The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets

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MOVE/ENER/SRD/2016-498 Lot 2

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Trinomics

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ADEME	Agence de l'Environnement et de la Maîtrise de l'Énergie (French Environment and Energy Management Agency)
AGI	Above Ground Installations
ANRE	Autoritatea Naţională de Reglementare în domeniul Energiei (Romanian NRA)
ARERA	Autorità di Regolazione per Energia Reti e Ambiente (Italian NRA)
bcm	Billion cubic meters
CAPEX	Capital expenditures
CBCA	Cost-benefit cost-allocation
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture Storage
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
CHP	Combined Heat & Power
CNG	Compressed natural gas
CRE	Commission de Régulation de l'Energie (French NRA)
CRU	Commission for Regulation of Utilities (Irish NRA)
DCCAE	Department of Communications Climate Action and the Environment
DEA	Danish Energy Agency
DERA	Danish Energy Regulatory Authority (Danish NRA)
DG ENER	European Commission’s Directorate General for Energy
DSO	Distribution System Operator
EC	European Commission
EED	Energy Efficiency Directive
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPBD	Energy Performance of Building Directive
ERO	Energy Regulatory Office (Polish NRA)
EU	European Union
FID	Final investment decision
FRSU	Floating Regasification, Storage and Unloading
GERG	European Gas Research Group
GHG	Green House Gas
GIE	Gas Infrastructure Europe
GNI	Gas Networks Ireland
GO	Guarantees of origin
GSP	Gas Storage Poland
HDT	Heavy Duty Truck
HHI	Herfindahl-Hirschman Index
IEA	International Energy Agency
IOM	Isle of Man

IP	Interconnection point
ISO	International Standardisation Organisation
ITO	Independent Transmission Operator
LBG	Liquid Bio-Gas
L-CNG	Liquefied-to-Compressed Natural Gas
LNG	Liquified natural gas
LPG	Liquefied petroleum gas
M/R	Metering and Regulation
MS	Member State
MWh	Mega Watt hour
NDP	Network Development Plan
NES	National Energy Strategy
NBP	National Balancing Point
NMP	National Mitigation Plan
NRA	National Regulatory Authority
OECD	Organisation for Economic Co-operation and Development
OPEX	Operating expenses
P2G	Power to Gas
PCI	Project of Common Interest
PPE	Pluriannual Energy Programming
R&D	Research & Development
RAB	Regulatory asset base
RES	Renewable energy sources
SEAI	Sustainable Energy Authority of Ireland
SECA	Sulphur Emission Controlled Area
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SoS	Security of supply
TEN-E	Trans-European Energy Network
TEN-T	Trans European Transport Network
TPA	Third Party Access
TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	Tera Watt hour
TYNDP	Ten Year Network Development Plan
UGS	Underground gas storage
UNFCCC	United Nations Framework Convention on Climate Change
URE	Poland's National Energy Regulatory Authority
WACC	Weighted Average Cost of Capital

Types of gas

The term "gas" is in this study not limited to natural gas, i.e. of fossil origin, but it is used for several gaseous energy carriers, including

- **Natural gas** (mainly CH_4) from fossil sources; in full decarbonisation by 2050 only relevant with CCS, e.g. natural gas fuelled power plants with pre- or post-combustion carbon capture and storage;
- **(Renewable) synthetic methane** (e-CH_4), synthetic methane produced from H_2 from (renewable) electricity through water electrolysis and CO_2 obtained from organic processes, or captured from air by elevated temperature processes;
- **Biomethane** (bio-CH_4), i.e. methane from organic matter (purified biogas), produced by anaerobic digestion or thermal gasification;
- **(Renewable) Hydrogen** (H_2): either fossil-based hydrogen in combination with CCS, e.g. from steam methane reforming of natural gas, or produced through water electrolysis from (renewable) electricity.

Mixtures of methane with hydrogen, often dubbed hythane are not addressed as a separate type of gas.

Executive Summary

The required sharp decrease in CO_2 and other greenhouse gas emissions by 2050 – as committed to in the Paris Agreement - may drastically reduce the share of natural gas in the European energy mix. Therefore, the role of the European gas infrastructure may change substantially within the next thirty years. Taking into account the long lifetime of gas infrastructure assets, a forward-looking exercise is essential to take informed decisions and to reduce the risk that existing or planned assets would become devalued or stranded in the medium or long term. In this context, the objective of the study is to assess the role of Trans-European gas infrastructure in the light of the EU's long-term decarbonisation commitments. The assessment is performed on the basis of three selected storylines which have been developed under Tasks 1 and 2 of this study:

(1) electricity becoming the major energy carrier for transport and buildings;
(2) a coordinated role of the gas and electricity infrastructures with a focus on carbon-neutral methane either as synthetic methane ($PtCH_4$) or biomethane; and
(3) a coordinated role of the gas and electricity infrastructures with a focus on hydrogen.

This report focuses on the assessment of the consequences for existing and planned trans-European gas infrastructure under the three developed storylines for six selected TSOs[1] as well as on the readiness of three selected national regulatory regimes[2] in a significantly changing energy landscape.

Based on the information gathered from literature and stakeholder consultation, country sections have been developed including the following information:

- Impact of the storylines on existing and planned gas infrastructure in the Member State;
- Main national developments that influence investments in and use of gas infrastructure;
- Impact of the storylines on the TSO's business and transmission grid tariffs;
- Readiness of the national regulatory framework (only for Poland, France and Denmark).

Investments in gas infrastructure

Current and planned investments in large gas infrastructure are mainly driven by security of gas supply objectives (N-1 infrastructure standard, access to diversified gas sources), wholesale markets' integration and shifts in gas supply (decreasing domestic gas production, conversion of L-gas to H-gas, shift from pipeline gas to LNG). The gas system has in general reached a high level of security of gas supply and market integration, and future investments would hence mainly focus on maintenance and safety (replacement of ageing assets), refurbishment to accommodate renewable gas, and projects to enhance the adequacy and operational reliability of the energy system.

Role of gas in the shift towards a carbon-neutral energy system

Several countries are taking initiatives to stimulate the use of natural gas (CNG or LNG) in the transport sector, to replace coal or peat with gas for power generation and to support the development of renewable gas. These actions mitigate the decreasing trend of natural gas demand for heating, while contributing to the transition to a low(er) carbon energy supply. The deployment of renewable gas – which can play a major role to cost-efficiently achieve the shift towards a carbon-neutral energy system - strongly varies across the considered Member States. While an enabling policy framework is in general in place for local production and use of biogas, its conversion to biomethane and injection into

[1] Energinet (Denmark), GRTgaz (France), Gaz System (Poland), Transgaz (Romania), Gas Networks Ireland, Snam Rete Gas (Italy)
[2] Denmark, France, Poland

the gas grid is still very limited and not yet common practice in all considered countries. Production of carbon-neutral hydrogen and transport via the gas grid are in the study and demonstration/pilot phase. In view of stimulating this development, injection of renewable gas into the grid should be facilitated by enabling and more harmonised technical specifications and priority dispatch. Further, adequate research, development and innovation projects are needed to improve the technical and economic feasibility of the deployment of renewable gas, in particular hydrogen. Specific research is also needed to assess the potential and the possible cost impact to use existing storage and transport infrastructure for hydrogen. The possible role of grid operators in the different related activities (in particular installations for conversion of power to gas and storage as well as gas filling stations) should be clarified (e.g. via guidelines) in order to clearly determine their potential involvement, while respecting fair competition and market rules. Finally, in order to keep the energy bill affordable for households and competitive for industrial energy end-users and to reach the energy and climate objectives cost-efficiently, it is important to reduce the costs of the energy system, by fully utilising potential synergies within the gas sector, and by optimising sector coupling between electricity and gas and with the demand sub-sectors, in particular buildings, transport and industry.

Impact of decreasing natural gas demand in the selected storylines on gas infrastructure

Although the overall gas demand would in storylines 2 and 3 remain at a high level, and only in storyline 1 significantly decline, the natural gas demand would in all three storylines drastically decrease. Moreover, the gas volumes transported via the TSO-grid would be lower than the overall gas demand, as part of the renewable gas production would be locally used or injected into the DSO-grid.

The selected storylines would have diverging implications on gas infrastructure depending on the country and type of gas infrastructure. In all three storylines, the utilisation level of LNG terminals and import pipelines would significantly decrease, and some assets might need to be decommissioned or used for other purposes. The negative impact on the transmission grids and storage would be lower due to the expected use of this infrastructure for renewable gas. Existing gas storage could in principle be used for biomethane, while some types (e.g. salt caverns) would be suitable for refurbishment to hydrogen and could also contribute to short term flexibility needs.

While biomethane can be transported via the gas grid without major technical constraints, there is still some uncertainty with regard to the level of hydrogen that could be injected into the gas grid, without requiring adaptations to the gas transmission infrastructure and end-user appliances. This issue should be further clarified, in order to have a better estimate of the cost impact of the refurbishments of the infrastructure, which would be needed to accommodate large amounts of hydrogen as expected in storylines 1 and 3.

Implications for the transmission system operators

TSO assets represent a high economic value which will be affected by the transition

Due to large investment programs in the past and long depreciation periods, TSOs have at present high Regulatory Asset Bases (RAB) or net accounting values (€ 28.7 billion for the 6 TSOs), which are expected to further increase for most TSOs until 2025 and would then become stable or slightly decline depending on the country and storyline.

CAPEX would remain high with slightly different impact per storyline

The CAPEX (which currently represent 40 to 65% of the overall TSO costs) are expected to remain at a relatively high level in all storylines, due to high investments in the past which still have to be depreciated to a large extent. Moreover, the current investment levels are still high for some TSOs (e.g. Poland), but relatively low in other countries (e.g. Denmark). The overall investment levels are expected to slightly decline in the coming 10 years, but specific investments are expected after 2030, to refurbish grids to accommodate H_2 in storylines 1 and 3, and to allow for reverse flows of renewable gas between distribution and transmission, in particular in storyline 2. Moreover, in some countries, gas transmission assets are ageing and investments will be needed for their maintenance/replacement.

OPEX are mainly fixed and falling transported gas volumes would not lead to a proportionate cost decrease

The OPEX, which currently represent between 35 and 60% of the total TSO costs, would remain at a relatively high level in all storylines. In case of falling transported gas volumes, the OPEX would only decrease slightly, as most cost components (e.g. maintenance, administrative costs) are fixed or infrastructure related, while only a limited share (2 to 10%) is volume related. Hence, the evolution of the OPEX will be only slightly different depending on the storylines.

Falling transported gas volumes and stable/slightly decreasing overall cost levels would lead to higher grid tariffs

A regulated Third Party Access (TPA) regime applies for almost all assets owned and operated by the considered TSOs. Tariffs for access to and use of grid infrastructure are regulated and calculated on the basis of actual or ‘authorised’ operational expenses, depreciation costs and a regulated remuneration of capital. This means that, under the current regulatory regimes, TSOs have ‘guaranteed’ revenues, which are in principle not influenced by changes in the utilisation level of their assets. Therefore, a decline in the transported gas volumes would not directly affect their revenues but would mainly translate in higher transmission grid tariffs per transported MWh. The impact of falling transported gas volumes (expected in storylines 1 and 3) on distribution grid tariffs would be much higher, and the negative impact on the grid tariff might undermine the affordability and competitiveness of gas. Storyline 2 (strong development of biomethane) would allow maintaining the gas grid tariffs at the lowest level.

Readiness of the national regulatory frameworks

Regulation should enable investments in future-proof assets

In the context of an expected declining natural gas demand and increasing deployment of (locally produced) renewable gas, new investment projects in large gas infrastructure (such as those in the TYNDP and labelled as PCIs) should be very carefully evaluated in order to avoid or reduce the risk that these assets would become ‘useless’ before the end of their depreciation period.

Appropriate regulation should stimulate TSOs to ensure that their assets are refurbished or replaced in a way which is consistent with the long-term policy objectives and gas demand projections, and in particular with the development of renewable gas. In this context, the implementation of differentiated remuneration levels could be considered in order to better reflect the added value of gas infrastructure investments for the overall energy system and their future-proofness. At the same time, some kind of capacity remuneration scheme or specific regulatory measure could be considered for gas assets (e.g. storage) that are necessary to ensure security of supply, including adequacy and operational reliability of the energy system, but that otherwise would be decommissioned (e.g. strategic capacity reserve whose costs could be socialised via regulated tariffs). However, measures that might have distortive impacts on the market should be avoided.

Review of depreciation rules for gas infrastructure assets might be appropriate

The expected decrease in natural gas demand and transported volumes could lead to gas assets becoming devalued or stranded before the end of their depreciation period (50 years for pipelines in several countries). At present, depreciation rules are mostly based on the technical or economic lifetime of the equipment and do not yet properly take into account the specific risks related to the changing energy demand and supply patterns. In order to anticipate these expected changes and to mitigate the risks for stranded assets, a review of the depreciation rules is suggested, in particular for new investments. The pros and cons of different options could be assessed, such as the Danish example of shorter linear depreciation periods, degressive front-loaded depreciation and accelerated depreciation.

Grid tariff methodologies: evolution towards capacity-based tariffs

The **entry-exit tariff system** is used in most EU Member States[3], and has proven its effectiveness. As the availability of physical capacity is in general no longer a constraint, TSOs suggest to review this tariff system, also in order to properly ensure that there are no bottlenecks in the system.

Two-part tariff structures consisting of a fixed (capacity) charge and a commodity charge are currently used in many countries. **Capacity charges** reflect the basic transmission services and are mainly based on contracted (i.e. booked) capacity, while the **commodity charge** is based on the actually transported volumes. This type of tariff reflects the actual cost of providing transport services to grid users and results in high revenue stability for grid operators, as their revenues are only slightly affected by changes in consumption. From a gas grid user's perspective, the two-part cost structure with a high capacity related share might penalise applications with a low or flexible (and unpredictable) load profile. TOSs should hence be stimulated to make adequate products and short-term capacity reservations available to facilitate flexible use of the gas grid. The tariff methodologies are not yet based on harmonised principles regarding cost allocation and recovery. The new Gas Tariff Network Code[4] is leading to greater harmonisation; once fully implemented, most of the transmission services related costs will be recovered via capacity charges.

(Cross-)Subsidisation of grid infrastructure could be considered to mitigate the impact of falling transported gas volumes on grid tariffs, but it has distortive impacts

Gas grid tariffs are in most scenarios expected to increase as a consequence of falling transported volumes. Increasing grid tariffs would a priori have a positive impact on the climate objectives, as they would incentivize a more efficient end-use of gas, but they would at the same time negatively affect the competitiveness of gas for industry and its affordability for households. Increasing grid tariffs might also negatively affect the business case of transporting biomethane or hydrogen via the grid, and hinder their uptake.

In this context, (cross-)subsidisation of gas infrastructure could be considered to mitigate the impact of increasing grid tariff costs:

[3] http://www.inogate.org/documents/Gas%20pricing.pdf
[4] Commission Regulation EU 2017/460 of 16 March 2017

- **Cross-subsidisation.** Allocating the grid costs differently depending on the end-user type (e.g. residential versus industrial users) or the type of gas (e.g. natural versus renewable gas);
- **Public subsidy for (part of) the gas infrastructure** using taxes or a carbon levy**.**

However, neither cross-subsidisation nor public subsidies for gas infrastructure seem appropriate. The considered types of subsidies would not be compliant with the key requirements of grid tariffication, in particular cost-reflectiveness and cost-efficiency, and might have distortive impacts.

1 Introduction

The European Union has agreed on ambitious energy and climate policy goals that aim at, among others, limiting the global climate warming while ensuring secure and competitive energy supply at an affordable cost to society. This ambition is supported by the 2030 EU policy framework on climate and energy targets and the framework for an "Energy Union with a forward-looking climate policy". The initial target of 27% renewable energy by 2030 has in June 2018 been raised to 32%, while the energy savings target has been increased from 27% to 32.5%.[5]

The long-term EU energy policy objectives include an 80% to 95% reduction of greenhouse gas emissions by 2050[6]. With the 2015 Paris Agreement 195 UNFCCC members committed to limit the increase in the global average temperature to well below 2°C, and to pursue efforts to limit the temperature increase even further to 1.5°C above pre-industrial levels.[7] The Paris Agreement acknowledges that the global action will require adequate efforts to stop the increase of accumulated GHG in the atmosphere and to achieve climate neutrality in the second half of the century.

The required sharp decrease in CO_2 and other greenhouse gas emissions by 2050 may drastically alter the share of natural gas in the European energy mix. Therefore, the role of the European gas infrastructure may also change substantially within the next thirty years. Taking into account the long lifetime of gas infrastructure assets, a forward-looking exercise is essential to take informed decisions and to avoid that existing or planned assets could become devalued or stranded in the medium or long term. In this context, the objective of the study is to assess the role of Trans-European gas infrastructure in the light of the EU's long-term decarbonisation commitments. In order to gain a better understanding of possible evolutions, several existing storylines across the world have been analysed in task 1 and, on the basis of this input, three possible storylines have been defined for the EU in task 2.

The selected storylines which have been developed are the following:

(1) electricity becoming the major energy carrier for transport and buildings;
(2) a coordinated role of the gas and electricity infrastructures with a focus on carbon-neutral methane either as synthetic methane ($PtCH_4$) or biomethane; and
(3) a coordinated role of the gas and electricity infrastructures with a focus on hydrogen.

The natural gas demand will slightly decrease in 2020-2030 in the 3 storylines but will then decrease more drastically to nearly zero by 2050. Its substitution by carbon-neutral gases will be different depending on the storyline.

This report contains the results of the last two tasks of the study: **Task 3** assesses the consequences for (existing and planned) trans-European gas infrastructure under the three developed storylines for six selected TSOs. **Task 4** assesses the readiness of three selected national regulatory regimes in a significantly changing energy landscape.

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[5] EC (2018) Energy efficiency first: Commission welcomes agreement on energy efficiency. http://europa.eu/rapid/press-release_STATEMENT-18-3997_en.htm
6 In the context of necessary reductions according to the IPCC by developed countries as a group, to reduce emissions by 80-95% by 2050 compared to 1990 levels. In the Low Carbon Roadmap (2011), the Commission considered GHG reductions not only in the energy system but also in other sectors, notably agriculture (but did not consider emissions from land use change (e.g. role of GHG sinks).
7 See [https://ec.europa.eu/clima/policies/strategies/2050_en] and [http://unfccc.int/paris_agreement/items/9485.php]

1.1 Scope

During a bilateral meeting with DG ENER, the following TSOs and national regulatory frameworks (Member States) have been selected for this part of the study:

TSOs	Energinet (Denmark) GRTgaz (France) Gaz System (Poland) Transgaz (Romania) Gas Networks Ireland Snam Rete Gas (Italy)
National regulatory regimes	Denmark France Poland

The study focuses on large gas infrastructure, in particular cross-border pipelines, national transmission networks, LNG terminals and gas storage.

This report provides first an overview of the existing and planned (PCIs) gas infrastructure in each of the six Member States, followed by a high-level assessment of the potential impacts of the three storylines on the different types of gas infrastructure in the considered country.

It then analyses the main national developments that influence gas infrastructure: current and expected gas demand in the coming decade; evolution of gas supply (including security of supply issues); RES targets and policies, in particular regarding renewable gases; gas market integration and competition; specific environmental regulation. This analysis concludes with an overview of the main non-demand drivers for use of and investments in large gas infrastructure.

The study then qualitatively analyses the potential impact of the three storylines on the grid tariffs and TSO business. On the basis of the current OPEX and CAPEX, and the investment levels foreseen in the NDPs, a high-level evaluation is undertaken to roughly estimate the possible evolution of the overall cost levels and the related grid tariffs under the different storylines.

As for the regulatory aspects, the study focuses on the tariffication principles for access to and use of gas transmission infrastructure and the regulation of revenues of TSOs. The accounting rules (in particular depreciation rules for gas transmission assets) and the allocation of grid infrastructure costs are also issues which are considered. The analysis of the national regulatory schemes also evaluates to what extent the development and injection of renewable gases into the gas grid is facilitated.

Specific aspects such as the unbundling regime, balancing system and entry/exit regimes are not part of the scope, as they do not have a direct impact on the use of and investments in gas infrastructure.

1.2 Methodology

The methodology consisted of an in-depth **literature review,** using both EU level and Member State specific data sources. These included, for example, the following:

- EU level statistics (Eurostat);

- EU level publications regarding gas markets from ACER/CEER;
- EU level publications regarding gas infrastructure from ENTSOG and GIE (including ENTSOG's TYNDP[8], the system development map[9], transmission capacity map[10], etc.);
- TSO annual reports and TYNDPs;
- NRA and other national publications.

The literature review was complemented by **interviews** with representatives from the TSOs and NRAs in the selected Member States. The table below provides an overview of these interviews.

Table 1-1 Overview of interviews

Country	Organisation	Contact persons	Date
Denmark	Energinet	Thomas Young Hwan Westring Jensen	27 March 2018
		Nina Synnest Sinvani Frederik Peter Sveistrup Kjerulf	7 May 2018
		Thomas Jensen Frederik Kjerulf Jeppe Danoe	16 May 2018
	NRA (Energitilsynet)	Henrik Nygaard Mads Lyndrup	12 June 2018
	Danish Energy Agency	Frank Marcher	
Ireland	Ervia/Gas Networks Ireland	Brian Murphy Philip Connolly Stephen Oriordan	11 April 2018 26 April 2018
France	GRTGaz	Christophe Poillion Jonathan Losser	20 March 2018 27 April 2018 19 June 2018
	NRA (CRE)	Benoît Esnault	30 May 2018
		François Berthélemy Edith Hector François Léveillé	12 June 2018
Italy	SNAM Rete Gas	Paolo di Benedetto	20 April 2018
Poland	Gaz System	Artur Wozniak Jakub Przyborowicz Pawet Sek Kus Piotr	19 April 2018
	NRA (URE)	Maciej Syroka	13 June 2018
Romania	Transgaz	Alexandra Militaru	18 April 2018

Based on the information gathered, country sections have been developed including the following information:

- Existing and planned gas infrastructure in the Member State;
- Main national developments that influence investments in and use of gas infrastructure;
- TSO's business model and financial indicators;
- Regulatory framework (only for Poland, France and Denmark).

[8] http://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017
[9] https://www.entsog.eu/maps/system-development-map
[10] https://www.entsog.eu/maps/transmission-capacity-map

Based on this input, we assessed the of the three storylines developed in tasks 1 and 2 on existing and planned gas infrastructure as well as on gas grid tariffs and TSO's business, and evaluated the readiness of the current regulatory frameworks to cope with current and expected changes.

1.3 Structure of the report

The report is structured as follows:

- Chapter 1 provides the scope and methodology of the study and the structure of the report
- Chapters 2 to 7 provide country specific analysis comprising:
    - An overview of the existing and planned gas infrastructure in the country, including planned Projects of Common Interest (PCIs) and the estimated impact of the storylines on this infrastructure;
    - An overview and assessment of the national developments that influence investments in gas infrastructure, focusing on gas supply and demand, renewable energy policy, gas market integration and competition, and other relevant issues;
    - An assessment of the TSO, including key financial figures and viability analysis for the selected storylines;
    - For Denmark, France and Poland, a regulatory framework assessment.
- Chapter 8 provides an overview of the key findings and conclusions.

2 Denmark

Key data for gas system in Denmark		Unit	Source
Annual gas consumption	33,676	GWh/year	Eurostat 2016
Peak load	286	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	17	%	Eurostat 2016
Domestic natural gas production	47,149	GWh/year	Eurostat 2016 (nrg_100a)
Imports	7,116	GWh/year	Eurostat 2016 (nrg_100a)
Exports	22,060	GWh/year	Eurostat 2016 (nrg_100a)
Capacity of entry pipelines	61	GWh/day	ENTSOG transmission capacity map
LNG import terminal capacity	0		GIE LNG map
Gas Storage Capacity	10,820	GWh/year	GIE AGSI+
Number of gas PCIs in 2017 list	2	projects	PCI list 2017
Other general information[11]			
Regulatory system	**Transmission:** regulated Third Party Access with tariffs based on actual TSO costs[12] **Storage:** negotiated Third Party Access		
NRA	Energitilsynet - Danish Energy Regulatory Authority (DERA)		
TSO	Energinet (state-owned) – owns and operates the electricity and gas transmission network		

2.1 Existing and planned gas infrastructure

Denmark has a large natural gas production (exceeding domestic demand), an extensive gas grid and two gas storage facilities, but no LNG terminals. The gas transmission network links the gas production locations in the North Sea, and the interconnectors with the neighboring countries to the distribution grids supplying the consumers. The transmission grid in Denmark is owned and operated by Energinet, and the access to the network is regulated. The Danish gas system has an exit-zone and two cross-border connection points. Denmark is involved in two Projects of Common Interest (PCI) on the third PCI list which would connect Denmark with Poland. Depending on the storyline, the gas storage facilities could be further used or would require refurbishment for storing H_2. As the gas demand would in Denmark in the 3 storylines remain at a relatively high level compared to today, the transmission network would in the medium and long term continue to be used for an increasing share of renewable gas. Some existing pipelines (e.g. connecting gas production fields) would however be substantially less utilized and might need to be decommissioned as part of holistic planning and adequate coordination such as conversion to CO2 transport.

[11] OECD/IEA (2017), Energy policies of IEA countries: Denmark. 2017 Review.
[12] Energinet (2017), Sustainable energy together: Annual report 2016.

2.1.1 *Main large infrastructure in Denmark*

LNG terminals

There are no LNG terminals in Denmark,[13,14] nor have any terminals been proposed. Denmark has only a few operational and planned small scale liquefaction plants (see section 2.2.1).

Gas storage

Denmark has two gas storage facilities, Stenlille in Zealand and Lille Torup in Northern Jutland. Both are operated by Gas Storage Denmark, an independent company which is a fully-owned subsidiary of Energinet.[15] In 2015, Gas Storage Denmark introduced a 'one storage point concept', allowing to operate the two physical storage facilities as one in relation to the market and in the way storage users nominate gas in and out of storage.[16] The storage facilities are used to ensure security of gas supply and to compensate for seasonal fluctuations in consumption and take advantage of price differentials for commercial reasons. The total storage capacity is equivalent to about one third of Denmark's annual gas consumption, ensuring a high security of supply level.[17]

According to the Danish Natural Gas Act, the access to gas storage is negotiated. Tariffs for use of storage capacity are hence not regulated, but DERA still has to make sure that Third Party Access is provided in a transparent, non-discriminatory and objective manner.[18] Gas storage is a deregulated activity that competes in a growing regional market with other flexibility tools, e.g. new transmission infrastructure and more flexible supply contracts.[19] DERA monitors the access to storage and assesses whether the negotiated access rules might have negative impacts. If that would be the case, DERA will evaluate whether the negotiated access regime can be maintained or should be changed to a regulated regime.[20]

In 2016, the whole storage capacity was reserved before the start of the storage year. It was allocated at an average tariff of 1.7 €/MWh.[21] The demand for gas storage capacity seems hence to be high, which is due to the actual pricing of storage capacity that corresponds to the forward market valuation of seasonal storage. However, this means that storage capacity is priced below long run marginal cost.

The table below shows an overview of the storage facilities in Denmark. Further information is available on the Gas Storage Denmark's website.[22] One of the facilities is a salt cavern, while the other is an aquifer. The advantage of salt caverns is that gas can be quickly added and withdrawn. In the future, when more biomethane and hydrogen are integrated into the natural gas system, different caverns could potentially store different gases.[23]

[13] DERA (2017), National report Denmark: Status for 2016.
[14] GIE (2018), GIE LNG map.
[15] OECD/IEA (2017), Energy policies of IEA countries: Denmark. 2017 Review.
[16] DERA (2017), National report Denmark: Status for 2016.
[17] Energinet (2017), The future role of the gas system.
[18] DERA (2017), National report Denmark: Status for 2016.
[19] DERA (2017), National report Denmark: Status for 2016.
[20] DERA (2017), National report Denmark: Status for 2016.
[21] Energinet (2017), Sustainable energy together: Annual report 2016.
[22] https://gasstorage.dk/
[23] Energinet (2017) The future role of the gas system.

Table 2-1 Gas storage facilities in Denmark. Source: GIE Storage Map 2016[24]

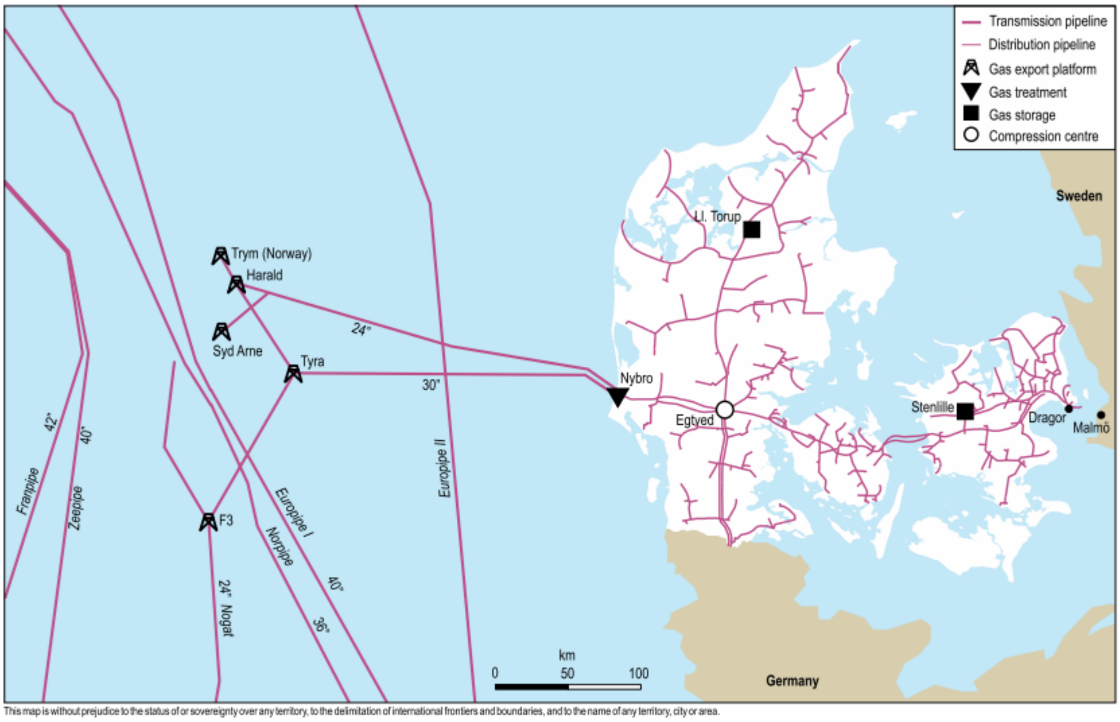
Facility/Location	Status	Start-up year	Type	onshore/ offshore	Operator	Working gas (technical)= TPA TWh	Withdrawal technical = TPA GWh/day	Injection technical = TPA GWh/day	Access regime
Lille Torup	Operational -physical	1987	Salt cavern	Onshore	Gas Storage Denmark	n.a.	n.a.	n.a.	nTPA
Stenlille	Operational - physical	1994	Aquifer	Onshore	Gas Storage Denmark	n.a.	n.a.	n.a.	nTPA
GSD virtual gas storage	Operational - virtual	2015	Virtual	Onshore	Gas Storage Denmark	10.8	196.8	100.8	nTPA

[24] GIE (2016), GIE Storage Map 2016.

Gas transmission network

The gas transmission network links the gas production locations in the North Sea and the interconnectors with the neighbouring countries to the distribution grids connecting to consumers. The transmission grid in Denmark (924 km pipelines at the end of 2016) is owned and operated by Energinet.[25] The access to the network is regulated. DERA approves the tariff methodology for Energinet, which sets the actual tariffs and submits them to DERA.[26]

Figure 2-1 Map of Danish natural gas infrastructure 2017[27]



In October 2013, a new 94 km gas pipeline in southern Jutland, from Ellund to Egtved, and a new compressor station in Egtved started operation. This investment significantly increased the capacity of the gas transmission network and allows Denmark to import sufficient natural gas quantities from Germany to cover both the Danish and Swedish consumption in the future, when gas production in the Danish part of the North Sea will decline. The concerned German TSO, Gasunie Deutschland, has also expanded the capacity on the German side of the Ellund interconnection point, which has raised the available firm capacity for Ellund (DE > DK) to approx. 450,000 Nm^3/hour.[28] The North Sea pipeline can transport energy corresponding to Denmark's total electricity, gas and oil consumption.[29]

With declining consumption onshore and falling production offshore, the transport capacity is not being fully utilised today and this trend is continuing. The TSO is therefore undertaking actions in view of transforming the gas system to new usages and ensuring that it remains sustainable in terms of technology and economics, and can optimally contribute to the green transition. Even with a further reduction in the utilisation of the gas system in 2035, Energinet considers that it can save the national

[25] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[26] DERA (2017), National report Denmark. Status for 2016.
[27] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[28] DERA (2017), National report Denmark: Status for 2016.
[29] Energinet (2017), The future role of the gas system.

economy €268 – €403 million annually compared to a scenario where the natural gas grid would not be used any more.[30]

Interconnections

The Danish gas system consists of an exit-zone and two cross-border connection points Ellund (towards Germany) and Dragør (towards Sweden). Dragør is a unidirectional pipeline with no gas flow from Sweden to Denmark[31] and there are no plans to establish a reverse flow.

Natural gas in Denmark comes primarily from the Danish North Sea fields through two subsea pipelines of approximately 235 and 260 km. The gas comes ashore at the beach terminal in Nybro where it is possible to treat the gas before its injection into the transmission network. Normally the gas quality is within the specifications and no treatment is necessary. With regard to transit from the North Sea to the European market, the Danish system is in competition with the Dutch gas infrastructure, which is also linked to the fields in the Danish part of the North Sea. The gas is transported via the route with the lowest transport costs.[32]

Table 2-2 Interconnection points[33]

Type	*N*	*Point*	*Arc*	*Technical physical capacity (GWh/d)*	*From*	*To*	*From op*	*To op*
Cross-border IP within EU and with non-EU (export)	36	Ellund	Y-DKe>	**32.7**	DK	DE	Energinet.dk	Open Grid Europe / Gasunie Deutschland
			>Y-DKe	**60.6**	DE	DK	Open Grid Europe / Gasunie Deutschland	Energinet.dk
Cross-border IP within EU and with non-EU (export)	37	Dragør	DK>SE	**87.8**	DK	SE	Energinet.dk	Swedegas AB

Regarding biomethane, although the gas infrastructure enables gas flow without any adaptation required, due to differences in the thresholds for O_2 concentration there is currently no possibility of exporting Danish biomethane to Germany. The threshold in Denmark is 0.5% while in Germany it is significantly lower, namely 0.001%. These two should be harmonised in order to enable biomethane flow between the two countries. It should be investigated where in the value chain it is the most cost effective to remove the O_2 and which operator (biomethane producer or TSO/DSO) should bear the related cost.

2.1.2 Planned Projects of Common Interest[34]

Denmark has two gas PCIs in the same project cluster together with Poland on the third PCI list (2017). The combined projects under this cluster will allow for further development of the BEMIP-region by linking Norway, Denmark and Poland. The supply of gas to Poland is expected to range from 7 to 10 bcm per year[35] and these new developments are expected to make it more attractive to use gas instead of coal resulting in a positive climate impact.

[30] Energinet (2017), The future role of the gas system.
[31] DERA (2017), National report Denmark: Status for 2016. A
[32] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[33] ENTSOG (2016), ENTSOG capacity map 2016.
[34] PCI project fiches available DG ENER's interactive map of PCIs: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html
[35] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.

The project cluster involves an off-shore pipeline between Denmark and Poland (Baltic Pipe, PCI 8.3.2), reinforcement of the existing transmission system in Denmark and Poland (Reinforcement of Nybro — Poland/Denmark Interconnection, PCI 8.3.1) including compressor stations in both countries. Furthermore, the project cluster includes an offshore pipeline between the Danish gas system and the Norwegian upstream system (not PCI, FID expected in 2018 and commissioning by 2022).[36] If this project will effectively be realised, it will enable Denmark to further diversify its gas supply, increase competition and ensure more stable tariffs. The tariff element is important for the Danish business case since the project will help stabilize tariffs that may otherwise increase due to decreasing Danish gas consumption.

The two PCIs are further described below.

Reinforcement of Nybro — Poland/Denmark Interconnection (PCI 8.3.1)

The project allows for linking the Baltic Pipe to the North Sea and requires grid expansions across the Danish territory, including reinforcement of the Danish Transmission System for transporting approx.10 bcm /year from Egtved to the Baltic Pipe entry/exit point in Denmark. The project includes:

- about 200 km new onshore pipeline (DN900-DN1000);
- about 4 km offshore crossing of Lillebælt (DN900);
- and 1 compressor station in Denmark i.e. Zealand CS (36 MW).

The expected commissioning year is 2022.

Poland-Denmark interconnection ["Baltic Pipe"] (PCI 8.3.2)

In December 2016, Energinet and the Polish TSO (GAZ-SYSTEM) completed a feasibility study[37] which assessed the technical and economic feasibility of the Baltic Pipe and was partially funded by the EU.[38] The study showed substantial socio-economic benefits for both Denmark and Poland[39]: more competition, lower Danish gas tariffs and higher security of gas supply, which is important as the Danish gas production in the North Sea will decline.[40]

The project includes:

- a new, bi-directional offshore gas pipeline connecting Poland and Denmark through the Baltic Sea with a capacity of approx. 10 bcm/y and a length of approximately 260-310 km;
- a receiving terminal (Poland);
- onshore pipelines connecting the offshore pipeline with the national grids in Poland and Denmark;
- a DN 1000 Goleniow – Lwowek pipeline (Poland) of approx. 188 km;
- and three compressor stations in Poland i.e. Goleniow CS (approx.12 MW), Odolanow CS (approx.14 MW) and Gustorzyn CS (approx.15 MW).

The project is currently in the design and permitting phase and commissioning is planned for 2022.

Social acceptance & additional support

Energinet has experienced challenges with lack of social acceptance for large infrastructure projects and tries to solve this through dialogue and information. In special cases it is possible to expropriate land use rights with full compensation and approval from relevant authority given that the project is of national interest.

[36] Energinet (2017), Sustainable energy together: Annual report 2016.
[37] Gas Feasibility Study regarding the PCI Poland-Denmark interconnection Baltic Pipe supply and demand
[38] Energinet (2017), Sustainable energy together: Annual report 2016.
[39] DERA (2017), National report Denmark: Status for 2016.
[40] Energinet (2017), Sustainable energy together: Annual report 2016.

There are no special national incentives for PCIs in Denmark, but these projects do have a high priority in the permitting procedure.

2.1.3 Estimated impact of the storylines on Danish gas infrastructure

Table 2-3 Impact of storylines on Danish large gas infrastructure.[41] Source: Own assessment

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane			Storyline 3 Strong development of hydrogen		
Gas demand 2015 & share	23.3 TWh			23.3 TWh			23.3 TWh		
	Natural Very high	Methane Negligible	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Negligible
Gas demand 2030 & share	Decrease			Increase			Stable		
	Natural Very high	Methane Negligible	Hydrogen Negligible	Natural Very high	Methane Low	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Low
Gas demand 2050 & share	Decrease			Increase			Stable		
	Natural Negligible	Methane Medium	Hydrogen High	Natural Negligible	Methane Very high	Hydrogen Low	Natural Negligible	Methane Low	Hydrogen Very high
LNG terminals	No LNG terminals and no projects, hence no impact			No LNG terminals and no projects, hence no impact			No LNG terminals and no projects, hence no impact		
Gas storage	Existing gas storage in aquifer could be used for biomethane while existing salt cavern site could be refurbished for hydrogen storage after 2030. New additional storage facilities may be required to store hydrogen.			Existing gas storage sites can be further used for methane. The requirements regarding a more dynamic operation of gas storages to cope with fluctuating renewable production might require an update or retrofitting of gas storage infrastructure.			Existing gas storage in aquifer could be used for biomethane while existing salt cavern site could be refurbished for hydrogen storage after 2030. New storage facilities may be required to store hydrogen, e.g. in new or converted salt caverns (i.e. Lille Torup). The possibility of H2 storage in aquifers still has to be evaluated.		
Transmission network & import/transit pipelines	Utilisation level of large pipelines and transmission network will decrease after 2030. Some assets might need to be refurbished (if hydrogen injection exceeds technical threshold) and/or might need to be decommissioned (or could be used for CO_2 transport).			Some pipelines (connecting production) will be less utilised and might need to be decommissioned. Transmission assets will continue to be used (increasing gas demand - high volumes of biomethane). Investments might be needed to allow reverse flow of biomethane from distribution to transmission grid			Utilisation level of large pipelines will decrease but transmission network will after 2030 continue to be used (stable gas demand). The grid would need to be refurbished for hydrogen (90% of renewable gas). Some pipelines could be decommissioned or converted for CO_2 transport.		

*Note: The overall gas demand 2030 and 2050 is compared to the current level and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease 5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The gas shares are categorised as follows: 76%-100%= **'very high'**; 51%-75%= **'high'**; 26%-50%= **'medium'**; 6%-25%= **'low'**; 0%-5%= **'negligible'**.*

[41] Future gas demand will increasingly be covered by local production of renewable gas, partly locally used and partly injected into the distribution or transport grid. The volumes to be transported by the transmission grid will hence be lower than the overall gas demand.

2.2 Main national developments that influence investments in and use of gas infrastructure

Denmark is self-sufficient in natural gas and trades its surplus production with neighbouring countries. The share of natural gas in Denmark's total primary energy consumption fell from 22% in 2006 to 17.4% in 2016, mainly due to increasing deployment of renewable energy. Denmark has already in 2014 reached its target of 30% renewable energy by 2020. Even though natural (fossil) gas is planned to be gradually phased out in Denmark towards 2050, it is expected that the gas infrastructure will continue to play a key role in the energy system, as biomethane is already increasingly being injected into the gas grid and the deployment of hydrogen is expected. Several initiatives are being taken to stimulate this development and to reduce the climate impact of the use of gas. The expansion of the Danish and German gas transmission network in 2013 has increased competition in the gas market and has contributed to reducing the price spread between the two markets. The gas supply security is in Denmark in general well ensured by its own gas production and access to pipeline gas from several sources. The gas system and market in Denmark are properly interconnected with the neighbouring countries.

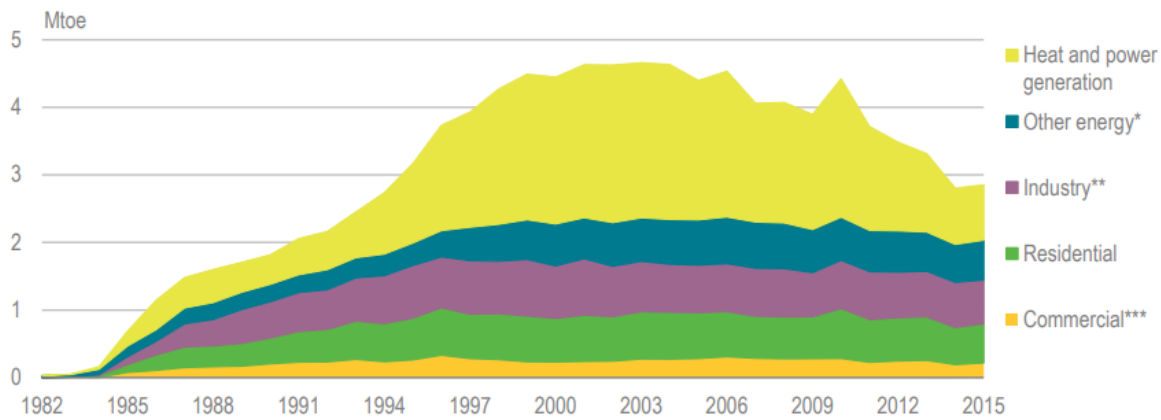
2.2.1 Gas supply and demand

Denmark is self-sufficient in natural gas and trades it with Germany, Sweden, the Netherlands and, although there is no direct grid connection, with Norway.[42]

Demand

Gas consumption in 2016 was 2.9 Mtoe (over 3 bcm) of which 28.7% for heat and power generation, 22.7% for industry, 20.6% other energy, 20.4% residential, 7.5% commercial and 0.1% transport.[43] The share of natural gas in Denmark's total primary energy supply fell from 22% in 2006 to 17.4% in 2016, mainly as wind power replaced gas for power generation.[44] The figure below shows the evolution of gas demand per sector from 1982 to 2015. According to the Danish Energy Agency (DEA), consumption of natural gas is projected to further decrease (by around 30% compared to 2015 levels) and to stay at a relatively constant level after 2020.[45] District heating production and power plants are expected to shift from coal and natural gas to biomass.

Figure 2-2 Natural gas consumption by sector in Denmark from 1982 to 2015 (domestic demand)[46]



[42] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[43] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[44] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[45] DEA (2017), Denmark's Energy and Climate Outlook 2017.
[46] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.

Energy taxes in Denmark are levied within the framework of the 2003 EU Energy Tax Directive, which sets minimum rates for the taxation of energy products in Member States. Within this framework, taxes are levied on the use of fossil fuels which incentivize end-users to lower their natural gas consumption and/or to switch to renewable gas:

- An energy tax applies to oil products, natural gas, coal and coke and fossil waste, at rates varying in proportion to the fuels' energy content;
- A CO_2 tax applies to oil products, natural gas and coal and coke products, at rates varying in proportion to the fuels' carbon content.[47] This tax amounts for natural gas to 0.1232 €/Nm^3.

These taxes on fossil fuels as well as policies to reduce energy consumption (Denmark has committed to reduce its primary energy consumption by 14.5% in 2020 compared with 2006[48]) have an impact on natural gas demand and incentivize the shift to renewable energy.

Trends that might lead to a higher future gas demand than currently expected

Use of gas in the transport sector

Natural gas and biomethane currently play a marginal role in the transport sector in Denmark with only about 460 vehicles and one ferry, which might be the result of the currently weak legislative framework/support for gas in transport. The use of natural gas or biomethane is taxed more than diesel. CO_2 reductions from the use of biomethane can be proven by means of guarantees of origin, but they do currently not count as CO_2 reductions in the transport sector. Lastly, light duty vehicles using CNG are taxed higher due to the value-based vehicle tax system and less discount for efficiency than comparable diesel vehicles.

According to an analysis carried out by Energinet[49] there is a potential growth of about 10 PJ of gas use in the transport sector, mainly for heavy duty vehicles and ships. This potential of 10 PJ only considers domestic shipping and not ships passing through Danish ports. With an energy usage of 280 PJ in 2015[50] for ships docking in Danish ports, the potential gas usage in the maritime sector would increase significantly if international routes would be included. Bunkering of ships is thought to be based on local LNG production from biomethane or natural gas. The use of biomethane in the transport sector is considered as a cost-effective means to reduce CO_2 emissions from the transport sector.

An increased use of gas in the transport sector depends on a number of conditions:

- That gas vehicles are available on the market at competitive prices;
- That LNG liquefaction infrastructure will be developed;
- That the legislation supports the use of gas for transport.

The availability of gas vehicles depends on developments outside Denmark and could be supported by initiatives at EU level.

Currently only two smaller LNG bunkering facilities exist in Denmark (Hirtshals and Hou[51]). Recently, market operators are showing interest for the development of bunkering facilities in combination with a liquefaction facility in order to supply liquefied biogas gas (LBG). Two concrete projects are currently being considered: a consortium consisting of Hirtshals Harbor, Fjordline, and HMN Gashandel[52] is looking into the possibility of establishing an LBG liquefaction facility with a capacity of 160 ton/day, while a

[47] OECD (2018) Taxing Energy Use 2018: Denmark.
[48] Centre for Energy Efficiency (2017), Denmark NEEAP 2017.
[49] Energinet (2017), El og Gas Til Transport (Projection of electricity and gas use in the transport sector).
[50] Accounting for half of their total travelled distance (source: Wisdom 2017).
[51] The LNG is imported for both bunkering facilities.
[52] In July 2017 HMN Gashandel was acquired by SEAS-NVE and Eniig.

consortium with Kosan Cristplant, Bunker Holding and NGF Nature Energy considers a similar project in Frederikshavn with a capacity of 300 ton/day. It is uncertain at this moment whether these bunkering- and liquefaction facilities will effectively be realised.

Hybrid heat pumps

According to an analysis carried out by Energinet[53] the use of hybrid heat pumps (combination of air to water heat pump and gas condensation boiler) might offer an appropriate solution to lower the overall energy consumption for heating, while enabling the use of renewable electricity for heating and providing flexibility to the electricity system. Energinet also argues that this option would require less reinforcement of the electricity grid than a large-scale deployment of electric heat pumps.

In current long projections[54] of gas demand, the use of gas for heating is expected to be replaced with renewable alternatives in order to comply with the 2050 target. Energinet considers the development of hybrid heat pumps as an effective means to use both biomethane and renewable electricity for heating, while continuing to use the gas connection for flexibility purposes. Hybrid heat pumps are at present not yet used in the Danish heating sector.

Future study – System Perspektiv 2035

Energinet has recently published an analysis under the title ‘System Perspective 2035 – Long term perspective for the efficient use of Renewable in the Danish energy system’.[55] The analysis investigates how large amounts of renewable electricity can be handled in an economical and efficient way in the Danish energy system. The analysis describes scenarios for 2035 and 2050 with input from ENTSOG and ENTSO-E’s scenarios for TYNDP2018. As part of the efficient handling of renewable electricity production, power to gas and also the production of biomethane is emphasized. Power to gas has the possibility to balance the seasonal fluctuations in renewable electricity production as well as to provide fuels for purposes that are hard to electrify: industry, heavy duty vehicles, airplanes and ships. Batteries in electric vehicles and grid connected batteries play a similar role for the short-term fluctuations. Biomethane plays a similar role, CO_2 from production of biomethane is combined with hydrogen from electrolysis to produce either gaseous or liquid fuels. The study concludes that the gas system can play a crucial role in the energy transition.

Trends that might lead to a lower future gas demand

The energy needs for heating will in the future further decrease as a consequence of the impact of energy efficiency measures, implemented amongst others in the context of the EED and EPBD. Next to these measures, the following developments are expected to negatively impact the future gas demand in Denmark.

Electric heat pumps and growth of district heating

The current target of the Danish authorities is to become independent from fossil fuels by 2050. One possible measure to reach this target is to replace natural gas and oil boilers for building heating with electric heat pumps and district heating for buildings close to heating networks. In many cases heat pumps are competitive compared to fossil fuel boilers, and also offer a higher energy efficiency level.

53 Energinet (2018), Hybridvarmepumper (Hybrid heat pumps).
54 Danish Energy Agency (2016), Arbejdsgruppen for analyse af gassektoren – en effektiv gassektor. (The taskforce for analysis of the gas sector – an efficient gas sector).
55 Energinet (2018), Systemperspektiv 2035. The report is not yet translated to English.

In previous scenarios for 2050, it was considered that the large-scale deployment of electric heat pumps and district heating would lead to a gradual phase out of gas for heating.

Reduction in combined heat and power plant capacity

A large share of the Danish gas demand has historically been used for combined heat and power plants (up to 50%). In recent years this share has dropped significantly mainly due to low electricity prices but also due to the tax imposed on heating from gas fired production. Power plants in operation have reduced load factors and heat is being produced with alternative sources such as heat-only boilers. Owners/operators of power plants are assessing alternative solutions such as biomass-based heat-only boilers, district heating scale heat pumps and large-scale solar heating. Currently the legislation prevents in most cases conversion from natural gas CHP to biomass-heat. Additionally, plants are kept online due to a support scheme called “Grundbeløb 1 & 2” which is scheduled to be removed by end of 2018 and 2019.[56] At that moment, several power plants might shut-down completely, and the gas for electricity production will further reduce.

Supply

Denmark is a natural gas producer. In 2016, Denmark exported 2.1 bcm (of which 43% to Sweden).[57] In the same year, Denmark imported 0.7 bcm – 71% from Norway (via tankers) and 29% from Germany.[58]

The Danish domestic natural gas production is decreasing, but Denmark was in 2016 still a net exporter.[59] In 2016, the Danish production of natural gas was 4,269 million Nm^3 [60] and Denmark is expected to remain a gas producer in the coming decades.[61]

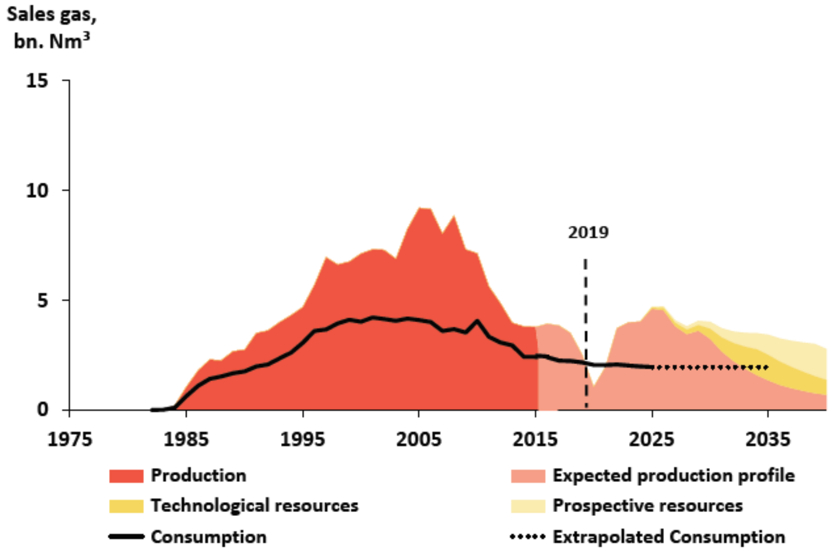
Table 2-4 Current and expected gas production for sales (domestic production)[62]

	2016	2017	2018	2019	2020
Gas production for sales, bn Nm^3	3.9	3.9	3.5	2.5	1.1

Natural gas production is expected to decrease substantially from 2019 to 2022 due to the renovation of Tyra. In 2022 Tyra will again be operational and the commissioning of the Hejre Field is planned in 2021.[63] The expected production profile in 2020-2035 is presented in the figure below.

[56] For the legislation: https://www.retsinformation.dk/Forms/R0710.aspx?id=152628
[57] IEA: Denmark - Energy System Overview. Available from: https://www.iea.org/media/countries/Denmark.pdf
[58] DERA (2017), National report Denmark: Status for 2016.
[59] DERA (2017), National report Denmark: Status for 2016.
[60] DERA (2017), National report Denmark: Status for 2016.
[61] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[62] ‘The production of sales gas is subject to the condition that sales contracts have been concluded. Such contracts may either be long-term contracts or spot contracts for very short-term delivery of gas.’ Source: Danish energy Agency (2016), Energy and Resources.
[63] Danish energy Agency (2016), Energy and Resources.

Figure 2-3 Production and long-term sales[64] gas forecast[65]



Biogas/biomethane represents a growing share of gas supply; at the end of 2017, upgraded biogas accounted for approximately 5% of total Danish gas consumption.[66]

Security of energy supply

While Danish gas production has been sufficient for meeting internal demand, the security of gas supply may temporarily be at risk due to the reconstruction of the Tyra field in 2019-22. This temporary shut-down is considered as a specific risk for security of supply in the ENTSOG analysis.[67] The total Danish gas production is expected to decline to around 12% per year during that period.[68] The expansion of the transmission system in Germany, which increased the import capacity from Germany to Denmark to 10.8 mcm/day, provides additional supply security and flexibility to the system. Furthermore, Gasunie Deutschland is examining the possibility of expanding the capacity with 1 GWh/day at Ellund.

Sweden has no indigenous gas production and no gas storage or LNG facilities, and depends entirely on gas supplies from Denmark to cover its consumption of approx. 1 bcm per year. Security of supply is therefore a major issue for the Danish/Swedish cooperation.[69] Under normal conditions, the capacity at Ellund (see Interconnections) is sufficient to cover the combined Danish and Swedish consumption, and the import capacity together with the total Danish storage capacity (withdrawal rate of approx. 16 mcm/day and total capacity of approx. 1 bcm) is sufficient to also cover shorter periods of extremely high demand or extreme temperatures. The Danish and Swedish supply situation is hence only at risk in case of prolonged cold winter spells and/or inadequate use of the storage facility by the gas actors.[70] On the basis of the current situation and expected evolution, security of supply is not expected to be a driver for new investments in gas infrastructure in Denmark, as the supply - with domestic production and import form different sources – is well diversified, and the import, storage and transmission

[64] 'The production of sales gas is subject to the condition that sales contracts have been concluded. Such contracts may either be long-term contracts or spot contracts for very short-term delivery of gas.' Source: Danish energy Agency (2016), Energy and Resources.
[65] Danish energy Agency (2016), Energy and Resources.
[66] Energinet (2017), The future role of the gas system.
[67] ENTSOG (2017), Union-wide simulation of supply and infrastructure disruption scenarios.
[68] Energinet (2017), Security of gas supply report.
[69] DERA (2017), National report Denmark: Status for 2016.
[70] DERA (2017), National report Denmark: Status for 2016.

capacity is sufficiently developed and large to withstand an unplanned unavailability of an important gas system component.

2.2.2 *Renewable energy policy and targets*

Denmark has committed to a target of 30% renewable energy by 2020 in the context of the 2009 EU Directive. This target was already reached in 2014, when Denmark had a 30.8% share of renewable energy in final energy consumption.[71] Further, in 2011 the Danish government published its Energy Strategy 2050, with the main goal of becoming independent of coal, oil and gas by 2050.[72]

Even though natural gas is expected to be gradually phased out in Denmark towards 2050, it is expected that the natural gas infrastructure will continue to play a key role in the green transition, as biomethane will increasingly be injected into the gas grid.[73]

Renewable energy based or carbon neutral gas

Production of biogas and upgrading it to biomethane for injection into the natural gas grid has in Denmark been steadily increasing since 2014 following a new regulatory support framework. It is now the most common use of biogas. Biomethane injected volumes at the beginning of 2018 corresponded to almost 7% of Danish gas consumption and are expected to increase to above 10% in early 2019.

27 biomethane facilities were connected to the gas network at the beginning 2018 (one to transmission and 26 to distribution grids). These facilities have a total capacity of above 200 mcm/year.[74] In periods of low demand, it is expected that the quantity of injected biomethane in the distribution network will exceed local gas consumption. Energinet is therefore engaged in projects to ensure that excess biomethane can be reversed into the transmission grid. Furthermore, differences in gas quality specifications in Denmark (5,000 ppm oxygen) and Germany (10 ppm for sensitive assets), can lead to a reduction in the available capacity at Ellund towards Germany and hinder an optimal functioning of the gas system. Energinet has therefore started a so-called 'Oxygen Task Force' with the aim of assessing possible sustainable solutions whereby market distortions are avoided e.g. by exploring the possibility of removing the oxygen directly at the production site, at the border point, at the sensitive assets etc., and developing a long-term view of how oxygen levels at a European level can be determined without distorting the growth of biomethane production.

The main feedstock used for biogas production is manure – only three grid connected plants are based on sewage treatment. Organic wastes from industry and sewage sludge also make a significant contribution to the biogas production, while the share of energy crops is small due to limitations imposed by the Danish Government for environmental sustainability reasons. The interest in using deep litter and straw for the production of biogas is however growing.
Aarhus University[75] has estimated the technical potential of biogas at 105 PJ. Based on this study, the Danish gas system operators have estimated that it would be possible to reach 100% renewable gas supply within the Danish gas system by 2035 if appropriate framework conditions are in place.[76]
According to the Danish Energy Strategy 2050, biogas shall play an essential role in the fossil independent energy system as storable renewable fuel used for flexible power production, industrial

[71] SWD (2017) 390, Energy Union Factsheet Denmark. Accompanying the 'Third report on the state of the Energy Union'.
[72] Danish government (2011), Summary Energy Strategy 2050 – from coal, oil and gas to green energy.
[73] Energinet (2017), Sustainable energy together: Annual report 2016.
[74] Energinet (2018), Report Security of gas supply 2017.
[75] Henrik B. Møller (2017), Biogas fra landbrugsråvarer: Så meget mere kan vi producere.
[76] www.groengasdanmark.dk

feedstock and for transport. Its use as a transport fuel will be mainly in heavy duty vehicles and transport uses where electricity is not competitive. Its use in light duty vehicles will be limited due to the national preference for electric light duty vehicles.

The use of biogas/biomethane is, according to the energy agreement 2012, financially supported:

- €10.6/GJ for use in combined heat and power heating (direct and indirect subsidies);
- €10.6/GJ for upgrading to biomethane and distribution via the natural gas grid;
- €5.2/GJ for use in industrial processes and transport.

In addition:

- €3.5/GJ for all applications – scaled down with increasing price of natural gas. If the natural gas price in year n-1 is higher than a basis price of €7.1/GJ the subsidy is reduced accordingly;
- €1.34/GJ for all applications – scaled down linearly every year from 2016 to 2020 when the subsidy expires (IEA).[77]

The subsidy scheme only covers biogas/biomethane produced from anaerobic digestion, meaning that other renewable gases such as H_2 and synthetic gases (SNG) are not eligible for support. These types of gases can only be sold to the market at the "normal" price for fossil natural gas, even though it has been generated from renewable CO_2 and electricity with low carbon intensity.

