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

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ENER/B1/2017-412
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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)
bcm	Billion cubic meters
CAPEX	Capital expenditures
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)
DCCAE	Department of Communications Climate Action and the Environment
DG ENER	European Commission's Directorate General for Energy
DSO	Distribution System Operator
EC	European Commission
ENTSOG	European Network of Transmission System Operators for Gas
EU	European Union
GHG	Green House Gas
GIE	Gas Infrastructure Europe
GNI	Gas Networks Ireland
GO	Guarantees of origin
IP	Interconnection point
LNG	Liquified natural gas
MS	Member State
MWh	Mega Watt hour
OPEX	Operating expenses
P2G	Power to Gas
PCI	Project of Common Interest
R&D	Research & Development
RAB	Regulatory asset base
RES	Renewable energy sources
SMR	Steam Methane Reforming
SoS	Security of supply
TEN-E	Trans-European Energy Network
TEN-T	Trans European Transport Network
TPA	Third Party Access
TSO	Transmission System Operator
TWh	Tera Watt hour
TYNDP	Ten Year Network Development Plan
UNFCCC	United Nations Framework Convention on Climate Change

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 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 report provides an overview of different existing storylines developed by various stakeholders from industry, policy makers, research and NGOs derived from an extensive literature research. Based on this, well-reasoned storylines were developed for the expected development of the gas sector in Europe until 2050 in an ambitious decarbonisation context[1]. The report further assesses the consequences for existing and planned trans-European gas infrastructure under the three developed storylines for six selected TSOs[2] as well as the readiness of three selected national regulatory regimes[3] in a significantly changing energy landscape.

Assessment of existing storylines

In general, the storylines agreed in a holistic future key role of the gas infrastructure, its value and ability to store energy at large scale and across seasons, to efficiently transport energy at large scale and to supply industry with an energy carrier and chemical base material simultaneously. As such the gas infrastructure's role is believed to change to not only providing flexibility to the energy and specifically the electricity system but also as an infrastructure in its own rights to provide energy services and material supply for other large energy users such as transport and industry. The majority of the studies predict a decreasing gas demand for heating uses due to significantly improved building insulation and the substitution of significant shares of today's gas-based heating appliances by more efficient electric heat pumps. However, this development does not necessarily result in a decreasing overall gas demand as the reduction in the heating sector can be compensated by an increase in other sectors such as transport or industry (e.g. steel industry). Hence, the future utilization level of the gas infrastructure depends on the respective strengths and magnitude of opposing trends. From a technological perspective, almost all the alternative and advanced gas technologies have reached a high technological readiness level of at least 7 and have either already been introduced to the market commercially, or are close to this stage.

Taking into account the variety of technical options presented in the storylines and further assessed in the full report of this study, a one-size-fits-all solution for all Member States seems rather unlikely. Yet, common rules need to be developed while providing the flexibility to select and implement the most appropriate options across Europe.

[1] In this context it is noted that some players prefer the term defossilization as it denotes that fossil-based carbon energy carriers should be phased out, allowing renewable carbon-based fuels such as biomethane to be used beyond 2050, paying tribute to a sustainable and circular use of carbon.
[2] Energinet (Denmark), GRTgaz (France), Gaz System (Poland), Transgaz (Romania), Gas Networks Ireland, Snam Rete Gas (Italy)
[3] Denmark, France, Poland

Development of three well-reasoned storylines

Three generic storylines have been developed in order to analyse possible future roles of gas and the gas infrastructure until 2050 together with their potential impacts without claiming quantitative technical or economic justification by modelling. Yet, all three storylines have in common the achievement of the -95% GHG emission reduction target by 2050 compared to 1990 levels as an illustration of deep decarbonisation efforts. The storylines are defined as follows:

(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 three storylines would have a different impact on security of energy supply, in particular the energy system's adequacy and operational reliability, and related costs., Issues such as the impact of massive development of fluctuating renewable electricity, reduced seasonality of heat demand, availability and cost of different types of electricity or gas storages and back-up systems and the overall impact on energy end-user prices necessitate further in-depth studies.

Impact of decreasing natural gas demand and development of renewable gas on gas infrastructure

Although the overall gas demand would remain at a high level in storylines 2 and 3, and only significantly decline in storyline 1, 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.

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.

Several countries are taking initiatives to stimulate the use of natural gas (CNG or LNG) and biomethane in the transport sector, to replace coal or peat with gas for power generation and to support the development of renewable gas. While an enabling policy framework is in general in place for local production and use of biogas, its conversion to biomethane and injection into the gas grid is still very limited. Production of carbon-neutral hydrogen and transport via the gas grid are in the study and demonstration/pilot phase.

Implications of the storylines for transmission system operators

TSO assets represent a high economic value which will be affected by the transition. The CAPEX (which currently represent 40 to 65% of their overall costs) are expected to remain at a relatively high level in all three storylines, due to high investments in the past which still have to be depreciated to a large extent. 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.

The OPEX would remain at a relatively high level in all three storylines given that these costs are mainly fixed (e.g. only a small fraction is volume related), thus the projected falling transported gas volumes would not lead to a proportionate cost decrease.

As for most gas infrastructure assets regulated Third-Party Access (TPA) tariffs apply based on actual or 'authorised' costs, falling transported gas volumes in storylines 1 and 3 would with stable/slightly decreasing overall cost levels, have an increasing impact on grid tariffs, which might in the medium and long term 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 national regulatory frameworks

The following considerations result from the analysis of three national regulatory regimes:

- Regulation should focus on investments in future-proof assets and enable the gradual replacement of natural gas with carbon-neutral gas to avoid devalued or stranded assets;
- Depreciation rules for gas infrastructure assets may need to be revised to properly take into account the specific risks related to the changing gas demand and supply patterns;
- National regulation regarding renewable gas and conditions and tariffs for connection and access to gas infrastructure, including support schemes and priority dispatch, should be assessed and implemented or adapted where appropriate, in order to facilitate the transition to a carbon-neutral gas supply, while avoiding distortions amongst energy vectors and technologies;
- Valuing potential synergies within the energy sector and with end-users (sector coupling) would allow to reduce energy system costs;
- Innovation and R&D will be needed to accelerate the deployment of renewable gas. It is also deemed appropriate to clarify the possible role of grid operators in activities that contribute to valuing gas infrastructure, such as power-to-gas installations and gas fuelling stations;
- Cross-subsidisation or subsidies for gas infrastructure could be considered to keep gas grid tariffs affordable, but might have distortive impacts;
- Security of gas supply has been an important driver for investments in gas infrastructure. In the future, investments would mainly be driven by safety imperatives, development of renewable gas, and flexibility needs to ensure the adequacy and operational reliability of the overall energy system.

Résumé

La forte diminution des émissions de CO2 et des autres gaz à effet de serre d'ici 2050, telle que convenue dans l'Accord de Paris, pourrait réduire considérablement la part du gaz naturel dans le mix énergétique européen. Par conséquent, le rôle de l'infrastructure gazière européenne pourrait changer considérablement au cours des trente ans à venir. Compte tenu de la longue durée de vie des infrastructures gazières, un exercice prospectif est nécessaire afin de prendre des décisions en toute connaissance de cause et ainsi réduire le risque que certains actifs existants ou prévus n'auraient plus de valeur économique à moyen ou à long terme. Dans ce contexte, l'objectif de cette étude est d'évaluer le rôle des infrastructures gazières transeuropéennes en prenant compte des engagements de l'UE en matière de décarbonisation à long terme.

Le rapport présente un aperçu de différents scénarios existants élaborés par différents groupes de parties prenantes dont l'industrie, des responsables politiques, des chercheurs et des ONG. Sur la base d'une recherche documentaire approfondie, des scénarios bien argumentés ont été développés sur l'évolution possible du secteur du gaz en Europe jusqu'en 2050, dans un contexte de décarbonisation ambitieux[4]. Le rapport évalue en outre les conséquences de trois scénarios élaborés pour les infrastructures gazières transeuropéennes existantes et prévues en général et pour six GRT[5] en particulier, ainsi que l'adéquation de trois régimes régulatoires nationaux[6] dans un paysage énergétique en profonde mutation.

L'évaluation des scénarios existants

En général, les scénarios prévoient un futur rôle clé de l'infrastructure gazière, compte tenu notamment de sa capacité à stocker de l'énergie à grande échelle et à travers des saisons, à transporter efficacement l'énergie à large distance et à fournir à l'industrie un vecteur énergétique qui sert également comme produit chimique de base. En tant que tel, le rôle de l'infrastructure gazière va changer, non seulement en offrant de la flexibilité au système énergétique, et, en particulier, au système électrique, mais aussi en tant qu'infrastructure permettant de fournir des services énergétiques et des produits de base aux grands utilisateurs d'énergie tels que le transport et l'industrie. La plupart des études prévoient une diminution de la demande de gaz pour le chauffage en raison de l'isolation des bâtiments considérablement améliorée et du remplacement de parts importantes des appareils de chauffage au gaz par des pompes à chaleur électriques plus efficaces. Cependant, cette évolution n'entraîne pas nécessairement une diminution de la demande globale de gaz, la réduction dans le secteur du chauffage pouvant être compensée par une augmentation dans d'autres secteurs, tels que le transport ou l'industrie (par exemple, la sidérurgie). Par conséquent, le niveau d'utilisation futur de l'infrastructure gazière dépend de l'intensité et de l'ampleur de tendances opposées. D'un point de vue technologique, presque toutes les technologies de gaz alternatives et avancées ont atteint un niveau de maturité technologique élevé d'au moins 7 et ont déjà été commercialisées ou sont au stade de commercialisation.

[4] Dans ce contexte, il est important de noter que certains acteurs préfèrent le terme « défossilisation » parce qu'il dénote le renoncement aux combustibles à base de carbone, ce qui permet les combustibles à base de carbone renouvelables (comme le biométhane) d'être utilisés au-delà de 2050, ce qui s'inscrit dans le cadre d'une utilisation durable et circulaire de carbone.

[5] Energinet (Danemark), GRTgaz (France), Gaz System (Pologne), Transgaz (Roumanie), Gas Networks Ireland (Irlande), Snam Rete Gas (Italie).

[6] Danemark, France, Pologne.

En tenant compte de la variété d'options technologiques présentées dans les scénarios ci-dessus et présentées en plus de détail dans le rapport, une solution unique valable pour tous les États membres semble peu probable. Néanmoins, des règles communes devraient être établies, tout en leur permettant la flexibilité de choisir et d'établir les options les plus pertinentes à travers l'Europe.

L'élaboration de trois scénarios bien argumentés

Trois scénarios génériques ont été développés afin d'analyser le futur rôle possible du gaz et des infrastructures gazières d'ici 2050, et d'évaluer leur impact potentiel, toutefois sans se servir d'une modélisation quantitative. Les trois scénarios ont en commun d'atteindre l'objectif de réduction des émissions de GES de 95% en 2050 par rapport aux niveaux de 1990, ce qui implique des efforts importants afin de réaliser une telle décarbonisation profonde. Les scénarios sont définis ci-après :

(1) L'électricité devenant le vecteur principal d'énergie dans les secteurs du transport et des bâtiments;
(2) Un rôle coordonné des infrastructures de gaz et d'électricité davantage intégrées, en mettant l'accent sur le méthane neutre en carbone, sous forme de méthane synthétique (PtCH_4) ou de biométhane;
(3) Un rôle coordonné des infrastructures de gaz et d'électricité davantage intégrées, en mettant l'accent sur l'hydrogène.

Les trois scénarios auraient un impact différent sur la sécurité de l'approvisionnement énergétique, en particulier l'adéquation et la fiabilité opérationnelle du système énergétique, ainsi que les coûts y associés. Certaines questions telles que l'impact du développement massif de l'électricité renouvelable intermittente, la saisonnalité réduite de la demande de chauffage, la disponibilité et le coût du stockage de gaz ou d'électricité et des systèmes de secours, ainsi que l'impact général sur le prix de l'énergie pour l'utilisateur final, nécessitent encore des études approfondies.

L'impact de la baisse de la demande de gaz naturel et le développement du gaz renouvelable sur les infrastructures gazières

Bien que la demande de gaz globale reste à un niveau élevé dans les scénarios 2 et 3, et ne diminue que de manière significative dans le scénario 1, la demande de gaz naturel diminuerait considérablement dans les trois scénarios. De plus, les volumes de gaz transportés via le réseau des GRT seraient inférieurs à la demande globale de gaz, car une partie de la production de gaz renouvelable serait utilisée localement ou injectée dans le réseau des GRD.

Dans les trois scénarios, le niveau d'utilisation des terminaux GNL et des gazoducs d'importation diminuerait considérablement, et certains actifs pourraient devoir être mis hors service ou utilisés à d'autres fins. L'impact négatif sur l'utilisation des réseaux de transport et du stockage serait moins élevé en raison de l'utilisation prévue de cette infrastructure pour le gaz renouvelable. Le stockage de gaz existant pourrait en principe être utilisé pour le biométhane, tandis que certains types (par exemple les cavernes de sel) pourraient être reconditionnés pour stocker de l'hydrogène et pourraient également contribuer aux besoins de flexibilité à court terme.

Tandis que le biométhane peut être transporté via le réseau de gaz sans contraintes techniques majeures, il existe encore des incertitudes quant au niveau d'hydrogène pouvant être injecté dans le réseau sans que l'infrastructure gazière et les appareils des utilisateurs finaux nécessitent des adaptations. Cette question devrait être clarifiée afin d'avoir une meilleure estimation de l'impact technique et économique des adaptations de l'infrastructure nécessaires pour accueillir de grandes quantités d'hydrogène, comme prévu dans les scénarios 1 et 3.

Plusieurs Etats membres de l'UE sont en train de prendre des initiatives pour stimuler l'utilisation du gaz naturel (GNC ou GNL) et du biométhane dans le secteur du transport, le remplacement du charbon ou de la tourbe par du gaz naturel pour la production d'électricité et le développement du gaz renouvelable. Bien qu'un cadre politique favorable soit en général en place pour la production et l'utilisation locales du biogaz, sa conversion en biométhane et son injection dans le réseau de gaz restent encore très limités. La production d'hydrogène neutre en carbone et son transport via le réseau de gaz sont en phase d'étude et de démonstration.

Les enjeux des scénarios à prendre en compte par les gestionnaires des réseaux de transport

Les actifs des GRT ont une valeur économique importante qui sera affectée par la transition énergétique. Les dépenses en capital (représentant entre 40% et 65% de leurs coûts totaux) sont prévues de rester à un niveau relativement élevé dans les trois scénarios, notamment à cause des investissements importants dans le passé, qui doivent encore, dans une large mesure, être dépréciés. Le niveau d'investissement global devrait légèrement baisser au cours des dix prochaines années, mais certains investissements spécifiques sont attendus après 2030 pour remettre en état les réseaux afin de permettre le transport de l'hydrogène dans les scénarios 1 et 3, et de permettre des flux inverses de gaz renouvelable entre les réseaux de distribution et de transport (en particulier dans le deuxième scénario).

Les coûts d'investissement et d'exploitation demeureraient à un niveau relativement élevé dans les trois scénarios, étant donné que ces coûts sont principalement fixes (seulement une petite partie est liée au volume), alors la baisse prévue des volumes de gaz transportés ne conduirait pas à une diminution proportionnelle des coûts.

Etant donné que pour la plupart des infrastructures gazières les tarifs d'Accès aux Tierces Parties sont régulés sur base des coûts de réseau réels ou 'approuvés', la baisse des volumes de gaz transportés résultant des scénarios 1 et 3, aurait un impact négatif sur les tarifs de réseau, vu le fait que les coûts globaux resteraient plus ou moins stables ou diminueraient seulement légèrement. Cette évolution pourrait, à moyen et à long terme, avoir un impact négatif sur le caractère abordable et concurrentiel du gaz. Le scénario 2 (développement élevé de biométhane) permettrait de maintenir les tarifs de réseau au plus bas niveau.

L'adéquation des régimes régulatoires nationaux

Les considérations suivantes résultent de notre analyse de trois régimes régulatoires nationaux :

- La réglementation devrait être axée sur des investissements dans des actifs qui répondent aux besoins futurs et devrait faciliter le remplacement progressif du gaz naturel par un gaz neutre en carbone;
- Il convient de réviser les règles d'amortissement applicables aux infrastructures gazières afin de tenir compte des risques liés aux tendances changeantes de l'offre et de la demande de gaz ;
- La réglementation nationale concernant les gaz renouvelables et les conditions et tarifs de raccordement et d'accès à l'infrastructure gazière, y compris les régimes de soutien spécifique

ainsi que l'accès prioritaire, devraient être évalués, et le cas échéant introduits ou adaptés afin de faciliter la transition vers un approvisionnement en gaz neutre en carbone tout en évitant de créer des distorsions entre vecteurs technologies ou technologies;

- Une valorisation optimale des synergies potentielles au sein du secteur de l'énergie et avec les utilisateurs finaux (couplage sectoriel) permettrait de réduire les coûts du système énergétique;
- L'innovation et la recherche et le développement seront nécessaires pour accélérer le déploiement du gaz renouvelable. Il est également jugé approprié de clarifier le rôle éventuel des gestionnaires de réseau dans des activités qui permettent de valoriser l'infrastructure gazière, notamment les installations de conversion de l'électricité en gaz et les stations-service de gaz;
- Des subventions croisées ou des subventions publiques pourraient être envisagées pour des infrastructures gazières afin de maintenir les tarifs des réseaux de gaz à un niveau abordable, mais de telles subventions pourraient avoir des effets de distorsion;
- La sécurité de l'approvisionnement en gaz a été un moteur important des investissements dans les infrastructures gazières. À l'avenir, les investissements dans ce secteur seraient principalement motivés par des considérations de sûreté, de déploiement du gaz renouvelable et des besoins de flexibilité pour garantir l'adéquation et la fiabilité opérationnelle du système énergétique global.

