.

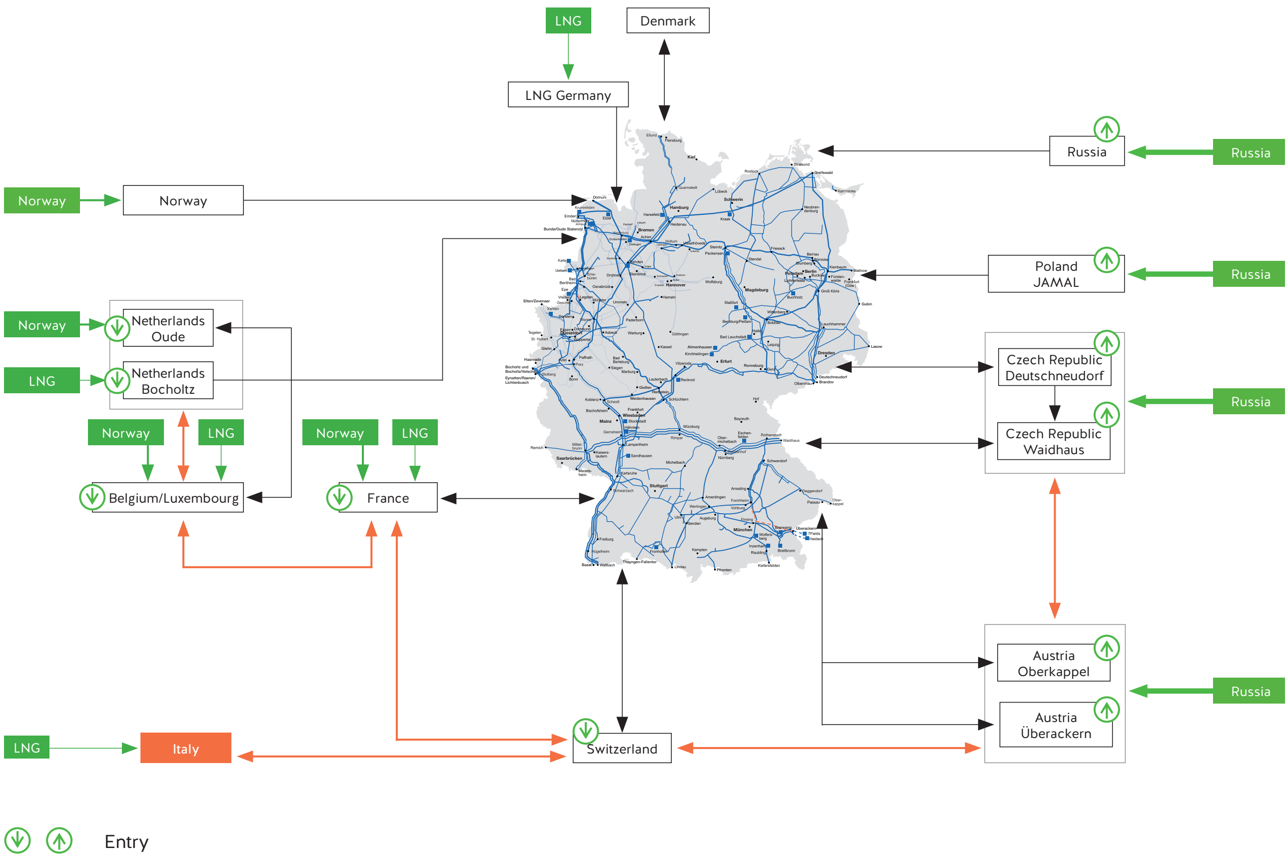
Figure 19: Variation in the supply of the German market area – Grouping of the entry and exit interconnection points



Source: Transmission system operators

The transfer of the volumes between these three groups is primarily considered in pairs: e.g. Russia and Norway, Russia and LNG, etc.

Figure 20: Example of redistribution – Reduction in imports from Western Europe (LNG), compensation through higher imports from Russia



Source: Transmission system operators

Each scenario configuration is described by 1,096 network use cases. To this end, the values from the base scenario are adjusted depending on the scenario definition.

6.3.2 Node-edge model in the newcap

Statistical approaches produce meaningful information only if a sufficiently large amount of data is available. For this reason, the transmission system operators evaluate more than 130,000 network use cases as a basis in their model. These are simulated in a node-edge model that has been specially developed for this purpose.

The node-edge model is an abstraction of the network topology between the transmission system operators of the two market areas as well as of the connections with neighbouring market areas.

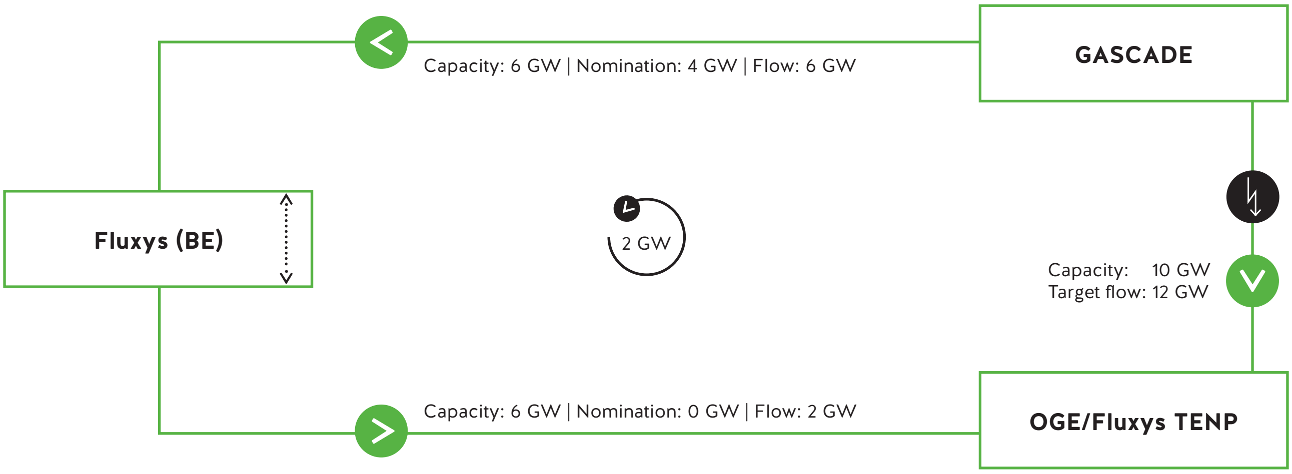
The node-edge model consists of the following elements:

- Nodes represent among other things an aggregation of the networks into large entry and exit areas (e.g. networks of the transmission system operators, important interconnection points, neighbouring countries). It is assumed that, within an area aggregated by a node, a situation where there are no bottlenecks prevails in the context of the individually determined capacities of the transmission system operators per network area.
- Edges represent the connections between the aggregated entry/exit areas. The transmission possibilities and restrictions between the individual aggregated entry/exit areas are described in terms of edges.

The MBIs described in more detail below (wheeling, third-party network use and exchange-based spread products) are currently under discussion in terms of their design and required level. In order to take the requirement of cost-efficiency into account, these MBIs are always intended to be used only as needed, i.e. only when the given infrastructure is not sufficient for resolving the network use case. Furthermore, their use must have an optimal cost and benefit impact on the network.

Figure 21: Example of wheeling

Wheeling: gas transmission from one transmission system operator to another transmission system operator via an interconnection point or nearby network interconnection points

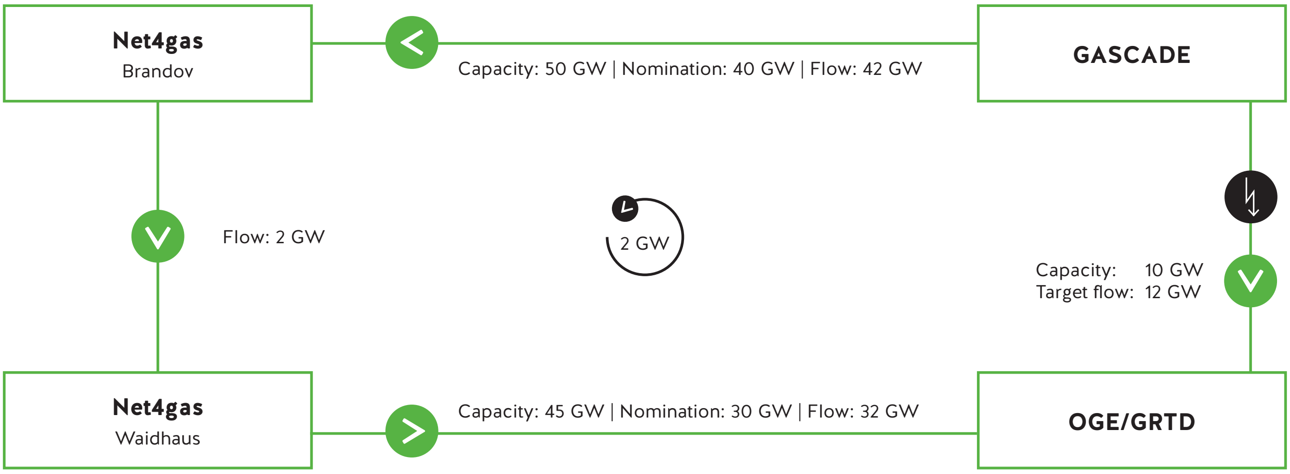


Example of wheeling: bypassing a bottleneck between GASCADE and OGE/Fluxys TENP by a flow via an interconnection point in Belgium

Source: Transmission system operators

Figure 22: Example of third-party network use

Third-party network use: gas transmission from one transmission system operator to another transmission system operator via two interconnection points

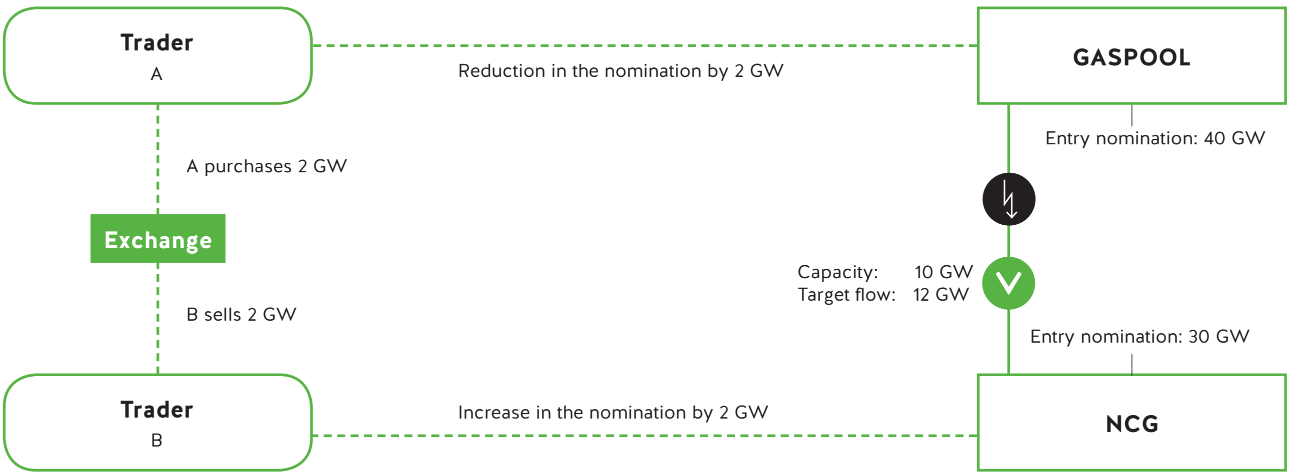


Example of third-party network use: bypassing a bottleneck between GASCADE und OGE/GRTD by a flow through two interconnection points in the Czech Republic

Source: Transmission system operators

Figure 23: Example of an exchange-based spread product

Exchange-based spread product: fictitious gas transmission from one transmission system operator to another transmission system operator by a local purchase and sale of gas volumes. In this solution, the excess volumes in a network area are sold and the additional volumes accordingly required in another network area are purchased. The networks are thus balanced with the help of the market participants.



Example of an exchange-based spread product: bypassing a bottleneck between GASPOOL and NCG by the sale of the excess volumes in the GASPOOL market area and the purchase of the missing volumes in the NCG market area (source: http://www.marktgebietszusammenlegung.de/en)

Source: Transmission system operators

Based on the (current legal) assessment of the BNetzA, the application of the above-mentioned commercial instruments should take place within the framework of an overbooking system. The transmission system operators are coordinating with the BNetzA on this. To this end, a formal consultation process that aims to create a definition has been launched by the BNetzA.

6.4 Alternatives to market-based instruments

An alternative to MBIs proposed by the transmission system operators is the expansion of the network in order to maintain the capacity in the entire German market area. One argument against this is the fact that a majority of the measures required can be realised only in five to seven years and the expansion can therefore definitely not be implemented by the time the integrated market area comes into being. Another is that the costs for an expansion of this kind – depending on the suggested capacity structure – would be in the range of several billion euros, while costs would furthermore be incurred over a depreciation period of up to 55 years, which does not represent a reasonable cost-benefit ratio.

Another alternative to the use of MBIs is to reduce entry capacity. Conditionally firm freely allocable capacity and free allocable capacity in particular could not be fully maintained in a combined market area. A reduction by approximately 200 GWh/h – which would correspond to around 78 % compared with the Gas NDP 2018–2028 – would result. Capacity that has already been booked and the booking quotas are not affected by this.

6.5 NewCap in the gas network development plan

The identification of the expansion measures on account of the new system in a market area will have to be supplemented by additional process steps in the Gas NDP 2020–2030. In principle, an assessment has to take place for this purpose as part of the modelling to determine whether the use of MBIs or an expansion of the network is advantageous. To this end, the costs of the relevant variant analysis have to be juxtaposed on a comparable basis, e.g. the calculation of a present value.

6.6 Treatment of costs for market-based instruments

Based on the model, MBIs are used at the most efficient place, which does not necessarily have to be the same as the place where the bottleneck was caused. Neither the bottlenecks nor the resulting costs can thus be assigned clearly and by cause to the individual transmission system operators. These also have to be taken into consideration in the efficiency comparison of BNetzA. The costs for MBIs therefore have to have a neutral impact on the profit of the transmission system operators and may not exert an influence on the efficiency comparison.

In order to ensure efficient network access, it should be reviewed on a regular basis in the Gas NDP whether the costs of the MBIs permanently exceed the costs of an alternative network expansion. Should this be the case, the MBIs should be replaced by an appropriate network expansion.

6.7 Market dialogue – Opinions based on market information

The first market dialogue event on the market area merger was held on 6 February 2019 during E-world. The transmission system operators presented their initial thoughts on a Germany-wide capacity model at the trade fair. The market was asked to provide feedback on the observations presented by the TSOs by 17 March 2019.

The opinions have been published at http://www.marktgebietszusammenlegung.de/en/comments/.
The contents and proposals were discussed at the second market dialogue event on 4 June 2019 in Berlin.

There are essentially three key topics that the market introduced during the dialogue: capacity model, structure of market-based instruments and organisational matters.

Only the two thematic blocks relating to capacity model and design of market-based instruments are to be addressed at this juncture.

The issue of capacity is of central importance for the market, as a drastic reduction in the offer would have a negative impact. The following arguments can be taken from the opinions:

- Reducing entry capacity weakens market liquidity, Germany's security of supply (also in other EU countries) and the intensity of competition
- Negative impact on procurement diversification and investment security
- Economic viability of German storage facilities possibly jeopardised and relocation of transits possible
- Germany is Europe's gas hub, Germany's position in the competition in the EU jeopardised
- Capacity reduction contradicts the goal of increasing market liquidity, which is the starting point for EU cross-border developments
- Goal of the EU gas target model of EU regulators – creating liquidity – jeopardised
- Supply obligations in Germany put at risk. (Supplier and consumer affected); cost burden on end consumers increases
- Higher gas price expected, also has an impact on the price of electricity

The market has expressed the following views on the capacity model and in particular in relation to the use of market-based instruments:

- Network expansion cannot be realised as a solution in the short term and is associated with high long-term costs
- Market-based solution is heavily supported
- Market-based instruments essential for prompt and cost-efficient implementation
- Advantages upon start on 1 October 2021 with MBIs: no cost burden if there is no demand
- Transparent instruments as alternatives to cost-intensive network expansion
- Competitive cost optimisation, needs-based, more cost-efficient, shorter implementation period
- Reference to market area cooperation in France

Gas exchange 7

7 Gas exchange between Germany and its neighbouring countries

This chapter identifies current trends in the incremental capacity process (cf. Chapter 7.1). The assumptions and results relating to the distribution of H-gas sources are then described (cf. Chapter 7.2), before the interconnection points of the three regions are looked at in Chapters 7.2.4 to 7.2.6. Chapter 7.3 presents the virtual interconnection points (VIPs). The development of capacity demand at the Wallbach interconnection point in the direction of Switzerland and Italy is highlighted in Chapter 7.4. Chapter 7.5 describes the development of capacity demand at the Oude Statenzijl interconnection point.

7.1 Incremental capacity

The new Regulation (EU) 2017/459 (NC CAM) became effective in April 2017. This provides for a European process for incremental capacity. Using this instrument, capacity demand of the shippers is intended to be included at an early stage in a sustainable further development of the gas transmission infrastructure in a market-based process.

The process starts at least every two years from 2017 onwards after the annual auction with a non-binding market survey of the demand for additional cross-market area capacity. The transmission system operators will subsequently publish analyses of this demand. If the capacity required can be provided without expansion, the process ends. Otherwise, the transmission system operators publish a draft of their project proposal for creating the transmission capacity that is in demand, including a technical study. Following a public consultation, they review the draft document and submit the project proposal to the BNetzA for approval. Depending on this approval, supply levels with incremental capacity are offered at the next annual auctions. An economic test is carried out after the bookings. The BNetzA examines in this whether a project for incremental capacity will actually be implemented. To this end, incremental capacity must be booked on a scale that covers a reasonable part of the expected project costs.

In the course of the 2017–2019 incremental capacity cycle, incremental capacity from GASPOOL to the TTF (Netherlands) will be offered in the annual auction on 1 July 2019.

The auctions are thus taking place during the consultation phase for this document from 17 June 2019 to 12 July 2019. If the project for the incremental capacity is initiated, the technical capacity corresponding to the successful offer level will be included in the revised scenario framework. The documents on the 2017–2019 incremental capacity cycle are published on the homepage at www.fnb-gas-capacity.de/en.

The 2019–2021 incremental capacity cycle will start with the annual auctions on 1 July 2019. Its results will be incorporated at the earliest, however, in the scenario framework for the Gas NDP 2022–2032.

Transmission system operators are still seeing a trend towards shorter-term capacity bookings on the market. In light of this, transmission system operators are sceptical that the incremental capacity process alone can provide sufficient expansion signals. If necessary to safeguard supply, transmission system operators have to be able to take into account additional capacity to demonstrate sufficient security of supply in addition to the incremental capacity procedure.

7.2 Distribution of H-gas sources

The decline in Europe's own production and the conversion from L-to H-gas mean that the import demand for H-gas will increase in Europe in the coming years. As the German transmission infrastructure is traditionally heavily characterised by cross-border natural gas streams to supply its neighbouring western and southern European states, it can be expected that the requirements in terms of the cross-border exchange of natural gas will continue to grow in the future.

To be able to assess the impact of future expansions of the infrastructure for importing H-gas into Europe on the German transmission networks, the transmission system operators have updated the model for the distribution of sources that was first produced as part of the Gas NDP 2013 and further developed in the subsequent network development plans.