The EU approval of state aid for biomass CHP and biogas/biomethane under the state aid rules expires in 2019 and 2023 respectively, which means that a new political decision will have to be taken on whether to continue to subsidise these technologies. The existing plants will anyhow continue to receive aid according to the same rules as applied before the expiry of the aid scheme.[78]
Due to a high share of renewable electricity in the energy system, combined with a widespread district heating system to absorb waste heat, and rapid development of biogas plants, Denmark can be seen as an attractive location for the deployment of P2G and/or subsequent P2X production, as the access to green carbon is relatively high.
Denmark is heavily involved in research related to renewable gas. In 2017, €80.5 million have been assigned to 62 R&D-projects under the Danish Energy Technology Development and Demonstration Programme. Out of the 62 projects eight of them are demonstration/pilot projects:

Table 2-5 Demonstration/pilot projects

Name	Objective	Electrolyser	Methanation
Biocat	Upgrading of biogas	1 MW Alkaline	Biological
El-upgraded Biogas	Upgrading of biogas	40 kWe SOEC	Catalytic
EEEHy - Efficient and Economic Electrolytic Hydrogen Production	Enhancement of the efficiencies of electrolysis technology	N.A.	Not part of scope
HyBalance	H_2 for transportation and grid balancing	1.2 MW PEM	Not part of the scope
MegaStoRE	Upgrading of biogas	250 kW Alkaline	Catalytic focusing on enhancing the cleaning technology

[77] ISAAC project (2016), Deliverable D5.2: Report on the biomethane injection into national gas grid.
[78] DEA (2017), Denmark's Energy and Climate Outlook 2017.

Name	Objective	Electrolyser	Methanation
SYMBIO	Upgrading of biogas	Unknown	Direct injection of H_2 into the biogas digester
SYNFUEL	Upgrading of biogas from thermal gasification	SOEC	Catalytic
XEL2GAS	Combining H_2 and CO_2 to acetic acid for either storing or gasification	Unknown	Not part of the scope

In addition to the listed projects, Energinet is together with some Danish partners examining the consequences of injecting hydrogen directly into the natural gas grid via metering and regulation stations (M/R stations). In this project, a closed loop between two M/R stations is established. An electrolysis plant for on-site production of hydrogen is installed adjacent to the M/R stations and hydrogen is injected directly into the closed loop. The M/R stations' ability to handle significant amounts of hydrogen (up to 15%) will be examined and the necessary modifications will be conducted. The electrolysis system will be developed as a stand-alone production unit with associated user interface, monitoring and smart-grid-ready control systems. A lengthy test period of 24 months, started in the spring 2017, allows for a comprehensive test program, in which the interaction between the electrolysis plant and the M/R stations is investigated. The test phase also includes lifetime testing of critical components in both electrolyser and M/R stations.

With the current technology costs for power to gas and current market conditions, the costs of electricity limit the entrance of power-to-gas units into the market.[79] However with the increasing share of renewables in the electricity system, the proportional share of hours with low electricity prices is also increasing. Yet, there seems to lack investments in R&D and infrastructure development with long time horizon - given the current price and energy market dynamics and regulatory framework.

Guarantees of Origin for renewable gas

Enabling trade of renewable gas injected into the grid from producer to end consumer, by using the gas system's flexibility, storage and distribution potential, is seen as key for future green gas development. Most countries, including Denmark, with green gas traded through the grid have guarantees of origin systems enabling this trade. The Danish system – biomethane certificate system – is administrated by Energinet. It is a cornerstone of the green gas market model which enables biomethane to be distributed from its production site to consumers in Denmark or abroad. Energinet is working on enabling cross-border trade of green gas and in 2017 it entered into an agreement with the German Biogasregister (administered by the Deutsche Energie-Agentur) making it possible to transfer guarantees of origin between the two registries in a transparent and reliable way.[80] In addition Energinet together with other European biomethane registries' managers, are working towards establishing a common European system through the organization ERGaR – the European Renewable Gas Registry (www.ergar.eu). In this context it is also important to clarify how renewable gas is counted towards the national RES targets pursuant to article 3 of the RES Directive, when it has been exported and used as a fuel in another country.

The Danish model for guarantees of origin is designed to handle all types of renewable gas, though at present guarantees of origin are only issued for biomethane. As the first methanation plant was

[79] ForskEl (2017), Power-to-Gas via Biological Catalyst (P2G-Biocat).
[80] Energinet (2017), Denmark sells biomethane certificates to Germany.

commissioned in 2017 and a few projects are currently being developed, combined with an increasing interest from the gas market to explore the possibility of expanding the current GO scheme to other types of renewable gas, Energinet is considering extending its model to also include renewable synthetic methane from methanation.

2.2.3 Gas market integration and competition

The expansion of the Danish (and German) gas transmission network in 2013 has increased competition in the gas market and contributed significantly to reducing the price spread between the Danish gas exchange and the German hubs – a convergence that started in 2009.[81] Structural developments have made a positive contribution to market competition in the gas market, but there are still only a few companies bringing gas onto the market and in general only a few active players and limited amounts of gas available.[82] Further, there are several vertically integrated companies which operate at many or all levels of the supply chain, and which can have competition-impeding consequences.[83]

There is in general no physical congestion in the Danish transmission system, and in view of the expected fall in gas consumption and the improved capacity situation, it is very unlikely that any long-term congestion will occur in the future.[84] However, short term congestion could arise due to the temporary unavailability of the Tyra field that is shut down from 2019 to 2022. During this period Danish-Swedish gas market prices are expected to become higher and more volatile.

It is foreseen that the Danish and Swedish gas market will be further integrated in 2019 by creating a Joint Balancing Zone. This integration could also increase the liquidity in the Danish and Swedish markets.

A major change to the Danish market will occur in 2022 if the Baltic Pipe will effectively be realised. This connection could take up to 10 bcm of gas from Norway to Poland - through Denmark. In comparison the Danish gas consumption is roughly a fourth of this. The Baltic Pipe is expected to increase liquidity and competition in the Danish gas market thanks to easier access to more diversified sources.

Between 2014 and 2016, the gas wholesale prices in the Danish trading point NCG converged further towards the prices of the Dutch TTF trading point, which is seen as a reference point for European gas wholesale prices.[85] In more than 85% of the trading days in 2016, the price difference between the NCG and TTF trading points has remained below 0.4 €/MWh.

2.2.4 Environmental and climate related regulation and measures

A Danish government platform has in 2015 agreed on a full phase-out by 2050 of fossil fuels, including natural gas. Meanwhile, several initiatives are taken to reduce the climate impact of the use of natural gas and biogas.

[81] DERA (2017), National report Denmark: Status for 2016.
[82] DERA (2016), Analysis of competition on the Danish wholesale market for natural gas
[83] According to DERA, negative consequences can occur partly because of the risk of cross-subsidisation between regulated and non-regulated (competitive) parts of the market, and partly because of the risk of discrimination in access to transport gas onshore from the North Sea. Source: DERA (2016), Analysis of competition on the Danish wholesale market for natural gas
[84] DERA (2017), National report Denmark: Status for 2016
[85] ACER/CEER (2017) Annual report on the results of monitoring the internal electricity and gas markets in 2016 – Gas wholesale market volume.

Methane emissions from Danish biogas plants have been addressed in different studies.[86] A voluntary scheme for measuring methane leakages from biogas production plants has been launched by the Danish Energy Authority and the Danish Biogas Association. All partners of the Biomethane Sector Declaration (Branchedeklarering) have committed to only sell biomethane from plants following this program. The voluntary scheme might become obligatory for future support schemes.

The foot print from gas transmission is caused either by fugitive methane or CO_2 emissions from utility needs. The Danish Gas TSO works constantly to reduce the greenhouse gas emissions; its foot print is reported in its publication “Samfundsansvar 2017”. The focus for the Gas TSO is the reduction of greenhouse gases, scope 1 and 2 from the Greenhouse Gas Protocol. The Danish Gas-TSO works together with 6 other European TSOs in the Green Gas Initiative to reduce their climate impact by sharing experiences and setting up common goals for reducing the carbon foot print.

There is no specific official environmental regulation to reduce GHG emissions. For installations with an environmental permit the environmental regulation requires renewal of the permit every 8 years. Part of the renewal process is to address new technologies.

Methane (natural gas) emissions

Methane emissions originate from leaks and emissions from known sources, for example measuring equipment. Emissions from fugitive leaks are reduced by corrective maintenance. Regular measurements (several times per year) with sniffing equipment help to find leaks to be repaired. Emissions from measuring equipment are primarily reduced by changing measurement principles and improvement of technology reducing the need for gas throughput in measuring circles.

Reconstruction of gas pipelines can cause significant emissions. There are several means to reduce the amount of methane emitted, and the footprint is taking into consideration in decision making how to securely carry out the repair work.
During 2017 the Danish Gas-TSO has performed a measurement campaign to obtain an emission benchmark from the TSO’s facilities, which will help it to reinforce maintenance where it will be most valuable.

CO_2 emissions

CO_2 emissions origin from flue gas emissions by operating the gas grid. The largest contributor to the carbon foot print is caused by the necessity to heat the gas before delivering it to a lower pressure system. The Danish Gas TSO is reducing these emissions by several means, e.g. replacing old boilers with more efficient ones, close follow up on the operation of the boilers and reducing the needed gas exit temperature.

2.2.5 Overview of impact of non-gas demand drivers on Danish gas infrastructure

Table 2-6 Overview of non-gas demand drivers in Denmark

Policy objective	Issue	Likely impact on gas infrastructure
Security of supply	Diversified supply sources	Denmark has own gas production, and access to pipeline gas from several sources. Supply is sufficiently diversified, and situation will further improve with planned PCIs

[86] Agrotech (2014), Methane emission from Danish biogas plants - Economic Impact of Identified Methane Leakages; and DCG (2015), Methane emission from Danish biogas plants - Quantification of methane losses.

Policy objective	Issue	Likely impact on gas infrastructure
	Well-developed infrastructure (N-1 standard is respected)	Network and storage capacities are sufficient to cope with unplanned unavailability of major infra component. Temporary supply security risk due to refurbishment of gas production facility.
Climate / Environment	Back-up of intermittent capacity	Denmark has high share of intermittent power generation capacity, particularly wind energy. Natural gas is used for back-up power plants, but most gas fired power plants are expected to shut down or be replaced with small scale biomass power plants in line with the 2050 targets (independence from oil, coal and gas).
	Biogas/biomethane development	Denmark is strongly supporting biomethane development. Biomethane and decarbonised gas will replace major part of natural gas consumption. Gas infrastructure can be used without adaptation
	Hydrogen development	Hydrogen production (PtG), transport and storage is being considered. Injection of hydrogen into transmission grid might need refurbishment if technical threshold is exceeded
	Substitution of fossil fuels	Deployment of CNG/LNG and renewable gas for transport will partly compensate reduction in transported gas volumes for heating and power production
	Environmental regulation	High pressure to prevent/reduce GHG emissions
Competitiveness / market development/ market integration	Market integration	Denmark is properly interconnected with its neighbouring countries, and markets are well integrated; no further cross-border expansion needed to improve market integration.
	Enhance competition	No need for gas infrastructure investments to further enhance competition on gas market

2.3 Assessment of the impact of the storylines on the Danish TSO

Energinet owns and operates the gas and electricity transmission network in Denmark; it also owns two gas storage facilities, which are operated by its daughter company Gas Storage Denmark. The non-current assets accounting value related to its gas transmission infrastructure totalled €618 million in 2017; it is expected to gradually decline by 2050. The investment level in gas transmission assets was in 2017 only €3.6 million, but this would substantially increase as of 2019, if the planned projects for the expansion of the transmission grid will effectively be realised. Storylines 1 and 3 would have the highest impact on the investment level (refurbishment for hydrogen). The overall gas transmission related costs of Energinet amounted in 2017 to €60 million, of which the OPEX represented €32 million (53%) and CAPEX €28 million (47%); the overall costs would in the 3 storylines slightly decline as of 2025. Energinet is a state-owned company which is not allowed to build up equity or to pay out dividends; it is regulated under a strict cost-plus regime which means that its revenues must be equal to the "necessary" costs for efficient operations, including the actual cost of capital. The decarbonisation of the energy supply would in Denmark lead to a high use of renewable gas (except in storyline 1), which means that the gas transmission infrastructure could to a large extent be further used. Some interconnectors and pipelines that connect production facilities would however as of 2050 not be utilised any more, and might need to be decommissioned or refurbished for H2 or CO2 transport. Mainly storylines 1 and 3 would have a negative impact on the transmission grid tariffs; the realisation of the Baltic Pipe project would mitigate this impact.

2.3.1 Key financial indicators: Energinet

Energinet owns and operates the gas transmission network in Denmark, owns the two underground gas storage facilities (operated by its daughter company Gas Storage Denmark) and is the owner and operator of the Danish high-voltage electricity grid.

Table 2-7 Key financial indicators: Energinet

General data for Energinet		Unit	Source
Infrastructure			
Pipelines	924	km	DERA (2017)[87]
LNG Terminals	0		DERA (2017)[88]
Storage	948	bcm	www.gasstorage.dk
Compressor stations	1	Units	Energinet (2017)[89]
Interconnection Points	2	Units	Energinet (2017)[90]
Transport volumes			
Transported gas	4	bcm	Energinet (2017)[91]
Investments			
Current investment level	3.6	M EUR/year	Bilateral communication with Energinet
Investment plan[92]	91.3	M EUR/year	Bilateral communication with Energinet
Non-current assets[93]	617.5	M EUR	Bilateral communication with Energinet
Revenues			
Tariff revenue, gas transmission	87	M EUR	

[87] DERA (2017), National report Denmark: Status for 2016.
[88] DERA (2017), National report Denmark: Status for 2016.
[89] Energinet (2017), Security of gas supply 2017.
[90] Energinet (2017), Sustainable energy together: Annual report 2016.
[91] Energinet (2017), Sustainable energy together: Annual report 2016.
[92] This figure will highly depend on the realisation of the Baltic Pipe project
[93] Energinet does not have a regulatory asset base

General data for Energinet		Unit	Source
Total revenue	1,796	M EUR	Energinet (2017)[94]
EBITDA	253.7	M EUR	
Shareholder			
Public: state-owned[95]			

2.3.2 *Regulated Asset Base (RAB)*

In 2017, the non-current assets accounting value related to gas transmission infrastructure owned and operated by Energinet totalled €618 million. In Denmark a specific “regulatory asset base” is not determined for grid operators.[96]

The investment level in gas transmission infrastructure was in 2017 €13 million (€18 million foreseen for 2018), but it would substantially increase as of 2019, if the planned investments for the expansion of the Danish transmission grid, CS Zealand and the Norwegian tie-in will effectively be realised. These projects would represent an investment amount of €700 million in 2019-2022. Next to these investments related to grid development, limited investments will be needed for maintenance (ITC, replacement of compressor stations and metering equipment, etc.) to ensure a secure and safe functioning of the gas network. Depending on the development of hydrogen, specific refurbishment investments might be needed in the long term to accommodate hydrogen into the grid, if the concerned volumes would exceed the technical threshold, which has to be respected for safety reasons. Investments in reverse flows might also be necessary in the long term if locally injected volumes of biomethane or hydrogen into the system would exceed local demand.

Taking into account the existing assets which are not yet depreciated and the above mentioned planned new investments, the net accounting value would substantially increase in 2019-2022, and would only as of 2023 gradually decrease.

2.3.3 *OPEX & CAPEX*

The overall gas transmission related costs of Energinet amounted in 2017 to about €60 million, of which the OPEX represented €32 million (53%) and the CAPEX €28 million (47%).

OPEX

The OPEX for the gas transmission activities of Energinet (approx. €32 million in 2017) would remain stable in 2020-2050, but if the planned new investments (expansion of the Danish transmission grid, CS Zealand and the Norwegian tie-in) will effectively be realised, the OPEX would as of 2023 increase by about €11 million annually. Declining transported gas volumes would not lead to a proportionate decrease of the OPEX, as about 90% of these costs are fixed or infrastructure related (maintenance, administrative costs) and only a small share is volume related (e.g. energy for compressor stations). The overall OPEX would hence as of 2023 increase to a level ranging between €40 to €45 million annually.

CAPEX

Depreciation and financial costs amounted in 2017 to €28 million. Pipelines and compressor stations are linearly depreciated over 30 years. That means that current assets and planned investments (including

[94] Energinet (2017), Sustainable energy together: Annual report 2016.
[95] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[96] From bilateral communication with Energinet

the Baltic Pipe project) will in principle be depreciated by 2052. The choice for a shorter depreciation period, compared to other EU Member States, is related to the expectation that gas will have a decreasing role in the energy mix in the medium and long term.

The CAPEX related to the existing assets would only as of 2025-2030 slightly reduce (by about 20%). However, taking into account the above-mentioned investment plans (€700 million in 2019-2022), the additional CAPEX as of 2023 would amount to €40 to €44 million annually. The overall CAPEX would hence as of 2023 amount to about €70 million annually. These estimates do not include the CAPEX related to possible investments to adapt the grid to renewable gas.

2.3.4 Grid tariffs and TSO revenues

The above mentioned annual expenses (OPEX + CAPEX) constitute the basis for the determination of the grid tariffs. Energinet is a state-owned company which is not allowed to build up equity or to pay out dividends to its owner, the Danish Ministry of Energy. Energinet is regulated under a strict cost-plus regime which means that its regulated revenues must in principle be equal to the "necessary costs" for efficient operations, including the actual cost of capital. The TSO has to transfer any surplus income (over coverage) back to its grid users through reduced tariffs – in principle in the year following the year which gave rise to the surplus income. In extraordinary cases, the payback period may be longer in order to secure a stable tariff development. The same principle applies if Energinet has an under coverage (deficit) but of course with opposite effect for the grid users.[97] This legislation is currently under review in order to provide a new regulation to Energinet which would ensure a stronger incentive for economic efficiency (See section 2.4 for more details).[98]

Based on the current cost levels (about €60 million in 2017) and transported volumes (about 51 TWh), the average grid tariff amounts to 1.18 €/MWh. As the transported gas volumes are expected to decline in 2018-2021, the revenues of the TSO would under the current regulatory regime evolve in line with the evolution of its OPEX and CAPEX, and grid tariffs would hence proportionally increase. The profitability of Energinet would not be affected in relative terms, but the impact would mainly be reflected in the transport tariffs. The new planned investments would lead to substantially increasing transported volumes (transit) as of 2023, which would result in lower grid tariffs in 2023-2030. According to the estimates of Energinet, transit volumes would decrease as of 2030, and hence result in higher grid tariffs.

For 2018, about 50% of the revenues of the gas TSO stems from transit activities, versus 50% from gas transport for end-use in Denmark. If it is decided to invest in the Baltic Pipe, the share of transit revenues would as of 2023 increase to about 75%. The evolution of gas supply and consumption in neighbouring countries has hence also an important impact on the grid tariffs in Denmark.

The share of capacity and commodity related tariffs in the overall revenues of Energinet was in gas year 2016-2017 55% and 45% respectively. A high share of capacity revenues (and in particular long-term bookings) reduces the risks and income volatility for the gas TSO, but capacity tariffs can, depending on their design and structure, negatively affect the competitiveness of gas for flexible uses (e.g. back-up for intermittent power generation). For this reason, grid users prefer short term bookings, which de facto are more volume related than long term bookings. A review of the tariffication principles is currently considered by the NRA; this will in principle result in a higher capacity related tariff share.

97 DERA (2017), National report Denmark: Status for 2016.
98 Energistyrelsen (2016), Ny økonomisk regulering af Energinet.dk.

2.3.5 TSO viability analysis: Estimated impact on end-users (tariffs) and/or on the business of the TSO

The above-mentioned figures and trends are based on scenarios elaborated by the TSO. If, in the context of the decarbonisation of the energy supply, transported gas volumes would earlier and more drastically decline than anticipated by the TSO, the impact on the gas transmission tariffs would be higher. However, taking into account the anticipated important role of renewable gas in the energy mix in Denmark (in particular in storylines 2 and 3), it is not expected that the gas grid would become a stranded asset, as the gas infrastructure will continue to be needed to balance the electricity system, to ensure security of gas and electricity supply and to facilitate the development of renewable gas.

The table below provides an overview of the expected qualitative impacts of the three storylines.

Table 2-8 Estimated impact of the selected storylines

	Figures 2016/2017	Storyline 1 Strong electrification		Storyline 2 Strong development of bio- and synthetic methane		Storyline 3 Strong development of hydrogen	
Gas demand (TWh)	34 TWh	2030 Decrease	2050 Decrease	2030 Increase	2050 Increase	2030 Stable	2050 Stable
Transported gas volumes (TWh)[99]	51 TWh	Decrease		Increase		Stable or decrease	
TSO investments	€ 3.6 m	2019-2023: depends on investment decision Baltic Pipe Post 2023: decrease (limited to maintenance and refurbishment H_2)		2019-2023: depends on investment decision Baltic Pipe Post 2023: decrease (limited to maintenance)		2019-2023: depends on investment decision Baltic Pipe Post 2023: decrease (limited to maintenance and refurbishment H_2)	
Net accounting value of TSO assets	€ 617.5 m	Will gradually decline by 2050		Will gradually decline by 2050		Will gradually decline by 2050	
OPEX	€ 32 m	Will remain stable or slightly decline (due to efficiency standard imposed by NRA) Baltic Pipe project would have increasing impact		Will slightly decline (due to efficiency standard imposed by NRA) Baltic Pipe project would have increasing impact		Will remain stable or slightly decline (due to efficiency standard imposed by NRA) Baltic Pipe project would have increasing impact	
CAPEX	€ 25.1 m	Will slightly reduce as of 2025-2030 unless Baltic Pipe project is realised		Will reduce as of 2025-2030 unless Baltic Pipe project is realised		Will slightly reduce as of 2025-2030 unless Baltic Pipe project is realised	
TSO grid tariffs for end-users	1.18 €/MWh	Highest increase Baltic Pipe project would have mitigating impact (revenues from transit)		Lowest increase Baltic Pipe project would have mitigating impact		Medium increase Baltic Pipe project would have mitigating impact	
Overall assessment of storylines from gas TSO perspective				Preferred storyline			

Note: The overall gas demand is compared to the 2015 level and categorised as follows: increase>51%= ***'High increase'****; increase 6-50%=* ***'increase'****; decrease -5% to increase 5%=* ***'stable'****; decrease -5% to -50%=* ***'decrease'****; decrease > -51% =* ***'high decrease'****.*

[99] Future gas demand will increasingly be covered by local production of renewable gas, partly locally used and partly injected into the distribution or transport grid. Moreover, domestic natural gas production is expected to decline. The evolution of the volumes to be transported via the transmission grid will hence be different than the evolution in gas demand.

2.4 Regulatory framework in Denmark

Gas network tariffs are in Denmark based on the 'authorized' grid costs, and most of the TSO's income stems from regulated tariffs. Gas transport and emergency supply tariffs are fixed ex-ante for a period of one gas year. According to national law, the NRA DERA approves the tariff methodology while the Danish TSO sets the actual tariffs in accordance with the approved methodology and submits the resulting tariffs to DERA. Tariffs are at present partly commodity based, but a shift to mainly capacity based tariffs is envisaged. Pipelines are linearly depreciated over a period of 30 years, which means that the ongoing investments will be depreciated by 2050. Further changes of the regulatory regime are foreseen to make it more future-proof: income cap regulation for the TSO, multi-annual regulatory periods and grid tariffs, risk adjusted return on capital and macro-economic global optimisation of electricity and gas network investments. With these initiatives, the Danish authorities are adapting the regulation to the new gas market context, that will be characterised by decreasing domestic gas production, stable or (slightly) decreasing overall gas demand, and gradual replacement of natural gas with renewable gas.

The Danish Natural Gas Supply Act sets the roles and responsibilities for transmission, distribution, supply and storage of gas and the usage of biomethane in the natural gas system. It also stipulates the roles and responsibilities of the TSO and distribution system operators (DSOs) and defines certain consumer rights as well as the frames for regulating access to the upstream pipeline network.[100]

2.4.1 *Regulated tariffs and revenues for gas infrastructure owners/operators*

Energinet is subject to the principle of self-financing of its authorized costs via network tariffs for its gas transmission activities, and most of its income stems primarily from regulated tariffs.[101] Gas transport and emergency supply tariffs are fixed ex-ante for a period of one gas year (October to September). According to national law (executive order No 816, 2016), the NRA DERA approves the tariff methodology while the Danish TSO sets the actual tariffs in accordance with the approved methodology and submits the resulting tariffs to DERA.
In 2013, Denmark has moved away from uniform tariffs (postage stamp principle) and has introduced differentiated tariffs for the different entry/exit points in the Danish transmission system. The tariff differentiation was introduced to have a more cost reflective allocation of the new costs arising from the investment in expanding the gas infrastructure at Ellund which was necessary to be able to import more gas via Germany and to ensure security of supply in Denmark when the production from the North Sea will no longer be sufficient to cover the Danish and Swedish gas consumption.[102]

In 2016, DERA has reviewed the tariff regime and has implemented a more even cost allocation across the system that better reflects the actual use of the system and the benefits to the overall system and the market of new infrastructure, e.g. in terms of improved security of supply and better market integration.[103] As a consequence of this review, a larger share of the capital costs for new infrastructure has been transferred from the cross-border point Ellund (entry) to the Danish exit zone (end users) and the Dragør Exit and to the security of supply tariff which is paid by all end-users. In addition, the allocation of the costs for new compressors has been made variable according to objectively defined flow scenarios.[104]

[100] OECD/IEA (2017), Energy policies of IEA countries: Denmark 2017 review.
[101] Energinet (2017), Sustainable energy together: Annual report 2016.
[102] DERA (2016), Analysis of competition on the Danish wholesale market for natural gas
[103] DERA (2017), National report Denmark: Status for 2016.
[104] DERA (2017), National report Denmark: Status for 2016.

The gas transport tariffs are fixed so as to cover the costs of transmission grid operation, grid expansion and security of gas supply. They have risen in recent years, due to the inclusion of less excess revenue and to smaller volumes of transported gas. Transport tariffs are expected to continue to rise in the medium and long term to the extent that the transported gas volumes would continue to decline.

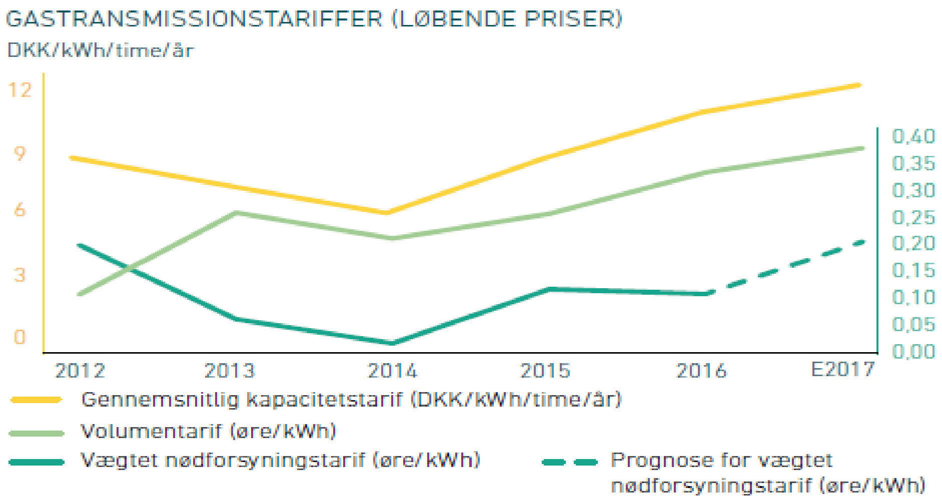
In addition to the transport tariff, end users pay in Denmark emergency supply tariffs. In this context, end users are divided into two customer groups:

- Non-protected customers: around 47 industrial companies and central power stations, which together account for approx. 22.6% of annual gas consumption in Denmark;
- Protected customers: around 400,000 private customers, public enterprises, CHP and district heating plants and small businesses, which together account for approx. 77.4% of consumption.

As there are differences in the treatment of the two customer groups in an emergency situation, there are also two different tariffs: one tariff for protected customers and another much lower tariff for non-protected customers. The overall cost of tools which can be used in an emergency situation is allocated between protected and non-protected customers in a ratio of 85/15. The emergency supply tariffs are hence different for the two customer types; the weighted average emergency supply tariff is 0.0631 €/MWh in 2017-2018.

The evolution of the gas transmission tariffs from 2012 to 2017 is presented in the figure below.

Figure 2-4 Evolution of the gas transmission tariffs from 2012 to 2017[105]



Energinet applies both capacity and commodity related tariffs for gas transport. The capacity charges are not fully differentiated by location but are also not completely uniform. Entry and exit capacity at IP Ellund — connected with Germany — are priced differently than other entry and exit points.

The commodity related tariffs (‘variable charges’) are only charged at the exit points. Next to a regular commodity charge (transport fee), there is an emergency commodity charge which is different for protected and non-protected customers (see supra).

[105] Energinet (2016), Sammen om Bæredygtig energi: Årsrapport 2016.

Regulation of gas TSO revenues

Energinet's finances are based on a self-financing principle. This means that its revenues and expenses must balance. Differences in income and expenses, called over- or under-recovery, are transferred to next year's budget. Most of its income is collected via regulated tariffs.

Energinet is by law allowed to recover all reasonable and necessary costs via grid tariffs. The TSO is operating under a 2% OPEX efficiency requirement, which means that Energinet has to ensure improvements in its effectiveness so that it can reduce the OPEX in nominal terms by roughly 2% per year. All over-/under-recovery is to be returned/recovered in the following year.

Agreement on a future-proof economic regulation for the TSO

A wide political agreement has been reached in May 2018 regarding a 'new' future-proof economic regulation of Energinet.[106] The aim of this review of the regulatory framework is to increase transparency on Energinet's business and investments. At the same time, it should strengthen incentives for Energinet's efficient operation and investment in view of an optimal integration of renewable energy into the electricity and gas systems.

According to the agreement[107], the new future-proof regulation will be based on the following principles:

1. **Income cap regulation** for Energinet to provide proper incentives for an efficient operation and necessary investments. In order to ensure that the 'necessary' costs can be recovered, Energinet's income cap is determined on the basis of the "authorised" costs on the one hand and a regulated return on capital on the other hand. The regulation will be based on a more business-oriented approach;
2. **Multiannual regulatory periods** which aim to offer tariff predictability for grid users and to ensure focus on long-term efficiency improvements. Energinet's income cap is set by DERA for a multi-annual regulatory period, and only pre-defined adjustments can be made to the income-cap during the regulatory period;
3. **Income cap to be reflective of cost development** – The framework for Energinet's costs is to be determined on the basis of actual and expected costs which will secure the financing of Energinet's tasks. DERA is to set for each regulatory period efficiency requirements for Energinet to the benefit of consumers, taking into account costs that are non-controllable;
4. **Risk adjusted return on capital** set by DERA that can be incorporated into the income cap framework and that will enable Energinet to finance its invested capital;
5. **Adequate quality of supply** – The regulation will underpin system optimization and a continued high level of security of supply. Therefore, DERA will set standards for quality of supply of the transmission network and sanctions may be imposed;
6. **Socio economic investments and investment decisions** – Energinet is to make sure that the socio-economically best solutions for the development of the electricity and gas networks are chosen and that market-based risk are properly reflected in the investment decisions. The investment framework is set on the basis of long-term development plans approved by the competent authorities. If the investment framework entails additional costs that result in exceeding the overall income cap, an allowance corresponding to the additional costs can by DERA be added to the income cap framework.

[106] https://www.efkm.dk/aktuelt/nyheder/2018/maj/ny-aftale-om-fremtidssikret-energinet/
[107] https://www.efkm.dk/media/11998/aftale-om-fremtidssikret-regulering-af-energinet.pdf

The agreement implies that a ceiling is imposed on overall grid costs that can be recovered from grid users while imposing stricter requirements for efficiency improvements in the energy network. The agreement will thus benefit both residential and commercial grid users and pave the way for efficient integration of renewable energy and green transition. The agreement is another step in implementing the government's supply strategy "Supply for the Future - a supply sector for citizens and businesses" from September 2016.[108]

2.4.2 Accounting rules for large gas infrastructure

Pipelines and compressor stations are linearly depreciated, taking into account an economic lifetime of 30 years. This means that current assets and planned investments (Baltic pipe) will in principle be depreciated towards the year 2052 including that year. The Danish gas TSO applies a shorter depreciation period than most other European TSOs, which reduces the risk for stranded assets.

As there is no particular legislation in Denmark concerning stranded assets, there are two possibilities to recover the net accounting value cost of stranded assets: either the residual value is depreciated at the expense of the asset owner, or the related cost is socialised via the grid tariffs and recovered from the gas grid users.

2.4.3 Legal and regulatory framework for renewable gas

The Danish legislator and regulator are facilitating and supporting the development of biomethane and its injection into the gas grid via different measures, inter alia exemption from energy and CO_2 taxes, specific subsidies, guarantees of origin, etc. These aspects are extensively commented in section 2.3.

Bio-methane producers connected to the distribution grid also pay a transmission tariff; this practice is based on the principle that all gas volumes are virtually being transported via the transmission grid and hence use specific services (flexibility, balancing), even though physically part of the injected volumes does not effectively enter the transmission grid.

Some ‘improvements’ in the regulatory framework could be considered to further accelerate the deployment of renewable and carbon neutral gas, for instance the extension of the guarantees of origin scheme to all types of renewable gas and trade of the related GOs at EU level and the harmonisation of the technical specifications for injection of renewable gas into the gas grid, in order to enable cross-border flows of biomethane.

2.4.4 Readiness of the Danish regulatory regime

The regulatory regime in Denmark has to a certain extent already been adapted to the new gas market context, that will be characterised by decreasing domestic gas production, stable or decreasing overall gas demand, and gradual replacement of natural gas with renewable gas.

The changes in the Danish regulatory framework for gas are in line with its Energy Strategy 2050, which aims to have an energy system by 2050 that is fully independent of coal, oil and fossil gas. Several measures have been implemented to support the transition to non-fossil fuels, in particular (high) energy and CO_2 taxes on fossil fuels. As the phase-out of natural gas by 2050 will have an important impact on the gas infrastructure, Denmark has opted for a shorter depreciation period of only 30 years

[108] Danish government (2016), Forsyning for fremtiden - en forsyningssektor for borgere og virksomheder.

for pipelines (compared to 40 or 50 years in most other Member States). This entails that existing assets and currently planned investments (including the planned Baltic Pipe project) would be depreciated by 2050/2052, limiting the risk for devalued or stranded assets due to decreasing (natural) gas demand.

Even though natural gas is planned to be phased out by 2050, the existing gas infrastructure is also in Denmark expected to continue to play a key role in the green transition. Denmark has a large biomass potential and has in 2012 implemented an enabling framework, including financial incentives and guarantees of origin, for biogas/biomethane, that also stimulates the injection of biomethane into the grid. The Danish government has also assigned large budgets to R&D related to renewable gas under the Danish Energy Technology Development and Demonstration Programme. The current and expected developments in Denmark seem to be strongly in line with storyline 2 of this study.

Additional regulatory changes are being planned to support the transition to a carbon neutral energy system. The proposed future-proof economic regulation for Energinet is tackling several aspects in this regard. For example, it proposes to take gas infrastructure investment decisions from a global socio-economic perspective taking into account the government's long-term objectives and market needs. It also imposes to the grid operator cost efficiency improvements in order to mitigate the impact of falling gas demand on grid tariffs. Further measures that are implemented or being considered to improve the efficiency and effectiveness of the energy sector relate to vertical and horizontal integration in order to value potential synergies within the distribution sector, between electricity and gas network activities and between distribution and transmission network activities. In this context, the possible take-over of upstream gas activities by Energinet is also being considered. All these initiatives should allow to reduce fixed costs of network operators and contribute to maintaining affordable grid tariffs. At the same time, a review of the gas market model is being prepared, which includes amongst others the merger of the Swedish and Danish balancing zones.

The gas TSO revenues are at present partly (50%) generated by commodity related tariffs and partly (50%) by capacity bookings. A review of the tariff principles is currently under consideration (public consultation in August 2018); the proposed changes will amongst others entail a higher share of capacity related grid tariffs, in line with the Commission Regulation and Gas Network Code. Falling gas demand would in the current Danish regulatory regime not necessarily lead to lower revenues for the TSO, but rather to higher grid tariffs per transported MWh. In the medium and long term, lower transported gas volumes could undermine the business perspectives of the gas TSO. The realisation of the Baltic Pipe would have a positive impact on the grid tariffs in Denmark, as the transit volumes would generate revenues for the TSO of which Danish gas consumers would benefit.

3 France

Key data		Unit	Source
Gas consumption	478,100	GWh/year	CRE 2017
Peak load	4,018	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	15	%	Eurostat 2016
Domestic primary gas production	209	GWh/year	Eurostat 2016 (nrg_100a)
Imports	479,556	GWh/year	Eurostat 2016 (nrg_100a)
Exports	38,801	GWh/year	Eurostat 2016 (nrg_100a)
Capacity of entry pipelines	1,667	GWh/day	ENTSOG transmission capacity map
LNG import terminal nominal capacity	34.25	Billion m^3(N)/year	GIE LNG map 2018
Gas storage capacity	138	TWh	GIE Storage map 2018
Number of gas PCIs in 2017 list	3	projects	PCI list 2017
Other general information			
Regulatory system	**Transmission:** regulated tariffs based on actual costs and regulated remuneration of capital **LNG terminals:** regulated Third Party Access (TPA) (one LNG terminal is exempted) **Storage:** regulated TPA since January 2018 (negotiated until December 2017)		
NRA	Commission de Régulation de l'Energie (CRE)		
Main TSO	GRTgaz		

3.1 Existing and planned gas infrastructure

France has four operating LNG terminals with a total regasification capacity of 34.25 bcm/y and 16 gas storage facilities (138 TWh capacity). France’s natural gas transmission network is split up into three distinct regional transmission network areas, owned and operated by two TSOs, GRTgaz and Teréga. France has significant interconnection capacities on its northern borders, over 2000 GWh/d entry capacity from Germany, Belgium and Norway) but has limited capacity on its southern border, from France to the Iberian Peninsula, the 5th biggest European market, with only 165 GWh/d. Therefore, France is involved in three Projects of Common Interest (PCI) on the third PCI list. The utilization level of LNG terminals and import pipelines is already decreasing and would in the 3 storylines further and substantially decrease after 2030; some infrastructure might by 2050 need to decommissioned or refurbished for alternative uses as part of holistic planning and adequate coordination. The storage sites and transmission network would however continue to be further used for (renewable) gas, with a different utilization depending on the storyline.

3.1.1 Main large gas infrastructure in France

At the end of 2016, the firm daily gas import capacities on the French territory amounted to around 3,600 GWh, 65% of which was pipeline capacity and 35% LNG capacity (4 terminals). This capacity equals more than 2.5 times France’s average daily consumption, but to cover peak demand (4,018 GWh/day), additional volumes from storage facilities (overall capacity is 138 TWh) are necessary.

France has an entry/exit gas system with 6 entry/exit points (see Table 3-3). The number of market areas has been reduced over time to three virtual trading points in 2009 (PEG North, PEG South and PEG TIGF); in 2015 the new Trading Region South was created, merging PEG South and Teréga (formerly known as TIGF). Infrastructure investments are ongoing to merge the two remaining market areas in November 2018.

LNG terminals

France has four operating LNG terminals with a total regasification capacity of 34.25 bcm/y of which Montoir-de-Bretagne 10 bcm/y - Fos Tonkin 3 bcm/y - Fos Cavaou 8.25 bcm/y and Dunkerque 13 bcm/y. The utilisation level of the LNG terminals is decreasing since 2010 in France as well as in the rest of Europe; the average utilisation at EU level has decreased from 29.1% in 2012 to 19.6% in 2018.[109] This negative trend is due to a significant increase of the available regasification capacity in Europe since 2010, the declining gas demand in some EU Member States, and less LNG imports due to the diversion of LNG cargoes to higher-priced markets in Asia, South-America and the Middle East and the competition between LNG and pipeline gas. The LNG imports in France amounted in 2017 to 9.3 bcm (7 bcm in 2016)[110] versus a regasification capacity of 34.25 bcm (21.25 bcm in 2016). Despite an increase of net LNG imports by 33%, the average utilisation level has hence decreased from 33% in 2016 to 27% in 2017.

The table below provides an overview of the existing and planned LNG terminals in France. Operators are Elengy[111], Fosmax LNG[112] and Dunkerque LNG.[113] The terminals mainly import LNG from the Persian Gulf states and the Mediterranean and Atlantic basins.[114]

Table 3-1 Existing and planned LNG terminals in France. Source: GIE LNG Map 2018[115] and input from TSO

Name of installation	Operator	Status	Start-up year	Max. Hourly Cap. m^3(N)/hour	Nom. Annual Cap. billion m^3(N)/year	LNG storage capacity m^3 LNG	Number of tanks	TPA regime
Fos-Tonkin LNG Terminal	Elengy	operational	1972	620,000	3.00	80,000	1	regulated
Montoir-de-Bretagne LNG Terminal	Elengy	operational	1980	1,600,000	10.00	360,000	3	regulated
		Planned (expansion)	2023	2,000,000	12.50	550,000	4	regulated
Fos Cavaou LNG Terminal	Fosmax LNG	operational	2010	1,160,000	8.25	330,000	3	regulated
		Planned (expansion)	2021	1,550,000	11.00	330,000	3	regulated
		Planned (expansion)	2023	2,320,000	16.50	550,000	5	regulated
Dunkerque LNG Terminal	Dunkerque LNG	operational	2017	1,900,000	13.00	600,000	3	exempted

The facilities at Fos-Tonkin, Fos-Cavaou and Montoir-de-Bretagne follow a regulated third-party access (TPA) regime and tariffs for capacity use at these facilities are set similarly to network access tariffs. The Dunkerque LNG terminal however was granted full exemption from TPA and tariff regulation for a period of 20 years as of the date of its commissioning.

[109] Figures communicated by GIE to DG ENERGY.
[110] International Group of LNG Importers (2018), The LNG industry GIIGNL annual report 2018.
[111] www.elengy.com
[112] www.fosmax-lng.com
[113] www.dunkerquelng.com
[114] www.grtgaz.com/en/our-company/our-network.html
[115] GIE (2018), LNG map – Existing and planned infrastructure 2018.

Gas storage

France has 16 gas storage facilities, most of which (about 105 TWh capacity) are operated by Storengy (subsidiary of ENGIE) and some (about 33 TWh capacity) by Teréga. Since 2012, three storage facilities have been mothballed, due to worsening economics for storage assets.

In France, storage capacity has been designed and built to cover extremely cold winters, which occur statistically every fifty years or to cover low temperatures during three consecutive days (peak cold 2% risk). This capacity level is however not always properly remunerated by the market, as the negotiated prices do not internalise the full value of security of gas supply. In most European countries, the market value of gas storage has decreased over the last few years as increasing flexibility resources have come to the market, leading to a decline in seasonal price spreads.
History shows however that gas storage plays a crucial role in responding to supply disruptions or unexpected increases in demand. For this reason, the French government has recently changed the regulatory framework for gas storage access with the aim of maximising its use and ensuring that the insurance and system values are fully recognised. The new scheme has been enacted in the law of 30 December 2017 and implemented by the CRE in February 2018.[116] The new regulatory framework for storage comprises both market-based mechanisms and residual storage obligations. Storage capacities can be reserved through auctions to allow shippers to dispose of the required capacity at market-based prices. If a minimum level of storage, set by the minister of energy, is not reserved on a voluntary basis, specific obligations to reserve additional capacity are implemented to ensure security of supply. This new framework is expected to offer an adequate remuneration level to gas storage operators in order to maintain the storage capacity available to the market.

The table below provides an overview of the existing and planned gas storage facilities in France. Operators are Storengy[117] and Teréga[118].

[116] CRE (2018), The CRE is implementing the reform of the natural gas storage.
[117] www.storengy.com/countries/france/en/
[118] www.tigf.fr/en/what-we-can-offer/storage.html

Table 3-2 Existing and planned gas storage facilities in France. Source: GIE Storage Map 2018 and input from TSO

Facility/Location	Status	Start-up year	Type	onshore/ offshore	Operator	Working gas (technical= TPA) TWh	Withdrawal technical = TPA GWh/day	Injection technical=TPA GWh/day	Access regime
SERENE Nord: Trois-Fontaines l'Abbaye	Operational - **mothballed**	1970	Depleted Field	Onshore	Storengy				nTPA
SERENE Nord: Cerville	operational	1970	Aquifer	Onshore	Storengy				nTPA
SERENE Nord: Germigny-sous-Coulombs	operational	1982	Aquifer	Onshore	Storengy				nTPA
SERENE Nord: Saint-Clair-sur-Epte	Operational - **mothballed**	1982	Aquifer	Onshore	Storengy				nTPA
Storengy Serene Nord (storage group)	***operational***		***Aquifer***	***Onshore***	***Storengy***	***16.70***	***195.8***	***153.2***	***nTPA***
SEDIANE Nord: Beynes Profond	operational	1956	Aquifer	Onshore	Storengy				nTPA
SEDIANE Nord: Beynes Supérieur	operational	1956	Aquifer	Onshore	Storengy				nTPA
SEDIANE Nord: Saint-Illiers-la-Ville	operational	1965	Aquifer	Onshore	Storengy				nTPA
Storengy Sediane Nord (storage group)	***operational***		***Aquifer***	***Onshore***	***Storengy***	***11.60***	***271.4***	***159.0***	***nTPA***
SERENE Littoral, SERENE Sud: Chémery	operational	1968	Aquifer	Onshore	Storengy				nTPA
SERENE Littoral, SERENE Sud: Soings-en-Sologne	Operational - **mothballed**	1981	Aquifer	Onshore	Storengy				nTPA
SERENE Littoral, SERENE Sud: Céré-la-Ronde	operational	1993	Aquifer	Onshore	Storengy				nTPA
Storengy SERENE Littoral, SERENE Sud (storage group)	***operational***		***Aquifer***	***Onshore***	***Storengy***	***49.00***	***542.6***	***408.8***	***nTPA***
Saline: Tersanne/Hauterives	operational	1970	Salt cavern	Onshore	Storengy				nTPA
Saline: Etrez	operational	1980	Salt cavern	Onshore	Storengy				nTPA
Saline: Manosque[119]	operational	1993	Salt cavern	Onshore	Storengy				nTPA
Storengy Saline (storage group)	***operational***		***Salt cavern***	***Onshore***	***Storengy***	***11.55***	***571.3***	***101.4***	***nTPA***
SEDIANE B: Gournay-sur-Aronde	***operational***	***1976***	***Aquifer***	***Onshore***	***Storengy***	***13.10***	***246.8***	***105.1***	***nTPA***
Etrez	***Planned (expansion)***	***2022***	***Salt cavern***	***Onshore***	***Storengy***	***0.68***	***45.6***	***0.0***	***nTPA***
Hauterives	***operational 18/19***	***2018-2019***	***Salt cavern***	***Onshore***	***Storengy***	***1.14***	***91.2***	***22.8***	***nTPA***
Lussagnet	operational	1957	Aquifer	Onshore	Teréga				nTPA
Izaute	operational	1981	Aquifer	Onshore	Teréga				nTPA
Teréga (storage group)	***operational***		***Aquifer***	***Onshore***	***Teréga***	***32.60***	***561.2***	***292.2***	***nTPA***

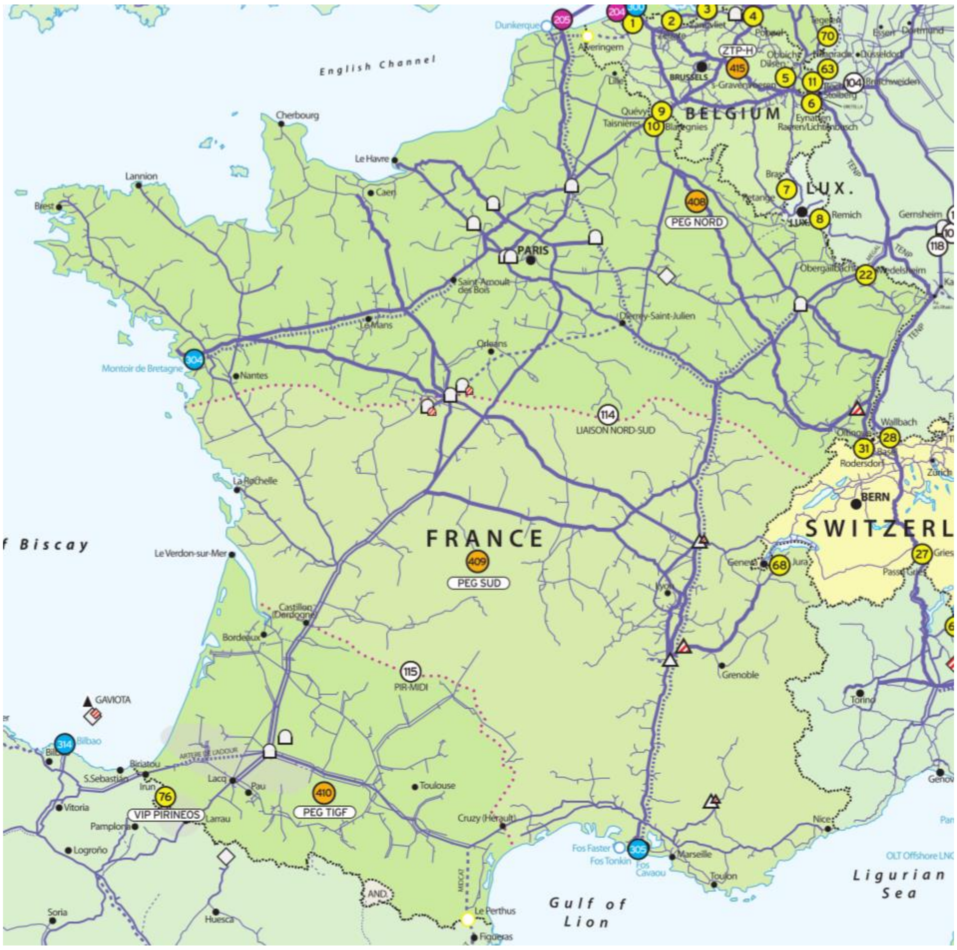
119 www.storengy.com/countries/france/en/nos-sites/manosque.html

Gas transmission network[120]

France's natural gas transmission network is split up into three distinct regional transmission network areas, owned and operated by two TSOs. GRTgaz operates 7,498 km of main network (which connects the LNG terminals, interconnectors and storage facilities) and 24,916 km of regional network, while Teréga operates 650 km of main network and 4,450 km of regional network in the south-west of France. The NRA CRE regulates both gas operators. In line with Energy Code Article L 111-3 and L 111-4, CRE certified in 2012 GRTgaz as independent transmission operator (ITO), owned by ENGIE (75%) and a consortium made up of the Caisse des Dépôts et Consignations (CdC) and CNP Assurances (25%). TIGF (now Teréga) was in 2014 recertified as ownership unbundled TSO, following the change in its shareholder's structure. Teréga is currently owned by the Italian gas operator SNAM Rete Gas (40,5%), Singapore GIC Limited (30,5%), EDF (18%) and Predica[121] (10%).

The GRTgaz network is interconnected with the German, Belgian, and Swiss networks, as well as with the Teréga network which serves the south-west of France and is connected to Spain.

Figure 3-1 Map of French gas network. Source: ENTSOG capacity map 2016[122]



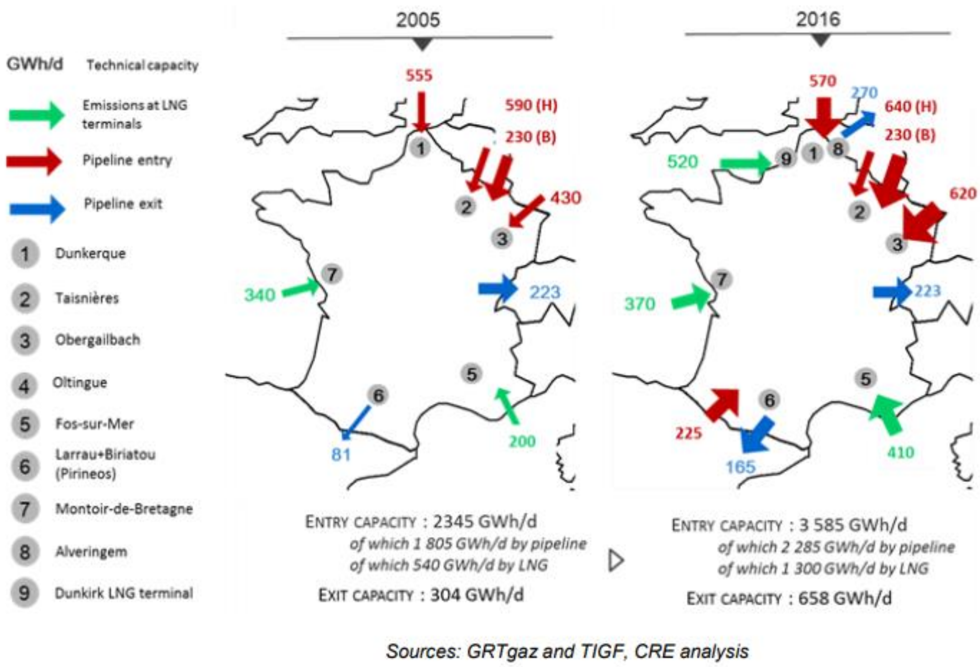
[120] www.grtgaz.com/en/our-company/our-network.html
[121] Subsidiary of Credit Agricole – Evolution in TIGF Capital occurred in 2015
[122] ENTSOG (2017), The European natural gas network 2017 – Capacities at cross-border points on the primary market

Interconnections[123]

The French TSOs have from 2005 to 2015 invested about 3 billion euros to reinforce and extend their transmission system and interconnections. Firm entry and exit capacity of France increased in 2015 to 3,585 GWh/d and 658 GWh/d respectively against 2,345 GWh/d and 304 GWh/d in 2005, an increase of 52% in entry and 116% in exit in 10 years.

France has significant interconnection capacities at all of its borders, and the French market is well interconnected with the rest of Europe. In 2015, France commissioned new interconnection capacity with Spain; at Pirineos, firm entry capacity has been increased from 165 GWh/d to 225 GWh/d, and interruptible exit capacity of 60 GWh/d has become available. Also in 2015, the Alveringem interconnection with Belgium (270 GWh/day) was commissioned. These investments strengthen the contribution of LNG to the supply of North-West Europe and security of supply.

Figure 3-2 LNG interconnection and entry points (2005 to 2016)[124]



**Note: Capacity of Montoir-de-Bretagne (7) is 370 GWh/d in summer and 400 GWh/d in winter.*

The table below lists the key interconnection points.

Table 3-3 Interconnection points. Source: ENTSOG capacity map 2016[125]

Type	N	Point	Arc	Technical capacity (GWh/d)	From	To	From	To
Cross-border IP within EU and with non-EU (export)	9	Virtualys entry	BEh>FRn	**640.0**	BE	FR	Fluxys Belgium	GRTgaz
Cross-border IP within EU and with non-EU (export)	10	Blaregnies L (BE) / Taisnières B (FR)	BEl>FRn	**230.0**	BE	FR	Fluxys Belgium	GRTgaz

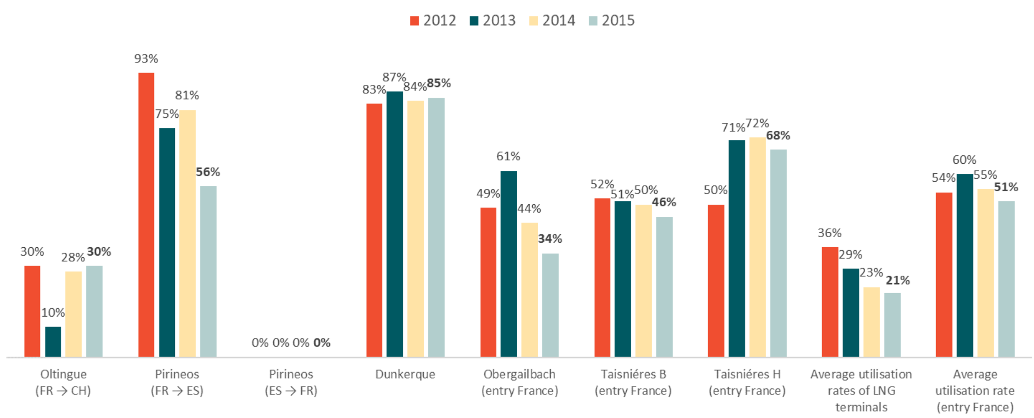
[123] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[124] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[125] ENTSOG (2017), The European natural gas network 2017 – Capacities at cross-border points on the primary market.

Type	*N*	*Point*	*Arc*	*Technical capacity (GWh/d)*	*From*	*To*	*From*	*To*
Cross-border IP within EU and with non-EU (export)	22	Obergailbach (FR) / Medelsheim (DE)	Y-DEnm>	**620**	DE	FR	Open Grid Europe / GRTgaz Deutschland	GRTgaz
Cross-border IP within EU and with non-EU (export)	31	Oltingue (FR) / Rodersdorf (CH)	FRn>CH	**223.0**	FR	CH	GRTgaz	FluxSwiss
Cross-border IP within EU and with non-EU (export)	68	Jura	FRs>CH	**37.4**	FR	CH	GRTgaz	Gaznat
Cross-border IP within EU and with non-EU (export)	76	VIP PIRINEOS	FRt>ES	**165.0***	FR	ES	Teréga	Enagás
Cross-border IP within EU and with non-EU (export)	76	VIP PIRINEOS	ES>FRt	**225.0**	ES	FR	Enagás	Teréga
Cross-border IP within EU and with non-EU (export)	80	Virtualys exit	Y-FRnd>	**271.2**	FR	BE	GRTgaz	Fluxys Belgium
Cross-border IP with non-EU (import)	205	Dunkerque	NO>FRn	**570.0**	NO	FR	Gassco	GRTgaz
LNG Entry IP	304	Montoir de Bretagne	LNG_Tk_FRn>FRn	**370.0 winter) 400.0 (summer)**	FR	FR	Elengy	GRTgaz
LNG Entry IP	305	Fos (Tonkin/Cavaou)	LNG_Tk_FRs>FRs	**410.0**	FR	FR	Elengy / Fosmax LNG	GRTgaz
LNG Entry IP	320	Dunkerque LNG	Y-FRnd>	**100.0**	FR		GRTgaz	
LNG Entry IP	320	Dunkerque LNG	>Y-FRnd	**300**		FR		GRTgaz

Note: 165 GWh/d firm + 60 GWh/d interruptible capacity*

The utilization rate of import infrastructure to France has been decreasing since 2013, due to increasing import capacity on the one hand and declining gas demand on the other hand. In 2015, the average utilisation of 51% reached its lowest level in 4 years. The utilisation levels in 2015 strongly varied depending on the type of infrastructure: from 21% (average of LNG terminals) to 85% (interconnection point of Dunkerque).[126] The decreasing utilization rates reflect changing sourcing decisions made by market participants and the declining French gas consumption versus increasing import capacity.

Figure 3-3 French interconnection utilization rate (% of effective technical capacity)[127]*



**Note:* *the interconnection of Pirineos: lower utilisation rate from 93% in 2012 to 75% in 2013 is due to increase in firm capacity to 165 GWh/d available from April 2013.*

[126] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[127] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market

3.1.2 Planned Projects of Common Interest[128]

France has three projects in the third PCI list (2017):

Adaptation of network from low to high calorific gas in France and Belgium (PCI list 2017, project 5.21)

This project aims at making the low calorific gas grid in some parts of Belgium and France suitable to high calorific gas, in order to anticipate the end of low calorific gas imports from the Groningen field by 2029 at the latest.

South Transit East Pyrenees [currently known as "STEP"] (PCI list 2017, project 5.5.1)

This project is considered as a first phase of Midcat (see below), and consists of a 227 km pipeline across the border and a new compressor station in Spain. Notwithstanding its high investment cost (€452 million of which €290 million in France), this project would not offer firm capacity to Spain, but only interruptible capacity. A Cost Benefit Analysis was commissioned by the High Level Group with an adapted methodology, consistent with ENTSOG's. It identified positive results in two cases out of six, all located in the Iberian Peninsula, assuming the LNG price being constantly higher than the pipeline gas price by 5 or 10 €/MWh from 2023 to 2041 and Algerian gas capacity reduced from 40 bcm to 15 bcm in 2040.

Eastern Gas Axis Spain — France — interconnection point between Iberian Peninsula and France, including the compressor stations at St-Avit, Palleau and St. Martin de Crau ["Midcat"] (PCI list 2017, project 5.5.2)

The realisation of this new large-scale pipeline project (Midcat project in the East of the Pyrenees) is currently under discussion. The project is part of the PCI list and would, if realised, double the gas exchange capacity between Spain and France. The EU Commission and the governments of France, Portugal and Spain signed in March 2015 the so-called Madrid Declaration where they agreed on the need to assess the project in order to move forward. In April 2016 the project was allocated a grant of EUR 5.6 million from the Connecting Europe Facility (CEF) aimed at funding up to 50% of the feasibility studies.