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%.[7]

The long-term EU energy policy objectives include an 80% to 95% reduction of greenhouse gas emissions by 2050[8]. 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.[9] 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.

Task 3 assessed the consequences for (existing and planned) trans-European gas infrastructure under the three developed storylines for six selected TSOs. Task 4 assessed the readiness of three selected national regulatory regimes in a significantly changing energy landscape.

1.1 Scope

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

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[7] EC (2018) Energy efficiency first: Commission welcomes agreement on energy efficiency. http://europa.eu/rapid/press-release_STATEMENT-18-3997_en.htm
[8] 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).
[9] See [https://ec.europa.eu/clima/policies/strategies/2050_en] and [http://unfccc.int/paris_agreement/items/9485.php]

Task 1 focuses on the collection, selection and assessment of European and five non-EU storylines for their gas infrastructure strategies, comprising the future role of potentially CO_2-free gases including fossil natural gas with CCS, biomethane, synthetic methane from PtG and hydrogen, preferably until the year 2050.

In task 2 of this study, three generic storylines for the possible future development of the European gas demand are developed. Each storyline addresses fundamentally different energy system configurations to be able to evaluate to full range of potential developments in the gas sector.

Task 3 focuses on the following TSOs and related Member States:

- Energinet (Denmark);
- GRTgaz (France);
- Gaz System (Poland);
- Transgaz (Romania);
- Gas Networks (Ireland);
- Snam Rete Gas (Italy).

Task 4 addresses the regulatory regimes from three of the 6 countries assessed in Task 3: Denmark, France and Poland.

1.2 Methodology

The methodology for Task 1 comprised a wide literature research in order to arrive at a comprehensive overview of storylines and their analysis of a selected subset of most relevant storylines. In this context, a list of criteria with growing level of detail has been developed and applied to both collection and sorting of storylines. The results of the analysis were presented for a number of selected aspects such as general scope of the study, decarbonisation level of the storyline, future role of gas, type of gas and type of stakeholders involved in the development of a specific storyline. Further detailed aspects are covered in a separate full background report: Role of gas and gas infrastructure, potential environmental impact, technological aspects, regional aspects and political and economic aspects.

Next to the storyline collection, selection and assessment, five non-EU storylines on the future role of their gas sectors have been assessed, namely Russia/Ukraine/Belarus, Japan, Norway, China and MENA countries providing relevant insights into market perspectives, strategies and technology developments.

The storyline development within Task 2 is mainly based on the literature review of task 1. To be able to derive a semi-quantitative estimation on the possible development of gas demand in Europe, a simple and straight-forward approach is used. For each storyline, the gas demand per country/region is estimated based on a few central assumptions. Those assumptions are based on learnings from the literature review or are taken directly from literature. Gas demand is estimated for 2030 and 2050 for the power, the heating, the transport and the industry sector. Values for 2020 and 2040 are linearly interpolated also using today’s gas demand in each sector. The relevance of different energies is altered in each storyline, resulting in the storylines “strong electrification”, “strong development of methane (CO_2 neutral)” and “strong development of hydrogen”.

The methodology for Tasks 3 and 4 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[10], the system development map[11], transmission capacity map[12], 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. Based on the information gathered, country-specific chapters were 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).

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. Summaries of the findings at country level are presented in the Annex, and the full assessment is included in the previous report for Tasks 3 and 4.

1.3 Structure of the report

The report is structured as follows:

- Chapter 1 provides an introduction to the study, along with the scope and methodology;
- Chapter 2 provides a review of existing 2050 storylines;
- Chapter 3 presents the three storylines developed;
- Chapter 4 provides an overview of relevant developments to stimulate the deployment of (renewable) gas;
- Chapter 5 assesses the main consequences of the three storylines for both gas infrastructure and the considered TSOs;
- Chapter 6 assesses the readiness of selected national regulatory frameworks in a changing environment.

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

2 Review of existing 2050-storylines

The objective of Task 1 was to identify the potential developments in the gas sector and other sectors towards deep decarbonisation by 2050 on the basis of existing literature. To this end, the study identifies and assesses strategy papers and analyses results with wide European coverage, which provide plans, visions (= storylines) or scenarios (= quantified storylines) for the future European gas sector, or individual elements thereof, on the pathway to deep European decarbonisation in 2050. Whereas the focus is on European developments, the study also analyses five international storylines, in those regions where natural gas and other gases that can be transported via gas infrastructure to Europe or play an important role today or may play one in the future, or which are otherwise relevant for Europe. The international storylines can provide a better understanding of potential best practices and economies of scale. They cover Russia in connection with Ukraine and Belarus, Japan, Norway, China as well as the Middle East and North Africa (MENA) region. In order to compare the different storylines and to understand the ambitions behind them, a structured approach is employed already for the phase of collecting them. The methodology therefore comprises three sub-tasks, one to define the search and sorting criteria (Sub-task 1.1), the second to select relevant storylines in order to achieve a comprehensive overview (Sub-task 1.2), and the third to assess their contents (Sub-task 1.3).

2.1 Categorization of existing storylines

In general, the existing storylines can be classified according to three major criteria: (1) decarbonisation level of the energy system, (2) role of gas in the energy system (energy demand and supply) and of gas infrastructure and (3) type of gas (namely natural gas with CCS – which would present a 10% CO_2 leakage in practical applications[13] - , synthetic methane from $PtCH_4$, biomethane and hydrogen from PtH_2).

Types of gas

For the sake of this study, the term “gas” is not limited to natural gas, i.e. of fossil origin. Rather, the term “gas” is used for gaseous energy carriers, including

a) **Natural gas** (mainly CH_4) from fossil sources; in full decarbonisation by 2050 only relevant with CCS[14], e.g. NG power plant with pre- or post-combustion CCS,

b) **(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

c) **Biomethane** (bio-CH_4), i.e. methane from organic matter (purified biogas), produced by anaerobic digestion or thermal gasification, and

d) **(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.

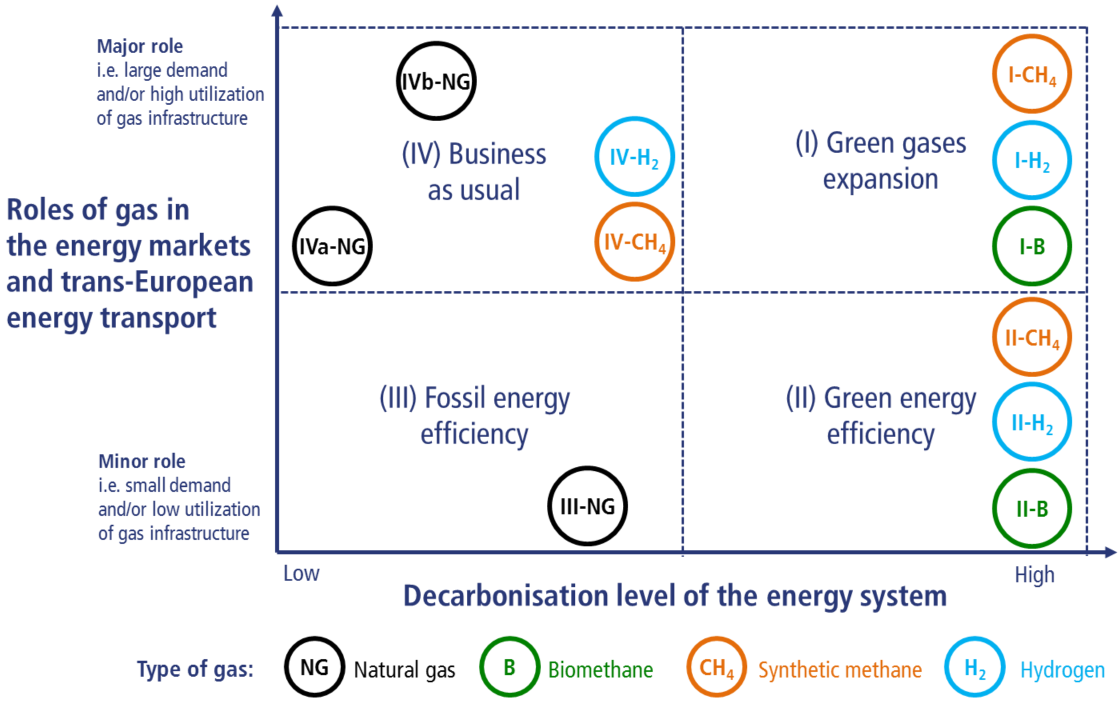
Mixtures of methane with hydrogen, often dubbed hythane are not addressed as a separate type of gas.

13 See e.g. for natural gas with CCS [RWE 2016] or for coal with CCS [2005]

14 CCS stands for Carbon Capture & Storage and describes a group of concepts which either capture CO_2 released during the combustion or extract the carbon contained in fossil energy carriers or the flue gas and, in both cases, stores it preferably for an unlimited period of time in underground structures at very large scale. In the first case, pure hydrogen is produced as energy carrier which burns without delivering CO_2 to the atmosphere (and it is equivalent to steam reforming described in point (d)).

In this context, the literature research reveals four different storyline categories with different characteristics which are further explained below.

Figure 2-1 Classification of the storylines according to the decarbonisation level of the energy system and the role of gas for energy supply and of gas infrastructure (roman number explained in the text)



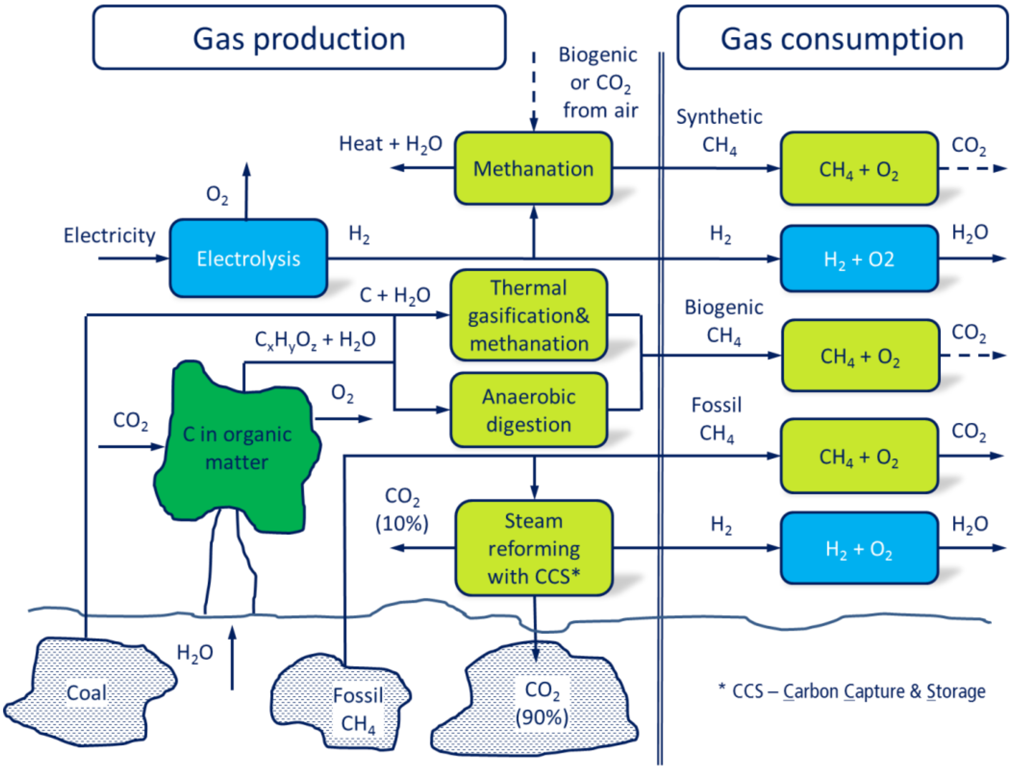
- In the first storyline category (referred to as "Green gases expansion") the gas demand remains high until 2050, but the GHG emission targets will be achieved through a switch of gas type from fossil natural gas to synthetic methane, biomethane or renewable hydrogen;
- The storylines in the second category (referred to as "Green energy efficiency") typically achieve the same level of decarbonisation and utilise the same types of gas. The overall gas demand, however, decreases as electricity becomes the major energy carrier mainly due to the better overall efficiency of direct power use in all demand sectors;
- In the third storyline category (referred to as "Fossil energy efficiency"), the overall gas demand also decreases, but the GHG emission reduction targets are less ambitious, typically less than 80%, whereas this study takes the 95% reduction as starting point for the storylines. Therefore, in such storylines fossil natural gas is used in selected niches to stabilize the renewable energy system (e.g. through the use of fossil natural gas fuelled gas turbines);
- In the fourth storyline category (referred to as "Business as usual"), fossil natural gas is used in the same way as today or even more extensively mainly in order to substitute other more CO_2-intensive fuels such as coal and petroleum products. Obviously, this leads to the highest GHG emissions often failing to achieve ambitious environmental goals. However in order to avoid the GHG emissions, some storylines in this category also advocate the use of CCS technology in combination with steam methane reforming (for hydrogen production), possibly also producing negative CO_2 emissions in combination with biomethane, and coal gasification (for hydrogen or synthetic methane production).

The threat of devalued or stranded assets of the gas infrastructure is high in the second and third storyline categories as the existing infrastructure designed for current gas demand would not be needed anymore if gas demand would decrease significantly as assumed in such storylines.

The major objective of the literature review in Task 1 is to understand and summarize different strategies, visions, plans or ideas for the development of a future gas infrastructure towards a clean energy system in Europe from the perspective of different stakeholders, markets and Member States. Therefore, a wide literature research has been carried out in order to arrive at a comprehensive overview and to develop a good understanding of storylines across Europe. In order to analyse a large number of documents in an efficient way, a structured approach based on well-defined search and sorting criteria has been followed. In this context, a list of criteria with growing level of detail has been developed and applied to both collection and sorting of storylines.

The physical production pathways and their interdependencies are depicted in Figure 2-2. The figure shows the major processes and energy flows involved to produce the final gas types (from the above list) from the relevant primary energy sources (natural gas, biomass, electricity and coal). In addition, the major auxiliary media are presented. If fossil energies are applied, their use makes only sense in combination with decarbonization[15] technology (CCS & CCU) in an otherwise decarbonized world. Even though the use of CCS does not enable the production of fuels without GHG emissions, as in practical applications a share of up to 10% of the CO_2 still escapes into the atmosphere[16]. Combining CCS to the use of biomethane would lead to negative carbon emissions, yet with high costs and limited overall potential.

Figure 2-2 Types of energy gases assessed in this study and their interdependence



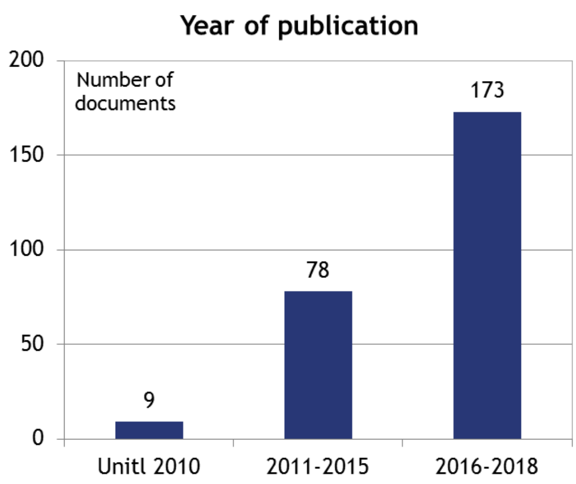
[15] Some prefer the term 'defossilization' as it denotes that fossil based carbon energy carriers should be phased out, allowing renewable carbon based fuels such as biomethane to be used beyond 2050, paying tribute to a sustainable and circular use of carbon.
[16] See e.g. for natural gas with CCS [RWE 2016] or for coal with CCS [2005].