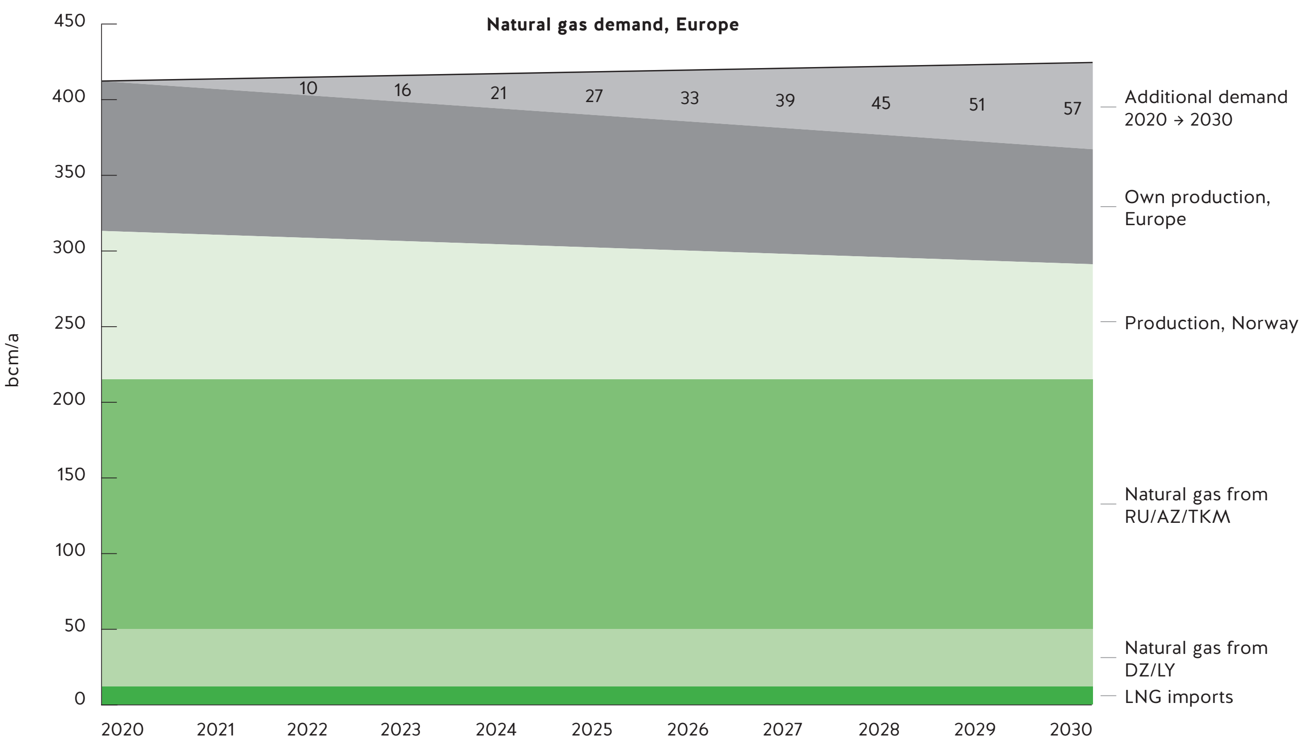
In principle, the following changes have resulted in comparison with the Gas NDP 2018–2028 when the distribution of H-gas sources was drawn up:

- TYNDP: use of TYNDP 2018 instead of TYNDP 2017
- Pipelines: new pipeline projects are taken into consideration only if an FID is available

7.2.1 Natural gas demand in Europe

On the basis of the data in the current TYNDP 2018, import demand for Europe will further increase by around 57 bcm/a up to 2030 compared with start year 2020 (cf. Figure 24).

Figure 24: Possible development of supply and demand in the balancing area



Source: Transmission system operators on the basis of the TYNDP 2018

In addition to the EU28 states, the area for which the balance is drawn up includes Switzerland, Bosnia-Herzegovina, Serbia and Macedonia on the demand side.

The "EUCO30 scenario" was used from the TYNDP 2018 for the demand side, as it maps a middle road as part of the ENTSOG scenarios up to 2030 in due consideration of the European climate protection targets. The values for the start year 2020 have been taken from the best estimate scenario.

On the supply side, the natural gas volumes that are delivered through existing pipelines and also from existing LNG plants are assumed to be constant across all years at the level of the base year of 2020 that is assumed in the planning. In order to cover the gas demand in the start year of 2020 for pipeline deliveries in the planning, the mean value from the minimum and maximum scenarios for 2020 is taken as the basis here and the remaining demand is covered for planning purposes by LNG.

As the Norwegian and internal European production volumes are in decline, an additional planning demand in relation to the base year results together with the assumed development of the gas demand pursuant to the EUCO30 scenario. On the supply side, significant internal production in Cyprus (around 11 bcm/a) is assumed in the TYNDP 2018 from 2022 onwards, which could be provided to the European market through infrastructure projects that are yet to be implemented (EastMed). As this involves a project where the status is "less advanced", the transmission system operators do not take these production volumes into consideration.

7.2.2 Transport routes and infrastructure projects

In principle, the transmission system operators assume along the lines of the Gas NDP 2018–2028 that the new natural gas volumes will be shipped to Europe using two means of transport. On the one hand, additional natural gas will be transported to Europe through new pipelines from Russia, Africa and the Caspian region, while volumes will be provided as LNG (liquefied natural gas) by tanker on the other.

As the additional import demand assumed for planning purposes has once again fallen on the basis of the TYNDP 2018 in comparison with the TYNDP 2017 and is thus considerably lower than was the case in the TYNDP 2015, the transmission system operators assume that significantly fewer additional infrastructure projects will be required for Europe's supply than was believed just a few years ago.

Only projects for which a final investment decision is available (known as FID projects) are therefore taken into consideration in principle in the scenario framework for the Gas NDP 2020–2030.

The German LNG terminals in Brunsbüttel and Wilhelmshaven are not taken into consideration in the distribution of H-gas sources, as these are recognised directly in the H-gas balance in the Gas NDP 2020–2030.

Annexes A and C of the TYNDP 2018 serve as the data basis for the LNG terminals taken into account in the consideration. In addition, the GIE Investment Database (as of January 2018) is used to determine the current technical capacity of the LNG terminals. Table 23 provides an overview of the infrastructure projects, plus their technical capacities and commissioning dates as well as the allocation to the regions under consideration, that are potentially relevant for the distribution of H-gas sources and that are listed in the TYNDP 2018.

The transmission system operators do not expect any additional natural gas volumes to become available for Europe through the Baltic Pipe. This project is therefore not recognised in the distribution of H-gas sources.

Table 23: Infrastructure considered in the distribution of H-gas sources

Type	Infrastructure project	Commissioning	Technical capacity (bcm/a)	Consideration in the distribution of H-gas sources	Region
Pipeline	NORD STREAM 2[1)]	2019	19.60	–	North-east
Pipeline	BALTIC PIPE	2022	10.00	–	North-east
Total pipelines, north-east			**29.60**	**–**	
Pipeline	NORD STREAM 2	2019	35.40	35.40	South
Pipeline	TAP	2019	10.00	10.00	South
Pipeline	GALSI	2019	9.00	–	South
Pipeline	EASTMED	2020	12.00	–	South-east
Pipeline	WHITE STREAM	2022	17.00	–	South-east
Pipeline	EASTRING (expansion phase I)	2023	19.25	–	South-east
Pipeline	AGRI	2026	8.00	–	South-east
Pipeline	EASTRING (expansion phase II)	2028	19.25	–	South-east
Total pipelines, south/south-east			**129.90**	**45.40**	
LNG	Klaipeda LNG Terminal[2)]	2014/2025	4.00	4.00	North-east
LNG	Świnoujście	2015	5.00	5.00	North-east
LNG	Gothenburg Go4LNG	2021	1.00	–	North-east
LNG	Skulte	2022	5.00	–	North-east
LNG	Muuga (Tallin LNG)	2023	4.00	–	North-east
LNG	FSRU Baltic Sea Coast	2023	4.65	–	North-east
LNG	Świnoujście (expansion)	2024	2.50	–	North-east
LNG	Paldiski	2026	4.70	–	North-east
Total LNG, north-east			**30.85**	**9.00**	

[1)] The NORD STREAM 2 pipeline located in the north-east region has a technical capacity of 55 bcm/a. As 35.4 bcm/a was booked in the 2017 annual auction for transmission in the direction of the Czech Republic through the new Deutschneudorf-EUGAL interconnection point, the total capacity in the distribution of H-gas sources is allocated to the north-east and south regions. The consideration of the remaining 19.6 bcm/a is discussed in the subsection below.
[2)] Existing terminal/substitute terminal

Type	Infrastructure project	Commissioning	Technical capacity (bcm/a)	Consideration in the distribution of H-gas sources	Region
LNG	Fos-Tonkin	1972	3.40	3.40	West
LNG	Montoir	1980	10.00	10.00	West
LNG	Zeebrugge	1987	9.00	9.00	West
LNG	Isle of Grain	2005	19.50	19.50	West
LNG	Teesside LNG port	2007	4.20	4.20	West
LNG	Milford Haven – Dragon	2009	21.00	21.00	West
LNG	Milford Haven – South Hook	2009	7.60	7.60	West
LNG	Fos Cavaou	2010	8.25	8.25	West
LNG	Gate Terminal	2011	12.00	12.00	West
LNG	Dunkirk	2016	13.00	13.00	West
LNG	Zeebrugge (expansion)	2019	4.00	4.00	West
LNG	Gate Terminal (expansion)	2021	4.00	–	West
LNG	Inisfree LNG Cork	2023	3.75	–	West
LNG	Shannon	2023	2.90	–	West
LNG	Fos Cavaou (expansion)	2024	8.25	–	West
LNG	Montoir (expansion)	2024	3.40	–	West
Total LNG, west			**134.25**	**111.95**	
LNG	Barcelona	1968	17.10	17.10	South-west
LNG	Huelva	1988	11.80	11.80	South-west
LNG	Cartagena	1989	11.80	11.80	South-west
LNG	Bilbao	2003	8.80	8.80	South-west
LNG	Sines	2004	7.60	7.90	South-west
LNG	Sagunto	2006	8.80	8.80	South-west
LNG	Mugardos	2007	3.60	3.60	South-west
LNG	El Musel/Gijón[3)]	2014/2020	7.00	7.00	South-west
LNG	Tenerife (new plant)	2022	1.40	–	–
LNG	Mugardos (expansion)	2024	3.60	–	South-west
LNG	Gran Canaria (new plant)	2028	1.40	–	South-west
Total LNG, south-west			**82.9**	**76.50**	
LNG	Panigaglia	1971	3.40	3.40	South
LNG	Adriatic LNG Terminal (Porto Levante)	2009	7.58	7.58	South
LNG	OLT Offshore LNG Toscana	2013	3.80	3.80	South
LNG	Delimara Malta LNG	2017	1.00	–	South
LNG	Krk Island (new plant)	2020	2.75	2.75	South
LNG	Cagliari (new plant)	2021	0.50	–	South
LNG	Porto Empedocle (new plant)	2022	10.00	–	South
LNG	Krk Island (expansion)	2024	2.75	–	South
Total LNG, south			**31.78**	**17.53**	
LNG	Revithoussa	2000	5.00	5.00	South-east
LNG	Revithoussa (expansion)	2019	2.75	2.75	South-east
LNG	Alexandroupolis (new plant)	2021	6.00	–	South-east
LNG	CyprusGas2EU, Lemesos Port	2021	1.40	–	South-east
Total LNG, south-east			**15.15**	**7.75**	
Total pipelines			**159.50**	**15.40[4)]**	
Total LNG			**294.93**	**222.73**	

3) Existing terminal. Final network connection in 2020
4) Substitution quantities for the Ukraine transit (30 bcm/a) taken into consideration

Source: Transmission system operators on the basis of the TYNDP 2018

7.2.3 Supply variant for Europe

The impact of the infrastructure projects on Germany is determined within the framework of the distribution of H-gas sources.

On the assumption of the premises set out in Chapter 7.2.1, additional import demand for Europe of around 57 bcm/a arises for 2030, which has to be covered by LNG and additional pipeline projects.

The transmission system operators assume that additional gas volumes will be available for Europe through the Nord Stream 2 (55 bcm/a) and TAP (10 bcm/a) FID projects.

For the Nord Stream 2 pipeline project, transmission capacity has been offered on the European capacity platform PRISMA and has been purchased in a good 400 annual auctions within the framework of more capacity in a multi-stage process. The bookings related to the market area interconnections between GASPOOL and Russia as well as between GASPOOL and the Czech Republic and include dynamically allocable capacity that extends up to 2039.

This has to be taken into appropriate consideration in the distribution of H-gas sources, as the auction results are recorded as binding bookings in the H-gas balance.

- According to the auction result, around 35.4 bcm/a will be shipped from the Lubmin II landing point through the new Deutschneudorf-EUGAL interconnection point to the Czech Republic and will thus be additionally available for the south/south-east region.
- The remaining amount of around 19.6 bcm/a is also booked on the entry side and will be available for the German and Western Europe market. Although 9.7 bcm/a of this 19.6 bcm/a will be shipped as dynamically allocable capacity at existing interconnection points in the Czech Republic, these exits have previously been supplied from entry points in the West and via the Mallnow interconnection point. In the opinion of the transmission system operators, the availability of this entry capacity is also secured as a source for Germany in the future. For this reason, they will be “moved” from interconnection points to the Czech Republic by the new dynamically allocable capacity from Lubmin II and instead be linked with other exit points. For this reason, all of the 19.6 bcm/a is recognised as additional entry.

In the distribution of H-gas sources, the transits to the Czech Republic of around 35 bcm/a are therefore taken into additional consideration in the south/south-east region, where only around 5 bcm/a of this is assumed to be potentially additionally available natural gas for Germany and Western Europe. In a similar way to the assumptions of the Gas NDP 2018–2028, the remaining volumes are taken into consideration as substitution for a part of the delivery volumes from Russia via Ukraine.

As the roughly 20 bcm/a remaining from Nord Stream 2 is booked as binding on the entry side, the effect does not have to be determined across the distribution of H-gas sources. As a result, the import demand of around 57 bcm/a to be taken into consideration across the distribution of H-gas sources is reduced to around 37 bcm/a.

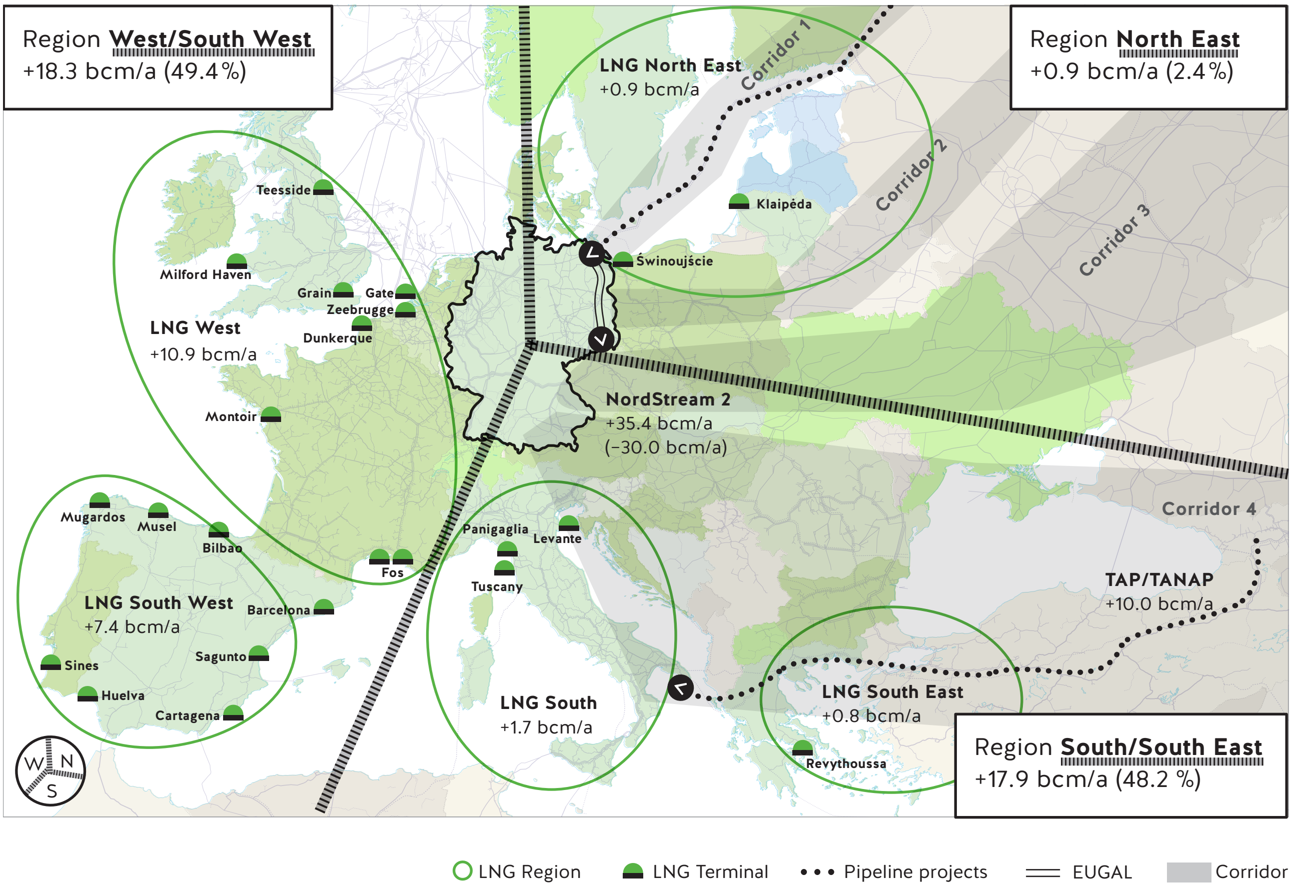
Deducting the substitution volumes for the Ukraine transit, around 15 bcm/a is additionally available in the south/south-east region from the TAP pipeline projects and the transit volumes of Nord Stream 2. As these volumes are not sufficient to cover the additional demand of around 37 bcm/a in 2030, additional LNG volumes of around 22 bcm/a will have to be arranged. Taking the expected LNG demand in 2020 of around 12 bcm/a into consideration, total LNG demand in 2030 runs to 34 bcm/a, which results in a pro rata utilisation of all new and existing facilities of around 15 %.

The result for the additional pipeline and LNG volumes to cover the additional demand as well as the distribution of the volumes to regions and sub-regions are presented in the figure below.

The following regional distribution results overall:

- North-east region share: 2.4 %
- West/south-west region share: 49.4 %
- South/south-east region share: 48.2 %

Figure 25: Coverage of the additional European demand up to 2030



Source: Transmission system operators

The volumes additionally required from the north-east region of around 2 % above the distribution of H-gas sources come from LNG plants. In accordance with the statements in Chapter 7.2.6, no additional capacity from this region is recognised. The roughly 2 % in the Gas NDP 2020–2030 is therefore apportioned to the two other regions.

7.2.4 Interconnection points to the west/south-west Europe region

Norway

Dornum and Emden EPT interconnection points

The Norwegian export system is connected to the NCG market area and the GASPOOL market area at the Dornum and Emden EPT interconnection points. These interconnection points are used to receive H-gas from Norway.

Because of the development of the reserves in Norway and the “Baltic Pipe” (TRA-N-271, TRA-N-780) project for shipping gas from Norway in the direction of Denmark/Poland, no additional entry volumes are taken into consideration in the distribution of H-gas sources.

Netherlands

The Dutch transmission system is connected to the NCG market area at the Bunde/Oude Statenzijl, Vreden, Elten/Zeevenar, Tegelen, Haanrade, Bocholtz-Vetschau and Bocholtz interconnection points and with the GASPOOL market area at Bunde/Oude Statenzijl interconnection point.

Bunde/Oude Statenzijl interconnection points

The Bunde/Oude Statenzijl interconnection point is used to take over L-gas into the GASPOOL market area and H-gas into the GASPOOL and NCG market areas. The H-gas interconnection points to the GTS are operated bidirectionally.

The provision of additional transmission capacity in H-gas was provided for by GTS in the Dutch Network Development Plan 2017 (NDP) [GTS 2017]. Additional potential that can be recognised in the distribution of H-gas sources arises in particular as a result of the expansion of LNG terminals in the Netherlands.

For this reason, the Bunde/Oude Statenzijl interconnection points are recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Vreden interconnection point

The Vreden interconnection point is used today to receive L-gas from the Netherlands.

Based on the current planning of the conversion from L-gas to H-gas, the transmission system connected at the Vreden interconnection point will be converted to H-gas in 2029.

For this reason, the Vreden interconnection point is recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Elten/Zevenaar interconnection point

The Elten/Zevenaar interconnection point is currently used to receive L-gas from the Netherlands.

After the conversion to H-gas of regions that are supplied with L-gas today, the connected transmission system should continue to be operated efficiently.

For this reason, the Elten/Zevenaar interconnection point is recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Tegelen interconnection point

The Tegelen interconnection point is used today to receive L-gas from the Netherlands. Only a minor, regional L-gas transmission system is connected at the Tegelen interconnection point.