The project would need an investment of about €3 billion (over €2.5 billion for France). The CRE had already in 2010 launched an open season[129], which was unsuccessful. Taking into account the current and expected developments in the gas market (expected decline of gas demand and existing overcapacity), the CRE recently stated that the project is not needed for the Security of Supply of France, and a number of conditions should be met before its realisation, in particular a Cost Benefit Analysis should be undertaken and costs should be appropriately allocated between benefiting countries.[130] Although several studies have already been commissioned by the European Commission on the possible benefits of an additional interconnection between France and Spain,[131] it is still unclear whether the project will effectively be realised taking into account the lack of substantial benefits and

[128] PCI project fiches available DG ENER's interactive map of PCIs: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

[129] A procedure for demonstrating to a regulator that capacity is offered on a transparent basis. It is used principally where pipelines are required by regulation to offer only transportation services, for example in North America and the Southern Cone of South America. It is also being used elsewhere as a means of gathering information about potential interest in a pipeline, LNG, storage etc project to help the sponsors decide how and when to size the project.

[130] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.

[131] E.g: Ramboll et al. (2016), Study on the benefits of additional gas interconnections between the Iberian Peninsula and the rest of Europe – REKK et al. (2017), Follow-up study to the LNG and storage strategy - Pöyry et al. (2017), Cost benefit analysis of STEP, as first phase of MidCat.

market interest for a project of such a scale. As the implementation of the Midcat project is still unsure, the relevance of its 1st phase, the STEP project, could be questioned. It may indeed not be efficient to only develop interruptible capacities through the STEP project, if, in a second stage, firm capacities would not be made available through the Midcat project.

Some other projects were included in the previous PCI lists:

- Reinforcement of the French network from South to North – Reverse flow from France to Germany at Obergailbach/Medelsheim Interconnection point (FR) (PCI list 2015, project 5.6);
- Val de Saône pipeline between Etrez and Voisines (FR) (PCI list 2015, project 5.7.1), to be commissioned in 2018. This project will enable the creation of a single gas market area in France by removing physical bottlenecks between North and South of France;
- PCI Reinforcement of the French network from South to North to create a single market zone - Gascogne Midi pipeline (FR) (PCI list 2015, project 5.7.2), to be commissioned in 2018. This project will enable the creation of a single gas market area in France by removing bottlenecks between North and South of France;
- Est Lyonnais pipeline between Saint-Avit and Etrez (FR) (PCI list 2015, project 5.8.1), now part of PCI 5.5.2;
- Eridan pipeline between Saint-Martin-de-Crau and Saint-Avit (FR) (PCI list 2015, project 5.8.2), now part of PCI 5.5.2;
- Reverse flow interconnection between Switzerland and France (PCI list 2013, project 5.9),to be commissioned in 2018;
- New interconnection between Pitgam (France) and Maldegem (Belgium) (PCI list 2013, project 5.13), commissioned in 2015;
- Reinforcement of the French network from South to North on the Arc de Dierrey pipeline between Cuvilly, Dierrey and Voisines (France) (PCI list 2013, project 5.14), commissioned in 2016;
- Interconnection between France and Luxembourg (PCI list 2013, project 5.17.1)

3.1.3 *Estimated impact of the storylines on French gas infrastructure*

The table below provides a qualitative assessment of the possible impacts of the three selected storylines on existing and planned large gas infrastructure in France.

Table 3-4 Impact of storylines on existing and planned large gas infrastructure in France. Source: Own assessment

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon neutral methane			Storyline 3 Strong development of hydrogen		
Gas demand 2017	478.1 TWh			478.1 TWh			478.1 TWh		
	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen
	Very high	Negligible	Negligible	Very high	Negligible	Negligible	Very high	Negligible	- Negligible
Gas demand 2030[132]	Decrease			Increase			Stable		
	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen
	Very high	Low	Negligible	Very high	Low	Negligible	Very high	Negligible	Low
Gas demand 2050	Decrease			Increase			Increase		
	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen	Natural gas	Methane	Hydrogen
	Negligible	Medium	High	Negligible	Very high	Low	Negligible	Low	Very high

[132] Future gas demand will increasingly be covered by local production of renewable gas, partly locally used and partly injected into the distribution or transport grid. Volumes to be transported via the transmission grid might decrease more than overall gas demand.

	Storyline 1 Strong electrification	Storyline 2 Strong development of carbon neutral methane	Storyline 3 Strong development of hydrogen
LNG Terminals [133]	Utilisation of LNG terminals would substantially decrease after 2030. Excess capacity might appear for which a solution should be found (e.g. bunkering)	Utilisation of LNG terminals would substantially decrease after 2030. Import of liquefied biomethane by tankers could be considered. LNG infrastructure could also be used for methane from P2G and methanation.	Utilisation of LNG terminals would substantially decrease after 2030 and excess capacity might appear for which a solution should be found, such as adaptation to hydrogen import/storage.
Gas storage	Existing gas storage sites in aquifers and depleted gas field could be used for biomethane, while existing salt cavern sites could be refurbished for hydrogen storage. New additional storage facilities may be required for hydrogen. The suitability of aquifers and depleted gas fields for H2 storage still has to be evaluated.	Gas storage facilities can further be used for methane. A more dynamic operation of gas storages to cope with fluctuating renewable production might require update or retrofitting of gas storage infrastructure.	Existing gas storage sites in aquifers and depleted gas field could be further used for biomethane while existing salt caverns sites could be refurbished for hydrogen storage. New additional storage facilities may be required for hydrogen. The possibility of H2 storage in aquifers and depleted gas fields still has to be evaluated.
Transmission network & import pipelines	Utilisation of Import pipelines would substantially decrease as of 2030. Some pipelines could be converted to enable import/transport of hydrogen or transport of CO_2 (CCS or CCU in industry). Transmission infrastructure might require upgrade to H_2, when injection would exceed technical threshold.	Gaseous biomethane import via existing pipelines is a possible option to cover gas demand. Network of methane refuelling stations would be established by 2050, for which grid extensions might be needed. Grid would need to be upgraded to allow bi-directional flows between D and T-grid (if injected volumes at DSO level exceed local consumption).	Utilisation of Import pipelines would substantially decrease as of 2030. Some transport pipelines might require upgrade to H_2, when injection would exceed technical threshold. The system would need to be upgraded to allow bi-directional flows between D and T-grid (to enable local injection of hydrogen).

*Note: The overall gas demand 2030 and 2050 is compared to the current level and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease 5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The gas shares are categorised as follows: 76%-100%= **'very high'**; 51%-75%= **'high'**; 26%-50%= **'medium'**; 6%-25%= **'low'**; 0%-5%= **'negligible'**.*

[133] Existing LNG infrastructure could also be used to decarbonise the freight transport sector (maritime and road) by integrating small liquefaction units to liquefy green/blue gas for use in ships and lorries.

3.2 Main national developments that influence investments in and use of gas infrastructure

France is the 4th most important natural gas consumers in the EU; its domestic demand (445 TWh in 2016) is slightly decreasing (by 19% since 2006), amongst others due to substitution with biomethane. France has committed to cover 23% of its final energy demand in 2020 by renewable energy, and by 2030 10% of its gas consumption should be renewable energy based. Despite a generally well-developed gas infrastructure, the French gas system is suffering from physical congestion in the north-to-south link, which leads to diverging prices. Ongoing investments will allow to solve this bottleneck. GRTgaz has in the past strongly focused on reducing its emissions of CO_2 and NO_x, and is now considering the reduction of CH_4 emissions as a major priority for the coming years. The French gas system has an overall high resilience to supply crises and technical incidents and its short term security of supply is ensured by a large storage capacity. The French gas system and market are properly interconnected with northern neighbouring countries and additional cross-border pipeline capacity would in principle only be built at the Spanish-French border, if deemed necessary (currently listed as project of common interest).

3.2.1 Gas supply and demand

Gas demand

France is the fourth-highest gas-consuming country in the EU behind Germany, the United Kingdom and Italy. Its gas consumption was 445,493 GWh in 2016, which is about 19% below the 2006 level. The share of gas in total primary energy supply (15%) is lower than the EU average (23%), due to the significant use of (nuclear) electricity in the heating sector and the lower density of the gas distribution network in France. The industry and power sector had in 2015 a share of 32.6% and 16.1%, respectively, in total gas demand, while the households and commercial sector consumed 29.1% and 17.3%, respectively.
The main factors which determine the future gas demand are economic and demographic growth, development of RES and switch amongst energy vectors (e.g. to gas for transport); the highest uncertainties concern the gas use for power production. GRTgaz has estimated the natural gas demand on its grid up to 2035 for 3 scenarios.[134] In 2 scenarios a substantial decrease is expected by 2035; the results are presented in the next figure and table.

[134] GRDF et al. (2017), Perspectives gaz naturel & renouvelable.

Figure 3-4 Gas consumption forecasts of GRTgaz

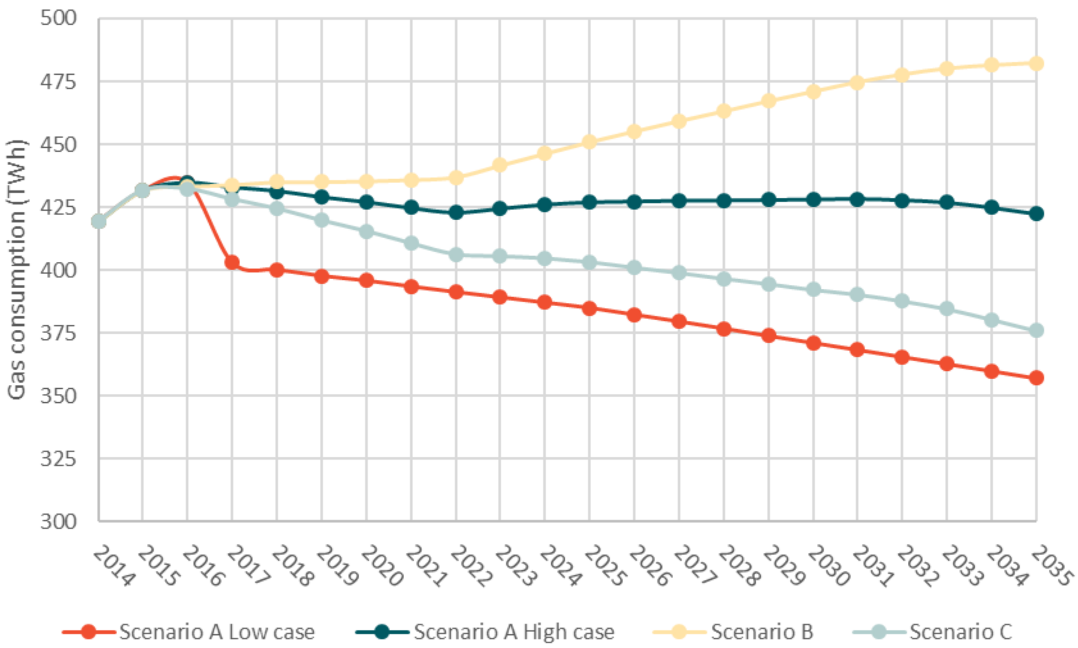


Table 3-5 Annual growth of the gas consumption based on the forecasts of GRTgaz

Annual growth	2016 - 2015	2015 - 2035	2012 - 2030	2023/2012	2030/2012
Scenario A (low case)	-0.2%	-0.1%	-0.3%	-7%	-5.4%
Scenario A (high case)	-1.3%	-0.9%	-1.1%	-15%	-18.0%
Scenario B	0.4%	0.6%	0.2%	-4%	4.1%
Scenario C	-2.0%	-1.6%	-1.7%	-12%	-25.9%

Gas supply

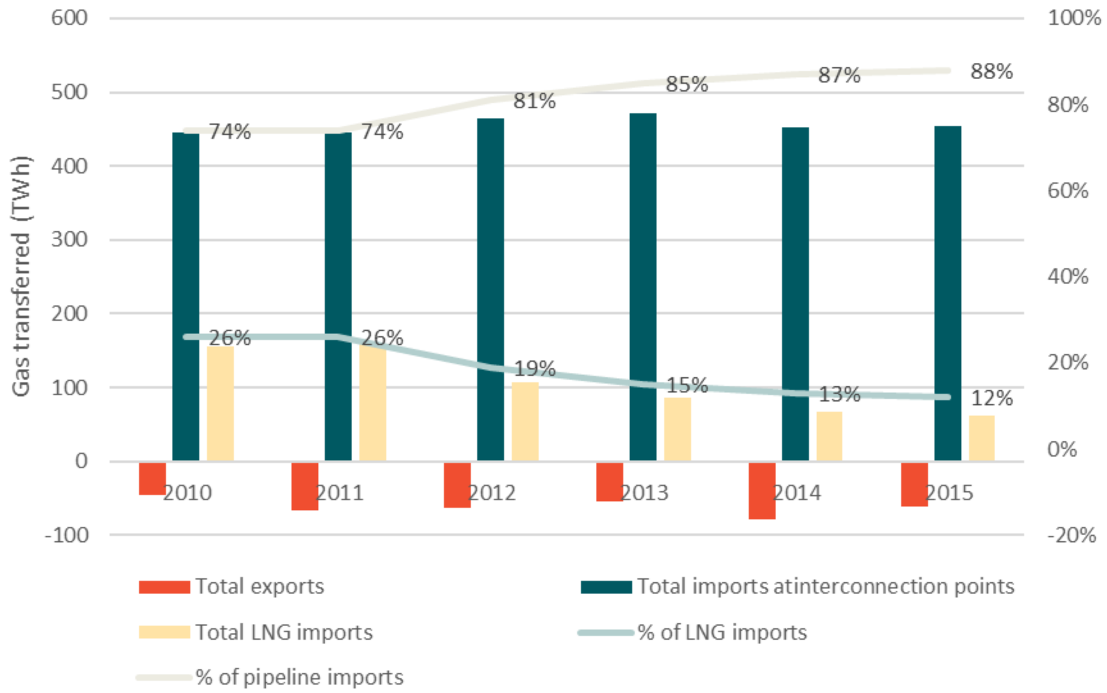
Natural gas supply amounted in 2015 to 39.1 bcm, and was mainly provided by imports of pipeline gas and LNG. Domestic gas production has dramatically fallen since 2005 and is at present negligible (only 0.02 bcm in 2015).

Imports and exports

In 2015, gas imports (454 TWh) came from diversified supply sources: Norway (46.8%), Russia (12.7%), the Netherlands (12%), Algeria (10.5%), Nigeria (3%) and others (15%). An increasing share (88% in 2015) was imported via pipelines and only 12% via LNG terminals.

Gas exports to Spain and Germany amounted in 2015 to 61 TWh.

Figure 3-5 Gas imports and exports in France.[135]



Security of supply

The security of gas supply policy in France relies on three pillars:

- **A prospective vision on gas system development.** The Energy Transition for Green Growth Act 2015 has introduced pluriannual energy programming (PPE) for all energy vectors, including natural gas. This program aims at identifying any investment needs in the energy sector. The gas TSOs from their side regularly elaborate a Winter Outlook to assess the supply-demand adequacy including storage levels;
- **Public service obligations.** These are obligations assigned notably to gas suppliers aimed in particular at ensuring continuity of gas supply to domestic customers in extreme weather conditions;
- **Emergency Action Plan.** When preventive actions are not sufficient to maintain supply, gradual specific measures can be enforced, which include, according to the decision of the minister of energy published on 28 November 2013, a recommendation for energy demand reduction, use of interruptible contracts and/or supply cuts by the TSO, beginning with industrial customers; The next update of the Emergency Action Plan will take into account the new EU Regulation 2017/1938 on security of gas supply;

The new regulatory framework for gas storage[136], which is in place since 1st of January 2018, is also an important measure to ensure gas supply security. Gas storage capacity can now be subscribed via an auction mechanism and a "specific storage compensation tariff" is included in the new TSO tariff as of 1st of April 2018 to ensure the coverage of the authorized revenue of the storage operators. Storage users have the obligation to fill storage at 85% level of the subscribed capacity, and if the required overall capacity level is not reserved, storage operators are obliged to store additional volumes if the

[135] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[136] Hydrocarbon Law dated 30/12/17

deficit is less than 20 TWh, while, if the deficit is higher, gas suppliers are obliged to reserve additional capacity.

While demand restrictions are mentioned as a potential emergency measure, there is in practice little scope for demand restraint. The flexibility provided by interruptible contracts only covers about 2% of peak demand. The government has recognised the limited ability of gas demand response to contribute to balancing the system in an emergency situation and has introduced in the Energy Transition for Green Growth Act measures to encourage the development of demand response.

A specific issue to be considered in the security of supply evaluation is the fact that France odorises its gas in the transmission networks, which can create inter-operability issues with neighbouring countries. Some of them are ready to accept odorized gas in emergency situations, and with the connection of the new Dunkirk LNG terminal, a new physical exit point to Belgium has been created which can export non-odorised gas to Belgium.

Another issue which might affect security of gas supply, is the conversion of low-calorific gas (L-gas), which covers around 10% of French consumption (1.3 million consumers in the northern part of France). In order to anticipate the decreasing availability and eventual end by 2029 at the latest of L-gas imports from the Netherlands, France has launched a conversion plan to switch its L-gas consumers to H-gas.

According to the CRE, the important investments which have been undertaken in transmission and import/interconnection capacity result in a gas system which has a high resilience to possible supply crises. Market operators can switch between different gas sources available and hereby address potential changes in flow patterns. The CRE concludes that it is no longer necessary to devote investments to security of gas supply in France.[137]

3.2.2 *Renewable energy policy and targets*

France has committed to cover 23% of its overall final energy demand in 2020 by renewable energy, though in 2016 this share amounted only to 15.98%[138]. The share of renewable energy in the electricity demand amounted to 19.6% in 2016 , of which 12.2% was provided by hydroelectricity, 4.3% by wind power, 1.7% by solar power and 1.4% by bio-energy. According to the “Multi-annual Programming of Energy”, published in October 2016, renewable energy-based electricity generation capacity is planned to grow from 41 GW in 2014 to between 71 and 78 GW by 2023. The share of renewable gas is still very limited; biogas only represents 0.3% of the total gross inland energy consumption or 2% of the total domestic gas demand.

The Energy Transition for Green Growth Act has set an ambitious RES target of 32% for 2030: RES would need to cover 40% of electricity demand, 38% of heat consumption, 15% of energy used in the transport sector and 10% of gas consumption. These ambitious targets will have a major impact on the development of the gas sector.

[137] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[138] Eurostat SHARES 2016 results.

Renewable gas

A recent study[139] by ADEME (French environment and energy management agency) shows that – technically - by 2050, 100% of France's gas consumption could be covered by renewable gas.[140] The injectable renewable gas resources in this study are estimated at 460 TWh in 2050 and could be provided by three types of processes: fermentation (30% of the resources), gasification (40%), and power-to-gas (30%). The technical potentials are based on available resources which do not compete with food uses and raw materials. However, several barriers would need to be overcome. Including the obstacles to agricultural methanation, generalising the growing of intermediate crops (temporary crops which protect the soil between two saleable crops), harnessing more agricultural and forestry resources. Further, the technologies which are not yet mature (gasification, fermentation of algae, etc.), but have a strong potential need to be further developed.

Biomethane

The French gas network operators assume that renewable gas could account for 30% of total gas consumption in 2030 (90 TWh/year of renewable gas production, including 70 TWh/year of biomethane). According to a study carried out by GRDF in 2013 the technical potential for the production of biomethane via gasification would range from 150 to 250 TWh/year over the 2030-2050 period (depending on the scenario). While these figures illustrate the potential contribution of renewable gas, they should be confirmed by additional studies and the technology for synthetic gas purification needs to be technically validated.

Several measures have been taken or are being considered to encourage the production of biomethane and its injection into the gas grid. The Multi-annual Energy Programme (PPE), which is based on the Decree of 27 October 2016, has set targets for biomethane injection of 1.7 TWh in 2018 and 8 TWh in 2023. These objectives are based on ADEME's (French Environment and Energy Management Agency) Biomethane 2030 roadmap[141], which evaluates the potential of biomethane injection at 30 TWh/year.[142] While the Law on Energy Transition for Green Growth (LTECV) imposes a target of 10% of green gas consumption by 2030,[143] ADEME forecasts that 15% of the overall gas volumes in the network could come from biogas plants in 2030 and 50% in 2050.[144] Reaching a 30% share of renewable gas in total gas consumption in 2030 as advocated by French gas network operators would imply ambitious objectives in the Multi-annual Energy Programme for 2028: 60 TWh of renewable gas production, including 50 TWh of biomethane.

At the present there are about 736 biogas plants in France, which are being supported by feed-in-tariffs for electricity from biogas.[145] In 2016, 215 GWh of biomethane were injected into the gas network, compared with 82 GWh in 2015, which represents an increase of 162%. At the end of 2016, the biomethane plants had an annual injection capacity of 410 GWh.[146]

The current regulatory framework favours the development of biomethane. The 2011 regulation introduced a feed-in tariff for injected biomethane; tariffs vary from 65 to 125 €/MWh, depending on the biomass input type and the capacity of the installation.

[139] ADEME (2018), Un mix de gaz 100 % renouvelable en 2050?
[140] GRTgaz (2018), A 100% renewable gas mix in 2050?
[141] ADEME (2014), French Biomethane Roadmap and Proposed Action Plan for the Period up to 2030.
[142] GRDF et al. (2016), Renewable gas French panorama 2016.
[143] ISAAC (2016), D5.2: Report on the biomethane injection into the national gas grid.
[144] ADEME (2014), French Biomethane Roadmap and Proposed Action Plan for the Period up to 2030.
[145] ISAAC (2016), D5.2: Report on the biomethane injection into the national gas grid.
[146] GRDF et al. (2016), Renewable gas French panorama 2016.

In addition, there are national (ADEME) and/or local subsidies. There are no specific tax incentives for the injection of biomethane into the grid, but its use as biofuel is supported via tax incentives.
There are also tax incentives for on-farm installations; they benefit since January 2016 from a total exemption from Property tax on buildings (TFPB) and Company real-estate contribution (CFE).
According to a government decision by the minister of energy, 40% of the costs to connect a biomethane production plant to the gas distribution grid are socialised, and hence covered by the general grid access tariffs.[147] A similar decision regarding recovery of connection costs to the gas transmission grid is expected in the coming months.

A future reduction of biomethane production costs could contribute to stimulate its development in the coming years. For instance, a study commissioned by stakeholders involved in the French biomethane sector shows that production costs could decrease by 30% in the next 5 to 10 years.[148]

Use of gas in the transport sector[149]

We observe in France a strong growth in the use of natural gas for transport, mainly for heavy duty vehicles. France is currently preparing a national strategy to implement the energy transition in the freight transport sector. As transport represents 30% of total GHG emissions in France, and as this energy use is difficult to decarbonize, the switch from diesel to gas is considered as a first concrete step to lower GHG emissions, while in the medium and long term, the increasing share of renewable gas (biomethane, gasification and power-to-gas) will contribute to the further decarbonization of the road freight transport sector. Gas could also play an important role to decarbonise the maritime and waterway transport.
In March 2018, there were 90 filling stations (75% of them are compatible with HDV, +100% compared to 2015) for about 3500 vehicles (trucks, buses and garbage trucks). The direct use of biomethane is increasingly developed; in 2017, it represented 9% of the global NGV consumption (6% in 2016). The use of BioNGV (Natural bio-Gas for Vehicles) is (at least until 2022) supported by a reduced national tax on energy products (TICPE) and by favourable depreciation rules for the purchase of NGV vehicles >3.5t.

Hydrogen

The possibility of coupling H_2 and CH_4 through e.g. injecting hydrogen into the gas networks gives direct access to large energy transport and storage capacities: in France, the flexibility offered by linepack[150] and gas storage capacity (137 TWh) could contribute to balancing the electricity system. In order to test the production of hydrogen and synthetic methane from the surplus production of renewable electricity, and their injection into the grid, GRTgaz has, together with Teréga and other partners including RTE, launched a power-to-gas demonstration project (Jupiter 1000). Injections of this first power-to-gas installation on this scale in France are planned for 2018.[151]

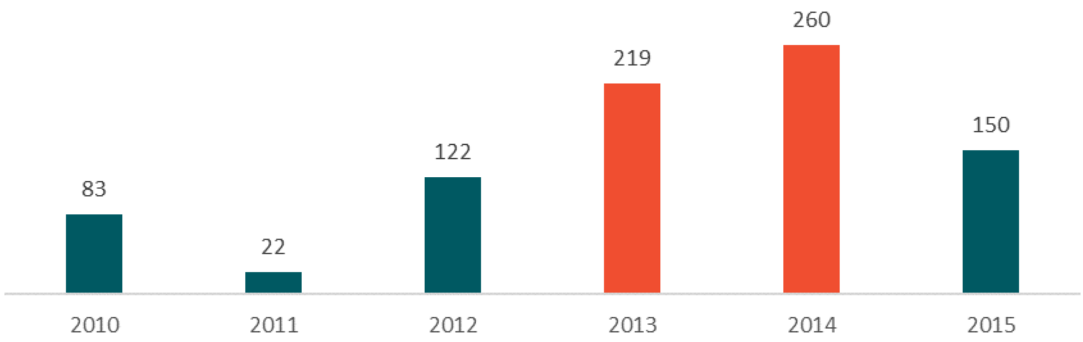
3.2.3 Gas market integration and competition

Despite a generally well-developed gas infrastructure, the GRTgaz network has suffered from congestion in the north-to-south link between PEG North and PEG South in recent years. Looser LNG balances since mid-2014 have helped to reduce the price differentials between north and south

[147] Ministère de la Transition écologique et solidaire (2017), Arrêté du 30 novembre 2017 relatif au niveau de prise en charge des coûts de raccordement à certains réseaux publics de distribution de gaz naturel des installations de production de biogaz, en application de l'article L. 452-1 du code de l'énergie.
[148] ENEA (n/a), Etat des lieux du biométhane en France et pistes de réflexion pour le développement de la filière.
[149] ISAAC (2016), D5.2: Report on the biomethane injection into the national gas grid.
[150] Linepack refers to the volume of gas that can be "stored" in a gas pipeline and hence provides flexibility within the gas network.
[151] GRDF et al. (2016), Renewable gas French panorama 2016.

(because of the heavy dependence of southern France on LNG imports). In late 2013 and early 2014 the gas price spread between PEG Nord and PEG South reached however levels above 10 €/MWh.[152]

Figure 3-6 Number of incidents of physical congestion in the North-South link (utilization rate>=98%)[153]



In order to remove these physical bottlenecks between the North and South of France, which cause large price differentials, two projects with a total cost of around EUR 900 million are being realised and will be commissioned in 2018:

- Val de Saône project (188 km pipeline plus 3 compression stations with a total cost of about EUR 700 million for GRTgaz);
- Gascogne Midi project (60 km pipeline plus 3 compression stations for a cost of about EUR 150 million for Teréga and EUR 20 million for GRTgaz).

The gas wholesale prices at French trading points are increasingly converging with prices in neighbouring markets.[154] However, wholesale prices in the PEG Nord trading point were much more in line with the TTF prices than the prices in the southern trading point, where price differences still exceeded 3 €/MWh in 20% of the trading days in 2016. This price divergence is linked to the above-mentioned grid bottleneck, which will be solved in 2018.

3.2.4 Environmental and climate related regulation and measures

GRTgaz has in the past strongly focused on reducing its emissions of CO_2 and NOx, and is now considering the reduction of its CH_4 emissions as a major strategic objective for the coming years. Such emissions represent a very small share of the transported gas volumes (about 0.05%) but have a higher climate factor than CO_2 and GRTgaz is committed to reduce these emissions by 2/3 by 2020.[155]

[152] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[153] CRE (2016), Networks Electricity and gas interconnections in France - A tool for the construction of an integrated European market.
[154] ACER/CEER (2017) Annual report on the results of monitoring the internal electricity and gas markets in 2016 – Gas wholesale market volume.
[155] GRTgaz (2017), Connecting the energy of tomorrow

3.2.5 Overview of impact of non-gas demand drivers on French gas infrastructure

Table 3-6 Non-gas demand drivers for investment in and use of large infrastructure in France

Policy objective	Issue	Likely impact on gas infrastructure
Security of supply	Access to diversified supplies and flexibility resources	France disposes of access to diversified gas sources via 4 terminals (further expansion of LNG regasification units is envisaged) and several import pipelines Gas system has high resilience to possible supply crises Short term security of supply is ensured by large storage capacity
	Infrastructure standard (N-1) to ensure security of supply	Gas system is resilient to unplanned temporary unavailability of largest infrastructure component Conversion from L-gas to H-gas in the North of France (currently undertaken) will improve security of supply
Climate / Environment	Back-up of intermittent RES capacity	France plans large intermittent power generation capacity, particularly wind. Gas will be essential for back-up, at least until 2030. Networks are already sufficiently developed.
	Biogas/biomethane development	Large potential of biogas/biomethane in France Development could compensate for fall in natural gas transported volumes, though financial and other hurdles need to be addressed (currently relies highly on subsidies)
	Hydrogen development	Hydrogen production (P2G), transport and storage offers potential to compensate for fall in natural gas volumes Transport of hydrogen via grid requires investments if H_2 share exceeds technical transport thresholds. Storage also to be refurbished
	Substitution of other fuels	Coal capacity for power generation will be phased out and nuclear energy will not be expanded. Use of gas (LNG, biomethane, hydrogen) for transport will also have impact on gas infrastructure
	Environmental regulation	Maintenance/investments will be needed to control/reduce CH_4 and CO_2 emissions from gas infrastructure
Competitiveness / market development/market integration	Market integration	France is properly interconnected with neighbouring countries, no major cross-border expansion needed/envisaged, except if Spain confirms its need to have more import capacity from the North in order to rely less on LNG supplies.
	Enhance competition	Wholesale gas market is competitive; competition issue has no major impact on gas infrastructure

3.3 Assessment of the impact of the storylines on the French TSO

The Regulatory Asset Base (RAB) of GRTgaz amounted in 2017 to €8.3 billion and is expected to increase to €8,9 billion in 2020. In the medium and long term, the RAB would gradually decline, but the evolution will be different depending on the storyline (highest decrease in storyline 2). The OPEX of GRTgaz amounted in 2017 to € 763.9 million, while the CAPEX was €993.4 million and is projected at €1,071 million in 2020. The TSO's OPEX are to a large extent fixed or infrastructure related and are hence in the medium and long term expected to only slightly reduce with falling transported gas volumes. The future decrease of the CAPEX will depend on the storyline, and will be lower in storylines 1 and 3 where investments will be needed in the gas transmission system to accommodate hydrogen. The overall costs would in storylines 1 and 3 reduce less than the transported volumes, which would have an increasing impact on the grid tariffs. Storyline 2 would be the preferred option from a gas TSO perspective.

3.3.1 Key financial indicators: GRTgaz

Table 3-7 Key financial indicators GRTgaz

General data for GRTgaz		Unit	Source
Infrastructure			
Pipelines	32,414	km	GRTgaz Chiffres clé 2017 [156]
Compressor stations	26	Units	GRTgaz Chiffres clé 2017
Interconnection Points	11	Units	GRTgaz Chiffres clé 2017
Transport volumes 2017			
For end-use	467	TWh	GRTgaz Chiffres clé 2017
For transit	102.5	TWh	GRTgaz Chiffres clé 2017
Investments			
Investments	€657 ml in 2017 (€2.6 bl 2013-16)	EUR/year	GRTgaz Chiffres clé 2017 GRTgaz (2016) Connecting the Energy of Tomorrow[157]
Investment plan	€5 bn in 10 years (from 2016)	EUR/x years	GRTgaz (2016) Connecting the Energy of Tomorrow
RAB 2017			
Transmission	€8.281 ml	EUR	Deliberation CRE of 07/02/2018
Revenues 2017			
Operating revenues	€1,771 ml	EUR	Deliberation CRE of 07/02/2018
EBITDA	€1,124 ml	EUR	GRTgaz Chiffres clé 2017
Shareholders			
Public limited company; 75% of the TSO shares are owned by ENGIE and 25% by Société d' Infrastructures Gazières, a public consortium of CNP Assurances and Caisse des Dépôts et Consignations (CdC)			

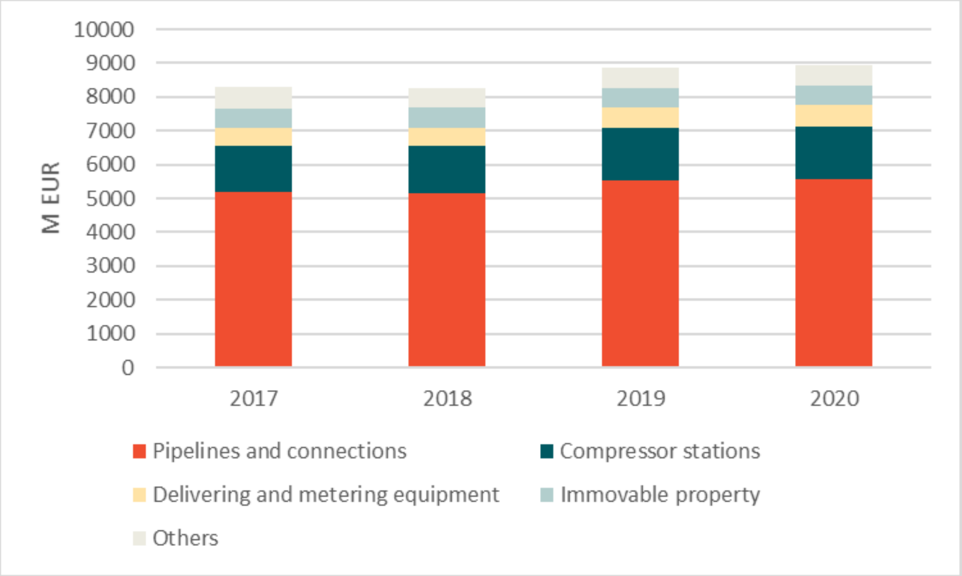
[156] GRTgaz (2018), Chiffres cles 2017
[157] GRTgaz (2017), Connecting the energy of tomorrow

3.3.2 Regulatory Asset Base (RAB)

According to the CRE Deliberation of 7 February 2018, the Regulatory Asset Base of GRTgaz amounted on 01/01/2017 to €8.3 billion and would increase to €8.9 billion in 2020. The main components of the RAB are pipelines/connections (62.5%) and compressor stations (16.7%); metering and delivering equipment, immovable property and other assets represent the remaining 20.8%.

The RAB represents the economic value of the TSO assets, which can be affected by the energy transition. The three storylines would have a different impact on the evolution of the RAB: storyline 1 (strong electrification) and 3 (strong development of hydrogen) might require specific investments to refurbish some assets (to accommodate high hydrogen volumes or CO_2 transport) or might even lead to divestments in some assets, while the second storyline based on strong development of carbon neutral gas, would allow a high utilisation rate of existing and planned transmission assets in the medium and long term, but would necessitate investments in reverse flows to enable injection of high biomethane volumes at distribution level.

Figure 3-7 Expected evolution of the regulated asset base of GRTgaz



Source: CRE deliberation of 14.12.2017, p.13.[158]

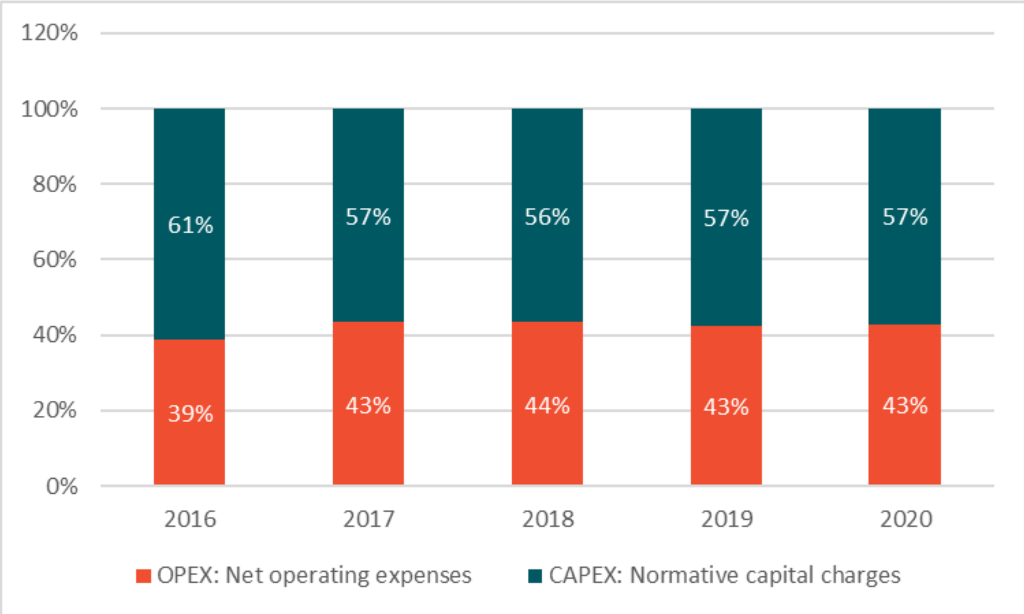
3.3.3 OPEX & CAPEX and their impact on revenues/grid tariffs

According to the CRE Deliberation of 7 February 2018, the OPEX of GRTgaz amounted in 2017 to € 763.9 million, and would rise to €777.1 million in 2018. It is expected that, with falling transported gas volumes in 2 storylines, the OPEX would only slightly reduce, as most cost components (e.g. maintenance, administrative costs) are to a large extent fixed or infrastructure related. Some cost components are volume related (e.g. energy cost for compressor stations), but these costs only represent a limited share of the overall OPEX (11.6% in 2017 according to the CRE deliberation of 14 December 2017). The evolution of the OPEX would hence only slightly be different depending on the storyline.

[158] CRE DELIBERATION N°2018-022 Délibération de la Commission de régulation de l'énergie du 7 février 2018 portant décision sur l'évolution du tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et TIGF au 1er avril 2018

The CAPEX was shown to be €993.4 million in 2017 and projected at €1,070.8 million by 2020. Due to the long depreciation periods, the net accounting value of GRTgaz is high compared to the current investment level. The CAPEX would hence in the coming 10 to 20 years remain at a high level. The evolution of the CAPEX depends on the one hand on the depreciation of existing assets and related capital costs, which are the same for the 3 storylines, and on the other hand on the future investment levels, which would be different depending on the storyline. As TSOs benefit from regulated revenues, falling gas demand would not necessarily lead to lower revenues for TSOs. Currently TSOs mainly recover their costs via long term capacity bookings and capacity-based tariffs. However, when gas demand falls, infrastructure capacity will become largely available and congestion will no longer occur; in these circumstances capacity reservations will shift from long-term to short-term bookings (i.e. less capacity will be booked), which will translate into increasing grid tariffs per transported MWh.

Figure 3-8 Share of CAPEX and OPEX in the total revenues of GRTgaz

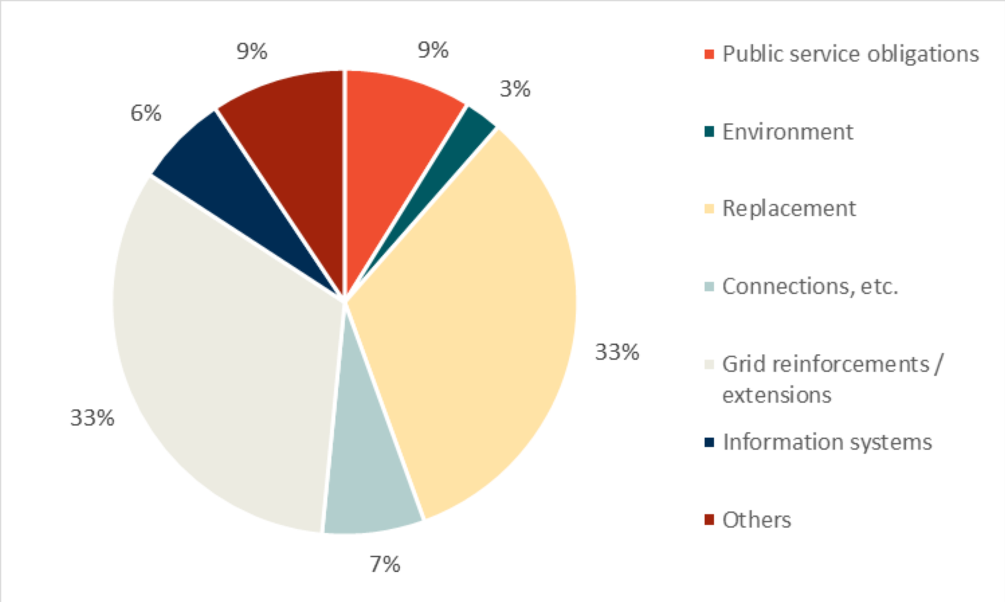


Source: CRE deliberation of 15.12.2016, p.64.[159]

According to the CRE Deliberation of 21 December 2017, the investment budget of GRTgaz for 2018 amounts to €576 million.[160] The diagram below presents a split of the €576 million across the different investment categories, and shows that replacements and grid reinforcements/extensions represent the largest share.

[159] Deliberation of the French Energy Regulatory Commission of 15 December 2016 forming a decision on the tariff for the use of GRTgaz and TIGF natural gas transmission networks
[160] CRE DELIBERATION N°2017-284. Délibération de la commission de régulation de l'énergie du 21 décembre 2017 portant approbation du programme d'investissements pour l'année 2018 de GRTgaz

Figure 3-9 Split of the 2018 investment budget of GRTgaz



Source: CRE deliberation of 21.12.2017, p.2.[161]

Recent investment plans illustrate that, in order to ensure the operational security and safety of the network, a high investment level would still be needed, even with falling transported gas volumes in 2 storylines. Depending on the storyline, specific additional investments for refurbishment (e.g. to facilitate injection of high volumes of hydrogen) or development/extension of the grid would be needed, e.g. to allow reverse flows in all parts of the grid.

As all assets owned by GRTgaz are operated under a regulated TPA scheme and assuming that the current regulatory framework (cost +) would be maintained, the 2 storylines with decreasing transported volumes would not directly affect the relative profitability of GRTgaz, but would lead to higher grid tariffs per transported MWh. In the medium and long term, higher grids tariffs could deteriorate the competitiveness and affordability of gas and might hence undermine the business perspectives and profitability of the TSO in a downward spiral (where investments for lower transported energy volume lead to higher grid tariffs per MWh which in turn reduces demand because of higher prices).

3.3.4 TSO viability analysis: estimated impact of the 3 storylines on end-user tariffs and on the TSO business

The table below provides an overview of the expected qualitative impacts of the three storylines.

[161] CRE DELIBERATION N°2017-284 Délibération de la commission de régulation de l'énergie du 21 décembre 2017 portant approbation du programme d'investissements pour l'année 2018 de GRTgaz

Table 3-8 Impact of the 3 storylines on TSO tariffs and business

	Figures 2017	Storyline 1 Strong electrification		Storyline 2 Strong development of carbon neutral methane		Storyline 3 Strong development of hydrogen	
Gas Demand in France TWh	478.1	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
	478.1	Decrease	Decrease	Increase	Increase	Stable	Increase
Gas volumes transported by GRTGaz[162]	627.3	Decrease		Increase		Stable/Decrease	
TSO Investments	€657 million	Future investments at **medium** level => to ensure operational security and safety + to refurbish some pipelines to H_2 after 2030		Future investments at **lowest** level => to ensure operational security and safety + limited extensions No need for refurbishment to H_2		Future investments at **highest** level => to ensure operational security and safety + to substantially refurbish grids to H_2	
TSO OPEX	€764 million	Relatively stable Impact of storyline is not decisive		Relatively stable Impact of storyline is not decisive		Relatively stable Impact of storyline is not decisive	
TSO CAPEX	€993 million	CAPEX related to existing assets will still represent high share in coming 10-20 years. CAPEX for new investments will be at medium level in this storyline		CAPEX related to existing assets will still represent high share in coming 10-20 years. CAPEX for new investments will be at lowest level in this storyline		CAPEX related to existing assets will still represent high share in coming 10-20 years. CAPEX for new investments will be at highest level in this storyline	
Impact on TSO grid tariff	2.7 €/MWh	Medium negative impact		'Positive' impact		Medium to high negative impact	
Overall assessment from gas TSO perspective				Preferred storyline			

*Note: The overall gas demand 2030 and 2050 is compared to the 2015 level and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease 5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The gas demand for 2030 and 2050 includes volumes of renewable gas which are locally used or are transported via the distribution grid only. The effective impact on the transmission grid might hence be slightly more negative than indicated.*

[162] Future gas demand will increasingly be covered by local production of renewable gas, partly locally used and partly injected into the distribution or transport grid. Volumes to be transported via the transmission grid would hence decrease more than overall gas demand.

3.4 Regulatory framework in France

All TSO gas assets in France are operated under a regulated third-party access regime. The annual tariffs for gas transmission services are based on the 'authorized' operational costs, the depreciation costs and a regulated cost of capital (WACC), applied on the RAB value. They are approved by the CRE (NRA) according to the Entry-Exit tariff model and methodology in line with European and French legislation and regulation. The CRE determines each year the RAB value of the TSOs taking into account the inflation level, their new investments and the depreciation costs. The RAB value is used as a basis to determine the 'authorised' return on equity for TSOs.
There are in France several policy and regulatory measures to stimulate the development of renewable gas, including biomethane transported via the gas grid.
Taking into account the uncertainty about the future use of the gas infrastructure, a review of the depreciation rules could be considered to ensure that current investments are mostly depreciated by 2050. Moreover, the regulatory regime could in the future more specifically stimulate investments that are future-proof (flexible, suitable for renewable gas) and investment projects should be evaluated on the basis of more "conservative" demand scenarios. It is also suggested to value synergy potentials within the gas infrastructure sector in order to reduce fixed costs, and to assess and possibly redefine the potential role of gas TSOs in new developments, such as power-to-gas installations and dedicated hydrogen or CO2 transport infrastructure.

3.4.1 Regulated tariffs and revenues for gas infrastructure owners/operators

All TSO gas assets in France are operated under a regulated third-party access regime. The tariffs are based on the 'authorized' operational costs (taking into account an imposed cost efficiency increase level), the annual depreciation costs and a regulated cost of capital (WACC), applied on the RAB value. The 2018 grid tariff was established on the basis of a WACC level of 5.25% approved by the French NRA. For priority projects (PCIs), a specific additional remuneration applied until 2017 (+ 3% on WACC). For new interconnection investments since 2017, the value and allocation of an additional remuneration depend on the results of the CBA performed by the CRE for each project.

The tariff for gas transmission services is approved by the NRA according to the Entry-Exit tariff model and methodology in line with European and French legislation and regulation.
In accordance with the CRE deliberation of 15 December 2016, French gas TSOs apply only capacity tariffs (no volume related grid fees), which are different depending on the contracted capacity and the connection type:

- ▪ physical points of entry to the transmission system and gas storage facilities;
- ▪ physical points of exit from the transmission system and storage fields.

Since 1 April 2018, the TSOs also charge a specific storage fee (297.10 €/MWh/d/y) in accordance with the CRE deliberation of 27 March 2018.

The revenues of TSOs are hence mainly related to capacity reservations. Although shippers increasingly tend to favour short-term capacity bookings, long-term capacity bookings are still largely predominant in the TSO's income. GRTgaz had in 2017 an allowed revenue of almost €1.8 billion, of which only a few millions stemmed from short-term bookings.[163]

[163] Roughly €25 million stem from monthly and daily bookings on GRTgaz upstream network and €12.5 million downstream. Source: Bilateral communication with GRTGaz.

According to the CRE deliberation of 15 December 2016, the average transmission tariffs amounted in 2016 to 100 €/MWh/d/y for entry points and 120 €/MWh/d/y for exit points.

3.4.2 *Accounting rules for large gas infrastructure*

CRE determines each year the RAB value of the TSOs taking into account the inflation level, their new investments and the depreciation costs. The RAB value is used as a basis to determine the 'authorised' revenues for TSOs. The economic asset lifetimes used to calculate the depreciation charges are 50 years for pipelines, 30 years for compressor stations and 10 years for other technical equipment and installations.

3.4.3 *Legal and regulatory framework for renewable gas*

The French legislation is facilitating and supporting the injection of biomethane, via different measures: specific target for renewable gas, financial support, reduction on connection costs to gas grid (part of the connection cost is socialised), guarantees of origin, etc. These aspects are extensively discussed in section 3.3.

There is not yet a specific regulation or legislation with regard to injection of hydrogen or biomethane.

3.4.4 *Readiness of the French regulatory regime*

The current regulatory regime in France (and in most other EU Member States) has been designed for a developing and growing natural gas market. It has supported massive investments in natural gas infrastructure and has fostered the harmonisation of market rules in France and the neighbouring countries in view of creating a competitive and integrated supra-national natural gas market. The French regulation has in particular enabled the development of an extensive gas grid thanks to the guaranteed remuneration of the regulated asset base of the gas TSOs and a specific national incentive regulation for priority projects, inter alia those facilitating cross-border flows of gas.

The transition to a carbon neutral energy system, which will lead to a substantial evolution of the use and role of gas infrastructure, should be facilitated by an enabling regulatory framework. The deployment of biomethane is already facilitated in France, but further changes in the legal and regulatory framework will be necessary to accelerate this transition, while at the same time mitigating its potentially negative impact on existing gas infrastructure and users.

Depending on the considered storyline, the anticipated decrease in transported gas volumes could imply that transmission assets which are not yet depreciated, are more or less likely to become devalued or stranded, especially as their economic lifetime is long (e.g. 50 years for pipelines in France). Taking into account the increasing uncertainty about the gas volumes that will use the transmission infrastructure, an adjustment of the depreciation rules could be considered in order to reflect this new situation; the regulator could for (new) gas transmission assets allow an accelerated depreciation, either by applying a linear depreciation over a shorter time period, or by allowing a degressive depreciation method, where most of the value of the assets would be depreciated at the beginning of the assets' lifetime, and less towards the end. This approach would allow to have depreciation cost levels that are more consistent with the evolution of the transported gas volumes, ensuring that assets are mainly depreciated when transported gas volumes are still high, thus minimising the impact of falling transport volumes on network tariffs.

As the current “cost +” system in France encourages the development of the network via the remuneration of the RAB, an evolution of the regulatory regime could also be envisaged in order to move towards a remuneration of TSOs based on criteria (sustainability, flexibility, security of supply), which would specifically incentivize future-proof investments and ensure that existing assets are renewed in a way which is consistent with the transported gas volumes’ projections (e.g. suitable for renewable gas, capacity of compressor stations to be adapted/decreased when they are replaced).

In order to ensure that gas infrastructure assets that are still useful for the market are not prematurely decommissioned or mothballed when they are not profitable any more for their owners/operators, a specific remuneration scheme could be considered (for example, strategic reserve capacity financed via the public budget or the grid tariff). This approach has been implemented in France in January 2018 for the storage assets. Such a system would allow keeping ‘useful’ capacity available to the market, without major negative impact on the competitiveness or affordability of gas. This would be especially relevant for gas infrastructure assets (pipelines, LNG terminals, storages) that already have or will have (very) low utilisation levels but are nevertheless useful to ensure security of gas and electricity supply. The flexibility that can be provided by these infrastructures to the power system also needs to be properly taken into account in this assessment.

The negative impact of decreasing transported gas volumes could also be mitigated by cost reductions; the current regulatory regime does not allow to fully value operational synergy potentials between TSO, storage and LNG activities. A review of the legal rules could be considered in order to increase the overall efficiency of the gas system and lower the global operational costs.

In order to avoid the risk to invest in assets that would become useless (‘stranded’) before the end of their depreciation period due to a decrease of the transported gas volumes, new investments in gas infrastructure should be evaluated on the basis of more “conservative” scenarios. The current scenarios used by ENTSOG and the TSOs are in general still rather optimistic.

A specific policy measure implemented in France to reduce GHG emissions and to mitigate the impact of falling gas demand on grid tariffs, is the development of natural gas (CNG, LNG) in the transport sector. This measure has a direct positive impact on GHG emissions, and paves the way towards a system where renewable gas (biomethane, hydrogen) can increasingly be used as transport fuel for large vehicles, ships, etc., where electricity does not offer a competitive solution. In order to accelerate this evolution and maintain its business, GRTgaz is interested in developing CNG/LNG filling stations, but the current legal and regulatory framework does not allow TSOs to engage in such activities. A thorough legal and economic analysis would be useful to check whether and under which conditions a TSO involvement in gas filling stations would contribute to cost-efficiently reaching the climate targets, while respecting the unbundling principles and competition rules. GRTgaz welcomes that part of the connection costs of gas filling stations can be socialised via the gas tariffs. The NRA has recently also decided that the French gas TSOs can offer connection fee discounts to new industrial customers (for example switching from coal or fuel to gas); such a measure is also foreseen for production sites of renewable gas. These legal and regulatory measures are helpful to facilitate the injection of renewable gas into the network.

In order to accelerate the development of renewable gas (biomethane as well as hydrogen and synthetic methane produced by using ‘excess’ renewable electricity), TSOs suggest allowing them to also (co-)invest in green gas facilities (for instance, in power to gas installations which are not yet commercially viable). Such an involvement is currently not possible, and would necessitate changes in the legal framework. It would be appropriate to assess whether and under which conditions a TSO could effectively be allowed to develop or participate in such projects without risks for competition distortion.

The French authorities and TSOs support the transition to a low-carbon gas supply by dedicated R&D which is in particular needed to improve the technical and economic performance of "power to gas". In this context the "GRTgaz 2020" project to reinforce the TSO's ability to prepare the future of the gas networks (support to biomethane, Power to Gas, green mobility…) was taken into account by the French NRA in its decision setting transmission tariffs. In particular, incentive regulation for R&D activities has been implemented in the new tariff framework in France.

Finally, in order to ensure a global optimisation of the energy system, it is suggested that gas TSOs should be allowed to also build and operate dedicated CO_2 and hydrogen networks, if market needs for such infrastructure would emerge. This option would offer economic benefits (economies of scale), while allowing to organise non-discriminatory third-party access to the networks and proper competition on the concerned markets.

4 Poland

Key data		Unit	Source
Annual gas consumption	170,186	GWh/year	Eurostat 2016
Peak load	804	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	15	%	Eurostat 2016
Domestic primary gas production	41,318	GWh/year	Eurostat 2016 (nrg_100a)
Imports	141,713	GWh/year	Eurostat 2016 (nrg_100a)
Exports	8,324	GWh/year	Eurostat 2016 (nrg_100a)
Capacity of entry pipelines	1,531	GWh/day	ENTSOG transmission capacity map 2016
LNG import terminal capacity	5	Billion m^3(N)/year	GIE LNG map 2016
Number of gas PCIs in 2017 list	8	projects	PCI list 2017
Other general information			
Regulatory system	LNG terminals, gas storage and transmission: regulated TPA		
NRA	Energy Regulatory Office		
TSO	Gaz-System S.A.		

4.1 Existing and planned gas infrastructure

Poland has one operating LNG terminal and is planning to build an additional one, and has seven storage facilities with a total capacity of 33 TWh. TSO Gaz-System S.A. owns and operates the transmission network in Poland, and is also responsible for the Polish section of the Yamal-Europe Transit Gas Pipeline System. The utilization rate of the National Transmission Network reached 58% in 2016 and the use of the Transit Gas Pipeline System reached 81% in the same year. Poland is involved in several PCI projects, the most important one being the Baltic Pipe connecting Poland with Denmark. The utilisation level of the LNG terminal(s) is expected to substantially decrease after 2030, while the gas storage facilities would be further used to meet the increasing flexibility needs; some storage sites would require refurbishment depending on the storyline. The transmission network would in the 3 storylines also be further used, but in storylines 1 and 3, it would require upgrade to be able to transfer high volumes of hydrogen.

4.1.1 Main large gas infrastructure

LNG terminals

Poland has one LNG terminal, which is operational since 2016 and is planned to be expanded by 2023. There are also plans for building a second LNG terminal.

The Świnoujście LNG terminal was completed in October 2015 and received its first commercial cargo in June 2016. It will be connected via the North-South Gas Corridor with the Baltic Pipe (to be constructed), through central Poland, the Czech Republic, Slovakia and Hungary with the planned Adria LNG terminal in Croatia.[164] The terminal is owned and operated by Polskie LNG, which is a subsidiary of Gaz-System. It has a regasification capacity of 5 bcm/y, which is, according to the PCI list 2017 (PCI 8.7) planned to be expanded up to 7.5 bcm/y (nominal capacity) by 2023. It currently has two storage tanks with a capacity of 160,000 m^3 each; the construction of an additional storage tank is planned. Additional small-scale LNG services are also planned to be offered to the market participants (e.g.

[164] Gaz-System (2016), North-South gas corridor.

bunkering, transhipment, rail loading). The capacity is offered to the market under a regulated third-party access (TPA) regime.

Gaz-System is also assessing the possibility of building an additional LNG terminal at the Baltic Sea Coast, which would provide new services and functionalities, depending on market demand. The terminal is planned to be commissioned in 2023.[165]

Table 4-1 Existing and planned LNG terminals in Poland. Source: GIE LNG Map 2018[166] and PCI-list

Name of installation	Operator	Status	Start-up year	Max. Hourly Cap. $m^3(N)/hour$	Nom. Annual Cap. billion $m^3(N)/year$	LNG storage capacity m^3 LNG	TPA regime
Swinoujscie LNG Terminal	Gaz-System	operational	2016	656,000	5.0	320,000	regulated
Swinoujscie LNG Terminal (expansion)	Gaz-System	planned	2023	1,312,000	10.0	520,000	regulated
FSRU Polish Baltic Sea Coast	Gaz-System	planned	2022	635,000	4.5	165,000	regulated

Gas storage

Currently, there are seven storage facilities for high-methane gas in Poland with a total capacity of about 33 TWh, which corresponds to approximately 19% of the annual national consumption.[167] All of them are managed/operated by Gas Storage Poland (GSP) limited liability company which is part of PGNiG Capital Group (Polish Oil and Gas Company). Storage facilities belong to PGNiG. Several new storage facilities are planned or under construction (see table).

PGNiG[168] owns nine underground gas storage facilities located in salt caverns or in depleted natural gas reservoirs. PGNiG created a separate company, Gas Storage Poland (previously called Operator Systemu Magazynowania (OSM)), in order to comply with the legal unbundling requirement. The storage facilities operated by Gas Storage Poland Sp. z o.o. under regulated TPA conditions, offer long-term and short-term capacity as well as firm and interruptible storage products.[169] For some other storage facilities owned and operated by PGNiG, negotiated access applies (see table).[170] PGNiG also operates two storage facilities for nitrogen-rich gas used at the gas production sites in Bonikowo and Daszewo. As these facilities are not used for market security of supply purposes but to optimise gas production, these facilities are not classified as energy storage facilities by the Polish Energy Law, hence PGNiG could remain in charge of operating these facilities.[171]

The effective use of the available storage capacity in Poland could be improved; storage capacity for security of supply purposes is often separated from commercial capacity creating an artificial scarcity in the market. According to ACER/CEER, a reduction of regulatory obligations on storage capacity allocation that go beyond security of supply needs, would attract new market entrants and further

[165] ENTSOG (2018), Press Release: ENTSOG publishes list of projects to be included in TYNDP 2018.
[166] GIE (2018), GIE LNG Map 2018.
[167] TOE (2017) Electricity and gas market in Poland - Status on 31 March, 2017.
[168] IEA (2016), Energy policies of IEA countries - Poland: 2016 review.
[169] IEA (2016), Energy policies of IEA countries - Poland: 2016 review.
[170] IEA (2016), Energy policies of IEA countries - Poland: 2016 review.
[171] PGNiG (2013), Annual Report 2014.

develop hub liquidity. Poland should hence investigate whether a more market-driven approach could be implemented for storage use.[172]

Poland is continuing to expand its gas storage capacity. The expansion of the storage capacity in the Kosakowo facility from 119 to 250 mcm is planned to be completed in 2021, and further administrative decisions are expected for an additional expansion of the capacity to 656 mcm.[173] Also, the storage capacity of the facility in Mogilno would be expanded from 600 mcm to 800 mcm, which is planned to be completed in 2024.[174] Finally, Gaz-System is currently exploring the feasibility of constructing a gas storage facility in a salt cavern in Damasławek.[175]

[172] ACER/CEER (2017), Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016 Gas Wholesale Markets Volume.
[173] PGNiG (N/A), Development prospects.
[174] PGNiG (N/A), Storage.
[175] Gaz-System (2017), The second research borehole provided for the “Damasławek” gas warehouse.