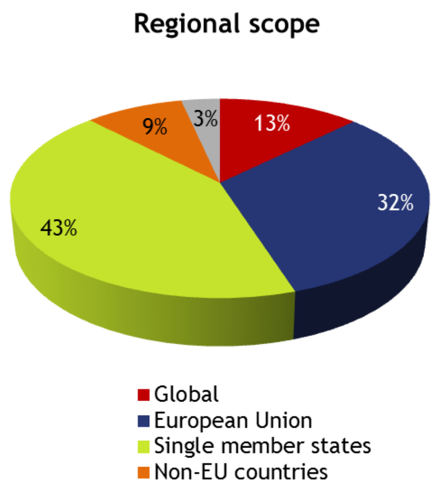
2.2 Selection of storylines

In order to conduct a comprehensive literature review on the future role of gas and gas infrastructure across Europe, a wide range of documents has been collected for a stepwise analysis. The search for adequate literature was mainly based on the joint expertise of the consortium, in-depth discussions with the client, personal interviews with selected experts from different European Member States and extensive desktop research[17]. In total, the literature collection comprises 260 documents, referred to as primary literature, with different scope, level of detailedness and overall results. At this point it is important to highlight that this primary literature containing storylines or storyline elements is a basis for the in-depth analysis in chapter 2.3**Error! Reference source not found.** while secondary literature with a large number of additional documents has been used to better understand individual aspects of the various storylines, specifically in a regional context.

As indicated in Figure 2-3 two-thirds of the documents from the primary literature identified based on the search criteria have been published in 2016 or later and the majority of which are hence assumed to take into account the climate protection goals of the Paris Agreement of December 2015. Only 33% of the documents have been published before the Paris Agreement out of which only 9 documents are dated before the Fukushima nuclear disaster in March 2011. Since the focus of this study is on the role of the European gas infrastructure, most of the documents, in terms of regional scope, cover the European Union or individual Member States. Some selected studies take a global perspective (13%) or cover other non-EU countries (9%) mainly in line with the analysis of the non-EU storylines presented in the Tasks 1 and 2 report whereas a small fraction of the literature (3%) is of a more general character without a specific geographic scope.

Figure 2-3 Year of publication (left) and regional scope (right) of collected documents



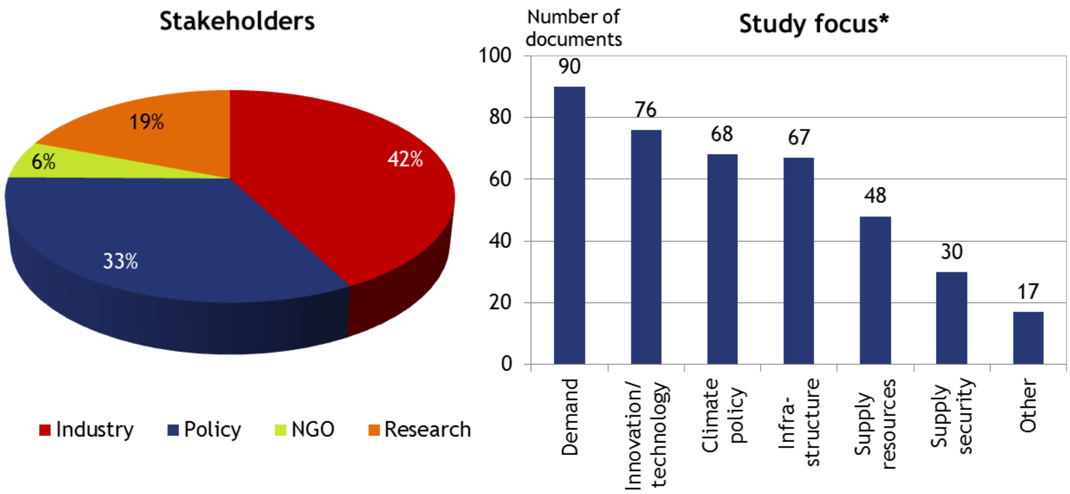


The distribution of the stakeholders involved in the preparation of the selected documents either as main author or as a client (see Figure 2-4) shows a good balance between industry (43% of all documents) and policy makers (33%). Analyses provided by research institutes account for around 18%. The comparatively low figure of 6% for studies motivated by non-profit / non-governmental organisations (NGO) is related to the fact that analyses conducted by a professional author for an NGO

[17] The research was eased by a command of a wide set of language skills: English, German, French, Spanish, Polish, Nordic languages and Russian as some of the key documents were only available in the language of the individual country.

have been classified as 'industry work'. In this context, the balance between the stakeholders of the underlying studies ensures that the future role of European gas and gas infrastructures has been analysed from different perspectives and by taking into account the various stakeholder interests and points of view.

Figure 2-4 Distribution of stakeholders involved in study preparation (left) and study focus (right) of the primary literature identified (* Multiple study foci per document are possible)



Moreover, and as illustrated in Figure 2-4, the primary literature collected also covers a wide range of relevant topics. Most studies focus on research questions related to the future gas demand and potential innovative technologies for gas production, transportation and use.[18] This is followed by analyses addressing climate policy issues as well as by studies explicitly assessing the role of the gas infrastructure today and in the future. Supply resources and security of supply are less frequently covered topics in the literature collected as these play a major role for fossil natural gas, but typically a lesser role for new and clean gas technologies. It is worth mentioning that studies focusing on fossil natural gas without CCS or CCU were partially disregarded already during the collection process as a key aspect of this study is the deep decarbonisation of the future energy system. Although most studies are in English language, the literature review has also taken into account documents in other languages from different Member States, in particular in German, French, Spanish, Polish, Dutch, Danish, Norwegian, Russian and Ukrainian.

Furthermore, around half of the documents have been identified as containing in-depth analyses with multiple scenarios (with 3 scenarios on average and 5 scenarios as a maximum). Thus, the total number of storylines collected in the course of this literature review amounts to more than 360 individual storylines.

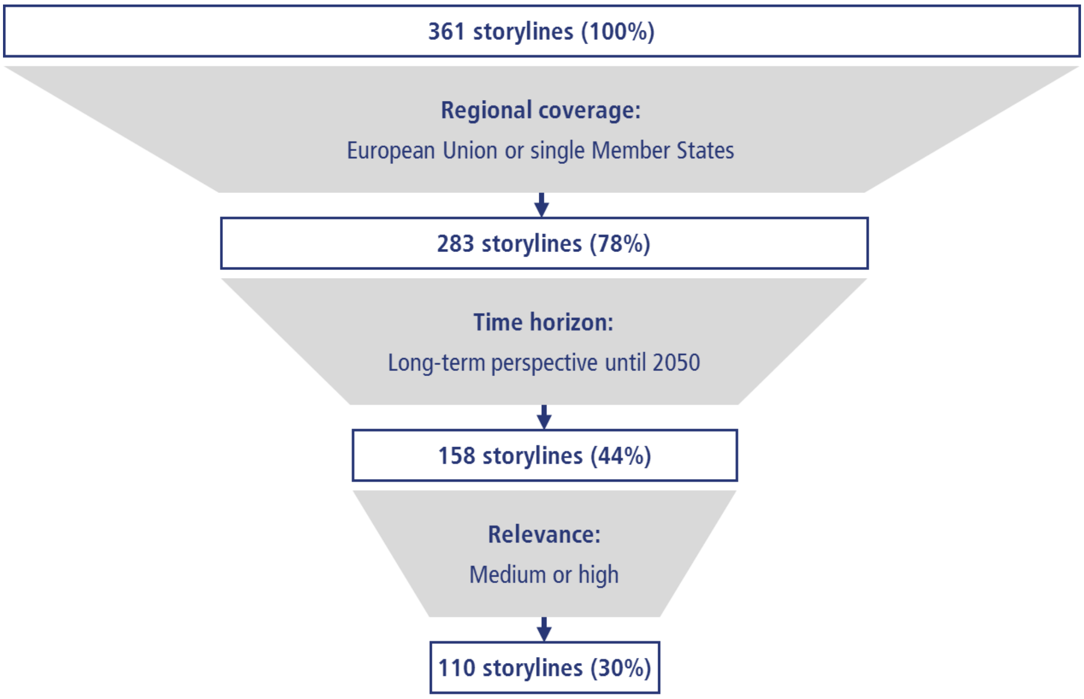
In order to narrow down such a large number of storylines for a more detailed analysis a selection process has been employed based on the following three steps (see Figure 2-5):

1. Regional coverage: The total number of 361 individual storylines was reduced to 283 (78% of all storylines) based on the regional scope by focusing on the European Union or single Member States;

[18] In this context all types of gas are included as defined previously.

2. Time horizon: Secondly, the collection was further narrowed down by filtering only those storylines covering a long-term perspective until 2050, resulting in 158 storylines (44%) matching both aforementioned criteria;
3. Finally, 110 storylines (30%) were selected as most relevant for a more detailed analysis based on the expert judgment of the researchers/scientists.

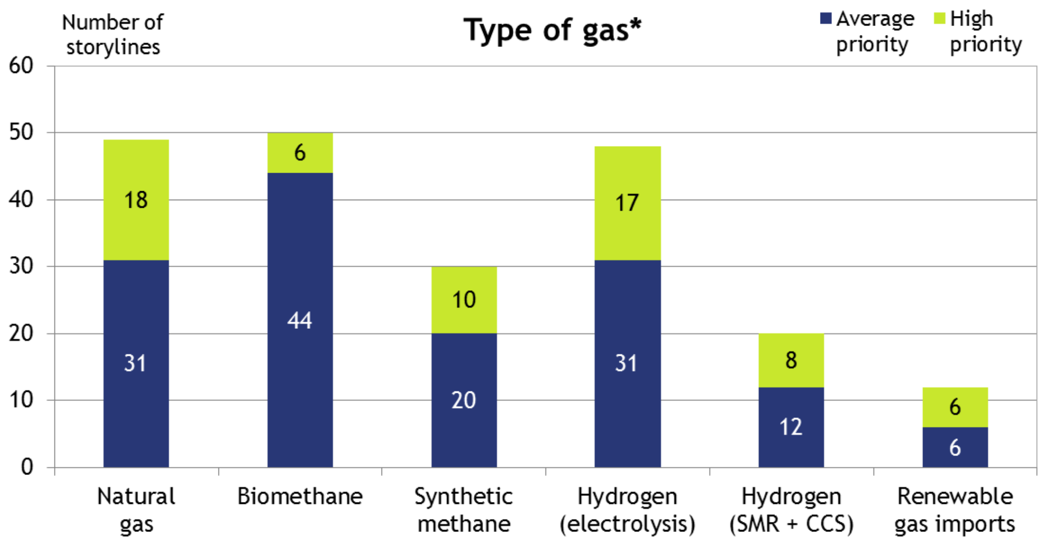
Figure 2-5 Down-selection of storylines from the primary literature for further analysis



The distribution of the relevant storylines in respect of the publication year and stakeholders is similar to the corresponding distribution of the entire primary literature with a slight shift towards more recent as well as industry and NGO-related studies. Also, the study focus is similar to the primary literature with major scope on demand, technological solutions and climate policy, and with a reduced coverage of supply resources and security of supply issues. However, the selected storylines tend to address infrastructure issues less frequently than the unfiltered document collection revealing a potential research gap in this area in the context of the decarbonisation of the gas sector. Furthermore, half of the selected studies include multi-sectoral analyses by taking into account all demand sectors for gas, namely power, heating, industry and mobility sectors. Thus, the focus of the storylines is well balanced across the different markets for gas.

Figure 2-6 shows the relevance of different types of gas covered by the selected storylines. Natural gas from fossil sources, biomethane and hydrogen provided by water electrolysis are covered most frequently as future types of gas. However, in comparison to the other two gases, at EU average biomethane is given a lower priority, i.e. only few studies put biomethane as an energy carrier at the forefront with high priority, One reason could be that biomethane already is a commercial fuel other than hydrogen and synthetic methane. Interestingly, power-based synthetic methane (“power-to-methane”) is given high priority by a comparatively small number of storylines. In addition, few studies also consider hydrogen production from steam methane reforming with subsequent carbon capture and storage and usage (CCS or CCU) to ensure emission free energy use. However, this solution seems to be a concept developed by individual stakeholders from only a few Member States and Norway as main advocate with ample of experience. Finally, few storylines address renewable gas imports, and if they do then the issue is examined with a lower level of detail revealing a potential research gap.

Figure 2-6 Type of gas in the selected storylines with average and high priority (* Multiple gas type counts per storyline are possible)



As illustrated in Figure 2-7, the vast majority of the selected storylines (91%) expect GHG emission reductions in 2050 beyond 80% in line with the current EU goals (80% to 95% reduction) whereas only few storylines do not achieve this target. This is not surprising as the criterion of strong decarbonisation has been applied already during the literature collection process as well as for the expert judgment on the relevance of the corresponding documents. Almost half of the storylines (44% of the selected storylines) assume a very strong decarbonisation of the energy system with more than 95% GHG emission reduction by 2050.

A large number of the selected storylines assumes or projects a decreasing demand for gas until 2050 (76%; see Figure 2-7). This is further broken down into almost 20% of the selected storylines predicting a significantly decreasing gas demand (i.e. almost no gas demand) typically caused by the use of electricity as a major energy carrier (e.g. electrification of transport and/or heating) based on renewable sources, and 57% expecting a moderate decrease (i.e. lower gas demand than today). However, still a significant number of storylines (24%) expect a constant or even growing gas demand. This is mainly due to the strategy of switching from CO_2-intensive fuels such as coal or oil to comparatively less carbon-intensive natural gas within the power and mobility sectors. In general, more recent studies also examine deeper decarbonisation of the energy system than the older studies.

Figure 2-7 Share of selected storylines by expected gas demand until 2050 (left) and GHG emission reduction until 2050 (right)

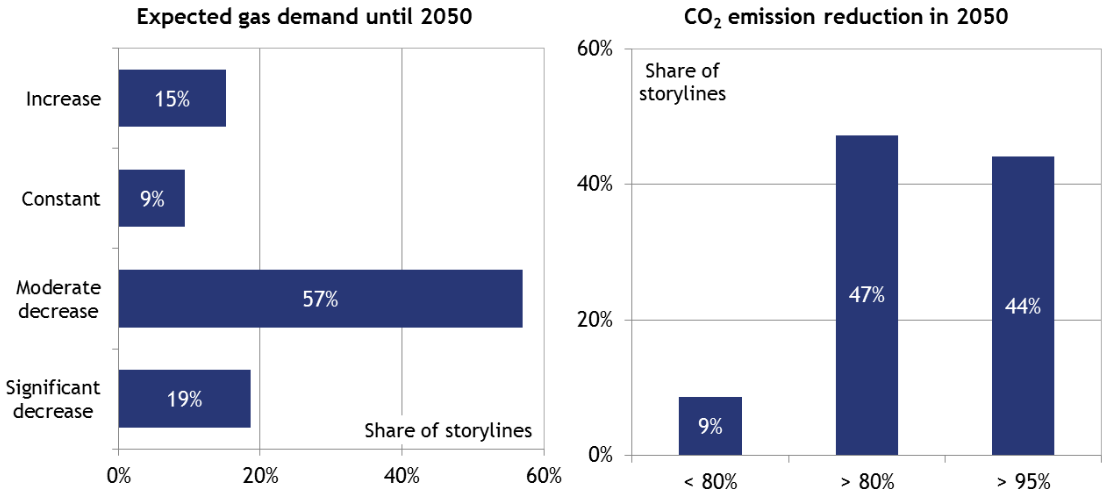
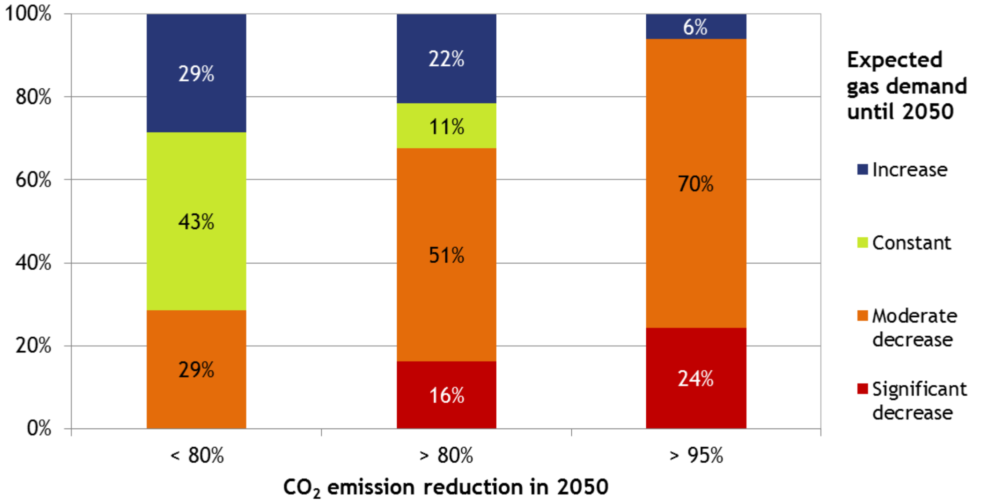


Figure 2-8 demonstrates a clear correlation between the GHG emission reduction until 2050 and the expected gas demand in 2050; and Figure 2-9 demonstrates a clear correlation between the GHG emission reduction until 2050 and the preferred type of gas. On the one hand, more than 70% of the storylines with a GHG emission target less ambitious than 80% reduction predict constant or increasing gas consumption in the future. In such storylines, (fossil) natural gas is the most important energy carrier (57% of the relevant storylines) followed by biomethane, both typically substituting coal in the power sector. Also, some storylines with a GHG reduction level between 80% and 95% allow for the use of (fossil) natural gas since it is valued as being comparatively clean and as an adequate option to balancing the intermittent feed-in of renewable power plants.