An increase in the import capacity at the Tegelen interconnection point would therefore bring with it an immediate need for the expansion of the network of the connected regional transmission system and investments in the connection to other, onward transmission systems.

The transmission system operators favour the interconnection points connected to the trans-regional transmission system for receiving gas volumes.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Haanrade interconnection point

The Haanrade interconnection point is connected to the Dutch regional network and is currently used to receive L-gas from the Netherlands.

The downstream stand-alone network will be operated with L-gas until further notice. A conversion can also be carried out in this network area only when the L-to-H-gas conversion has been completed on the Dutch side. Based on the previous planning status, this will be the case only after 2030.

The transmission system operators favour the interconnection points connected to the trans-regional transmission system for receiving gas volumes.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Bocholtz-Vetschau interconnection point

The Bocholtz-Vetschau interconnection point is used to receive L-gas from the Netherlands.

Together with the Lichtenbusch interconnection point and the Broichweiden South market area interconnection point, it forms an entry grouping for the connecting pipeline system. The progress of the market area conversion produces additional sales potential on a regional basis and thus opportunities to increase the entry volumes.

For this reason, the Bocholtz-Vetschau interconnection point is recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Bocholtz interconnection point

The Bocholtz interconnection point is used today to receive L-gas from the Netherlands.

The H-gas import capacity currently pending at the Bocholtz interconnection point is planned in full.
An increase in the import capacity at the Bocholtz interconnection point would therefore bring with it an immediate need for the expansion of the northern TENP transmission system. Instead, the interconnection points that are still supplied with L-gas today will continue to be operated efficiently.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Belgium

Eynatten/Raeren/Lichtenbusch interconnection point

The Belgian transmission system is connected to the NCG market area at the Eynatten/Raeren/Lichtenbusch interconnection point and to the GASPOOL market area at the Eynatten interconnection point. These interconnection points are currently operated bidirectionally.

Gas volumes of up to 13 bcm/a, with additional potential of up to 20 bcm/a, can be provided by Fluxys SA from Belgium through the Eynatten interconnection point for the German market from the LNG plants in Zeebrugge and Dunkirk (France).

For this reason, the Eynatten/Raeren/Lichtenbusch interconnection point and the Eynatten interconnection point are recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Luxembourg

Remich interconnection point

The Luxembourg transmission system is connected to the NCG market area at the Remich interconnection point. The Remich interconnection point is purely an exit point for Luxembourg's supply.

Maintenance of the previous capacity is called for in the TYNDP 2018.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

7.2.5 Interconnection points to the south/south-east Europe region

France

Medelsheim interconnection point

The French transmission system is connected to the NCG market area at the Medelsheim interconnection point. The Medelsheim interconnection point is used today to transfer H-gas to France.

In accordance with the obligation to conduct demand-oriented management pursuant to Section 15(3) EnWG, the free allocable capacity exiting to France in Medelsheim is essentially in competition with the domestic demand for internal orders and intended for systemically important power plants in the region in question. The transmission system operators point out to the shippers that exit free allocable capacity that was offered at this point in the 2019 annual auction, but not booked, can potentially be shifted away from the Medelsheim point and the French-German VIP in the course of 2019 in order to satisfy internal orders.

With regard to a possible flow reversal at the interconnection point, GRTgaz SA France continues to describe the "Reverse capacity from France to Germany at Obergailbach" project in its Plan Decennal 2018–2027 with the necessary network expansions and incorporated it in the TYNDP 2018 (TRA-N-047). It is intended with this project to create the transfer of H-gas in the amount of 100 GWh/d from France to Germany at the Medelsheim interconnection point from 2023 onwards in order to maintain access to the Atlantic LNG terminals. A final investment decision on the French project has not yet been made.

For this reason, the Medelsheim interconnection point is recognised in the distribution of sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Switzerland

The Swiss transmission system is connected to the NCG market area at the Wallbach as well as the RC Thayngen-Fallentor and RC Basel interconnection points.

Wallbach interconnection point

The Swiss transmission system is connected to the NCG market area at the Wallbach interconnection point. The Wallbach interconnection point is used today to transfer H-gas to Switzerland and on to Italy.

The cross-border project of Snam Rete Gas and FluxSwiss to enable transmission flows from Italy via Switzerland in the direction of Germany and France was completed on the Italian and Swiss sides in 2018. The volumes intended for Germany totalling 10 GWh/h can be shipped away through the Wallbach interconnection point as a result of the TENP flow reversal project (ID 305-02) coming into operation.

For this reason, the Wallbach interconnection point is recognised in the distribution of H-gas sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

RC Basel interconnection point

The Swiss transmission system is connected to the NCG market area at the RC Basel interconnection point. The RC Basel interconnection point is purely an exit point for the urban district of Basel.

As this is a network used for shipping odorised gas and there is no adequate connection to Switzerland's transmission network, reversion is not provided for.

Injection volumes for Germany are not available at the RC Basel interconnection point.

RC Thayngen-Fallentor interconnection point

The Swiss transmission system is connected to the NCG market area at the RC Thayngen-Fallentor interconnection point. The RC Thayngen-Fallentor interconnection point is purely an exit point for eastern Switzerland.

As this is a network used for shipping odorised gas and there is no adequate connection to Switzerland's transmission network, reversion is not provided for.

Injection volumes for Germany are not available at the RC Thayngen-Fallentor interconnection point.

Austria

The Austrian gas networks are connected to the NCG market area at the RC Lindau, Pfronten, Kiefersfelden, Überackern, Überackern 2 and Oberkappel interconnection points.

Furthermore, the Haidach, 7Fields and Nussdorf-Zagling storage facilities at the USP Haidach and Haiming 3, Haiming 2-7F and Haiming 2-RAGES storage connection points are connected directly to the German transmission system. Furthermore, the 7Fields and Nussdorf-Zagling storage facilities at the Austrian Überackern 7Fields storage connection point are connected directly to the German transmission system through Penta West at Überackern.

RC Lindau interconnection point

The Austrian transmission system is connected to the NCG market area at the RC Lindau interconnection point. The RC Lindau interconnection point is purely an exit point for supplying Vorarlberg, Liechtenstein and Graubünden.

These regions have no adequate connection with other transmission systems.

Injection volumes for Germany are not available at the RC Lindau interconnection point.

Pfronten interconnection point

The Austrian distribution area of the Tirol market area is connected to the NCG market area at the Pfronten interconnection point. The Pfronten interconnection point is purely an exit point to a distribution system operator in the Tirol market area in Austria. This distribution region has no connection with other networks.

The Kiefersfelden (bayernets) and Pfronten interconnection points are consolidated by bayernets into the Kiefersfelden-Pfronten exit zone.

Injection volumes for Germany are not available at the Pfronten interconnection point.

Kiefersfelden interconnection point

The Austrian distribution area of the Tirol market area is connected to the NCG market area at Kiefersfelden through the Kiefersfelden (bayernets) interconnection point and the Kiefersfelden/Kufstein (OGE) interconnection point. The Kiefersfelden (bayernets) and Pfronten interconnection points are consolidated by bayernets into the Kiefersfelden-Pfronten exit zone. OGE markets capacity at this point using the designation “Kiefersfelden-Kufstein”.

The Kiefersfelden interconnection point is purely an exit point to a distribution system operator in the Tirol market area in Austria. This distribution network has no connection with other transmission systems.

Injection volumes for Germany are not available at the Kiefersfelden interconnection point.

Überackern interconnection point

The Austrian transmission system is connected to the NCG market area at the Überackern interconnection point. bayernets and OGE market capacity at this point using the designation "Überackern'.

The Überackern interconnection point is currently operated bidirectionally.

In the coordinated network development plan KNEP 2019–2028 [KNEP 2018], Gas Connect Austria (GCA) continues to show technical exit capacity (exit Austria/entry Germany) at the Überackern interconnection point of around 7.3 GWh/h, with no changes from the KNEP 2016.

For this reason, the Überackern interconnection point is recognised in the distribution of H-gas sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Überackern 2 interconnection point

The Austrian transmission system is connected to the NCG market area at the Überackern 2 (bayernets) interconnection point. The Überackern interconnection point is currently operated bidirectionally.

In the KNEP 2017–2026 [KNEP 2016], GCA reports additional demand for free allocable capacity (exit Germany/entry Austria) of 250,000 Nm^3/h (around 2,800 MWh/h) at the Überackern 2 (Überackern-SÜDAL) interconnection point. The auction of incremental capacity at the Überackern 2 interconnection point carried out for the first on a Europe-wide basis by GCA in accordance with the requirements of the network code for capacity allocation mechanisms shows that, according to GCA, there is apparently no demand at the moment for access to the Austrian virtual trading point. Feedback from market participants indicate that there is interest in incremental capacity between the Überackern 2 und Oberkappel entry and exit points. Gas Connect Austria GmbH (GCA) has therefore incorporated a corresponding project under the project name "GCA 2018/01 Überackern – Oberkappel" in the Coordinated Network Development plan 2019–2028 [KNEP 2018] in order to increase the technical capacity at the Überackern 2 (Überackern-SÜDAL) entry/exit point and at the Oberkappel entry/exit point and to cover additional capacity demand between these two points.

In the KNEP 2019–2028 [KNEP 2018], Gas Connect Austria continues to show technical entry capacity (exit Germany/entry Austria) at the Überackern 2 interconnection point of around 4.75 GWh/h. bayernets reports technical exit capacity (conditional allocable capacity exit Germany/entry Austria) of 9.0 GWh/h. In the KNEP 2019–2028 [KNEP 2018], GCA continues to show technical exit capacity (exit Austria/entry Germany) at the Überackern 2 interconnection point of around 7.3 GWh/h, with no changes from the KNEP 2016.

For this reason, the Überackern 2 interconnection point is recognised in the distribution of H-gas sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Oberkappel interconnection point

The Oberkappel interconnection point is currently operated bidirectionally.

In accordance with the distribution of sources (cf. Chapter 7.2.3) less the substitution volumes for the Ukraine transit, around 15 bcm/a is additionally available in the south/south-east region from the TAP (TRA-F-051, TRA-N-1193) pipeline projects and the transit volumes of Nord Stream 2 (TRA-F-937).

For this reason, the Oberkappel interconnection point is recognised in the distribution of H-gas sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Czech Republic

The Czech transmission system is connected to the NCG market area at the Waidhaus interconnection point and to the GASPOOL market area at the Brandov-STEGAL, Olbernhau II and Deutschneudorf interconnection points. Moreover, the new Deutschneudorf-EUGAL interconnection point is planned, which, based on the current planning, is scheduled to come into operation at the end of 2019.

Waidhaus interconnection point

The Waidhaus interconnection point is used today to receive H-gas from the Czech Republic.

In accordance with the distribution of sources (cf. Chapter 7.2.3) less the substitution volumes for the Ukraine transit, around 15 bcm/a is additionally available in the south/south-east region from the TAP (TRA-F-051, TRA-N-1193) pipeline projects and the transit volumes of Nord Stream 2 (TRA-F-937).

For this reason, the Waidhaus interconnection point is recognised in the distribution of H-gas sources and the amount of the capacity to be taken over is reviewed in the course of the production of the H-gas balance for the Gas NDP 2020–2030.

Brandov-STEGAL interconnection point

The Brandov-STEGAL interconnection point is used today to receive H-gas from the Czech Republic.

No entry capacity is envisaged in the TYNDP 2018, as the Polish regulatory authority has not yet issued approval for competing entry capacity between the Brandov-STEGAL interconnection point and the Mallnow interconnection point.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Olbernhau II interconnection point

The Olbernhau II interconnection point is used to transfer H-gas to the Czech Republic.

Injection volumes for Germany are not available at the Olbernhau II interconnection point.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Deutschneudorf interconnection point

The Deutschneudorf interconnection point is operated bidirectionally.

Expansion measures are still not planned from the south/south-east region.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Deutschneudorf-EUGAL interconnection point

The Deutschneudorf-EUGAL interconnection point is intended to be used for the transfer of H-gas from the Russian Nord Stream 2 export system (TRA-F-937) via EUGAL to the Czech Republic.

Injection volumes for Germany are not available at the Deutschneudorf-EUGAL interconnection point.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

7.2.6 Interconnection points with the north-east Europe region

Poland

The Polish YAMAL VTP market area is connected to the GASPOOL market area at the Mallnow interconnection point, while the Polish E-Gas market area is connected at the GCP GAZ-SYSTEM/ONTRAS interconnection point.

GCP GAZ-SYSTEM/ONTRAS interconnection point

The GCP GAZ-SYSTEM/ONTRAS interconnection point is operated bidirectionally.

The further development of the transmission capacity in the east-west direction with the goal of establishing the GCP GAZ-SYSTEM/ONTRAS interconnection point in the medium term as an additional physical H-gas source for Germany continues to be the focus of the ONTRAS and GAZ-SYSTEM system operators.

No additional injection volumes are taken into consideration in the distribution of H-gas sources.

Mallnow interconnection point

The Mallnow interconnection point is currently operated bidirectionally.

Maintenance of the previous injection volumes is provided for in the TYNDP 2018.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Russian Federation

The Russian Nord Stream export system is connected to the GASPOOL market area at the Greifswald interconnection point. The new Lubmin II interconnection point is additionally provided for, which, according to current planning, is scheduled to come into operation at the end of 2019. The Russian Nord Stream 2 export system will also be connected to the GASPOOL market area through Lubmin II.

Greifswald interconnection point

The Greifswald interconnection point is used to receive H-gas from Nord Stream.

The booked entry capacity is taken into consideration in accordance with the NDP gas database in the course of the modelling of the Gas NDP 2020–2030.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Lubmin II interconnection point

The Lubmin II interconnection point is set up to receive H-gas from Nord Stream 2 (TRA-F-937).

The booked entry capacity in the 2017 annual auction is taken into consideration in accordance with the NDP gas database in the course of the modelling of the Gas NDP 2020–2030.

No additional injection volumes are therefore taken into consideration in the distribution of H-gas sources.

Denmark

Ellund interconnection point

The Danish transmission system is connected to the NCG market area and the GASPOOL market area at the Ellund interconnection point. This interconnection point is operated bidirectionally.

DanisH-gas production in the North Sea supplied the market in Denmark and Sweden in the past, with exports going to Germany and, via an offshore pipeline, to the Netherlands. DanisH-gas production has been in decline for several years. The largest gas field in the Danish North Sea is the Tyra field, which has delivered the major contribution to DanisH-gas production since 1984. The offshore production facilities of the Tyra field, which constitute the most
important hub for gas production and processing in the Danish North Sea, will be taken out of operation in the period from September 2019 to July 2022 according to ENERGINET. The infrastructure for the future production from the Tyra field is intended to be completely replaced in this period [ENERGINET 2019a].

As a result of the temporary discontinuation of the Denmark's own production, exports to Denmark at the Ellund interconnection point will represent the key contribution to Denmark's supply in the period under review in the Gas NDP 2020–2030. ENERGINET coordinates closely with GUD and OGE. Based on the
assessment by ENERGINET, Denmark's supply is guaranteed through the existing capacity in Ellund and the use of the Danish storage facilities during the Tyra shutdown. Furthermore, the construction of the Baltic Pipe (TRA-N-271, TRA-N-780) is set to create a new connection between Norway, Denmark and Poland. Imports of gas for Denmark should be possible from January 2022 onwards [ENERGINET 2019b].

In the peak load scenarios, no gas flow from Denmark to Germany is recognised and no additional injection volumes from Denmark are taken into consideration in the distribution of sources.

7.3 Virtual interconnection points (VIPs)

In accordance with Article 19(9) of Regulation (EU) 2017/459 (NC CAM), the transmission system operators are required to set up virtual interconnection points at the market area borders, where shippers can book capacity without having to refer to the availability of capacity at the physical border and market area interconnection points of different transmission system operators. Because of the large number of uncertainties and vaguely defined requirements for the implementation in the NC CAM, not all VIPs are currently in operation yet.

An overview of the VIPs already established as well as those still to be set up is presented in Table 24.

Table 24: Overview of the VIPs for Germany

VIP	Associated IP	TSO	Competent TSO	ITSO	Start
VIP-TTF-NCG-H	Bocholtz (Fluxys TENP), Oude Statenzijl (OGE), Bocholtz (OGE), Bocholtz-Vetschau (TG)	OGE, Fluxys TENP, TG	OGE	GTS	1 January 2020 or 1 February 2020
VIP-TTF-NCG-L	Elten (OGE), Vreden (OGE), Tegelen (OGE), Zevenaar (TG)	OGE, TG	TG	GTS	1 January 2020 or 1 February 2020
VIP-TTF-GASPOOL-H	Bunde (GASCADE), OUDE STATENZIJL H (GUD)	GASCADE, GUD	GUD	GTS	1 January 2020 or 1 February 2020
VIP-TTF-GASPOOL-L	Oude Statenzijl L-Gas (GTG NORD), OUDE STATENZIJL L (GUD)	GTG Nord, GUD	GUD	GTS	1 January 2020 or 1 February 2020
VIP Belgium-NCG	Eynatten/Raeren (Fluxys TENP), Eynatten (TG), Eynatten/Raeren (OGE)	OGE, Fluxys TENP, TG	OGE	Fluxys Belgium	1 July 2019
VIP France-Germany	Medelsheim (GRTD), Medelsheim (OGE)	GRTD, OGE	GRTD	GRTgaz France	1 March 2019
VIP Germany-CH	Wallbach (Fluxys TENP), Wallbach (OGE)	Fluxys TENP, OGE	Fluxys TENP	FluxySwiss, SwissGas	1 July 2019
VIP Oberkappel	Oberkappel (OGE), Oberkappel (GRTD)	OGE, GRTD	OGE	GCA	1 March 2019
VIP Waidhaus NCG	Waidhaus (GRTD), Waidhaus (OGE)	OGE, GRTD	OGE	Net4Gas	1 March 2019
VIP Brandov-GASPOOL	Deutschneudorf (ONTRAS), Olbernhau II, Brandov-STEGAL (alL-GASCADE), Brandov (OGT)	GASCADE, ONTRAS, OGT	GASCADE	Net4Gas	1 November 2018
VIP L GASPOOL-NCG	Zone OGE (L), Ahlten, Steinbrink	Nowega, GUD	Nowega	OGE	1 November 2018
VIP L GASPOOL-NCG	Zone GUD (L), Ahlten, Steinbrink	OGE	OGE	Nowega, GUD	1 November 2018
GCP GAZ-SYSTEM/ONTRAS	GCP GAZ-SYSTEM/ONTRAS (ONTRAS)	ONTRAS	ONTRAS	GAZ-System	1 April 2016
Denmark after market area merger		OGE, GUD			
Norway: no VIP envisaged		OGE, TG, GUD			
No VIP Belgium-GASPOOL: Eynatten (GASCADE) is the only GASPOOL-Belgium connection		GASCADE			
Russia: no VIP envisaged		Fluxys D, NEL, OPAL, Lub-min-Brandov, GUD, GASCADE, ONTRAS			

Source: Transmission system operators

It must be noted in the context of the imminent market area merger on 1 October 2021 that the some of the VIPs already established at the market area interconnection points of GASPOOL and NCG will have to be regarded as obsolete when the combined market area comes into effect and all bookings at these points will cease to apply from 1 October 2021 onwards. This essentially concerns the L-GASPOOL-NCG VIP. Consultations are currently still in progress concerning the relevant details relating to the implementation.

The transmission system operators therefore show VIP capacity for the first time in the scenario framework for the Gas NDP 2020–2030. The existing VIPs are mapped in the NDP gas database as of the reporting date of 6 May 2019.

7.4 Development of capacity demand at the Wallbach interconnection point in the direction of Switzerland and Italy

This chapter summarises the most recent developments concerning the exit capacity demand at the interconnection point in Wallbach and presents the key elements of a joint analysis conducted by the transmission system operators Snam Rete Gas, Swissgas, FluxSwiss, Transitgas, Fluxys TENP and OGE.

Summary of the most recent development in the exit demand at the Wallbach interconnection point

As a consequence of the temporary shutdown of TENP I, one of the two natural gas pipelines of the two-way pipeline system from Bocholtz on the German-Dutch border to Wallbach on the German-Swiss border, on account of corrosion damage, the transmission system operators have modelled a security of supply variant, which is included in the Gas NDP 2018–2028 and which has been confirmed by the BNetzA.