Table 4-2 Existing and planned gas storage facilities in Poland (all onshore). Source: Gas Storage Poland (2018)[176]

Facility/Location	Status	Start-up year	Type	Operator	Working gas (technical) TWh	Withdrawal technical GWh/day	Injection technical GWh/day	Access regime
Swarzow	Operational	1979	Depleted Field	Gas Storage Poland Sp. z o.o.	1.01	11.2	11.2	rTPA
Brzeznica	Operational	1979 (expansion finished in 2017)	Depleted Field		1.13	16.1	16.2	rTPA
Strachocina	Operational	1982	Depleted Field		4.05	37.9	29.7	rTPA
Husow	Operational	1987	Depleted Field		5.63	64.6	46.7	rTPA
Wierzchowice	Operational	1995	Depleted Field		13.20	105.6	66.0	rTPA
Mogilno	Operational	1997	Salt cavern		6.57	200.5	106.9	rTPA
Mogilno	Under construction	Between 2020 and 2025	Salt cavern		8.91*	No data	No data	rTPA
Kosakowo	Operational	2014	Salt cavern		1.33	107	26.8	rTPA
Kosakowo	Planned	2021	Salt cavern		7.33**	No data	No data	rTPA
Damasławek***	Planned	2026	Salt cavern	Gaz-System S.A.	No data	No data	No data	rTPA
Total (current)	Operational	N.A.	N.A.	N.A.	**32.92**	**545.55**	**303.5**	

*Based on http://pgnig.pl/reports/annualreport2016/en/segmenty-dzialalnosci/obrot-i-magazynowanie/perspektywy-rozwoju/ . The working capacity will increase to 800 mcm, which is equivalent to approximately 8.91 TWh using the current volume energy ratio used by gas Storage Poland (590 mcm / 6,570.9 GWh).

** Based on http://pgnig.pl/reports/annualreport2016/en/segmenty-dzialalnosci/obrot-i-magazynowanie/perspektywy-rozwoju/. The working capacity will increase to 656 mcm, which is equivalent to approximately 7.33 TWh using the current volume energy ratio used by gas Storage Poland (119 mcm / 1,326.9 GWh).

*** Gaz-System is currently exploring the feasibility of constructing a gas storage facility in a salt cavern in Damasławek; however, indicating any figures regarding plans seems

[176] Gas Storage Poland (2018), Technical characteristics – underground gas storage facilities in Poland. Available at: https://ipi.gasstoragepoland.pl/en/menu-en/transparency-template/services-and-facilities/technical-characteristics/

Gas transmission network

Gaz-System S.A. is the TSO (ownership unbundling model) which owns and operates the transmission network in Poland, and is also designated and certified as an independent system operator (ISO) responsible for the Polish section of the Yamal-Europe Transit Gas Pipeline System.[177]

The transmission network comprises two operationally interlinked systems, the Transit Gas Pipeline System and the National Transmission System.

The Polish TSO is strongly investing in the extension of its gas transmission infrastructure, e.g. in the context of the North-South Gas Corridor. By 2025 about 2,000 km of new gas pipelines will be constructed in the Western, Southern, and Eastern parts of Poland.[178]

The current and planned investments are not only based on the expected evolution of domestic gas demand in Poland, but also aim at responding to future needs for gas transit and exports, for which further development of interconnections with the neighbouring countries is required.[179] The current investment plans mainly focus on enhancing security of gas supply on the one hand and on contributing to gas markets' integration (creation of single market) on the other hand.

[177] Gaz-System (2018), National Ten-Year Transmission System Development Plan – Development plan for satisfying the current and future transmission demand for natural gas for 2018-2027.
[178] Gaz-System (2016), Energy for Poland – Report on the operation and efficiency of the coordination system for the LNG terminal in Swinoujscie 2010-2016.
[179] Gaz-System (2014), Development Plan for satisfying the current and future transmission demand for natural gas for 2014 – 2023.

Figure 4-1 Gas infrastructure map of Poland. Source: ENTSO-G (2017).[180]

The utilization rate of the National Transmission Network reached 58% in 2016 and the use of the Transit Gas Pipeline System reached 81% in the same year.[181]

180 ENTSOG (2017), The European natural gas network 2017 map.
181 TOE (2017) Electricity and gas market in Poland – Status on 31 March, 2017.

Interconnections

The table below provides an overview of the cross-border interconnection points (IP) to and from Poland, as well as the LNG entry points. Currently, Poland has three cross-border interconnection points with other EU countries, namely one with the Czech Republic and two with Germany. Both interconnection points with Germany allow for bidirectional gas flows, whereas the interconnection point with the Czech Republic only allows for gas imports. Next to the three existing intra-EU interconnectors, additional interconnectors with the Czech Republic, Slovakia and Lithuania are planned.[182] Also, Poland has three cross-border interconnection points with Belarus and one with Ukraine, which allow for gas imports.[183] Gaz-System offers the reverse flow to Ukraine via IP Hermanowice.[184]

182 TOE (2017) Electricity and gas market in Poland – Status on 31 March, 2017.
183 TOE (2017) Electricity and gas market in Poland – Status on 31 March, 2017.
184 https://swi.gaz-system.pl/swi/public/#!/ksp/points?lang=en

Table 4-3 Interconnection points. Source: ENTSOG capacity map 2017[185], URE (2018)[186] and TOE (2017)[187]

Type	*N*	*Point*	*Arc*	*Technical physical capacity (GWh/d)*	*Transmission capacity in 2017 (bcm/year)*	*From*	*To*	*From operator*	*To operator*
Cross-border IP within EU and with non-EU (export)	38	Mallnow	DE>PL/YAM	**117.6**	6.1	DE	PL	GASCADE Gastransport	Gaz-System (ISO)
Cross-border IP within EU and with non-EU (export)	38	Mallnow	PL/YAM>DE	**931.5**	28.1	PL	DE	Gaz-System (ISO)	GASCADE Gastransport
Cross-border IP within EU and with non-EU (export)	44	Cieszyn (PL) / Český Těšín (CZ)	CZ>PL	**28.0**	0.6	CZ	PL	NET4GAS	Gaz-System
Cross-border IP within EU and with non-EU (export)	82	GCP Gaz-System /ONTRAS[188]	DE>PL	**48.7**	1.6	DE	PL	ONTRAS	Gaz-System
Cross-border IP within EU and with non-EU (export)	82	GCP Gas-System /ONTRAS[189]	PL>DE	**0.1**	0.9	PL	DE	GAZ-SYSTEM	ONTRAS
Cross-border IP with non-EU (import)	214	Tieterowka	BY>PL	**7.3**	0.2	BY	PL	Gazprom Belarus	Gaz-System
Cross-border IP with non-EU (import)	215	Kondratki	BY>PL/YAM	**1,024.3**	30.9	BY	PL	Gazprom Belarus	Gaz-System (ISO)
Cross-border IP with non-EU (import)	216	Wysokoje	BY>PL	**169.1**	5.2	BY	PL	Gazprom Belarus	Gaz-System
Cross-border IP with non-EU (import)	217	Drozdovichi (UA) - Drozdowicze (PL)	UA>PL	**135.6**	4.4	UA	PL	PJSC Ukrtransgaz	Gaz-System
LNG Entry IP	321	Swinoujscie	LNG_Tk_PL>PL	**158.0**	**5 + option to increase to 7.5**	PL	PL	Polskie LNG	Gaz-System

185 ENTSOG (2017), The European natural gas network 2017.
186 URE (2018) Sprawozdanie z działalności Prezesa Urzędu Regulacji Energetyki w 2017 r.
187 TOE (2017) Electricity and gas market in Poland - Status on 31 March, 2017.
188 According to Art. 19 (9) of CAM NC, ONTRAS and Gaz-System agreed to offer the capacity at one virtual interconnection point - GCP Gaz-System /ONTRAS
189 According to Art. 19 (9) of CAM NC, ONTRAS and Gaz-System agreed to offer the capacity at one virtual interconnection point - GCP Gaz-System /ONTRAS

Utilisation of interconnection infrastructure

The table below gives an overview of the utilization of the entry and exit points in the Polish gas transmission system. From these figures it can be seen that cross-border gas imports represent the largest part of the gas transport volumes. In 2017, most gas imports entered at the connection point between the Yamal transit pipeline and the Polish national gas transmission grid (PWP). The second most important entry point for imported gas was the interconnector at Drozdowicze (Ukraine) and the third was the interconnector at Wysokoje (Belarus). Domestic production accounted for 29 TWh of gas entering the transmission grid and gasified LNG for 18 TWh. In 2016, 58% of the maximum national transmission network (NTN) interconnection capacity was effectively utilised.[190]

Table 4-4 Utilisation of the most important entry and exit points in the Polish gas transmission network in 2017. Source: Gaz-System[191]

Gas entering the Polish grid (2017) - TWh		Gas exiting the Polish grid (2017) -TWh	
Cross-border imports		***Cross-border exports***	
Punkt Wzajemnego Połączenia (PWP) - import via Yamal transit pipeline	56	Hermanowice k. (UA)	14
Drozdowicze (UA)	50		
Wysokoje (BY)	34		
GCP Gaz-System/Ontras (DE)	6		
Cieszyn (CZ)	1		
Tietierowka (BY)	1		
Total cross-border inputs	***148***		
Domestic production		***Withdrawal of gas for storage***	
Produkcja krajowa (E)	12	GIM Sanok zatłaczanie	9
E/Produkcja kraj-Odazotownia/Wejście	12	IM Wierzchowice zatłaczanie	9
Produkcja krajowa (L)	5	GIM Kawerna zatłaczanie	6
Injection from storage facilities		***Gas entering the distribution grids***	
IM Wierzchowice	9	High methane gas for OSD (Polish DSO)	133
GIM Sanok	8	Low-methane gas for OSD (Polish DSO)	4
GIM Kawerna	6	**Final gas use - large consumers**	
Injection from LNG terminal		Total final gas use - large consumers	43
LNG Terminal Świnoujście	18		

190 TOE (2017) Electricity and gas market in Poland - Status on 31 March,2017.
191 Gaz-System (N/A), Actual quantity of transmitted gas. Available at: https://swi.gaz-system.pl/swi/public/embed.seam?lang=en&viewId=E_PUB_042&cid=479570

Table 4-5 Interconnection capacities of the Polish gas transmission system in 2017 (in bcm/year). Source: URE (2018)[192]

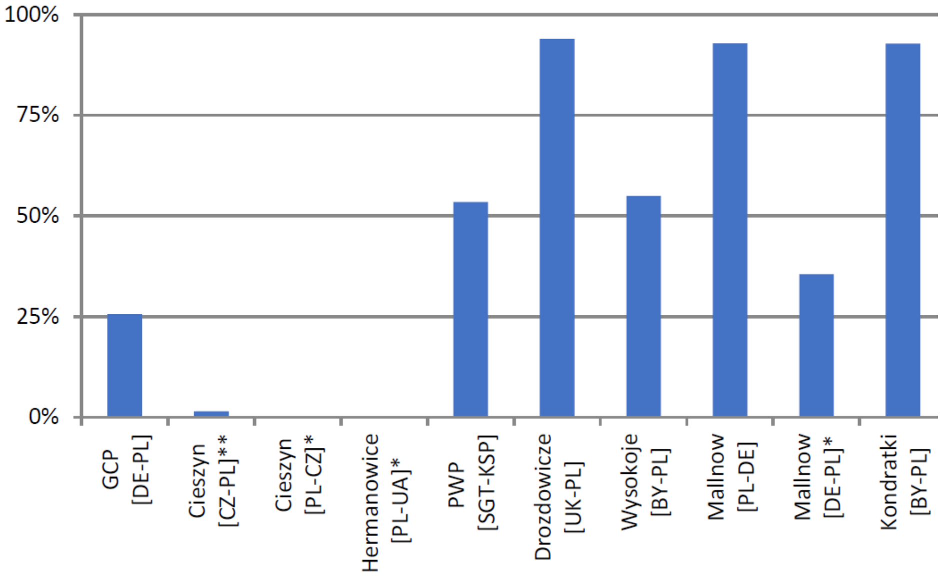
Point	*From*	*To*	*Transmission capacity*	*Reserved capacity*	*Unused reserved capacity*	*Non-reserved capacity*	*Realised transmission**	*Unit*
Mallnow	DE	PL	6075	4093	916	2078	3177	Bcm/year
			67308.3	45348.3	10151.5	23019.7	35195.8	GWh/year
Mallnow	PL	DE	28048	30303	0	421	30384	Bcm/year
			314580	339873.1	0	4726.0	340779.3	GWh/year
Cieszyn (PL) / Český Těšín (CZ)	CZ	PL	587	563	450	67	112	Bcm/year
			6593.9	6319.0	5056.4	747.2	1262.6	GWh/year
GCP Gaz-System /ONTRAS	DE	PL	1594	642	95	904	547	Bcm/year
			17776.6	7156.6	1055.3	10078.8	6101.3	GWh/year
GCP Gas-System /ONTRAS	PL	DE	857	0	0	754	2	Bcm/year
			9552.7	0	0	8404.2	18.2	GWh/year
Tieterowka	BY	PL	237	209	131	28	78	Bcm/year
			2665.6	2352.7	1473.3	312.9	879.4	GWh/year
Kondratki	BY	PL	30856	33215	603	523	32612	Bcm/year
			346080	372540.7	6762.4	5865.8	365778.3	GWh/year
Wysokoje	BY	PL	5220	3328	278	2038	3050	Bcm/year
			58834.7	37505.4	3134.2	22973.6	34371.2	GWh/year
Drozdovichi (UA) -Drozdowicze (PL)	UA	PL	4380	4325	0	55	4400	Bcm/year
			49494	48868.8	0	625.2	49724.3	GWh/year

** Note that in certain cases realised transmission is above capacity, as reported by the NRA.*

192 URE (2018) Sprawozdanie z działalności Prezesa Urzędu Regulacji Energetyki w 2017 r.

The figure below provides an overview of the use of existing technical gas transmission capacity at the different interconnection points in Poland.

Figure 4-2 Technical transmission capacity utilisation rate in 2016 (%). Source: TOE (2017)



Import and export capacities

The import and export capacities are currently still rather limited, but ongoing investments will lead to substantially higher capacities as of 2025.

Table 4-6 Current and planned capacities for natural gas import through the transmission network[193]

Point of import	bcm/year 2016	bcm/year 2025	TWh/year 2016	TWh/year 2025
Interconnection Point (IP) on Yamal Pipeline	8.4	9.1	92.9	100.5
Czech Republic (Cieszyn)	0.5	0.5	10.2	10.2
Germany (GCP Gaz-System /Ontras)	1.5	1.5	17.8	18.7
LNG Terminal	5.0	7.5	57.7	86.6
Ukraine (Drozdowicze)	4.4	5.0	56.1	57.7
Belarus (Vysokoye)	5.5	5.5	61.7	61.7
Lithuania	-	1.9	-	21.3
Czech Republic (Hat)	-	6.5	-	72.7
Slovakia	-	5.7	-	63.8
Baltic Pipe	-	10.0	-	105.4
Floating Storage Regasification Unit	-	4.5	-	52.0

The overall import capacity amounted in 2016 to 296.4 TWh (compared to a consumption level of 170.2 TWh) and is expected to increase to 650.6 TWh by 2025.

[193] Gaz-System (2016), How to use the services of the LNG terminal in Swinoujscie and the transmission system?

Table 4-7 Current and planned capacities for natural gas export through the transmission network[194]

Point of export	bcm/year		TWh/year	
	2016	2025	2016	2025
Germany (GCP Gaz-System /Ontras)	0.9	0.9	9.8	9.8
Ukraine (Hermanowice*)	1.5	5.0	16.5	56
Lithuania	-	2.4	-	26.9
Czech Republic (Hat)	-	5.0	-	56
Slovakia	-	4.7	-	52.6
Baltic Pipe	-	3.0	-	31.7

** Interruptible capacity*

The export capacity of the Polish gas system was in 2016 still very limited (26.3 TWh) but would substantially increase to 233 TWh by 2025.

4.1.2 Planned Projects of Common Interest[195]

Poland has six PCIs in the current 2017 list, as shortly described below. Poland also had several PCIs in previous lists, particularly the 2013 list and are under construction.

The "Baltic Pipe" project (Gaz-System - Poland and Energinet - Denmark), infrastructure cluster 8.3. as defined in the third PCI list, adopted by the European Commission on 24 November 2017, consists of the following two PCIs:

- **8.3.1 Reinforcement of Nybro — Poland/Denmark Interconnection and;**
- **8.3.2 Poland-Denmark interconnection [currently known as "Baltic Pipe"]**

The Baltic Pipe Project is a strategic gas infrastructure project with the goal of creating a new gas supply corridor in the European market. The Baltic Pipe Project will allow transport of gas from Norway to the Danish and Polish markets, as well as to end-users in neighbouring countries. At the same time, the Baltic Pipe Project will enable supply of gas from Poland to the Danish and Swedish markets. The project is being developed in collaboration between the Danish transmission system operator Energinet and the Polish transmission system operator Gaz-System. The capacity of the Baltic Pipe Project will be up to 10 bcm/year of natural gas flow from the Norwegian Continental Shelf, through Denmark towards Poland and up to 3 bcm/year from Poland towards Denmark.

The project includes:

- Construction of a new offshore and onshore gas pipeline connecting the Norwegian upstream system with the Danish transmission system via a receiving terminal at the west coast of Jutland (the Norwegian tie-in). This part of the Baltic Pipe Project is not covered by the PCIs 8.3.1 and 8.3.2 of cluster 8.3 on the third PCI list. It is upstream infrastructure and hence not eligible to obtain a PCI status;
- Construction of a new infrastructure in Denmark to allow the transmission of gas from Norway to Poland via the Baltic Sea, including new onshore gas pipelines;
- Construction of a new gas compressor station in Zealand to allow for bidirectional gas flow between Denmark and Poland;

[194] Gaz-System (2016), How to use the services of the LNG terminal in Swinoujscie and the transmission system?
[195] PCI project fiches available DG ENER's interactive map of PCIs: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

- Construction of a new bidirectional offshore gas pipeline between Denmark and Poland through the Baltic Sea;
- Construction of a new onshore infrastructure and expansion of the existing transmission system in Poland, including three gas compressor stations and gas pipelines, which will allow the reception and transmission of gas coming from Norway through Denmark to Poland.

The total costs of this project are estimated at approximately € 1.6 billion (of which 50% relates to investments on Danish territory). The cross-border cost sharing has been approved by the two concerned NRAs, that have issued a coordinated cost-benefit cost-allocation (CBCA) decision pursuant to Article 12 of the TEN-E Regulation.[196]

The Baltic Pipe Project, which is planned to be commissioned by 2022, will substantially enhance the security of gas supply in Poland and will provide benefits to Denmark in the form of transit revenues.

The final investment decision (FID) will be taken in 2018 by the project promotors and their respective owners.[197] Gaz-System and Energinet have organised an Open Season procedure, which has allowed the submission of bids for capacity of this new pipeline.[198] This Open Season procedure has confirmed the market interests in the project, and enabled the investors to secure binding contracts for capacity reservation before making the final investment decision.

Capacity extension of Świnoujście LNG terminal in Poland (Project 8.7 on PCI list 2017, Gaz-System)

This project, which is expected to be commissioned in 2023, consists of the expansion of the LNG terminal to improve access to the global market to gas consumers in Poland and in other countries of Central and Eastern Europe.[199] As part of the project additional small-scale LNG services (bunkering, transhipment, rail loading) will be provided to the market participants.

Poland Slovakia interconnection (Project 6.2.1 on PCI list 2017, Gaz-System, Eustream)

This project comprises the construction of a cross-border pipeline (164 km) with maximum capacity of 15.6 mcm/day in the direction Slovakia to Poland and 12.9 mcm/day in the direction Poland to Slovakia, construction of a new compressor station in Poland, modification of the compressor station in Slovakia, and construction of a gas metering station at the border with Slovakia. The interconnection will offer Slovakia access to gas supplies from the LNG terminal in Poland and the Baltic Pipe. The PCI is currently in the design and permitting phase and is expected to be commissioned by 2021. It has received financial assistance via CEF for preparatory studies, and engineering and construction works.

North -South Gas Corridor in Eastern Poland (Project 6.2.2 on PCI list 2017, Gaz-System)

This project, which is currently in the phase of feasibility assessment and planning, aims to provide an improved cross-border connection between Poland and Slovakia. It will involve the installation of new onshore pipelines from Gustorzyn in central Poland through Wronów to Strachocina in the southeast, from where gas can be transported from or to Slovakia. It is expected to be commissioned after 2023.

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196 EC REGULATION (EU) No 347/2013 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.
197 Energitilsynet (2018), Godkendelse af omkostningsfordelingen mellem Polen og Danmark for Baltic Pipe Projektet.
198 Gaz-System (N/A), Baltic Pipe Project.
199 Gaz-System (2014), Development Plan for satisfying the current and future transmission demand for natural gas for 2014 – 2023.

Poland - Czech Republic interconnection [known as "Stork II"] (Project 6.2.10 on PCI list 2017, Gaz-System, NET4GAS)

The project consists of a new on shore cross-border pipeline (249 km) with a maximum capacity of 153.2 GWh/day (13.7 mcm/day) in the direction Poland to Czech Republic and 219.1 GWh/d (19.6 mcm/day) in the direction Czech Republic to Poland. It also includes a 30 MW compressor station. Currently, the planned commissioning date is the end of 2022.

North-South Gas corridor in Western Poland (Project 6.2.11 on PCI list 2017, Gaz-System)

This project supports the interconnection between Poland, Slovakia and Hungary. It consists of new onshore pipelines (205 km) and one compressor station (34 MW) in Western Poland to ensure a cross-border network expansion. It is expected to be connected to the PL-CZ and PL-SK interconnectors. The project is under construction and is expected to be commissioned by 2021.

Poland-Lithuania interconnection [known as "GIPL"] (Project 8.5 on PCI list 2017, Gaz-System; AB Amber Grid))

The project includes:

- a new onshore, bidirectional pipeline with a total length of approx. 503 km (165 km in Lithuania and 338 km in Poland) with capacity of 2.4 bcm/year in the direction PL->LT (may be extended to 4.1 bcm/year), and up to 1.9 bcm/year in the direction LT->PL;
- the extension, modernization and connection of the onshore pipeline to the Hołowczyce node and compressor station;
- the compressor station in Gustorzyn (30 MW).

The project is in the design and permitting stage and is expected to be commissioned by 2021. It received financial assistance under CEF in 2014 for preparatory works and for the construction.
A cost benefit analysis has shown that the overall societal impact of this project is positive; it offers benefits to Lithuania, Latvia and Estonia, but the net impact for Poland would be negative. Therefore, taking into account its pan-European importance, the Polish NRA supports the development of this project, but insists that it should be cost neutral for the Polish users of the gas network.[200]

4.1.3 *Estimated impact of the storylines on Polish gas infrastructure*

The table below provides a qualitative overview of the impact of the three selected storylines on the existing and planned large gas infrastructure in Poland.

Table 4-8 Impact of storylines on Polish large gas infrastructure. Source: Own assessment

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane[201]			Storyline 3 Strong development of hydrogen		
Gas demand 2016	170 TWh			170 TWh			170 TWh		
	Natural gas Very high	Methane Negligible	Hydrogen Negligible	Natural gas Very high	Methane Negligible	Hydrogen Negligible	Natural gas Very high	Methane Negligible	Hydrogen Negligible
Gas demand 2030	Stable			Increase			Stable		
	Natural gas	Methane Negligible	Hydrogen Negligible	Natural gas	Methane Low	Hydrogen Negligible	Natural gas	Methane Negligible	Hydrogen

200 ERO (2017) National report 2017.
201 Taking into account the important coal reserves in Poland, this country could consider producing carbon-neutral methane from coal (gasification with CCS)

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane[201]			Storyline 3 Strong development of hydrogen		
	Very high			Very high			Very high		Low
Gas demand 2050	Decrease			High increase			Increase		
	Natural gas Negligible	Methane Medium	Hydrogen High	Natural gas Negligible	Methane Very high	Hydrogen Low	Natural gas Negligible	Methane Low	Hydrogen Very high
LNG Terminal	Limited impact until 2030 Utilisation level would substantially decrease after 2030			LNG terminal(s) would have substantially decreasing utilisation level after 2030. Liquefied biomethane imports by tanker and existing LNG infrastructure are option to be considered.			LNG terminal(s) would have substantially decreasing utilisation level after 2030. Building of new hydrogen terminal could be considered.		
Gas storage	Existing storage sites in depleted gas fields could be further used for biomethane while existing storage in salt caverns could be refurbished for H2 storage. Suitability of depleted gas fields for H2 storage still to be assessed.			Existing gas storage sites can be used for biomethane. Requirements regarding more dynamic operation of gas storage to cope with fluctuating RES might require some retrofitting of gas storage facilities.			Existing storage sites in depleted gas fields could be further used for biomethane while existing storage in salt caverns could be refurbished for H2 storage. It might also be required to develop new storage sites for hydrogen.		
Transmission network & transit pipelines	Import pipelines would be less utilised after 2030. Some transport pipelines might require further reverse flow investments. Upgrade of transmission infrastructure to allow higher volumes of hydrogen pipelines might be required.			Biomethane injection in grid (and imports via pipeline) are an option to decarbonise gas supply. Gas grid can be used for fossil gas (decreasing) and biomethane (increasing). Network of (bio)methane refuelling stations could be established for transport sector. In regions without adequate gas grid, alternative options[202] can be applied. Reverse flow will be required to allow injection high volumes of biomethane at distribution level.			Transmission network would need to be upgraded to be able to transport high volumes of hydrogen. The system also needs to be adapted to allow bi-directional flows (reverse-flow).		

*Note: The overall gas demand is compared to 2015 levels, and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease -5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The changes in gas shares were categorised as follows: 76%-100%= **'very high'**; 51%-75%= **'high'**; 26%-50%= **'medium'**; 6%-25%= **'low'**; 0%-5%= **'negligible'**.*

202 Such as e.g. virtual pipelines, onsite methane production or road transport of liquid methane.

4.2 Main national developments that influence investments in and use of gas infrastructure

Between 1990 and 2016, the overall energy demand in Poland has slightly declined, while its natural gas demand has increased by 63%. Poland has around 250 bcm of conventional national gas reserves. As its domestic gas production has remained stable over the last two decades, the growth in gas consumption has led to an increase in Poland's dependence on imports. The share of renewable energy in Poland has reached 11.3% of final energy consumption in 2016 versus a target of 15% by 2020. The domestic biogas potential is estimated at 5 bcm/y, which is equivalent to around 36% of the current gas demand. Biogas is already being developed, but conversion to biomethane and injection into the grid is not yet common practice. The gas market in Poland is still very concentrated and remains dominated by PGNiG, which currently has a market share of around 98%. Poland still heavily relies on fossil fuels, and due to its large domestically availability of fossil energy resources, it seems not to intend to completely decarbonise its energy supply by 2050. Poland relies on (declining) domestic gas production and (increasing) imports, mainly pipeline gas from Russia. It still has limited interconnection capacity with neighbouring systems, but the ongoing and planned investment projects will substantially enhance this capacity and contribute to security of gas supply and market integration.

4.2.1 Gas supply and demand

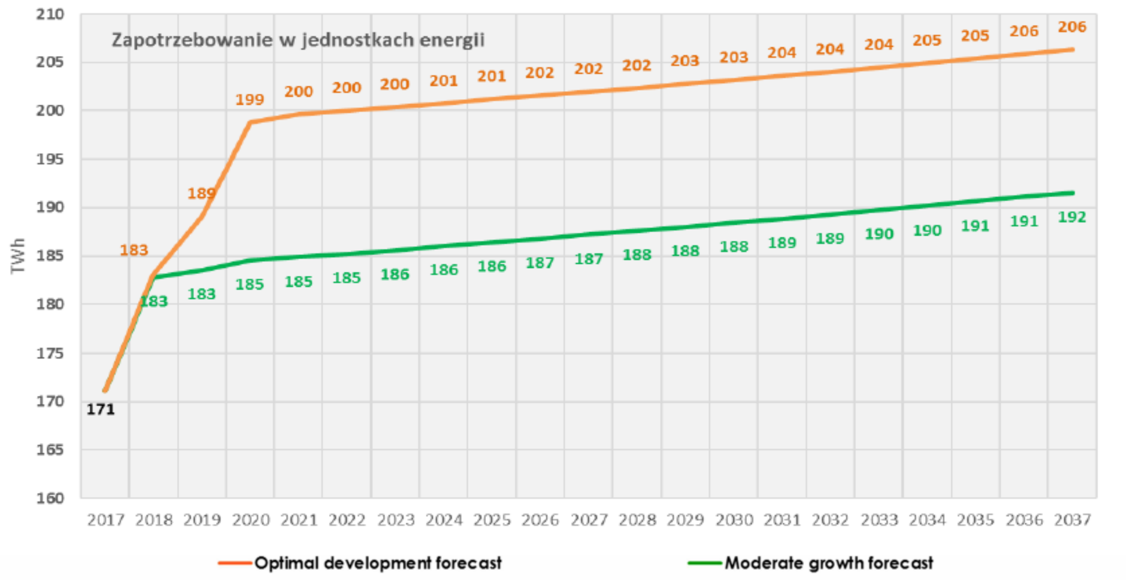
Gas demand

Between 1990 and 2016, the overall final energy demand in Poland declined slightly, while natural gas demand increased by 63%.[203] The residential and services sector were the main contributors to this consumption increase[204], mainly due to switching from coal and biomass to gas for space heating. Industry accounted for 39% of total gas demand in 2016, while the power and district heating sectors are still mainly using coal (the share of domestic coal in the power generation mix is still very high, 81% in 2015[205]) and represented only 9% of total gas demand in 2016. In Poland, gas is at present hardly used for transport, but the country has recently adopted an ambitious plan for compressed natural gas (CNG) and liquefied natural gas (LNG) vehicles and fuelling infrastructure.[206] The Electro-mobility Law – which also covers other alternative fuels for transport - concerns both CNG and LNG vehicles and stations.

The future gas demand and related transmission volumes have been estimated by the Polish authorities in their National Report 2017. The projected scenarios are presented in the graph below.[207] According to this plan, gas demand is expected to further increase in Poland between 2020-2035, while it would in that period remain stable or decrease in several Western European countries.

[203] Eurostat (2018), Simplified energy balances - annual data (nrg_100a).
[204] IEA (2014) Energy Supply Security 2014 – Part 2 - CHAPTER 4: Emergency response systems of individual IEA countries – Poland.
[205] IEA (2016), Energy policies of IEA countries – Poland.
[206] IEA (2016), Energy policies of IEA countries – Poland.
[207] ERO (2017), National Report 2017.

Figure 4-3 Comparison of forecasts for gas demand[208]



The future gas demand will be affected by further efforts to lower the energy needs for buildings and industrial processes. The energy intensity in Poland has already substantially decreased in the last two decades; between 1995 and 2016 Poland's energy intensity declined fourfold, whereas the average energy intensity in the EU-28 only declined by 50%.

Energy efficiency policies (such as the transposition of the Energy Efficiency Directive and related energy saving measures) are expected to impact gas demand. However, it is unclear to what extent energy efficiency policies have affected and will further affect gas demand in Poland.

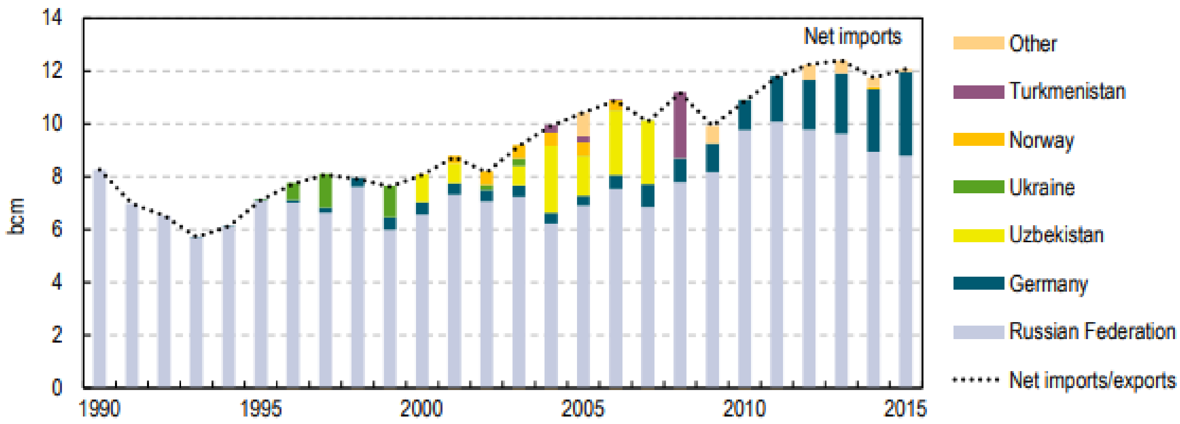
Gas supply

Poland has around 250 bcm of conventional national gas reserves.[209] However, as domestic gas production has remained relatively stable over the last two decades, the growth in gas consumption has led to an increase in Poland's dependence on imports. While in 1995 35% of gas consumption in Poland was produced domestically, this share declined to 24% in 2016.[210]

In 2016 imports from the Eastern direction under a long-term contract concluded between PGNiG S.A. and Gazprom were still a significant share.[211] The Russian Federation is the dominant gas supplier of Poland (74% in 2016), but since the late 1990s Poland has started to diversify its supply. The second-largest importer in 2016 was Germany, which itself is a large importer of Russian gas.

[208] Gaz-system (2017), Krajowy dziesięcioletni plan rozwoju systemu przesyłowego. Plan rozwoju w zakresie zaspokojenia obecnego i przyszłego zapotrzebowania na paliwa gazowe na lata 2018-2027
[209] Polish Geological Survey (2014) Oil & Gas in Poland: new opportunities.
[210] Eurostat (2018), Simplified energy balances - annual data (nrg_100a).
[211] ERO (2017), National Report 2017

Figure 4-4 Natural Gas net imports in Poland[212]



Security of supply

Key elements of Poland's gas security of supply policy are further diversification of supply sources and routes, development of natural gas infrastructure, expansion of underground storage capacity, increasing domestic gas production and acquisition of shares in gas resources outside Poland.[213] The development of gas infrastructure (including cross-border interconnections and the LNG terminal in Świnoujście, as described in section 4.1) have already increased the technical potential for gas imports.

The start-up of the LNG terminal in Świnoujście in 2016 marked an important step towards diversification of gas supply to Poland as this facility has a regasification capacity of 5 bcm/year, which is more than a quarter of the country's annual gas consumption.[214] Moreover, the establishment of the possibility of reverse gas flow at the Mallnow interconnection point with Germany, has also enhanced security of supply and competition amongst shippers.[215] According to the Second Report of the European Commission of 1 February 2017 (SWD 2017 32 final) on the State of the Energy Union, Poland has meanwhile effectively reached the N-1 infrastructure standard determined in the latest EU legislation regarding security of gas supply. Poland is no longer isolated, and Russian gas is no longer the only choice (though it still accounts for the largest volume of imported natural gas). Given this dominance of the Russian Federation, the development of gas infrastructures to ensure direct access to diversified sources of supply is needed. To this end, investments are under implementation to ensure diversification of gas supply (Baltic Pipe project, upgrade of LNG terminal in Świnoujście) and to distribute new sources of supply across Central-Eastern Europe (cross-border connections with Lithuania, Slovakia, Ukraine and the Czech Republic).

4.2.2 Renewable energy policy and targets

The share of renewable energy in Poland has increased by more than 70% during the last decade, and reached 11.3% of final energy consumption in 2016.[216] It is still uncertain whether Poland will meet its renewable energy target of 15% by 2020; a recent study estimates that under optimistic assumptions, Poland would reach a RES share of 13.8% in 2020, but under pessimistic assumptions the share might decline to 10%.[217] The Polish Ministry of Energy foresees the share of renewables in *primary energy*

[212] IEA (2016), Natural gas information 2016. Available at: www.iea.org/statistics/
[213] IEA (2016), Energy policies of IEA countries – Poland.
[214] IEA (2016), Energy policies of IEA countries – Poland.
[215] ERO (2017) National Report 2017.
[216] Eurostat (2018) Renewable energy statistics.
[217] Ecofys (2017) 2020 Renewable energy target realisation forecast for Poland - Final report.

demand to grow to 12.4% in 2030.[218] Wind energy has a high expansion potential in Poland and represented in 2015 6.6% of power generation,[219] which means that gas has a potential for use as back-up source for power generation.

Poland has set a very ambitious goal of one million electric vehicles (EVs) by 2025, alongside a comprehensive network of charging infrastructure including over 7,000 publicly accessible charging points by 2020.[220]

Biogas and biomethane

Poland has a large potential for biogas generation from domestic organic material and a roadmap[221] for biomethane market development was published in 2013. Poland's biogas generation potential is estimated at 5 bcm/y, which is equivalent to around 36% of current gas demand.[222] Two bcm/y of biogas could be produced from waste streams, but to date only 16% of this potential is effectively utilised. Currently, there are 301 digesters in Poland with a total installed capacity of 234 MW, but none of these installations upgrades the biogas to grid-quality biomethane.[223] All the produced biogas is locally used to generate electricity and/or heat. Without changes in the Polish energy policy, it is not likely that there will be significant volumes of biomethane injection into the gas grid in the near future (and therefore no related impact on gas infrastructure).[224]

Synthetic methane and hydrogen

Hydrogen is not explicitly mentioned in Poland's long-term energy policies (as outlined in the document Energy Policy of Poland until 2030).[225] Although there is a significant technical potential for the use of hydrogen in the energy system in Poland, it seems unlikely that it will be utilised at large scale in the short or medium term.[226]

In 2017 a consortium of seven European companies received approval to build a waste gasification plant in Gliwice in southern Poland. The 'Polygen' plant will produce synthetic natural gas, electricity and heat from waste sludge, municipal waste and biomass. The installation is expected to be commissioned in 2019.

4.2.3 Gas market integration and competition

The gas market in Poland is still very concentrated and remains dominated by PGNiG, which currently has a market share of around 98%.[227] This is mainly a result of the historical situation. Some specific factors are still hindering new entrants, in particular the fact that almost all transmission capacities have been allocated to PGNiG, notwithstanding the fact that there is a capacity auctioning system. Moreover, the Polish obligation on suppliers to dispose of gas reserve capacity represents a barrier, as

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218 Note that this 2030 target is expressed as a share of primary energy demand, whereas the EU's 2020 target defines the renewable energy share as % of final energy demand.
219 IEA (2016), Energy policies of IEA countries – Poland.
220 IEA (2016), Energy policies of IEA countries – Poland.
221 Green Gas Grids (2013), Roadmap for biomethane market development in Poland.
222 Biogas Action (2016) Biogas situation in Poland. Available at: http://biogasaction.eu/biogas_pl/
223 World Biogas Association (2017) Anaerobic digestion market report Poland.
224 Green Gas Grids (2013), Roadmap for biomethane market development in Poland.
225 Polish Ministry of Economy (N/A), Projection of demand for fuels and energy until 2030. Appendix 2 for Energy Policy of Poland until 2030.
226 Stygar, Mirosław & Brylewski, Tomasz. (2013). Towards a hydrogen economy in Poland. International Journal of Hydrogen Energy. 38. 1-9.
227 https://www.ure.gov.pl/en/energy-in-poland/24,Gas.html

access to national storage facilities remains difficult for new entrants. At present, mandatory reserves for gas are maintained outside of Poland by three supply companies.

Until 2016, wholesale and retail gas prices were regulated in Poland. In 2015, the European Court of Justice ruled that the Polish gas price regulations were not compliant with the EU's internal energy market rules.[228] In 2016, the Polish government proposed an amendment to the energy law to implement deregulation of gas prices.[229] The deregulation of prices occurs in three steps. Since 1 January 2017, wholesale prices of natural gas sold at virtual trading points, CNG and LNG are exempted from the obligation to submit their gas tariffs for approval.[230] From 1 October 2018 onwards, retail gas prices for non-household end-users will be deregulated and as of 1 January 2024, gas prices for households will also be deregulated.

Currently, the Polish gas market is still poorly integrated with the markets in neighbouring countries. Notwithstanding the existence of physical interconnectors, the incompatibility of trading systems and regulation still prevents effective trade even in the presence of price signals.[231] A recent gas market report published by ACER/CEER shows a slight improvement. The incidence of extreme price differences between the TTF price (reference for the EU gas market) and the price at the Polish gas trade market VPGZ has decreased between 2014 and 2016, but at the same time the frequency of very low price differences decreased as well.[232] Further efforts to enhance gas market integration and competition in this European region are hence necessary, but these efforts should also focus on implementing appropriate market rules and regulation, as lack of physical transmission or storage capacity is not the only reason for the current weaknesses in market functioning.

4.2.4 Environmental and climate related regulation and measures

Poland still heavily relies on fossil fuels, and due to its large domestically availability of fossil energy resources, it has not the political intention to completely decarbonise its energy supply by 2050. In this context the Polish vision on combating climate change is not yet fully aligned with that of most other EU Member States. In order to be able to continue to use its own natural resources, Poland has opposed the EU's Low-carbon 2050 Roadmap and Energy 2050 Roadmap, and wants more leeway for choosing its own climate and energy policy measures.

[228] http://www.cms-lawnow.com/ealerts/2015/09/ecj-ruling-polands-system-of-regulated-prices-violates-eu-regulations
[229] http://www.nortonrosefulbright.com/knowledge/publications/144847/price-deregulation-and-the-removal-of-the-tariff-obligation-in-the-polish-gas-market
[230] http://www.nortonrosefulbright.com/knowledge/publications/144847/price-deregulation-and-the-removal-of-the-tariff-obligation-in-the-polish-gas-market
[231] The Oxford Institute for Energy studies (2017) European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration.
[232] ACER/CEER (2017) Annual report on the results of monitoring the internal electricity and gas markets in 2016 – Gas wholesale market volume.

4.2.5 Overview of impact of non-gas demand drivers on Polish gas infrastructure

Table 4-9 Impact of non/gas demand drivers on gas infrastructure in Poland

Policy objective	Issue	Likely impact
Security of supply	Access to diversified gas sources	Poland relies on (declining) domestic gas production and (increasing) imports, mainly pipeline gas from Russia. Expansion of LNG regasification units is envisaged, and pipeline investments are ongoing to diversify supply sources
	Infrastructure standard N-1	Overall gas infrastructure capacity is sufficient to cope with peak demand, also in case of temporary unavailability of major infrastructure component. Reverse flow investments are realised or planned to further enhance security of supply; N-1 standard is achieved
Climate / Environment	Back-up for intermittent renewable energy sources	Development of intermittent power generation capacity, particularly wind might create potential for gas as back-up source.
	Biogas/biomethane development	Biomethane is not yet injected into gas grid. Large biogas potential in Poland can be used if enabling regulatory framework is put in place. Gas infrastructure can be used to transport biomethane.
	Hydrogen development	Currently no installations or projects for injection of hydrogen or synthetic methane into gas grid. No major impact expected in short/medium term.
	Substitution of fossil fuels	Limited substitution of coal/oil by gas for power generation and heating => limited impact Initiative has been taken to substitute oil with CNG in transport sector => limited impact in medium term
	Environmental regulation	Maintenance/investments needed to reduce/prevent CH4 leakages
Competitiveness / market development/ market integration	Market integration	Very concentrated market, vastly dominated by one company; Limited interconnection capacity between Polish gas system and adjacent systems; infrastructure projects will enhance potential for full market integration
	Enhance competition	Limited access to diversified sources of supply to attract new suppliers and counterparts to the Polish market (and other markets in Central-Eastern Europe)

4.3 Assessment of the impact of the storylines on the Polish TSO

The Polish gas demand would in storylines 2 and 3 in 2030 and 2050 (substantially) exceed the current level, but a major part of the renewable gas production would be locally used or injected into the distribution grid, and hence not use the TSO-grid. In storyline 1, gas demand would be (slightly) lower than the current level.

The regulated asset base of the Polish gas TSO used to calculate the tariffs for 2018 equals to €1,649 million; the RAB is expected to increase until 2025 and might then become stable or slightly decline, depending on the storyline. The OPEX and CAPEX amount to €245 million and €512 million, respectively. The future evolution of the OPEX would not be significantly different depending on the storyline. The CAPEX would remain at a high level until 2025, and would after 2030 differently develop, depending on the investment needs to accommodate the transport infrastructure to hydrogen. As the gas TSO has a regulated income based on its actual (authorized) costs, the expected developments would not have a major direct impact on the profitability of the TSO, but would mainly affect the grid tariffs. Storyline 2 would lead to the most positive outcome from a gas TSO perspective.

At present, Gaz-System obtains 10% of its revenues from commodity-based tariffs and 90% from capacity-based tariffs, but as of 2019 the tariff scheme will shift to capacity-based tariffs only.

4.3.1 *Key financial indicators: TSO Gaz-System*

Key data		Unit	Source
Infrastructure			
Pipelines (transmission - owned by Gaz-System)	11,059	km	Gaz-System [233]
Pipelines (transit - owned by Transit Gas Pipeline System EuRoPol GAZ s.a & operated by Gaz-System)	684	km	Gaz-System [234]
LNG Terminals	5	bcm	Gaz-System [235]
Underground storage[236]	3	bcm	PGNiG[237]
Compressor stations	14	Units	Gaz-System [238]
Interconnection Points	8 (of which 2 are bi-directional)	Units	Gaz-System
Transport volumes			
For domestic use	174.9	TWh	Gaz-System
Transit via Transit Gas Pipeline system	362.1	TWh	Gaz-System [239]
Total in Gaz-System pipelines	198	TWh	Gaz-System [240]
Investments			
Current Investment level	512	€ million	Gaz-System [241]
Investment level 2017-2026	3,661	€ million	Gaz-System
RAB			

233 http://en.gaz-system.pl/strefa-klienta/system-przesylowy/przesyl-w-liczbach/
234 http://en.gaz-system.pl/customer-zone/transit-yamal-pipeline/transit-gas-pipeline-system-tgps/
235 http://en.gaz-system.pl/lng-terminal/
236 Excluding local Nitrogen-rich gas storage facilities (without injection capacity) operated by PGNiG.
237 http://en.pgnig.pl/underground-gas-storage-facilities
238 Gaz-system (2015), Integrated annual report - The Gaz-system group. & http://en.gaz-system.pl/strefa-klienta/system-przesylowy/przesyl-w-liczbach/
239 http://en.gaz-system.pl/customer-zone/transit-yamal-pipeline/tgps-key-figures/
240 http://en.gaz-system.pl/customer-zone/transmission/transmission-key-figures/
241 Gaz-system (2017), Publication document in fulfilment of the requirements arising from art. 30 of the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.

Key data		Unit	Source
RAB Transmission (2018)	1,649	€ million	Gaz-System [242]
Revenues			
Maximum revenues allowed (2018)	369	€ million	Gaz-System [243]
Operating revenues	475	€ million	Gaz-System [244]
EBITDA (2015)	223	€ million	Gaz-System [245]
EBIT (2015)	137	€ million	Gaz-System [246]
Shareholders			
State-owned. Joint-stock company (100% shares belong to the State Treasury)			

4.3.2 *Regulatory Asset Base (RAB) of Gaz-System*

The regulated asset base for the tariff year 2018 equals to PLN 6,975 million (€1,649 million) and was calculated based on the following formula[247]:

$$M2018 = M2016 + ½(I2017 + I2018) - ½(A2017 + A2018)$$

where

- M2018 is the net value of the fixed assets as per 31 December 2018;
- M2016 is the net value of the fixed assets as per 31 December 2016;
- I2018 is the planned net value of the investment costs for 2018;
- I2017 is the planned net value of the investment cost for 2017;
- A2017 is the depreciation cost for 2017;and
- A2018 is the depreciation cost for 2018.

The RAB represents the regulated economic value of the TSO assets, which will be affected by the energy transition. The three storylines would impact the evolution of the RAB differently: storylines 1 and 3 might require additional investments to transform some assets to be able to transfer high volumes of hydrogen (or CO_2), or might even lead to devalued or stranded assets. In storyline 2, strong development of carbon neutral methane would allow a high utilisation rate of existing and planned transmission assets in the medium and long term, but would need investments in reverse flows to enable injection of high biomethane volumes at distribution level.

As the planned investments in new infrastructure in 2017-2026 are substantially higher than the current RAB (€3,661 versus 1,649 million), the RAB is expected to further increase in the coming decade.

4.3.3 *OPEX & CAPEX*

OPEX

The operational expenditures taken into consideration for the calculation of the 2018 tariffs amount to 1,037 million PLN (€245 million).[248] In two storylines a decrease in the transported gas volume is

242 Gaz-system (2017), Publication document in fulfilment of the requirements arising from art. 30 of the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.
243 http://en.gaz-system.pl/fileadmin/Art_30_1_b__i__EN.pdf
244 Gaz-system (2015), Integrated annual report – The Gaz-system group.
245 Gaz-system (2015), Financial integrated annual report – The Gaz-system group.
246 http://en.gaz-system.pl/customer-zone/transit-yamal-pipeline/transit-gas-pipeline-system-tgps/ and Gaz-system (2015), Financial integrated annual report – The Gaz-system group.
247 Gaz-system (2017), Publication document in fulfilment of the requirements arising from art. 30 of the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.
248 Gaz-system (2017), Publication document in fulfilment of the requirements arising from art. 30 of the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.

predicted. Nevertheless, this would have only limited impact on the OPEX, as most cost components are either fixed or infrastructure related.

CAPEX

The capital expenditures taken into consideration in the 2018 tariffs amount to 2,169 million PLN (€512 million). The capital expenditures are based on the depreciation costs and a regulated return on investments, based on the weighted average cost of capital (WACC). This WACC is determined by the regulator and is applied on the regulated asset base (RAB). In 2018 the WACC equals 6.19% and the regulated asset base amounts to 6,975 million PLN (€1,649 million). Guidelines on WACC calculation for gas network companies are published.[249].

Gaz-System is planning significant investments in infrastructure, new pipelines, compressor stations and a new gas storage facility (in Damasławek). The length of pipelines that are planned to be built by 2020 is 1,617 km and another 847 km between 2020 and 2025.[250] These investments will represent an expansion of the current network by almost one quarter. The CAPEX and RAB are hence expected to substantially increase in the coming years. Global investment levels are available, but, for confidentiality reasons, the Polish NRA and Gaz-System do not report on the exact level of investment that will be required to construct the planned projects.[251]

4.3.4 TSO Revenues

At present, Gaz-System obtains 10% of its revenues from commodity-based tariffs and 90% from capacity-based tariffs.[252] About 50% of the capacity-based revenues stem from entry-point capacity payments and 50% from exit-point capacity payments. Almost all of the revenues (99%) derives from transactions within the Polish system, and only 1% from cross-border transactions. With the current tariff scheme and regulation, decreasing gas demand would not have a major impact on the TSO revenues, but would mainly lead to higher transmission tariffs. In the recently approved transmission tariff[253] (to be applied in 2019) there are no commodity charges and revenues will be recovered by capacity charges only. The entry/exit split for 2019 is 45/55. This new tariff framework has been introduced by secondary legislation amended on 15 March 2018 and is in line with the concerned Commission Regulation and new Gas Network Code.

4.3.5 TSO viability analysis: estimated impact of the 3 storylines on end-users tariffs and on the business of the TSO

The table below provides an overview of the expected qualitative impacts of the three storylines.

[249] URE (2015). The methodology for a calculation of cost of capital employed by gas network companies for years 2016-2018
[250] Gaz-system (2016), National ten-year transmission system development plan - Development plan for satisfying the current and future transmission demand for natural gas for 2016-2025.
[251] ACER (2016), On gas network development plans to assess their consistency with the EU TYNDP and monitoring of the implementation of the EU TYNDP and investments to create new interconnector capacity.
[252] Gaz-system (2017), Publication document in fulfilment of the requirements arising from art. 30 of the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.
[253] This solution was introduced by secondary legislation amended on 15 March 2018.

Table 4-10 Estimated impact of the 3 storylines on the gas TSO

	Current level	Storyline 1 Strong electrification		Storyline 2 Strong development of biomethane		Storyline 3 Strong development of hydrogen	
		2030	2050	2030	2050	2030	2050
Gas demand TWh	170 TWh	Stable	(Slight) Decrease	Increase	High Increase	Stable/ Slight increase	Increase
Investment for maintenance of transmission/transit network		No impact from storylines In medium and long term, maintenance investments will still be needed to ensure operational security and safety		No impact from storylines In medium and long term, maintenance investments will still be needed to ensure operational security and safety		No impact from storylines In medium and long term, maintenance investments will still be needed to ensure operational security and safety	
Investment for development of transmission/transit network		High investment level until 2025. After 2030 investments would be needed to refurbish grids if injected volumes of H_2 exceed threshold		High investment level until 2025. After 2030, limited investments to accommodate transport of biomethane (grid connections, reverse flows)		High investment level until 2025. After 2030 investments would be needed to refurbish grids to allow high volumes of H_2	
RAB	€1,649 million	Will increase until 2025 and might then slightly decline		Will increase until 2025 and might then decline		Will increase until 2025 and might then become stable	
OPEX	€245 million	No major impact from storylines OPEX expected to remain at same level (increase if Baltic Pipe project is realised)		No major impact from storylines OPEX expected to remain at same level (increase if Baltic Pipe project is realised)		No major impact from storylines OPEX expected to remain at same level (increase if Baltic Pipe project is realised)	
Evolution of transported gas volume[254]	198 TWh[255]	Decreasing after 2030		Increasing		Slightly increasing after 2030	
Evolution of transmission tariffs for end-users	3.8 €/MWh	Increasing, also due to large ongoing and planned investments Highest expected increase per MWh		Increasing, also due to large ongoing and planned investments Lowest expected increase		Increasing, also due to large ongoing and planned investments2017-2026 Medium expected increase	
Overall assessment from gas TSO perspective				Most positive storyline from gas TSO perspective			

[254] Transported volumes can in the future be lower than gas demand if gas is locally produced and used without being transported via the gas grid (e.g. biomethane)
[255] http://en.gaz-system.pl/strefa-klienta/system-przesylowy/przesyl-w-liczbach/

4.4 Regulatory framework in Poland

As all major gas assets (LNG terminals, storage, transmission) are regulated in Poland, the operators apply regulated tariffs to recover their 'justified' costs, based on a regulated cost of capital, operational expenses and depreciation costs. The Polish NRA has recently decided to extend the depreciation period from 40 to 50 years for investments in pipelines as of 2018. in view of the expected developments in the gas sector, it might be appropriate to reconsider this measure.

Poland has an enabling technical regulation for the injection of biomethane into the gas grid, but at present the energy from biogas installations is still mostly locally used. Amendments to the support scheme are currently being prepared, which would stimulate the deployment and injection of biomethane. The Polish authorities are also taking measures to stimulate the use of natural gas in the transport sector.

The regulatory regime in Poland has been designed for a developing and growing natural gas market, which was (and still is) highly concentrated and dependent on one main supply source. Therefore, gas related policies in Poland are still heavily focusing on investments in gas infrastructure that allow to enhance security of energy supply and to foster markets' integration. Recently, some initiatives have been taken that contribute to the decarbonisation of the gas supply, but reaching a fully carbon-neutral gas supply by 2050 would be very challenging for Poland.

4.4.1 Regulated tariffs and revenues for gas infrastructure owners/operators

There is one gas TSO in Poland - OGP Gaz-System S.A. It operates its own transmission network and the network owned by SGT EuRoPol GAZ S.A. (Yamal pipeline) under the ISO formula. All major gas assets (LNG terminals, storage, transmission) are regulated in Poland.

Energy companies dealing with transmission and/or distribution (gas and/or electricity) are legally obliged to hold a licence and to do their billing based on regulated tariffs approved by the President of the Energy Regulatory office (URE). According to article 47 of the Energy Law, tariffs are set by the concerned network operators and submitted for approval by the President of URE, who can refuse approval if he considers that the proposed tariff is not in line with the provisions of articles 44-46 of the Energy Law. Gas transmission and distribution tariffs can only cover justified costs of conducting licensed network related activities (set ex-ante) and a justified return on capital employed. Moreover, customers should be protected against unjustified levels of tariffs and charges. The postage stamp cost allocation methodology is applied. There is no distinction between domestic and cross-border transmission tariff, i.e. the same tariff applies both for domestic and cross-border network users. In case of gas storage facilities and LNG facilities connected to the transmission system an 80% and 100% discount is applied, respectively. The transmission tariff is calculated and approved for a yearly period - the calendar year.

The 2018 tariff was established on the basis of the following WACC specifications approved by the Polish NRA[256]:

- Risk free rate of return: 2.91%;
- Premium for shareholders equity: 4.50%;
- Beta coefficient: 0.5;
- Loan capital cost: 3.91%.

[256] http://en.gaz-system.pl/fileadmin/The_tariff_for_transmission_services_No_10.pdf

The tariff for gas transmission services is proposed by the TSO and approved by the NRA according to the Entry-Exit tariff model and method of settlements in line with EU standards. Gas-System [257] applies the following types of transmission charges:

- fixed charges depending on the contracted capacity, applied at:
  - physical points of entry to the transmission system and gas storage facilities;
  - physical points of exit from the transmission system and storage fields;
- variable charges depending on the quantity of gas transported, applied at physical points of exit from the transmission system.

The current tariff conditions for short-term gas sale agreements are not yet aligned to those used by the neighbouring countries.[258] According to article 28 of the Network Code on harmonised transmission tariff structures for gas[259], the Polish NRA has planned to carry out consultations regarding tariffs for short term services with NRAs of neighbouring Member States. A decision is expected in March 2019.

In the recently approved transmission tariff[260] (to be applied in 2019) there are no more commodity charges and revenues will hence be recovered by capacity charges only. The entry/exit split for 2019 is 45/55.

4.4.2 *Accounting rules for gas infrastructure assets*

The main component of RAB for gas assets is made up by tangible fixed assets in use and intangible assets[261], revealed in the latest audited financial statement of the gas network company, deducted by assets financed by subsidies. Remunerated assets include the average value (from the tariff period and the previous period) of planned capital expenditures from network development plans accepted by the President of URE, deducted by planned connection fees and corrected in some cases by a coefficient indicating the average underperformance of planned capital expenditures in previous years. Moreover, an average planned depreciation for the tariff year and the previous year is subtracted. The RAB is based on a re-evaluation of the assets (made for 31 December 2008). In the subsequent years the RAB was adjusted mostly due to investments, deprecation and connection fees.

The depreciation rules are dependent on the kind of assets involved. All fixed and intangible assets of the TSO are depreciated using the linear method. The depreciation period is 40 years for investments in gas pipelines made before 2018, and has been extended to 50 years for new investments in pipelines from 2018 onwards.[262] This measure, which has probably been taken to mitigate the impact of the huge investment program on grid tariffs, is a remarkable development, considering the increasing uncertainty regarding the future gas demand and the ability to recover investment costs in the long-term. Shorter depreciation periods are used for compressor stations and metering equipment.

The economic useful lifetime of the TSO assets is set according to the requirements of the Polish accountancy law. The table below provides some details regarding depreciation rates. The value of amortization as of December 31, 2016 comes from the audited financial statements.

[257] Gaz-System (2016), How to use the services of the LNG terminal in Swinoujscie and the transmission system?
[258] TOE (2017) Electricity and gas market in Poland – Status on 31 March, 2017.
[259] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
[260] This solution was introduced by secondary legislation amended on 15 March 2018.
[261] net value, i.e. deducted by depreciation,
[262] Gaz-System (2018) Personal communication.

Table 4-11 Depreciation rates for different groups of assets used by Polish TSO. Source: Gaz System[263]

Group name	Value of amortization as of Dec 2016 (PLN)	(years)	(%)
Group 0 Land	2,124	Up to 20	Not less than 5%
Group I Buildings	238,994	5-40	2.5% - 20%
Group II Structures (including pipelines)		2-40	2.5% - 50%
Group III Boilers and power machines	98,043	3-15	6.7% - 33.3%
Group IV General machines		2-25	4% - 50%
Group V Specialist machines		5-20	5% - 20%
Group VI Technical devices		2-20	5% - 50%
Group VII Means of transport	9,915	3-10	10% - 33.3%
Group VIII Equipment	12,671	2-5	20% - 50%
Intangible and legal assets	12,682	2-5	20% - 50%

4.4.3 Legal and regulatory framework for renewable gas

Biogas/biomethane generation and injection to the grid

There is an enabling regulation (technical specifications) in Poland for the injection of biomethane into the gas grid, but at present the energy of biogas installations is mostly locally used for generation of electricity and/or heat. There are, however, plans to introduce new policies which would include incentives for both biogas and biomethane; this new measure could lead to an increase in biomethane injection into the grid.

At present, upgrading biogas to biomethane in view of its injection into the distribution or transmission network in Poland is in general less profitable than local utilization of biogas. On the one hand, the upgrading process is rather expensive and on the other hand, there are barriers for injection into the gas grid (e.g. time-consuming procedures for location decisions and acquiring connection, no guarantee of connecting the concerned plants to the gas grid, etc.). While legal mechanisms were adopted in order to facilitate injection of biomethane into gas networks (technical standards), the current conditions do not sufficiently encourage biomethane injection, and local electricity/heat production remains hence the preferred option for biogas plant owners.

The Polish Renewables Act is currently being amended. The draft prepared by the Polish Government and submitted to the Parliament proposes to establish a new support mechanism for the production of electricity from biogas. It proposes to:

- establish new rules for reference prices for particular types of installations producing electricity from biogas (separately for installations with a capacity from 500 kWe to 1 MWe, and above 1 MWe);
- cover the electricity produced from biomethane after transport through the network. This means that if biomethane is transported via the gas distribution grid to a power plant, the production of this gas will be financially supported;
- abolish the mandatory building permit in case of very small installations for biogas production.