On the other hand, almost all storylines analysing strong decarbonisation of the energy system above the 95% target expect a decreasing role of gas in the future. Thus, increased or constant gas demand could be mainly associated with less ambitious climate goals, while strong climate goals seem to go hand in hand with decreasing gas demand.

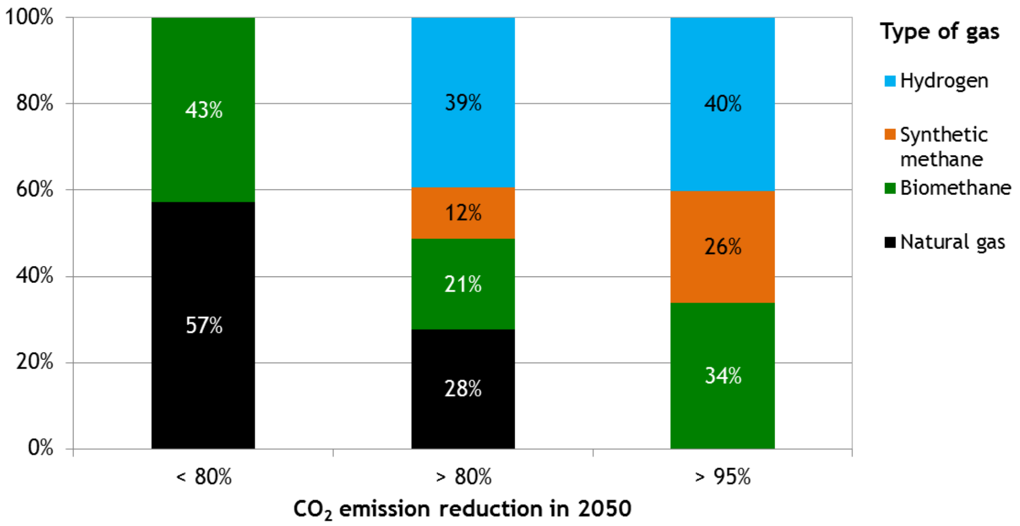
In this context it is relevant to note that some studies expect an increasing demand for gas in single sectors, in particular in the power sector to provide flexibility and in the transport sector. However, the overall gas consumption is typically falling based on strongly decreasing gas demand in the other sectors, e.g. in the heating sector through improved building insulation and switching to electricity for heating using high energy efficiency electrical heat pumps.

Figure 2-8 Correlation between GHG emission reduction and expected gas demand until 2050



In the studies, such strong decarbonisation of the energy system does not allow for the use of natural gas from fossil sources and thus most storylines recommend using renewable electricity for the production of hydrogen or synthetic methane (66% of the storylines). This is mainly due to the fact that both gases are able to store large amounts of energy on a seasonal basis in an almost fully renewable energy system at comparatively low costs. 34% of the studies cover biomethane in strong decarbonisation storylines. In essence, the stronger the GHG reduction ambition, the higher the importance of synthetic methane and hydrogen and the lower the importance of natural gas; biomethane is rather covered independently of the GHG reduction ambition, which is possibly related to its limited overall potential.

Figure 2-9 Correlation between GHG emission reduction until 2050 and type of gas



In general, and based on the literature review, the storylines on the future role of gas in the energy system can be classified and grouped according to three major criteria: (1) decarbonisation level of the energy system, (2) role of gas for energy supply and of gas infrastructure and (3) type of gas. Figure 2-1 provides an overview of potential storylines in a portfolio representation based on the first two criteria, which be analysed in chapter **Error! Reference source not found.**.

2.3 Analysis of European and non-EU storylines

The collection and sorting of storylines in is based on the following main criteria:

- **General scope** of the study (regional coverage by EU regions, time horizon, energy demand sectors considered and study focus);
- **Decarbonisation level** of the storyline (-95% GHG reductions by 2050 (compared to 1990) as agreed with DG ENER as target for this study);
- **Future role of gas** (expected development of gas demand and its share in different demand sectors (power, heating, mobility, industry);
- **Type of gas** (natural gas from fossil sources, power-based synthetic methane, biomethane and hydrogen); and
- **Type of stakeholders** involved in the development of a specific storyline for the critical appraisal of its motivation.

The above list of criteria is further detailed and supplemented by additional aspects for the storyline assessment: **Role of gas and gas infrastructure; Potential environmental impact**; **Technological aspects; Regional aspects** and **Political and economic aspects.** The detailed assessment of storylines applying a second list of further detailed criteria can be found in the Tasks 1 & 2 report of this Study.

2.3.1 Major results of the existing storylines

In general, the majority of storylines assessed agreed in a holistic future key role of the gas infrastructure, its value and ability to store energy at large scale and across seasons, to efficiently transport energy at large scale and to supply industry with an energy carrier and chemical base material simultaneously. As such the gas infrastructure's role is believed to change to not only providing flexibility to the electricity system but also as an infrastructure in its own rights to provide energy services and material supply for other large energy users such as transport and industry. Outstanding examples are the use of gas in chemical and other industry such as steel making as well as fertilizer, methanol and polymer production. In order to become fully effective, sectoral integration of the end-use sectors (households, mobility, industry, agriculture) and energy infrastructures (electricity, gas) has been identified as mandatory by some of the storylines, to be pursued and supported politically by an adapted regulatory framework in the short-term.

The analysis of the relevant storylines reveals that the majority of the studies predict a decreasing gas demand for heating uses due to significantly improved building insulation and due to the substitution of significant shares of today's gas-based heating appliances by more efficient electric heat pumps. However, this development does not necessarily result in a decreasing overall gas demand as the reduction in the heating sector can be compensated by an increase in other sectors such as transport or industry (e.g. steel industry). Hence, the future utilization level of the gas infrastructure depends on the respective strengths and magnitude of the opposing trends from above. Although the assumptions, approaches and results in most of the analysed storylines are reasonable, some studies leave open questions with respect to the use of fossil natural gas in an almost fully renewable energy system. Biomass potential[19] transparent comparison of all technological options, limits for the electrification in specific energy demand sectors (e.g. heavy-duty vehicles) and consistent energy price assumptions are the most important.

[19] None of the studies on biomass potential consider the aquatic biomass potential.

From a technological perspective, almost all the alternative and advanced gas technologies have reached a high technological readiness level of at least 7 (out of a scale of 9[20]) and have either already been introduced to the market commercially, or are close to this stage[21]. In addition, biomass potentials in Europe are limited. Moreover, synthetic methane is exposed to potentially high CO_2 supply costs as biogenic CO_2 resources are strongly decentralized and limited in availability, and CO_2 extraction from air is costly. Hydrogen and fuel cell technologies have only recently started commercialization and need to be integrated into the energy system in order to achieve the necessary ramp-up in the energy market. Also, hydrogen used in the gas grid would require an adaptation of the existing gas infrastructure and possibly larger transport and storage capacities taking into account the lower energy content of hydrogen per volume compared to methane. Hydrogen and fuel cells enable the gas infrastructure to better harmonise with the electricity grid for efficiency reasons and because they represent customer-friendly end-use technologies hydrogen and fuel cells. Yet, they may possibly be of 'disruptive' nature. Countries like China entering this market seriously could have a big impact on any current cost-projections and feasibility assumptions.

The literature review also shows that the different CO_2 emission reduction targets of -80% and -95% lead to significantly different designs of the future energy system. Although in the -80% case fossil natural gas still is a good source for balancing fluctuating power generation, in the -95% case the power, heating and transport sectors must become fully zero carbon by 2050 squeezing out all fossil fuels from the market. In this case, the required flexibility in the energy system will have to be provided by renewable gases such as synthetic methane, biomethane or hydrogen and other measures such as demand response / demand side management, trans-European power exchange, etc. Moreover, the role of large-scale energy storage and renewable energy imports will become increasingly important. In addition, recent studies explicitly warn of methane leakages from natural gas extraction and transport with a GHG impact of about a factor 34 or 86 higher than from CO_2, in particular for shale gas, with a severe impact on global climate change[22]. Such increased methane emissions have been identified as potential roadblock for alternative natural gas production by some studies. The same might go for the future of piped imports from suppliers with a jurisdiction in which methane leakage at source and in transport to the EU border are not addressed.

A number of storylines stress that strong decarbonisation of the future energy system will necessitate behavioural changes of the end user such as different mobility habits and more resource-saving lifestyle. Moreover, the societal acceptance of new energy infrastructure projects such as new overhead high voltage power lines, the costs of DC undergrounding, CCS or the use of appliances compatible with the new renewable gases will become crucial for an important future role of gas in the energy system. In this context, missing public acceptance with respect to the above-mentioned issues could become a major roadblock.

The assessment of the existing storylines also reveals that Eastern Europe and Western Europe have different approaches and policy priorities with regards to the supply of gas. Whereas Eastern Europe at this moment seems to focus mostly on security of supply for natural gas and pursues a substitution of

[20] The EC has published the following definition of Technology Readiness Level (TRL) at http://ec.europa.eu/research/participants/data/ref/h2020/other/wp/2016_2017/annexes/h2020-wp1617-annex-g-trl_en.pdf
21 In the full study report a comprehensive technology review has been undertaken in view of all gas types considered and existing storylines screened and structured by TRL in table 4 and scale / power rating (LHV), efficiency (LHV) and specific investment in table 5.
[22] These values contradict today's agreed greenhouse gas equivalence factor of 25 as current convention (https://ec.europa.eu/eurostat/statistics-explained/index.php/Glossary:Carbon_dioxide_equivalent)

coal by fossil natural gas to reduce CO_2 emissions, Western Europe seems more concerned about the decarbonisation of the gas grid by 2050. The number of major stakeholders promoting a consequent decarbonisation of the gas grid through full substitution of fossil natural gas by other renewable gases such as hydrogen, synthetic methane or biomethane is growing. Some isolated storylines including CCS technology have been identified, e.g. for the UK or the Netherlands proposing hydrogen production form natural gas and for Poland considering coal gasification hydrogen or synthetic methane generation.

On a sideline, and as an interpretation from the storyline assessment, the authors of this study understand that today's role of the gas infrastructure in balancing seasonal demand fluctuations will probably have to be adapted to also balance more short- and medium-term supply fluctuations in the future, having a possible impact on how to consider both the annual gas transport and storage volumes and the short-term peak requirements. This role will have to be assessed in more detail by dynamic modelling.

As the use of biogas and biomethane as well as the use of any other form of renewable energy or electricity will strongly depend on the regional as well as total resources and specifically the technical and economic potentials, it is suggested to take up this discussion in great detail in future analyses of individual members states' own assessments as well as at European level.

2.3.2 General appraisal of the selected storylines

Methodology and detailedness of the storylines

Literature differs widely in terms of methodology and detail of publications. Most important in the context of this study, however, is the fact that so far only very few storylines are using complex and powerful methodologies and present detailed results (and assumptions or input parameters). If full coverage of the European Union at country level granularity, an hourly time resolution, a timeline until 2050 and a climate ambition of 95% GHG reduction by 2050 were taken as additional criteria, the selection would go down to zero.

In order to showcase the variety of methodologies employed and the detail of the results published, two examples are pointed out in the following, the first describing a powerful methodology with detailed results published, and a simpler approach with generic results published. A number of storylines are in between these two examples, many focusing on an individual Member State.

Among the most powerful methodologies the ones by ENTSO-E and ENTSOG [Entsog 2018] are to be mentioned for the development of the TYNDP 2018 scenarios, currently available as draft edition. Input is generated in a scenario development process involving stakeholder consultations, electricity sector assumptions and results come from a mix of top-down (e.g. European targets on renewable energies) and bottom-up (e.g. country-level demand data, technology penetration, installed plant capacity, etc.) approaches, commercially available market modelling tools are used to determine how the power system will behave in each zone, for each hour of the year, and each of the three climate situations included (warmer or colder / dryer or wetter years), energy consumption is predicted, the penetration of electricity demand side technologies (including demand response, electric vehicles, heat pumps and home storage) is forecasted, gas demand data for scenarios include a sectoral breakdown for all countries. Results are published at country-level. However, the scenarios are only calculated until the year 2040 while GHG emissions are allegedly targeted at 80% to 95% reduction by 2050. Furthermore, only gas and electricity are covered while other fuels are not included, notably oil-based transport fuels, bio-energy other than biomethane, etc. GHG reductions are results of market forces and policy measures in the various scenarios, and result from different assumptions on fuel prices (coal, gas, oil) and on GHG emission allowances.

A simpler, but nonetheless scientifically sound, approach has been employed by [ADEME 2018] with the aim of refining the methodology in future steps by 2019 using global optimization models of all energy carriers and uses. It is a prospective techno-economic study and serves to analyse techno-economic conditions for achieving 100% renewable gas in 2050. Covering France, the approach is based on existing energy scenarios calculated in a previous study achieving a GHG reduction by 2050 above 70%, and aims at testing the techno-economic feasibility of achieving 100% renewable gas production by 2050. Three renewable gas production technologies are included: fermentation of wet biomass (incl. residues) producing methane; gasification of dry biomass (including residues) producing methane; Power-to-Gas producing methane (and hydrogen as long as it can be injected into the gas grid and mixed with methane without adaptations of the gas grid). Power-to-Hydrogen (PtH_2) has been excluded where it would require a dedicated hydrogen grid. The study focuses on 2050, no trajectory of the transition from today towards 2050 has been included. Electricity for Power-to-Gas is primarily ‘excess’ power; data are based on a detailed study with regional and hourly resolution. In 2050, the renewable gas is produced to 100% in France; no gas imports are assumed. Gas grid adaptations have been analysed and optimised for four typical regions (départements). The results are published in an 18-page extended summary report only; more detailed results are not available. However, the study is based on detailed previous energy-climate scenario work published in great detail in 2017.

Reasonability of the storylines

In general, the selected storylines apply reasonable approaches, and present plausible results compared to the input assumptions and parameters. However, some examples of issues meriting discussions and further research are highlighted in the following.

GHG reduction ambition by 2050

[Entsog 2018] targets GHG reductions of -80% to -95% by 2050. However, GHG reductions calculated until the year 2040 in the various scenarios on the one hand vary considerably between the scenarios, and on the other hand the share of fossil gas in the overall gas mix is still rather high in 2040. Unfortunately, the draft report does not discuss this issue, so it remains open which scenario would achieve the GHG reduction by 2050. In general, the selected storylines cover the full spectrum of -80% to -95% GHG reduction by 2050, while less ambitious storylines have not been selected. It needs to be emphasized here that a number of studies specifically point to the fact that structural differences develop in the energy system between a -80% GHG reduction ambition and the -95% ambition. In other words, a solution for -80% may not be viable for a simple extrapolation to -95%.

Biomethane focus versus synthetic methane and hydrogen

There is a slight tendency in the literature to study biomass-based gas production pathways in more detail than the renewable electricity-based pathways providing synthetic methane or hydrogen, e.g. in [Ecofys 2018] or [ADEME 2018]. Furthermore, Power-to-Hydrogen has been excluded in [ADEME 2018] where it would require a dedicated hydrogen grid or other dedicated infrastructure; only hydrogen admixture to methane in the gas grid is covered. As a consequence, hydrogen applications such as fuel cell electric vehicles are not covered. Similarly, [FhG-ISI 2017a] have excluded fuel cell electric vehicles from the very detailed cost optimization modelling approach for Germany because of alleged excessive technology costs.

Incumbent gas sector stakeholders seem to tend towards favouring methane in the development towards renewable gas because of the existing infrastructure rather than to fully explore new opportunities provided by hydrogen. The latter would require a refurbishment of the existing gas infrastructure to hydrogen, but on the other hand opens opportunities based on significantly higher efficiencies of fuel cells compared to conventional technologies, notably in transport. However, [Northern Gas Networks, et al. 2016] in the UK is either an exception to the rule, or is a forerunner just as the Dutch TSO2020 Synergy Action [CEF 2017] developing hydrogen for transport and its admixture to natural gas in the grid. Furthermore, incumbent gas sector stakeholders seem to favour the more traditional biomethane production over gas production using renewable power (synthetic methane, hydrogen) [Ecofys 2018].

How much electrification in the heating and transport sectors is possible and economically advantageous?

In general, relevant storylines agree qualitatively that future gas demand will come under pressure notably in the heating sector. On the one hand, heating energy demand will more or less strongly decrease based on improved insulation of buildings, and to a small extent by more efficient heating technologies. And on the other hand, electric heat pumps in buildings using ambient, low-temperature heat and electricity or district heating systems based on renewable heat or electric heat pumps[23] will compete with gas-based technologies potentially reducing the share of gas in space heating. Both, assumptions and results on the share of gas-based technology versus electricity-based technologies in the heating sector vary widely.