The projects included in this variant are intended to provide the following capacity, which was already an element in the Gas NDP 2018–2028, from the end of 2024 onwards:

- The capacity taken into account totalling 5.2 GWh/h along the TENP to supply Baden Wuerttemberg;
- 13.3 GWh/h at the Wallbach interconnection point to supply Italy and Switzerland

In order to identify the exit capacity required at the Wallbach interconnection point to ensure the security of the supply for Italy and Switzerland, the transmission system operators had started by conducting an analysis of historical data for the period from 1 October 2013 to 1 October 2017 and on this basis determined a necessary exit capacity at the Wallbach interconnection point of 13.3 GWh/h.

On 18 January 2019, the German Federal Network Agency (BNetzA), the Swiss Federal Office of Energy, the Swiss Federal Department of the Environment, Transport, Energy and Communications, the Italian Ministry of Economic Development and the Italian regulatory authority ARERA sent a letter to the transmission system operators Snam Rete Gas, Swissgas, FluxSwiss, Transitgas, Fluxys TENP and OGE requesting a joint review of the level of the necessary exit capacity in Wallbach. The aim here is to determine in close cooperation between the parties involved whether the exit capacity of 13.3 GWh/h taken into consideration is sufficient in terms of the security of supply of Switzerland and Italy. If this investigation finds that the capacity currently taken into account in Wallbach is not sufficient, the transmission system operators involved would be instructed to add the additional capacity to the scenario framework for the Gas NDP 2020–2030.

Results of the working group of the transmission system operators relating to the necessary exit capacity at the Wallbach interconnection point

The extensive analysis of the different, future supply scenarios for Italy and Switzerland produced by the working group of the transmission system operators (Snam Rete Gas, Swissgas, FluxSwiss, Transitgas, Fluxys TENP, OGE) resulted in a capacity demand of -8.4 GWh/h (south-north flow) to 22.3 GWh/h (north-south flow) at the Wallbach exit point. The result of this analysis and the recommendation of the working group to raise the exit capacity at Wallbach to 16.2 GWh/h in the future have been submitted to the BNetzA. In order to meet the demands of the BNetzA, the Swiss Federal Office of Energy, the Swiss Federal Department of the Environment, Transport, Energy and Communications, the Italian Ministry of Economic Development and the Italian regulatory authority ARERA, the transmission system operators Fluxys TENP and OGE therefore propose including the required exit capacity of 16.2 GWh/h in this scenario framework for the Gas NDP 2020–2030 and in the NDP gas database (cf. Annexe 3). In the opinion of Fluxys TENP and OGE, this exit capacity adjustment is a correction based on additional information of the capacity demand in Wallbach, calculated in spring 2018 as part of the security of supply variant, necessary to maintain security of supply in Italy and Switzerland.

7.5 Development of capacity demand at the Oude Statenzijl interconnection point in the direction of the Netherlands

As a result of the decline in L-gas production in the Netherlands and the accelerated market area conversion, the Dutch transport network operator GTS approached GUD with the request to examine increased H-gas capacity in the direction of the Netherlands. In cooperation with ENTSOG, GTS calculated various scenarios that consider the decommissioning of the Grijpskerk storage facility in 2021 and the accelerated market area conversion. This identified a supply bottleneck on the Dutch side. The additional H-gas is needed both to be able to provide sufficient capacity for Dutch H-gas consumers and to operate conversion facilities.

Security of supply 8

8 Security of supply

In line with Section 15a(1) EnWG, assumptions concerning the impact of conceivable disruptions to supply are made in the scenario framework.

- The transmission system operators modelled the failure of the largest gas import point (H-gas) and a reduction in domestic production (L-gas) in the 2012 Gas NDP.
- The strained gas supply situation in the first half of February 2012 was analysed in the 2013 Gas NDP. The results of these investigations into these supply disruptions were also taken into account in the modelling for the 2014 Gas NDP.
- How the reduced L-gas availability, taking into account the progress of the market area conversion planning, is handled up to 2030 was presented in the 2014 and 2015 Gas NDPs.
- In the Gas NDP 2016–2026, the detailed conversion planning up to 2030 was continued and fleshed out and the Germany-wide availability of H-gas needs was examined, and both of these were presented in a detailed H-gas balance up to 2030.
- The transmission system operators looked in depth at several security of supply scenarios in the Gas NDP 2018–2028. On the one hand, the security of supply scenario – Development of the L-gas supply – was fleshed out and detailed in greater depth. On the other the security of supply scenario – Development of the H-gas supply – was investigated using an up-to-date, detailed H-gas capacity balance up to 2030 and the additional demand identified in the energy balance was allocated to the identified interconnection points in accordance with the distribution of H-gas sources.
  Furthermore, the transmission system operators have presented the TENP security of supply variant, which investigates the effects of any limited availability of the transport capacity of the TENP system that may persist over a longer term.

In its prevention and emergency plans for gas, the BMWi will carry out a risk assessment in accordance with Article 7 of the Regulation (EU) 2017/1938 (security of supply regulation) for Germany in cooperation with the BNetzA and with the support of the gas industry. In addition to the national analysis, this risk assessment also includes for the first time a regional analysis, which has to be carried out within the relevant risk groups in accordance with Annex 1 of the security of supply regulation[3]. The risk report derived from the assessment on the consequences of potential disruptions in the gas infrastructure both for the supply situation in Germany and within the risk groups was notified to the EU Commission in October 2018. The prevention and emergency plans will subsequently be published and submitted to the EU Commission, which will send an opinion, including possible recommendations for changes, to the BMWi within four months; the relevant recommendations for changes are not obligatory here. The BMWi has to furnish comprehensive reasons for not taking these recommendations into consideration, however.

The German Federal Ministry for Economic Affairs and Energy published the updated monitoring report – Security of supply in natural gas – in accordance with Section 51 EnWG in February 2019 [BNetzA/BKartA Monitoring Report 2019]. In summary, it is stated among other things:

“The results of the report allow the conclusion that the security of supply concept in Germany has proven its worth. The gas supply companies have guaranteed in the past and in the reporting period – even following changes in the general conditions – a high standard of security of supply up to now, with the result that the supply of gas in Germany has previously always been ensured. In the light of the dependence on imports, the differentiation of the market roles played by the companies, the long lead times until a project is completed and the high capital intensity of the investments in the gas sector, further developments have to be carefully monitored and analysed.”

Against this background, there is no need in the opinion of the transmission system operators for the Gas NDP 2020–2030 to model a hypothetical disruption to supply. Rather, the transmission system operators see the necessity of further fleshing out and detailing the in-depth conversion plans up to 2030 on account of the future reduction in the availability of L-gas for the German market. Furthermore, the Germany-wide availability of H-gas needs to be examined in the Gas NDP 2020–2030 and presented in an up-to-date H-gas balance up to 2030. The available injection volumes from storage facilities and at interconnection points are considered in more detail here among other things.

[3] Germany is a member of the “Eastern gas supply” and “North Sea gas supply” risk groups.

8.1 Development of the L-gas supply

The development of the L-gas supply and of the L-to-H-gas conversion is described in this chapter in terms of the security of supply issue. Following a short description of the current situation (cf. Chapter 8.1.1), the situation involving gas imports from the Netherlands (cf. Chapter 8.1.2) and then domestic production (cf. Chapter 8.1.3) will be addressed. Finally, an outlook on the planned procedure in the Gas NDP 2020–2030 is given (cf. Chapter 8.1.4).

8.1.1 Description of the situation

Part of the German gas market is supplied with low calorific value natural gas (L-gas). While the high calorific value natural gas (H-gas) comes to Germany essentially from Norway, Russia and through LNG terminals, the L-gas consumed in Germany originates exclusively from the Netherlands and Germany itself. The two different groups of natural gas quality must be shipped in separate networks for technical and calibration reasons. The market area with overlapping qualities ensure, however, that every customer can be supplied with energy, irrespective of the gas quality, in terms of the energy balance – in physical terms, however, the gas composition limits have to be complied with.

L-gas production in Germany is in continual decline. The remaining German L-gas reserves should continue to be extracted if possible and can be injected into the natural gas transmission network. L-gas production in the Netherlands is also in decline and subject to restrictions on account of earthquakes that are seen in connection with production. A continual decrease in natural gas exports from the Netherlands to Germany will result from this from October 2020 onwards. For this reason, the German transmission system operators take part in regular exchanges with the Dutch transmission system operator Gasunie Transport Services B.V. (GTS) on harmonising and updating the planning assumptions for future L-gas imports.

These developments have significant impact in relation to both the annual volumes available in Germany and the available capacity. The transmission system operators therefore developed at an early stage a concept for converting the areas supplied with L-gas to H-gas and started on its implementation. The conversion will require consumer appliances to be modified, among other things.

8.1.2 Situation involving gas imports from the Netherlands

The last few years have seen an increase in the number of earthquakes in the area around the Groningen field, which are regarded as being linked to the extraction of natural gas. On 8 January 2018, an earthquake registering 3.4 on the Richter scale shook the Groningen region. This earthquake led to a heightened political discussion in the Netherlands about production in the Groningen field.

In order to take the risks arising from natural gas production into consideration, the Dutch Ministry of Economic Affairs and Climate Policy announced in March 2018 that the production of natural gas in the Groningen area will be ended completely by 2030 at the latest. As an interim target, the production volume is to be limited to 12 billion m^3 in the 2022/2023 gas year at the latest [RVO 2018a].

The Dutch Ministry of Economic Affairs and Climate Policy set a production volume of 19.4 billion m^3 for the current 2018/2019 gas year. [RVO 2018b]. A reduced production volume of 15.9 billion m^3 is targeted for the coming 2019/20 gas year. The reduction is compensated by expanded conversion from H-gas to L-gas in the Netherlands, by the reduced demand for imports in Germany based on the 2019 implementation report in comparison with the Gas NDP 2018 and additionally by the planned inclusion of the mixing plant of GTG Nord [Rijksoverheid 2019].

The expansion of the Dutch conversion facilities, which are planned to come into operation by April 2022, will make a significant contribution compensating for the further reduction in production in Groningen. Furthermore, it is planned to convert major industrial customers (annual consumption of more than 100 million m^3 per industrial customer) in the Netherlands to H-gas, which will also play a part in further reducing production in Groningen.

The reduction of the Groningen production and the resulting rise in the planned conversion from H to L-gas as well as the accelerated switching of industrial customers to H-gas is significantly increasing the demand for H-gas in the Netherlands. GTS has launched a process for assessing the security of supply taking the growth in demand into consideration.

Despite the reductions in the production volume that have already been decided, another powerful earthquake measuring 3.4 on the Richter scale hit at around 6 o'clock in the morning of 22 May 2019.

Both the Staatstoezicht Op De Mijnen (SodM – Dutch State Supervision of Mines) and the producer at the Groningen field (NAM) have published their initial opinions on the new earthquake. Both assessments assert that, although the reductions in production already lessened the probability of a major earthquake, they are not able to "rule out" the possibility of any earthquakes. The SodM therefore also recommends a further reduction in production as early as the 2019/2020 gas year.

It cannot be predicted at the moment (7 June 2019) whether and, as the case may be, to what extent the new earthquake will impact the L-gas volumes and capacity available for Germany.

The transmission system operators maintain close contacts with GTS in this connection and also in order to coordinate the relevant plans in the Netherlands and Germany. GTS and the German transmission system operators will continue the coordination meetings on a regular basis in order to guarantee harmonised planning assumptions also in the future.

8.1.3 Domestic production

The BVEG sent its current forecast for domestic production to the transmission system operators in May 2019. Minor changes were made to the previous forecast values from 2018 in the updated publication (cf. Table 25).

The development of production capacity presented in the table below is based on the data from the BVEG. The production capacities have been furnished with a safety margin by the BVEG.

Table 25: Capacity forecast in accordance with BVEG

Year	Elbe-Weser region with safety margin according to BVEG 2019	Weser-Ems region with safety margin according to BVEG 2019	Sum of both regions with safety margin according to BVEG 2019	Sum of both regions with safety margin according to BVEG 2019	Sum of both regions with safety margin according to BVEG 2018	Difference between BVEG 2019 and BVEG 2018
	Million m³/h			GWh/h	GWh/h	
2019	0.31	0.38	0.69	6.8	6.8	0.0
2020	0.29	0.35	0.63	6.2	6.3	−0.2
2021	0.26	0.37	0.63	6.1	6.3	−0.1
2022	0.25	0.33	0.58	5.7	5.8	−0.1
2023	0.24	0.29	0.53	5.2	5.2	0.0
2024	0.22	0.28	0.49	4.8	4.6	0.2
2025	0.20	0.25	0.45	4.4	4.1	0.3
2026	0.18	0.22	0.40	3.9	3.7	0.2
2027	0.16	0.19	0.35	3.4	3.3	0.1
2028	0.14	0.16	0.30	3.0	3.0	0.0
2029	0.13	0.14	0.27	2.7	2.7	0.0
2030	0.11	0.13	0.24	2.3	---	---

Source: Transmission system operators on the basis of BVEG 2019, BVEG 2018

The transmission system operators will review and take the current BVEG forecast into consideration. The capacities previously assumed for the injection volume have been adjusted slightly. The plans resulting from that are taken into consideration in the Gas NDP 2020–2030 here.

At the end of the formal review period in 2030, the possibility of diverting L-gas production volumes will continue to exist only in the Nowega network. At the same time, the security of supply will have to be ensured using the sources that will then still be available (domestic production, Empelde underground gas storage facility, Rehden conversion facility). The transmission system operators are developing a forecast for this particular situation for the period after 2030 up to the completion of the market area conversion process on the end customer side and will present the possibilities for diverting any domestic production available at that time and provide market participants with an early and transparent opportunity to join the consultation on this special issue.

Both in terms of the network planning and from the regulatory perspective, this will result in new duties for guaranteeing adequate entry capacity and volumes in L-gas over the long term.

8.1.4 Outlook for the Gas NDP 2020–2030

The transmission system operators set out to present the following points in the Gas NDP 2020–2030:

- Determine and present the output and volume balance of the coming years for L-gas in due consideration of local factors up to 2030
- Further develop the conversion planning introduced in the 2019 implementation report and the overview of all L-gas conversion areas
- Adjust the conversion areas in order to achieve optimal utilisation of the resources
- Consider the available up-to-date detailed plans of the distribution system operators
- Consider of the number of gas appliances to be modified per year
- Identify specific expansion measures to secure supply
- Continue the coordination to convert storage facilities
- Consider the remaining L-gas market as well as the structuring instruments required

The current L-to-H-gas conversion process is presented in the Gas NDP 2020–2030. The reporting date for coordination of the conversion projects between the distribution and transmission system operators is 1 October 2019. It will be possible to take conversion amendments received after 1 October 2019 into consideration only in the 2021 implementation report.

8.2 Development of the H-gas supply

The transmission system operators see a need to continue also to examine the availability of H-gas alongside the reduced L-gas availability up to 2030.

Hydrogen and synthetic methane will also be taken into consideration as green gases in the next Gas NDP 2020–2030. The requirements resulting for gas infrastructure from the implementation of the energy transition and the phase-out of fossil fuel are adopted by the transmission system operators and investigated in the course of the development of the H-gas supply.

The following points that will exert a considerable influence on the supply of H-gas will additionally be presented in the Gas NDP 2020–2030:

- Discussion of the consideration of the entry capacities (interconnection points, storage facilities, conversion, production)
  - Key assumptions here are that interconnection points are taken into consideration in principle as part of the technical capacity and that seasonal employment can be assumed for storage facilities, where retrieval is assumed in the peak load case.
- Breakdown of the exit capacity by groups with particular requirements (power plants, industry, distribution system operators, interconnection points)
- Determination and presentation of the H-gas capacity balance up to 2030
- Determination of additional demand on the basis of the H-gas capacity balance
- Allocation of the additional demand as well as discussion on the procedure for the allocation based on the distribution of H-gas sources (cf. Chapter 7.2) to individual interconnection points

8.3 Disruptions

The transmission system operators have conducted detailed investigations into historical disruptions in the 2013 to 2018–2028 Gas NDPs. It has regularly been stated here that historical disruptions can at most serve as an indication for more in-depth investigations of the future trends at the interconnection points in question. Viewed in isolation, historical disruptions do not represent a basis for an expansion decision. The trends in future disruptions are very difficult to assess on account of measures that are already under construction and regulatory changes, such as the introduction of VIPs and, in particular, the market area merger.

The transmission system operators furthermore see major additional expense for the preparation of the network development plan, which results from the discussion on the capacity model as part of the market area merger.

Against this background, the transmission system operators dispense with an assessment of the historical disruptions.

Modelling 9

9 Modelling and modelling variants

In this chapter the transmission system operators put forward modelling variants for the Gas NDP 2020–2030. Chapter 9.1 provides an overview of the modelling variants envisaged. The modelling variants are subsequently described in Chapter 9.2. Chapter 9.3 describes the consideration of hydrogen and synthetic methane in modelling. The base network criteria that the transmission system operators envisage for including measures from the Gas NDP 2018–2028 in the base network for the modelling of the Gas NDP 2020–2030 are described in Chapter 9.4.

9.1 Overview of the modelling variants

This scenario framework forms the basis for the creation of the Gas NDP 2020–2030. The transmission system operators propose a network modelling variant (base variant). Furthermore, the security of supply scenarios in L-gas and H-gas up to 2030 are updated.

As a result of the statutory requirements in the selection of the modelling variants to be calculated for the Gas NDP 2020–2030, the transmission system operators face the challenge of mapping key future developments on the one hand and, on the other, of limiting themselves in the calculations to a scope of work that is feasible in the given time frame. Modelling load flow scenarios and determining the expansion demand triggered as a result is a highly complex, laborious and time-consuming procedure. The first modelling in the combined market area increases the complexity and the coordination work between the transmission system operators.

Against this background, the transmission system operators envisage the following selection and specification for the modelling in the Gas NDP 2020–2030 (cf. Table 26).

Table 26: Modelling variants in the scenario framework for the Gas NDP 2020–2030

<table>
<tr><th>Modelling variant</th><th>Base variant 2025</th><th>Base variant 2030</th><th>L-gas balance 2030</th><th>H-gas balance 2030</th></tr>
<tr><td>Designation</td><td>B.2025</td><td>B.2030</td><td>L.2030</td><td>H.2030</td></tr>
<tr><td>Calculation</td><td>complete 2025</td><td>complete 2030</td><td colspan="2">Balance analysis</td></tr>
<tr><td>Reporting date/period</td><td>31 December 2025</td><td>31 December 2030</td><td colspan="2">1 October 2030</td></tr>
<tr><td>Distribution system operators (internal orders)</td><td colspan="2">Start value: Internal orders 2020, development: the 10-year forecast of the DSOs up to and including 2025, the plausibility of which has been verified, constant updates thereafter</td><td rowspan="12">Analysis of the long-term L-gas balances up to 2030</td><td rowspan="12">Analysis of the long-term H-gas output balance up to 2030</td></tr>
<tr><td>H-gas sources</td><td colspan="2">Additional demand by distribution of H-gas sources in accordance with Chapter 7.2 of the scenario framework</td></tr>
<tr><td>IP/VIP</td><td colspan="2">Inventory according to “2020 – SF consultation” database cycle, need for expansion in line with Chapter 7 of the scenario framework in due consideration of the TYNDP</td></tr>
<tr><td>Use of MBIs</td><td colspan="2">Use of commercial instruments for planning purposes</td></tr>
<tr><td>Market area interconnection points</td><td colspan="2">Discontinuation of market area interconnection points with effect from October 2021 on account of the market area merger</td></tr>
<tr><td>L-to-H-gas conversion</td><td colspan="2">Modelling of the conversion areas, including conversions up to 2031 in order to identify the necessary network expansions measures up to 31 December 2030</td></tr>
<tr><td>Underground gas storage facilities</td><td colspan="2">Inventory according to “2020 – SF consultation” database cycle, new build in accordance with Chapter 2.3.2: 100 % temperature-dependent capacity</td></tr>
<tr><td>Power plants</td><td colspan="2">Inventory according to “2020 – SF consultation” database cycle, currently on interruptible basis directly connected systemically important power plants in accordance with Chapter 2.2.1, new build in accordance with Chapter 2.2.2, 100% firm dynamically allocable capacity (fDZK)</td></tr>
<tr><td>LNG</td><td colspan="2">New build in line with “2020 – SF consultation” database cycle, see also Chapter 2.4.3</td></tr>
<tr><td>Industry</td><td colspan="2">Constant capacity demand, consideration of the binding additional demand, free allocable capacity approach</td></tr>
<tr><td>Biomethane</td><td colspan="2">According to “2020 – SF consultation” database cycle</td></tr>
<tr><td>Hydrogen and synthetic methane</td><td>Consideration of the hydrogen projects for which specific implementation intentions, including project data, are available</td><td>Consideration of FfE study and market surveys on hydrogen and synthetic methane</td></tr>
</table>

Source: Transmission system operators

9.2 Explanation of the base variant for the modelling of the Gas NDP 2020–2030

- Full calculation for 2025 and 2030
- The cut-off date for the calculation of the network expansion measures is 31 December of the year in question.
- Capacity demand of the distribution network operators:
  With its decision of 11 December 2015 on the confirmation of the scenario framework for the Gas NDP 2016–2026, operative provision 6a, the BNetzA defined the consideration of the capacity demand of the distribution system operators as obligatory. The transmission system operators therefore provide for an appropriate consideration for the scenario framework for the Gas NDP 2020–2030. With the decision of the BNetzA, the direct reference to a gas demand scenario of the scenario framework is dispensed with. The political requirements recognised there and in particular here the climate protection targets are thus not taken into full consideration.