[263] Gaz-System (2017) Spełniający wymogi wynikające z art. 30 rozporządzenia komisji (UE) 2017/460 z dnia 16 marca 2017 roku ustanawiającego kodeks sieci dotyczący zharmonizowanych struktur taryf przesyłowych dla gazu

Use of natural gas (CNG/LNG) in transport

The Polish Parliament is currently working on amendments to the Excise Tax Act, which propose to reduce the level of excise tax for LNG and CNG used in combustion engines to zero. The proposed amendments would probably enter into force on 1st January 2019.

The act on electro-mobility and alternative fuels adopted in February 2018, implementing directive 2014/94/EU[264], establishes incentives for the promotion of the use of vehicles powered by alternative fuels, mainly electricity but also natural gas, and introduces mechanisms to support investments in the necessary infrastructure. With respect to gas it facilitates the use of vehicles powered by CNG and LNG and inter alia imposes obligations on gas DSOs to develop LNG and CNG filling stations in urban agglomerations and other densely populated areas.

DSOs are required to develop a network development plan which should include a section dedicated to the construction of publicly accessible CNG/LNG refuelling stations. The plan should first be agreed with the NRA and then DSOs will be required to build the planned stations by 31 December 2020. If the required number of filling stations is not achieved, the DSOs might be subject to fines. Once the filling stations will have been built, the DSOs will need to select – for each of the stations built within this procedure – a station operator.

4.4.4 Readiness of the Polish regulatory regime

The regulatory regime in Poland has been designed for a developing and growing natural gas market, which was (and still is) highly dependent on one main supply source. The Polish legislation and regulation have hence mainly stimulated and supported investments in natural gas infrastructure that allow to enhance security of energy supply through a diversification of supply sources and to foster markets' integration.

The transition to a carbon neutral energy system will only be possible if the use of fossil fuels is substantially reduced or coupled with CCS/CCU. Due to the large availability of fossil fuels in Poland, the Polish energy system is still heavily carbon-intensive, and Poland seems to be lagging behind in the energy transition. For example, it remains uncertain whether Poland will meet its renewable energy target of 15% by 2020. Further, in order to be able to continue to use its own resources, Poland has opposed the EU's Low-carbon 2050 Roadmap and Energy 2050 Roadmap, and wants more leeway for choosing its own climate and energy policy measures.

However, several steps have recently been taken in view of reducing the GHG emissions. Poland has an ambitious goal of one million electric vehicles (EVs) by 2025, alongside a comprehensive network of charging infrastructure including over 7,000 publicly accessible charging points by 2020. Poland is also supporting the use of natural gas in transport, i.e. by incentivising the use of vehicles powered by alternative fuels and proposing lower excise tax for LNG and CNG used in combustion engines. DSOs are also required to develop CNG/LNG charging stations by 2020.

At the same time, in order to value its large potential for biogas generation (this potential is equivalent to 36% of its current gas demand), Poland has also set in place an enabling regulatory framework for the use of biogas and for injection of biomethane into the grid. Nonetheless, biogas is currently mainly

[264] Alternative Fuels Infrastructure Directive

locally used for electricity and/or heat production, and hence, further incentives were deemed necessary to also encourage its injection into the gas grid. To this end, the Polish Renewables Act is currently being amended and proposes to include a support mechanism for the production of electricity from biogas or from biomethane that has been injected into the distribution grid.

Regarding transmission tariffs, in its recently approved tariffs to be applied in 2019, Poland is shifting from partly commodity-based charges to capacity-based charges only. This is in line with the Commission Regulation and Gas Network Code. Transmission tariffs are at present based on the actual TSO costs and falling gas demand or reduced capacity bookings would hence not necessarily lead to lower revenues for the TSO, but rather to higher grid tariffs per transported MWh. However, given the fact that transported gas volumes are not expected to decline in Poland (or only slightly in the first storyline after 2030), there should in principle be no major risk for stranded assets or substantially rising grid tariffs. Poland has a large domestic biomass potential, which can be used for biogas/biomethane production, and also disposes of large coal resources which could be converted into carbon-lean hydrogen by using CCS/CCU. Poland has hence the technical potential and resources to decarbonise its gas consumption while continuing to use its gas infrastructure; the economic and environmental impact and feasibility of these options have however not been assessed in the context of this study.

The recent decision in Poland to increase the depreciation period (from 40 to 50 years) for investments in gas pipelines seems counterintuitive in the current energy transition context, even if it would mitigate the impact of the ambitious investment programme on grid tariffs.

5 Italy

Key data for Italy		Unit	Source
Annual gas consumption	794,549	GWh/year	Italian Ministry of Economic Development - 2017[265]
Peak load	4,881	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	38	%	Eurostat 2016
Domestic primary gas production	58,556	GWh/year	Italian Ministry of Economic Development - 2017[266]
Imports	736,387	GWh/year	Italian Ministry of Economic Development - 2017[267]
Exports	2,882	GWh/year	Italian Ministry of Economic Development - 2017)[268]
Capacity of entry pipelines	3,204	GWh/day	ENTSOG transmission capacity map
LNG import terminal capacity	15.25	Billion m3(N)/year	GIE LNG map 2018
Number of gas PCIs in 2017 list	5	projects	PCI list 2017
Other general information			
Regulatory system for gas transmission	Combined model of cost cap (OPEX) and regulated rate of return (CAPEX)		
NRA	ARERA		
Main gas TSO	Snam Rete Gas		

5.1 Existing and planned gas infrastructure

In order to cover its currently high gas demand (75.1 bcm in 2017), Italy has three LNG terminals in operation (15.25 bcm/year) and some projects in study, a large storage capacity in depleted natural gas fields (17.9 bcm), and an extensive transmission grid with seven interconnection points. Gas transmission activities in Italy are mainly carried out by Snam Rete Gas S.p.A., Società Gasdotti Italia S.p.A. and Infrastrutture Trasporto Gas S.p.A.. Italy is involved in five Projects of Common Interests in two different clusters. The utilization level of the LNG terminals is currently rather low (17 to 25%), except for the Adriatic LNG terminal (> 80%), and would after 2030 substantially decrease in the 3 storylines. The use of the interconnectors with Austria, Switzerland, Slovenia, etc., would also significantly decrease, but some capacity might be needed to trade renewable gas. After 2030 some LNG or pipeline capacity that is specifically used to import natural gas, might need to be decommissioned or reconverted for other purposes. The existing gas storage facilities could be further used for biomethane, but would not be suitable for hydrogen. The utilization level of the transmission network would decline in the 3 storylines and investments would be needed to accommodate renewable gas.

5.1.1 Main large gas infrastructure

LNG terminals

Italy has three LNG terminals connected to the national gas network:

- **GNL Italia terminal in Panigaglia**, with a capacity of 3.5 bcm/year, owned by Snam (100%);

[265] Ministero dello Sviluppo Economico (2017). Bilancio Gas Naturale.
[266] Ministero dello Sviluppo Economico (2017). Bilancio Gas Naturale.
[267] Ministero dello Sviluppo Economico (2017). Bilancio Gas Naturale.
[268] Ministero dello Sviluppo Economico (2017). Bilancio Gas Naturale.

- **Adriatic LNG's Porto Levante offshore terminal in Rovigo**, with a capacity of 8 bcm/year owned by ExxonMobil (70,7%), Qatar Terminal (22%) and Snam (7,3%);
- **Floating Storage Regasification Unit (FSRU) OLT offshore terminal**, with a capacity of 3.75 bcm/year owned by IREN group (49,07%), Uniper (48,24%) and Solar LNG (2,69%).

The energy ministry MiSE has authorized the construction of three other LNG terminals (but the first two are no longer included in the 2018 GIE LNG map):

- **LNG terminal in Falconara Marittima**, planned by Api Nòva Energia, with a capacity of 4 bcm/year;
- **LNG terminal in Gioia Tauro**, planned by MedGas LNG Terminal, with a capacity of 12 bcm/year; and
- **LNG terminal in Porto Empedocle**, planned by Nuove Energie (acquired by Enel in 2007), with a capacity of 8 bcm/year (the latter has also received authorization from the Sicily Region).

Another project for a new terminal that has been considered in ENTSOG's TYNDP 2017 – 2026 (but which is not included in the 2018 GIE LNG map) is Zaule, proposed by Gas Natural, with a capacity of 8 bcm/year. This project was included in the PCI list 2013.

Table 5-1 Existing and planned LNG terminals in Italy. Source: GIE LNG Map 2018

Name of installation	Operator	Status	Start-up year	Type	Max. Hourly Cap. m^3(N)/hour	Nom. Annual Cap. billion m^3(N)/year	LNG storage capacity m^3 LNG	TPA regime
Panigaglia LNG terminal	GNL Italia	operational	1971	large onshore	427 000	3.50	100 000	regulated
Porto Levante LNG terminal	Adriatic LNG	operational	2009	large offshore	1 038 857	8.00	250 000	hybrid
FSRU OLT Offshore LNG Toscana	OLT Offshore LNG Toscana	operational	2013	FSRU	592 465	3.75	135 000	regulated
Porto Empedocle (Sicilia) LNG terminal	Enel	Planned (new facility)	2021	large onshore	962 000	8.00	320 000	-

The utilisation level of the Adriatic LNG terminal is high, 82.5% of its regasification capacity was on average used in 2017 and 85% in the first months of 2018, which is much higher than the utilisation level of most other European plants.[269] The OLT terminal, which started activities in December 2013, has only received deliveries under regulated tariffs for peak-shaving and LNG storage and regasification, and had in 2016 a low utilisation rate of only 25%. The Panigaglia terminal regasified 0,6 bcm of LNG during 2017[270], which represents an average use level of 17%.
Greater global availability of LNG in the coming years coupled with an auction-based capacity allocation mechanism may lead to higher utilisation levels.

LNG terminals are in Italy increasingly offering additional services in line with market needs, such as:

a) Flexibility services (intraday and day ahead);
b) Storage services (peak shaving, temporary storage).

269 Adriatic LNG (2018), Company profile Adriatic LNG terminal.
270 SNAM (2018), SNAM Annual report 2017.

Gas storage

The Italian gas storage system consists of depleted natural gas fields that have been converted to storage.[271] The overall capacity is about 17.9 bcm[272], including 4.6 bcm of strategic reserve (which is defined by the Ministry of Economic Development (MiSE) to cope with possible gas emergencies).[273] There were 89 active storage users in 2017 (compared to 91 in 2016). Gas storage is operated under concessions issued by the Ministry of Economic Development. The business is regulated by the Italian NRA which defines inter alia the gas storage tariff and the allowed return as well as non-discriminatory conditions for the access to the infrastructure. The gas is injected in the reservoir during periods of lesser demand and withdrawn to cover peak consumption needs (i.e. during the winter, when around 30% of Italian gas consumption is covered by gas from the storage system).

With 9 operating fields in its storage group, Stogit[274] is Italy's leading storage operator with around 95% of Italian storage capacity; its available working gas capacity for Thermal Year 2018/19 is 16.8 bcm, including 4.5 bcm of strategic reserves. Edison Stoccaggio Spa[275] (owned by Edison Group) is also developing and managing gas storage activities. It entered the storage market in the early 1980s, when it converted one of the Cellino production fields into a storage facility. Ital Gas Storage[276], Geogastock[277] and Gas Plus Storage[278] have planned storage facilities.

The current gas storage capacity allows to properly manage seasonal peaks in demand. The utilisation level of the storage is relatively high; Snam reported for 2017 a replenishment level at the end of the injection campaign of 98% compared to a European average of 89%.[279]

271 Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
272 Overall Italian storage capacity for Thermal year 2018/19: 16.8 bcm for Stogit (http://www.Snam.it/en/storage-services/storage_capacities/offered_capacities.html), 1.0 bcm for Edison Stoccaggio (http://www.edisonstoccaggio.it/it/capacit%C3%A0-offerta)
273 The Ministerial Decree of 15 February 2013 and the Ministerial Decree of 6 February 2015 have regulated storage to ensure adequate coverage of peak demand in periods of high demand. The decrees define mechanisms for commercial allocation of storage withdrawal capacity, avoiding the risk of excessive anticipated withdrawals that would not allow adequate system performance during January and February. The commercial peak, therefore, is lower than the technical peak, which corresponds to the maximum service in the absence of any plant unavailability and which can possibly be accessed for limited periods in the event of a supply emergency." Source: Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017. Available from: http://www.sviluppoeconomico.gov.it/images/stories/documenti/all1_gas_italy_pap_en.pdf
274 http://www.Snam.it/en/about-us/company-structure/stogit/index.html
275 http://www.edisonstoccaggio.it/en
276 http://italgasstorage.it/eng/progetto.html
277 http://www.geogastock.it/ITA/Home.asp
278 http://ir.gasplus.it/home/show.php?menu=00002
279 SNAM (2018), SNAM Annual report 2017.

Table 5-2 Existing and planned gas storage facilities in Italy. Source: GIE Storage Map 2016

Facility/Location	Status	Start-up year	Type	onshore/ offshore	Operator	Working gas (technical) TWh	Working gas TPA TWh	Working gas no TPA TWh	Withdrawal technical GWh/day	Withdrawal TPA GWh/day	Withdrawal no TPA GWh/day	Injection technical GWh/day	Injection TPA GWh/day	Injection no TPA GWh/day	Access regime
Cellino	operational	1984	Depleted Field	Onshore	Edison Stoccaggio	1.2793	1.2476	0.0317	9.0	9.0	0.0	9.0	9.0	0.0	rTPA
Collalto	operational	1994	Depleted Field	Onshore	Edison Stoccaggio	6.1322	5.9207	0.2115	84.6	47.6	37.0	68.7	48.6	20.1	rTPA
Cotignola & San Potito	operational	2013	Depleted Field	Onshore	Edison Stoccaggio	2.5692	2.3260	0.2432	79.3	23.3	56.0	67.7	6.1	61.5	rTPA
Palazzo Moroni	Planned (new facility)	2017	Depleted Field	Onshore	Edison Stoccaggio	0.7401	0.7401		9.5	9.5		9.5	9.5		rTPA
Bagnolo Mella	Planned (new facility)	-	Depleted Field	Onshore	Edison Stoccaggio	0.9680	0.9680		6.6	6.6		6.6	6.6		rTPA
STOGIT (storage group)[280]	operational	-	Depleted field	Onshore	STOGIT	177.5933	128.7344	48.8589	2595.6	2595.6		1526.8	1526.8		rTPA
Bordolano	under construction (expansion)	2019	Depleted Field	Onshore	STOGIT	8.7248	8.7248		185.4	185.4		163.6	163.6		rTPA
Ripalta	under construction (expansion)	2020	Depleted Field	Onshore	STOGIT	3.9262	3.9262		0.0	0.0		0.0	0.0		rTPA
Ripalta	Planned (expansion)	2026	Depleted Field	Onshore	STOGIT	0.0000	0.0000		98.2	98.2		0.0	0.0		rTPA
Sergnano	under construction (expansion)	2020	Depleted Field	Onshore	STOGIT	3.8171	3.8171		0.0	0.0		0.0	0.0		rTPA
Minerbio	under construction (expansion)	2020	Depleted Field	Onshore	STOGIT	4.5805	4.5805		0.0	0.0		21.8	21.8		rTPA
Sabbioncello	under construction (new facility)	2023	Depleted Field	Onshore	STOGIT	1.7450	1.7450		0.0	0.0		0.0	0.0		rTPA
Fiume Treste F	Planned (expansion)	2021	Depleted Field	Onshore	STOGIT	2.1812	2.1812		43.6	43.6		43.6	43.6		rTPA
Fiume Treste	Planned (expansion)	2021	Depleted Field	Onshore	STOGIT	2.1812	2.1812		0.0	0.0		0.0	0.0		rTPA

280 Grouping: Cortemaggiore (1964); Sergnano (1965); Brugherio (1966); Ripalta (1967); Minerbio (1975); Fiume Treste (1982); Sabbioncello (1985); Settala (1986); Bordolano (2016).

Facility/Location	Status	Start-up year	Type	onshore/ offshore	Operator	Working gas (technical) TWh	Working gas TPA TWh	Working gas no TPA TWh	Withdrawal technical GWh/day	Withdrawal TPA GWh/day	Withdrawal no TPA GWh/day	Injection technical GWh/day	Injection TPA GWh/day	Injection no TPA GWh/day	Access regime
Settala	Planned (expansion)	2026	Depleted Field	Onshore	STOGIT	8.1795	8.1795		0.0	0.0		54.5	54.5		rTPA
Alfonsine	Planned (new facility)	2026	Depleted Field	Onshore	STOGIT	1.6359	1.6359		27.3	27.3		27.3	27.3		rTPA
Cornegliano	Planned (new facility)	2017	Depleted field	Onshore	Ital Gas Storage	24.2000	14.3000	9.9000	297.0	297.0		297.0	297.0		rTPA
Cugno le Macine (Grottole-Ferrandina)	Planned (new facility)	-	Depleted field	Onshore	Geogastock	8.8000	8.8000		110.0	110.0		110.0	110.0		rTPA
Sinarca	Planned (new facility)	-	Depleted Field	Onshore	Gas Plus Storage	3.5640	2.3760	1.1880	35.2	35.2		35.2	35.2		rTPA
San Benedetto	Planned (new facility)	-	Depleted Field	Onshore	Gas Plus Storage	5.7420	3.8280	1.9140	65.3	65.3		65.3	65.3		rTPA
Poggiofiorito	Planned (new facility)	-	Depleted Field	Onshore	Gas Plus Storage	1.8260	1.2173	0.6087	18.7	18.7		18.7	18.7		rTPA

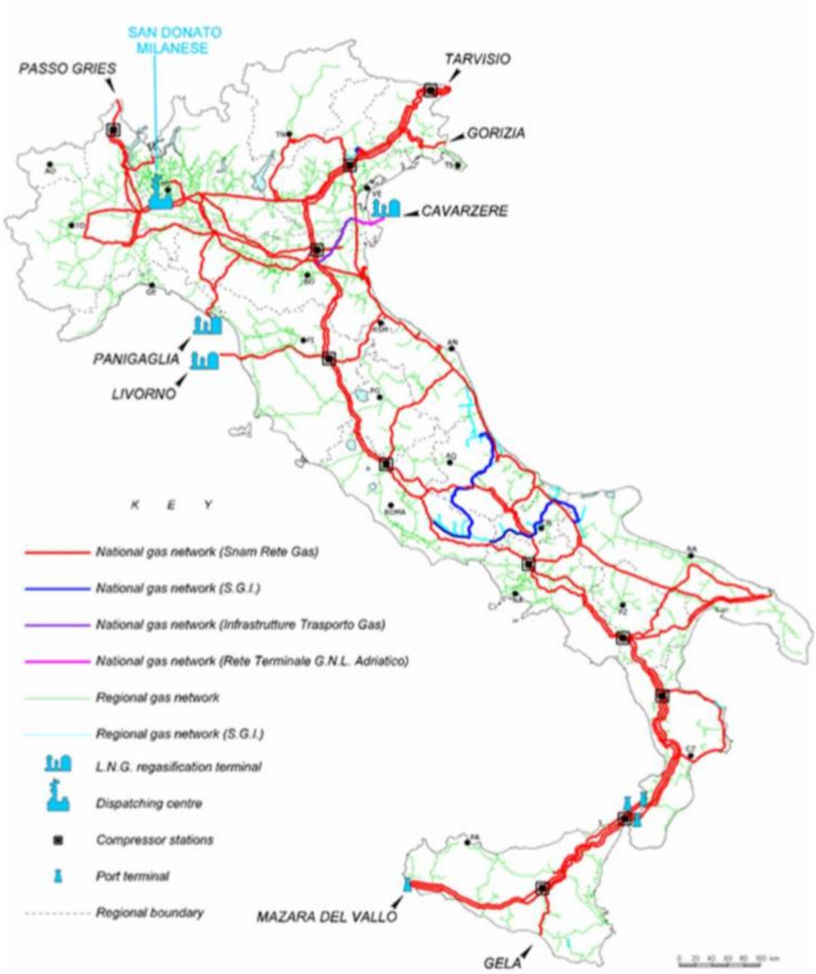
Note: TPA includes volumes allocated for production and transmission operation purposes. Non-TPA refers to strategic storage volumes with no withdrawal/injection capacity associated.

Gas transmission network

Gas transmission activities in Italy are carried out by Snam Rete Gas S.p.A., Società Gasdotti Italia S.p.A., Infrastrutture Trasporto Gas S.p.A. and a small number of companies operating at regional or local level. Snam Rete Gas, an investor-owned company, owns and operates approximately 97% of the natural gas transmission network. The national transmission network of Snam Rete Gas (9.704 km) comprises the pipes that transport gas from the entry points (import gas pipelines, LNG regasification plants and major domestic production centres) to regional transmission network interconnection points[281] and to gas storage facilities.

The average transportation capacity provided in 2017 was 364.2 million cubic metres/day, which was in line with 2016 (-0.8%), while booked capacity totalled 258.8 million cubic metres/day on average. Network saturation[282] was 71.0%, a decrease compared with 2016 (79.1%)[283].

Figure 5-1 Italian gas system infrastructure (transmission network, LNG terminals and gas storage facilities). Source: Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017; Figure 2



The transportation infrastructure is built in such a way that none of its parts, or systems, are critical to the Italian supply system. Most of the import lines have been duplicated or triplicated over time to

281 Snam Rete gas also operates 22 918km of regional gas network.
282 Ratio of capacity booked to available capacity
283 SNAM (2018), SNAM Annual report 2017.

meet the needs of new transportation capacity, and the compressor stations always have a back-up unit in order to ensure system security.[284]

Interconnections

An overview of the interconnection points is presented in the table below.

Table 5-3 Interconnection points. Source: ENTSOG capacity map 2016

Type	N	Point	Arc	Technical physical capacity (GWh/d)	From	To	From op	To op
Cross-border IP within EU (import)	26	Tarvisio (IT) / Arnoldstein (AT)	>IB-ITe	**1 150.5**	AT	IT	TAG	Snam Rete Gas
Cross-border IP within EU and with non-EU (import)	27	Griespass (CH) / Passo Gries (IT)	>IB-ITe	**634.7**	CH	IT	FluxSwiss / Swissgas	Snam Rete Gas
Cross-border IP within EU (export)	29	Gorizia (IT) /Šempeter (SI)	IT>SI	**28.5**	IT	SI	Snam Rete Gas	Plinovodi
Cross-border IP within EU (import)	29	Gorizia (IT) /Šempeter (SI)	SI>IT	**21.5**	SI	IT	Plinovodi	Snam Rete Gas
Cross-border IP within EU and with non-EU (export)	66	Bizzarone	IT>CH	**12.9**	IT	CH	Snam Rete Gas	
Cross-border IP with non-EU (import)	209	Mazara del Vallo[285]	>IB-ITi	**1 203.3**	DZ	IT	TMPC	Snam Rete Gas
Cross-border IP with non-EU (import)	210	Gela[286]	>IB-ITi	**513.3**	LY	IT	Green Stream	Snam Rete Gas
LNG Entry IP	306	Panigaglia	LNG_Tk_IT>IT	**112.7**	IT	IT	GNL Italia	Snam Rete Gas
LNG Entry IP	307	Cavarzere (Porto Levante / Adriatic LNG)[287]	LNG_Tk_IT>IT	**274.3**	IT	IT	GNL Adriatico	ITG / Snam Rete Gas
LNG Entry IP	317	OLT LNG / Livorno	LNG_Tk_IT>IT	**156.4**	IT	IT	OLT	Snam Rete Gas

Utilisation of entry points, including LNG terminals

While most entry points had in 2016 and 2017 a relatively high utilisation level, some LNG terminals (particularly OLT Livorno LNG and Panigaglia) have in 2016 and 2017 operated well below their technical capacity as cargoes preferred more profitable global destinations. The low utilisation level could also be partially due to the capacity allocation mechanism[288] applied at that moment, which has been recently modified introducing an auction-based capacity allocation mechanism.

The saturation levels, which refer to booked capacity compared to available capacity were in average 71% in 2017, with certain entry points booked for over 90% of their available capacities (i.e. Mazara del Vallo, Gela, Cavarzere and Livorno) while Panigaglia only had 15.5% of its available capacity booked in 2017.

284 Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
285 SRG entry points at Mazara and Gela are limited by a cluster capacity of 1385,3 Gwh/d
286 SRG entry points at Mazara and Gela are limited by a cluster capacity of 1385,3 Gwh/d
287 Snam Rete Gas is reporting the data at Cavarzere on behalf of Infrastrutture Trasporto Gas, which is the actual operator at the point.
288 Greater availability of LNG in the coming years coupled with an auction-based capacity allocation mechanism that will be introduced starting from thermal year 2018/19 may spur spot deliveries to the terminals https://www.argusmedia.com/-/media/files/pdfs/white-paper/italian-energy-strategy-white-paper.pdf?la=en

Table 5-4 Saturation (booked capacity/available capacity) of the entry points of Snam. Source: Snam Annual Report 2017[289]

(millions of m³ average/day)	Calendar year 2015			Calendar year 2016			Calendar year 2017		
Entry points	Transport capacity	Transferred capacity	Saturation (%)	Transport capacity	Transferred capacity	Saturation (%)	Transport capacity	Transferred capacity	Saturation (%)
Tarvisio	111.8	97.9	87.6	111.6	93.4	83.7	**111.4**	**94.6**	**84.9**
Mazara del Vallo (*)	101.1	85.9	85.0	91.5	84.9	92.8	**84.4**	**78.3**	**92.8**
Gries Pass	64.4	36.6	56.8	64.4	22.1	34.3	**64.4**	**22.4**	**34.7**
Gela (*)	35.3	29.3	83.0	30.8	26.0	84.4	**23.8**	**22.0**	**92.4**
Cavarzere (LNG)	26.4	24.4	92.4	26.4	24.4	92.4	**26.4**	**24.4**	**92.5**
Livorno (LNG)	15.0	15.0	100.0	15.0	15.0	100.0	**15.0**	**15.0**	**100.0**
Panigaglia (LNG)	13.0	4.6	35.4	13.0	0.6	4.6	**13.0**	**2.0**	**15.5**
Gorizia	4.6	0.1	2.2	4.6			**4.6**	**0.1**	
Competing capacity (*)				9.7			**21.2**		
	371.6	**293.8**	**79.1**	**367.0**	**266.4**	**72.6**	**364.2**	**258.8**	**71.0**

(*) The capacities at the Mazara del Vallo and Gela entry points do not include competing capacity.This capacity, pursuant to Regulation (EU) No. 984/2013 in force as of 1 November 2015, represents the transportation capacity available at one point, the allocation of which fully or partly reduces the capacity available for allocation at another point in the transportation system.

Gas entry capacity

In 2017, the average transport capacity offered at entry points interconnected with foreign countries and with LNG terminals was 364.2 million cubic metres/day. At the entry points of Mazara del Vallo and Gela a competing capacity of 18,6 mcm/day is made available in accordance with the Gas Network Code. In addition to the entry capacity for interconnection points and LNG terminals, there is 26 mcm/day of entry capacity available for national fossil gas production and 0.1 mcm average/day for injection by biomethane plants.

5.1.2 Planned Projects of Common Interest[290]

The following PCI projects are included in the 2017 PCI list:

Support to the North West market: Reverse flow interconnection between Italy and Switzerland at Passo Gries interconnection point (project n° 5.11; promoter Snam Rete Gas)

The project consists in expanding the capacity of the existing gas network from East to West of the Po Valley and of Reverse flow between Italy and Switzerland; it will allow to make 40 mscm/day of additional capacity available at Passo Gries: 22 msmc/day of firm technical capacity at Passo Gries exit point and 18 mscm/day of firm capacity competing between Passo Griess and Tarvisio exit point. It includes 81 km pipelines, 2 new compressor stations and the upgrade of an existing one (total capacity of 82 MW). The project is currently under construction and is expected to be commissioned in October 2018.

[289] SNAM (2018), SNAM Annual report 2017.
[290] PCI project fiches available DG ENER's interactive map of PCIs: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

Facilitate new imports from the South: Reinforcement of the South-North internal transmission capacities in Italy (Adriatica line) (project N° 7.3.4, previously 6.18; promoter Snam Rete Gas).
The project consists in a new onshore pipeline of 430 km and a new compressor station of 33 MW that allow to realize new transmission capacity of approximately 24 MCM/day (264 GWh/day) to transport gas from new or existing entry points in the south of Italy. It is currently in the permitting stage and is expected to be commissioned in 2024.

Malta connection to the European gas network (interconnection with Italy at Gela) (project N° 5.19; Ministry for Energy and Water Management).
The MT-IT Gas pipeline interconnection concerns a bi-directional 159 km long pipeline to be installed between Gela in Sicily and Delimara in Malta for the purpose of ending Malta's gas isolation from the European Gas Network. The pipeline's capacity is 232,000 Sm3 of gas per hour (2 bcma or 56 GWh/day) intended for the import of natural gas from the Italian gas network to Malta. A pre-feasibility study and cost-benefit analysis were completed in 2015 while a CEF co-funded study identifying the optimal corridor was completed in 2017.[291] The project is currently in the permitting stage and the commissioning is expected by 2024.[292]

Gas pipeline connecting Greece to Italy through Albania and Adriatic Sea [known as Trans-Adriatic Pipeline (TAP)] (project N° 7.1.3; TAP AG)
The TAP Pipeline is a new 878 km pipeline (773 km onshore and 105 km offshore) between Greece/Turkey and Italy. Connecting with TANAP at the Greek-Turkish border, TAP will cross Greece, Albania and the Adriatic Sea before reaching Italy. The initial capacity is 10 bcm/a and the total capacity of the compressor stations to be realized is 90 MW. The pipeline is under construction and is expected to be commissioned in 2020. TAP received CEF funding for archaeological trench investigations and rescue excavations.

Gas pipeline connecting Greece to Italy [known as "Poseidon Pipeline"] (PCI 7.3.3, previously 7.1.4; IGI Poseidon SA)
This pipeline is designed to transport up to 14 bcm of natural gas a year from East Mediterranean, Middle East and/or Caspian areas to Italy and Europe through Turkey and Greece. The project comprises a 207 km long offshore pipeline, from the compressor station to be located near the landfall on the Thesprotia Coast where it will be connected to the Greek gas system, from where it will traverse the Strait of Otranto, crossing the Greek shelf, descending the slope into the north Ionian Basin and then ascending the Italian slope, to make landfall east of Otranto. It will continue up to the metering station in Otranto where it will be connected to the Italian gas system grid.[293] It is a mature project, having completed the permitting procedure in Italy and being well-advance with permitting in Greece.[294]
Projects from previous PCI lists (not in the 2017 one) are:

- Gas Pipeline connecting Algeria to Italy (via Sardinia) [currently known as "Galsi " pipeline] (2015 list, PCI 5.20). It will have a capacity of 8 bcm a year and is expected to go on stream in 2019.[295];

291 Ministry for Energy and Water Management (N/A), Malta – Italy Gas Pipeline Interconnection Non-Technical Summary.
292 Ministry for Energy and Water Management (N/A), Malta – Italy Gas Pipeline Interconnection Non-Technical Summary.
293 DEPA (N/A), IGI Poseidon: Interconnector Greece – Italy Pipeline.
294 IGI Poseidon (N/A), A Multi-Source Project.
295 ENTSOG (2017), TYNDP

- Gas pipeline Omišalj (HR) – Casal Borsetti (IT) (2013 list, PCI 6.5.4). No information has been found regarding its current status;
- PCI Interconnection Slovenia – Italy (Gorizia (IT)/Šempeter (SI) – Vodice (SI) (2013 list, PCI 6.7). It will have a capacity of 340 GWh/d in both directions and is expected to be commissioned by 2022.[296];
- Onshore LNG terminal in the Northern Adriatic (IT) (2013 list, PCI 6.19). It is expected to be commissioned by 2021 and will have a capacity of 258 GWh/d.[297]

5.1.3 Estimated impact of the storylines on Italian gas infrastructure

The table below provides a qualitative overview of the impact of the three selected storylines on the large gas infrastructure in Italy.

296 ENTSOG (2017), TYNDP
297 ENTSOG (2017), TYNDP

Table 5-5 Impact of storylines on Italian large gas infrastructure. Source: Own assessment

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane			Storyline 3 Strong development of hydrogen		
Gas demand 2016	794.6 TWh			794.6 TWh			794.6 TWh		
Gas demand 2030	Decrease			Stable			Slight decrease		
	Natural Very high	Biomethane Negligible	Hydrogen Negligible	Natural Very high	Biomethane Low	Hydrogen Negligible	Natural Very high	Biomethane Negligible	Hydrogen Low
Gas demand 2050	High decrease			Stable			Decrease		
	Natural Negligible	Biomethane Medium	Hydrogen High	Natural Negligible	Biomethane Very high	Hydrogen Low	Natural Negligible	Biomethane Low	Hydrogen Very high
LNG Terminals	Substantially decreasing utilisation level after 2030 and some assets would become devalued or stranded.			Substantially decreasing utilisation level after 2030. Liquefied biomethane trade by tanker could be considered. Existing LNG infrastructure could be used for this purpose.			Substantially decreasing utilisation level after 2030 and some capacity would become devalued or stranded. New hydrogen terminals might need to be built.		
Gas storage	Existing gas storage sites (depleted gas fields) could be used for biomethane. Their possible refurbishment for H_2 is still to be assessed; it might be required to develop new storage sites for hydrogen.			Gas storage fields could be used for biomethane storage. The requirements regarding a more dynamic operation of gas storage to cope with fluctuating RES might require retrofitting of gas storage infrastructure (suitability of depleted gas fields still to be assessed).			Existing gas storage sites (depleted gas fields) could be used for biomethane. Their possible refurbishment for H_2 is still to be assessed; it might be required to develop new storage sites for hydrogen.		
Transmission network & transit pipelines	Import pipelines would have substantially decreasing utilisation level after 2030. Some transport pipelines might require further reverse flow investments. Upgrade from methane to hydrogen pipelines might be necessary for some pipelines, while others might after 2030 become devalued or stranded due to strong fall in gas demand.			Import pipelines would have substantially decreasing utilisation level after 2030. Biomethane trade via existing pipelines is possible option. Grid investments needed to allow extension of methane refuelling network for vehicles. Reverse flow capabilities would be required to allow injection of high biomethane volumes at distribution level.			Import pipelines would have substantially decreasing utilisation level after 2030. Some pipelines would need to be upgraded to be able to transport hydrogen. The system also needs to be upgraded to allow bi-directional flows (reverse-flow).		

5.2 Main national developments that influence investments in and use of gas transport infrastructure

Italy is among the most important gas consumers in the EU with 75.1 bcm (842 TWh) of natural gas demand in 2017. Gas is in Italy largely used for heating buildings and power generation, and it is also increasingly used for transport purposes, with approximately one million vehicles currently being fuelled with natural gas and 1040 CNG filling stations across the country. The future gas demand in Italy will be affected by the decision to phase out coal fired power plants by 2025 and by the RES policies and targets; the RES targets have been set at 17% by 2020 and 28% by 2030, while renewable energy accounted in 2016 for 17.4% of final energy demand. Biomass is largely available in Italy and biogas is already at large scale being developed (1406 MW installed capacity in 2016). The share of biomethane in the gas mix is still very limited but is expected to substantially increase in the coming decade (10.5 bcm in 2035 according to Snam).

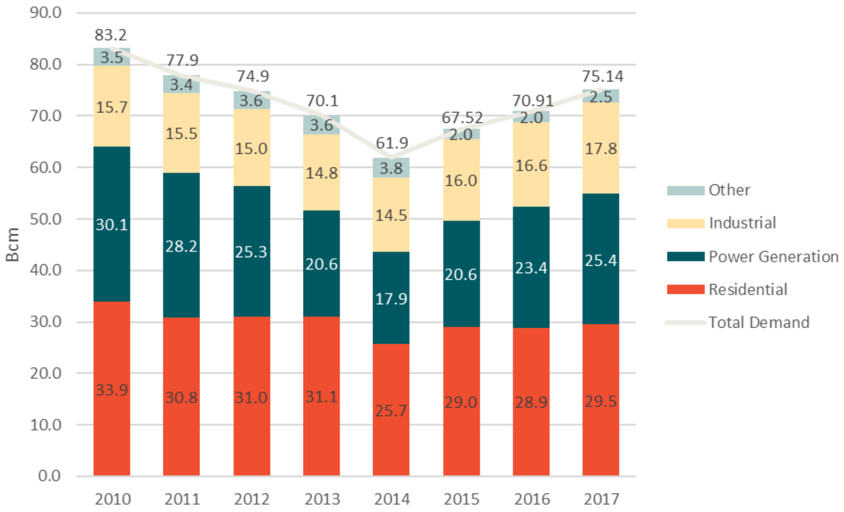
Ongoing and planned investments in the Italian network, in particular to enable reverse flows and in new pipelines, will further improve the markets' integration and access of Italy and its neighbours to diversified gas supply sources via different routes.

5.2.1 Gas supply and demand

Gas demand

In 2017, natural gas demand in Italy amounted to 75.1 bcm. Notwithstanding an increase over the years 2015 to 2017, the gas demand has in 2017 not reached the level of 2010, mainly due to lower consumption for power generation and industry, as a consequence of the economic crisis.[298] With the development of intermittent renewable energy-based power, the climate conditions increasingly determine the role of gas for power generation. Moreover, a growing number of power generators are moth-balling gas-fired capacity (for example, Enel removed six gas-fired units totalling 1.3 GW of capacity from the market in 2014).[299]

Figure 5-2 Sectorial gas demand in Italy (bcm)



298 Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
299 IEA (2016), Energy Policy Review Italy

The daily demand peak amounted in 2017 to 422 mcm which was higher than the import capacity, and hence partly covered by storage capacity. The highest peak demand was registered on 6 February 2012 and amounted to 472 mcm, with an overall consumption in line with the value of 2017.

The integration of new intermittent renewable energy sources as well as specific climate conditions, as occurred in the past, are expected to influence the future daily peak demand of the gas system.

Italy has been considering carbon taxes for several years. For example, a finance law was introduced in 2012 including a green tax; however, it was never implemented. Such a step, while uncertain in Italy's policy, may affect the gas demand by supporting a shift from fossil fuels to renewable energy (including renewable gas). The National Energy Strategy (NES), approved in 2017, includes a commitment to phase out coal by 2025. This Strategy also sets out the target to 'save' 10 Mtoe of final energy per annum by 2030, with energy efficiency gains being considered as one of the main priorities of the Italian energy policy to emission reductions. It is unclear to what extent such energy efficiency measures will effectively impact the gas demand. The expected gas demand in 2020-2035, forecasted by Snam, is presented in the following table.

Table 5-6 Natural gas and biomethane demand forecast in Italy. Source: Snam Rete Gas (2017)

B SCM @ 10.6 KWH/SCM	2016	2020	2026	2030	2035	VAR. % AVERAGE ANNUAL CHANGE 2016-2026	VAR. % AVERAGE ANNUAL CHANGE 2016-2035
RESIDENTIAL AND COMMERCIAL	28,9	28,2	27,2	25,9	23,8	-0,6%	-1,0%
POWER GENERATION	23,3	23,2	28,2	31,5	31,2	1,9%	1,5%
INDUSTRY	14,6	14,1	13,1	12,4	11,6	-1,1%	-1,2%
OTHER (*)	2,1	3,6	8,3	11,4	14,3	14,9%	10,8%
CONSUMPTION AND LOSSES	2,0	2,1	2,5	2,7	2,6	2,1%	1,5%
TOTAL DEMAND	70,9	71,3	79,2	83,8	83,5	1,1%	0,9%

(*) Including consumptions for Agriculture and Fishing, Chemical synthesis, automotive and bunkering

As a consequence of the growing development of renewable energy, natural gas demand will be under pressure and will become more uncertain and volatile, but gas is in Italy expected to continue to play a role in the energy transition, also due to the planned decommissioning of coal-fired thermal power plants by 2025, as back-up resource for the power system, and as feedstock for the industry.

LNG and CNG for transport

Gas is in Italy extensively used for transport purposes. About 1 million vehicles are currently fuelled with natural gas[300] and there are 1040 CNG filling stations across Italy. The transport sector is expected to consume considerable quantities of CNG: 7.9 bcm in 2035 (+6.8 bcm compared to 2016). The LNG market for transport is in full development in Italy. In 2017 the LNG consumption for Heavy duty trucks (HDT) was around 31 kton/year with a 100% growth in LNG consumption compared to 2016. In Italy 20 L-

[300] http://www.Snam.it/it/gas-naturale/energia-del-futuro-oggi/gas-naturale-compresso/

CNG[301] stations have been built up to now, and approximately 1000 trucks are using CNG. The LNG market is expected to grow by 2025 to circa 300 kton/year with 9000 LNG trucks in operation. A slower growth is expected in the marine LNG bunkering market to about 600 kton/year in 2030. This development is favoured by more stringent emission constraints as of 2020 for engines and by the development of LNG as fuel for heavy road transport and maritime transport, according to the guidelines laid down by Directive 2014/94/EU "Deployment Alternative Fuel Infrastructure".

As part of its strategy, Snam aims to contribute to the development of LNG and CNG infrastructure for the maritime and HDT transport sectors. In this context, Snam is cooperating with FCA and IVECO, which intend to further expand their respective product lines of natural gas vehicles, as well as with ENI, API group and independent retailers which intend to construct new CNG and L-CNG facilities within their point-of-sale network. The project shall make it possible to double the road and highway distribution network, currently consisting of 1,100 service stations, to reach up to more than 2,000 in 10 years.[302] Snam is also considering the development of the so called Small Scale LNG infrastructure to enable the use of LNG across the country.

Gas supply

Natural gas supply to Italy was in 2017 mainly covered by imports, which amounted to 69.4 bcm, representing approximately 93% of total supplies (national production was covering the remainder). Imports came from Tarvisio (44.0%), Mazara del Vallo (27%), Passo Gries (10%), and other import points with lower percentages.[303] The countries of origin were Russia (42%), Algeria (30%), Qatar (9%) Libya (8%), Netherlands (4%), Germany (3%), and other countries (4%).[304]

Exports have so far represented a negligible part of transported volumes (only 0.3% in 2017), but an increase is expected with the availability of bidirectional capacity at Passo Gries interconnection point. Domestic production shows a decreasing trend; the maximum daily production is about 20 mcm.[305] The production in 2017 amounted to 5.2 bcm (5.9% or 0.3 bcm lower than in 2016).

Security of supply

Ongoing investments in the Italian network, in particular in reverse flow projects, will allow bidirectional flows of gas at national borders. The investments also aim to ensure a greater interconnection between infrastructures and more diversified procurement sources. Italy is strategically part of the European corridors network and new supply routes, particularly in the Caspian Sea area. Investments in reverse flow shall also bring gas from North Africa to Europe through Italy.[306]

Italy's national energy strategy 2017 foresees to further diversify supply sources, by optimising the use of existing infrastructure, and by developing new connection infrastructure; to improve the flexibility of supply sources, by strengthening gas pipelines and the peak-demand security margin; and to coordinate national contingency plans, including mutual support between EU countries.[307]

301 Liquefied-to-compressed natural gas
302 SNAM (2018), Annual report 2017.
303 Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
304 https://www.statista.com/statistics/787720/natural-gas-imports-by-country-of-origin-in-italy/
305 Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
306 SNAM (2017), Annual report 2016.
307 http://www.sviluppoeconomico.gov.it/images/stories/documenti/BROCHURE_ENG_SEN.PDF

The proposed concrete actions to ensure security of energy supply are:

- promoting the construction of new gas import pipelines by private parties, in accordance with market principles, in order to further diversify supply sources and routes;
- holding auctions (instead of using regulated tariffs) for LNG regasification services in order to make the use of Italian gas terminals more attractive;
- converting local networks of distribution of LPG and propane-air mixtures in Sardinia to natural gas from regasified LNG and developing them by connecting them incrementally to small-scale LNG storage terminals; and using LNG to implement the first pilot project of Sulphur Emission Controlled Area (SECA) for maritime traffic in Sardinia.

Natural gas is in Italy still the main primary energy source for electricity generation. Due to the high interdependency between the electricity and gas sector, the Italian authorities deem it necessary to consider these interactions in the assessment of risks originating in the electricity system but impacting the gas one. The interactions must also be examined for the preparation of possible measures to reduce demand in the Emergency Action Plans. In particular, in case of a gas availability crisis requiring the reduction of daily demand, power generation plants may be required to contribute to the reduction of consumption to allow the continuous gas supply to protected customers.[308]

Italy's natural gas supply infrastructure is compliant with the N-1 standard referred to in the EU Regulation, which means that it is capable of maintaining reliable delivery of natural gas to consumers in the event of a single substantial contingency event, such as an unplanned loss of its single largest pipeline, interconnector or LNG terminal.

However, the Italian gas system margin with respect to exceptional peaks in demand is slightly decreasing; the safety margin currently amounts to 105% while it was 114% in 2013. This decrease is due to a reduction in the maximum technical withdrawal storage capacity.

Italy can rely on well diversified supply sources and routes. Besides domestic production, the Italian gas system can receive gas via four import pipelines (Algeria, Libya, Russia and Norway) and three regasification terminals. The planned additional LNG terminals will enable Italy to further diversify its gas sources, and the new TAP pipeline will allow to also import gas from the Caspian Region. The ongoing development of bidirectional capacity in the north of Italy and the North-South corridor (reverse flow) will improve access to diversified supply sources and will also make Italian supply sources accessible to other European countries.[309]

5.2.2 Renewable energy policy and targets

The need for and use of gas infrastructure will be strongly affected by the deployment of renewable energy. In 2014, Italy had already achieved its RES target for 2020 (of 17%). In 2016, Italy had a RES share of 17.41% in its gross inland energy consumption.[310] The government has meanwhile also set a target for 2030: 28% RES in total energy consumption, broken down as follows: 55% of RES-E by 2030 (34.01% in 2016), 30% of RES-H&C by 2030 (18.9% in 2016) and 21% of RES-T by 2030 (7.24% in 2016).[311]

[308] Italian government (2017), Italian natural gas system's Preventive Action Plan. Annex 1 to the Ministerial Decree of 18th October 2017.
[309] SNAM (2018), Annual report 2017.
[310] Eurostat SHARES 2016 results.
[311] Italian Government (2017), Strategia Energetica Nazionale & Eurostat SHARES 2016 results.

Biogas and biomethane[312]

In 2016 there were about 1924 operating biogas plants (1406 MW installed capacity) in Italy, of which more than 1200 plants in the agricultural sector. Italy is the second largest producer of biogas after Germany. Next to the plants of agricultural origin (more than 80% of the total number), 12% of the biogas plants are fuelled with landfill, 3% with municipal solid waste and 5% with biomass derived from water treatment. In its position paper of 2011, the Italian Biogas Consortium had estimated the potential production of 8 bcm equivalent of biomethane to be achieved by 2030 by using 400,000 hectares of land for extensive production of biomass.[313]

The new biomethane Decree of 2nd March 2018 on “Promotion of the use of biomethane and other advanced biofuels in the transport sector”[314], establishes priority incentives (up to 1.1 bcm per year) for advanced biomethane injected into the natural gas network and intended for the transport sector. The new decree also provides incentives for the injection of biomethane into the gas network without destination of use for which the decree enforces the system of guarantees of origin.

Snam includes a scenario of gas demand in its 10-year development plan supporting decarbonization through the development of biomethane.[315] The contribution from biomethane is expected to be about 4 bcm in 2026 and 10.4 bcm in 2035, with significant growth as of 2022. Another estimate mentions, however, that the biomethane potential by 2030 is around 75 TWh/year.[316]

Snam Rete Gas contributes to the “evolution of the gas sector” through the development of biogas and its conversion into biomethane for injection into the transportation network.[317] In 2016, two agreements were signed for the injection of biomethane into its grid.[318] Since 2016 18 contracts have been signed for biomethane connections to the grid. In June 2017, the first biomethane was injected in the national pipeline network by Montello SpA, an Italian company specialised in bio-waste recovery and recycle.[319]

Snam Rete Gas is taking part in a research project looking into the potential impacts on the entire gas chain, of chemical components present in traces in biomethane in order to create the conditions for the safe development of biomethane as a gas injection source in the transportation network.[320]

Hydrogen and synthetic methane

There are no installations or concrete projects for injection of hydrogen or synthetic methane into the gas grid in Italy. There is currently also no enabling legislative framework, although the 2017 National Energy Strategy mentions that hydrogen could become a component of the energy mix if significant R&D investments are made.[321] The only hydrogen grid developed in Italy is in the gold district of Arezzo (Tuscany), where there is a 4 km storage facility at 200 bar pressure with a 1 km pipeline that connects the plants that use hydrogen directly in gold processing and also to produce heat and power with CHP. In addition, hydrogen systems supplier Hydrogenics is piloting a project in Puglia with the aim to

[312] ISAAC (2016), Deliverable D5.2: Report on the biomethane injection into national gas grid.
[313] ISAAC (2016) Deliverable D5.2: Report on the biomethane injection into national gas grid.
[314] http://www.gazzettaufficiale.it/eli/id/2018/03/19/18A01821/SG
[315] Snam Rete Gas (2017), Ten-year development plan of the natural gas transmission network: 2017-2026
[316] https://www.consorziobiogas.it/wp-content/uploads/2017/02/76-Potenzialit%C3%A0_biometano_Italia_DEFINITIVO.pdf
[317] SNAM (2017), Annual report 2016.
[318] SNAM (2017), Annual report 2016.
[319] http://www.Snam.it/en/Natural-gas/energy-for-the-future-today/biomethane/
[320] SNAM (2017), Annual report 2016.
[321] Italian Government (2017), Strategia energetica nazionale 2017 p.245

balance surplus renewable energy supply with actual demand by hydrogen production and storage and subsequent feeding of hydrogen (renewable energy based) into the grid.[322]

5.2.3 Gas market integration and competition

Wholesale gas prices show in Italy a converging trend with most other gas markets across Europe.[323] The price difference between Italy's trading point Punto di Scambio Virtuale (PSV) and TTF, the Dutch virtual trading point that is used by ACER as the reference for European gas wholesale prices, has decreased between 2014 and 2016. Price differences exceeding € 5/MWh no longer occurred in 2016. Recently, it also happened a few times that PSV prices were below TTF prices. The PSV is considered by the Oxford Institute for Energy Studies as an active market place with developing depth, transparency and liquidity.[324]

The concentration on the Italian gas market is not a major issue of concern. The HHI index[325] increased by 40% between 2011 and 2015 (from 2093 to 2924), but remains well below the EU28 average of 4771.[326]

The Italian gas system is highly interconnected with the networks in neighbouring countries. Wholesale markets are integrated at regional level, and as physical bottlenecks (congestion) only occur very rarely, wholesale prices converge to a large extent. On the basis of the current and expected market development, the need for major additional gas infrastructure investments in order to further enhance market integration and/or competition is limited. Current and future investment priorities hence mainly focus on supply diversification, and only one major infrastructure project ("Support to the north west market and bidirectional cross-border flows") is focusing on market integration.

5.2.4 Environmental and climate related regulation and measures

According to the National Energy Strategy (NES), approved in 2017, Italian authorities are considering accelerating the phasing-out of coal from the power generation mix. All coal-fired plants would have to close by 2025, while Italy had in 2017 still around 7.9 GW coal-fired capacity[327] and coal-fired output accounted for around 13% of Italy's power generation mix in 2015. This measure will have an impact on future gas demand,[328] and will also allow to reduce the environmental impact, including GHG emissions, related to coal use.

The gas TSO is actively engaged in efforts to reduce the environmental impact of its activities and has committed to 2 specific targets:

1. to reduce its methane emissions by 10% from 2016 to 2021;

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322 https://www.windpowermonthly.com/article/1412122/industrial-scale-hydrogen-storage-trial
323 ACER/CEER (2017), Annual report on the results of monitoring the internal electricity and gas markets in 2016. Gas wholesale markets volume.
324 The Oxford Institute for energy studies (2017), European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration
325 The Herfindahl-Hirschman Index (HHI) is defined as the sum of the squared market shares of each wholesale gas supply company measured in percentages of total wholesale gas supply, with 10,000 corresponding to a monopoly. It measures market concentration at the level of upstream sourcing companies supplying gas to a given Member State. Thus, in addition to considering geographical diversification, it takes into account diversification at supplier company level. In general, Member States with well-functioning hubs and/or those that benefit from varied supply sources exhibit low HHI values of around 2000.
326 SWD (2017) 32 final - Monitoring progress towards the Energy Union objectives – key indicators.
327 ENTSO-E Transparency Platform. Available from: https://transparency.entsoe.eu/generation/r2/installedGenerationCapacityAggregation/show
328 https://www.argusmedia.com/~/media/files/pdfs/white-paper/italian-energy-strategy-white-paper.pdf?la=en

2. to reduce its vented emissions by 33% annually from 2017 to 2022 (Recovery of potential emissions deriving from maintenance activities to limit natural gas emissions from the transport network).[329]

Several best practices have been implemented in order to achieve these targets. Snam is also developing new activities for the assessment of natural gas emissions from gas infrastructure in order to update the natural gas emissions estimates and is also participating in basic research projects on methane emissions, in co-operation with GERG (European Gas Research Group).

Italy has joined the multilateral initiative *Mission Innovation*, which includes 22 Nations (and the European Commission) with the objective of promoting the acceleration of technological innovation to support the energy transition through a significant increase in public funds dedicated to clean technology research in relevant technologies, including the application of Carbon Capture and Storage. In Italy there are a few experimental CCS projects but their impacts on CO2 emissions are expected to be limited by 2030. The future development of this technology will potentially be strengthened by the cost increase of CO_2 emissions.

5.2.5 Overview of impact of non-gas demand drivers on Italian gas infrastructure

Table 5-7 Impact of non/gas demand drivers on gas infrastructure in Italy

Policy objective	Issue	Likely impact
Security of supply	Access to diversified gas sources	Italy can rely on well diversified supply sources and routes (domestic production, pipeline gas and LNG). Pipeline investments are ongoing to further diversify supply and expansion of LNG regasification units is also under consideration.
	Infrastructure standard N-1 is respected	Overall capacity (import, storage and network capacity) is sufficient to cope with peak demand, also in case of temporary unavailability of major infrastructure component. Reverse flow investments are realised or planned to further enhance security of supply of Italy and its neighbouring countries.
Climate / Environment	Back-up for intermittent renewable energy sources	Italy plans large expansion of intermittent energy generation capacity, particularly wind and solar energy. Gas will maintain (at least until 2030) a primary role in the energy mix.
	Biogas/biomethane development	Biomethane is injected into gas grid since 2017. There is a target of a yearly increase of biomethane injected into the grid up to 1,1 bcm per year and the necessary regulatory framework is in place. Biomethane development will hence have major impact on gas infrastructure, possibly also for imports.
	Hydrogen development	There are no installations or concrete projects for injection of hydrogen or synthetic methane into the gas grid in Italy. No impact in short term.
	Substitution of fossil fuels	Phase out of coal for power generation and substitution of oil products with LNG and CNG in transport sector will have positive impact on use of gas infrastructure.
	Environmental regulation	Maintenance/investments needed to reduce/prevent CH4 leakages
Competitiveness / market development/ market integration	Market integration	Italian gas system and market are well interconnected with neighbouring countries; ongoing investment project is contributing to this objective and few projects are envisaged to further expand cross-border trade capacity.
	Enhance competition	No major impact on gas infrastructure; ongoing investment project is contributing to this objective.

329 SNAM (2018), Annual report 2017.

5.3 Assessment of the impact of the storylines on the Italian TSO

The Italian TSO Snam Rete Gas (part of Snam Group) owns and operates 32,584 km of high- and medium pressure gas pipelines, which corresponds to approximately 94% of the Italian transportation system. The RAB for transportation, dispatching and metering assets amounted end 2017 to € 16.0 billion. Taking into account the current investment program, and the required future investments, the RAB is expected to only slightly decline as of 2025, also taking into account the long depreciation periods (e.g. 50 years for pipelines). The capital costs (fixed at 5.4% in 2016-2018) would hence remain at a relatively high level.

The OPEX for gas transportation ranged between € 441 and 485 million per annum in 2015-2017. As only 2% of the costs are variable, decreasing transport volumes would only have a minor impact on the OPEX level.

In 2017, the Snam group spent € 917 million for investments in its gas transmission grid, of which € 432 million for maintenance (replacement of ageing assets) and € 485 million for transmission capacity extensions. As the gas grid would in the long term be continued to be used for (renewable) gas, be it in lower quantities (gas demand would in Italy in 2050 - depending on the storyline – be up to 55% lower than the current level), investments would be needed to maintain the network (same level in the 3 storylines) and to make it suitable for renewable gas (different level depending on the storyline).

As the TSO benefits under the current regulatory regime of "guaranteed" revenues based on its "authorised" costs, the profitability level of the TSO would not directly be affected by this evolution. As the expected fall of the transported gas volumes in storylines 1 and 3 would not be accompanied by an equivalent decrease in costs, gas grid tariffs would increase. Storyline 2 would offer the best outcome in terms of impact on gas grid tariffs.

5.3.1 Key financial figures: Snam Rete Gas

General data for Snam (2017)	Value	Unit	Source
Infrastructure			
Pipelines (Snam Rete Gas)	32 584	km	Snam annual report 2017
- *National*	*9 704*	km	
- *Regional*	*22 880*	km	
LNG Terminals (GNL Italia)	3.5	bcm/year	
Storage capacity (STOGIT)	16.7*	bcm	
Compressor stations	11	Units	
	922	MW	
National network entry points[330]	8	Units	
Transport capacities			
Available	364.2	mcm/day	Snam annual report 2017
Booked	258.8	mcm/day	
Natural gas injected into transportation network	74.59	bcm	
Consolidated Investments			
Technical investments	1 199	M EUR/year	Snam annual report 2017
- *Of which in transport*	*1,034*	M EUR/year	

330 national network entry points for gas from abroad, located at connection points with the import pipelines (five entry points) and the LNG regasification terminals (three entry points)

General data for Snam (2017)	Value	Unit	Source
Net invested capital	17 738	M EUR/year	
Investment plan 2017-2021	5.2	B EUR/5 years	
- *Of which in Italy*	4.7	B EUR/5 years	
RAB			
Transmission	15	B EUR	Snam annual report 2017
Storage	4	B EUR	
LNG Terminals	0.1	B EUR	
Revenues (Consolidated)			
Total revenue	**2 533**	**M EUR**	Snam annual report 2017[331]
Non-regulated revenues	**99**	**M EUR**	
Regulated revenue	**2 434**	**M EUR**	
- *Transportation*	*1 889*	*M EUR*	
- *Regasification*	*18*	*M EUR*	
- *Storage*	*435*	*M EUR*	
- *Revenues items offset in the cost* **	92	*M EUR*	
Adjusted EBITDA	2 022	M EUR	
Adjusted EBIT	1 363	M EUR	
Shareholders[332]			
Listed on the Milan stock exchange since 2001. Shareholders are: CDP Reti (30,10%), Romano Minozzi (5.75%), Snam (2.45%), other shareholders (61.7%).			

Note: includes strategic storage capacity (if this is excluded, the available storage capacity is 12bcm)*
*** The main revenue items offset in costs relate to interconnection and sales of natural gas carried out for balancing purposes.*

5.3.2 *Activities of the Snam Group in Italy*

Snam Rete Gas, part of Snam Group, is the major Italian natural gas transportation and dispatching operator; it owns and operates 32,584 km of high- and medium pressure gas pipelines (approximately 94% of the Italian transportation system). Snam Rete Gas manages the gas pipeline network via 8 districts, 48 maintenance centres throughout Italy, 11 compressor stations and a dispatching unit.

331 http://www.Snam.it/export/sites/Snam-rp/repository/ENG_file/investor_relations/reports/annual_reports/2016/financial-indexed-2016/08_Natural_gas_transportation.pdf
332 SNAM (2018), Annual report 2017.

Figure 5-3 Snam's presence in Italy. Source: Snam annual report 2017

5.3.3 *Regulatory Asset Base (RAB) and rate of return*

The RAB of Snam as of 31 December 2017 for its transportation, dispatching and metering assets amounted to € 16.0 billion[333]; it amounted € 4.0 billion for its storage assets and € 0.1 billion for its regasification assets.[334] Taking into account the current investment program for gas transportation, and the need to maintain relatively high investment levels in the coming decades, either to replace ageing assets (in the 3 storylines), to upgrade assets for H_2 transportation (in storylines 1 and 3), or to enable reverse biomethane flows between distribution and transmission (storyline 2), it is expected that the RAB related to transmission would only slightly decline as of 2025. The RAB is based on the historical investment costs, and annually adjusted on the basis of the inflation level.

The authorised return on investment capital is currently (2016-2018) 5.4% for transmission assets. For new investments, specific incentives apply depending on the asset type (see figure).