In the transport sector, gas plays a very small role today, but is anticipated by many studies to gain a significant market share from the oil-based dominance of today. This may be based on commercially available internal combustion engine propulsion systems fuelled by methane, or increasingly on fuel cell electric vehicle technology currently in the commercial market entry phase fuelled by hydrogen. However, battery electric vehicles compete with gas vehicles. Current major competitive disadvantages of electric vehicles are higher (but falling) prices, a thin (but developing) electric recharging network and a growing hydrogen refuelling station infrastructure, while environmental advantages are strongly based on zero local emissions and full renewable potential. In passenger cars and light duty vehicles, all technologies compete, while long-distance freight traffic has demanding range requirements which can only be met by diesel or methane combustion engine trucks, and fuel cell electric or overhead line electric trucks. The latter concept is notably being developed in Germany and Sweden, and requires a new overhead line infrastructure on major traffic routes [FhG-ISI 2017b]. Available studies vary widely in their assumptions or results on the share of methane combustion engine vehicles versus battery electric vehicles versus hydrogen fuel cell electric vehicles in the passenger car, light and heavy duty vehicle segments.

[23] District heating system can rely on other heat sources as well, including gas-based technologies such as CHP systems, CCGT or fuel cells. Also, gas-based boilers or fuel cells for the combined production of heat and power are viable options for installation in buildings.

Consistent scenario comparisons of these options in heating and transport within a unified, European methodologic framework would help better understand market opportunities for the different gas types, competitive strengths and weaknesses of the competing technologies, societal advantages, infrastructure requirements in both gas and electricity (as covered by [Entsog 2018], albeit with limited exploration of the above-mentioned transport aspects), necessary fuel supply infrastructures (electric charging, hydrogen refuelling, overhead lines, etc.).

Electricity prices for synthetic methane or hydrogen production

For Power-to-Gas, renewable electricity price assumptions seem high in some studies, and low in others. In [ADEME 2018] average electricity prices are assumed to be 67-82 €/MWh in 2050 (grid costs including adaptation and storage go on top), while [Ecofys 2018] calculates hydrogen production costs of 23 €/MWh for a hydrogen quantity of 24 bcm/a. As the latter price for hydrogen seems to be low even at marginal electricity costs of 0 €/kWh this example shows that further research is required to consolidate the assumptions at European level as it is well known that hydrogen production costs can vary significantly with the assumptions (i.e. electricity price and electrolyser specific investment) and local conditions (electrolyser utilization). The above mentioned figures typically do not take into account the game changing effect of China entering this market, both on technology cost and development, and upscaling potential. It is worth mentioning that solar and wind power production cost reductions continue to be faster than anticipated by experts. In this sense, most storylines may prove to be on the conservative side in terms of renewable electricity costs [FhG-ISE 2018], [McKinsey 2018].

Emerging challenges have short-term impact on storylines

The literature review of storylines reveals changing development trends over the past years that coincide with concrete events or developments of historic nature (see Table 5 below). Cause and effect relationships may only be assumed here, but do not require rigorous scientific proof in the framework of this study. Rather, this illustrates that most storylines and scenarios developed before 2014 have been assessed as not providing value to the present study; in general, only more recent storylines provide relevant information and insights.

These changing trends notably relate to the level of ambition of protecting the global climate, to resource depletion issues and to local air quality, to list the most important in the context of this study. All stakeholders developing storylines seem to have become more and more aware in recent years of the urgency for action in view of ambitious climate targets for 2050, a timeframe only 32 years into the future. This is reflected in quickly developing parameter sets, sometimes significantly adjusted within short timeframes.

Table 2-1: Emerging challenges for the energy market evolution since 2011

Event/development	Impact Changing parameters
Nuclear disaster in Fukushima / Japan March 11, 2011	• Diminishing role of nuclear power (e.g. Germany) • Push for and strong focus on (fluctuating) renewable electricity • Need to develop large-scale, long-term next to small-scale, short-term energy storage technologies and concepts
Ukraine/Russia unrest begins in February 2014	• Security of supply considerations for natural gas • Push for PtG pathway as alternative gas source • Emerging importance of gas infrastructure

Event/development	Impact Changing parameters
Paris Agreement signed at 21st Conference of the Parties of UNFCCC in Paris on 12 December 2015	• Wide acceptance of the 2°C goal • Gradual understanding that this requires full decarbonisation for the EU/-95% GHG emission reduction by 2050 • Sectoral integration becoming important issue • PtX gaining momentum
Volkswagen diesel pollutant emission scandal gradually emerging since September 2015	• Perception of underestimated role of mobility's contribution • Diesel technology's apparent failure as low CO_2 silver bullet • Push for e-mobility (BEVs and FCEVs across all transport modes)
Local pollution challenges in China's Megacities	• China's boom in renewable electricity, gas imports and alternative energy technologies in transport

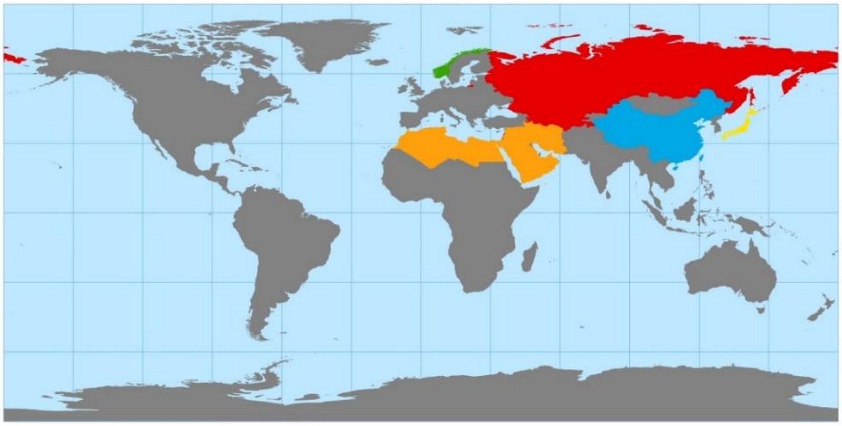
2.3.3 Five non-EU storylines affecting the future role of gas in Europe

In addition to the European storylines, this study also analyses the major developments in the gas sector of five non-EU regions, namely Russia/Ukraine/Belarus, Japan, Norway, China and MENA countries. These provide relevant insights into market perspectives, strategies and technology developments. For the selection of non-EU storylines the highest priority was broad consistency with the climate goals as defined by the Paris Agreement. Furthermore the storylines should either:

- contain relevant experience for the EU to learn from; or
- provide the potential for technology and/or energy trade, e.g. gas import to the EU; or
- impact the cost reduction rates of technologies, and thereby the commercial viability, of these technologies in the EU.

The selected world regions are shown on the map in Figure 2-10. Three of the five regions (NO, MENA, Russia and Eastern Europe) are in direct proximity to Europe with major gas export potentials towards Europe, the other two (JP, CN) farther away and potential competitors to Europe in terms of renewable gas imports.

Figure 2-10 Selection of world regions for non-EU storyline assessment



Based on Russia's role as the world's largest exporter of natural gas today and the dominance of Ukraine's and Belarus's role as gas transit countries, little evidence was found in literature on any activities to reduce the carbon burden of natural gas in this region. However, even though not being widely discussed, the existing natural gas pipeline infrastructure could be used to import renewable gases from east to west in the future. Only recently hydrogen from methane cracking was earmarked as potential transition strategy to renewable hydrogen in the longer term[24].

With an electricity shortage and a high dependency on fossil energy imports today, Japan has identified hydrogen as a clean fuel to import fossil energy in the short to mid-term, and renewable energy at a growing pace until 2050 from other world regions such as Australia or South America. Even though the energy strategies of Europe and Japan have different foci with Japan creating a secure electricity resource base, the proposed technologies along the value chains are similar, which opens opportunities to Europe for cooperation or as competitor.

Although Norway is a major exporter of natural gas, the country has succeeded in becoming the blueprint country for the application of relevant clean energy technologies such as battery electric vehicles, and has started introducing hydrogen, e.g. for clean propulsion in maritime applications. In this context, a strong development of renewable electricity in Norway, based on its vast wind energy potentials and pumped hydropower plants, could enhance the existing gas and electrical link to Europe in view of balancing power services for European grids, or concerning large green energy quantities imported to Europe both as electricity and as clean gas.

China may leapfrog the gas infrastructure technology development in many aspects as both methane and hydrogen grids will be developed to transport increasing quantities of green gas. Also, hydrogen and fuel cell technologies are now being commercialized at a yet unnoticed speed, offering Europe the role of co-operator or competitor.

The huge renewable energy potential of North Africa and the Middle East as one possible source for energy imports at large scale have so far focused on electricity imports to Europe. For the import of large renewable energy quantities, the gas infrastructure has great potential. In all cases of export to the EU, indigenous use, for instance in the case of MENA for desalination, will need further consideration This, however, would have to be put into focus by the major stakeholders on both sides.

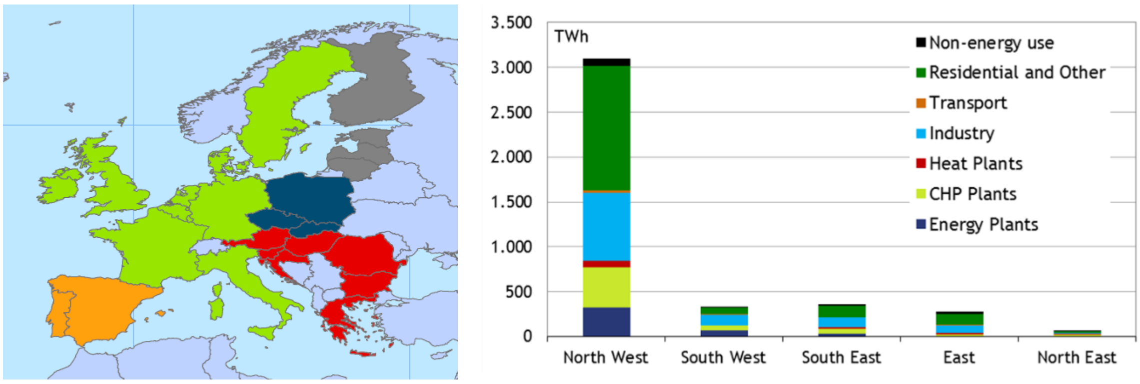
For the above-mentioned export possibilities in some cases the methane leakage issue needs to be fully assessed and addressed as well as the potential under consideration of the regions' own energy or electricity needs.

[24] Technical Workshop "Carbon-free hydrogen production from natural gas", facilitated by Zukunft Erdgas e.V., Berlin, August 31, 2018.

3 Development of three storylines

Three generic storylines have been developed in order to analyse potential future roles of gas and the gas infrastructure until 2050 together with their potential impacts. The storylines address fundamentally different energy system configurations based on (1) electricity becoming the major energy carrier, (2) a coordinated role of the gas and energy infrastructures with a focus on methane gas either as synthetic methane ($PtCH_4$) or biomethane and (3) a coordinated role of the gas and energy infrastructures with a focus on hydrogen gas. All three storylines have in common the achievement of the -95% GHG emission reduction target by 2050 compared to 1990 levels as an illustration of deep decarbonisation effort. Moreover, in all three storylines Europe is subdivided into five different regions comprising Member States in geographical proximity and with similar interests in energy and environmental policy: “Northwest” (BE, DE, DK, FR, IE, IT, LU, NL, SE, UK), “Southwest” (Spain and Portugal), “Southeast” (mainly Balkan countries), “East” (Czech Republic, Poland and Slovakia) and “Northeast” (Baltic countries and Finland). Based on current consumption levels, gas demand in the Northwest region is a factor of three higher than in the other four regions together, underlining the outstanding role of these Member States for the future development of the gas sector in Europe and pointing at the different individual Member State’s energy policies.

Figure 3-1 Representation of the five European regions for further analysis (left) and today’s gas consumption by region (right)



Green: Northwest; Orange: Southwest; Red: Southeast; Blue: East; Grey: Northeast.

To be able to derive a semi-quantitative estimation on the possible development of gas demand in Europe, a simple and straight-forward approach is used. For each storyline, the gas demand per country/region is estimated based on a few central assumptions. Those assumptions are based on learnings from the literature review or are taken directly from literature. Gas demand is estimated for 2030 and 2050 for the power, the heating, the transport and the industry sector. Values for 2020 and 2040 are linearly interpolated also using today’s gas demand in each sector.

In the power sector, 2030 gas demand is estimated based on figures from the latest ENTOS-G’s ten-year network development plan. For 2050, a factor is used to calculate gas demand for electricity production based on the electricity demand today. This factor is derived from literature. The gas demand in the transport sector is estimated based on an assumption regarding the share of gas-powered vehicles (trucks and passenger cars) in combination with a slightly increasing transport demand. In all storylines, directly electric driven vehicles (e.g. BEV, overhead wires) take a relevant share of the transport sector. In the heating sector, a significant reduction of total heat demand is assumed for all countries/regions. In addition, for each storyline the share of heat from gas and the type of gas is assumed. For this, today's share of gas (per country) in the heating sector is the basis. In the industry sector, a reduction of gas demand based on literature values is the fundamental assumption to estimate future gas demand.

Central assumptions and prerequisites valid for all three storylines are listed in the following bullet points:

- All three storylines successfully achieve a 95% GHG emission reduction by 2050 compared to 1990 levels;
- Emissions from certain industrial processes and from agriculture can be considered "unavoidable". These emissions are assumed to account for the great majority of the remaining 5% of 1990s GHG emissions. As a consequence, all energy related GHG emissions need to be fully avoided to achieve a 95% emission reduction. This means that by 2050, virtually no fossil energy carriers will be consumed (without CCS) in the energy sector;
- The 95% GHG emission reduction target is assumed to be agreed as of today, i.e. there will be no change in the target ambition over the timeframe until 2050. This is important to avoid any undesirable developments or lock-in effects (e.g. a late introduction of near zero emission technologies) an 80% reduction target might allow or require, and to enable a high level of planning security for all stakeholders;
- A wide societal acceptance of the 2050 emission reduction target in all Member States is assumed. People show high commitment and acceptance towards required measures to achieve this target. As a consequence, infrastructure expansions and adaptions can effectively be pursued; new technologies (e.g. new heating systems, new transport technologies) can successfully be introduced. New technologies such as e.g. hybrid end-user appliances find acceptance and support a cost-efficient transition to a fully decarbonised light transport and domestic heating sector by reducing stress on the electricity grid in times of peak consumption;
- An increasing integration of the energy systems and markets towards a fully integrated, well-functioning EU internal energy market for electricity and gases by 2050 is assumed;
- Most of the international ambitions (except of the U.S.) regarding emission reductions are assumed to be consistent with the ambitions in Europe in accordance with the Paris Agreement. This is a prerequisite for avoiding carbon leakage and economic disadvantages for EU companies (especially the energy intensive and export oriented industry) and Member States as a consequence of a 95% emission reduction target;
- The EU is anticipated to experience a moderate economic growth until 2050. This results in a slightly increased demand in road transport (tkm, Pkm) until 2050. The energy demand of the industrial sector remains constant at about today's level thanks to increasing energy efficiency on the one hand and economic growth on the other. The residential and commercial heat demand is significantly reduced to about half of today's values by applying efficient heating systems and deep insulation of buildings;
- The energy demand of aviation and maritime transport is assumed to be supplied without having any relevant impact on the European gas pipeline infrastructure. For this sector, energy is provided e.g. via domestic or imported Power-to-Liquids (PtL) or other fuels. If applied as LNG fuel from PtCH4 could also be used in e.g. maritime applications.

The following table shows the major parameters of the three storylines.[25]

25 When referring to innovative technologies in the context of chapter 3, we consider the technologies which have been studied in more detail in the full report of this study, with a focus on gas provision, infrastructure and end-use.