> Start value: internal orders for 2020; development in line with the verified 10-year forecast of the distribution system operators in accordance with Section 16 of the cooperation agreement up to and including 2025, constant updating thereafter

  For the verification of plausibility, the transmission system operators apply the following procedure:

  > If the forecast value for 2025 is higher than the order value for 2020, a verifiable justification by the distribution system operator is required for this. The premises of the long-term forecast (assumed sectoral trends, including verifiable justifications) that are indicated by the distribution system operators in Part B of the form for the internal order are used by the transmission system operators to verify the plausibility. If justifications are not provided or cannot be verified, the transmission system operator will contact the distribution system operator in accordance with Section 16(3) of Cooperation Agreement X in order to develop a coordinated forecast. Should a joint assessment of the capacity demand not be produced, it may be necessary to consult the BNetzA.

  > In all other cases, the forecasts of the distribution system operators up to 2025 are taken over into the modelling without any changes being made to them.

- Gas exchange with neighbouring countries at the interconnection points and H-gas sources:
  > Existing capacity according to NDP gas database cycle “2020 – SF consultation”

  > Analysis of the additional import demand for Europe on the basis of the TYNDP 2018 taking into account the Nord Stream II and TAP pipeline projects and assuming uniform utilisation rates for new and existing LNG plants (only FID projects). Building on this, a percentage distribution is made to the three regions (cf. Chapter 7.2).

  > Distribution of the additional demand based on distribution of H-gas sources to cross border interconnection points

- Market area interconnection points:
  The market interconnection points are expected to be discontinued from October 2021 on account of the market area merger.

- Underground gas storage facilities:
  > Consideration of existing storage facilities according to “2020 – SF consultation” database cycle

  > Consideration of new storage facilities and storage facility expansions in accordance with Chapter 2.3.2 with 100% of the requested capacity as firm temperature-dependent capacity

- Power plants:
  > Consideration of existing power plants according to “2020 – SF consultation” database cycle

  > Consideration of new power plants in accordance with Chapter 2.2.2, taking the criteria into account with 100% firm dynamically allocable capacity

  > Consideration of systemically important power plants on the network of the transmission system operators in accordance with Chapter 2.2.1

- LNG facilities:
  > Consideration in accordance with Chapter 2.4 in application of the criteria

- Industry:
  > Updating of the existing capacity (constant capacity demand)

  > Consideration of the binding additional demand requested by industrial customers if the request has been received by the transmission system operators by 15 July 2019

- Biomethane:
  - Biomethane generation is recognised in accordance with the previous network development plans. New requests, arising among other things from the market survey of green gas projects, may possibly be taken into consideration after their plausibility has been verified by the transmission system operators.
- Hydrogen and synthetic methane (cf. Chapter 9.3):
  - For the 2025 calculation year, the green gas projects for which there are concrete implementation plans may be taken into consideration after their plausibility has been verified by the transmission system operators.
    In this connection, green gas projects can be reported for the scenario framework for the Gas NDP 2020–2030 by companies and project managers up to and including 12 July 2019. In due consideration of the FfE study and market surveys on hydrogen and synthetic methane, 7.5 GW_e is recognised in 2030. The PtG generation capacity is differentiated by hydrogen and synthetic methane here.
- L-gas balance 2030:
  - Analysis of the long-term L-gas balances up to 2030, cf. Chapter 8.1
- H-gas balance 2030:
  - Analysis of the long-term H-gas output balance up to 2030, cf. Chapter 8.2

9.3 Consideration of hydrogen and synthetic methane in the modelling

The development path for PtG plants in Germany assumed in this scenario framework is described below in Chapter 9.3.1. Chapter 9.3.2 explains the planned procedure for taking hydrogen and synthetic methane into consideration in the Gas NDP 2020–2030.

9.3.1 Development path for PtG facilities in Germany up to 2030

A dynamic development for PtG plants up to 2030 results in Germany. The expansion path for PtG facilities has been developed on the basis of available studies [dena 2018, DLR 2015, Energy Brainpool/Greenpeace Energy 2017, Frontier 2017, Moser 2017, UBA 2010, UBA 2017] and using the assumptions concerning current technical availability and the potential for innovation of PtG plants.

Depending on the relevant design and objective of the studies providing the basis, it can be established that the forecast PtG capacity for 2050 lies between 40 GW_e and 254 GW_e. Target values of up to 16 GW_e are given for 2030. It can be established in principle that, irrespective of the design of the study in question, the development of PtG plants has to be carried out on a large technical scale in the short term. A capacity of 7.5 GW_e, which is categorised in the middle of the range of the available studies, is assumed for the development path. On the basis of the current development status of PtG plants, it is assumed in the Gas NDP 2020–2030 that installed PtG capacity of 1.5 GW_e in total will be possible by 2025. With the knowledge gained and thus the cost reduction achieved from this first expansion and development phase, a further average expansion of 1.2 GW_e per year up to 2030 is taken as a basis, which corresponds to total capacity of 7.5 GW_e in 2030.

9.3.2 Basic procedure

Additional builds of PtG plants of up to 7.5 GW_e (cf. Chapter 9.3.1) in total generation capacity is modelled up to 2030 for the scenario framework. Input values are formed by projects with concrete implementation plans based on the market partner survey of green gas projects, the results of the study by the Forschungsstelle für Energiewirtschaft, the TSO infrastructure and its expected use as well as the confirmed scenario framework for the Electricity Network Development Plan 2019–2030 [BNetzA 2018]. Only PtG projects with concrete implementation plans as well as TSO infrastructure and its expected use are taken into consideration for 2025 in the modelling. All the above-mentioned input values are included in the modelling for 2030.

The differentiation of the PtG generation capacity into hydrogen and synthetic methane up to 2025 is based on the project-specific implementation details. Endogenous influencing factors will be taken into consideration from 2025 onwards.

The transmission system operators intend to take hydrogen and synthetic methane into consideration as follows:

Modelling year 2025

- Existing facilities: existing facilities for the injection of green gases will continue to be taken into consideration.
- Projects with concrete implementation plans from the market partner survey: the projects planned to be implemented by 2025 (cf. Chapter 2.5) are taken into consideration after they have been reviewed and their plausibility has been verified.

Modelling year 2030

- Existing facilities: existing facilities for the injection of green gases will continue to be taken into consideration.
- Projects with concrete implementation plans from the market partner survey: the projects planned to be implemented by 2030 (cf. Chapter 2.5) are taken into consideration after they have been reviewed and their plausibility has been verified.
- FfE study and electricity network development plan: to achieve up to 7.5 GW_e PtG generation capacity in 2030, other potential generation locations are identified on the basis of the FfE study and of the confirmed scenario framework for the Electricity Network Development Plan 2019–2030 [BNetzA 2018] in addition to the two points specified above. The following factors are taken into consideration here: using the hydrogen consumption centres (cf. Figure 7) and taking into account the TSO infrastructure in these core regions, potential generation capacity for hydrogen is identified by means of the requirements. In the next step, a comparison is carried out with the potential PtG locations (cf. Figure 13) in 2030 and the TSO gas infrastructure. Clusters for hydrogen generation are produced from this data. PtG production locations that cannot be associated with consumption centres are taken into consideration in terms of their usefulness for the network and based on demand as injection points for hydrogen and for synthetic methane.

9.4 Criteria for including measures from the Gas NDP 2018–2028 in the base network for the modelling of the Gas NDP 2020–2030

The base network forms the basis for the modelling of the transmission systems for identifying the network expansion demand that is additionally required.

The base network defined for the modelling of the transmission systems comprises the current stock of the transmission system, measures put into operation set against the previous gas network development plans and set against the previous implementation reports as well as measures currently under construction.

Furthermore, the transmission system operators intend, in the same way as the previous procedure, to include other selected measures from the previous gas network development plans in the base network. The following unchanged criteria of the Gas NDP 2018–2028 are to be used as of the reporting date of 1 January 2020 for the selection of additional measures for the base network of Gas NDP 2020–2030.

- The final investment decision (FID) by the transmission system operators has been taken and
- the approvals under public law and private law that are required for the measure are available.

The measures included in the base network are treated in the network simulation in the same way as already existing pipelines and plants of the existing network. Measures included in the base network can thus no longer be the result of the modelling. They are thus in fact given the status of the existing network.

Appendices

Appendix 1: NDP gas database

The transmission system operators have updated the database for the scenario framework for the Gas NDP 2020–2030 and provide this for the public at http://www.nep-gas-datenbank.de.

The database contains the following information for the cycle of the scenario framework for the Gas NDP 2020–2030 (name of the cycle in the NDP gas database: "2020 – SF consultation"):

- Capacities (cross border interconnection points/VIPs, storage facilities, power plants, LNG facilities, industry, production, biomethane/hydrogen)

The capacities as of 1 January of the year in question are presented in the NDP gas database. Thus the capacities as at 1 January 2030 are shown for 2030, for example. Expansion measures for 2025 are identified in the modelling for the Gas NDP 2020–2030, some of which can only be completed at the end of 2025 (implementation periods of up to six years). For reasons of consistency, 31 December 2030 is therefore also used as the basis for the 2030 modelling year. It is therefore planned to estimate the capacities for 1 January 2030 in the modelling.

The transmission system operators carried out various comparisons of capacity data, especially at interconnection points, in the previous scenario framework and network development plan cycles. These comparisons can no longer be carried out for the time being in the 2020 scenario framework and the Gas NDP 2020–2030. The capacities at the interconnection points have changed or can change in the course of the introduction of the virtual interconnection points (VIPs) and the market area merger. A comparison with the start value, the Gas NDP 2018–2028 and with the TYNDP 2018 is thus not meaningful, as the previous NDPs and TYNDPs did not yet map any capacity data on VIPs and on the market area merger.

The transmission system operators will add information on the green gas projects (biomethane, hydrogen, synthetic methane) from the market partner survey in the course of producing the draft scenario framework for the Gas NDP 2020–2030.

Appendix 2: List of gas power plants

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA0005	Ahrensfelde	Brandenburg	Administrative district of Barnim	1990	temporarily shut down (with notification of closure)	Natural gas	37.5		
BNA0006	Ahrensfelde	Brandenburg	Administrative district of Barnim	1990	temporarily shut down (with notification of closure)	Natural gas	37.5		
BNA0007	Ahrensfelde	Brandenburg	Administrative district of Barnim	1990	temporarily shut down (with notification of closure)	Natural gas	37.5		
BNA0008	Ahrensfelde	Brandenburg	Administrative district of Barnim	1990	temporarily shut down (with notification of closure)	Natural gas	37.5		
BNA0012b	Werkskraftwerk Sappi Alfeld	Lower Saxony	Administrative district of Hildesheim	1947	in operation	Natural gas	11.0		x
BNA0015	Heizkraftwerk Altbach/Deizisau	Baden-Wuerttemberg	Administrative district of Esslingen	1997	in operation	Natural gas	65.0	x	
BNA1103	UPM Augsburg	Bavaria	Urban district of Augsburg	1967	temporarily shut down (with notification of closure)	Natural gas	29.0		
BNA0033	Gasturbine	Bavaria	Urban district of Augsburg	2004	in operation	Natural gas	30.7		
BNA1507		Rhineland-Palatinate	Administrative district of Bad Kreuznach	2006	in operation	Natural gas	10.7		
BNA0051	KWK-Anlage Barby	Saxony-Anhalt	Administrative district of Salzlandkreis	1994	in operation	Natural gas	17.8		
BNA0059b	GuD Baunatal, VW Werksgelände	Hesse	Administrative district of Kassel	2011	in operation	Natural gas	78.0		
BNA1293c	Kraftwerk	North Rhine-Westphalia	Administrative district of Rhein-Erft-Kreis	1995	in operation	Natural gas	3.0		
BNA0073	Mitte	Berlin	Urban district of Berlin	1996	in operation	Natural gas	444.0		
BNA0075	Lichterfelde	Berlin	Urban district of Berlin	1972	in operation	Natural gas	144.0		x
BNA0088a	Industriekraftwerk Bernburg (IKB)	Saxony-Anhalt	Administrative district of Salzlandkreis	1994	in operation	Natural gas	140.5		
BNA0100	GuD Kraftwerk Hillegossen	North Rhine-Westphalia	Urban district of Bielefeld	2005	in operation	Natural gas	37.5		
BNA0105	GuD Bitterfeld	Saxony-Anhalt	Administrative district of Anhalt-Bitterfeld	2000	in operation	Natural gas	106.0		
BNA0111	HKW Hiltrop	North Rhine-Westphalia	Urban district of Bochum	2013	in operation	Natural gas	44.0		
BNA1524	Heizkraftwerk Bomlitz	Lower Saxony	Administrative district of Soltau-Fallingbostel	1969	in operation	Natural gas	15.6		x
BNA0129	HKW	Brandenburg	Urban district of Brandenburg an der Havel	1997	in operation	Natural gas	36.0		
BNA0130	Kirchmöser	Brandenburg	Urban district of Brandenburg an der Havel	1994	in operation	Natural gas	160.0		
BNA1334	KWK-Anlage	Free Hanseatic City of Bremen	Urban district of Bremen	1993/2002	in operation	Natural gas	14.8		
BNA1820	KW Mittelsbüren	Free Hanseatic City of Bremen	Urban district of Bremen	2016	in operation	Natural gas	444.5		
BNA1671		Free Hanseatic City of Bremen	Urban district of Bremerhaven	2014	in operation	Natural gas	17.1		
BNA1117	Industriekraftwerk Breuberg	Hesse	Administrative district of Odenwaldkreis	1999	in operation	Natural gas	11.4		
BNA0156b	Egger Kraftwerk Brilon	North Rhine-Westphalia	Administrative district of Hochsauerlandkreis	1996	in operation	Natural gas	13.5		
BNA0172a	Burghausen 01 – GT	Bavaria	Administrative district of Altötting	2001	in operation	Natural gas	120.0	x	
BNA0172b	Burghausen 01 – DT	Bavaria	Administrative district of Altötting	1979	in operation	Natural gas	50.0	x	x
BNA0174	Industriepark Werk Gendorf	Bavaria	Administrative district of Altötting	2002	in operation	Natural gas	73.1		
BNA1925	HKW Lusan	Thuringia	Urban district of Gera	2018	in operation	Natural gas	17.3		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construc-tion	Status according to the Federal Network Agency's list of power plants (up-dated 7 March 2019)	Energy source	Net output in MW_e	Systemi-cally im-portant	CHP re-placement by 2030
BNA1926	HKW Tinz	Thuringia	Urban district of Gera	2018	in operation	Natural gas	22.1		
BNA1487	GTKW Darmstadt	Hesse	Urban district of Darmstadt	2013	closure prevented by law	Natural gas	94.6	x	
BNA1873	KWK Dingolfing BA 1	Bavaria	Administrative district of Dingolfing-Landau	2017	in operation	Natural gas	16.0		
BNA0199	Dormagen	North Rhine-Westphalia	Administrative district of Rhein-Kreis Neuss	2000	in operation	Natural gas	586.0		
BNA0202	Dortmund	North Rhine-Westphalia	Urban district of Dortmund	2004	in operation	Natural gas	26.0		
BNA1911	HKW Dresden-Nord	Saxony	Urban district of Dresden	2018	in operation	Natural gas	11.5		
BNA1131	MT, Düren	North Rhine-Westphalia	Administrative district of Düren	1940	in operation	Natural gas	14.0		x
BNA0220	GuD	North Rhine-Westphalia	Urban district of Düsseldorf	2000	in operation	Natural gas	100.0		
BNA0221a	GT	North Rhine-Westphalia	Urban district of Düsseldorf	1975	in operation	Natural gas	64.7		
BNA0221b	GT	North Rhine-Westphalia	Urban district of Düsseldorf	1974	in operation	Natural gas	66.7		
BNA1503	BHKW H.120	North Rhine-Westphalia	Urban district of Düsseldorf	2012	in operation	Natural gas	21.1		
BNA1817	GuD	North Rhine-Westphalia	Urban district of Düsseldorf	2016	in operation	Natural gas	595.0		
BNA0232c	Werkskraftwerk Sappi Ehingen	Baden-Wuerttemberg	Administrative district of Alb-Donau-Kreis	1977	in operation	Natural gas	4.0		x
BNA0239	Huntorf	Lower Saxony	Administrative district of Wesermarsch	1978	in operation	Natural gas	321.0		
BNA0243	HKW Eltmann	Bavaria	Administrative district of Hassberge	2007	in operation	Natural gas	57.0	x	
BNA0245a	Emden Gas	Lower Saxony	Urban district of Emden	1973	in operation	Natural gas	52.0		
BNA0245b	Emden Gas	Lower Saxony	Urban district of Emden	1973	temporarily shut down (without notification of closure)	Natural gas	433.0		
BNA0255	HKW Iderhoffstrasse	Thuringia	Urban district of Erfurt	1996	in operation	Natural gas	11.0		
BNA0256a	HKW Erfurt-Ost	Thuringia	Urban district of Erfurt	1999	in operation	Natural gas	76.5		
BNA0256b	HKW Erfurt-Ost	Thuringia	Urban district of Erfurt	2014	in operation	Natural gas	32.6		
BNA1138	BHKW an Klink-erweg	North Rhine-Westphalia	Administrative district of Mettmann	2000	in operation	Natural gas	10.2		
BNA0261a	HKW Erlangen	Bavaria	Urban district of Erlangen	2005	in operation	Natural gas	21.6		
BNA0261c	HKW Erlangen	Bavaria	Urban district of Erlangen	2014	in operation	Natural gas	6.7		
BNA1023	Weisweiler	North Rhine-Westphalia	Administrative district of Region Aachen	2006	in operation	Natural gas	200.0		
BNA1024	Weisweiler	North Rhine-Westphalia	Administrative district of Region Aachen	2006	in operation	Natural gas	200.0		
BNA1819	Heizkraftwerk FL	Schleswig-Holstein	Urban district of Flensburg	2016	in operation	Natural gas	78.0		
BNA0285	HKW Niederrad	Hesse	Urban district of Frankfurt am Main	2004	in operation	Natural gas	70.0	x	
BNA0286	HKW West	Hesse	Urban district of Frankfurt am Main	1994	in operation	Natural gas	99.0	x	
BNA1541	HKW Freiberg	Saxony	Administrative district of Mittelsachsen	2013	in operation	Natural gas	13.4		
BNA0293	GuD Anlage WVK	Baden-Wuerttemberg	Urban district of Freiburg im Breisgau	1998	in operation	Natural gas	40.0	x	
BNA1492a	Kraftwerk 3	Hesse	Administrative district of Fulda	2012	in operation	Natural gas	26.2		
BNA1492b	Kraftwerk 2	Hesse	Administrative district of Fulda	1982	in operation	Natural gas	7.5		
BNA0343	Heizkraftwerk Gera-Nord	Thuringia	Urban district of Gera	1996	temporarily shut down (with notification of closure)	Natural gas	74.0		
BNA0360	HKW "Helmshäger Berg"	Mecklenburg-Vorpommern	Administrative district of Vorpommern-Greifswald	1996	in operation	Natural gas	14.7		
BNA0361	Kraftwerk Gren-zach-Wyhlen	Baden-Wuerttemberg	Administrative district of Lörrach	2017	in operation	Natural gas	30.0		
BNA0374	Staudinger	Hesse	Administrative district of Main-Kinzig-Kreis	1977	closure prevented by law	Natural gas	572.0	x	
BNA0386	Energiezentrum Mohn Media	North Rhine-Westphalia	Administrative district of Gütersloh	1994	in operation	Natural gas	25.0		
BNA0389	Heizkraftwerk Hagen-Kabel	North Rhine-Westphalia	Urban district of Hagen	1980	temporarily shut down (with notification of closure)	Natural gas	230.0		
BNA0392a	HKW Halle Trotha	Saxony-Anhalt	Urban district of Halle (Saale)	2005	in operation	Natural gas	97.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA0392b	HKW Halle Trotha	Saxony-Anhalt	Urban district of Halle (Saale)	2013	in operation	Natural gas	56.1		
BNA0400	GuD Tiefstack	Free and Hanseatic City of Hamburg	Urban district of Hamburg	2009	in operation	Natural gas	127.0		
BNA0401	Heizkraftwerk	Free and Hanseatic City of Hamburg	Urban district of Hamburg	1993	in operation	Natural gas	22.5		
BNA0410	Trianel Gaskraftwerk	North Rhine-Westphalia	Urban district of Hamm	2008	in operation	Natural gas	417.1		
BNA0411	Trianel Gaskraftwerk	North Rhine-Westphalia	Urban district of Hamm	2008	in operation	Natural gas	420.9		
BNA0418	GKL	Lower Saxony	Administrative district of Region Hanover	1998	in operation	Natural gas	230.0		
BNA0419	KWH	Lower Saxony	Administrative district of Region Hanover	1975	temporarily shut down (with notification of closure)	Natural gas	102.0		
BNA1810		Lower Saxony	Administrative district of Region Hanover	2014	in operation	Natural gas	30.2		
BNA1151	KWKK Heidelberg	Baden-Wuerttemberg	Urban district of Heidelberg	2001	in operation	Natural gas	13.5		
BNA1292b	IHKW Heidenheim	Baden-Wuerttemberg	Administrative district of Heidenheim	2014	in operation	Natural gas	18.9		
BNA0442	Cuno Heizkraftwerk Herdecke	North Rhine-Westphalia	Administrative district of Ennepe-Ruhr-Kreis	2007	in operation	Natural gas	417.0		
BNA0444	Wintershall	Hesse	Administrative district of Hersfeld-Rotenburg	2009	in operation	Natural gas	69.0		
BNA1463		Lower Saxony	Administrative district of Osterode am Harz	1978	in operation	Natural gas	19.5		x
BNA1499	Werk Clauen	Lower Saxony	Administrative district of Peine	2003	special case	Natural gas	15.8		
BNA0548a	Knapsack Gas I	North Rhine-Westphalia	Administrative district of Rhein-Erft-Kreis	2006	in operation	Natural gas	800.0		
BNA0548b	Knapsack Gas II	North Rhine-Westphalia	Urban district of Cologne	2013	in operation	Natural gas	430.0		
BNA0499	Heizkraftwerk	Hesse	Urban district of Frankfurt/Main	2003	in operation	Natural gas	86.0	x	
BNA0497	ADS-Anlage	Hesse	Urban district of Frankfurt/Main	2012	in operation	Natural gas	96.5	x	
BNA0514	Rheinhafen-Dampfkraftwerk	Baden-Wuerttemberg	Urban district of Karlsruhe	1998	closure prevented by law	Natural gas	353.0	x	
BNA0521	Kombi-HKW	Hesse	Urban district of Kassel	1988	in operation	Natural gas	50.0		
BNA1528		North Rhine-Westphalia	Administrative district of Viersen	1990	in operation	Natural gas	13.2		
BNA0527	HKW Humboldtstr.	Schleswig-Holstein	Urban district of Kiel	2005	in operation	Natural gas	21.5		
BNA1506	Werk Klein Wanzleben	Saxony-Anhalt	Administrative district of Börde	1994	Special case	Natural gas	23.4		
BNA0545	HKW Niehl 2	North Rhine-Westphalia	Urban district of Cologne	2005	in operation	Natural gas	413.0		
BNA0546	HKW Merkenich	North Rhine-Westphalia	Urban district of Cologne	2004	in operation	Natural gas	108.0		
BNA1182	HKW Merkenich	North Rhine-Westphalia	Urban district of Cologne	2010	in operation	Natural gas	15.5		
BNA1183	HKW Merheim	North Rhine-Westphalia	Urban district of Cologne	2001	in operation	Natural gas	15.8		
BNA1818	Niehl 3	North Rhine-Westphalia	Urban district of Cologne	2016	in operation	Natural gas	459.9		
BNA0556a	KWK-Anlage Krefeld DT	North Rhine-Westphalia	Urban district of Krefeld	1999	in operation	Natural gas	25.8		
BNA0556b	KWK-Anlage Krefeld VM	North Rhine-Westphalia	Urban district of Krefeld	1999	in operation	Natural gas	14.0		
BNA1502	Heizkraftwerk Krefeld	North Rhine-Westphalia	Urban district of Krefeld	2011	in operation	Natural gas	12.6		
BNA1450	GUD-Anlage DREWSEN	Lower Saxony	Administrative district of Celle	2000	in operation	Natural gas	13.0		
BNA0574a	Landesbergen Gas	Lower Saxony	Administrative district of Nienburg (Weser)	1973	in operation	Natural gas	56.0		
BNA0574b	Landesbergen Gas	Lower Saxony	Administrative district of Nienburg (Weser)	1973	temporarily shut down (with notification of closure)	Natural gas	431.0		
BNA1658	HKW-Mitte	North Rhine-Westphalia	Administrative district of Lippe	1980	in operation	Natural gas	11.3		x