333 Snam (2018), Annual report 2017
334 Snam (2018), Annual report 2017.

Figure 5-4 Gas infrastructure financial regulation in Italy. Source: Snam Annual Report 2017

	Transportation	Regasification	Storage
End of regulatory period (TARIFFS)	*Current period:* 31 December 2017 *Transitional period:* 1 January 2018 - 31 December 2019	*Current period:* 31 December 2017 *Transitional period:* 1 January 2018 - 31 December 2019	*Current period:* 31 December 2018 *Transitional period:* 1 January 2019 - 31 December 2019
Calculation of net invested capital recognised for regulatory purposes (RAB)	Revalued historical cost	Revalued historical cost	Revalued historical cost Deduction of restoration costs recognised
Return of net invested capital recognised for regulatory purposes	**5.4% 2016-18 (*)**	**6.6% 2016-18 (*)**	**6.5% 2016-18 (*)**
Incentives on new investments	*Current period (investments in 2014-2017):* **+1% for 7 years** (regional network development investments) **+1% for 10 years** (national network development investments) **+2% for 10 years** (entry point development investments) **WACC +1%** on investments made in 2014-2016 to offset the regulatory time-lag *Transitional period* (investments in 2018-2019): **+1% for 12 years** (investments in new transportation capacity and with positive cost-benefit analysis) Return on investments t 1 (from 2017 investments) to offset regulatory time-lag	*Current period (investments in 2014-2017):* **+2% for 16 years** (new terminals or expanding existing terminal capacity >30%) **WACC +1%** on investments made in 2014-2016 to offset the regulatory time-lag *Transitional period* (investments in 2018-2019): **+1.5% for 12 years** (investments in new regasification capacity) Return on investments t 1 (from 2017 investments) to offset regulatory time-lag	*Current and transitional period:* Withholding for 8 years of 20% of revenues in excess of revenue recognised resulting from insolvency procedures Return on investments t-1 to offset the regulatory time-lag (from 2014)
Efficiency factor (X FACTOR)	*Current period:* **2.4%** - on operating costs *Transitional period:* **1.3%** - operating costs	*Current period and transitional period:* **0%**	*Current period:* **1.4%** - on operating costs *Transitional period:* To be defined in P.T. 2019

5.3.4 OPEX & CAPEX

Operating costs

The operating costs for gas transportation ranged in 2015-2017 between € 485 and 441 million. The OPEX for regulated activities consist of 66% fixed costs, 2% variable costs, 9% other costs and 23% cost items offset in revenue.[335] The variable (volume related) costs are hence relatively low, which means that decreasing transported volumes would not translate in proportionately decreasing OPEX. The regulator imposes efficiency factors (1.3% in 2018-2019), but these are not related to fluctuations in transported volumes. The costs shown in the table below include also costs related to non-regulated activities, pass through costs as well as costs for non-recurrent items.

335 Snam (2018), Annual report 2017.

Table 5-8 Operating costs by sector of activity in million Euros. Source Snam Annual Report 2017

Operating Costs by Business segments

2015	(millions of €)	2016	2017	Change	Change %
	Business segments				
485	Transportation	469	**441**	(28)	(6.0)
19	Regasification	12	**15**	3	25.0
145	Storage	151	**165**	14	9.3
208	Corporate and other activities	245	**252**	7	2.9
(287)	Elisions from consolidation (*)	(304)	**(362)**	(58)	19.1
570		**573**	**511**	**(62)**	**(10.8)**

(*) The figures for 2015 and 2016 include the restoration of the eliminations deriving from intercompany transactions with discontinued operations.
(**) With reference to 2017, the cost of interconnections to Gas Transport Infrastructures was adjusted by the corresponding revenue from Snam Rete Gas (€ 5 million in the period October-December 2017).

Operating costs - Regulated and non-regulated activities

2015	(millions of €)	2016	2017	Change	Change %
463	**Costs of regulated activities**	**456**	**404**	**(52)**	**(11.4)**
268	Controllable fixed costs	271	**267**	(4)	(1.5)
13	Variable costs	9	**7**	(2)	(22.2)
64	Other costs (*)	31	**38**	7	22.6
118	Cost items offset in revenue (**)	145	**92**	(53)	(36.6)
107	**Costs of non-regulated activities (***)**	117	**107**	**(10)**	**(8.5)**
570	**Total operating costs**	**573**	**511**	**(62)**	**(10.8)**

(*) Net special items.
(**) The main revenue items offset in revenue relate to interconnection and sales of natural gas carried out for balancing purposes.
(***) The figures for 2015 and 2016 include restoring the adjustments deriving from inter-company transactions with discontinued operations.

CAPEX

In 2017, the Snam group has spent € 917 million (€ 776 million in 2016) for investments in gas transportation infrastructure, in view of replacement of ageing assets (€ 534 million), development of additional import/export capacity (€ 276 million) and development of new domestic transportation capacity (€ 107 million).

Table 5-9 Transportation technical investments. Source: Snam Annual Report 2017

Technical investments

Fourth regulatory period		**Financial year 2015**	**Financial year 2016**	**Financial year 2017**
Type of investment	**Higher compensation in fourth regulatory period (%) (*)**	**€/million**	**€/million**	**€/million**
New import and/or export capacity	2.0%	249	226	**276**
New National Network transportation capacity	1.0%		1	**10**
New Regional Network transportation capacity	1.0%	79	118	**97**
Replacement and other		365	431	**534**
		693	**776**	**917**

(*) Compared with the base WACC of 6.3% for 2015 and 5.4% for 2016 and 2017, in addition to 1% to offset the regulatory lag for 2015 and 2016 .

In the 5-year period 2017-2021 the overall CAPEX plan for transport and CNG amounts to € 4.6 billion of which 32% related to development, 39% to maintenance, 18% to replacement, 11% to other and CNG.[336] As the allowed rate of return is different depending on the type of gas infrastructure, the technical investments in transportation infrastructure are classified in accordance with Resolution 514/2013/R/gas of the Electricity, Gas and Water Authority, which defines specific premiums for different durations on the basic rate of return depending on the investment typology (see figure 5-4).

Future investment priorities

Snam's current 10-year development plan 2017-2026 includes projects to expand the infrastructure to allow for new import and export capacity. The plan includes the construction of about 1070 km of new pipelines and 95 MW of new compressor units. Another element of the plan is the implementation of the bidirectional capacity towards Switzerland (at Passo Gries), for which the construction is ongoing with expected commissioning in October 2018.[337]

The priority projects included in the plan are:

- Support to the north west market and bidirectional cross-border flows;
- TAP interconnection;
- Methanation of Sardinia;
- Adriatica line.

The first project aims to increase the integration with other European markets (connecting Italy to Northern Europe), which would also allow further price alignment between PSV and other interconnected hubs. The project also contributes to diversification of supply sources making available new sources of natural gas to northern and central Europe countries. The TAP interconnection is functional to link the new entry point to the national gas pipeline network, while the methanation of Sardinia allows the supply of natural gas to the Sardinian region, thus supporting replacement of more carbon intensive fuels with natural gas. The Adriatica line is functional to transport gas from new supply sources from Sicily to the middle Adriatic.

The storage projects included in the latest 10-year investment plan, are intended to improve the overall flexibility and security of the system. They will deliver an increase in available storage capacity (12.0 billion standard cubic metres in 2016) of about 7% over the concerned period and an increase of around 8% in delivery point capacity (238 million standard cubic metres per day in 2016). [338]

Regulated transmission grid tariffs based on 'authorised' revenues for the TSO

The tariffs for grid access and use are regulated and mainly capacity-based (85% versus 15% commodity-based); they are calculated on the basis of the allowed costs and a regulated remuneration of capital:

1. The allowed **REMUNERATION** of capital is calculated by multiplying the weighted average cost of capital (WACC) by the Regulatory Asset Base (RAB). Each year, the RAB remuneration is updated according to the evolution of the RAB itself (including the adjustment deriving from the inflation registered in the period);
2. The allowed **DEPRECIATION** cost is calculated on the basis of the economic-technical lifetime of the assets, set for regulatory purposes. A linear depreciation method is applied, and gas

336 Snam Full year 2017 results and plan update 14th March 2018
337 Snam Rete Gas (2017), Ten-year development plan of the natural gas transmission network: 2017-2026.
338 Snam (2017), Annual report 2016.

transportation assets are depreciated over a period of 50 years for pipelines, 20 years for compressor stations and 5 years for ICT. The depreciation period for pipelines was previously 40 years and has been changed in 2010. As the future use of gas infrastructure has become more uncertain, and taken into account the expected fall in transported gas volumes, the implementation of shorter depreciation periods could be considered;

3. The allowed **OPERATING EXPENSES**, which are updated according to the price-cap methodology, as reflected in the «RPI – X» formula, i.e. Retail Price Index less the X factor, which expresses the target-rate of productivity recovery.

Additional information about the tariff regulation is available in Snam's Euro Medium Term Note Programme.[339]

With the current regulatory regime in Italy, the profitability level of the TSO is not directly affected by changes in transported gas volumes. This means that a possible fall in gas demand would mainly translate in increasing grid tariffs per effectively transported gas volumes.

The risk for the gas TSO is hence rather limited: no inflation exposure (yearly adjustment of RAB and revenues) and low gas demand exposure (adjusted capacity-based revenues).

5.3.5 TSO viability analysis: Estimated impact of the 3 storylines on end-users (tariffs) and on the business of the TSO

The table below provides an overview of the expected qualitative impacts of the three storylines.

339 Snam (2017), Euro Medium Term Note Programme.

Table 5-10 Estimated impact of the selected storylines on the gas TSO

	Figures 2017	Storyline 1 Strong electrification		Storyline 2 Strong development of carbon-neutral methane		Storyline 3 Strong development of hydrogen	
		2030	**2050**	**2030**	**2050**	**2030**	**2050**
Gas Demand (TWh_{th})[340]	795 (2016) 842 (2017)	Decrease	High decrease	Stable	Stable	Slight decrease	Decrease
Investment for maintenance of transmission/transit network	€ 432 million	Stable (replacement of ageing assets to ensure safe and secure operation)		Stable (to ensure security of operation)		Stable (to ensure security of operation)	
Investment for development of transmission/transit network	€ 485 million	Stable, taking into account specific investments for refurbishment of gas grid to accommodate H2, depending on supply points and peak[341] demand needs		Stable, taking into account specific investments to accommodate biomethane, depending on supply points and connection of biomethane plants, including reverse flows D -> T (if local injection > local demand)		Stable to slight increase, taking into account specific investments needed to accommodate high H2 volumes in network, depending on supply points and peak demand needs.	
Net assets (accounting value)	€ 16 billion	Stable		Stable		Stable to slight increase	
OPEX	€ 441 million	Stable, taking into account efficiency improvements		Stable to slight decrease, taking into account efficiency improvements		Stable to slight increase, taking into account efficiency improvements	
Possible impact on gas grid tariff for end-users	2.5 €/MWh	Slight increase in €/cm, assuming that IT TSO will play major role in EU transit of gas => slightly lower overall transported volumes. Increasing tariff per MWh transported gas		Stable in €/cm, assuming that IT TSO will play major role in EU transit of gas => stable overall transported volumes. Stable tariff per MWh transported gas		Stable in €/cm, assuming that IT TSO will play major role in EU transit of gas => stable overall transported volumes. Increasing tariff per MWh transported gas.	
Overall assessment				Most favourable scenario from gas grid users and TSO perspective			

340 All types of gas, including renewable gas. The transported volumes will be lower than the overall demand due to local use of biomethane and hydrogen.

341 Taking into account that the lower calorific value of hydrogen versus natural gas can necessitate capacity extension investments

6 Ireland

General data for IRELAND		Unit	Source
Natural gas consumption	49,334	GWh/year	Eurostat 2016
Peak load	258	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	29	%	Eurostat 2016
Domestic natural gas production	28,879	GWh/year	Eurostat 2016 (nrg_100a)
Imports	19,770	GWh/year	Eurostat 2016 (nrg_100a)
Exports	0	GWh/year	Eurostat 2016 (nrg_100a)
Capacity of entry pipelines	432	GWh/day	ENTSOG transmission capacity map
LNG import terminal capacity	0	Billion m^3(N)/year	GIE LNG map
Number of gas PCIs in 2017 list	3	projects	PCI list 2017
Other general information			
Regulatory system for gas transmission	Revenue Cap based on regulated Rate-of-Return with Incentive-based Regulation		
NRA	Commission for Regulation of Utilities (CRU)		
TSO	Gas Networks Ireland		

6.1 Existing and planned gas infrastructure

There is at present no operational LNG terminal in Ireland, but 2 projects are being considered. Ireland had since 2006 a gas storage facility (capacity of 230 mcm), but decided in 2016 to close it for economic reasons. The natural gas transmission network (2.433 km pipelines) is owned and operated by Gas Networks Ireland (GNI); it is connected Great Britain by an onshore pipeline system in Southwest Scotland (with an offtake to Northern Ireland) and two subsea pipelines. Ireland is at present involved in three PCIs of the same cluster.

As the domestic gas production is expected to decline, the utilization level of the import pipelines would until 2030 increase, also due to the expected phasing out of peat and coal for power generation. In order to ensure a secure and sustainable electricity supply at competitive cost and achieve 2050 emissions targets, the Irish TSOs suggest opting for CCGTs with CCS as coal and peat fuelled power plants are phased out. Natural gas with CCS would according to the TSO's study continue to play an important role in the Irish energy supply (share of 24 to 42% of gas mix in 2050, depending on the storyline), next to biomethane (42 to 56%), and hydrogen (15 to 20%). While according to our assessment, the storylines would lead to a lower (storyline 1), stable (3) or only slightly higher (2) overall gas demand, the Irish TSO assumes that the gas demand would in any storyline increase by 2050. The impact on existing and planned gas infra infrastructure would hence be different depending on the assumptions and storylines, but in any scenario the transmission network would continue to be used for increasing volumes of renewable gas.

6.1.1 Main large gas infrastructure

LNG Terminals

Currently there is no operational LNG terminal in Ireland, but two projects are being considered: the Shannon LNG project (in the west of Ireland) has been included in the third PCI list published in 2017 (see also section 6.1.2), and a Floating Storage Regasification and Unloading (FRSU) LNG project is considered in Cork harbour.

Table 6-1 Planned LNG terminal in Ireland. Source: GIE (2018), LNG Map (adjusted)

Name of installation	Investment	Max. Hourly Cap. m³ (N)/hour	Nom. Annual Cap. billion m³(N)/year	LNG storage capacity m³ LNG	Number of tanks	Max. ship class size receivable (m³ LNG)
Shannon LNG terminal	New facility	671,000	2.70	200,000	1	266,000
	Expansion	671,000	2.90 additional	400,000	2	266,000
	Expansion	1,116,000	3.40 additional	800,000	4	266,000
Cork Floating Storage Regasification and Unloading LNG terminal	New facility			174,000		

Shannon LNG

Shannon LNG has indicated an earliest possible start date of 2021 for commercial operation, assuming a resolution to a number of uncertainties and delays. Shannon LNG has received planning permission for both its proposed Liquefied Natural Gas (LNG) terminal near Ballylongford in Co. Kerry, and for the associated transmission pipeline which will deliver gas into the ROI transmission system. The initial phase will involve the construction of LNG process tanks, and re-gasification facilities with a maximum export capacity of up to 17.0 mscm/d (191.1 GWh/d).

Shannon LNG has applied for planning permission to also develop a 500 MW Combined Heat and Power (CHP) plant on its site to produce heat required to convert LNG to natural gas. The use of a CHP plant results in a substantial reduction in fuel consumption and greenhouse gas emissions compared to alternative solutions.

The terminal would operate under a Regulated Third Party Access exemption, which has been issued for 20 years by the Irish Energy Regulator and approved by the EU Commission.

Cork LNG

In 2017 GNI received a Connection Enquiry for a new LNG Entry point close to an existing AGI in Cork harbour. Port of Cork (PoC), Next Decade LNG and Flex LNG commenced investigating the potential of developing a Floating Storage Regasification and Unloading (FRSU) LNG project in Cork harbour last year. The project, known as “Innisfree FRSU LNG” is being progressed as a merchant LNG import terminal and has a potential storage capacity of 174 mscm and a daily delivery of 0.5 mscm/d to 26 mscm/d.

Gas Storage

The Southwest Kinsale[342] Gas Field (discovered in 1995) was brought on stream as a gas production reservoir in 1999 and redeveloped in October 2001 as storage for nearby offshore gas fields. In 2006 this gas field was converted to a fully-fledged offshore storage facility with a storage capacity of 230 mcm.[343] In 2016, a decision was taken to close the facility and commence the sale of the cushion gas from the reservoir.[344] The decommissioning is mainly due to worsening economics of gas storage resulting from lower price spreads between winter and summer periods. The last of the storage gas was

342 Kinsale Energy (N/A), Gas Storage.
343 1 cubic meter of gas is equivalent to about 10 kWh of energy
344 Cushion gas provided the pressure support for the Southwest Kinsale storage service

withdrawn from the reservoir in March 2017 and Southwest Kinsale currently operates as a gas production reservoir in which the remaining indigenous gas is produced. Production is expected to cease in 2020.

A new storage facility (Islandmagee Underground Gas Storage) is planned to be commissioned by 2021 in Northern Ireland. It has been selected as PCI (project 5.1.3 on PCI list 2017) and will have a gas storage capacity of 420 mcm.

Table 6-2 Gas storage facility in Ireland. Source: GIE Storage Map 2016 (adjusted)

Facility/Location	Kinsale Southwest
Status	No longer operational as a storage facility - currently in blowdown mode and due to close in 2020.
Start-up year	2006
Closing year	2017
Type	Depleted gas field
Onshore/ offshore	Offshore
Operator	Kinsale Energy
Working gas capacity (technical and TPA) TWh	2.53
Withdrawal capacity (technical and TPA) GWh/day	28.6
Injection capacity (technical and TPA) GWh/day	18.7
Access regime	nTPA

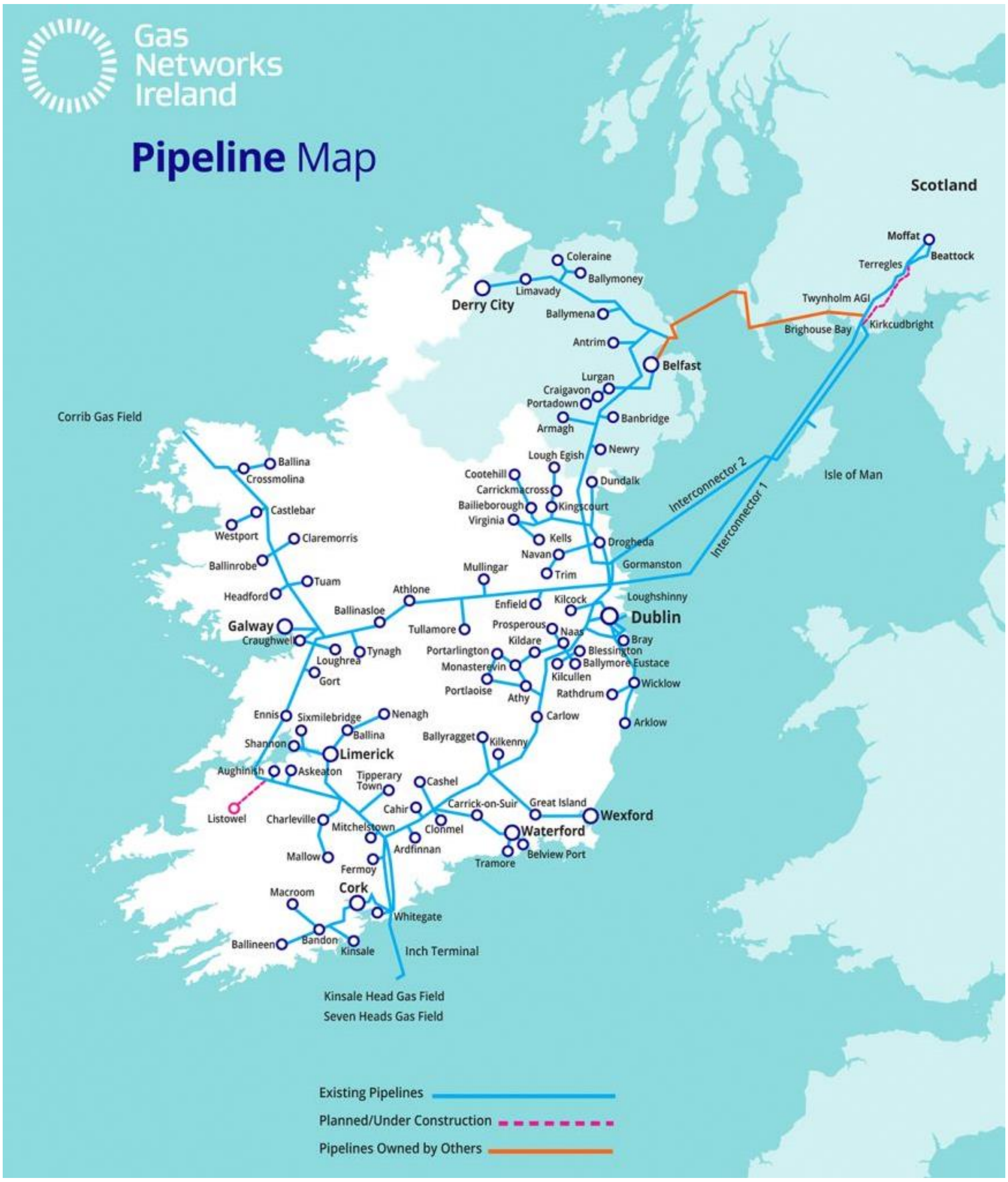
Gas transmission network

Gas Networks Ireland (GNI) owns, operates, builds and maintains the natural gas transmission network in Ireland. The transmission and distribution gas network in Ireland is 13,954 km in length, of which 2,433 km high pressure steel transmission pipelines, operating above 16 bar.

The Gas Networks Ireland transmission network includes onshore Scotland, interconnectors and the onshore Irish network. The Gas Networks Ireland network includes assets in ROI and GNI (UK) Limited own assets in NI & South West Scotland. The interconnector (IC) sub-system comprises two subsea Interconnectors between the Republic of Ireland (ROI) and Scotland, compressor stations at Beattock and Brighouse Bay, and 110 km of onshore pipeline between Brighouse Bay and Moffat in Scotland. The Interconnector system connects to Great Britain's (GB) National Transmission System (NTS) at Moffat in Scotland.

Gas Networks Ireland also supplies gas to the Northern Ireland (NI) market at Twynholm and the Isle of Man (IOM) market via the second subsea Interconnector (IC2). In 2016 Gas Networks Ireland transported over 72,000 GWh of energy through its network, which is more than double the energy carried by the electricity network (approx. 27,000 GWh).

Figure 6-1 Gas transmission in Ireland[345]



Interconnector system

Two high pressure subsea Interconnectors, IC1 and IC2 come to shore (2 physical entry points) north of Dublin. The Corrib gas field came on stream in late 2015 adding a third entry point to the system in addition to the Moffatt and Inch entry points. This has further enhanced Ireland's energy security, providing additional capacity in the network to meet the still growing demand. The Corrib entry point has also changed the operation of the interconnector system, necessitating lower and variable flows[346] as the interconnector is now the marginal source of gas supply. The prevalence of intermittent renewables, wind in particular, in the electricity system has also impacted the variability of gas flows.

345 https://www.gasnetworks.ie/corporate/company/our-network/pipeline-map/
346 Gas Networks Ireland (2017), Systems performance report 2016.

The Moffat Interconnection Point has currently a technical capacity of 31 mcm/d (342 GWh/d) and supplies gas to ROI, NI and IOM. This technical capacity is expected to increase to 35 mcm/d following the completion of the twinning of South West Scotland Onshore system (PCI 5.2). It has reliably met the systems energy demand requirements and ensured security of supply for Ireland since the construction and commissioning of IC1 in 1993. This connection to the GB National Transmission System (NTS) facilitates Ireland's participation in an integrated European energy market.

Table 6-3 Interconnection points in Ireland. Source: ENTSOG capacity map 2016

Type	*N*	*Point*	*Arc*	*Technical physical capacity (GWh/d)*	*From*	*To*	*From op*	*To op*
Cross-border IP within EU and with non-EU (export)	19	Moffat	Y-UKm>	431.7	UK	IE	National Grid Gas	GNI

6.1.2 Planned Projects of Common Interest[347]

Ireland has three projects in the third (2017) PCI list and another, which was included in the first PCI list in 2013 is nearing the end of the construction phase. They all benefit from European co-funding; there are in Ireland no specific national regulatory incentives for PCIs.

Physical Reverse Flow at Moffat interconnection point IE/UK (PCI list 2017. PCI 5.1.1)

The Moffat interconnection point is currently physically uni-directional with gas flowing from Great Britain to Ireland. This project will entail making the Moffat interconnection bi-directional. The project will involve investments in compression installations in Ireland along with 6 km of pipeline reinforcements and modifications to existing installations with a planned capacity of 38.5 GWh/d.

This project is aimed at enhancing Ireland's security of supply position acting as a key enabler for other projects such as PCI 5.3 and would encourage further investment in gas infrastructure on the island of Ireland. Physical reverse flow at the Moffat Interconnection point would also enhance market integration and competition at regional level.

GNI was allocated funding by the EU Commission for 50% of the total budget for feasibility studies for this project granted under the Connecting Europe Facility (CEF). These studies are currently ongoing and are due for completion in 2018.

Shannon LNG Terminal and connecting pipeline (PCI list 2017, PCI 5.3)

The Shannon LNG project (as described in section 6.1.1) has 2021 as earliest start date for commercial operation, assuming a resolution to a number of uncertainties and delays. Shannon LNG has received planning permission for both its proposed Liquefied Natural Gas (LNG) terminal near Ballylongford in Co. Kerry, and for the associated transmission pipeline which will deliver gas into the ROI transmission system. The initial phase will involve the construction of LNG process tanks, and re-gasification facilities with an export capacity of up to 17.0 mcm/d (191.1 GWh/d).

347 Information extracted from the PCI project fiches and implementation plans available from DG ENER's PCI interactive map: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

Development of the Islandmagee Underground Gas Storage (UGS) facility at Larne (Northern Ireland) (PCI list 2017, PCI 5.1.3)

IMSL plans to create eight caverns, capable of storing up to 420 mcm of gas.
This facility will safeguard Northern Ireland's ability to meet the increasing demand peak whilst also providing security of supply to Ireland and Great Britain. This PCI has received support from CEF for different purposes in 2014, 2015 and 2016.

Twinning of Southwest Scotland onshore system between Cluden and Brighouse Bay (PCI list 2013, PCI 5.2)

The twinning of the southwest Scotland onshore system was included in the 1st PCI list published by the EU Commission in October 2013, and is supported by CEF-funding (€33,764,185). The balance of the funding is provided through a national regulatory allowance (usual regime).

The second Scotland to Ireland Gas Interconnector is an important project for the Irish economy as it reinforces security of energy supply across Ireland and the UK, facilitating the transport of additional gas supplies from Beattock, South West Scotland, to Gormanstown in Co. Meath. Phase one of this project, a 29.6 km pipeline was constructed between Beattock and Brighouse Bay in 2002. Gas Networks Ireland is now undertaking phase 2, which consists of constructing the remaining 50 km of gas pipeline from Brighouse Bay to Cluden in Scotland.

The construction commenced in 2017 and the project is scheduled for completion in 2018. This project will result in a fully twinned pipeline between Beattock and Brighouse Bay compressor stations and an entire dual interconnector sub-system between Great Britain and Ireland. It will secure this vital link to the UK gas market, and will also boost the operational flexibility of the Irish gas network which is essential to providing backup to intermittent renewable electricity generation.

6.1.3 Estimated impact of the storylines on Irish gas infrastructure

The table below provides a qualitative overview of the impact of the three selected storylines on the existing and planned gas infrastructure in Ireland.

Table 6-4 Impact of storylines on Irish large gas infrastructure. Source: Own assessment

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane			Storyline 3 Strong development of hydrogen		
Gas demand 2015 in Ireland	50 TWh			50 TWh			50 TWh		
	Natural Very high	Methane Negligible	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Negligible
Evolution gas demand 2030[348] according to our study	Decrease			Increase			Stable		
	Natural Very high	Methane Low	Hydrogen Negligible	Natural Very high	Methane Low	Hydrogen Negligible	Natural Very high	Methane Negligible	Hydrogen Low
Evolution gas demand 2050	Decrease			(High) Increase			Stable		
	Natural Negligible	Methane Medium	Hydrogen High	Natural Negligible	Methane Very high	Hydrogen Low	Natural Negligible	Methane Low	Hydrogen Very high

348 Future gas demand will increasingly be covered by local production of renewable gas, partly locally used and partly injected into the distribution or transport grid. The volumes to be transported by the transmission grid will hence be lower than the overall gas demand.
Note that the evolution in Ireland is expected to be different due to national specificities, in particular substitution of peat and coal with gas for power generation, declining domestic gas production and high national potential of biomass.

	Storyline 1 Strong electrification	Storyline 2 Strong development of carbon-neutral methane	Storyline 3 Strong development of hydrogen
Specificities in Ireland	Peat and coal is replaced by gas for electricity production => positive impact on gas demand, at least until 2030.	High potential for biomethane generation in Ireland will be gradually exploited.	Hydrogen using SMR with CCS. Initially using distribution network.
Impact on planned LNG terminals	No existing LNG terminal, hence no impact. New LNG import capacity could in this storyline be used to cover gas demand for power generation by new CCGTs with CCS.	No existing LNG terminal, hence no impact. New LNG terminals could in this scenario be used to trade liquefied biomethane via ocean tankers.	No existing LNG terminal, hence no impact. New LNG import capacity could in this storyline be used to import gas required to feed SMR plants for hydrogen production. New hydrogen terminal could possibly also need to be built.
Impact on planned gas storage	No existing/planned gas storage, hence no impact. New hydrogen storage might be needed for seasonal storage and/or short term balancing purposes.	No existing/planned gas storage, hence no impact. New biomethane storage might be needed for seasonal storage and/or short term balancing purposes.	No existing/planned gas storage, hence no impact. New hydrogen storage might be needed for seasonal storage and/or short term balancing purposes.
Impact on transmission network & import pipelines	Import pipelines would in medium term continue to be utilised, up from current levels possibly, as national production declines. Transport pipelines might require upgrade for reverse flow; existing PCIs are key enablers. Reclassification from methane to hydrogen pipelines may be required for some pipelines. However, hydrogen likely to be at distribution level initially using SMR with CCS to produce hydrogen at city gate locations	Gaseous biomethane imports via pipeline are possible option to replace declining domestic gas production. Existing import pipelines could be used for this purpose. Investments would be needed to connect methane refuelling stations.	Import pipelines would in medium term continue to be utilised, up from current levels possibly, as national production declines. Transmission network might need to be refurbished for H2. However, hydrogen likely to be at distribution level initially using SMR with CCS to produce hydrogen at city gate locations.

***Note**: The overall gas demand is compared to 2015 levels, and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease -5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The changes in gas shares were categorised as follows: 76%-100%= **'very high'**; 51%-75%= **'high'**; 26%-50%= **'medium'**; 6%-25%= **'low'**; 0%-5%= **'negligible'**.*

Gas Networks Ireland and Eirgrid have developed long-term gas demand forecasts as part of a resilience study in relation to the gas and electricity networks. This study is being carried out at the request of the Department of Communications Climate Action and the Environment (DCCAE). The table below provides an overview of the resulting gas demand under the 3 storylines. Contrary to the expected trends at EU level, gas demand would, according to this source, in Ireland further increase until 2030 in each storyline, and would only in storyline 1 slightly decrease after 2030.

Table 6-5 National assessment of the impact of storylines on Irish demand. Source: GNI/Eirgrid, bilateral communication

	Storyline 1 Strong electrification			Storyline 2 Strong development of carbon-neutral methane			Storyline 3 Strong development of hydrogen		
TWh Gas demand - 2030	62			70			70		
	Natural 66% (8% CCS)	Methane 19%	Hydrogen 15%	Natural 66% (7% CCS)	Methane 19%	Hydrogen 15%	Natural 61% (7% CCS)	Methane 19%	Hydrogen 20%[349]
TWh Gas demand -2050	58			70			70		
	Natural 42% (26% CCS)	Methane 43%	Hydrogen 15%	Natural 29% (21% CCS)	Methane 56%	Hydrogen 15%	Natural 24% (21% CCS)	Methane 56%	Hydrogen 20%

349 Assuming Cork area is a Hydrogen network, Cork accounts for about 15% of overall demand in Ireland, with 15% blending at distribution level on a national basis. The distribution sector accounts for about 30% of gas demand.

6.2 Main national developments that influence investments in and use of gas transport infrastructure

Natural gas is in Ireland the dominant energy vector for electricity generation (48% in 2016) and in the overall energy demand (30% share). From 2005 to 2016 natural gas demand has increased by 22% (50 TWh in 2016). Notwithstanding the impact of energy efficiency policies, the gas demand in Ireland is expected to grow by 12.5% in the coming 10 years. The natural gas demand was in 2016 covered by indigenous production (60%) and imports (40%). The domestic production is however expected to gradually decline in the near future.
Ireland has ambitious policies and targets for renewable energy (40% RES-E by 2020), and disposes of a large biogas potential, which could cover 28 to 50% of its current gas consumption. In 2018, a specific support scheme for Renewable Heat will be implemented to replace fossil fuel-based heating systems with renewable energy technologies. This support mechanism, along with enabling grid connection conditions recently approved by the NRA and a specific certification scheme for renewable gas which is currently being developed in Ireland, will stimulate the deployment and injection of biomethane into the grid.

6.2.1 Gas supply and demand

Current gas demand

Natural gas plays a significant part in the Irish economy, providing in 2018 about 30% of total primary energy demand[350] (gas demand 2016 = 4,231 ktoe). Over the period 2005 – 2016, natural gas use increased by 22% (1.8% per annum in average). Natural gas remains the dominant fuel in electricity generation; its share fell from a peak of 61% in 2010 to 42% in 2015, but it rose to 48% in 2016 (gas demand 2016 for power generation = 2.334 ktoe), and it remains crucial to ensuring security of electricity supply.

The increase in gas demand from 2005 to 2016 can mainly be attributed to economic growth and increasing gas demand for electricity generation. Despite the growth in wind capacity, gas fired power generation has risen due to increasing electricity demand and in particular increasing electricity exports to Great Britain (GB). This is a result of the Carbon price floor introduced in GB which was raised to €20.55 per ton CO_2 in April 2015.

The total amount of natural gas transported through the Irish gas network by Gas Networks Ireland was 55,110 GWh in 2016. Daily average gas transported amounted to about 151 GWh, while peak day transported volume raised to 225 GWh.[351]

Evolution of gas demand

Notwithstanding the impact of energy efficiency policies, the overall gas demand in Ireland is expected to grow by 12.5% in the coming 10 years. The projections presented hereafter are based on GNIs' 10 years Network Development Plan (NDP) 2017, which covers the period up to 2026. GNI has developed three gas demand scenarios for the purposes of its NDP; these are low, median and high demand scenarios. The projections presented hereafter are based on the median demand scenario.

350 Gas Networks Ireland (2018), Meeting Ireland's targets under the 2020 Climate and Energy Package
351 Gas Networks Ireland (2017), Systems performance report 2016.

Electricity generation

As described above, the gas demand for electricity generation has risen substantially mainly as a result of increased electricity interconnector exports to GB. It is expected that the balance will remain in favour of exports to GB in the short to medium term. However, the trend will gradually swing back in favour of imports from GB to Ireland in the longer term (mid 2020's), as carbon prices under the ETS are expected to rise. An increase in gas demand for power generation is however expected in the medium term with the growth in wind capacity levelling off somewhat and with two peat fuelled power plants coming off Public Service Obligations in 2020. The Kilroot coal plant in Northern Ireland will also be subject to the Industrial Emissions Directive (IED) restrictions from July 2020 and as a result its run hours will be limited. The North-South electricity interconnector will also be complete by the end of 2020 which should lead to an increase in Ireland's gas demand due to the removal of the existing physical constraint[352] on the electricity transmission network between Ireland and Northern Ireland. Over the considered time horizon, gas demand growth of 13.9% is predicted in the power generation sector by 2025/26.

Industrial and commercial sector gas demand

Industrial & Commercial (I/C) sector gas demand is assumed to continue to increase in line with the economic growth and additional I/C connections to the gas grid, which will outweigh the impact of energy efficiency measures. The I/C sector demand to 2025/26 is expected to grow by 9.6%.

Gas Networks Ireland has identified data centre demand and CHP as two key areas for gas demand growth, and has developed a combined offering of natural gas, renewable gas and combined heat and power (CHP), as a sustainable and efficient energy solution for the data centre sector.

Residential gas demand

In the residential sector, gas demand is expected to remain stable until 2025 with growth in new grid connections balanced by energy efficiency measures. The new connections projections are based on the observed fuel switching in the housing sector. Gas Networks Ireland aims to increase fuel switching for individual houses located in close proximity to the gas network, from more carbon intensive fuels such as oil or solid fuels to natural gas. It is estimated that there are over 700,000 households in Ireland using oil for central heating and 300,000 of those have a gas network nearby and could be readily connected to gas. This would result in a more energy and cost-effective heating solution for the consumer and significant benefits from an environmental perspective. The growth strategy also intends to capture new gas estates i.e. housing estates which are currently not connected to the gas network but are located in close proximity. As a result, Gas Networks Ireland expects to connect circa 125,000 new domestic customers to the gas network over the next ten years.

Gas in the transport sector

Gas Networks Ireland is undertaking a European funded project called the Causeway Study and will roll out 14 high capacity fast CNG filling stations and a renewable gas injection point as part of this project. The 14 CNG units will be located along the TEN-T (Trans European Transport Network) Core Road Network and represent the minimum number of publicly accessible stations required to develop CNG on a national basis. The Causeway project received approval for €6.5 million of co-funding from European Commission's Connecting Europe Facility. The CRU approved €12.83 million of innovation allowances to

[352] The wholesale electricity market in Ireland (the Single Electricity Market) covers both Republic of Ireland and Northern Ireland, however there is currently limited interconnection between the two jurisdictions.

fund the balance of the overall requirement. The study aims to examine the impact of increased levels of fast fill CNG stations on the operation of the transmission and distribution gas networks in Ireland. Activities will encompass developing an understanding of the operation and planning of the network, CNG equipment, CNG user demand patterns and behaviours, and the injection of renewable gas into the gas transmission system.

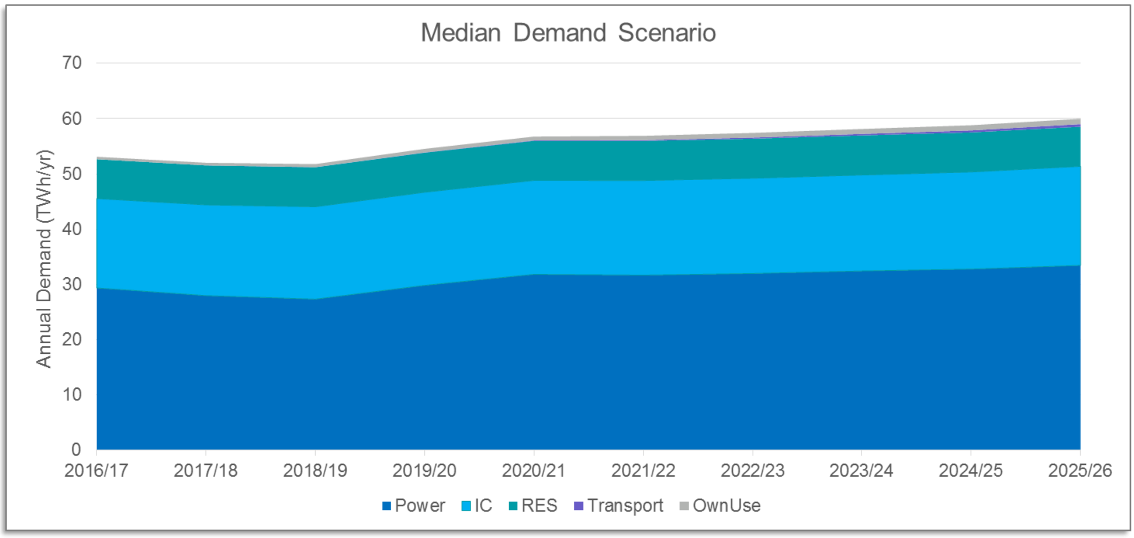
The first public station in the rollout programme is due for completion in 2018 at the Topaz Dublin Port service station. This will be quickly followed by other key strategic locations on the motorway network. In the longer-term Gas Networks Ireland is proposing to develop a 70-station CNG fuelling network by 2025, targeting 102 stations by 2030. Gas Networks Ireland is currently targeting at least 5% penetration of CNG or renewable gas for commercial transport and 10% of the bus market in Ireland by 2025, with demand of up to 700 GWh on an annual basis.

The National Mitigation Plan (NMP)[353] was published in July 2017 and includes an action to continue to encourage the adoption of natural gas as a cleaner transport fuel by maintaining the excise rate applied at the minimum level allowable under the Energy Taxation Directive. The National Mitigation Plan also highlights the 14 fast filling stations to be delivered as part of the Causeway study as a key initiative.

Aggregate gas demand

According to this scenario developed by GNI, the aggregate annual gas demand across the electricity generation, industrial & commercial, residential and transport sectors is expected to grow by 12.5% between 2016/17 and 2025/26 as shown in Figure 6-2.

Figure 6-2: Gas Demand projections by sector



The Sustainable Energy Authority of Ireland (SEAI)[354] also forecasts an increasing gas demand in the short and medium term:

- **Up to 2020:** Natural gas grows significantly in all scenarios primarily driven by increasing electricity demand.[355] Ireland continues the recent trend of being a net electricity exporter.

[353] DCCAE (2017), National mitigation plan.
[354] SEAI (2017), Ireland's energy projections.
[355] Coal combustion to generate electricity continues to make up a sizable proportion of fuel use. Peat declines as policy support for burning peat in electricity generation ends in 2018.

Natural gas is projected to surpass oil for residential heating applications by 2023, as a result of more residential buildings in areas serviced by the gas grid;

- **Post 2020:** There is strong growth in electricity and transport energy demand. These trends have implications for fuel use with continuing dependence on oil and an increase in the share of natural gas in total energy consumption. Coal use will drop significantly should Moneypoint power station close at the end of its useful lifetime (assumed to be 2025). More natural gas will be combusted to meet the electricity demand previously supplied by coal generation, and due to increasing demand from a larger housing stock and more industrial applications.

Gas supply

Ireland's natural gas comes from both indigenous production and imports. The indigenous resources include gas fields at Kinsale and Corrib.

The Corrib gas field commenced production in December 2015. In 2016 Corrib production accounted for approximately 55% of the overall gas demand. This production is however expected to decline. The Kinsale production field covered in 2016 6% of gas demand, and 40% of the 2016 gas consumption was imported into Ireland via the Moffat interconnector with Scotland.

Ireland's gas system and market are heavily interconnected with those of the UK. While Great Britain currently supplies 40% of Ireland's gas demand, this has historically been as high as 92%. In turn, 100% of the gas supplies to Northern Ireland and the Isle of Man are delivered through Gas Networks Ireland's network in Scotland. GB's import capacity is currently around 152 bcm/year, split into three sources: Norway (56 bcm/year), the Continent (46 bcm/year) and LNG (49 bcm/year). With a demand of less than 90 bcm in 2016, this implies that there is in GB ample import capacity over and above domestic demand for transit to Ireland.

Security of gas supply

Ireland's reliance on imported gas has significantly reduced with the coming ashore of indigenous gas from Corrib. Imports from Great Britain via the Moffat Interconnection Point remain the key source of gas supply for Ireland (40% in 2016). In the medium term the Moffat Entry point will re-emerge as the dominant source of gas supply when the Corrib production will decline.

The previously approved PCI project (PCI 5.2) Twinning of the South West Scotland Onshore system, will enhance security of supply to the island of Ireland. This project is due to be completed in gas year 2017/18. Further work is required to allow the interconnectors to be operated as two fully independent interconnectors; this work will be completed by 2021 and will significantly improve the Irish security of supply position.

Gas Networks Ireland is looking to develop indigenous bio-methane for gas grid injection which will help diversify gas supplies and enhance the security of supply position (see section 6.2.2 for further details). Gas Networks Ireland and Eirgrid are currently engaging with the Department of Communications, Climate Action and Environment in undertaking a resilience study in relation to the gas and electricity networks, the purpose of which is to identify options and to make recommendations, in order to ensure that Ireland is resilient to a gas/electricity disruption for an extended period of time. The overall objective is to inform the formulation of future policy measures to maintain the resilience of Ireland's gas and electricity networks and supply.

The gas infrastructure in Ireland is in general well developed and ensures a high level of supply security, particularly with the Shannon LNG terminal potentially coming online. However, Shannon LNG has indicated an earliest possible start date of 2021 for commercial operation, assuming a resolution to a number of uncertainties and delays. Given that global LNG capacity is expected to grow strongly to 2020, an LNG terminal would further enhance Ireland's security of supply position.

If the planned LNG terminal would effectively become operational, the supply sources would be further diversified, and the physical import and transmission capacity would be robust enough to withstand the temporary unavailability of a large system component or gas source.

6.2.2 Renewable energy policy and targets

Ireland has excellent renewable energy resources, which will be a growing component of its energy supply, and will have a major impact on natural gas demand. Under the 2009 Renewable Energy Directive, Ireland is committed to reach a RES share of 16% of all energy consumed in 2020. This is expected to be met by 40% from renewable energy based electricity, 12% from renewable energy for heating/cooling and 10% from renewable energy in the transport sector. The target to have 40% of electricity consumed from renewable sources by 2020 is one of the most demanding in the EU.

The Government White Paper "Ireland's Transition to a Low Carbon Energy Future, 2015-2030" envisages a shift away from more carbon-intensive fuels, like peat and coal, to lower-carbon fuels like natural gas in the short to medium term.

In 2016, 6.8% of the energy used for heating purposes was renewable. A specific support scheme for Renewable Heat has been designed to replace fossil fuel-based heating systems with renewable energy technologies. This scheme is made up of two support mechanisms; an on-going operational support and a grant. Funding of €7 million was provided for the initial stage of the scheme in Budget 2018. This new support scheme is expected to start in 2018, subject to European Commission State aid approval.

Renewable gas

A recent EU Commission report (Optimal use of biogas from waste streams)[356] identifies Ireland as having the largest potential of renewable gas production per capita in the EU, with a potential of 13 TWh national production by 2030. This would equate to more than 20% of the current gas demand. Furthermore, a report assessing the theoretical potential for biomethane published by the SEAI[357] found that the potential could be as high as 28% of current gas demand.

Renewable gas offers substantial environmental and socioeconomic benefits, particularly for Ireland. It can make a significant contribution to the decarbonisation of the agricultural sector, while also increasing and diversifying farm incomes through the development of better farming practices such as organic farming and enhanced soil sequestration through the efficient management of digestate and catch crops. The development of a renewable gas industry can create over 8,000 jobs in Ireland. These jobs would have significantly less leakage potential than alternative technologies and will be primarily based in rural locations.

[356] EC (2016), Optimal use of biogas from waste stream: An assessment of the potential of biogas from digestion in the EU beyond 2020.
[357] SEAI is Ireland's national sustainable energy authority. https://www.seai.ie/about/

Biomethane can be produced from many indigenous feedstocks. Ireland can theoretically produce 81% of its current gas demand from grass silage and cattle slurry alone. Several other sustainable feedstocks are available such as food industry wastes, poultry litter, pig slurry, catch and rotation crops, future gasification of woody residues and Power to Gas, which means that Ireland has the resource potential to become a net exporter of renewable gas.

Sustainable sources of grass silage represent a significant element of the potential. Teagasc[358] conservatively estimates that approximately 33% of the grassland is under-utilised in Ireland. The productivity on this land bank could be improved by producing additionally 6.83 million tonnes of Dry Matter, which, if converted to biomethane, could produce 28.1 TWh/annum (about 50% of current gas demand). This represents over 50% more productivity than could be achieved by converting this land to forestry, without the expense, time, and permanent land use change.
Higher efficiency output could be achieved by co-digestion with cattle/pig slurry. In addition, the bio-fertiliser output from anaerobic digestion would greatly assist decarbonisation of slurry based GHG emissions and pollution, while also improving soil, water and air quality.

When considering the volumes of renewable gas achievable, GNI is confident that a figure of between 11.5 TWh and 13 TWh is realistic by 2030, equivalent to approximately 20% - 25% of current demand (2017). The theoretical feedstocks for biomethane are estimated to be able to produce 49 TWh (this encompasses all current feedstocks including waste) by 2050 and GNI is assuming that 80% of this potential can effectively be realised (39.2 TWh).

Gas Networks Ireland is involved in a project to install the first renewable gas injection facility in Ireland with Green Generation in Co. Kildare. The Network Entry Facility for this project is designed to inject up to 1,200 m^3/hr of renewable gas (108 GWh/annum) and will act as a template for following project designs. GNI has the intention to construct six injection points over the next five years with a total combined annual capacity of 1,450 GWh.[359]

The current re-cast draft of the EU Renewable Energy Directive provides for clear recognition of renewable gas and associated Guarantees of Origin for supply of renewable gas via gas grid systems. A key requirement that comes with this recognition is for a robust Green Gas Certification scheme and service. A certification scheme for renewable gas is currently being developed in Ireland. Green Gas Certificates will allow end users to purchase renewable gas in confidence and give government and regulators the certainty that the sales of renewable gas are transparent and accounted for. The scheme will be the first of its kind in Ireland.

In order to facilitate the connection of renewable natural gas facilities to the gas grid, the CRU has decided (CRU reference 18089 of 16 May 2018) that the following rules will apply:

- The economic viability of renewable natural gas connections will be assessed and recovered over a ten year period;
- Financial security will be required for seven years;
- The existing connection charges as outlined in the GNI Connections Policy will apply for renewable natural gas facilities;

358 Teagasc is the state agency providing research, advisory and education in agriculture, horticulture, food and rural development in Ireland. https://www.teagasc.ie/
359 Ervia (2017), Annual report and financial statements 2016.

- Renewable natural gas facilities will pay a 30% upfront connection cost with the remainder recouped over ten years.

Hydrogen and synthetic methane

The gas network can transport renewable low or carbon free gas and, as happened before, the gas it transports can be changed within certain limits, taking into account the characteristics of the end-user appliances. Before natural gas became available, the gas networks transported town gas which comprised circa 50% hydrogen. The experience gained in this previous conversion may be utilised by the gas industry. The potential of hydrogen is currently being considered In Ireland, as its gas distribution networks are of polyethylene materials which are assumed to be compatible with hydrogen.

Hydrogen has the potential to assist in significantly decarbonising Ireland’s heating needs by 2050 in these three ways:

- Methanation: combining carbon dioxide from anaerobic digestion with hydrogen to produce methane. This may supplement existing biomethane volume proposals;
- Blending: hydrogen can be blended with methane (natural gas or biomethane) to a level where it can be used by existing appliances;
- 100% hydrogen: the gas distribution networks can be converted to supply 100% hydrogen. This would be a fully decarbonised gas that requires the replacement of end-user appliances.

Each of these potential decarbonisation pathways is under consideration with international developments being monitored.

Hydrogen/natural gas blends are to varying degrees common in continental Europe already reducing the carbon content of the gas supplied. More locally Cadent, the largest UK gas distribution network operator, is leading a project at Keele University testing the private network and appliances present at blends of up to 20% hydrogen. This is overseen by the Health and Safety Executive in the UK and is intended to inform changes to gas specifications and regulations that facilitate lower carbon gases through blends.

The most prominent project evaluating the potential for 100% hydrogen is the UK’s Northern Gas Networks Leeds H21 project. In the first phase it concluded that it was feasible to convert the city of Leeds to 100% hydrogen using the existing gas distribution network. More ambitious proposals for converting the North of England and national plans are under development. The UK Government has invested circa €40 million into research on hydrogen appliances and network suitability through OFGEM and BEIS.

The Leeds project and other heat decarbonisation studies highlight the high costs and disturbance associated with heat electrification and instead put forward hydrogen as a lower cost and less disruptive alternative that overcomes security of supply concerns.

Ervia is currently progressing a study on the potential for hydrogen in Ireland. This is initially based on the conversion of Cork City as it is adjacent to the proposed CCS facility utilising the Kinsale gas fields for capturing carbon dioxide should steam methane reforming be used for hydrogen production. The Leeds H21 study is being used as a template to produce detailed costings, evaluating the distribution network capacity and determining production and storage requirements. In common with the Leeds H21 project it would be proposed that the transmission network would continue to supply methane (natural gas) with hydrogen production locally. However, Ireland would most likely differ to the UK in the extent of its use of hydrogen given its significant biomethane potential.

Carbon Capture and Storage

Gas fired power generation currently provides over 50% of Ireland's electricity needs. Significantly it provides the flexibility to allow for intermittent wind power to operate on the system. Ervia is currently investigating the potential for a large CCS project in Ireland to capture the CO_2 from a number of gas-fired CCGT power plants so that they provide clean electricity. Very early initial findings show that CCS is technically and economically viable for Ireland and over the next few years Ervia will progress an early pre-feasibility study into the technology for Ireland.

The Irish Government's National Mitigation Plan[360] recognises that "CCS could facilitate decarbonisation of the electricity sector while allowing an appropriate level of gas fired generation to balance intermittent renewable generation". The Government has also set an action to carry out a feasibility into utilising suitable CO_2 storage sites stating that "within the next five years and in advance of the subsequent NMP, a feasibility study should be undertaken to determine the potential application of CCS in Ireland in the future".

6.2.3 Gas market integration and competition

The gas systems in the Republic of Ireland, Northern Ireland, Isle of Man and Great Britain are interconnected. Ireland is connected to Great Britain through two separate subsea interconnector gas pipelines and to Northern Ireland via the South North pipeline. The operation of the gas interconnectors is governed under the Ireland / UK inter-governmental gas treaty signed in 1993.

Thanks to the well interconnected gas system, the Irish gas market is well integrated with the neighbouring gas markets in Northern-Ireland and Great-Britain. There are in general no physical bottlenecks (congestion), and wholesale prices are well aligned (adjusted accordingly for incremental gas transport costs) in Great-Britain, Northern Ireland and Ireland. Although Ireland is now primarily supplied by indigenous gas sources, the wholesale price has continued to be set by reference to the wholesale price at the National Balancing Point (NBP) trading hub in Britain.[361] There is hence no need for new investment projects in large gas infrastructure to enhance market integration and/or competition.

6.2.4 Environmental and climate related regulation and measures

Gas Networks Ireland is legally obliged to monitor the technical and environmental performance of its system, including its GHG emissions. In addition, maintenance and calibration policies are in place for all meters and instruments, whilst maintenance policies are in place to prevent leakage and minimise venting of gas. In 2016 there were 6 publicly reported escapes of gas in transmission infrastructure with no major line breaks leading to leakage.[362] Gas Networks Ireland has engaged with Marcogaz in completion of CH_4 survey and estimation of emissions for the GNI transmission system.

360 DCCAE (2017), National mitigation plan.
361 CRU (2017), Electricity and Gas Retail Markets Report Q3 2017.
362 Gas Networks Ireland (2017), Systems Performance Report 2016.

Methane emissions monitoring is currently in place for compressor stations. Compressor station projects and potential upgrades are currently under review which will look at a suite of options with aim of reducing CO, CH_4 and NOx. GNI is also considering operational measures aimed at reducing methane emissions including reviewing the period of time within which venting/depressurisation is required after a compressor shutdown; currently this is four hours. Continuous improvement plans also required as part of compressor station permits.

In order to mitigate against leakage and fugitive GHG emission from pipeline damages, Gas Networks Ireland operate a comprehensive third-party damage prevent programme. Under Irish Standard IS328 and the TSO Safety Case, Gas Networks Ireland is responsible for ensuring that the transmission pipeline network is suitably marked to reduce the risk posed by third party activity in the vicinity of the pipelines. Since 2011 Gas Networks Ireland has developed policies and procedures in accordance with legislative requirements and in line with EU best practise

Projects and upgrades underway which will reduce CH_4 emissions including boiler upgrades and a cast iron replacement programme. Gas Networks Ireland has put in place a policy for replacement of grey cast iron pipes with polyethylene pipes (PE). To date there is a negligible amount of cast iron main pipelines in Ireland as a result of the policy and is resulting in a higher safety level, less greenhouse gas emissions, cost savings due to reduced gas losses and lower repair costs.

The Irish Department of Communications, Energy and Natural Resources produced a White Paper on energy in 2015, with aims to cut current dependence on fossil fuels from current 90% energy consumption to 19-30% of final energy demand by 2050.[363]

6.2.5 Overview of impact of non-gas demand drivers on Irish gas infrastructure

Table 6-6 Non-gas demand drivers for investment in and use of large infrastructure for Ireland

Policy objective	Issue	Impact on Irish gas infrastructure
Evolution in supply Security of supply	Access to diversified supplies and flexibility resources	Development of LNG terminal and gas storage is envisaged High share of domestic production (will decline in medium term) Access to pipeline gas via GB
	Security of supply	Import and network capacity is sufficient to cope with current and expected gas demand evolution
	N-1 Infrastructure standard	Completion of the Twinning of the Southwest Scotland Onshore System (PCI 5.2) will allow the interconnector system to be split into two separate systems, significantly improving Ireland's N-1 infrastructure standard.
Climate / Environment	Back-up of intermittent RES capacity	Ireland plans large expansion of intermittent power generation capacity, particularly wind energy. Gas is essential for back-up (Ireland does not have nuclear power).
	Biogas/biomethane development	Development/injection of biomethane has started. Large potential: over 40% of gas demand according to TSO assessment. No need to refurbish gas network/appliances
	Hydrogen development	Feasibility and impact assessment studies ongoing. Primary production likely to be Steam Methane Reforming of natural gas and potentially biogas with carbon neutral methane. Power to Gas also feeding into Hydrogen Networks

[363] DCCAE (2015) Ireland's Transition to a Low Carbon Energy Future 2015-2030.

Policy objective	Issue	Impact on Irish gas infrastructure
	Substitution of fossil fuels	Substitution of more carbon intense peat and coal for power generation with gas. Ireland's National Development Plan 2017[364] commits to the end of coal burning by 2025. Support for peat energy in Ireland is due to end in 2030.[365]
	Carbon Capture & Storage	Gas fired power plants and large industry with CCS, storing CO_2 in depleted offshore gas field.
	Compressed Natural gas / biomethane for transport	Substitution of oil products with CNG in transport sector, initially from natural gas transitioning to more and more renewable bio-methane over time.
	Environmental regulation	Maintenance/investments needed to reduce/prevent CH_4 leakages. These are currently being progressed.
Competitiveness / market development/market integration	Market integration	Irish gas system is well interconnected with neighbouring countries, no further cross-border capacity expansion needed Planned reverse flow project (PCI) will improve integration
	Enhance competition	Irish gas market is properly functioning, no infrastructure investments needed to enhance competition

364 DCCAE (2018), Minister Denis Naughten announces Ireland to join Powering Past Coal Alliance.
365 Bord na Mona (2017), Annual report 2017. & http://ireland2050.ie/past/peat/

6.3 Assessment of the impact of the storylines on the Irish TSO

Gas Networks Ireland owns and operates the Irish gas transmission (and distribution) network.
GNI's Regulatory Asset Base related to its transmission assets, is currently valued at approximately €1.4 billion. The RAB is expected to depreciate by up to €500 million by 2030 excluding incremental additions, and would as of 2040 significantly reduce.
GNI's revenues, OPEX and CAPEX allowances are set every 5 year by the regulator.
In 2017, gas transmission OPEX amounted to €86.4 million; in the future a decrease is expected in line with the cost efficiency targets imposed by the NRA. However, deployment of CCS and H2 in Ireland may have an increasing impact.
The current annual investment level in transmission assets is € 47.2 million, of which €19.1 million was in 2016 spent for maintenance. Capital expenditures will in the future be more focused on replacement rather than on expansion of the network.
The total costs for the "traditional" gas networks would decrease in the medium and long term; in storylines 1 and 3 however, this reduction would be balanced out by incremental costs to accommodate the grid for H2 transport.
As the TSO has regulated revenues based on its 'authorised' costs, storylines 1 and 3 would have a negative impact on the gas tariffs. The risk for stranded gas assets is in Ireland limited as it does not have LNG terminals or gas storage facilities, while its gas network is expected to be further used in the 3 storylines.