Table 3-1 Main assumptions per story

	Storyline:		**Strong electrification**		**Strong development of methane**		**Strong development of hydrogen**	
Category	**Criteria**		**Parameter**					
General aspects	Macroeconomics		Moderate growth					
	International context		Strong international climate ambitions					
	Acceptance		High public acceptance for energy transition					
	Energy market		Well-functioning EU internal energy market					
	Decarbonisation path		Medium		Fast		Slow	
Energy system	Long-term energy storage		Low, hydrogen		High, methane		Medium, hydrogen	
	Utilisation of gas pipeline infrastructure (compared to today; on Energy basis)		Significantly reduced		Constant		Reduced	
	Power grid expansion/investments		High		Medium		Medium	
	Cross border power transfer capacity		High		Medium		Medium	
	Pressure on renewable potentials (in contrast to other storylines)		Low		High		Medium	
	Total efficiency of energy system		High		Low		Medium	
	Flexibilities		Batteries, DR/DSM, electrolysis (minor role)		CH_4 production (and re-electrification); also batteries and DR/DSM		H_2 production (and re-electrification); also batteries and DR/DSM	
			2030	**2050**	**2030**	**2050**	**2030**	**2050**
Power sector	Gas for power production (compared to today)		Increasing		Increasing	Decreasing	Increasing	Decreasing
	Share methane		High	Low	High	High	High	Low
	Share hydrogen		Low	High	Low	Low	Low	High
Transport sector (Road)	Transport demand		Increasing 0.5% p.a. (tkm, Pkm)					
	Public road transport and private cars (Share of vehicles)	Electric	Medium	High	Low	Medium	Low	Medium
		Methane	None	None	Low	High	None	None
		Hydrogen	None	Low	None	None	Low	High
		Other	High	None	High	None	High	None
	Heavy goods transport, commercial vehicles (Share of vehicles)	Electric	Low	High	Low	Medium	Low	Medium
		Methane	Low	Low	Low	High	None	None
		Hydrogen	Low	Low	None	None	Low	High
		Other	High	Low	High	Low	High	Low
Other transport	Rail		No gases, mainly electric					
	Maritime, Air, …		No gases, mainly PtL					
Heating sector (Residential/ Commercial)	Heating demand		Significantly decreasing, -50% by 2050					
	Share in heating	Electric	Medium	High	Medium	Medium	Low	Medium
		Methane	Medium	Low	Medium	Medium	Medium	Low
		Hydrogen	None	Low	None	None	Low	Medium
		Other (e.g. direct biomass)	Low, about at today's level					
Industry	Gas demand		Significant decrease		Moderate decrease			
Domestic gas production	Natural gas		Medium	Negligible	Medium	Negligible	Medium	Negligible
	Synthetic methane		Low	Low	Medium	High	Low	Low
	Biomethane		Low	Low	Medium	High	Low	Low
	Hydrogen		Low	Medium	Low	Low	Low	High

3.1 Storyline 1 - Strong electrification

In this storyline, decarbonisation is achieved by strong and profound electrification of the most important energy consuming sectors in Europe. The direct use of electricity enables a highly efficient distribution and use of energy, but will generate high infrastructure investment needs which might be challenging due to lack of public acceptance. The pressure on renewable potentials is, compared to the other storylines, on a reduced level as domestic production of gas from electricity is limited, while the lower level of energy variety might negatively affect security of energy supply. The 2050 emission reduction target (-95%) is achieved in time, with major emission reductions already materialising around 2030. The importance of gas as energy carriers is significantly reduced.

Despite the seemingly small role of gas in this storyline, gas and gas infrastructure (especially gas storage, transport and re-electrification units) would be crucial to the stability of the energy system as a whole. Gas assets would continue to provide a large share of the required dispatchable peak power production capability, as well as important long-term and strategic energy storage. It is therefore important to ensure that all relevant infrastructures remain available to the energy system throughout the transformation process.

3.1.1 General drivers

Today, major technologies required for the electrification of the European energy system such as battery electric vehicles, electric heat pumps, PV, hydro and wind power already exist. In this storyline, these technologies see (further) rapid commercial expansion already in the short to medium-term, enabling a rather quick substitution of relevant shares of fossil energies with a related reduction of emissions. This is possible by first focusing on applications that can be considered as rather easy to electrify which are notably the heating sector, passenger cars and delivery vans. Other applications such as long-distance transport or industry processes are decarbonised mainly after 2030. The focus on strong direct electrification without the wide usage of hybridized (e.g. electricity plus gas hybrid) end user appliances results in a rather high stress on the electricity transport and distribution grid. This will require relevant investments in the electricity storage, transport and distribution infrastructure as well as in assured power production capacities. In the short-term, further development of fossil technologies is significantly reduced and then completely stopped. CCS and CCU technologies might be an exemption for a limited number of member states. Instead, technologies which enable the production, transport, storage and use of renewable electricity are increasingly in the focus of R&D and commercialization. This enables a continuous improvement in terms of e.g. efficiency and costs, and also widens the possible field of applications for these technologies.

Assuming that even in the long-term some applications cannot be supplied directly with electricity (e.g. due to technical, economic and/or practical reasons), hydrogen production, (long-term and strategic) energy storage, (intercontinental) energy transport and end-use technologies are also continuously under development, however, initially with reduced efforts. These technologies become available and are being introduced to the market on a larger scale after 2030. Compared to technologies that directly use electricity, hydrogen plays a lesser but unneglectable role in 2050. For some niche applications, methane (first fossil then renewable) and liquid fuels (PtL) remain an option until 2050 either due to the lack of other viable options or due to the easy availability of renewable methane (from biomass or electricity) in some regions or for some stakeholders. In 2050, other renewable energies (except for PV and wind) such as geothermal or the direct use of biomass for heating[26] are used at about the same level as today.

The power sector is ramping up renewable energy sources rather quickly. The increasing demand for electricity from the heating and the transport sector is satisfied by increasing installations of mainly PV and wind power (on and offshore). To geographically balance fluctuating power production from these sources, the European power grid is continuously expanded. Pumped hydro power potentials e.g. in Norway are well-integrated into the power system to provide short-term electricity storage. In the medium to long-term additional flexibilities are provided e.g. by stationary batteries and demand response / demand side management (incl. charging of electric vehicles and operation of heat pumps). Towards 2050, electrolysis for hydrogen production provides some additional flexibility and seasonal electricity storage. Assured power capacity is provided by hydrogen re-electrification and biomass fired power plants.

In 2050, no fossil energies are used in the European energy system. Electricity is the most commonly used energy carrier in all sectors ensuring high energy efficiency. Applications that are not suitable for direct electrification exist and usually rely on hydrogen as energy carrier. Hydrogen is also used for seasonal and strategic energy storage as well as for intercontinental trade. Further CO_2-neutral energy carriers such as renewable methane and liquid energy carriers are used in small amounts, mainly in aviation and maritime transport. Overall, the use of the existing gas infrastructure is at a low level.

3.1.2 Gas demand until 2050

The development of the total gas demand per sector and per region is shown in Figure 3-2. Gas demand decreases from about 4.000 TWh/a today to about 2.500 TWh/a by 2040. After 2040, gas demand decreases less strongly to 2,400 TWh/a by 2050.

Figure 3-2 Development of total gas demand per region (own assumption)

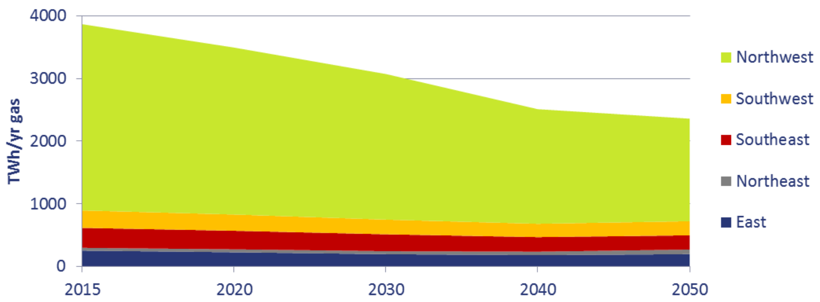
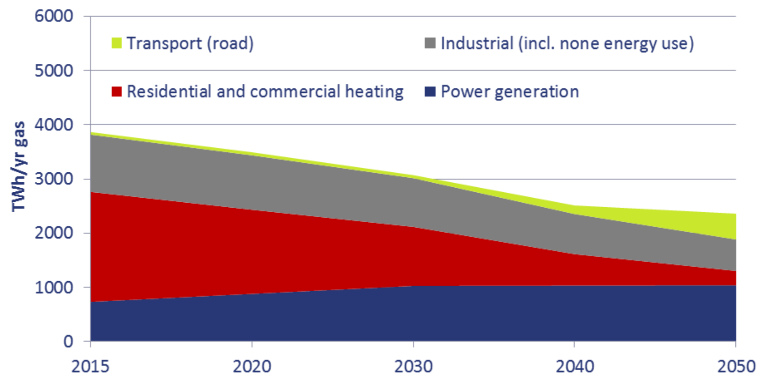


Figure 3-3details the contribution of each sector to the total gas demand. Demand reductions in the heating and industry sector are partly compensated for by increasing demand from the power sector until 2040. Between 2040 and 2050, further reductions are almost completely compensated by increasing demand from the transport sector.

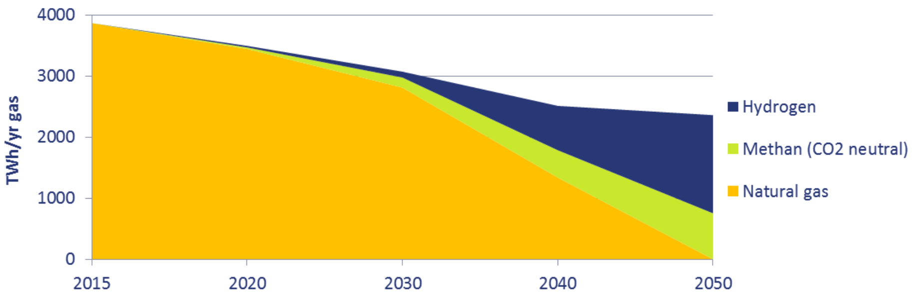
[26] Assuming that particle emissions from biomass for heating are not of concern anymore

Figure 3-3 Development of gas demand per sector (own assumption)



Today, virtually all gas consumed in Europe is fossil energy based. Renewable gases such as e.g. biomethane or hydrogen from electrolysis are used in marginal quantities. By 2030, still about 90% of the gas consumed will be natural gas. About 5% of the gas will be from renewable sources, another 5% hydrogen. Between 2030 and 2050, mainly hydrogen but also synthetic and biomethane or decarbonised gas completely replace natural gas as relevant energy carrier in Europe. Hydrogen, however, is used to a greater extent due to the comparable high efficiency of production and use (e.g. as vehicle fuel, seasonal energy storage).

Figure 3-4 Development of type of gas in the energy system (own assumption)



In 2050, hydrogen will mainly be produced from water electrolysis using renewable electricity. A CO_2-lean[27] production of hydrogen is also possible by using SMR in combination with CCS technology. However, this technology option has so far only been discussed for the UK [Northern Gas Networks, et al. 2016] and the Netherlands [WEC 2018]. In total 1,600 TWh of hydrogen will be used in Europe by 2050. The demand for CO_2-neutral methane amounts to about 750 TWh per year by 2050. This amount can be produced from biomass or catalytically from electricity in combination with CO_2. [Ecofys 2018] estimates an EU potential of 1,000 TWh of biomethane from biomass per year in 2050. In addition, up to 400 TWh of methane per year could be produced catalytically using CO_2 from large-scale concentrated renewable sources [LBST; Dena 2017]. Therefore, the estimated methane demand is within the European production potentials.

3.1.3 Gas infrastructure

Gas demand in the heating sector is significantly reduced due to strong insulation of buildings (-50% in average), increased efficiency of heat production (e.g. condensing boilers) and due to a fuel switch

[27] To make SMR+CCS truly CO_2-neutral, additional measures such as avoiding any natural gas leakage and compensating for incomplete removal of CO_2 from SMR exhaust stream, are required.

from gas to electricity for the majority of today's gas users for heating. As a consequence, large parts of the gas distribution grid are not in use anymore and are decommissioned. Remaining gas customers will not be spread across the entire distribution grid, they will rather be concentrated in single (island) grids which will be kept operational. Those remaining island grids will crystalize around easily available CO_2-neutral gas sources e.g. in rural areas with a high availability of required feedstock (e.g. biomass for methane or renewable surplus electricity for hydrogen production). In 2050, the grids are fed with pure methane, pure hydrogen or a mixture of both gases (hythane). The switch from natural gas to renewable methane can be slow and the share of renewable methane in gas can vary e.g. based on seasonal availability[28]. In contrast, the switch to hydrogen or hydrogen dominated mixtures needs to develop at a high gradient to be able to adapt all equipment in a grid section in a short time span (as experienced with the conversion from town gas to natural gas e.g. in the UK and Germany in the 50s/60s and 70s/80s). The limited spatial reach of individual grids will permit a rather flexible choice of these gases.

Despite the strongly reduced gas demand of individual gas consumers, their absolute cost contribution for the low pressure distribution grid (grid fees) will (at least) remain constant due to more or less constant total costs for the grid section. For those remaining distribution grids it was possible to stop the cost spiral of high (grid) costs causing high energy costs which again will cause additional customers to switch fuels. As a consequence (grid) costs for remaining consumers would increase even further causing again additional consumers to turn their back on gas usage, and so on [EWI 2017].

The operational distribution grids will likely require their own gas storage for short- and long-term storage or alternatively need to be connected to a gas transport pipeline, hence in need of reversing today's typical gas flows backwards from distribution to transport grid. Gas transport pipelines will mainly be kept operational to connect central gas power plants to gas sources, collect biomethane from decentral plants and especially to connect gas storage facilities (e.g. underground storages). Due to the higher gas production efficiency hydrogen will play a major role for long-term energy storage (e.g. in underground salt caverns) and re-electrification in periods with low power production from renewables. Total gas storage capacity will be lowest compared to the two other storylines due to an overall reduced energy demand as a consequence of efficient use of energy (e.g. heat pumps, battery electric vehicles). To store sufficient amounts of hydrogen it might be required to develop new storage sites. Transport pipelines will also be used for inter-European as well as intercontinental energy trade and transport. This might require to upgrade certain pipelines for reverse flow. Also the reclassification from methane (natural gas) pipeline to hydrogen pipeline will be required for a relevant share of pipelines. However, not all gas will be hydrogen. Methane will still play a role in the energy and pipeline system mainly due to the advantage of existing infrastructure, especially of assets that cannot be converted to hydrogen use (e.g. some natural gas storages) or of industrial customers that require methane (but not hydrogen) as feedstock.

By 2050, a relevant quantity of hydrogen will be used for the road transport of goods and people. This fuel can be transported to the refuelling stations by a gird of pipelines and hence unburden the electricity distribution grids. However, relevant alternative hydrogen supply technologies exist and are used and discussed for the transport sector, today. Those technologies (e.g. transport of liquefied hydrogen, onsite hydrogen production) do not use the gas grid. Hydrogen transport to the refuelling

[28] It may then be required to add gases such as nitrogen or propane to stabilize the heating value of the gas.

station by pipeline will likely only be economically attractive for the case that decommissioned natural gas pipelines can easily be converted and used or if new required hydrogen pipelines stretches are rather short.

Considering that not all hydrogen in the transport sector is transported via pipeline, the amount of gas in the European pipeline system is about halved by 2050 compared to today. Thus, the utilization of the system as a whole will drop dramatically. However, this might partly be compensated by the decommissioning of relevant shares of the distribution and transport grid. A certain (increased?) share of the gas might be transported twice through the system, 1) after production from renewable sources to be fed into a seasonal storage and 2) after withdrawal from the seasonal storage to be used for re-electrification, in industry and for the transport or heating sector. Some new investments might be required to make certain parts of the pipeline system compatible to hydrogen or hydrogen-methane mixtures.

In this storyline, no major imports of liquefied gases into the EU have been assumed, neither methane nor hydrogen. As a consequence, LNG import terminals and gasification plants will be decommissioned. Hydrogen liquefaction plants will exist in Europe e.g. to supply high purity gas to the industry and to supply some hydrogen refuelling stations (e.g. stations with low footprint). Existing import pipelines will also see very strong underutilization. The share of imported gases will likely become insignificant.

3.2 Storyline 2 - Strong development of methane (CO_2-neutral)[29]

Methane is key to achieving a 95% reduction of GHG emission by 2050 in this storyline. In sectors such as heating and industry, gas will continue to play a major role until and beyond 2050 widely using existing gas infrastructure. In other sectors it will replace large shares of fossil energy carries such as petroleum products (transport sector) or coal (power sector). The remaining fossil energies will mainly be replaced by electricity. Compared to the other storylines, very large renewable potentials need to be developed to supply sufficient methane quantities towards 2050. Security of supply will remain high with large gas storages still being in operation. They will be required less for the reason of seasonality (lower gas-for-heating demand) but more for provision of flexibility in the electricity grid. The 95% emission reduction target is met in time, relevant emission reductions are already achieved around 2030. The role of gas in the energy system remains strong.

3.2.1 General drivers

Methane is one of the most important energy carriers today. Especially in the heating, industry and power generation sectors it represents relevant shares of the total energy consumption. In the transport sector, the CO_2-lean gas (compared to other fossil fuels) is currently used in very low quantities despite the fact that required technologies are available.

In this storyline, methane remains strong in the heating, industry and power sector until and beyond 2050. In the transport sector, methane internal combustion engines quickly gain foothold in the short to medium-term. Rather early, the existing gas infrastructure, including a Europe-wide gas refuelling network, are expended, adapted and optimized to also supply the transport sector. In parallel, electric technologies such as e.g. battery electric vehicles and heat pumps are further developed. Battery

[29] Methane based on biomass or electricity

electric vehicles are introduced fast in the short to medium-term, but are considered not suitable for a rather large share of users due to technical and economic constraints and missing user acceptance. Here, vehicles with methane ICE continuously replace diesel and gasoline engines. In the heating sector, electricity-based heating technologies are primarily used for buildings in areas without gas grid. The share of methane in the heating sector will remain rather at a 50% level throughout the period until 2050.