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construc-tion	Status according to the Federal Network Agency's list of power plants (up-dated 7 March 2019)	Energy source	Net output in MW_e	Systemi-cally im-portant	CHP re-placement by 2030
BNA1193	HKW-West	North Rhine-Westphalia	Administrative district of Lippe	2001	in operation	Natural gas	12.8		
BNA1556		Saxony	Administrative district of Bautzen	2014	in operation	Natural gas	36.0		
BNA0592	GuD Leuna	Saxony-Anhalt	Administrative district of Saalekreis	1998	in operation	Natural gas	39.0		
BNA0593	ILK-GuD	Saxony-Anhalt	Administrative district of Saalekreis	1994	in operation	Natural gas	35.0		
BNA0594	ILK-GuD	Saxony-Anhalt	Administrative district of Saalekreis	1994	in operation	Natural gas	35.0		
BNA0595	ILK-GuD	Saxony-Anhalt	Administrative district of Saalekreis	1994	in operation	Natural gas	37.0		
BNA0600a	X-Kraftwerk	North Rhine-Westphalia	Urban district of Lever-kusen		in operation	Natural gas	27.0		x
BNA0602	Emsland	Lower Saxony	Administrative district of Emsland	1974	in operation	Natural gas	116.0		x
BNA0603	Emsland	Lower Saxony	Administrative district of Emsland	1973	in operation	Natural gas	116.0		x
BNA0604	Emsland	Lower Saxony	Administrative district of Emsland	1973	in operation	Natural gas	359.0		x
BNA0605	Emsland	Lower Saxony	Administrative district of Emsland	1974	in operation	Natural gas	359.0		x
BNA0606	Emsland	Lower Saxony	Administrative district of Emsland	2010	in operation	Natural gas	887.0		
BNA1509	BP Werk Lingen	Lower Saxony	Administrative district of Emsland	1996	in operation	Natural gas	66.0		
BNA1531	Industriekraftwerk Greifswald	Mecklenburg-Vorpommern	Administrative district of Vorpommern-Greifswald	2013	in operation	Natural gas	38.0		
BNA0614a	KW Mitte	Rhineland-Palatinate	Urban district of Ludwigshafen am Rhein	1992	in operation	Natural gas	47.0		
BNA0615	Kraftwerk Süd	Rhineland-Palatinate	Urban district of Ludwigshafen am Rhein	1997	in operation	Natural gas	410.0	x	
BNA0614b	Kraftwerk Mitte	Rhineland-Palatinate	Urban district of Ludwigshafen am Rhein	2005	in operation	Natural gas	497.5	x	
BNA1196a	BHKW Lud-wigshafen	Rhineland-Palatinate	Urban district of Ludwigshafen am Rhein	2008	in operation	Natural gas	12.5		
BNA1196b	Industriekraftwerk Ludwigshafen	Rhineland-Palatinate	Urban district of Ludwigshafen am Rhein	2003	in operation	Natural gas	12.0		
BNA0626	Kraftwerk Mainz	Rhineland-Palatinate	Urban district of Mainz	2000	in operation	Natural gas	434.2	x	
BNA0627	Kraftwerk Mainz	Rhineland-Palatinate	Urban district of Mainz	1976	closure prevented by law	Natural gas	335.0	x	x
BNA0658	Kraftwerk III	North Rhine-Westphalia	Administrative district of Recklinghausen	1973	in operation	Natural gas	61.1		x
BNA0659	Kraftwerk III	North Rhine-Westphalia	Administrative district of Recklinghausen	1974	in operation	Natural gas	77.6		x
BNA1676	Kraftwerk IV	North Rhine-Westphalia	Administrative district of Recklinghausen	2016	in operation	Natural gas	60.8		
BNA1523a	Gemeinschafts-kraftwerk Weig	Rhineland-Palatinate	Administrative district of Mayen-Koblenz	1992	in operation	Natural gas	11.4		
BNA1523b	Gemeinschafts-kraftwerk Weig	Rhineland-Palatinate	Administrative district of Mayen-Koblenz	2013	in operation	Natural gas	27.4		
BNA1523d	Gemeinschafts-kraftwerk Weig	Rhineland-Palatinate	Administrative district of Mayen-Koblenz	1971	temporarily shut down (without notifi-cation of closure)	Natural gas	8.4		
BNA1396	EVC/ GLOBALFOUND-RIES	Saxony	Administrative district of Meissen	1998	in operation	Natural gas	34.3		
BNA1866		Saxony	Administrative district of Meissen	2005	in operation	Natural gas	33.9		
BNA0683a	Süd DT1	Bavaria	Urban district of Munich	1980	in operation	Natural gas	79.7	x	x
BNA0683b	Süd GT3	Bavaria	Urban district of Munich	1980	in operation	Natural gas	97.9	x	x
BNA0683c	Süd GT2	Bavaria	Urban district of Munich	1980	in operation	Natural gas	97.9	x	x
BNA0684a	Süd GT 61	Bavaria	Urban district of Munich	2004	in operation	Natural gas	124.9	x	
BNA0684b	Süd GT 62	Bavaria	Urban district of Munich	2004	in operation	Natural gas	123.9	x	
BNA0684c	Süd DT60	Bavaria	Urban district of Munich	2004	in operation	Natural gas	127.6	x	
BNA1327a	Energiezentrale 1992	Bavaria	Administrative district of Freising	1992	special case	Natural gas	9.5		
BNA1327b	Erweiterung Energiezentrale 2003 (expansion)	Bavaria	Administrative district of Freising	2003	in operation	Natural gas	7.4		
BNA1678	Energiezentrale 2016	Bavaria	Administrative district of Freising	2014	in operation	Natural gas	16.8		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA1406	FS-Karton	North Rhine-Westphalia	Administrative district of Rhein-Kreis Neuss	1992	in operation	Natural gas	18.9		
BNA0702	Cogeneration	Bavaria	Administrative district of Kelheim	1996	Special case	Natural gas	25.4		
BNA1498	Werk Nordstemmen	Lower Saxony	Administrative district of Hildesheim	1953	Special case	Natural gas	30.6		x
BNA1402	Heizkraftwerk zur Papierfabrik	Lower Saxony	Administrative district of Osnabrück	1996	in operation	Natural gas	18.1		
BNA0734	Thyrow	Brandenburg	Administrative district of Teltow-Fläming	1989	closure prevented by law	Natural gas	37.5		
BNA0738	Thyrow	Brandenburg	Administrative district of Teltow-Fläming	1987	closure prevented by law	Natural gas	36.5		
BNA0739	Thyrow	Brandenburg	Administrative district of Teltow-Fläming	1987	closure prevented by law	Natural gas	36.5		
BNA0740	Thyrow	Brandenburg	Administrative district of Teltow-Fläming	1987	closure prevented by law	Natural gas	36.5		
BNA0741	Thyrow	Brandenburg	Administrative district of Teltow-Fläming	1987	closure prevented by law	Natural gas	36.5		
BNA0742	HKW Sandreuth	Bavaria	Urban district of Nuremberg	2005	in operation	Natural gas	75.0	x	
BNA0743	HKW Sandreuth	Bavaria	Urban district of Nuremberg	2005	in operation	Natural gas	75.0	x	
BNA1444a	GT1	Bavaria	Urban district of Nuremberg	1993	in operation	Natural gas	4.2		
BNA1444b	GT2	Bavaria	Urban district of Nuremberg	1993	in operation	Natural gas	4.2		
BNA1444c	GT3	Bavaria	Urban district of Nuremberg	1994	in operation	Natural gas	5.1		
BNA1444d	GT4	Bavaria	Urban district of Nuremberg	1995	in operation	Natural gas	5.1		
BNA0752	HKW 1	North Rhine-Westphalia	Urban district of Oberhausen	1971	in operation	Natural gas	23.1		x
BNA0753	HKW 2	North Rhine-Westphalia	Urban district of Oberhausen	1996	in operation	Natural gas	24.5		
BNA0755a	Obernburg	Bavaria	Administrative district of Miltenberg	1920	in operation	Natural gas	36.0		x
BNA0755b	Obernburg	Bavaria	Administrative district of Miltenberg	1995	in operation	Natural gas	64.0	x	
BNA1516	HKW 1 Werk Offstein	Rhineland-Palatinate	Administrative district of Bad Dürkheim	1961	in operation	Natural gas	30.0		x
BNA0804a	Hattorf	Hesse	Administrative district of Hersfeld-Rotenburg	2013	in operation	Natural gas	35.0		
BNA0804b	Hattorf	Hesse	Administrative district of Hersfeld-Rotenburg	2013	in operation	Natural gas	17.0		
BNA0805	Kraftwerk Plattling	Bavaria	Administrative district of Deggendorf	2010	in operation	Natural gas	118.5	x	
BNA0814	HKW Potsdam-Süd	Brandenburg	Urban district of Potsdam	1996	in operation	Natural gas	81.8		
BNA1328	HBB	Bavaria	Administrative district of Rosenheim	2001	in operation	Natural gas	24.0		
BNA1861	Regensburg	Bavaria	Administrative district of Regensburg	2012	in operation	Natural gas	10.6		
BNA1862	Regensburg	Bavaria	Administrative district of Regensburg	2016	in operation	Natural gas	2.7		
BNA1238	Kraftwerk Meggle	Bavaria	Administrative district of Rosenheim	2000	in operation	Natural gas	15.1		
BNA0832	BHKW-Hauffstrasse	Baden-Wuerttemberg	Administrative district of Reutlingen	2011	in operation	Natural gas	9.8		
BNA1408	Heizkraftwerk Evonik Rheinfelden	Baden-Wuerttemberg	Administrative district of Lörrach	1979	in operation	Natural gas	15.7		
BNA0842a	Gasmotoren	Bavaria	Urban district of Rosenheim	2011	in operation	Natural gas	9.8		
BNA0842b	Gasmotor 4	Bavaria	Urban district of Rosenheim	2013	in operation	Natural gas	9.2		
BNA0843	Gasmotor 5	Bavaria	Urban district of Rosenheim	2012	in operation	Natural gas	4.3		
BNA0848	GuD Marienehe	Mecklenburg-Vorpommern	Administrative district of Rostock	1996	in operation	Natural gas	108.0		
BNA0857	GuD-Anlage Rüsselsheim	Hesse	Administrative district of Gross-Gerau	1999	in operation	Natural gas	112.1	x	
BNA1464	Gas- u. Dampfturbinenanlage Südraum	Saarland	Saarbrücken regional association	2012	in operation	Natural gas	38.6		
BNA1859	Ford Saarlouis	Saarland	Administrative district of Saarlouis	2016	in operation	Natural gas	22.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA1248a	UPM Schongau	Bavaria	Administrative district of Weilheim-Schongau	1954	closure prevented by law	Natural gas	64.0	x	x
BNA1248b	HKW3 UPM Schongau	Bavaria	Administrative district of Weilheim-Schongau	2014	in operation	Natural gas	76.0	x	
BNA1260	Heizkraftwerk Sindelfingen	Baden-Wuerttemberg	Administrative district of Böblingen	2013	in operation	Natural gas	95.0	x	
BNA1863	Gasturbinen- HKW St. Wendel	Saarland	Administrative district of St. Wendel	2014	in operation	Natural gas	19.5		
BNA0918b	Dow Stade	Lower Saxony	Administrative district of Stade	2015	in operation	Natural gas	157.0		
BNA1437	KWK AOS GmbH	Lower Saxony	Administrative district of Stade	2012	in operation	Natural gas	30.7		
BNA0922	GuD-Ikw Stassfurt	Saxony-Anhalt	Administrative district of Salzlandkreis	2015	in operation	Natural gas	100.0		
BNA1403	Steinitz	Saxony-Anhalt	Administrative district of Altmarkkreis Salzwedel	1999	in operation	Natural gas	11.4		
BNA0957	BHKW Obere Viehweide	Baden-Wuerttemberg	Administrative district of Tübingen	2000	in operation	Natural gas	13.4		
BNA1271	Unterbreizbach	Thuringia	Administrative district of Wartburgkreis	1995	in operation	Natural gas	20.0		
BNA1335a	PKV Kraftwerk	Lower Saxony	Administrative district of Friesland	1989	in operation	Natural gas	58.1		
BNA1335b	PKV Kraftwerk	Lower Saxony	Administrative district of Friesland	1968	in operation	Natural gas	0.5		x
BNA0994	Gemeinschaftskraftwerk Irsching	Bavaria	Administrative district of Pfaffenhofen a.d.Ilm	2010	closure prevented by law	Natural gas	846.0	x	
BNA0995	Ulrich Hartmann (Irsching)	Bavaria	Administrative district of Pfaffenhofen a.d.Ilm	2011	closure prevented by law	Natural gas	561.0	x	
BNA1407	STW	Saxony	Administrative district of Mittelsachsen	1997	in operation	Natural gas	19.1		
BNA1042	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	in operation	Natural gas	55.0		
BNA1039	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	in operation	Natural gas	55.0		
BNA1040	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	in operation	Natural gas	55.0		
BNA1043	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	temporarily shut down (with notification of closure)	Natural gas	355.0		
BNA1044	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	temporarily shut down (with notification of closure)	Natural gas	355.0		
BNA1045	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1973	in operation	Natural gas	355.0		
BNA1046b	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna	1984	in operation	Natural gas	112.0		
BNA1056	Wi-Biebrich	Hesse	Urban district of Wiesbaden	2006	in operation	Natural gas	25.0		
BNA1465d	Gaskraftwerk	Hesse	Administrative district of Werra-Meissner-Kreis	1990	special case	Natural gas	13.2		
BNA1504	BHKW	Rhineland-Palatinate	Administrative district of Germersheim	2013	in operation	Natural gas	13.0		
BNA1074	Spitzenlastkraftwerk Wolfen	Saxony-Anhalt	Administrative district of Anhalt-Bitterfeld	1997	in operation	Natural gas	40.0		
BNA1677	BHKW Braunschweig	Lower Saxony	Urban district of Wolfsburg	2014	in operation	Natural gas	10.4		
BNA1284	Co-Generation	Rhineland-Palatinate	Urban district of Worms	1991	in operation	Natural gas	11.5		
BNA1285	Sigmundshall	Lower Saxony	Administrative district of Region Hanover	1974	in operation	Natural gas	11.0		x
BNA1082	HKW Barmen	North Rhine-Westphalia	Urban district of Wuppertal	2005	mothballed for the summer season	Natural gas	82.0		
BNA1085	Heizkraftwerke an der Friedensbrücke	Bavaria	Urban district of Würzburg	1971	in operation	Natural gas	23.0	x	x
BNA1086	Heizkraftwerke an der Friedensbrücke	Bavaria	Urban district of Würzburg	1993	in operation	Natural gas	25.0	x	
BNA1087	Heizkraftwerke an der Friedensbrücke	Bavaria	Urban district of Würzburg	2009	in operation	Natural gas	29.5	x	
BNA1088	Heizkraftwerke an der Friedensbrücke	Bavaria	Urban district of Würzburg	2005	in operation	Natural gas	44.5	x	