6.3.1 Key financial indicators: Gas Networks Ireland (GNI)

General data for GNI in 2016		Unit	Source
Infrastructure			
Gas network (transmission & distribution)	13,954	km	ERVIA (2017)[366]
Gas network (transmission)	2,427	km	Gas Networks Ireland (2017)[367]
LNG Terminals	0	bcm	GIE LNG map
Storage	0	bcm	GIE Storage map
Compressor stations	3	Units	Gas Networks Ireland (2017)
Entry Points	3	Units	Gas Networks Ireland
Transport volumes			
Transported gas[368]	72.5	TWh	ERVIA (2017)
Transported gas in Irish network	55.1	TWh	Gas Networks Ireland (2017)
Daily average gas transported	151	GWh	
Peak day gas transported	225	GWh	
Investments			
Investment transmission & distribution	125	M EUR in 2016	ERVIA (2017)
CAPEX transmission[369]	236	M EUR/5 years	CRU (formerly CER)[370]
RAB			
Transmission	1.4	bn EUR	Communication GNI
Revenues			
Gross revenue	498	M EUR	ERVIA (2017), Gas Networks Ireland (2017)
Operating profit	194	M EUR	
Profit before income tax	146	M EUR	
EBITDA	323	M EUR	
Shareholders			
State owned as part of the Ervia multi-utility company			

366 Ervia (2017), Annual report and financial statements 2016.
367 Gas Networks Ireland (2017), Systems performance report 2016.
368 Gas transported through the gas network for Ireland, Northern Ireland and the Isle of Man (supplied through the Moffat Interconnector and the Corrib and Inch gas fields. Of this 76% was delivered for use in the Republic of Ireland with the remaining 24% transported to the Isle of Man and to Northern Ireland.
369 Transmission CAPEX allowed under the 4th Price control
370 CER (2017), CER Information Note: GNI Allowed Revenues for PC4 (From 2017 to 2022).

6.3.2 GNI as part of ERVIA group

Gas Networks Ireland owns and maintains the Irish transmission and distribution gas network (comprising 13,954 kilometres of gas pipelines, including two sub-sea interconnectors). The transmission (onshore and offshore) pipelines link Ireland's major urban areas and also connect Ireland to the UK. Power stations and large Industrial customers are also directly connected to the transmission network.[371]

GNI (UK) Ltd

A wholly-owned subsidiary of Gas Networks Ireland, GNI (UK) Ltd, operates and partly owns the high-pressure pipelines running from Moffat in Scotland to Ireland and the Isle of Man, via subsea pipelines which supply the Republic of Ireland, Northern Ireland and Isle of Man. It also owns and operates two pipelines in Northern Ireland, the South North pipeline running from Gormanston in Co.Meath to Co. Antrim and the North West Pipeline running from Carrickfergus to the Coolkeeragh power station. GNI (UK) is regulated by the Commission for Regulation of Utilities (CRU) in relation to the Republic of Ireland network, the Utility Regulator in relation to Northern Ireland and Ofgem in relation to the UK.

In relation to Northern Ireland, GNI (UK) owns and operates a high-pressure transmission system consisting of 295 km of pipelines and 18 Above Ground Installations (AGIs). Since 2002, €177 million has been invested in this transmission network. In October 2017, a new "single system operator" model went live under which the shipper/market activities of all the transmission network operators in Northern Ireland were consolidated into a single team going forward that administers a single code and related shipper interactions on behalf of GNI (UK) and the other three TSOs in Northern Ireland.

6.3.3 Possible evolution of RAB

GNI's Transmission RAB (Regulated Asset Base) is currently valued at about €1.4 billion. For the current price control period, GNI will earn revenues that cover the depreciation costs of the RAB plus a return on the asset base of 4.63% per annum which has been assessed to the weighted average cost of capital (WACC) by CRU for the current regulatory period (Oct 2017 to Sept 2022). The asset base is adjusted each year by the HICP index relevant to the year to reflect the real replacement cost of the assets. The transmission RAB will depreciate by up to €500 million by 2030 excluding incremental additions, and will start to significantly reduce after 2040. Capital expenditures will in the future be more focused on replacement rather than on expansion of the network.

6.3.4 Possible evolution of OPEX & CAPEX

GNI's revenues, OPEX and CAPEX allowances are set every 5 year by the regulator. Currently GNI is in its fourth regulatory period (PC4) which will run until September 2022.

Operating expenses and capital costs are expected to increase during the current tariff control period as GNI aims to increase its asset and revenue base by realising new connections to its grid and by supporting the transition to a low carbon economy by reducing the use of high carbon fossil fuels (peat and coal).

Operating costs

Transmission Operating costs in 2017 were €86.4 million in Gas Networks Ireland.[372] In setting the operating cost allowances for the next 5 years the regulator has taken into account increasing standards

371 Gas Networks Ireland (2017), Systems performance report 2016.
372 Ervia (2017), Annual report and financial statements 2016.

and requirements to maintain the network where components are aging and need replacing or increased maintenance. The overall profile of operating costs for the Transmission for the next 5 years is downward in real terms as the regulator has imposed rolling efficiency targets to the end of the current tariff control and it is expected that further efficiencies will be required in the next regulatory period (PC5 starting in October 2022).

Capital expenditures[373]

Gas Networks Ireland's spent €19.1 million for the maintenance of its transmission network in 2016.[374] The overall investment level of GNI amounted to €125 million in 2016, split between transmission, distribution and other.[375] A large part of the expenditure was related to the 50 km Pipeline Twinning Project in Scotland.[376] Other key projects were gas pipeline works in Nenagh Town, as part of a multi-utility project, the completion of a 46 km feeder main extension to Wexford Town and works at the first three CNG filling stations in Ireland.[377] In the near future, GNI will continue to invest in new connections to its network and in activities that facilitate alternative green gas sources such as biomethane. This will mainly impact on the distribution network but drive related costs in transmission. There is in general considerable emphasis on investing in new business areas such as natural gas vehicles and renewable gas.[378] The future investment perspectives are summarised in the table below.

6.3.5 Grid tariffs/TSO Revenues

The Commission for Regulation of Utilities (CRU) determines the allowed revenue, which constitutes, together with the capacity and gas demand forecast, the basis for the network tariff calculations. The allowed revenue is calculated to reward the Gas Networks Ireland investment in each of the transmission systems and to recover its allowable operating costs.

There is a 90:10[379] capacity/commodity split to recover the allowable revenue of each system. For the purpose of the tariff setting, the transmission network has been split into four separate systems: three entry systems (Interconnector, Inch and Bellanaboy) and one exit system (Onshore). A specific capacity and commodity tariff is payable in respect of each system which a shipper uses.

Current transmission tariff level

The transmission tariffs approved by the national regulator CRU for the current gas year is hereafter presented:

Table 6-7 GNI Illustrative Transmission Tariff for Gas Year 2017/18

Transmission Tariff	Capacity € per peak day MWh	Commodity € per MWh
UK Gas	788.605378	0.379205
Bellnaboy (Corrib) Gas	1038.815496	0.379205
Inch Storage Gas	481.410044	0.379205
Inch Production Gas	585.005502	0.379205

At the present, according to the CRU, about 33% of a domestic or business customer's gas bill relates to distribution tariffs and 10% to transmission tariffs.

373 The definition of OPEX and CAPEX is not harmonised across the EU. In this chapter, CAPEX refer to investments.
374 Ervia (2017), Annual report and financial statements 2016.
375 Ervia (2017), Annual report and financial statements 2016.
376 Ervia (2017), Annual report and financial statements 2016.
377 Ervia (2017), Annual report and financial statements 2016.
378 Gas Networks Ireland (2017), Systems performance report 2016. Available
379 Currently GNI recovers transmission revenue on the basis of a 90:10 capacity / commodity split. The split reflects the fixed nature of GNI's cost base. This was reviewed in 2015 when the CRU consulted on the tariff methodology (CER15140) and it was decided by the Regulator that it was still an appropriate split to maintain.

6.3.6 Impact of the 3 storylines on transmission grid tariffs/ business of GNI

Table 6-8 Impact of 3 storylines

	Figures 2016	Storyline 1 Strong electrification		Storyline 2 Strong development of carbon-neutral methane		Storyline 3 Strong development of hydrogen	
Gas demand[380]	50 TWh	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Demand trend resulting from our study		Decrease	Decrease	Increase	(High) increase	Stable	Stable
Demand trend resulting from IE studies[381]		Increase	Increase	Increase	Increase	Increase	Increase
Investment for maintenance of transmission/transit network	€ 19.1 million	Stable Investments to ensure operational security and safety.		Increasing Investments to ensure operational security and safety. Maintenance costs also associated with high levels of bio-methane.*		Increasing Investments needed to ensure operational security and safety & maintenance costs related to high H2 volumes. Transmission grid would also transport natural gas for H_2 production using SMR with CCS.	
Investment for development of transmission/transit network	€ 28.1 million	Possibly limited investments after 2025. Grid investments to accommodate H_2 & CCS.		Possibly limited investments after 2025. Grid investments to accommodate biomethane & CCS.		Possibly limited investments after 2025. Grid investments to accommodate H_2 & CCS.	
Net assets (accounting value)	€ 1.4 billion	Decreasing, however CCS and H_2 may have a significant impact.		Decreasing, however CCS may have a significant impact.		Decreasing, however CCS and H_2 may have a significant impact.[382]	
OPEX	€ 86.4 million	Slight decrease in line with cost efficiency targets. However, CCS and H_2 may have a significant impact.		Slight decrease in line with cost efficiency targets. However, CCS may have a significant impact.		Slight decrease in line with cost efficiency targets. However, CCS and H_2 may have an increasing impact.	
Possible evolution of grid tariffs for end-users	per Table 4-1	Decreasing overall costs for traditional gas networks in line with cost efficiency targets. However, this is balanced out by costs related to H_2. Overall impact on gas tariffs would be negative.		Decreasing, in line with cost efficiency targets and spread over growing gas demand.		Decreasing overall cost for traditional gas networks in line with cost efficiency targets and spread over growing gas demand. However, this is balanced out by costs related to H_2.[383] Overall impact on gas tariffs would be negative.	
Overall assessment		Limited risk for stranded gas assets Highest negative impact on grid tariffs.		No risk for stranded gas assets or rising grid tariffs. This storyline would be the preferred option for gas TSO and grid users.		Limited risk for stranded gas assets Medium negative impact on grid tariffs.	

**It is expected that there will be a mix of transmission and distribution connections. It is difficult to estimate how much at this stage of development. However, it is expected that there would be no need for reverse flows from distribution to transmission.*

[380] The gas demand refers to natural gas, biomethane and hydrogen. As some renewable gas will be used at the production site or injected into the distribution grid, the volumes to be transported via the transmission grid will be lower than the gas demand.
[381] See also section 6.1.3
[382] The possible impact of CCS on TSO's assets and activities is unclear at present, as the business and ownership model have not yet been defined.
[383] The impact of CCS on gas and electricity tariffs and the balance therein have still to be determined

7 Romania

Key data for Romania		Unit	Source
Annual gas consumption	104,766	GWh/year	Eurostat 2016
Peak load	761	GWh/day	ENTSOG TYNDP 2017
Share of gas in overall consumption	28	%	Eurostat 2016
Domestic primary gas production	90,528	GWh/year	Eurostat 2016 (nrg_100a)
Imports	13,680	GWh/year	Eurostat 2016 (nrg_100a)
Exports	10	GWh/year	Eurostat 2016 (nrg_100a)
Capacity of entry pipelines	73	GWh/day	ENTSOG transmission capacity map 2016
LNG import terminal capacity	0	Billion m3(N)/year	GIE LNG map 2016
Number of gas PCIs in 2017 list	6	projects	PCI list 2017
Other general information			
Regulatory system **for gas transmission** **for storage**	Regulated TPA (Revenue-cap methodology[384]) Regulated TPA		
NRA	Autoritatea Naţională de Reglementare în Domeniul Energiei (ANRE)		
Gas TSO	Transgaz		

7.1 Existing and planned gas infrastructure

There are in Romania no LNG terminals, but a project is currently being studied. Romania has several depleted natural gas fields utilised for gas storage with regulated Third Party Access; the total capacity (46 TWh) represents about 44% of the annual gas consumption. The gas transmission system (13,303 km of pipelines) is owned and operated by Transgaz, and is well interconnected (9 physical IPs) with the gas system in neighbouring countries. Romania is involved in five PCIs, all in the same cluster. There are on the Romanian territory three dedicated transit pipelines, which are however not connected to the national gas network. Romania is involved in five PCIs, all in the same cluster. The impact of the transition to a carbon-neutral gas supply would in Romania be lower than in countries with LNG import infrastructure. The existing storage facilities (depleted gas fields) could be further used for biomethane (storyline 2), but they would not be suitable for refurbishment to hydrogen storage (storylines 1 and 3). The utilization level of the import and transit pipelines would in the 3 storylines substantially decrease as of 2030; some natural gas pipelines might need to be decommissioned or could be adapted in view of other uses (biomethane, hydrogen or CO2 transport).

7.1.1 Main large gas infrastructure

LNG terminals

There are at present no operational LNG terminals in Romania, but a feasibility study has been undertaken by AGRI LNG to build a terminal in Constanta, which would have a capacity between 2 and 8 bcm per year.

Gas storage

In Romania there are several depleted natural gas fields, which are now used for gas storage and operated by Romgaz and Depomureș under a regulated TPA regime. The overall storage capacity amounted end 2016 to 32.6 TWh. An overview of the operational and planned storage facilities is presented in the table below.

[384] ANRE (2015), National Report 2015.

Table 7-1 Existing and planned gas storage facilities in Romania. Source: GIE Storage Map 2016

Facility/ Location	Status	Start-up year	Type	onshore/ offshore	Operator	Working gas (technical) TWh	Withdrawal technical = TPA GWh/day	Injection technical = TPA GWh/day	Access regime
Balanceanca	operational	1992	Depleted field	Onshore	Romgaz	0.5	5.0	4.1	rTPA
Bilciuresti	operational	1983	Depleted field	Onshore	Romgaz	14.0	130.6	106.5	rTPA
Cetatea de Balta	operational	2008	Depleted field	Onshore	Romgaz	1.0	9.5	7.7	rTPA
Ghercesti	operational	2004	Depleted field	Onshore	Romgaz	1.6	14.4	11.8	rTPA
Moldova (Falticeni)	planned	2023	Depleted Field	Onshore	Romgaz	2.2	21.6	21.6	rTPA
Sarmasel	operational	1995	Depleted field	Onshore	Romgaz	8.4	62.9	61.7	rTPA
Sarmasel	under construction	2016	Depleted field	Onshore	Romgaz	1.0	31.4	0.0	rTPA
Sarmasel	planned	2024	Depleted field	Onshore	Romgaz	6.8	10.5	43.1	rTPA
Târgu Mureş	operational	2002	Depleted field	Onshore	Depomures	3.2	15.0	15.0	rTPA
Târgu Mureş	planned	2018	Depleted field	Onshore	Depomures	1.2	22.8	22.8	rTPA
Târgu Mureş	planned	2020	Depleted field	Onshore	Depomures	2.2	16.2	16.2	rTPA
Urziceni	operational	1979	Depleted field	Onshore	Romgaz	3.9	36.5	29.8	rTPA

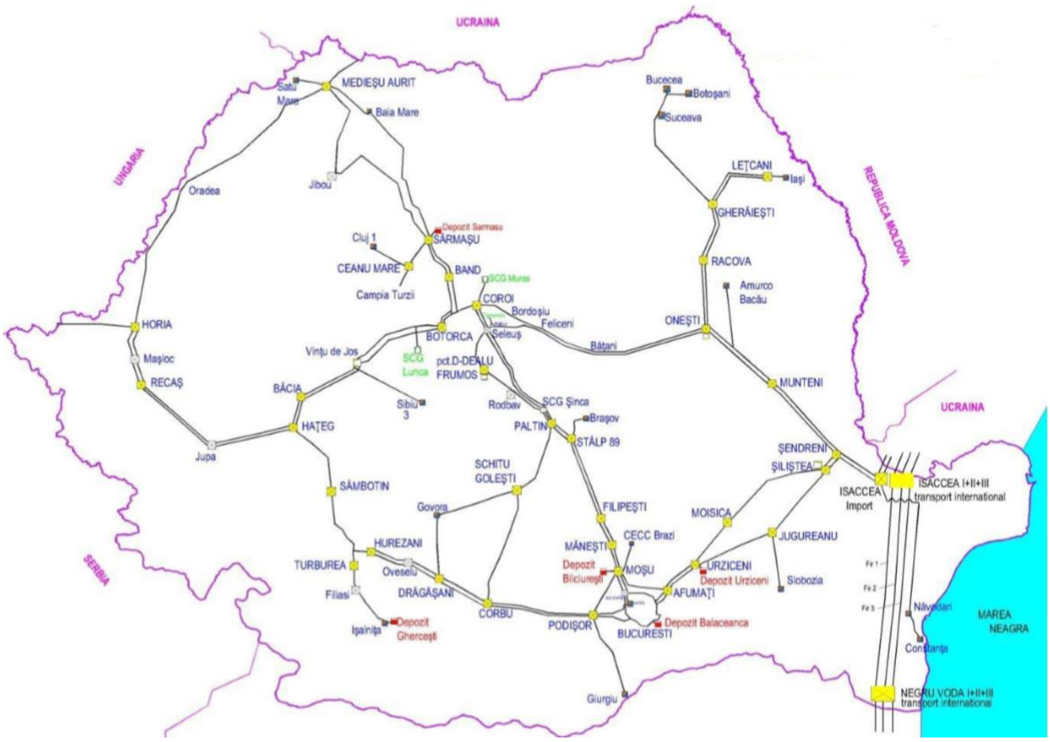
Gas transmission network

The gas transmission system in Romania was initially designed and developed to connect large industrial gas consumers to gas sources located mostly in the middle of the country and in Oltenia, and to the sole import source in Isaccea.[385] Transgaz owns and operates, as independent system operator (ISO), the national transmission system and is responsible for the maintenance of the transit pipelines on the Romanian territory.

The main components of the National Gas Transmission System are: [386]

- 13,303 km of main transmission pipelines (6 to 63 bar) and connections for gas supply, of which 553 km of pipelines for international transit of gas;
- 1,132 metering stations for regulated gas transmission, 6 for international transit and 3 for imported gas;
- 3 gas compressor stations with a total power of 28.9 MW;
- 1,042 cathodic protection stations and 60 valve stations / technological nodes.

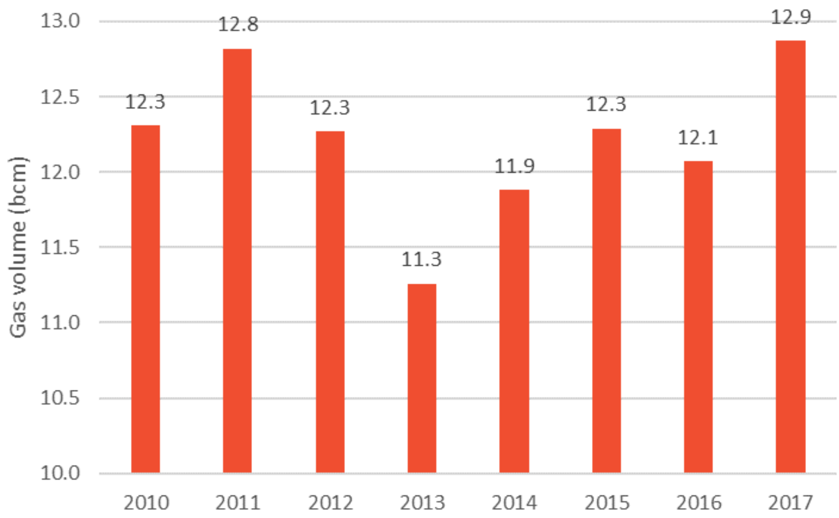
Figure 7-1 Map of the National Gas Transmission System[387]



The latest 10-year development plan elaborated by the TSO includes eight strategic projects aiming, among other things, at developing the gas infrastructure in the Black Sea, at completing the interconnection of the Romanian transmission system with the networks in Serbia, and at developing the connections with the Republic of Moldova.[388]
The transported volumes for domestic consumption have been very volatile since 2010, as shown in the figure below.

385 ANRE & Transgaz (N/A), Concept Paper for the Development of the Entry/Exit System in the Romanian Gas Market and Implementation of the EU Network codes.
386 Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.
387 Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.
388 Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.

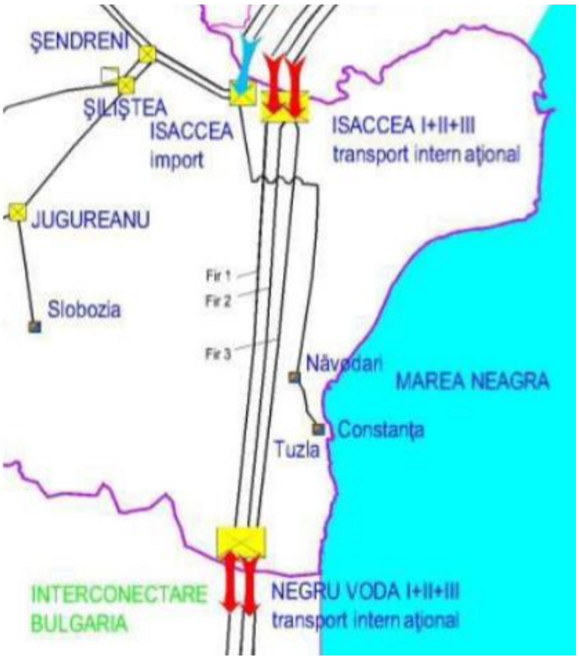
Figure 7-2 Amount of gas transmitted through the national transmission system in 2010-2017[389]



The international gas transmission (transit) is carried out through three dedicated transit pipelines that are not connected to the National Gas Transmission System[390]:

- **LINE I:** Dn = 1000 mm L = 184 km Technical capacity = 6.1 bcm/y International transmission of gas for Bulgaria;
- **LINE II:** Dn = 1200 mm L = 186 km Technical capacity = 9.6 bcm/y International transmission of gas for Turkey, Greece and FYROM;
- **LINE III:** Dn = 1200 mm L = 184 km Technical capacity = 9.7 bcm/y International transmission of gas for Turkey, Greece and FYROM.

Figure 7-3 Pipelines for gas transit (international transmission)[391]



[389] Transgaz (N/A), Planul de dezvoltare a sistemului national de transport gaze naturale 2018 – 2027.
[390] Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.
[391] Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.

The gas transit through the pipelines Transit 2 and 3 is currently not subject to the European regulations related to Third Party Access and is carried out according to the governmental agreements and contracts concluded with "Gazprom Export".[392] Since 2016 the capacity of Line I is being allocated based on auctions as per the provisions of the EU Network Code on Capacity Allocation Mechanisms.[393]

Interconnections

There are nine physical interconnection points between the national transmission network and adjacent systems. All these IPs, except the Csanádapalota physical IP, are operated by Transgaz.[394] Seven physical entry/exit points connect the transmission grid with gas storage facilities; these physical entry/exit points are not operated by Transgaz.[395]

Table 7-2 Interconnection points. Source: ENTSOG capacity map 2017

Type	*N*	*Point*	*Arc*	*Technical physical capacity (GWh/d)*	*From*	*To*	*From operator*	*To operator*
Cross-border IP within EU and with non-EU (export)	53	Negru Voda I (RO) / Kardam (BG)	RO/TBP>BGn	187.8	RO	BG	Transgaz	Bulgartransgaz
Cross-border IP within EU and with non-EU (export)	53	Negru Voda II, III (RO) / Kardam (BG)	RO/TBP>BGg/BGT	563.4	RO	BG	Transgaz	Bulgartransgaz
Cross-border IP within EU and with non-EU (export)	57	Csanadpalota	HU>RO	51.5	HU	RO	FGSZ	Transgaz
Cross-border IP within EU and with non-EU (export)	57	Csanadpalota	RO>HU	2.5	RO	HU	Transgaz	FGSZ
Cross-border IP within EU and with non-EU (export)	72	Ungheni	RO>MD	1.3	RO	MD	Transgaz	Vestmoldtransgaz
Cross-border IP within EU and with non-EU (export)	83	Ruse (BG) / Giurgiu (RO)	BGn>RO	21.6	BG	RO	Bulgartransgaz	Transgaz
Cross-border IP within EU and with non-EU (export)	83	Ruse (BG) / Giurgiu (RO)	RO>BGn	1.6	RO	BG	Transgaz	Bulgartransgaz
Cross-border IP with non-EU (import)	221	Isaccea (RO) - Orlovka (UA) I	UA>RO/TBP	202.9	UA	RO	PJSC Ukrtransgaz	Transgaz
Cross-border IP with non-EU (import)	221	Isaccea (RO) - Orlovka (UA) II	UA>RO/TBP	288.7	UA	RO	PJSC Ukrtransgaz	Transgaz
Cross-border IP with non-EU (import)	221	Isaccea (RO) - Orlovka (UA) III	UA>RO/TBP	274.6	UA	RO	PJSC Ukrtransgaz	Transgaz
Cross-border IP with non-EU (import)	226	VIP Mediesu Aurit - Isaccea (RO-UA)	UA>RO	370.4	UA	RO	PJSC Ukrtransgaz	Transgaz

At present, transmission capacities in the export direction are limited, but the TSO is carrying out investment projects to increase such capacities. This capacity extension will in particular be realised by increasing the pressure levels in the Romanian gas system by 2020.[396]

[392] Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.
[393] Transgaz (N/A), Planul de dezvoltare a sistemului national de transport gaze naturale 2018 – 2027.
[394] Transgaz (2013), NTS Infrastructure.
[395] Transgaz (2013), NTS Infrastructure.
[396] ANRE & Transgaz (N/A), Concept Paper for the Development of the Entry/Exit System in the Romanian Gas Market and Implementation of the EU Network codes.

7.1.2 *Planned Projects of Common Interest*[397]

The main gas PCIs in which Romania is involved are listed and shortly described hereafter.

Project 6.25.1 - interconnection with Bulgaria[398] (Pipeline system from Bulgaria via Romania and Hungary to Slovakia - currently known as 'Eastring').

This project aims to bring new gas sources accessible to the Central and South-Eastern European region in view of increasing the supply diversification of this region. The project consists of a bi-directional pipeline with a total length of 846 or 1,029 km depending on the route, of which 651 or 725 km respectively will be in Romania.[399] The annual capacity during phase one will be 208 TWh and 416 TWh during phase two and it is expected to secure gas supply for all Balkan countries and 100% of the Romanian consumption.[400] EASTRING will offer the opportunity to diversify transmission routes and hence enhance security of supply.[401] TRANSGAZ completed in 2016 the construction of a 25 km interconnection pipeline (1.5 bcm/y capacity) between Giurgiu and Ruse. An undercrossing of the Danube is being built in view of facilitating bidirectional gas flows between Romania (TRANSGAZ) and Bulgaria (BULGARTRANSGAZ). The joint Danube undercrossing works are supported by EU co-funding.[402] The implementation of this PCI is planned but not yet in the permitting phase.

Cluster 6.24 ROHUAT/BRUA

This project consists of a phased capacity increase on the Bulgaria — Romania — Hungary — Austria bidirectional transmission corridor.

ROHUAT/BRUA – 1st phase PCI 6.24.1

As per the 2017 PCI list, project 6.24.2 on the 2015 PCI list has been integrated into PCI 6.24.1. The project ROHUAT/BRUA – 1st phase includes:[403]

- Romanian-Hungarian reverse flow: Hungarian section 1st stage compressor station at Csanádpalota;
- Development of the transmission capacity in Romania from Podișor to Recas, including a new pipeline, metering station and three new compressor stations in Podisor, Bibesti and Jupa;
- GCA Mosonmagyarovar compressor station (development at the Austrian side).

The expected construction period will be from July 2018 to December 2019 and the expected commissioning date is January 2020.

The development of the Bulgaria – Romania – Hungary – Austria Route (BRUA) aims to increasing the interconnection capacity with Bulgaria (to the Southern Corridor) and Hungary (to the Central European transmission system).[404]

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[397] Information extracted from the PCI project fiches and implementation plans available from DG ENER's PCI interactive map: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html
[398] EC (2018), COMMISSION DELEGATED REGULATION (EU) 2018/540 of 23 November 2017 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest.
[399] Eastring (N/A), Eastring pipeline - connecting markets.
[400] Eastring (N/A), Eastring pipeline - connecting markets.
[401] Eastring (N/A), Eastring pipeline - connecting markets.
[402] Transgaz (N/A), Bulgaria - Romania Interconnection.
[403] EC (2018), COMMISSION DELEGATED REGULATION (EU) 2018/540 of 23 November 2017 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest.
[404] Transgaz (N/A), Major development projects.

By implementing this project, the following objectives will be attained:[405]

- Diversification of gas supply sources (in particular access to Caspian gas) for several European countries, in particular Romania, Bulgaria and Hungary;
- Availability of 1.75 bcm/y transport capacity to Hungary and 1.5 bcm/y to Bulgaria[406].

The length of the pipeline from the compressor station of Podisor to Recas will be approximately 479 km with a diameter of 32" and a maximum design pressure of 63 bar.[407] This BRUA project will allow future interconnections via pipelines that may be sourced by Black Sea shore LNG (AGRI Project) and Black Sea Gas.[408] A pipeline would be built between gas fields in Azerbaijan and the Black Sea coast in Georgia; from there LNG could be transported in tankers via the Black Sea, to the LNG terminal in Constanta, Romania. The realisation of the project has not started yet, as the participating countries are still completing the assessment stage.[409] The project is expected to cost approximately €478.6 million[410].

ROHUAT/BRUA -2nd phase PCI 6.24.4

As per the 2017 PCI list,[411] project 6.24.8 on the 2015 PCI list has been integrated into PCI 6.24.4. ROHUAT/BRUA –2nd phase includes:

- Városföld-Ercsi– Győr pipeline (HU);
- Ercsi-Százhalombatta pipeline (HU);
- Városföld compressor station (HU);
- Expansion of the transmission capacity in Romania from Recas to Horia towards Hungary up to 4,4 bcm/y and expansion of the compressor stations in Podisor, Bibesti and Jupa;
- Black Sea shore — Podișor (RO) pipeline for taking over the Black sea gas;
- Romanian-Hungarian reverse flow: Hungarian section 2nd stage compressor station at Csanádpalota or Algyő (HU).

The expected construction period will be from May 2020 to October 2022 and the expected commissioning of this project is planned for October 2022 but it is not yet in the permitting phase. The project is expected to cost around €68.8 million.[412]

The project includes a 50 km connecting Recas and Horia, upgrading the existing compressor stations in Jupa, Bibesti and Podisor and 308 km of new onshore pipeline with a capacity of 6 bmc/y with diameters of 48" and 40".

This project will connect central Europe with the Black Sea gas and imports of LNG from Azerbaijan through the AGRI pipeline increasing the diversification of suppliers.

ROHUAT/BRUA – 3rd phase PCI 6.24.10

As per the 2017 PCI list,[413] project 6.25.3 on the 2015 PCI list has been integrated into PCI 6.24.10. PCI 6.24.10 includes:

- Enhancement of the Romanian transmission system between Onesti-Isaccea and reverse flow at Isaccea;

[405] Transgaz (2016), BRHA A flagship project for Romania and Europe promoted by Transgaz.
[406] Transgaz (2017), Report issued by the board of administration 2017.
[407] Transgaz (2016), BRHA A flagship project for Romania and Europe promoted by Transgaz.
[408] Transgaz (2016), BRHA A flagship project for Romania and Europe promoted by Transgaz.
[409] AZERNEWS (2017) Azerbaijan, Romania continue to work on implementation of LNG project.
[410] Transgaz (2017) Report issued by the board of administration 2017.
[411] EC (2018), COMMISSION DELEGATED REGULATION (EU) 2018/540 of 23 November 2017 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest.
[412] Transgaz (2017) Report issued by the board of administration 2017.
[413] EC (2018), COMMISSION DELEGATED REGULATION (EU) 2018/540 of 23 November 2017 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest.

- Enhancement of the Romanian transmission system between Onesti – Nadlac;
- Extension of the Romanian transmission system for taking over gas from the Black Sea Shore.

It consists of different phases:

Phase I (commissioning in 2018)	• Interconnection between the NTS and the Transit 1 international transmission pipeline in the area of the Isaccea metering station; • Repair works to the Dn 800 mm Cosmesti-Onesti pipeline (66.0 km)
Phase II (commissioning planned in 2019)	• Upgrades and developments within the Silistea Compressor Station, additional power of 5.94 MW; • Upgrades within the Onesti Compressor Station, additional power of 3.34 MW; • Changes within the TN Silistea and the TN Onesti and works within the TN Sendreni. • Works within the TN Sendreni

This project aims at ensuring bi-directional flow towards Bulgaria between the Romanian gas transmission system and the Transit 1 pipeline to Bulgaria. This project includes rehabilitation works on some Romanian pipelines, the construction of a connection pipeline between the Transit 1 pipeline to Bulgaria and the Romanian network in Isaccea, a compressor station at Siliştea and works to allow bi-directional flows with Ukraine.[414] The project will ensure a natural gas transport capacity of 1.5 bcm/y towards Bulgaria and 4.4 bcm/y towards Hungary. The estimated investment amounts to € 560 million.[415] The project includes 833 km of pipeline from Isaccea to Nadlac and 25 – 30 km from the Black Sea shore to the T1 international transmission pipeline.

The investment related to phase III of this project is € 479 million. This part of the project is expected to be commissioned in 2023.

Expansion of gas storage facility in Târgu Mureș (Project 6.20.4 on PCI list 2017)

The gas storage facility of Depomures, which has a capacity of 300 mcm, will in two phases be expanded to respectively 400 and 600 mcm. The project will also increase flexibility of the storage by increasing injection and withdrawing capacity from an existing average 1.7 mcm/day to approximately 5 mcm/day after the implementation of Phase 2. The project is under construction and Phase 1 of the project should be finished in 2020 and Phase 2 in 2023.

Sarmasel underground gas storage in Romania (Project 6.20.6 on PCI list 2017)

The project belongs to cluster 6.20 to increase storage capacity in South East Europe. The project includes the extension and upgrading of storage facility in depleted field Sarmasel, and has the following characteristics:

- Increase the working gas volume by 650 mcm to reach 1550 mcm with a cushion gas of 1130 mcm;
  - Supplementing the gas cushion by approximately 400 mcm;
  - Increase the withdraw capacity by 3.25 mcm/day to reach 10 mcm/day;
  - Increase the injection capacity by 4 mcm/day to reach 10 mcm/day;
- Cycling rate 1 time/year;

[414] Transgaz (N/A), Interconnection of the national transmission system with the international gas transmission pipelines and reverse flow at Isaccea (RO).
[415] ANRE (2015), National Report 2015.

- Drilling new infill wells for injection/withdrawal;
- Upgrading and completing the surface facilities of the injection/withdrawal wells.

The construction is expected to start in February 2021 and be finalised by October 2024 while the planned date of commissioning is December 2024.

7.1.3 Estimated impact of the storylines on Romanian gas infrastructure

The table below provides a qualitative overview of the impact of the three selected storylines on the large gas infrastructure in Romania.

Table 7-3 Impact of storylines on Romanian large gas infrastructure. Source: Own assessment

<table>
<tr><th></th><th colspan="3">Storyline 1
Strong electrification</th><th colspan="3">Storyline 2 Strong development of carbon-neutral methane</th><th colspan="3">Storyline 3 Strong development of hydrogen</th></tr>
<tr><td rowspan="3">Gas demand - 2015</td><td colspan="3">85.6 TWh</td><td colspan="3">85.6 TWh</td><td colspan="3">85.6 TWh</td></tr>
<tr><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td></tr>
<tr><td>Very high</td><td>Negligible</td><td>Negligible</td><td>Very high</td><td>Negligible</td><td>Negligible</td><td>Very high</td><td>Negligible</td><td>Negligible</td></tr>
<tr><td rowspan="3">Gas demand - 2030</td><td colspan="3">Decrease</td><td colspan="3">Stable</td><td colspan="3">Slight decrease</td></tr>
<tr><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td></tr>
<tr><td>Very high</td><td>Negligible</td><td>Negligible</td><td>Very high</td><td>Low</td><td>Negligible</td><td>Very high</td><td>Negligible</td><td>Low</td></tr>
<tr><td rowspan="3">Gas demand - 2050</td><td colspan="3">Decrease</td><td colspan="3">Stable/slight increase</td><td colspan="3">Decrease</td></tr>
<tr><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td><td><u>Natural</u></td><td><u>Methane</u></td><td><u>Hydrogen</u></td></tr>
<tr><td>Negligible</td><td>Medium</td><td>Medium</td><td>Negligible</td><td>Very high</td><td>Low</td><td>Negligible</td><td>Low</td><td>Very high</td></tr>
<tr><td>LNG terminals</td><td colspan="3">No LNG terminals at present, hence no impact</td><td colspan="3">No LNG terminals at present, hence no impact</td><td colspan="3">No LNG terminals at present, hence no impact</td></tr>
<tr><td>Gas storage</td><td colspan="3">Depleted gas fields are currently used for gas storage; the feasibility to refurbish them for H_2 storage is still to be assessed. It might be required to develop new storage sites for hydrogen.</td><td colspan="3">Existing gas storage (depleted gas fields) can be used for both natural gas and biomethane storage.</td><td colspan="3">Depleted gas fields are currently used for gas storage; the feasibility to refurbish them for H_2 storage is still to be assessed. It might be required to develop new storage sites for hydrogen.</td></tr>
<tr><td>Transmission network & transit pipelines</td><td colspan="3">Utilisation of import and transit pipelines would after 2030 substantially decrease; decommissioning of some pipelines or their or refurbishment (H_2, CO_2) would need to be considered. Upgrade of transmission network to accommodate hydrogen would be required (> technical threshold).</td><td colspan="3">Utilisation of import and transit pipelines would after 2030 substantially decrease; decommissioning or biomethane imports/exports via existing pipelines could be considered. Reverse flow capabilities D => T would be required to allow biomethane injection at distribution level.</td><td colspan="3">Utilisation of import and transit pipelines would after 2030 substantially decrease; decommissioning of some pipelines or their refurbishment (H_2, CO_2) would need to be considered. Upgrade of transmission network to accommodate hydrogen would be required (> technical threshold).</td></tr>
</table>

Note: The overall gas demand is compared to 2015 levels, and categorised as follows: increase>51%= **'High increase'**; increase 6-50%= **'increase'**; decrease 5% to increase 5%= **'stable'**; -5% to -50%= **'decrease'**; > -51% = **'high decrease'**. The changes in gas shares were categorised as follows: 76%-100%= **'very high'**; 51%-75%= **'high'**; 26%-50%= **'medium'**; 6%-25%= **'low'**; 0%-5%= **'negligible'**.

7.2 Main national developments that influence investments in and use of gas infrastructure

The natural gas demand in Romania amounted in 2016 to 111 TWh and would, according to the TSO's estimates, slightly increase to 118 TWh in 2035. The demand is primarily covered by domestic production (97.3 TWh in 2016), supplemented by imports (13.7 TWh in 2016, mainly from Russia). The local natural gas production is expected to increase to 164 TWh by 2020. Natural gas is covering 27.1% of Romania's overall energy demand. Romania has a key role to play for energy security in the region, given its natural resources, strategic location and the transit pipelines crossing its land. The Romanian gas system is well interconnected with neighbouring countries, but the gas markets are not yet properly integrated due to technical issues and lack of appropriate legislation/market rules. Romania has a high target for renewable energy (24% by 2020), which was already reached in 2014. Notwithstanding its relatively high biomass potential, the deployment of renewable gas is still rather limited. The biogas production is only locally used for heat and/or power generation, as there were no appropriate economic incentives and legal provisions to enable upgrading of biogas to biomethane and injecting it into the gas grid. In April 2017, the Romanian government has introduced a new support scheme for 'less exploited' renewable energy sources, which will stimulate the deployment of renewable gas.

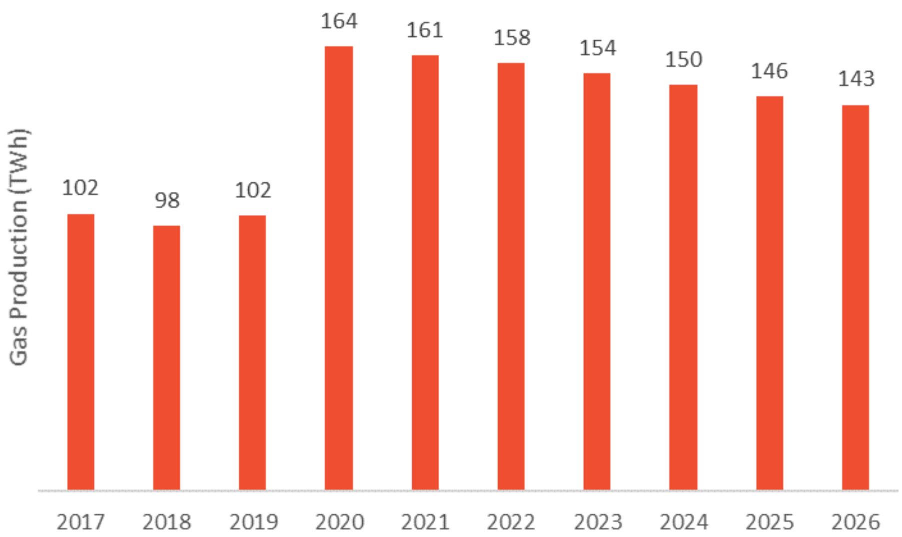
7.2.1 Gas supply and demand

Gas supply

The gas supply in Romania consists primarily of domestic production, supplemented by imports. The local natural gas production currently amounts to about 100 TWh (9 to 10 bcm) annually and is expected to increase to 164 TWh by 2020, but would as of 2020 slightly decrease by 2% annually. As the national production is higher than the demand, part of it is available for export. Increasing domestic gas production is explicitly mentioned in Romania's long-term energy strategy as a way to reduce import dependence and to increase security of gas supply.[416] The gas imports amounted in 2016 to 13,670 GWh, virtually all of which was imported from Russia.

[416] Ministry of Energy (2016) Romanian energy strategy 2016-2030, with an outlook to 2050.

Figure 7-4 Domestic gas production forecast (2014 - 2026) [417]



Security of supply

Romania has a key part to play for energy security in the region, given its strategic location. Its energy mix is well balanced: most of the energy it uses is derived from petroleum products (27.6%) and gas (27.1%), followed by solid fuels (17.9%), renewables (18.1%) and nuclear (9.1%). In comparison to the average energy mix in the EU, Romania's energy mix has a higher share of renewable energy and natural gas and a lower share of nuclear energy and oil. Romania considers security of energy supply as one of the five main strategic goals of its 2030 energy strategy, and has implemented several measures for contributing to it.[418] First, it aims to increase domestic production of natural gas, through development of new onshore and offshore production sites. Second, its policies should lead to lower gas consumption in the power sector, thanks to increased deployment of renewable energy and the development of new nuclear power generation capacity. Finally, an LNG terminal is planned in Constanta on the Black Sea coast, and is expected to enable as of 2025 LNG imports via the Black Sea.

According to Article 102 of Law no. 123/2012 on electricity and natural gas, the energy Ministry monitors security of supply, while in practice it is jointly ensured by the TSO, DSOs and gas storage operators. The continuity of gas supply is in particular ensured by legal obligations on licensed suppliers to maintain a minimum stock of gas in underground storage facilities. The minimum levels to be respected are set by ANRE.[419]

The N-1 infrastructure standard determines the required capacity of the gas transmission infrastructure to satisfy the total gas demand of Romania in the case that the single main gas network is affected, for one day of exceptionally high demand, recorded statistically once every 20 years.[420] According to the Second Report on the State of the Energy Union of 1 February 2017 (SWD 2017 32 final), Romania is effectively meeting this standard.

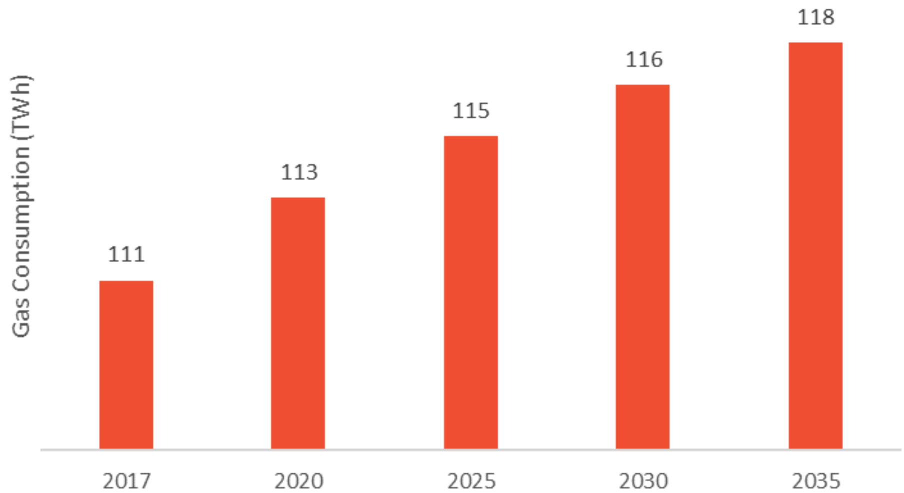
[417] Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.
[418] Ministry of Energy (2016) Romanian energy strategy 2016-2030, with an outlook to 2050.
[419] (N/A), Romania. Available at: ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_romania.pdf
[420] Transgaz (N/A), Development Plan for the National Gas Transmission System 2014 – 2023.

As Romania has the third largest gas reserves in the EU, while its domestic demand is not expected to (substantially) increase, the country could contribute to enhancing security of gas supply in neighbouring countries. However, this possibility is currently still limited as several pipelines are not yet equipped for bi-directional use. The ongoing and planned investments (PCIs) in reverse gas flows and compressor stations will improve this situation.

Gas demand

Over the last two decades natural gas consumption in Romania has decreased by more than twofold. This decline is mainly due to a decreasing use of gas for power generation and to a substantial decline in the overall final energy demand, mainly in the late 1990's and early 2000's. Since 2009 final energy demand in Romania has more or less stabilised. The domestic natural gas demand amounted in 2016 to 111 TWh and is, according to the TSO's estimates, expected to slightly increase to 118 TWh by 2035.

Figure 7-5 Domestic gas consumption forecast (2014 - 2035)[421]



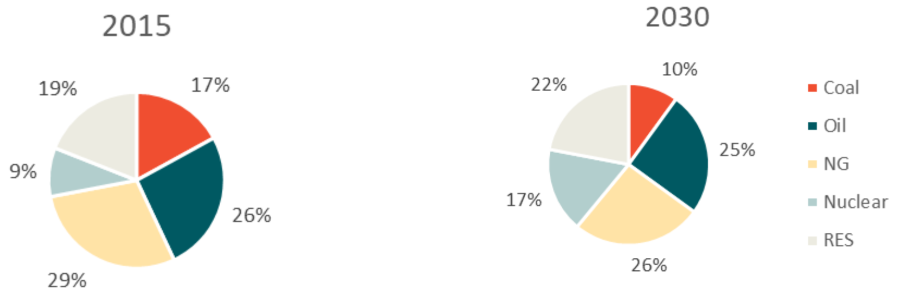
Around 36% of the gas consumption was in 2015 used for power and heat generation, about one quarter in the residential sector, another quarter by industry, 8% in the services sector and 4% for non-energy uses.[422] The role of gas in the power sector is declining, as Romania's power supply is increasingly coming from nuclear and more recently from intermittent renewable energy. Hydro-energy and coal are also very important sources in Romania's power generation mix, although the share of coal, which has increased until 2009, is since then declining.

7.2.2 Renewable energy policy and targets

Romania is quite active in the field of renewable energy deployment. Its national target of 24% renewable energy share in overall final demand was already reached in 2014.[423] The growth has primarily come from increased deployment of wind energy, biofuels and renewable heating sources. In its Energy Strategy for 2030, Romania committed to further modernise its energy system, which includes deployment of renewable sources as well as increased use of nuclear energy.[424]

[421] Transgaz (N/A), Development Plan for the National Gas Transmission System 2016 – 2027.
[422] IEA (2018) Statistics. Romania: Natural Gas for 2015.
[423] Eurostat (2018) SHARES.
[424] Ministry of Energy (2016) Romanian energy strategy 2016-2030, with an outlook to 2050.

Figure 7-6 Primary energy mix in 2015 and 2030[425]



Biogas production is currently rather limited in Romania. Although there were around 400 biogas installations in Romania in the late 1980s, privatisation of waste and water treatment services led to a rapid decline of the number of biogas installations.[426] Only recently, the number of biogas installations is increasing again. In 2014 there were 25 biogas installations in Romania, while the biogas potential is around 50 times higher than the current production levels. The biogas production is currently only locally used for heat and/or power generation, as there are no appropriate economic incentives and legal provisions to enable upgrading of biogas to biomethane and injecting it into the gas grid. In April 2017, the Romanian government has launched a new financial support scheme (Government Decision no 216/2017) for 'less exploited' renewable energy sources, including biogas. The fund will support a total of €100 million in investments, between 2017 and 2020, with 85% of this budget originating from the ERDF and 15% from the national treasury.[427]

The ongoing gas infrastructure investment projects in Romania will facilitate the development of renewable energy in the region (especially wind and solar energy), as they will improve the access to gas as backup energy vector for renewable energies.[428]

7.2.3 Gas market integration and competition

Although Romania has a gas pipeline connection with Bulgaria, cross-border trade via this pipeline has been negligible, also due to the fact that the required legislation for virtual trading points is not in place. This situation hampers cross-border trade and might favour the position of incumbent market players.[429]

In 2017, the European Commission has started an investigation about practices of TSO Transgaz, which would restrict Romanian gas exports. The Commission is investigating whether Transgaz has abused its position to prevent gas exports by levying interconnector fees, delaying investments in required transmission infrastructure and using unfounded technical arguments preventing or justifying export delays.[430]

Up to 2015 the capacity reservation tariff was higher for imports than for domestic production, which indirectly hampered trade. Since 2016, the same tariff applies for both entry and exit capacity reservation, such that no competitive advantage is granted any more to domestic production.[431]

[425] Transgaz (N/A), Planul de dezvoltare a sistemului national de transport gaze naturale 2018 - 2027.
[426] EPG (2017), Biogas: a high-potential, sustainable, yet untapped fuel in Romania.
[427] Volciuc-Ionescu (2017) New State Aid Scheme in Romania to encourage production of energy from biomass, biogas and geothermal resources.
[428] Transgaz (N/A), Development Plan for the National Gas Transmission System 2014 - 2023.
429 ACER & CEER (2017) Annual report on the results of monitoring the internal electricity and gas markets in 2016 - Gas wholesale market volume.
430 EC (2017) Antitrust: Commission opens investigation into gas export restrictions from Romania.
431 Transgaz (N/A), Planul de dezvoltare a sistemului national de transport gaze naturale 2018 - 2027.

Between 2011 and 2015 the market concentration in the wholesale of natural gas has increased. Despite the high market concentration, the gas wholesale prices in Romania are still slightly below EU average, although prices have increased between 2011 and 2015.
Further efforts to enhance gas markets integration at regional level and competition on the Romanian gas market are hence necessary, but these measures should mainly focus on market rules and regulation. Ongoing investments in grids, amongst others to enable bi-directional flows, will also contribute to enhancing competition by facilitating cross border trade.

For the gas household customers, the Romanian government and NRA (ANRE) have elaborated a new timetable for phasing out the regulated prices for the period 1 July 2015 – 30 June 2021 taking into account the downward trend of the evolution of the international prices for hydrocarbons.[432]

7.2.4 Overview of impact of non-gas demand drivers on Romanian gas infrastructure

Investments in and use of gas infrastructure are mainly determined by the evolution of the gas demand and supply (e.g. shift in sources). Other important drivers are security of supply, market integration and climate/environmental policies.

The impacts of these drivers for gas infrastructure in Romania are summarised in the table below.

Table 7-4 Impact of non-gas demand drivers on gas infrastructure

Policy objective	Issue	Likely impact on TSO assets
Security of supply	N-1 Infrastructure standard	N-1 security of supply standard is already met. Grid extensions, adaptations and reverse flow investments are being realised/planned (PCI projects) to further enhance security of supply
	Diversified gas sources	Romania has substantial own fossil gas reserves; their reduced deployment (decreasing production in medium term) will affect gas infrastructure Current investments in gas infra are mainly focusing on access to diversified gas sources
Climate / Environment	Gas fuelled back-up units for intermittent power generation	Romania plans further expansion of intermittent power generation capacity, particularly wind energy; gas might hence become more important for back-up. Romania does yet not plan to substantially reduce its coal or oil use, hence no major impact from substitution from oil/coal to gas
	Biogas/biomethane development	Large domestic potential for biogas production: injection of biomethane into gas grid is not yet considered but could become driver for TSO business
	Hydrogen development	Use of hydrogen is not yet considered but could in medium term become driver for TSO business
Competitiveness / market development/market integration	Market integration	Romanian gas system is interconnected with neighbouring countries, but markets are not yet properly integrated due to technical issues (pressure) and lack of appropriate legislation/market rules. Investments in interconnectors and reverse flows ongoing to enhance markets' integration
	Enhance competition	Mainly related to legal and market issues. No major driver for investment in gas infrastructure

432 ANRE (2015), National Report 2015.

7.3 Assessment of the impact of the storylines on the Romanian TSO

The Romanian gas TSO has under the current regulatory regime 'guaranteed' revenues recovered via regulated tariffs set by the NRA (ANRE), on the basis of the TSO's 'authorised' costs, comprising the capital costs based on a regulated rate of return on the RAB, the operational expenses (adjusted taken into account an efficiency factor of e.g. 3.5% in 2014-2017) and the depreciation costs. In the regulatory period 2017-2018, 35% of the gas TSO revenues stem from volume related tariffs, and 65% from capacity-based tariffs. The latter share will gradually increase to 85% in 2022.

The RAB currently amounts to € 649 million; it is expected to increase in the short term (+ 30% by 2020) and would be stable or only slightly decrease in the medium/long term.

The OPEX (€ 264 million in 2017) is the largest constituent of the overall costs of Transgaz. Decreasing gas transit or transmission volumes in the future would not lead to substantially lower operational expenses.

Transgaz has an extensive investment plan, at close to € 800 million, among others to finance the BRUA interconnection project, which comes on top of the regular maintenance CAPEX. The annual investment level currently amounts to € 120 million; the investments for maintenance would remain at a high level to replace ageing assets (46% of transmission pipelines > 40 years old), while the investments for development would after 2025 be limited and mainly relate to increasing injection volumes of H2 (storylines 1 and 3).

Storylines 1 and 3 (lower gas demand in 2030 and 2050) would overall have an increasing effect on grid tariffs, while storyline 2 (stable gas demand) would have a limited impact.

7.3.1 Key financial indicators: Transgaz

Key data for Transgaz		Unit	Source
Infrastructure			
Pipelines	13,303	km	Transgaz[433]
Compressor stations	3	Units	Transgaz[434]
Interconnection Points	3	Units	Transgaz[435]
Transport volumes			
For domestic use	138.1 (2017)	TWh	Transgaz[436]
For transit	19.4	bcm	
Investments			
Current investment level	30.3 (avg. last five years)	M EUR/year	Transgaz[437]
Future investment level -10 yr plan	1.6	B EUR/10 years	Transgaz[438]
Revenues			
Operating revenues[439]	211	M EUR	Transgaz[440]
EBITDA[441]	192	M EUR	Transgaz[442]
EBIT 2017	107	M EUR	Wood & Company
Shareholders			
Transgaz was partially privatised in 2007 and 2013. Shareholder structure, as of 2018: Ministry of Economy 58,5% - other shareholders 41.5%			

[433] Transgaz (2017), Development Plan for the National Gas Transmission System 2017 – 2026.
[434] Transgaz (2017), Development Plan for the National Gas Transmission System 2017 – 2026.
[435] Transgaz (2017), Development Plan for the National Gas Transmission System 2017 – 2026.
[436] Transgaz (2017), Report issued by the board of administration -2017.
[437] Transgaz (2017), Report issued by the board of administration -2017.
[438] Transgaz (2017), Development Plan for the National Gas Transmission System 2017 – 2026.
[439] Total operating revenue before the balancing and construction activity according to IFRIC12, for 2017 semester I
[440] Transgaz (2017), Report issued by the board of administration -Semester I 2017.
[441] Only for Semester I of 2017
[442] Transgaz (2017), Report issued by the board of administration -Semester I 2017.

7.3.2 Regulation of grid tariffs and TSO revenues

The gas transmission tariffs are set by the Romanian Energy Regulator, ANRE, and are based on various parameters such as the regulated rate of return, the required efficiency factor and the RAB. In the regulatory period 2017-2018, 35% of the gas TSO revenues come from regulated volume related transmission tariffs, and 65% from capacity-based tariffs.[443] In the regulatory period 2017-2022, the share of the latter has to increase with 5% per year to an overall share of 85% in 2022.[444] Of the total allowed TSO revenues, 45% is generated from charges concerning entry/exit points to/from the distribution network and 29% is generated by charges to end-users directly using gas from the transmission network. Whereas the TSO can determine itself the individual capacity-based tariffs taking into account the overall revenue cap, the volume-based tariffs are determined by the NRA (ANRE).

The regulatory period for the regulated activities of the TSO is 5 years, except for the first regulatory period which was established for 3 years.[445] The TSO operates under the obligation to achieve cost savings on OPEX of 3.5% in the regulatory period 2014-2017.[446] The TSO revenues are capped by an absolute amount determined by the NRA on an annual basis.[447] In this way ANRE ensures that the revenues of the TSO are in balance with its "authorised" costs.

The average transmission grid tariff in 2016 was about 1.5 €/MWh.

7.3.3 OPEX & CAPEX

OPEX

Currently, the OPEX is the largest constituent of the overall costs within Transgaz, accounting for a cost of 1.21 bn RON (€264 million).[448] During the last five years the operational costs within Transgaz have been increasing steadily. Decreasing gas transit or transmission volumes would not lead to substantially lower operational expenses, also taking into account that the transmission grid is ageing and hence will require high maintenance costs in the short and medium term.

CAPEX

Transgaz has an extensive investment plan, at close to € 800 million, in order to finance the BRUA interconnection project (between Bulgaria, Romania, Hungary and Austria). This comes on top of the regular maintenance CAPEX. The first phase of the project has already received € 179 million of financing from the EU. Implementing the entire project is likely to substantially increase the company's RAB. According to figures published by Wood & Company,[449] the RAB has increased from about 2,700 million RON in 2013 to 3,000 million RON in 2017, and is expected to further increase to 4,000 million RON in 2020. As the transported volumes are expected to remain stable or (slightly) decrease depending on the storyline, the CAPEX component in the grid tariffs will increase in the coming decades.

For investments in gas infrastructure linear depreciation is applied, with different depreciation periods depending on the type of project concerned.[450] Investments involving pipelines and related installations

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443 Transgaz (2017), Report issued by the board of administration -2017.
443 Transgaz (2017), Report issued by the board of administration -Semester I 2017.
444 ECRB (2018), Gas transmission tariffs in South and Central East Europe.
445 ANRE (2015), National Report 2015.
446 ANRE (2015), National Report 2015.
447 ANRE (2017), ANRE Order 74/2017.
448 Operating costs including gas balancing. Source: Transgaz (2017), Report issued by the board of administration -2017.
449 Wood & Company (2017), Romania Utilities
450 ANRE (N/A), Methodologies. Available at: www.anre.ro/en/natural-gas/legislation/tarrifs-methodologies/methodologies

have depreciation periods of 25 to 40 years. The annual amortization that is taken into account for the tariff setting is determined based on the regulated value of the concerned asset. According to Wood & Company (2017) the cumulative depreciation in 2014-2017 is about 710 million RON, and exceeds by 5 to 10% the investment level during that period.

The expected future investment levels in the Romanian gas transmission network will remain high. In order to ensure security of gas supply in Romania and the neighbouring countries, substantial investments in grid extensions and refurbishments (reverse flows, compressor stations) are being realised or planned to diversify gas supply sources and to improve the robustness of the infrastructure against unplanned availability of the largest source or infrastructure component.
Moreover, the asset base of the TSO is rather aged (about 46% of the gas pipelines is over 40 years old), and would require upgrading and modernisation in the coming decades.

Table 7-5 Service life of the main units of the National Transmission System[451]

Service life	Transmission pipelines (km)	Supply connections (km)	Regulating - Metering Stations (RMS)
> 40 years	5,182	219	127
30 - 40 years	2,583	170	51
20 - 30 years	1,064	191	69
10 - 20 years	1,043	553	463
< 10 years	1,431	675	530
TOTAL	11,303	1,808	1,240 RMS
	13,111		

The overall investment level for development and maintenance will hence remain high, and will in principle not be affected by a potentially decreasing gas demand. Moreover, if the development of hydrogen would lead to injected volumes into the gas grid that exceed the technical threshold, specific additional investments would be needed to refurbish the transmission infrastructure.
The financing methods taken into account for the major investment plans for 2014 – 2023 consist of 35% internal sources (i.e. depreciation and net profit appropriated for investments) and 65% external sources (i.e. grants, loans from financial and banking institutions or bond issues).[452]

7.3.4 TSO viability analysis: estimated impact of the 3 storylines on end-user tariffs and on the business of the TSO

The table below provides an overview of the expected qualitative impacts of the three storylines.

[451] Transgaz (N/A), Development Plan for the National Gas Transmission System 2014 – 2023.
[452] Transgaz (N/A), Development Plan for the National Gas Transmission System 2017 – 2026.