The extended use of electricity mainly in the heating and transport sector and the strong switch of the transport sector towards (synthetic) methane are the major drivers for profound reductions of GHG emission until about 2030. The strong reduction of heat demand mainly through building insulation (reducing methane demand in absolute terms in this sector) continues after 2030 until 2050. By 2030, methane from fossil sources still represents the majority of the gas consumed in Europe, only minor shares are biomethane or synthetic methane. Step by step, natural gas will be replaced by CO_2-neutral methane after 2030. Synthetic methane and to a lesser extent biomethane completely replace natural gas by 2050. Natural gas in combination with CCS technology is only an option for large scale power generation but not for the transport and heating sector. Due to lack of public acceptance and limited policy support, it may be assumed today that CCS will not be introduced to a large extent in Europe.

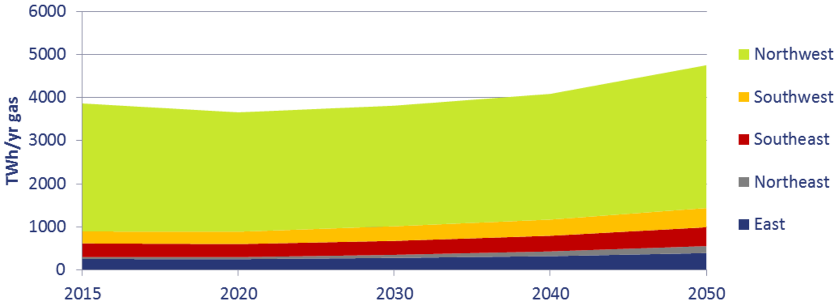
The large-scale production of methane from renewable electricity will require the installation of large renewable electricity generation capacities, especially PV and wind power (on and offshore). These fluctuating power sources will be balanced by inter-European electricity exchange, stationary energy storage in pumped hydro and battery storages as well as by demand response / demand side management. The production of synthetic methane offers significant additional flexibility to the power sector with electrolysis plants following consuming excess load in the system. Gas turbines and CCGT plants provide the majority of assured power generation capacity. Underground methane storages provide large-scale seasonal storage capacities.

By 2050, renewable methane and electricity have replaced all fossil energy carriers in Europe. Methane (gaseous and liquefied) is the commonly used energy carrier for seasonal and strategic energy storage as well as for international/intercontinental energy trade and transport. Other CO_2-free energy carriers such as hydrogen or Power-to-Liquids only play a negligible role. The utilisation of the existing gas infrastructure remains at a high level, new investments e.g. in refuelling stations are required in the short to mid-term.

3.2.2 Gas demand until 2050

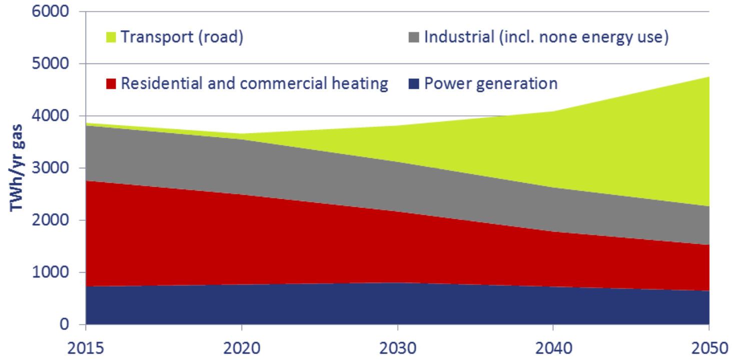
The total gas demand will be about constant until 2040, with a small dip around 2020. Starting around 2040, the gas demand will increase by about 25% until 2050.

Figure 3-5 Development of total gas demand per region (own assumption)



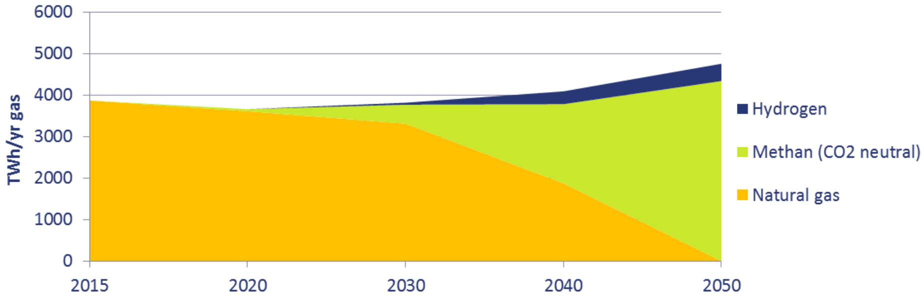
The increasing gas demand of the transport sector will overcompensate the demand reductions in the heating and industry sectors (see Figure 3-6).

Figure 3-6 Development of gas demand per sector (own assumption)



Between 2020 and 2050, fossil methane will completely be substituted by methane from renewable sources. In the industry and power sectors, small shares of hydrogen will be used. Most renewable methane will be used in the transport sector in 2050.

Figure 3-7 Development of type of gas in the energy system (own assumption)



By 2050, the total hydrogen demand will amount to roughly 400 TWh/yr; the demand for methane will then be above 4,000 TWh/yr. This value is slightly above today's gas consumption in Europe and significantly above the production potential of biomass based methane which is estimated to be at 1,000 TWh methane per year for the EU [Ecofys 2018]. This means that a large share of the methane has to be produced catalytically from electricity plus CO_2 (methanation), or alternatively needs to be imported from non-EU countries.

For the catalytic production of methane electricity will be used to produce hydrogen which is then combined with CO_2. For the production of CO_2-neutral methane two different CO_2 sources can be used.

CO_2 can either be taken from concentrated renewable sources such as e.g. exhaust gas of biomass fired heat or power plants or it can be extracted from air. The advantage of using concentrated renewable CO_2 sources is an increased efficiency compared to extraction from air. However, the availability of concentrated renewable CO_2 sources is limited, especially when considering that only sources of a certain size can reasonably be used. In a ballpark estimate, [LBST; Dena 2017] identifies CO_2 potentials from concentrated renewable sources to be able to support the production of about 400 TWh of methane annually in the EU (for 2015). This potential might increase until 2050, but it is unlikely that it will be sufficient to supply a few thousand of TWh of catalytic methane per year. Thus, the less efficient CO_2 extraction from air or imports will also need to be applied.

3.2.3 Gas infrastructure

By 2050, the demand of gas in the heating sector is halved due to increased insulation of buildings and increased efficiency of heat production (e.g. condensing boilers). The total number of end users in this sector stays relatively constant. While some new consumers (e.g. former oil heaters) can be connected to the existing gas distribution grid (fuel switch), other customers switch to electricity for heat production. The new investments into the distribution grid are limited to rather small adaptions and replacements. New distribution grids for the heating sector (low pressure) are not built due to missing economic feasibility (low gas demand per consumer due to insulation). However, the relevance of gas in the heating sector remains strong, providing about 50% of all heat required. With a constant number of customers connected to the low pressure distribution grid, the costs for this part of the gas grid will more or less remain constant. As a consequence, the absolute cost burden on the customer from this part of the grid will also remain constant. An increased specific (€/kwh) grid tariff has to compensate for the significantly reduced gas demand in the low pressure grid.

The reduction of gas demand in the heating sector frees capacities in the distribution and transport pipelines for the strong establishment of gas in the transport sector. A dense network of methane refuelling stations is established throughout Europe in 2050. To connect those to the gas grid, new pipelines stretches will be required. In regions without adequate gas grid, alternative supply options such as e.g. virtual pipelines, onsite methane production or road transport of liquid methane can be applied.

The supply of gas to the industry and power sector and the related infrastructure will change little in most cases. Total gas demand in both sectors will change only moderately until 2050. However, in the power sector the role of gas will significantly increase for European regions which do not use much gas for electricity production today. This is especially true for Eastern and North-eastern Europe. Here existing gas infrastructure might need to be supplemented, if a shift from coal to gas for electricity production would become an early ambition.

In cases where infrastructure needs to be adapted to comply with future needs of power generation, it might be worth thinking about using hydrogen instead of methane as energy carrier to exploit the higher efficiency of gas production from renewable sources. However, in most cases methane will remain dominant in this storyline.

The substitution of natural gas by CO_2-neutral methane can be gradual and regionally inhomogeneous. Even seasonal fluctuations in the share of renewable methane in the gas should not pose a major difficulty (in contrast to the strong admixture of hydrogen to natural gas „strong development of hydrogen" storyline). Depending on the source of the natural gas in the grid (Norway, Russia, Netherlands etc.) and the source of the renewable methane (e.g. fermentation of biomass), admixture of additional gases to the renewable methane might be necessary e.g. to adapt the heating value of the gas. The heating value of biomass based methane can be increased by adding (renewable) propane to then being mixed with natural gas from Russia. A reduction of the heating value can be achieved by adding nitrogen. The adjustment of renewable methane is not always subject to technical issues but rather to assure correct billing of delivered energy.

Today, gas for heating stands for more than half of Europe's gas demand. This share will be reduced to less than one fifth by 2050. The relevance of the transport sector increases from virtually zero today to about half of the total gas demand by mid-century. This shift impacts on the seasonal gas demand structure. The elevated gas demand during the winter season compared to summer is significantly reduced. This enables an adapted operation of existing gas storages to consider renewable electricity (and therefore also gas) production surpluses and deficits throughout the year. 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. This might also be true for gas transport pipelines. Reverse flow capabilities might be required in the European gas grid to allow for effective energy trade and balance of available energies (e.g. for gas production and transport: PV in summer in Southern Europe vs. Wind in winter in Northern Europe).

Considering the trend of increasing total gas use, the grids' new task of renewable gas "collection" on one hand and the possibility of decentral gas production and supply as well as the competing alternative transport modes of gas on the other hand, one can argue that gas throughput in the gas grid could possibly stay roughly at today's level.

By 2050, the European gas demand might not completely be supplied from European sources either due to limitations in ascertainable potentials (renewable electricity, CO_2, biomass, acceptance) or due to economical advantageous import opportunities. Methane imports either gaseous via pipeline or liquefied by ocean tanker are relevant options to cover domestic gas production deficits. Thus, existing LNG and pipeline import infrastructures will still be used in the long-term, in this storyline.

3.3 Storyline 3 - Strong development of hydrogen

This storyline strongly builds on the use of hydrogen as energy carrier in all sectors to achieve an emission reduction of -95% by 2050. Electricity-based technologies (heat pumps, BEVs) cover a low to medium share of sectoral energy demand by 2050. The use of hydrogen and electricity enables an energy system with a good efficiency: lower than in „Strong electrification", but higher than in „Strong development of methane". The 2050 emission targets are met in time. However, only less emission reduction materializes by 2030 due to the missing fast and strong deployment of direct electric technologies in the short-term. Hydrogen will play a strong role in the energy system in the long-term.

3.3.1 General drivers

Battery electric vehicles, electric heat pumps and other electricity-based technologies are available on the market today. However, so far the market penetration of these technologies is low. In this storyline, the expected rapid growth of electric technologies does not materialize. Instead, these technologies develop rather slowly in the medium-term. In parallel, hydrogen technologies are also being developed with increasing effort. The large-scale roll-out of hydrogen technologies gains momentum in the medium-term and greatly impacts the GHG emission reduction after 2030. In combination with a rather slow deployment of electric technologies, the decarbonisation is rather slow until 2030 compared to the other storylines. However, a reduction of -95% is nonetheless achievable by 2050.

Already in the short-term it becomes common understanding that electric and hydrogen technologies together are capable of efficiently replacing fossil energy carriers in almost all applications. As a consequence, rather early the development of fossil and methane-based technologies is significantly reduced and completely stopped in the mid-term. Despite the availability of some renewable methane e.g. from biomass, methane is not used in the transport sector in 2050. Instead, it is used to a very low extent in the heating sector, for power generation and in industry.

By 2050, electricity in combination with hydrogen will become the dominating energy carriers in Europe and worldwide. Hydrogen will have replaced methane (natural gas) as major energy carrier in the heating sector now accounting for about 50% of energy used for heating. In the transport sector, hydrogen has then become the standard fuel being used to power over half of the road transport. Battery electric vehicles contribute a relevant share as well. Hydrogen for all sectors will be produced (centralized and decentralized) in large quantities by water electrolysis within Europe. This production technology will provide significant flexibility (demand side management) to the power sector. Assured power capacity will be provided by hydrogen re-electrification technologies such as gas turbines, CCGT-plants or stationary fuel cells. Hydrogen (and electricity) will be transported and traded throughout Europe thanks to a well-functioning internal energy market and transport infrastructure of relevant capacity. Seasonal and strategic storage of energy will be provided by large-scale underground hydrogen storages (e.g. in salt caverns).

For international and intercontinental energy trade, hydrogen will be transported in gaseous form via pipelines or as liquid hydrogen in large tankers. PtL fuels are mainly used in aviation and maritime transport.

3.3.2 Gas demand until 2050

Gas demand will be slightly reduced between today and 2050. This development will be mainly driven by significant demand reductions in the heating sector, but also in the industry sector. Starting in 2030, a large share of the demand reduction in the above-mentioned sectors will be compensated by an increasing demand in the transport sector. However, due to the rather high efficiency of hydrogen-powered fuel cell electric vehicles, the impact will not be as pronounced as in the “Strong development of methane” storyline.

Figure 3-8 Development of total gas demand per region (own assumption)

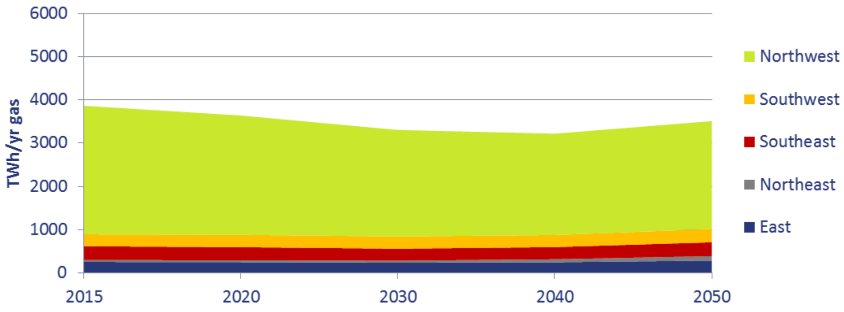
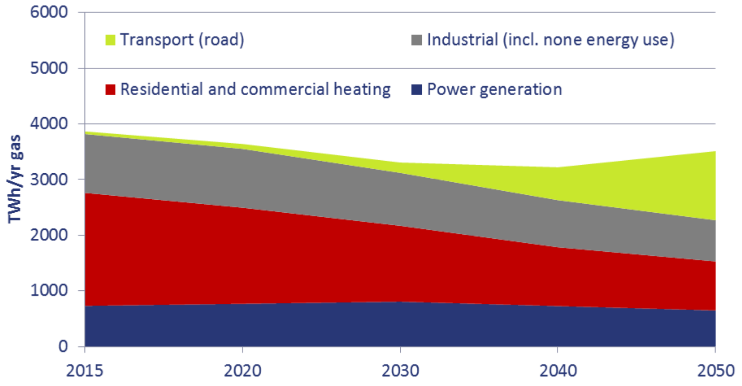
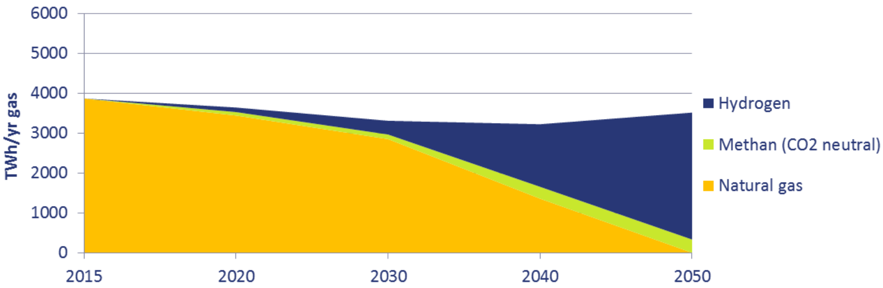


Figure 3-9 Development of gas per sector (own assumption)



The use of natural gas will be reduced from about 4,000 TWh per year today to about 3,000 TWh in 2030. By that year, minor amounts of CO_2-neutral methane and hydrogen will also be used. After 2030, hydrogen replaces natural gas rather quickly. In 2050, hydrogen will completely have replaced natural gas in the energy system. Renewable methane will be used to a low extent in the industry, heating and power sectors.

Figure 3-10 Development of type of gas in the energy system (own assumption)



Hydrogen from fossil sources (e.g. SMR) might be used to some extent in the medium-term. However, in the long term SMR+CCS will not be considered as acceptable option for large shares of total hydrogen demand. In fact, only the UK, Ireland and the Netherlands are currently considering CCS in addition to Norway which has gained practical experience for many years. The availability of by-product hydrogen is very limited and will not considered relevant in view of the medium- to long-term demanded quantities. Thus, hydrogen will mainly be produced by electrolysis using renewable (fluctuating) electricity.