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA1089	Zielitz	Saxony-Anhalt	Administrative district of Börde	1996	in operation	Natural gas	27.0		
BNA1097	Kohlekraftwerk	North Rhine-Westphalia	Administrative district of Rhein-Sieg-Kreis	1964	in operation	Natural gas	19.5		x
BNA1094	Gaskraftwerk	North Rhine-Westphalia	Administrative district of Rhein-Sieg-Kreis	1996	in operation	Natural gas	15.1		
BNA1557		Saxony	Administrative district of Zwickau	2014	in operation	Natural gas	12.9		
BNA1909	HKW 3 Stuttgart-Gaisburg	Baden-Wuerttemberg	Urban district of Stuttgart	2018	in operation	Natural gas	29.2		
BNA1927	GM	Thuringia	Administrative district of Wartburgkreis	2018	in operation	Natural gas	10.0		
BNA1934	KWK Landshut	Bavaria	Administrative district of Landshut		in operation	Natural gas	17.6		
	KWK-Anlagen				in operation	Natural gas	3,328.2		
BNA1337a	Heizkraftwerk	Bavaria	Urban district of Aschaffenburg		finally closed in 2012 (without notification of closure)	Natural gas	27.0		
BNA0118	Heizkraftwerk Süd	North Rhine-Westphalia	Urban district of Bonn		finally closed in 2012 (without notification of closure)	Natural gas	14.4		
BNA0913	GuD Anlage Spreetal	Saxony	Administrative district of Bautzen		finally closed in 2012 (without notification of closure)	Natural gas	50.0		
BNA0059a	HKW Kassel	Hesse	Administrative district of Kassel		finally closed in 2013 (without notification of closure)	Natural gas	12.2		
BNA0933	Heizkraftwerk Stuttgart-Gaisburg	Baden-Wuerttemberg	Urban district of Stuttgart		finally closed in 2014 (without notification of closure)	Natural gas	55.0		
BNA0099	Gasturbinenkraftwerk Bielefeld Ummeln	North Rhine-Westphalia	Urban district of Bielefeld		finally closed in 2015 (with notification of closure)	Natural gas	55.0		
BNA0681	Freimann GT 1	Bavaria	Urban district of Munich		finally closed in 2015 (without notification of closure)	Natural gas	80.0		
BNA0682	Freimann GT 2	Bavaria	Urban district of Munich		finally closed in 2015 (without notification of closure)	Natural gas	80.0		
BNA0922a	GuD-Ikw Stassfurt	Saxony-Anhalt	Administrative district of Salzlandkreis		finally closed in 2015 (without notification of closure)	Natural gas	9.0		
BNA0080	Lichterfelde	Berlin	Urban district of Berlin		finally closed in 2016 (without notification of closure)	Natural gas	144.0		
BNA0735	Thyrow	Brandenburg	Administrative district of Teltow-Fläming		finally closed in 2016 (without notification of closure)	Natural gas	37.5		
BNA0736	Thyrow	Brandenburg	Administrative district of Teltow-Fläming		finally closed in 2016 (without notification of closure)	Natural gas	37.5		
BNA0737	Thyrow	Brandenburg	Administrative district of Teltow-Fläming		finally closed in 2016 (without notification of closure)	Natural gas	37.5		
BNA0140	KW Hastedt	Free Hanseatic City of Bremen	Urban district of Bremen		finally closed in 2016 (without notification of closure)	Natural gas	155.0		
BNA1127	GHD	Bavaria	Administrative district of Dingolfing-Landau		finally closed in 2017 (without notification of closure)	Natural gas	6.7		
BNA1128	GHD	Bavaria	Administrative district of Dingolfing-Landau		finally closed in 2017 (without notification of closure)	Natural gas	6.7		
BNA1200	GuD-Kraftwerk	Baden-Wuerttemberg	Urban district of Mannheim		finally closed in 2018 (without notification of closure)	Natural gas	17.2		
BNA0076	Lichterfelde	Berlin	Urban district of Berlin		finally closed in 2018 (without notification of closure)	Natural gas	144.0		
BNA0544	HKW Südstadt	North Rhine-Westphalia	Urban district of Cologne		finally closed in 2018 (without notification of closure)	Natural gas	35.0		
BNA1041	Gersteinwerk	North Rhine-Westphalia	Administrative district of Unna		finally closed in 2018 (without notification of closure)	Natural gas	55.0		
BNA0110	Bochum	North Rhine-Westphalia	Urban district of Bochum		finally closed in 2018 (without notification of closure)	Natural gas	20.7		
BNA0221c	Gasblock	North Rhine-Westphalia	Urban district of Düsseldorf		finally closed in 2019 (without notification of closure)	Natural gas	293.0		
	Hagen-Kabel	North Rhine-Westphalia	Urban district of Hagen	2014	in operation	Natural gas	55.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA0016	Heizkraftwerk Altbach/Deizisau	Baden-Wuerttemberg	Administrative district of Esslingen	1971	in operation	Several energy sources	50.0	x	
BNA0017	Heizkraftwerk Altbach/Deizisau	Baden-Wuerttemberg	Administrative district of Esslingen	1973	in operation	Several energy sources	57.0	x	
BNA0018	Heizkraftwerk Altbach/Deizisau	Baden-Wuerttemberg	Administrative district of Esslingen	1975	in operation	Several energy sources	81.0	x	
BNA0025	Kesselhaus Zuckerfabrik	Mecklenburg-Vorpommern	Administrative district of Vorpommern-Greifswald	1993	in operation	Several energy sources	15.1		
BNA1458		Rhineland-Palatinate	Administrative district of Südliche Weinstrasse	1976	in operation	Several energy sources	28.0		x
BNA1337e	GuD-Anlage	Bavaria	Urban district of Aschaffenburg	2013	in operation	Several energy sources	47.0		
BNA1104	Heizkraftwerk	Bavaria	Urban district of Augsburg	1976	in operation	Several energy sources	20.4		x
BNA1105	HKW Bad Salzungen	Thuringia	Administrative district of Wartburgkreis	1994	in operation	Several energy sources	9.7		
BNA0081	Klingenberg	Berlin	Urban district of Berlin	1981	in operation	Several energy sources	164.0		x
BNA0074	Charlottenburg	Berlin	Urban district of Berlin	1975	in operation	Several energy sources	144.0		x
BNA1821	Energieversogung Wedding	Berlin	Urban district of Berlin	1972	in operation	Several energy sources	15.0		x
BNA0098	HKW Schildescher Strasse	North Rhine-Westphalia	Urban district of Bielefeld	1977	special case	Several energy sources	23.0		x
BNA0101	HKW Schildescher Strasse	North Rhine-Westphalia	Urban district of Bielefeld	1966	special case	Several energy sources	41.0		x
BNA0117b	Heizkraftwerk Karlstrasse	North Rhine-Westphalia	Urban district of Bonn	2013	in operation	Several energy sources	95.0		
BNA0135	HKW-Mitte	Lower Saxony	Urban district of Braunschweig	1971	in operation	Several energy sources	20.0		x
BNA0136	HKW-Mitte	Lower Saxony	Urban district of Braunschweig	2010	in operation	Several energy sources	74.0		
BNA0137	HKW-Nord	Lower Saxony	Urban district of Braunschweig	1965	in operation	Several energy sources	25.0		x
BNA1121	Energiezentrale	North Rhine-Westphalia	Administrative district of Recklinghausen	2005	in operation	Several energy sources	0.9		
BNA1120	Energiezentrale	North Rhine-Westphalia	Administrative district of Recklinghausen	1991	in operation	Several energy sources	10.2		
BNA0178	HKW Chemnitz Nord II	Saxony	Urban district of Chemnitz	1986	temporarily shut down (with notification of closure)	Several energy sources	57.2		
BNA1125	Heizkraftwerk	Hesse	Urban district of Darmstadt	1999	in operation	Several energy sources	10.0		
BNA0207	HKW Dresden-Nossener Brücke	Saxony	Urban district of Dresden	1995	in operation	Several energy sources	260.0		
BNA0213	HKW III/A	North Rhine-Westphalia	Urban district of Duisburg	2002	in operation	Several energy sources	40.0		
BNA0214	HKW III/B	North Rhine-Westphalia	Urban district of Duisburg	2005	in operation	Several energy sources	234.0		
BNA1336	Holthausen	North Rhine-Westphalia	Urban district of Düsseldorf	1948	in operation	Several energy sources	84.0		x
BNA0233	Kombikraftwerk	Saxony	Administrative district of Nordsachsen	1993	in operation	Several energy sources	46.6		
BNA1505	HKW Wiesengrund	Thuringia	Urban district of Eisenach	1993	in operation	Several energy sources	22.1		
BNA1868	HKW West M5	Hesse	Urban district of Frankfurt am Main	2018	in operation	Several energy sources	38.7		
BNA1315	HKW	Baden-Wuerttemberg	Urban district of Freiburg im Breisgau	2001	in operation	Several energy sources	27.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
BNA0354	HKW Göttingen	Lower Saxony	Administrative district of Göttingen	1998	in operation	Several energy sources	18.8		
BNA0504	HKW Jena	Thuringia	Urban district of Jena	1996	in operation	Several energy sources	182.0		
BNA0510a	HKW Karcherstr.	Rhineland-Palatinate	Urban district of Kaiserslautern	1989	in operation	Several energy sources	11.6		
BNA1165	P&L Werk Appeldorn	North Rhine-Westphalia	Administrative district of Kleve	2002	in operation	Several energy sources	11.4		
BNA0515	Heizkraftwerk West	Baden-Wuerttemberg	Urban district of Karlsruhe	1984	in operation	Several energy sources	33.0		x
BNA0531	KW Kirchlengern	North Rhine-Westphalia	Administrative district of Herford	1981	in operation	Several energy sources	146.5		
BNA1329	K&N PFK AG EV	Saxony	Administrative district of Mittelsachsen	1993	in operation	Several energy sources	13.1		
BNA1187	P&L Werk Lage	North Rhine-Westphalia	Administrative district of Lippe	2017	in operation	Several energy sources	10.2		
BNA0588	Heizkraftwerk Leipzig-Nord	Saxony	Urban district of Leipzig	1996	in operation	Several energy sources	167.0		
BNA1332	INEOS Kraftwerk	North Rhine-Westphalia	Administrative district of Wesel	1995	in operation	Several energy sources	24.0		
BNA0685	Heizkraftwerk Hafen	North Rhine-Westphalia	Urban district of Münster	2005	in operation	Several energy sources	104.1		
BNA0688	GuD-HKW Neubrandenburg	Mecklenburg-Vorpommern	Administrative district of Mecklenburgische Seenplatte	1997	in operation	Several energy sources	75.0		
BNA0744	Franken 1	Bavaria	Urban district of Nuremberg	1973	in operation	Several energy sources	383.0	x	
BNA0745	Franken 1	Bavaria	Urban district of Nuremberg	1976	in operation	Several energy sources	440.0	x	
BNA0800	Heizkraftwerk Pforzheim GmbH	Baden-Wuerttemberg	Urban district of Pforzheim	1980	in operation	Several energy sources	41.2		
BNA0856	HKW Schwarza	Thuringia	Administrative district of Saalfeld-Rudolstadt	1936	in operation	Several energy sources	26.5		x
BNA0861a	HKW Römerbrücke	Saarland	Saarbrücken regional association	2005	in operation	Several energy sources	75.0	x	
BNA0893	GuD Schwarzheide	Brandenburg	Administrative district of Oberspreewald-Lausitz	1994	in operation	Several energy sources	122.0		
BNA0896	HKW Schwerin Süd	Mecklenburg-Vorpommern	Urban district of Schwerin	1994	in operation	Several energy sources	44.9		
BNA0897	HKW Schwerin Lankow	Mecklenburg-Vorpommern	Urban district of Schwerin	1994	in operation	Several energy sources	23.0		
BNA1489	Heizkraftwerk Stendal	Saxony-Anhalt	Administrative district of Stendal	1994	in operation	Several energy sources	22.0		
BNA1333a	HKW Pfaffenwald	Baden-Wuerttemberg	Urban district of Stuttgart	1988	in operation	Several energy sources	12.2		
BNA1333b	HKW Pfaffenwald	Baden-Wuerttemberg	Urban district of Stuttgart	1969	in operation	Several energy sources	11.3		x
BNA1333c	HKW Pfaffenwald	Baden-Wuerttemberg	Urban district of Stuttgart	1968	in operation	Several energy sources	11.6		x
BNA1264	HKW Bohrhügel	Thuringia	Urban district of Suhl	1995	in operation	Several energy sources	13.5		
BNA1279	Gasturbine	North Rhine-Westphalia	Administrative district of Rhein-Erft-Kreis	1996	in operation	Several energy sources	51.9		
BNA1078	HKW Wörth	Rhineland-Palatinate	Administrative district of Germersheim	2007	in operation	Several energy sources	59.0	x	
BNA1400b	EZ1	Saxony-Anhalt	Administrative district of Burgenlandkreis	1993	in operation	Several energy sources	23.3		
BNA1904	K5/T7	Schleswig-Holstein	Urban district of Flensburg	2016	in operation	Several energy sources	29.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construc-tion	Status according to the Federal Network Agency's list of power plants (up-dated 7 March 2019)	Energy source	Net output in MW_e	Systemi-cally im-portant	CHP re-placement by 2030
BNA1275		Baden-Wuerttemberg	Administrative district of Rhein-Neckar-Kreis		finally closed in 2013 (without notification of closure)	Several energy sources	21.0		
BNA1276		Baden-Wuerttemberg	Administrative district of Rhein-Neckar-Kreis		finally closed in 2013 (without notification of closure)	Several energy sources	21.0		
BNA0918a	Dow Stade	Lower Saxony	Administrative district of Stade		finally closed in 2014 (without notification of closure)	Several energy sources	190.0		
BNA0810	Kraftwerk Veltheim	North Rhine-Westphalia	Administrative district of Minden-Lübbecke		finally closed in 2015 (without notification of closure)	Several energy sources	65.0		
BNA0811	Kraftwerk Veltheim	North Rhine-Westphalia	Administrative district of Minden-Lübbecke		finally closed in 2015 (without notification of closure)	Several energy sources	335.0		
BNA0799	Heizkraftwerk Pforzheim GmbH	Baden-Wuerttemberg	Urban district of Pforzheim		finally closed in 2016 (without notification of closure)	Several energy sources	11.3		
BNA1225	PWG	Bavaria	Administrative district of Weilheim-Schongau		finally closed in 2016 (without notification of closure)	Several energy sources	5.3		
BNA1226	PWG	Bavaria	Administrative district of Weilheim- Schongau		finally closed in 2016 (without notification of closure)	Several energy sources	5.3		
BNA0288	HKW Niederrad	Hesse	Urban district of Frankfurt am Main		finally closed in 2017 (without notification of closure)	Several energy sources	56.0		
Additional build, SF electricity	Klein KWK-Anlagen (small CHP plants) (<10 MW)	n.a.*		2025	in the planning stage	Natural gas	2,700.0		
Additional build, SF electricity	Klein KWK-Anlagen (small CHP plants) (<10 MW)	n.a.*		2030	in the planning stage	Natural gas	1,500.0		
Additional build, Sec-tions 38/39	GuD Leipheim I	Bavaria	Administrative district of Günzburg	2020	in the planning stage	Natural gas	670.0		
Additional build, Sec-tions 38/39	Kraftwerk Scholven (several requests)	North Rhine-Westphalia	Urban district of Gelsen-kirchen	2020	in the planning stage	Natural gas	130.0		
Additional build, Sec-tions 38/39	Kraftwerk Irsching	Bavaria	Administrative district of Pfaffenhofen a.d.Ilm	2021	in the planning stage	Natural gas	300.0		
Additional build, Sec-tions 38/39	Gasturbine Heilbronn	Baden-Wuerttemberg	Urban district of Heilbronn	2024	in the planning stage	Natural gas	600.0		
Additional build, Sec-tions 38/39	GuD-Anlage Altbach	Baden-Wuerttemberg	Administrative district of Esslingen	2024	in the planning stage	Natural gas	600.0		
Additional build, Sec-tions 38/39	GuD-Anlage Marbach	Baden-Wuerttemberg	Administrative district of Ludwigsburg	2024	in the planning stage	Natural gas	400.0		
Additional build, Sec-tions 38/39	GuD-KW Herne	North Rhine-Westphalia	Urban district of Herne	2022	in the planning stage	Natural gas	753.0		
Additional build, Sec-tions 38/39	BHKW Marl M1	North Rhine-Westphalia	Administrative district of Recklinghausen	2021	in the planning stage	Natural gas	31.0		
Additional build, BNetzA list	Lichterfelde	Berlin	Urban district of Berlin	2019	in the planning stage	Natural gas	300.0		
Additional build, BNetzA list	Küstenkraftwerk Kiel	Schleswig-Holstein	Urban district of Kiel	2019	in the planning stage	Natural gas	190.0		
Additional build, BNetzA list	KW5	Rhineland-Palatinate	Urban district of Mainz	2019	in the planning stage	Natural gas	100.0		
Additional build, BNetzA list	Marzahn	Berlin	Urban district of Berlin	2019	in the planning stage	Natural gas	254.0		
Additional build, BNetzA list	KWK Dingolfing BA 2	Bavaria	Administrative district of Dingolfing-Landau	2019	in the planning stage	Natural gas	15.0		
Additional build, BNetzA list	KWK München	Bavaria	Urban district of Munich	2019	in the planning stage	Natural gas	13.0		

Federal Network Agency ID	Name of power plant	Federal state	District	Year of construction	Status according to the Federal Network Agency's list of power plants (updated 7 March 2019)	Energy source	Net output in MW_e	Systemically important	CHP replacement by 2030
Additional build, BNetzA list	KWK München FIZ	Bavaria	Urban district of Munich	2019	in the planning stage	Natural gas	13.0		
Additional build, BDEW list	HKW Freimann	Bavaria	Urban district of Munich	2019	in the planning stage	Natural gas	106.0		
Additional build, BDEW list	GuD-Köln (IKW), Kessel 7	North Rhine-Westphalia	Urban district of Cologne	2019	in the planning stage	Natural gas	63.0		
Additional build, BDEW list	Umrüstung HKW Cottbus (retrofitting) (Gasmotoren)	Brandenburg	Urban district of Cottbus	2020	in the planning stage	Natural gas	50.0		
Additional build, BDEW list	HKW Reick (Gasmotoren), DREWAG	Saxony	Urban district of Dresden	2021	in the planning stage	Natural gas	90.0		
Additional build, BDEW list	Erweiterung HKW Jena (expansion) (Gasmotoren), TEAG	Thuringia	Urban district of Jena	2021	in the planning stage	Natural gas	60.0		
Additional build, BDEW list	HKW Chemnitz (Gasmotoren)	Saxony	Urban district of Chemnitz	2022	in the planning stage	Natural gas	80.0		
Additional build, BDEW list	Kessel 13, Stadtwerke Flensburg	Schleswig-Holstein	Urban district of Flensburg	2022	in the planning stage	Natural gas	70.0		
Additional build, BDEW list	HKW, Stadtwerke Pforzheim	Baden-Wuerttemberg	Urban district of Pforzheim	2022	in the planning stage	Natural gas	50.0		
Additional build, BDEW list	Gas engine plant, Stadtwerke Frankfurt (Oder)	Brandenburg	Urban district of Frankfurt/Oder	2022	in the planning stage	Natural gas	50.0		
Additional build, BDEW list	HKW-Süd (Gasturbinenanlage), Stadtwerke Leipzig	Saxony	Urban district of Leipzig	2023	in the planning stage	Natural gas	120.0		
Additional build, BDEW list	HKW Altchemnitz (Gasmotoren)	Saxony	Urban district of Chemnitz	2025	in the planning stage	Natural gas	50.0		
Additional build, BDEW list	BHKW (mehrere Gasmotoren) (several gas engines), Stadtwerke Heidelberg	Baden-Wuerttemberg	Urban district of Heidelberg	2025	in the planning stage	Natural gas	20.0		

* no allocation
Note: power plants that have been closed are not included in the modelling of gas demand.