Table 7-6 Assessment of the possible consequences of the 3 storylines for Transgaz

	Current figures	Storyline 1 Strong electrification		Storyline 2 Strong development of carbon-neutral methane		Storyline 3 Strong development of hydrogen	
Gas demand [453] **Transported volume**	105 TWh 158 TWh	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
		Decrease	Decrease	Stable	Stable/Slight increase	Slight decrease	Decrease
Investment for maintenance of transmission/transit network		Similar situation in 3 storylines: investment level for maintenance will remain at relatively high level to replace ageing assets and to ensure network security and safety		Similar situation in 3 storylines: investment level for maintenance will remain at relatively high level to replace ageing assets and to ensure network security and safety		Similar situation in 3 storylines: investment level for maintenance will remain at relatively high level to replace ageing assets and to ensure network security and safety	
Investment for development of transmission/transit network		High investment level in near future Post 2030 : investments required to refurbish grids to accommodate H2 (about 50% of gas demand in 2050)		High investment level in near future Post 2030 : limited investments to accommodate transport of biomethane (90% of gas demand in 2050)		High investment level in near future Post 2030: grid investments needed to accommodate H2 (90% of gas demand in 2050)	
Net assets value (RAB)	€ 649 million	High increase in short term - Stable in medium/long term		High increase in short term - Stable/decrease in medium/long term		High increase in short term - Stable in medium/long term	
Operational expenses	€ 264 million	No major impact: most OPEX are not volume related but are fixed or infrastructure related		No major impact: most OPEX are not volume related but are fixed or infrastructure related		No major impact: most OPEX are not volume related but are fixed or infrastructure related	
Depreciation and capital costs		Ongoing investment program will lead to high depreciation and capital costs until 2050 Overall level will be higher in this storyline due to H2 related investments		Ongoing investment program will lead to high depreciation and capital costs until 2050 Overall level will be lower in this storyline		Ongoing investment program will lead to high depreciation and capital costs until 2050 Overall level will be higher in this storyline due to H2 related investments	
Possible evolution of grid tariff for end-users	About 1.5 €/MWh	Increasing grid tariffs		Grid tariffs would remain more or less stable		Increasing grid tariffs	
Overall assessment		Highest negative impact on gas TSO and grid tariffs		Positive impact on gas TSO and grid tariffs		Medium negative impact on gas TSO and grid tariffs	

[453] Volumes transported via transmission grid will be lower than gas demand, as part of the gas demand will be covered by local production or be injected into distribution grid (e.g. biomethane)

8 Key Findings and Conclusions

In the first part of this study (tasks 1 and 2), three well-reasoned storylines have been developed in view of analysing and evaluating potential future roles of gas and gas infrastructure in the medium and long term (horizon 2030 and 2050). All three storylines have in common the achievement of the -95% GHG emission reduction target by 2050 compared to 1990 levels.

The three storylines address fundamentally different energy system configurations based on:

(1) electricity becoming the major energy carrier for transport and buildings;
(2) a coordinated role of the gas and electricity infrastructures with a focus on carbon-neutral methane either as synthetic methane ($PtCH_4$) or biomethane; and
(3) a coordinated role of the gas and electricity infrastructures with a focus on hydrogen.

In the 3 storylines, the development of renewable gas plays an important, but different role. The characteristics of the 3 storylines are briefly introduced in the table below.

Table 8-1 Characterisation of the storylines

Storyline	Characterisation
1. Strong electrification[454]	• Very strong electrification of buildings (75% - versus 10% today - of heating needs provided from electricity[455]); *limited role* for (renewable) gas • High electrification of transport sector • Long-term role for gas (mainly hydrogen) in industry and power generation, complementing renewable energy-based power generation.
2. Strong development of CO2-neutral methane	• Decarbonisation of transport sector based on strong electrification and use of renewable gas • Strong electrification of buildings (50% of heating demand versus 10% today); remaining share partly covered by biomethane • Long-term role for gas (mainly biomethane) for industry and power generation
3. Strong development of hydrogen	• Decarbonisation of transport sector based on strong electrification and use of hydrogen • Strong electrification of buildings (50% of heating demand); remaining share partly covered by hydrogen • Long-term role for gas (mainly hydrogen) for industry and power generation

In this part of the study (task 3 and 4), the consequences of these storylines for 6 selected Transmission System Operators have been evaluated on the one hand and the readiness of 3 National Regulatory regimes in a significantly changing energy landscape has been analysed on the other hand. The following sections provide an overview of the main findings and conclusions in this regard.

[454] This storyline would have a huge impact on the electricity infrastructure (changes in load curve and load levels); these impacts are not considered in this study.
[455] Mainly by using heat pumps.

8.1 Gas in the shift towards a carbon-neutral energy system

8.1.1 Current status and national policies regarding renewable gas deployment in the selected Member States

In several countries, a large share of the current natural gas consumption could, according to recent studies, be replaced with biogas/biomethane. Several policy initiatives have been taken to stimulate this development (see overview in table below). However, the level of deployment of renewable gas is still limited and strongly varies across the considered Member States.

Biogas for local use (heat and/or power) is developed in all countries, but its conversion to biomethane and injection into the grid is not common practice yet, either for technical-economic reasons or due to the lack of an enabling framework. On the basis of recent changes in legislation, it is expected that biomethane will develop in all considered countries, and that biomethane plants would mainly be connected to the distribution grid and to a less extent to the transport grid. Production and injection of synthetic methane and hydrogen are still in the R&D and pilot phase, with no large-scale facilities connected to the gas grid yet in the selected Member States.

Table 8-2 Overview of renewable gas deployment and supporting policies

MS	Overall RES target		Renewable gas injection	Policies facilitating renewable gas injection
	2020	2030		
Denmark	30%	NA	**Current:** 7% of gas demand 2018 covered by biomethane; 26 biomethane plants connected to DSO grid and 1 to TSO grid. Pilot project for H2 (1.2 MW PEM) **Target:** 10% in 2019	Subsidy scheme for biogas/biomethane produced from anaerobic digestion H2 and synthetic methane are not yet eligible for support
France	23%	32%	**Current:** 215 GWh biomethane (2016) P-2-G demonstration project (Jupiter 1000) Injection planned in 2018 **Target:** Law on Energy Transition imposes target of 10% of green gas consumption by 2030. 1.3 TWh biomethane in 2018 and 8 TWh in 2023	Feed-in tariff for biomethane: from 65 to 125 €/MWh, depending on biomass input type and capacity of installation Rebate on connection charges
Ireland	16%	NA	**Current:** 1 biomethane plant (108 GWh/yr) connected to TSO grid in 2018 **Target:** 6 injection plants connected to TSO grid in 2020	Specific support scheme for renewable heat implemented in 2018
Italy	17%	28%	**Current:** Large biogas capacity (1406 MW) 18 biomethane injection contracts signed in 2016-2017 with TSO. 1st biomethane injection plant in TSO grid (348 GWh/yr) in 2017. No projects for injection of H2 or synthetic methane **No target**	Biomethane Decree of 2nd March 2018 establishes incentives for biomethane injected into gas grid
Poland	15%	NA	**Current:** Only biogas (234 MW) for local use. No renewable gas injection **No target**	Changes in law ongoing to support injection of biomethane in DSO grid
Romania	24%	NA	**Current:** Only biogas for local use. No renewable gas injection **No target**	Financial support (Government Decision 216/2017) for 'less exploited' renewable energy sources, including renewable gas

National support mechanisms for renewable gas are in place in all considered MSs but some of them were only focusing on biogas and were excluding biomethane and other types or renewable gas. Recently, initiatives have been taken to also include biomethane. Support levels are at present mostly determined ex-ante, making it difficult to properly account for cost developments. An evolution towards a more technology-neutral support scheme, open to all renewable energy vectors and based on tenders or calls for proposals, would be more cost-effective and less distortive. Financial support for renewable energy (including gas) should in principle be temporary and gradually be phased out for mature technologies, also in order to avoid that the financial impact of subsidy schemes would harm the affordability of energy for households and the competitiveness of industrial end-users that are exposed to international competition. An EU wide implementation of a carbon tax or levy on all energy uses (including non-ETS installations) would improve the economic feasibility of renewable gas and reduce the need for specific support.

Injection of renewable gas into the grid could be further facilitated by **enabling and more harmonised technical specifications and by including priority dispatch for renewable gas in national legislation.** The cost for treating renewable gas to meet grid quality requirements can hinder its development. Joint initiatives (upscaling) could allow to reduce this cost. Moreover, TSOs and DSOs could be stimulated to review (e.g. via Marcogaz) the current specifications, in view of further reducing the technical-economic barriers for connecting renewable gas production facilities to the grid, while safeguarding the safety and technical performance of the gas grid and end-user equipment.

Production and trade of biomethane are facilitated via guarantees of origin (GOs) in some considered Member States (Denmark and France). An EU wide system of **guarantees of origin** for all types of renewable gas would be appropriate. As renewable gas can easily be stored, a longer validity period for gas related GOs could be considered (in comparison with the current 6 months validity after issuing). Guarantees of origin can also allow to properly count the share of renewable gas in the energy mix. As renewable energy will be increasingly converted in subsequent processes (e.g. from power to gas to power), the procedure for granting GOs should be properly determined to avoid double counting. These issues are currently being addressed in the ongoing review of the Renewable Energy Directive (see section 8.1.4).

Finally, the conditions and **charges for connecting production facilities of renewable gas to the grid** have also an impact on their development. In France, grid operators are obliged by law to grant a rebate on the connection charges for biomethane plants; in Ireland, the regulator approved in May 2018 a specific grid connection policy for renewable gas production facilities. As grid tariffs, including connection charges, have to be cost-reflective and non-discriminatory, rebates for specific technologies or vectors might not be the most appropriate approach. Authorities could rather opt for applying a ‘shallow’ methodology where only direct connection costs are charged to production facilities, while indirect costs (upstream investments), if any, are socialised.

8.1.2 Use of natural gas for transport and power generation as intermediate step in energy transition

Several Member States and gas companies are taking initiatives to stimulate the use of natural gas (CNG or LNG) in the transport sector, in view of mitigating the decreasing trend of gas demand for heating, while contributing to the shift to a less polluting energy use.

In **France**, a specific policy measure was implemented to develop natural gas (CNG, LNG) in the transport sector, with the aim of reducing GHG and other emissions, while paving the way towards a system where renewable gas (biomethane, hydrogen) can increasingly be used as transport fuel. Similarly, **Poland**, has adopted an ambitious plan for CNG and LNG vehicles and fuelling infrastructure (though currently there is hardly any gas used for transport). In **Italy** gas is to a large extent used for transport purposes, with approximately one million vehicles currently being fuelled with natural gas and 1040 CNG filling stations across the country.

In order to facilitate and stimulate this development, which can in particular be adequate for specific market segments (trucks, buses, ships) where electrification would not offer an adequate alternative, it would be appropriate to clarify the possible role of grid operators in developing and operating CNG, LNG or hydrogen filling stations for the transport sector. The related activities of grid operators should be subject to appropriate regulatory oversight, and should not lead to competition distortions. Part of the connection costs of gas filling stations to the grid (e.g. indirect costs related to upstream investments) could be socialised via the grid tariffs.

Similarly, in some Member States, measures are being taken to phase out coal or peat fired coal plants and substitute them with renewable energy and/or (natural) gas based capacity, mainly in order to reduce GHG and other emissions (see table). This measure also offers the possibility to shift in the medium or long term to renewable gas.

Table 8-3 Phase out policies for fossil fuels

MS	Phase out policy
Italy	Phasing out coal fired power plants by 2025
Denmark	Phasing out all fossil fuels by 2050 with gas playing an important role in the transition (mainly in back-up power plants for intermittent power generation capacity).
Ireland	Phasing out coal by 2025 and peat for power generation by 2030 Ireland would consider building CCGTs with CCS for baseload power generation
France	Switching in industry from coal or fuel to gas stimulated by NRA decision to grant connection fee discounts to new industrial gas users

8.1.3 Innovation and R&D to accelerate development of renewable gas

The transition to a carbon-neutral gas system will require significant R&D and innovation efforts, and a supportive and technology-neutral policy and regulatory framework. All relevant technologies, including water electrolysis, CO_2 extraction from air, conversion of existing natural gas appliances (see Chapter 2.3.3. of Tasks 1 & 2 Report) should be enabled to contribute. The political focus should be on the goals to be achieved (CO_2 emissions, air quality, affordability/costs, supply of security, end-user friendliness etc.), without privileging or excluding specific technologies. However, for non-mature technologies (e.g. P2G), specific ‘additional’ support could be granted for R&D and pilot projects. It would also be appropriate to periodically evaluate and adapt the policy instruments to ensure that potential benefits from relevant, available technologies are obtained in the best possible way.

Research, innovation, demonstration and pilot projects, and early-stage investments are necessary to improve the feasibility of new technologies. Involvement of grid operators in pilot and industrial scale projects could allow to speed up the transition. Some TSOs are already participating in R&D and demonstration projects (e.g. to assess the suitability of their infrastructure to accommodate hydrogen) and NRAs agree to recover the concerned costs via the grid tariffs. In this context, TSOs have suggested regulatory changes that would allow grid operators to invest in green gas production and storage facilities, possibly together with partners that would be responsible for the related commercial activities. They are also keen to invest in and operate dedicated hydrogen or CO_2 networks, which could be coupled with regulated or negotiated third-party access to the concerned networks[456], to ensure fair competition on the concerned markets. It would be appropriate to clearly determine the potential role and involvement of grid operators in these 'new' activities, in order to avoid market distortions, sub-optimal macro-economic outcomes and/or cross-subsidisation.

Innovation is also necessary in the products and services offered by TSOs. After having established a standardized product range facilitating the internal energy market, TSOs should now be enabled and stimulated by NRAs to focus on the new challenges related to decarbonization and sector coupling, which require more flexible and short-term products and services (e.g. gas take-off for power generation, gas infeed from renewable gas plants). In this context, TSOs should adapt their products to the current and future market needs (including development of renewable gas) and contribute to an overall optimal use of the energy infrastructure (global optimisation of both electricity and gas assets). Such developments should also include adoption of smart technologies and digitalization as well as possibilities to cooperate across the value chain, across sectors and across borders, whilst ensuring non-discrimination and open access to the gas infrastructure.

8.1.4 The current and proposed Renewable Energy directive and its implications

Renewable gas can effectively contribute to reaching the different sub-targets for renewable energy (electricity, heating/cooling, transport), and is being addressed in EU legislation[457]. At European level, several tools are available to co-finance investments related to the development of renewable gas (including for example biomethane production, power-to-gas or gas-to-power facilities, refurbishment of gas transport, distribution and storage infrastructure). These include support from the EIB, ERDF, NER 300 (specifically for innovative demonstration projects) and CEF (for some major projects that cannot be completely realised on market terms and have a cross-border impact as part of the trans-European energy gas network).

Gas from renewable sources (i.e. landfill gas, sewage treatment plant gas and biogases according to Article 2 of the RED) is supported in the current RED since it counts towards the binding targets for both the share of renewable energy in total energy and transport energy use of a Member State. Moreover, biogas/biomethane produced from waste streams may count double towards the transport target under the Renewable Transport Fuel Obligation (RTFO), providing an additional incentive above biogas and biofuels produced from energy crops.

The Renewable Energy Directive (2008/28/EC) and renewable gases

The Directive:

- Defines sustainability criteria for biofuels and bioliquids, including bio-CNG (compressed biomethane)
- Provides default values for GHG emission savings for biogas (as bio-CNG) from municipal organic waste, from wet and from dry manure.
- Requires Member States to assess the need to extend existing gas network infrastructure to facilitate the integration of gas from renewable energy sources.

[456] Though hydrogen pipelines are not covered by energy regulation (unbundling, access, etc.)
[457] Including Regulation EU 1315/2013 (TEN-T) and Directive 2008/28/EC (Renewable Energy Directive)

- States that the costs of connecting new producers of gas from renewable energy sources to the gas grids should be objective, transparent and non-discriminatory and due account should be taken of the benefit that embedded local producers of gas from renewable sources bring to the gas grids.

The reviewed draft Directive (RED II) will include further measures that stimulate and facilitate the deployment of renewable gas and its injection into the gas grid. The following is not a comprehensive assessment:

1. **Coverage of renewable gas**. It includes a number of biogas feedstocks (Annex IX) which can contribute to lower carbon emissions;
2. **Guarantees of origin and consumer transparency**. It aims to extend GOs, which are currently in place for renewable electricity and renewable energy for heating and cooling, to cover renewable gas (including e.g. biomethane and enabling their use also for other renewable gases such as hydrogen), facilitating their sales and (cross-border) trade;
3. **Mainstreaming renewables in the transport sector**. RED II would introduce a 14% renewable transport target to be implemented through a fuel supplier obligation to blend a minimum share of advanced biofuels and/or biogas from a list of feedstocks which includes a number of waste-based biogas feedstocks. RED II requires Member States to include a minimum share of renewable energy by 2021 in their transport fuels. This includes biogas from the feedstocks listed in Annex IX (such as manure, sewage sludge and household and municipal biowaste) as well as renewable gaseous transport fuels of non-biological origin. The overall obligation could also be met with hydrogen produced via electrolysis from renewable electricity which can be used in fuel cell propelled vehicles or liquid or gaseous fuels produced with energy from renewable hydrogen [power to gas or power to liquid];
4. **Heating and cooling sector**. RED II requires Member States to increase the share of renewable energy for heating and cooling by 1.1-1.3% point (pp) per year. The injection of biomethane in the natural gas network would qualify as "physical incorporation of renewable energy in the energy fuel supplied for heating and cooling";
5. **Sustainability**. RED II adapts the verification rules (i.e. mass balance system) to cover also injection of biomethane in the natural gas grid. It also reinforces the existing EU sustainability criteria for bioenergy, including by extending their scope to cover biomass and biogas for heating and cooling and electricity generation.

8.2 Gas Infrastructure in the medium and long term

8.2.1 Impact of the three storylines on gas use and infrastructure

The selected storylines have diverging implications on gas infrastructure at national level. Due to substantially decreasing natural gas demand in all three storylines, the utilisation level of LNG terminals and import pipelines would significantly decrease. The negative impact on the use of transmission grids and storage would be lower due to the expected use of this infrastructure for renewable gas.

Impact on overall gas demand

Storyline 1 would lead to a decreasing overall (natural and renewable) gas demand by 2030 and 2050 in all considered countries; in storyline 2 the overall gas consumption would in general increase, while in storyline 3 gas demand would increase (e.g. Poland) or decrease (e.g. Italy). National trends are different depending on local specificities, e.g. current energy mix and availability of biomass. The volumes fed in into the transmission gas grid, would be lower than the overall gas demand, as part of the produced biogas and hydrogen will be used locally for power/heat generation or for transport or industrial purposes, and part will be injected at distribution level. After 2030, natural gas consumption and hence related imported/transported volumes would substantially decline in all three storylines, while biomethane and hydrogen would gradually replace part of the natural gas consumption.

Table 8-4 Overview of the impact of the three storylines on gas demand

Storylines	1: Strong electrification	2: Strong development of carbon-neutral CH_4	3: Strong development of H_2
2030 gas demand*	**Lower**	**Slightly higher**	**Stable**
Mix	About 90% natural gas About 10% renewable gas	About 90% natural gas About 10% renewable gas	About 90% natural gas About 10% renewable gas
2050 gas demand*	**Substantially lower**	**Higher**	**Stable**
Mix	No natural gas 70% hydrogen + 30% carbon-neutral methane	No natural gas 10% hydrogen + 90% carbon-neutral methane	No natural gas 90% hydrogen + 10% carbon-neutral methane

*Note: * compared to 2015.*

There are significant differences in current and expected national developments. Some countries are already transitioning away from the use of natural gas and stimulate its replacement with renewable gas (e.g. France and Denmark), whereas others are still increasingly using natural gas in their energy mix, in particular for power generation (e.g. Poland). Some countries (e.g. Italy and France) also focus on the use of gas in the transport sector (CNG and LNG). The diverging national trends are mainly due to national policies and specificities, such as climate policies and goals, local availability of natural resources (fossil fuels and renewable energy sources), and large differences in the share of fossil fuels, in particular natural gas, in the energy mix.

The future gas demand will mainly be affected by:

- global market developments (e.g. prices of primary energies, development and cost of renewable energies and 'new' technologies such as P2G and fuel cells, innovations in low carbon industry processes and in heating and cooling technologies or pre/post combustion CCS and CCU developments);
- EU and national policy measures (e.g. carbon price, energy efficiency, energy taxation, targets and support schemes for renewable energies);
- Specific national market developments, such as the use of gas for:
    - heating (decreasing in most Member States);
    - power generation (different national trends depending on the role of gas as back-up for intermittent renewable energy and to replace phasing out nuclear and lignite/peat/coal-based power generation capacity);
    - transport (strong development of CNG/LNG is several EU Member States).

Impact on gas infrastructure

The expected changes in the gas demand and gas mix, in particular the expected decrease in the imported natural gas and transported gas volumes in the medium and long term, will have a huge impact on the utilisation of gas infrastructure and on future investment needs.

The utilisation level of LNG infrastructure, which has already substantially decreased (from 29.1% in 2012 to 19.6% in 2018) would further decrease in the 3 storylines and import pipelines would also be less utilised, although some EU Member States with limited biomass potential might consider importing gaseous (or liquified) biomethane via this infrastructure from other EU or non-EU countries (e.g. Ukraine or Russia). The negative impact of falling natural gas demand on the utilisation level of the transmission network will be lower than on import infrastructure, as it is expected that a major part of the locally produced renewable gas will be injected into the gas grid. Existing gas storage facilities could continue to be used for biomethane; some types, in particular salt caverns, could be refurbished for hydrogen and could also be used for short-term flexibility purposes, while the possible conversion of depleted gas fields (used in e.g. Poland, Romania and Italy) for storage of hydrogen is under study.

As regards the transport of hydrogen via gas grids, some studies suggest that hydrogen could be blended with natural gas up to 10 or 15% of the gas by volume, without requiring major adaptations to the gas transmission infrastructure and end-user appliances. Other sources refer to 2% maximum, in order to avoid risks for corrosion in the transmission grid, and negative impacts for end-user appliances, in particular gas fuelled vehicles. The currently used thresholds for the maximum hydrogen content by volume lie in general well below 10%.[458] Studies are currently ongoing (e.g. in France) to determine the technically maximum allowable hydrogen concentration level in gas grids. Ongoing studies could allow to assess the possibility of harmonising across the EU the specifications for injection of hydrogen into the transmission and distribution grids in order to facilitate this development.[459] Studies to properly estimate the investments required to refurbish the gas network to accommodate higher (above the ‘technical’ threshold) hydrogen volumes would in this context also be useful, as well as studies to assess the suitability of gas storage sites for hydrogen.

Given the expected decline in transported gas volumes and the fact that ongoing investment projects will allow reaching a high level of supply security and market integration, further **investment** in grid expansion of import or transport capacity would not be needed in general. If however, the above mentioned threshold for hydrogen would be exceeded (i.e. after 2030 in storylines 1 and 3), refurbishment investments of grids (and end-user appliances) would be required, and, in some cases, reverse flows from distribution to transmission grids would also need to be developed to allow upstream renewable gas flows, in particular if large quantities exceeding local consumption would be injected at distribution level.

Moreover, due to ageing gas infrastructure in most considered EU Member States, substantial investments for maintenance and replacement of grid components (e.g. pipelines, compressor stations – e.g. gas turbines to electric drives -, metering equipment) would be required in the three storylines, even with falling transported volumes, to keep the gas infrastructure safe and reliable. These

[458] FCH (2017) Development of business cases for fuel cells and hydrogen applications for regions and cities – Hydrogen injection into the gas grid. https://www.ctc-n.org/sites/www.ctc-n.org/files/resources/hydrogen_injection_into_the_natural_gas_grid-_development_of_business_cases_for_fuel_cells_and_hydrogen_applications_for_regions_and_cities.pdf

[459] CEER (2018) Study on the future role of gas from a regulatory perspective.

investment needs are comparable in the three storylines, and are only marginally influenced by decreasing utilisation levels.

The overall investment level is hence not expected to decrease substantially in any of the 3 storylines. In order to limit the risk for devalued or stranded assets, new investment programs should hence be subject to a thorough preliminary analysis, and, if technical-economically feasible, operators should opt for flexible and future-proof solutions (e.g. floating LNG regasification installations instead of fixed ones, infrastructure components also suitable for renewable gas).

Table 8-5 Overview of impact of the three storylines on gas infrastructure

1: Strong electrification	2: Strong development of carbon-neutral CH_4	3: Strong development of H_2
• Significant reduction in gas demand by 2050 → 20 to 50% lower than current level • Gas demand consisting in 2050 of 70% hydrogen and 30% biomethane • Renewable gas locally produced or imported => transported volume lower due to local use and injection in distribution grid • Diverging developments at national level • Further decreasing utilisation of gas import and transport infrastructure, leading to devalued or stranded assets (import pipelines, LNG regasification terminals) • Impact on storage assets (H_2) • Investments to accommodate TSO grid to hydrogen (> threshold)	• Increase in overall gas demand by 2050 → up to 50% higher than current level • Gas demand in 2050 consisting of 10% hydrogen and 90% biomethane • Decrease of demand in heating sector would be compensated by higher use in transport & industry • Renewable gas locally produced or imported =>transported volume lower due to local use and injection in distribution grid • Diverging developments at national level • Further decreasing utilisation of gas import infrastructure • Gas storage can be used for biomethane • Investments to allow reverse flows D -> T for biomethane	• Gas demand in 2050 (consisting of 90% hydrogen and 10% biomethane) lower or higher than current level depending on national specificities • Renewable gas locally produced or imported => transported volume lower due to local use and injection in distribution grid • Diverging developments at national level • Further decreasing utilisation of gas import infrastructure • Impact on storage assets (H_2) • Highest investments in infrastructure development and technical conversion or adaptation to accommodate TSO grid to hydrogen (> threshold)

8.2.2 *Drivers for gas infrastructure investments*

Current and planned investments in large gas infrastructure are mainly driven by security of gas supply objectives (N-1 infrastructure standard, access to diversified gas sources), wholesale markets' integration and shifts in gas supply (decreasing domestic gas production, conversion of L-gas to H-gas, shift from pipeline gas to LNG). The realised and ongoing investments are leading to a resilient gas system in the considered Member States that offers high system security and flexibility for gas sourcing. Some Member States (France and Italy) have developed large LNG terminal capacities, whose utilisation level has substantially decreased since 2010, mainly due to market reasons. Notwithstanding overall decreasing utilisation levels of LNG infrastructure, several Member States are still building or planning new LNG import capacity, mainly in order to have access to new gas sources and to reduce their dependency on Russian gas. The availability of LNG import capacity can also help them to improve the outcome of negotiations of new supply contracts for pipeline gas. The current gas supply split in the considered Member States is shown in the next table.

Table 8-6 Natural gas supply split in source type (pipeline, LNG, domestic production) in 2016[460]

	Pipeline import		LNG		Domestic production	
	mcm/day	%	mcm/day	%	mcm/day	%
Denmark	28	66.7	0	0.0	14	33.3
France	265	72.8	99	27.2	0	0.0
Ireland	30	75.0	0	0.0	10	25.0
Italy	339	85.0	43	10.8	17	4.3
Poland	157	83.5	14	7.4	17	9.0
Romania	24	16.4	0	0.0	122	83.6

The current investment projects in large gas infrastructure substantially enhance the security of gas supply situation in the considered countries/regions in view of complying with the criteria laid down in Regulation 2017/1938, and also contribute to market integration and enhanced competition. Most cross-border investment projects simultaneously contribute to both objectives. In France, the major ongoing investment project (North-South reinforcement) has been decided rather for market integration (competition) than for security of supply reasons. Most wholesale gas markets are meanwhile well-interconnected and competitive, in particular in Western-Europe, and prices are converging to a large extent. Some physical bottlenecks still remain, but these are being addressed in the current investment plans (e.g. reverse flows, harmonisation of pressure levels in Romania and neighbouring countries, reinforcement of interconnection between the northern and southern region in France). We notice that some regional gas markets, in particular in Eastern Europe, are still not properly functioning, but this is also due to inadequate market rules and regulation (e.g. price regulation and capacity allocation mechanism), and not only to a lack of interconnection capacity.

In the future, security of gas supply and markets' integration will no more represent major drivers for investments, but investments will mainly be driven by replacement needs of ageing assets, refurbishment to accommodate renewable gas and projects to enhance the adequacy and operational reliability of the integrated energy system.

8.2.3 Potential synergies within the energy sector and with end-users to reduce gas infrastructure costs

In order to reach the energy and climate objectives cost-efficiently, it is important to utilise the potential synergies within the energy sector, and to optimise the sector coupling between energy supply and demand in the different sub-sectors, in particular buildings, transport and industry.

Valuing potential synergies within the gas sector could allow to reduce the operational costs of gas infrastructure and mitigate the risk of increasing gas infrastructure tariffs, and hence improve the potential to use the gas infrastructure for renewable gas. Economies of scale could be realised within the gas sector by a more structural cooperation between operators of regulated assets (e.g. gas distribution, transmission, storage, LNG terminals); the cooperation could focus on specific services (e.g. joint investment reviews, joint procurement, shared services centres for HR, legal issues and IT) or in some cases mergers between operators could be considered. A more structural cooperation could also be envisaged between electricity and gas TSOs, not only in view of optimising the mutual investment programmes but also of realising possible operational gains via e.g. shared services. In this

[460] N/A (2016), Physical gas flows across Europe and diversity of gas supply in 2016. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/669709/Physical_gas_flows_across_Europe_and_diversity_of_gas_supply.pdf
Note however that the figures for Romania seemed to be inverted in the source document and have been revised here.

context, it might be useful to evaluate and learn lessons from the Danish model, where Energinet has been appointed as gas storage operator and as TSO for both electricity and gas. Further assessment of the potential constraints stemming from the unbundling rules may be required.

Sector coupling also offers a potential for cost reduction; it mainly focuses on technologies that couple electricity supply with end-user demand, but also encompasses options to improve the overall efficiency of the energy system by combined electricity-gas solutions, e.g. power-to-gas based on “excess” renewable energy-based electricity.

According to the gas TSOs, an integrated energy infrastructure building on the existing electricity and gas systems would in principle be more efficient, resilient, sustainable and less expensive than an all-electric energy infrastructure. The sector coupling (interaction) between the 2 systems can be optimised in order to have a cost-efficient outcome:

- Using both the electricity and gas infrastructure should a priori allow achieving the energy and climate goals at a lower cost than an all-electric energy system;
- A well-connected and resilient gas infrastructure already exists and can provide competitive capacity for long distance transportation of energy, peak capabilities, flexibility, and storage;
- The gas system has a significant potential for decarbonization by further developing biomethane, hydrogen, synthetic methane, etc.;
- A dual infrastructure is more resilient and provides improved security of supply, including enhanced adequacy and operational reliability of the energy system.;
- The removal of barriers for further interaction between electricity and gas will allow for an improved transition to a zero-carbon economy.

TSOs insist that European and national authorities should properly acknowledge the benefits of gas infrastructure (in a hybrid energy system), where gas infrastructure owners and operators continue to be properly remunerated for the services they provide, and are incentivized to further invest in the required assets.

This study focuses on the impacts of the 3 storylines on gas use and infrastructure only; a global assessment of the 3 storylines based on their impact on the global electricity and gas system would be useful to check to what extent a hybrid infrastructure and energy model would effectively offer economic and environmental benefits, compared to a model mainly based on electricity use and infrastructure.

8.3 Implications of the storylines for the considered TSOs

A regulated Third Party Access (TPA) regime applies for almost all assets owned and operated by the considered TSOs. Tariffs for access to and use of grid infrastructure are regulated and calculated on the basis of their actual or 'authorised' operational expenses, depreciation costs and a regulated remuneration of capital. According to our assessment, the overall annual costs of the TSOs would in storylines 1 and 3 not decrease to the same extent as the transported volumes, while storyline 2 would lead to a more positive outcome in this respect. As TSOs benefit of 'guaranteed' revenues, which allow them to 'pass through' their costs, changes in the utilisation level of the infrastructure would have no direct impact on their profitability, but would mainly affect the grid tariffs. The expected impact of the storylines on the accounting value (or RAB) of the TSOs and on their investments and costs, is hereafter briefly described.

8.3.1 TSO assets represent a high economic value which will be affected by the transition

Due to important investment programs in the past and generally long depreciation periods, TSOs have at present relatively high Regulatory Asset Bases (RAB) or net accounting values, which have to be depreciated in the coming decades and would result in increasing grid tariffs, if the transported volumes would decline more than the annual costs. We also notice that, due to national specificities (geographical situation, demand and transit level, investment level, accounting rules) the ratios between the asset values and currently transported volumes are quite different. The RAB or net accounting value will in most countries further increase until 2025 and then become stable or slightly decline depending on the country and storyline.

Table 8-7 RAB or net accounting value of the assessed TSOs

TSO	Net assets value/ RAB	Transported volumes	Outlook
Energinet (Denmark)	€ 618 million	51 TWh	Will gradually decline by 2050
GRTgaz (France)	€ 8.3 billion (RAB)	627.3 TWh	Slight increase in short term, then decreasing - different impact depending on storyline (highest decrease in storylines 2 and 1)
Gaz-System (Poland)	€ 1.7 billion (RAB)	198 TWh	Will increase until 2025 and might then slightly decline (storyline 1), decline (storyline 2) or become stable (storyline 3)
Snam Rete Gas (Italy)	€ 16 billion	795 TWh	Stable (storyline 1 & 2) or slight increase (storyline 3)
Gas Networks Ireland (Ireland)	€ 1.4 billion	72.5 TWh	Decreasing, however investments for CCS (independently of storylines) and H2 refurbishment (storyline 3) might limit decrease
TransGaz (Romania)	€ 649 million (RAB)	157.5 TWh	High increase in short term (+ 30% by 2020) - stable in medium/long term due to large investments in the 3 storylines to replace ageing assets

8.3.2 CAPEX would remain high with slightly different impact per storyline

As explained in the national chapters, the CAPEX (which currently represent 40 to 65% of the overall TSO costs) would remain at a relatively high level in all storylines. The CAPEX mainly consist of depreciation costs, which depend on the investment levels and depreciation rules on the one hand, and the capital costs on the other hand. The current investment levels are high for most considered TSOs, mainly due to investments related to security of gas supply and market functioning, though the levels diverge per Member State (e.g. relatively low in Denmark and high in Poland). The investments are expected to slightly decline (on average) in the coming 10 years, but some specific investments will be necessary, depending on the storyline to refurbish grids to accommodate H_2 in storylines 1 and 3, and to allow for reverse flows of renewable gas from distribution to transmission, in particular for biomethane in storyline 2.

Table 8-8 Investment levels of the assessed TSOs

TSO	Current investment level	Transported TWh	Outlook
Energinet (Denmark)	€ 3.6 million	51 TWh	Currently low investment level - 2020-2023: decrease or increase depending on decision about Baltic Pipe - Post 2023: decrease (mainly limited to maintenance and refurbishment H2)
GRTgaz (France)	€ 657 million	627.3 TWh	Future investments needed for ensuring operational security and safety. Investments for extensions and refurbishments will differ per storyline: highest in storyline 3 due to refurbishment H2
Gaz-System (Poland)	€ 512 million	198 TWh	High investment levels for network development until 2025 Post 2030 investments depend on storyline except for maintenance which will be needed to ensure operational security and safety
Snam Rete Gas (Italy)	€ 917 million	795 TWh	Stable maintenance investments to ensure security in operations Stable for network development in storylines 1 and 2; stable to slight increase for storyline 3.
Gas Networks Ireland (Ireland)	€ 125 million (including distribution)	72.5 TWh	Increasing maintenance costs, focus on refurbishment of existing network to ensure operational security and safety. Possibly limited investments after 2025, including investments to accommodate H_2, biomethane and CCS.
TransGaz (Romania)	€ 120 million	157.5 TWh	Investment level was in near past low (€ 30 million p/a) but would in coming 10 years substantially increase to € 120 million p/a, mainly for grid extensions/reinforcements and replacement of ageing assets. Investments post 2030 for network refurbishment will depend on storylines (i.e. to accommodate H_2 and biomethane)

Investments in gas transmission infrastructure are financed by own TSO resources and loans from commercial banks and the EIB as well as via other available instruments. In order to keep the grid tariffs affordable and to contribute to the overall security of supply and market integration objectives, some investments in (notably cross-border) gas infrastructure that cannot be completely realised on market terms are also co-financed by EU funds, in particular the CEF fund for Projects of Common Interest (PCIs).

8.3.3 OPEX are mainly fixed and falling gas demand would not lead to proportionate cost decrease

The OPEX, which currently represent between 35 and 60% of the total TSO costs, would remain at a relatively high level in all storylines. In case of falling transported gas volumes (expected in 2 storylines), the OPEX would only slightly decrease, as most cost components (e.g. maintenance, administrative costs) are fixed or infrastructure related to a large extent. Only a limited share (estimated at 2 to 10%) of the OPEX cost components are volume related (e.g. energy cost for compressor stations, odorisation). Hence, the evolution of the OPEX would only be slightly different depending on the storylines.

Table 8-9 OPEX levels of the assessed TSOs

TSO	Current OPEX level	Pipelines km	Outlook
Energinet (Denmark)	€ 32 million	924 km	Stable or slight decline due to efficiency standard imposed by NRA. Increase if Baltic Pipe project is realised
GRTgaz (France)	€ 764 million	32,414 km	Relatively stable. Impact of storyline is not decisive.
Gaz-System (Poland)	€ 245 million	11,743 km	No major impact from storylines. Expected to remain at same level (increase if Baltic Pipe project is realised)
Snam Rete Gas (Italy)	€ 441 million	32,584 km	Stable in storylines 1 and 2. Slight increase in storyline 3.
Gas Networks Ireland (Ireland)	€ 86 million	2,427 km	Slight decrease in line with cost efficiency targets imposed by NRA. However, CCS and H2 may lead to increase (depending on storyline).
TransGaz (Romania)	€ 264 million	13,303 km	Expected to remain more or less stable (ageing assets). No major impact of storylines: most OPEX are not volume related but are fixed or infrastructure related

8.4 Readiness of the selected national regulatory frameworks in a significantly changing energy landscape

The European and national regulations were basically designed for a growing gas market, where access to multiple gas sources and producers via adequate infrastructure on the one hand, and markets' integration on the other hand, were key objectives. In the meantime, security of gas supply is ensured at a high level, and European gas markets have become increasingly mature and interconnected. Some gas markets (e.g. Denmark and France) are largely saturated and are already declining, while other markets (e.g. Poland and Romania) are still growing. EU regulation that historically aimed at increasing interconnection capacity and preventing physical and contractual congestion, has become less relevant to those mature markets, where capacity is no longer scarce and where 'new' challenges (decreasing natural gas demand, local development of renewable gas, contribution of gas infrastructure to enhancing adequacy and operational reliability of energy system) are emerging that should be addressed by appropriate national and EU legislation.

While in the past investments were mainly aiming at ensuring a secure, competitive/affordable and sustainable energy supply, the climate objective has become more prominent. To meet the Paris Agreement commitments, the European gas system will have to become carbon neutral, which will translate in gradually decreasing natural gas demand, and replacing it (partly) with renewable gas for its different uses, including transport.
These anticipated evolutions will have to be facilitated by an appropriate regulatory framework.

On the basis of the analysis of the regulatory framework in three selected countries (France, Denmark and Poland), we hereafter summarize the key findings and conclusions regarding the readiness of national regulatory regimes in a significantly changing energy environment.

8.4.1 Possible evolution of grid tariffs under the current national regulatory regimes

Under the current regulatory regimes, regulated grid tariffs are applied for access to and use of grid infrastructure; they are calculated on the basis of the actual[461] or 'authorised' operational expenses of the TSOs, their depreciation costs and a regulated remuneration on the capital/equity or Regulated Asset Base (RAB) (see table). As TSOs benefit of 'guaranteed' revenues, decreasing transported gas volumes would have no direct effect on their income, but would lead to higher grid tariffs, if the annual TSO costs would decrease less that the transported volumes. According to our assessment, storylines 1 and 3 would have an increasing impact on grid tariffs, which might negatively affect the competitiveness and affordability of gas for end-users and the business case of transporting renewable gas via the grid. Storyline 2 would offer the most positive outcome from a gas grid user perspective.

Table 8-10 Overview of the grid tariff regulation in France, Denmark and Poland

Regulation of TSO grid tariffs	France	Denmark	Poland
Regulatory system	Revenue cap, incentive based with pass through of actual costs	Regulated tariffs based on actual costs - Energinet has to respect a break-even for all its tariffs[20]	Cost of service with elements of revenue cap
Capital remuneration	TSO capital remuneration-based on RAB	Regulated return on capital	Capital remuneration-based on RAB

[461] In some Member States an adjustment is applied on the operational expenses based on cost efficiency standards

The share of the TSO grid tariffs currently represents on average 7 to 10% of the overall gas bill, and varies depending on the level of the other cost components (commodity price, DSO tariff and taxes/fees) and the load profile. The impact of increasing transmission (and distribution) grid tariffs on gas end-users due to lower transported volumes might become an issue of concern, in particular for vulnerable households and industrial users that face international competition. In view of mitigating this impact, (cross-)subsidisation of gas infrastructure costs could be considered; this issue is addressed in section 8.4.5.

TSO tariffs have in most countries a two-part tariff structure consisting of a fixed (capacity) charge and a commodity charge. Capacity charges reflect the basic transmission services and are in general based on contracted (i.e. booked) capacity, while commodity charges are based on the actually transported volumes. Predominantly capacity related tariffs reflect the actual cost of providing transport services to grid users and result in more revenue stability for grid operators, as their revenues are only slightly affected by changes in consumption. From a consumer's perspective, the two-part tariff structure with a predominant capacity related share might penalise users with a low or flexible (and unpredictable) load profile (e.g. gas fired power generation as back-up for intermittent renewable energy). In some countries, TSOs already offer flexible tariff structures that facilitate short term bookings and hence mitigate this impact. TSO revenues from long-term transmission capacity reservations are in general decreasing. As in most Member States transport capacity is largely available, shippers are increasingly opting for short-term capacity reservations based on their effective nominations. This shift leads to a higher income volatility for TSOs, but deviations between their actual and projected revenues used for tariff setting are in principle corrected ex-post.

The revenue share of TSOs resulting from capacity based versus commodity-based tariffs is still quite different among Member States, e.g. 50/50 in Denmark versus 100/0 in France. We notice however that all assessed Member States are currently shifting to mainly capacity based revenues, which is in line with the Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (NC TAR). The new Gas Tariff Network Code[462] will lead to greater harmonisation in this regard, as its Article 4 states that transmission services revenues shall mainly be recovered by capacity-based transmission tariffs.[463] Once this Network Code will be implemented, most of the transmission services related costs will in all EU Member States be recovered via capacity charges.

Table 8-11 Overview of legislative/regulatory regimes for tariffication in France, Denmark and Poland

	France	Denmark	Poland
Access/use tariffs (Regulated or negotiated)	Regulated	Regulated	Regulated
Tariffs fixed ex-ante for x years	Fixed ex-ante for 4 years	Fixed ex-ante for one year	Fixed ex-ante for one year
Share of revenues related to commodity versus capacity-based tariffs	0-100	50-50 Capacity share will increase in future	10-90 0-100 from 2019

[462] Commission Regulation EU 2017/460 of 16 March 2017
[463] As an exception, subject to the approval of the national regulatory authority, a (small) part of the transmission services revenues may be recovered by commodity-based transmission tariffs: flow-based charges driven by energy flows (such as energy cost of compressor stations), which usually represent maximum 10% of the regulated revenues, and a complementary recovery charge which can be applied at points other than IPs (e.g. delivery points).

	France	Denmark	Poland
Allocation of costs amongst gas users	Based on capacity bookings and small fixed charges per delivery point	Based on capacity bookings and transported volumes	Based on capacity bookings and transported volumes
Specific conditions for transport of renewable gas via grid	Decree obliges grid operators to apply rebate on connection costs for biomethane*	No	No
Entry-exit split	35-65	Not predefined	45-55 for 2019

**This rebate results from a governmental measure, granting this rebate as a form of support to biomethane.*

The box below provides some examples from the country-level assessments.

Grid tariff methodologies in selected countries

Transmission grid users in France pay a capacity fee (based on the reserved capacity) applicable for use of the upstream transmission network, and a tariff for use of the downstream transmission network. Additionally, a delivery capacity term is applicable based on the delivery capacity subscriptions, and a fixed delivery charge per year and per delivery station.[464] Denmark applies both capacity and commodity related tariffs for gas transport. The capacity charges are not fully differentiated by location, but are also not completely uniform, as entry and exit capacity at the Interconnection Point with Germany are priced differently than other entry and exit points. The commodity related tariffs ('variable charges') are only charged at the exit points. Next to a regular commodity based charge (transport fee), gas consumers pay in Denmark also an emergency commodity related charge.

The current trend towards more harmonised methodologies across Member States for setting grid tariffs will limit the risk for competition distortion amongst end-users that operate at supranational level (power generators, industry) and will make it easier for gas traders and suppliers to operate across borders. Such a harmonisation will also facilitate further integration of national energy markets into a single EU energy market. The above mentioned network code (NC TAR) is hence a positive step in this respect. It enhances tariff transparency and coherency by harmonising basic principles and definitions used in tariff calculation. It also includes a mandatory comparison of national tariff-setting methodologies against a benchmark methodology, and stipulates publication requirements for information on tariffs and revenues of transmission system operators.

The entry-exit tariff system, which is used in most EU Member States,[465] has proven its effectiveness, and TSOs are in general in favour of it. They suggest however that, in a context where capacity is no longer a constraint in the system, it could be supplemented or modernised to better ensure that there are no bottlenecks in the system. Some countries apply locational signals, some use several market areas and some others use postage stamp tariffs. The postage stamp tariff system[466] is used where a simple entry-exit system exists with the entire costs of transmission being charged to consumers.

[464] More information available:
http://www.grtgaz.com/fileadmin/clients/fournisseurs/documents/en/2018-Transmission-tariff.pdf
http://www.grtgaz.com/en/acces-direct/customer/supplier-trader/tariffs.html
[465] http://www.inogate.org/documents/Gas%20pricing.pdf
[466] This system is applied in several smaller countries, especially, with a single external supplier.

As TSOs would in storylines 1 and 3 not be able to reduce their annual cost levels (OPEX + CAPEX) to the same extent as the expected decrease of the transported volumes, these storylines would have an increasing impact on the grid tariffs. Only storyline 2 would have a neutral or positive impact on grid tariffs. In order to mitigate the possible negative impact, several legal or regulatory measures could be considered, including strict(er) regulation of allowed costs and revenues of TSOs, review of legislation/regulation to enable structural measures to reduce the fixed costs of energy infrastructure operators (see section 8.2.3), more thorough ex-ante assessment of new investments (see section 8.4.2), stimulation of the use of the gas infrastructure for 'new' purposes (renewable gas, LNG/CNG for transport), review of the depreciation rules (see section 8.4.3) and of the criteria for public co-funding of investments and increased R&D in view of reducing the refurbishment costs.

In order to keep the grid tariffs in check in a scenario of falling gas demand, the CEER study suggests that regulatory authorities and legislators could consider lowering the allowed rate of return.[467] This measure would indeed reduce the capital costs of TSOs, and hence mitigate the increase of grid tariffs. This option seems adequate and a priori attractive for grid users and authorities, but it might negatively affect the ability of TSOs to further invest in assets that offer macro-economic benefits or are necessary for safety or security of supply reasons. The allowed rate of return should be market based and properly take into account their risks; in the current regulatory framework the risks related to assets operated under a regulated TPA are still limited but TSOs are concerned that the risk level might increase.

This study focuses on the impact of the three selected storylines on tariffs for gas transport assets, that are operated under a regulated regime. It would be appropriate to also assess more thoroughly the impact on the tariffs and viability of gas storage and LNG terminals in general and in particular of the assets which are currently exempted and hence operated under a negotiated regime. Moreover, it would be interesting to also study the impact of the storylines on gas distribution infrastructure.

Finally, it would be appropriate to further assess the specific connection and access conditions and costs for renewable gas plants that inject into the grid. Priority dispatch could be considered for renewable gas, and clear rules should be determined for the cost allocation between local gas infeed and take-off, based on robust methodologies and objective criteria, that also take into account possible positive impacts of local injection on the overall grid costs. Connection charges could be limited to the direct costs, while indirect costs (upstream investments) could be socialised. Moreover, clear and fair rules should be determined with regard to the applicability of transmission charges for renewable gas fed in into the distribution grid, taken into account the services that the TSO grid would provide for this type of grid users.

8.4.2 Regulation should enable investments in future proof assets

The current European and national regulation mainly stimulate investments in large gas infrastructure that contribute to security of gas supply and/or markets' integration (competition). As these objectives are to a large extent achieved, regulation should in the future more focus on the new major challenges, in particular the decarbonisation of the energy system at least cost, and the adequacy and operational reliability of the energy system. In this context, future regulation should stimulate TSOs to ensure that their assets are refurbished or replaced in a way which is consistent with the 'new' challenges and long-

[467] CEER (2018) Study on the future role of gas from a regulatory perspective.

term policy objectives as well as with realistic gas demand projections, and in particular with the development of renewable gas. For example, the capacity of compressor stations should be adjusted (decreased in most cases) when they are replaced and investments in transport or storage infrastructure should be future proof, i.e. the concerned assets should also be suitable for renewable gas.

Moreover, new investment projects at EU level (TYNDP and selection of PCIs) and at national level (NDPs), should be thoroughly evaluated in order to avoid or reduce the risk that the concerned assets would become 'useless' before the end of their depreciation period. The macro-economic evaluation (cost-benefit analysis including direct and indirect impacts), which is the core element of the PCI selection, should be based on several long-term scenarios which reflect different paths to reach the decarbonisation target (next to a scenario where the EU climate targets would not be met). Moreover, investment projects should be selected in view of a global optimisation of the overall energy (electricity and gas) system, taking into account their possible contribution to the adequacy and operational reliability of the energy system. Finally, investments should be future-proof; in this context, investing in floating storage and regasification facilities (cf. project in Cork, Ireland), could for instance be a better option than investing in fixed installations.

The current regulatory system in most Member States encourages the development of the TSO network via regulated remuneration. In order to foster investments that are future-proof, changes in the regulatory regime could be considered and new criteria could be implemented to regulate and remunerate TSOs. For example, regulators could consider implementing differentiated remuneration levels depending on the added value of the concerned assets in order to better reflect the benefits and future-proofness of investments, e.g. standard remuneration level for "conventional" replacement assets and specific national incentives for refurbished or new assets that meet strict flexibility and future-proofness criteria, similarly to the framework which is currently in place for investments with cross-border impact. In this context, energy infrastructure investments should be evaluated and stimulated on the basis of their potential impact on the overall energy system (e.g. economic and environmental benefits, quality and reliability of services, integration of renewable energy sources, security of supply including system adequacy and operational security), and according to selectivity criteria and output-based logic. The incentive mechanisms for the development of gas transport infrastructure, which are currently in several EU countries granting different remuneration levels depending on the assets' type, could be adapted in order to relate the remuneration levels to their added value for the energy system.

At EU level, the regulatory framework provides enabling measures and co-funding (e.g. TEN-E and CEF) to facilitate investments in gas infrastructure that have a cross-border impact and which cannot be completely realised on market terms. Some Member States (e.g. France) also provide specific national incentives for such investments. In the future, the need for additional import/transit pipeline capacity (including reverse flows) will be very limited. Additionally, gas infrastructure investments will mainly focus on maintenance (including replacement of ageing equipment) and refurbishment of existing assets, to accommodate injection and transport of renewable gas within Member States and across EU borders, as well as storage and delivery to end users. New dedicated transport or storage infrastructure may be needed for H_2 or CO_2. The TEN-E and CEF Regulations could be reviewed in order to focus on these 'new' investment priorities, while avoiding to further stimulate investments that can only be used for fossil energy.

Finally, some kind of capacity remuneration scheme could be considered for gas assets that are essential to ensure security of supply, including energy system's adequacy and operational reliability (e.g. strategic capacity reserve whose costs could be socialised). This measure could ensure that these assets are not prematurely decommissioned or mothballed when they are not profitable any more for their owners/operators. Such a scheme would contribute to security of energy supply and would, depending on the financing scheme, have a limited impact on the competitiveness of gas. This could be especially relevant for gas infrastructure (pipelines, LNG terminals, storage facilities) whose capacity is not booked under 'normal' market conditions, but nevertheless necessary to ensure security of gas and/or electricity supply. In this context, the flexibility that can be provided by these infrastructures to the power system, needs in this evaluation also to be properly taken into account. A careful assessment is however needed in order to avoid that such a scheme would undermine the market principles or would lead to distortions between energy technologies or vectors. An alternative solution is to opt for a regulated framework for assets (e.g. gas storage) which are considered strategic or necessary for the energy system; such an option has recently been taken for gas storage in France and has been in place in Italy for several years, and is a priori less distortive than implementing regulated schemes/safety measures within a negotiated market environment.

8.4.3 Review of depreciation rules for gas infrastructure assets might be appropriate

Due to the expected decrease in gas demand and transported volumes, some gas assets (in particular import infrastructure) could become devalued or stranded before the end of their depreciation period, especially as the lifetime which is currently considered for regulatory (tariffs) and accounting purposes can reach 50 years (e.g. for pipelines). The depreciation rules in the investigated Member States are still mostly based on the technical lifetime of the equipment, which can substantially exceed the economic lifetime taken into account the specific risks resulting from the changing energy demand and supply patterns. We notice that most TSOs still apply long depreciation periods, typically 50 years for pipelines and 30 years for compressor stations. In 2010, Italy extended the depreciation period for pipelines from 40 to 50 years, while Poland has taken a similar decision for new investments as of 2018. Only Denmark applies a shorter depreciation period (30 years) for new pipelines, in order to anticipate the expected decreasing role of natural gas in its energy mix in the medium and long term.

Table 8-12 Overview of depreciation rules for the TSOs in France, Denmark and Poland

Depreciation rules	France	Denmark	Poland
Depreciation period - Pipelines - Compressor stations	50 years 30 years	30 years 30 years	40 to 50 years 5 to 15 years
Depreciation approach (linear/ accelerated)	linear	linear	linear

On the basis of this assessment, a review of the depreciation rules is suggested, especially for new investments, in order to reduce the risks for devalued or stranded assets. The pros and cons of different options should be carefully considered, such as the Danish example of shorter linear depreciation periods, degressive front-loaded depreciation and accelerated depreciation rules.[468] This measure would in the short term have an increasing impact on grid tariffs, which could be mitigated by specific measures to reduce the costs in the gas sector (see section 8.2.3).

[468] CEER (2018) Study on the future role of gas from a regulatory perspective.

This recommendation might seem in contradiction with other policy recommendations that advocate for a long-term role of gas infrastructure through the development of renewable gas. However, as the transported volumes are expected to decline after 2030 in most scenarios, it would be appropriate to further assess this proposal, in particular for new assets.

TSOs also suggest that regulatory initiatives should be taken to cope with a possibly significant rise in network tariffs. They propose the following concrete measures:

- Energy regulators or other responsible authorities (e.g. finance ministries) should allow more flexibility in depreciation policy such as flexible depreciation periods and profile (e.g. depreciation based on shorter asset life and front-loaded depreciation can be used when TSOs are not covered against the volume risk);
- For fully depreciated assets with remaining technical lifetime, the TSOs suggest that it should be possible to recover revenues from these assets on the basis of the value of the transmission service they offer.

8.4.4 (Cross-)Subsidisation of grid infrastructure costs could be considered to mitigate the impact of falling gas demand on grid tariffs but it has distortive impacts

The distribution and transmission charges that cover the cost of transporting gas from entry points to end-users make up between 7 and 35% of the overall gas bill, depending on the grid to which end-users are connected (transmission or distribution) and their consumption profile. For large end-users directly connected to the transmission grid the share is limited, but for households and smaller businesses connected to the distribution grid, the grid costs represent a relatively high share of the overall gas bill.

Historically, the share of transmission tariffs represented 5 to 10% of the overall gas bill.[469] The falling gas demand in some Member States and the recent decrease in gas prices have led to an increase of this cost component for some users to over 10% of the gas bill.[470]

In the previous sections, we indicated that the gas grid tariffs are expected to increase as a consequence of falling gas demand. Increasing grid tariffs would a priori positively contribute to the energy and climate objectives, as they would incentivize a more efficient end-use of gas, but they would at the same time negatively affect the competitiveness of gas for industry and its affordability for (vulnerable) households. Increasing grid tariffs might also negatively affect the business case of transporting biomethane or hydrogen via the grid, and hence hinder their uptake.

In this context, different options could be considered to mitigate the impact of increasing grid tariff costs for specific uses and/or consumers:

- **Cross-subsidisation.** Allocating the grid costs differently in view of favouring specific market segments (e.g. industrial versus residential users; vulnerable versus other residential users) or gas types (e.g. renewable versus fossil natural gas).
- **Public subsidy for (part of) the gas infrastructure** in view of reducing the overall grid tariff level for all end-users and gas types, by using taxes or a carbon levy.

[469] SWD (2017) 107, Impact assessment for the Network Code on Harmonised Transmission Tariff Structures for Gas and for the Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems
[470] Ibid.

The key question is whether there are at present market or regulatory failures that justify (cross-)subsidisation of gas infrastructure costs to efficiently reach the energy (in particular competitiveness and security of supply) and climate objectives, and whether it is possible to design a subsidy scheme that would comply with the tariffication principles and state aid rules. As security of supply is a common good that is in general not properly priced by the market, subsidies could be considered to cover part of the cost of assets (e.g. gas storage) that are not sufficiently remunerated by the market, but that are anyhow necessary as back-up to ensure security of supply. Subsidies could also focus on the development of renewable gas, and provide more favourable grid connection and access costs for renewable gas compared to natural gas. Subsidies could finally be implemented to maintain gas affordable for vulnerable households and competitive for industrial users that face international competition.

Cross-subsidisation and/or public subsidisation could contribute to maintaining more affordable/ competitive gas bills for all or for specific end-users or gas types, but would entail several drawbacks.

When allocating gas infrastructure costs to grid users, the following major principles should be taken into account: economic efficiency, transparency (tariff setting process and data publication) and non-discrimination (of different groups of network users).[471] Economic efficiency means that tariff structures should be cost-reflective and should signal to grid users the marginal costs that they impose on the regulated company and encourage the operator to utilise its assets optimally. If gas infrastructure costs are not allocated according to this principle (due to cross-subsidisation) or are partly recovered by public means, this principle is not respected, and the tariff structure would hence not be economically efficient. Moreover, this practice could also lead to competition distortion amongst energy vectors (if other energy infrastructure would not be subsidised to the same extent) and/or amongst industrial end-users in different Member States.

Cross-subsidisation of grid costs would, depending on the concrete modalities, be more or less compliant with the principle of transparency of grid tariffs, which can be seen as a prerequisite for general acceptance by users and the general public, but would not be in line with the principle of non-discrimination, which requires to ensure that a level playing field is offered to all grid users; all users should indeed be treated equally, irrespective of their size, ownership or other factors, i.e. non-discrimination between users unless they generate different underlying cost patterns. In practice, this means that all users' tariffs should be based on the same methodology, but the calculated charges can of course be different depending on the demand level and consumption profile.

Subsidisation of gas infrastructure by public means could, depending on the concrete modalities, be compliant with the principles of transparency and non-discrimination. Gas assets necessary to ensure security of supply could for instance be subsidized; while this approach could be transparent and non-discriminatory, it could undermine the economic efficiency of the energy system, as tariff peaks to reflect scarcity of capacity would be reduced or eliminated, and market operators would hence not be adequately incentivized to invest in "emergency" capacity, or in other assets to cope with capacity constraints (e.g. demand side measures). Moreover, subsidisation of energy infrastructure in only one sub-sector (gas) might lead to competition distortion with other energy vectors (e.g. electricity).
A qualitative assessment of the three considered options is summarised in the next table.

[471] Ibid.

Table 8-13 Qualitative assessment of the options

Type of measure Criteria	Cross-subsidisation of renewable gas versus natural gas	Cross-subsidisation amongst grid users	Subsidisation via public funds
Cost-reflectiveness of access/use tariffs	negative	negative	negative
Economic efficiency	negative	negative	negative
Transparency	neutral or negative	neutral or negative	neutral or negative
Non-discrimination	negative	negative	neutral
Competitiveness - affordability	positive for renewable gas - negative for NG	positive for benefiting users - negative for other users	positive for gas users negative for tax payers
Security of supply	neutral	neutral	positive
Sustainability	positive	neutral	neutral or positive depending on concrete modalities[472]

Based on this assessment, neither cross-subsidisation nor public subsidies for gas infrastructure seem appropriate. Subsidies which would focus on specific energy vectors or end-users, would in general not be compliant with the principles of grid tariffication, in particular cost-reflectiveness and cost efficiency, and might have distortive impacts, and therefore such a policy measure is not recommended.

The TSOs point to the fact that the gas system will continue to provide a number of services, in particular short and seasonal flexibility as well as security of supply, to both the electricity and gas system and end-users. According to the TSOs, there is hence a rationale for not posing all costs of gas infrastructure usage on gas consumers only. The services that are made available (security of supply, flexibility) or effectively provided by gas infrastructure should be properly priced in order to have a correct remuneration of all system components. As the market does in general not properly price the cost of non-availability of energy, this is a domain in which the regulator or legislator should intervene.

[472] For example, this could be negative if it promotes use of gas against other non-fossil solutions.

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