Source: BDEW 2019b, BNetzA 2019a, Prognos AG, transmission system operators

Appendix 3: Analysis by the working group of the transmission system operators of the necessary exit capacity at the Wallbach interconnection point

The extract below from a working paper of the working group of the transmission system operators Snam Rete Gas, Swissgas, FluxSwiss, Transitgas, Fluxys TENP and OGEexplains the procedure, the assumptions and the results of the jointly conducted analysis as well as the joint recommendation.

A.1 Approach of the Gas NDP 2018–2028

In the Gas NDP 2018–2028, the German TSOs analysed the capacity requirements for SoS purposes in Italy and Switzerland as part of the TENP Security of Supply scenario. This was done on the basis of an analysis of publicly accessible, historical entry and exit flows from 2013 to 2017 for Italy and Switzerland. A consideration of the future development of entry capacities, especially in Italy, could only take place qualitatively, as detailed enough information was not publicly available for this purpose. This first analysis showed an exit capacity requirement in Wallbach of 13.3 GWh/h to ensure Security of Supply in Italy and Switzerland. The market consultations of the TENP Security of Supply scenario in 2018 showed no quantifiable evidence of additional capacity requirements to meet SoS needs. As a consequence, thanks to the investment projects approved in the NDP 2018–2028, the exit capacity in Wallbach has been secured at a level of 13.3 GWh/h at contractual conditions, this 13.3 GWh/h being the same amount available today in Wallbach by means of specific yearly SoS operating provisions agreed between adjacent TSOs. The additionally needed assets are expected to be in operations by the end of 2024.

A.2 Approach of the Gas NDP 2020–2030

In view of the upcoming process for the new Gas NDP 2020–2030, the JWG has carried out a forward looking analysis that takes into account the future Security of Supply of Italy and Switzerland. A wide range of scenarios in terms of demand and supply has been evaluated in order to detect the most relevant ones for the calculation of capacity needs at Wallbach.

On the Italian side, for each scenario an in-depth analysis of the winter period starting from the mid of January up to the end of February has been performed for the next 10 years. The choice of this period of the year allows including the highest daily gas demand (usually occurring in January) and the fast and progressive decrease of the withdrawal performance from Underground Storages -UGS- in the last part of the winter season (taking place in February typically).

A daily comparison between the forecast demand in case of stressed weather conditions and the supply potential has been made in order to define the most critical contexts. In these situations the supply need in Passo Gries to cover the Italian demand has been defined, as well as the corresponding Wallbach needs calculated taking into account the Swiss consumption and the potential supply from the French-Swiss interconnection point of Oltingue. The most relevant scenarios are summarised in the table in section A.8.

A.3 Italian gas demand

The Italian gas demand scenario has been built taking into account:

- Italian and European goals on limiting emission, penetration of renewables and energy saving;
- The macroeconomic forecast outlook;
- Power generation mix and gas-fired power generation.

In particular the Italian demand is widely impacted by the carbon phase-out foreseen by 2025. Starting from yearly data, daily data about stressed weather conditions have been computed taking into account historical registered temperature. Three weather conditions-related gas demands have been considered (Ref. EU Regulation 1938/2017 art. 5 and 6):

1. The peak demand forecast for every single day;
2. The demand forecast for every single day in case of extreme temperatures during a 7-day period;
3. The demand forecast for every single day in case of extreme temperatures during a 30-day period.

The figures considered in section A.8 of this document are related to the first weather conditions (i. e. 1-day peak demand) that is considered the most tense scenario for these purposes.

A.4 Swiss gas demand

As far as Switzerland is concerned, the analysis performed in this document refers to the concept of gas peak demand and is not assessing Security of Supply scenarios linked to potential disruption of supply sources.

Two scenarios have been considered to calculate the future Swiss peak demand:

- Best estimate: Swiss peak demand taking into account:
  - The Swiss goals on containing emission, penetration of renewables and energy saving (Swiss Energy Strategy 2050).
  - The cumulated bottom up demand figures which were delivered to Swissgas by the Swiss gas industry.
  - A slightly increasing number of gas-fired power heat cogeneration plants in Switzerland.
  - A consistently decreasing number of bivalent dual-fuel end consumers who currently represent an important part of the peak demand optimisation.
- Vision: equal to the Swiss peak demand taking into account additionally:
  - The future electric generation via 2 CCGT (Combined Cycle Gas Turbines).

The figures reported in section A.8 of this document consider the best estimate demand for two scenarios out of three (Scenarios 1 and 2) and the vision demand for the most tense scenario (Scenario 3).

A.5 Italian supply side: assumptions on entry points utilisation and relevant supply parameters

For all Italian entry points except Tarvisio (the only entry point from foreign countries whose capacity is always considered maximisable in case of need), several scenarios with an increasing level of supply stress have been taken into account. Although the more stressed the scenario, the lower the probability of occurrence, it is to be pointed out that all assessed supply scenarios are possible. The reduction of the UGS withdrawal performance during the considered period due to the progressive utilisation has been also taken into account. In addition, infrastructure development such as the new import source from TAP and UGS capacity development have been considered too.

For the Italian market the most sensitive parameters to be evaluated for supply scenarios are listed here below:

- Algerian import: two different scenarios (Low, High) have been evaluated and included in the analysis.
- Low supply source reactivity: apart from Tarvisio (and Passo Gries) Italian entry points are characterised by a limited reactivity to critical situations. This parameter has been considered based on the recorded data of the last three years.
- LNG: supply source highly conditioned by the LNG worldwide availability and by possible adverse weather conditions. As a matter of fact, stressed demand conditions due to cold spells are often combined with bad weather and it is not unlikely to observe LNG ships encountering difficulties due to the sea conditions preventing them to berth and discharge LNG.
- TAP: TAP gas availability for Italy could be affected by the gas consumption of the upstream countries (Bulgaria, Greece, Albania and Montenegro).

A.6 Swiss supply side: assumptions on entry points available capacities

The Swiss demand can be supplied from three different Interconnection Points (IPs) connected to the Transitgas pipeline (Wallbach, Oltingue, Passo Gries) and from some small scale IPs from France, Germany, Austria and Liechtenstein covering demand not directly supplied by the Transitgas system.

- Wallbach being the main import source for Switzerland, to balance the Swiss market a full utilisation of the small scale IPs (amounting to a total capacity of 2 GWh/h) is considered. In case of a shutdown or reduction of any of this small scale IPs during CH peak demand, this would directly lead to an additional demand from Transitgas and therefore Wallbach/Oltingue capacities.
- The Swiss capacity scenarios are based on the physical stability of the Swiss grids.
- The Swiss domestic market has guaranteed long term bookings in the past. Therefore long term needs of firm capacity have been considered for the future.
- Concerning the entry point Oltingue, the relevant capacity is considered in the analysis from a physical balance perspective, even though from a commercial point of view most of the gas entering Switzerland from Oltingue is transported to Italy.
- The current technical capacity at the Interconnection Point Oltingue equals 10.5 GWh/h, as a result of:
  - On the French side (exit Oltingue GRTgaz) the technical capacity is split into 9.3 GWh/h of firm capacity and 1.2 GWh/h of interruptible capacity due to contractual minimum pressure requirements.
  - On the Swiss side (entry Oltingue CH) instead, the 10.5 GWh/h technical capacity is all firm capacity.

Assuming a stable supply context in France, the risk of interruption on the French side depends on upstream network configuration in the GRTgaz grid. Based on historical flows, GRTgaz has proven to be able to secure the interruptible capacity on top of the firm capacity up to a total flow of 10.5 GWh/h at Oltingue also in critical situations such as the Baumgarten event that occurred in December 2017.

- The current technical capacities in Reverse Flow available at the Interconnection Point Passo Gries to supply not only the Swiss market but also the French and German ones have not been considered explicitly in the analysis. In any case, the first scenario described below at section A.8 shows a potential export from Italy which is compatible with the developed RF available capacities.

A.7 Reference gas year

Since the commissioning date for network expansion measures in Germany including a potential increase of capacity at exit Wallbach would be – according to planning assumptions in the German Network Development Plan – the end of year 2025, the analysis on the relevant scenarios has been carried out for gas year 2025/26 assuming the maximum supply gap will occur in February 2026.

A.8 Relevant scenarios and results

Several supply and demand scenarios of the Italian and Swiss gas markets have been analysed based on the aforementioned parameters resulting in three representative scenarios shown in the table below.

These three scenarios and the identified relevant scenario parameters cover the full range of possible supply and demand situations for bot gas markets.

- Scenario 1 "Italy: Fully maximised, CH: Fully maximised w/best estimate demand": this scenario considers the maximum foreseen utilisation of the Italian supply sources. These figures are equal to the maximum capacity for Tarvisio, Gorizia, TAP and LNG entry points while are based on the assumptions described at section A.5 for Mazara del Vallo and Gela. The Italian storage is set at the maximum relevant performance for each day in February taking into account the performance decrease during the winter period. With regard to the entry point Oltingue, the interruptible capacity is also considered on top of the firm.

- Scenario 2 "Italy: Low Algeria + Medium LNG + Low Supply Source Reactivity, CH: Low Oltingue w/best estimate demand": this scenario considers the identified relevant restrictions. On the basis of the consideration for the Italian supply explained in section A.5, this scenario includes the reduced utilisation of Mazara del Vallo up to the Low Algeria scenario, the reduction of Gela and Gorizia due to the Low supply source reactivity, a medium utilisation of LNG and a reduced flow from TAP due to the upstream consumption. With regard to the entry point Oltingue, the interruptible capacity is not considered.
- Scenario 3 "Italy: Low Algeria + Low LNG + Low Supply Source Reactivity + Low TAP, CH: Low Oltingue w/vision demand": this scenario is the most severe one where all possible supply restrictions are considered. With regard to the entry point Oltingue, the interruptible capacity is not considered.

The results of the above mentioned assumptions are reported in the table below (a GCV of 10.57275 kWh/cm(s) is considered for the relevant conversions):

Italy		**Scenario 1**	**Scenario 2**	**Scenario 3**
Entry Point	Type	Italy: Fully maximised	Italy: Low Algeria + Medium LNG + Low Supply Source Reactivity	Italy: Low Algeria + Low LNG + Low Supply Source Reactivity + Low TAP
		Mcm(s)/d	Mcm(s)/d	Mcm(s)/d
Demand Italy		**429**	**429**	**429**
Supply				
Storage (Sum)	Storage	156	156	156
Production	Production	14	14	14
Tarvisio	Pipeline (RUS)	115	115	115
Mazara del Vallo	Pipeline (ALG)	55	40	40
Gela	Pipeline (LYB)	24	17	17
Gorizia	Pipeline	3	1	1
Cavarzere, Livorno, Panigaglia	LNG	54	29	22
TAP	Pipeline (AZ)	26	21	16
Total Supply (w/o Passo Gries)		**446**	**393**	**381**
Necessary flow at Passo Gries for Italy		**-17.0**	**36.0**	**47.9**
		GWh/h	GWh/h	GWh/h
Flows at Passo Gries (negative = Reverse Flow to CH, positive = Forward Flow to IT)	**A**	**-7.5**	**15.9**	**21.1**
CH		**Scenario 1**	**Scenario 2**	**Scenario 3**
Entry Point	Type	CH: Fully maximised w/ best estimate demand	CH: Low Oltingue w/best estimate demand	CH: Low Oltingue w/ vision demand
		GWh/h	GWh/h	GWh/h
Peak Demand CH [GWh/h]	**B**	**11.6**	**11.6**	**12.5**
Supply other CH small scale IP	C	2.0	2.0	2.0
Need for Transitgas entries by downstream markets (IT/CH)	**D = A+B-C**	**2.1**	**25.5**	**31.6**
Oltingue – firm	Pipeline (FR)	9.3	9.3	9.3
Oltingue – interruptible	Pipeline (FR)	1.2	0	0
Wallbach w/o additional investment	E	13.3	13.3	13.3
Total existing Transitgas entries	**F**	**23.8**	**22.6**	**22.6**
Total needed capacity at Wallbach [GWh/h]	**G = E+D-F**	**-8.4**	**16.2**	**22.3**

Source: Joint Working Group Snam Rete Gas, Swissgas, FluxSwiss, Transitgas, Fluxys TENP, OGE

C.1 Recommended scenario

The scenarios described in section A cover the full range of possible capacity need at the exit point of Wallbach.

1. Scenario 1 "Italy: Fully maximised, CH: Fully maximised w/best estimate demand": according to this scenario, no additional capacity will be needed at Wallbach to supply the Swiss and Italian markets. In particular, the results of this scenario depict the Italian market as structurally long over the next decade so that a physical reversal of flows at Passo Gries could occur at some moment even on a peak day. The current available capacities in Reverse Flow will allow exporting this possible excess of gas from Italy towards Switzerland, Germany and France.
2. Scenario 2 "Italy: Low Algeria + Medium LNG + Low Supply Source Reactivity, CH: Low Oltingue w/best estimate demand": with the considered relevant restrictions, this scenario results in an additional capacity need of ca. 3 GWh/h at exit Wallbach (16.2 GWh/h).
3. Scenario 3 "Italy: Low Algeria + Low LNG + Low Supply Source Reactivity + Low TAP, CH: Low Oltingue w/vision demand": when taking into account all possible restrictions influencing the Italian and Swiss market, the capacity at exit Wallbach would need to be equal to 22.3 GWh/h (+9 GWh/h vs the currently available capacities).

After a thorough assessment of the data and considering:

- The importance of exit Wallbach to compensate a possible disruption of sources which have proven to be more intermittent (i. e. LNG) or whose long-term availability is less predictable (Algerian gas in particular).
- The need to identify an efficient and right-sized investment solution to tackle the risk of stressed downstream markets.

On the basis of the analysed scenarios, Scenario 2 (+3 GWh/h at exit Wallbach) would be the appropriate one to cover the relevant restrictions specific for the Italian supply situation in combination with best estimate peak demand for Switzerland.

C.2 Other measures

To the extent scenarios including further restrictions than the ones considered in Scenario 2 actually materialise on the Italian/Swiss markets in the future, some additional operational and structural measures could be activated among others:

a. Exit Oltingue interruptible capacities for 1.2 GWh/h: as reported in section A.6, based on historical flows GRTgaz has proven to be able to deliver the interruptible capacity on top of the firm capacity up to a total flow of 10.5 GWh/h at Oltingue also during exceptional events such as the Baumgarten incident occurred on 12 December 2017.

b. In addition to the capacity at letter a., further interruptible capacities to be created via contractual agreements at Wallbach/Oltingue (0.9 GWh/h): such capacities are linked to possible agreements between TSOs at the interconnection points of Wallbach and Oltingue aimed at increasing the maximum flows under specific operating conditions. Similar agreements are currently in place on yearly SoS support base on both IPs. Even in case of no extension of the current provisions after December 2024, such additional capacities amounting to the sum of +0.6 GWh/h from Wallbach and +0.3 GWh/h from Oltingue could be made available at least on a short term and interruptible basis in case of Security of Supply situations in Italy/Switzerland. Clearly, such additional capacities should not decrease the Swiss Security of Supply.

c. Should there be any unused capacity in Germany and/or Switzerland part of such unused capacity could become available for the Italian market.

d. Incremental Capacity Process in accordance with the CAM NC as well as any other process foreseen by the European Regulation.

Glossary

Transmission system operators

bayernets	bayernets GmbH
Ferngas	Ferngas Netzgesellschaft mbH
Fluxys	Fluxys TENP GmbH
Fluxys D	Fluxys Deutschland GmbH
GASCADE	GASCADE Gastransport GmbH
GRTD	GRTgaz Deutschland GmbH
GTG Nord	Gastransport Nord GmbH
GUD	Gasunie Deutschland Transport Services GmbH
LBTG	Lubmin-Brandov Gastransport GmbH
NGT	NEL Gastransport GmbH
Nowega	Nowega GmbH
OGE	Open Grid Europe GmbH
OGT	OPAL gastransport GmbH & Co. KG
ONTRAS	ONTRAS Gastransport GmbH
terranets	terranets bw GmbH
Thyssengas	Thyssengas GmbH

Other abbreviations

ARegV	Verordnung über die Anreizregulierung der Energieversorgungsnetze – Ordinance governing the incentive regulation for the energy supply network
BDEW	Bundesverband der Energie- und Wasserwirtschaft e.V. – German Federal Association of Energy and Water Industries
bFZK	Bedingt feste frei zuordenbare Kapazität – conditionally firm freely allocable capacity: capacity is firm if usage/gas flow-dependent conditions are met.
BKartA	Bundeskartellamt – German competition authority
BNetzA	Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen – German Federal Network Agency for Electricity, Gas, Telecommunication, Post and Railways
BVEG	Bundesverband Erdgas, Erdöl und Geoenergie e. V. – German Federal Association of Natural gas, Petroleum and Geoenergy, formerly Wirtschaftsverband Erdöl- und Erdgasgewinnung (WEG – German Industrial Association of Oil and Gas Producers)
BZK	Beschränkt zuordenbare Kapazität – conditional allocable capacity: capacity can be used only subject to an allocation condition. No virtual trading point access.
CS	Compression station
dena	Deutsche Energie-Agentur – German Energy Agency
DSO	Distribution system operator
DVGW	Deutscher Verein des Gas- und Wasserfaches e. V. – German Technical and Scientific Association for Gas and Water

DZK	Dynamisch zuordenbare Kapazität – dynamically allocable capacity. Capacity is firm if it can be used without a VTP for balanced transmission between entry and exit capacities with a nomination obligation.
EE	Erneuerbare Energien – renewable energies
EEG	Gesetz für den Ausbau erneuerbarer Energien – Renewable Energy Sources Act
FEC	Final energy consumption
ENTSOG	European Network of Transmission System Operators Gas
EnWG	Energiewirtschaftsgesetz – Energy Industry Act
EUGAL	Europäische Gas-Anbindungsleitung (European gas pipeline link)
FfE	Forschungsstelle für Energiewirtschaft – Research Institute for the Energy Economy
FID	Final investment decision
FZK	Frei zuordenbare Kapazitäten – free allocable capacity, enables booked entry and exit capacities to be used without stipulating a transmission path
GasNZV	Verordnung über den Zugang zu Gasversorgungsnetzen/Gasnetzzugangsverordnung – German Gas Network Access Regulation
GCA	Gas Connect Austria GmbH
GTS	Gasunie Transport Services B. V.
IP	Interconnection point
IR	Implementation report
KNEP	Koordinierter Netzentwicklungsplan – coordinated network development plan (of Gas Connect Austria)
KoV	Kooperationsvereinbarung Gas – Gas cooperation agreement
LaFZK	Lastabhängig zuordenbare Kapazität – load-dependent allocable capacity: capacity is firm if a specific network load is present.
LDGP	Long-distance gas pipeline
LNG	Liquefied natural gas
LOHC	Liquid organic hydrogen carrier
LULUCF	Land Use, Land-Use Change and Forestry
MBI	Market-based instruments
MÜP	Marktgebietsübergangspunkt – market area interconnection point
NAM	Producer at the Groningen field
NC CAM	Network code on capacity allocation mechanisms in gas transmission systems
NDP	Network Development Plan
NEL	Nordeuropäische Erdgas-Leitung – Northern Europe Natural Gas Pipeline
NEV	Nichtenergetischer Verbrauch – non-energy consumption
non-FID	No final investment decision (yet)

NOP	Netwerk Ontwikkelings Plan (Dutch NDP)
OPAL	Ostsee-Pipeline-Anbindungsleitung (Baltic Sea pipeline link)
PtG	Power-to-Gas
PV	Photovoltaics
SF	Scenario Framework
SodM	Staatstoezicht Op De Mijnen (SodM – Dutch State Supervision of Mines)
STEGAL	Sachsen-Thüringen-Erdgas-Leitung (natural gas pipeline)
TaK	Temperaturabhängige Kapazität – temperature-dependent capacity: capacity is firm within and interruptible outside a defined temperature range.
TAP	Trans Adriatic Pipeline
TC	Technical capacity
TENP	Trans Europa Naturgas Pipeline
TSO	(Gas) transmission system operator
TYNDP	Ten-Year Network Development Plan (from ENTSOG)
UGS	Underground gas storage
VTP	Virtual trading point
VIP	Virtual interconnection point

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