3.3.3 Gas infrastructure

In this storyline, the heating sector will experience the same development of gas demand as in the "strong development of methane" storyline. An increased insulation of buildings will significantly reduce the gas demand in the low-pressure distribution grids. The main difference in this storyline is that hydrogen instead of methane will be used to substitute natural gas in the grid. This substitution with hydrogen however, is more complex than with methane. Using hydrogen for residential heat production will require the adaption of end user equipment to handle the different burning properties of the gas. Admixture of small amounts of hydrogen (few percent) to natural gas does usually not cause a problem for most burners. However, as in the long-term hydrogen will completely substitute natural gas, it will be required at some point to convert the distribution grids incl. attached users step by step to hydrogen use. This conversion might not only be required within the domain of the end user but also in the distribution gird. For some industrial gas customers even slight changes in the properties of the gas are relevant. Those customers however, are usually not connected to the low-pressure distribution grid, but have to be considered when also converting medium and high pressure pipelines to hydrogen or hydrogen-methane mixtures.

Today, little practical experience is available regarding the conversion of the natural gas grid to hydrogen operation, except from a few scattered demo projects e.g. in Denmark and Germany. In [Northern Gas Networks, et al. 2016] such a conversion has theoretically been studied in detail for the city of Leeds. Single relevant studies and projects especially for the admixture of hydrogen to natural gas exist. Experience for the conversion of entire grid sections from L-gas to H-gas are available and might be of interest also for the conversion to 100% hydrogen.

Before converting the gas grids to 100% hydrogen, an increasing admixture of the gas to the grid will reduce the specific GHG emissions of the gas in the short-term. However, the admixture of hydrogen to the gas grid will be limited based on the consumer or asset with the lowest tolerance for that gas. This limit can be different for each grid section depending on connected assets (e.g. 2% hydrogen admixture in case a NG refuelling station is supplied). In this storyline, admixture of gas to selected grid sections will continuously increase until 2030. Between 2030 and 2050 entire grid sections will be converted to 100% hydrogen use, e.g. in batches of about 2,500 users as for the example of Leeds. The upcoming L-gas to H-gas conversion of grid sections in Europe due to decreasing natural gas production in the Netherlands will pose a chance for some grid sections to leapfrog H-gas and directly switch from L-gas to hydrogen. By 2050, virtually the entire gas distribution grid will distribute hydrogen. Methane and hydrogen-methane mixtures in single grid sections will play a minor role, but will exist. The distribution grids will be supplied from local hydrogen production assets and/or from the transport grid which is also converted to hydrogen use. Even though first conversion studies exist, the difference in conversion costs and technology options of transport and distribution grid will have to be further assessed in future studies.

Due to technical constraints, a significant reduction of gas (energy) demand in the heating sector will have become a prerequisite of using hydrogen as gas in the pipeline system. This is due to different gas characteristics. Pipeline transport capacities are significantly reduced when transporting hydrogen instead of methane (at same gas flow speed). This reduction can partly be compensated for in cases where the gas velocity can be increased substantially.

The transport sector will heavily begin using hydrogen as fuel after 2030. In 2050, hydrogen in the transport sector will account for about one third of total gas usage in Europe. In this storyline, the gas demand in the transport sector will be significantly reduced compared to the „strong development of methane" storyline. Although the same share of the transport sector is supplied with gas in both storylines, gas demand in this storyline is about half. This is due to the significantly higher efficiency of a fuel cell (incl. electric motor) over internal combustion engines. Not all of the hydrogen used as vehicle fuel will have to be transported via pipeline. In case of insufficient pipeline capacity or the absence of a gas grid, hydrogen can be produced locally via electrolysis or can be supplied by liquid or gaseous road tanker. Also hybrid supply solutions (e.g. electrolysis + truck) are concepts that are already in use today. Especially for larger hydrogen refuelling stations new pipelines stretches will be installed to close gaps in the gas distribution infrastructure or to increase transport capacities.

In the power sector hydrogen is used to produce power in periods with insufficient renewable electricity production. Those central and decentral power plants are a major source of assured power capacity in the system and will be connected to the gas grid to get access to the large-scale gas storage facilities.

Some industry processes (e.g. production of high temperature heat) can easily be converted to hydrogen while others will require methane (and not hydrogen) as feedstock. This is taken into account by still operating a minimum of gas infrastructure for methane supply to industrial customers. However, this might not be feasible in all cases.

To supply hydrogen from production and gas storage facilities to distribution grids, major parts of the gas transport pipeline system need also be converted to pure hydrogen transport. The pipeline system will also be used for hydrogen trade and transport in Europe and with neighbouring regions. This is enabled by upgrading the system to work (partly) bi-directional (reverse-flow). Central and decentral power plants will also be connected to that infrastructure. Large gas storage facilities will then be connected to the grid to supply energy to the transport, heating, industry and power sector in periods with low renewable electricity and/or gas production. Large-scale underground storage of hydrogen is possible in new or converted salt caverns. The possibility of storage in other geological formations such as e.g. aquifers still has to be evaluated [HyUnder 2014]. Next to central hydrogen sources, also decentral hydrogen production facilities will be developed and connected to the gas grid. In some grid sections this will require the capability of hydrogen flow from lower to higher pressure grid segments.

Hydrogen can be transported over large distances either gaseous by pipeline of liquefied by ocean tanker. This enables an international trade and transport of this gas in large quantities in the future. Hydrogen imports can be used in the future to supplement domestic hydrogen production. This is possible by e.g. converting existing natural gas import pipelines to hydrogen or by installing liquid hydrogen terminals and re-gasification units. The liquefied cryogenic gas infrastructures for methane (LNG) and hydrogen (LH_2) are neither compatible nor convertible (both liquefaction processes yields each gas with highest purity). The downstream inland transport (road, train) of liquid hydrogen imports is also an option in this storyline to supply customers that cannot withdraw their gas demand from the gas grid (e.g. due to missing transport capacities, or due to the absence of a gas grid).

The gas transported in the pipeline grid is likely to be lower (on a TWh/a basis) than today. This is a result of a stable gas demand in combination with alternative gas transport modes and onsite gas production technologies especially for the transport sector.

The significant adaption of the gas infrastructure required in this storyline poses as major challenge, the feasibility has to be considered carefully. However, the required efforts for hydrogen conversion allow for a gas system that is significantly more efficient than when used with CO_2-neutral methane.

3.4 Conclusions on the development of the three storylines

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 storylines address fundamentally different energy system configurations based on:

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

All three storylines have in common the achievement of the -95% GHG emission reduction target by 2050 compared to 1990 levels as an illustration of deep decarbonisation effort. Moreover, in all three storylines Europe is subdivided into five different regions comprising Member States in geographical proximity and with similar interests in energy and environmental policy: “Northwest” (BE, DE, DK, FR, IE, IT, LU, NL, SE, UK), “Southwest” (Spain and Portugal), “Southeast” (mainly Balkan countries), “East” (Czech Republic, Poland and Slovakia) and “Northeast” (Baltic countries and Finland). Based on current consumption levels, gas demand in the Northwest region is a factor of three higher than in the other four regions together, underlining the outstanding role of these Member States for the future development of the gas sector in Europe.

A focus on a future energy system dominated by electricity in the first generic storyline would significantly reduce the role of the gas and gas infrastructures and hence create devalued or stranded assets in the existing gas infrastructure (import pipelines, gas storages, LNG regasification terminals, bi-directional pipelines). In the second generic storyline, the decrease of gas demand mainly in the heating sector can be (over)compensated by the dedicated use of gas in transport as well as in industry. This could lead to a significant utilisation of the existing gas infrastructure for the case of methane and hydrogen, to be validated in furthermore detailed modelling exercises. Due to the lower energy efficiency along the energy chain of methane compared to hydrogen technologies the pressure on domestic European energy resources for gas production would be higher in the second storyline (methane case) than in the third storyline (hydrogen case). This may necessitate larger energy imports in the methane case.

Comparing the three generic storylines, the hydrogen-based storyline No. 3 requires the strongest level of infrastructure development and technical conversion or adaptation and will require the longest timespan for its realization. However, it might present a robust perspective concerning overall energy and economic efficiency and level of integration, as well as a high level of end-user friendliness.

4 Relevant developments to stimulate the deployment of (renewable) gas

4.1 Status and national policies regarding renewable gas deployment

In several countries, a large share of the current natural gas consumption could be replaced with (locally produced) biomethane or decarbonised gas. However, while some initiatives are in place to stimulate this development, the actual deployment of renewable gas is still limited.

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 4-1 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 H_2 (1.2 MW PEM) **Target:** 10% in 2019	Subsidy scheme for biogas/biomethane produced from anaerobic digestion H_2 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 H_2 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

N**ational 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.

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.

4.1.1 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. It could also be considered to socialize part of the connection costs of gas filling stations to the grid (e.g. indirect costs related to upstream investments) 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 4-2 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 energy 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

4.1.2 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 also in 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[30] , 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 plant). 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.

4.1.3 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[31]. 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 completely be 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

[30] Though hydrogen pipelines are not covered by energy regulation (unbundling, access, etc.)
[31] Including Regulation EU 1315/2013 (TEN-T) and Directive 2008/28/EC (Renewable Energy Directive)

integration of gas from renewable energy sources.

- 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.

5 Consequences of the selected storylines

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 following sections assess the impact of these storylines in different aspects.

Table 5-1 Characterisation of the storylines

Storyline	Characterisation
1. Strong electrification[32]	• Very strong electrification of buildings (75% - versus 10% today - of heating needs provided from electricity*33*); 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 CO_2-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

5.1 Gas Infrastructure in the medium and long term

5.1.1 *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 volumes of natural gas transported in all three storylines, the utilisation level of LNG terminals and import pipelines would significantly decrease. The negative impact on the overall use of transmission grids and storage would be lower due to the expected use of this infrastructure for renewable gas.

Impact on gas demand

Storyline 1 would lead to a decreasing overall (natural and renewable) annual 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

[32] 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.

[33] Mainly by using heat pumps.

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 5-2 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)[34] 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 20%.[35] 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.[36] 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 in the three storylines 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 in general not be neededl. 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

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[34] Figures communicated by GIE to DG ENERGY
[35] FCH (2017) Development of business cases for fuel cells and hydrogen applications for regions and cities – Hydrogen injection into the gas grid.
[36] 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 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 5-3 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)

5.1.2 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. Among the Member States which are in the scope of this study, France and Italy have developed large LNG terminal capacities, whose utilisation level has 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 5-4 Natural gas supply split in source type (pipeline, LNG, domestic production) in 2016[37]

	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 South-West and Eastern Europe, are still not properly functioning, which is not only due to lack of adequate gas infrastructure, but also to inadequate or incomplete implementation of EU regulation in particular in Eastern Europe (e.g. price regulation and capacity allocation mechanism).

In the future, security of natural gas supply and markets' integration will no longer represent the main drivers for investments in gas infrastructure (though differences are expected across regions), but they will mainly be driven by replacement needs of ageing assets and refurbishment to accommodate renewable gas on the one hand and by requirements to ensure the overall energy system adequacy and operational reliability on the other hand.

5.1.3 Valuing 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.

[37] 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.

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 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, 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 energy supply, including enhanced energy system 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.

5.2 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[38], 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.

5.2.1 TSO assets represent a high economic value that 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 5-5 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 H_2 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

[38] This was the case for the studied regimes (see chapter 6), though there may be an impact for price cap regimes.

5.2.2 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 gradually (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 5-6 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 H_2)
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 H_2
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 security of energy supply and market integration objectives, some investments in (notably cross-border) gas infrastructure that cannot completely be realised on market terms are also co-financed by EU funds, in particular the CEF fund for Projects of Common Interest (PCIs).

5.2.3 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 5-7 OPEX levels of the assessed TSOs

TSO	Current OPEX level	Pipelines[39] 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 H_2 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

[39] Note that length does not correlate directly with transported volumes

6 Readiness of 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. The national regulatory frameworks should be based on common principles and goals but should allow for different decarbonisation pathways and technology choices to properly take account of the specificities of the individual Member States.

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.

6.1.1 *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[40] 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.

[40] In some Member States an adjustment is applied on the operational expenses based on cost efficiency standards

Table 6-1 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

The share of the TSO grid tariffs currently represents on average 7 to 10% of the overall gas bill[41], and varies depending on the level of the other cost components (commodity price, DSO tariff and taxes/fees) and the load profile.[42] 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 the detailed Task 3 and 4 report.

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[43] 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.[44] Once this Network Code will be

[41] Though this can vary across countries. In the UK, for example, these costs are around 2% of the gas bill. Source: https://www.uswitch.com/gas-electricity/guides/utility-bills/
[42] 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
[43] Commission Regulation EU 2017/460 of 16 March 2017
[44] 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).

implemented, most of the transmission services related costs will in all EU Member States be recovered via capacity charges.

Table 6-2 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
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.[45] 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

[45] 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

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,[46] 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[47] is used where a simple entry-exit system exists with the entire costs of transmission being charged to consumers.

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, more thorough ex-ante assessment of new investments, stimulation of the use of the gas infrastructure for 'new' purposes (renewable gas, LNG/CNG for transport), review of the depreciation rules and of the criteria for public co-funding of investments and increased R&D in view of reducing the refurbishment costs. Additional information on these aspects is provided in the Tasks 3 and 4 report.

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.[48] 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. We expect that the impact will be quite different for LNG or storage infrastructure operated under a negotiated regime, also taken into account that LNG terminals will have a much lower utilisation level under all three storylines, and that storage assets will face different challenges and opportunities depending on the storage type and storyline.

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,

[46] http://www.inogate.org/documents/Gas%20pricing.pdf
[47] This system is applied in several smaller countries, especially, with a single external supplier.
[48] CEER (2018) Study on the future role of gas from a regulatory perspective.

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.

6.1.2 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-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, though a careful assessment of costs throughout the lifetime of the assets would be needed.

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 in order to better reflect the added value of investments for the energy system and their future-proofness, 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 overall 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 that cannot completely be 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 energy supply and the adequacy and operational reliability of the overall energy system (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.

6.1.3 Review of depreciation rules for gas infrastructure assets might be appropriate

Due to the expected decrease in transported volumes of gas, 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 and NRAs 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 6-3 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 (as well as to de-risk investments in innovative projects). 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 .[49] 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 the detailed Tasks 3 and 4 report).

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.

6.1.4 *(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.[50] 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.[51]

[49] CEER (2018) Study on the future role of gas from a regulatory perspective.
[50] 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
[51] Ibid.

In the previous sections, we indicated that the gas grid tariffs are expected to increase as a consequence of falling volumes of transported gas. 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.

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 energy 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 energy 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 energy supply and operational reliability of the energy system. 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).[52] 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

[52] Ibid.

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 energy supply and operational reliability of the energy system 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.

Table 6-4 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[53]

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.

[53] For example, this could be negative if it promotes use of gas against other non-fossil solutions.

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 energy supply, to both the electricity and gas system and end-users. This role may grow with the advent of sector coupling and may bring overall costs down (relative to operating in silos). 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 ensure supply, flexibility to ensure operational reliability of the energy system) 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.

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Annex A - Key gas-related data for selected Member States

Table A-1 Overview of key data regarding gas demand and infrastructure in selected countries

	Denmark	France	Poland	Italy	Ireland	Romania
Annual gas consumption (GWh)	33,676	478,100	170,186	794,549	49,334	104,766
Peak load (GWh/d)	286	4,108	804	4,881	258	761
Share of gas in overall consumption (%)	17	15	15	38	29	28
Domestic natural gas production (GWh/y)	47,149	479,556	41,318	58,556	28,879	90,528
LNG terminals	None	34.25 bcm	5 bcm	15.25 bcm	None	None
Planned LNG terminals	None	40 bcm	14.5 bcm	8 bcm	9 bcm	2-8 bcm
Gas storage capacity	10.8 TWh	138 TWh	33 TWh	187 TWh	None	32.6 TWh
Transmission grid	924 km	27,514 km	NA	9,704 km	2,433 km	13,303 km
Cross-border interconnections	2 IPs	8 IPs	7 IPs	6 IPs	1 IP	6 IPs
Planned gas PCIs (2017 list)	2 PCIs	3 PCIs	8 PCIs	5 PCIs	3 PCIs	6 PCIs

Annex B - Brief country assessments[54]

Denmark

Existing and planned gas infrastructure in Denmark

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 neighbouring 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 CO_2 transport.

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.

Assessment of the impact of the storylines on the Danish TSO: Energinet

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

[54] For the full country assessments please see report on Tasks 3 and 4.

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 H_2 or CO_2 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.

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.

France

Existing and planned gas infrastructure in France

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.

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 CH4 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 a project of common interest).

Assessment of the impact of the storylines on the French TSO: GRTgaz

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.

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 France several policy and regulatory measures are in 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 CO_2 transport infrastructure.

Poland

Existing and planned gas infrastructure in Poland

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.

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.

Assessment of the impact of the storylines on the Polish TSO: Gaz-system

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.

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.

Italy

Existing and planned gas infrastructure in Italy

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.

Main national developments that influence investments in and use of gas 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.

Assessment of the impact of the storylines on the Italian TSO: Snam Rete Gas

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.

Ireland

Existing and planned gas infrastructure in Ireland

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 to 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.

Main national developments that influence investments in and use of gas 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.

Assessment of the impact of the storylines on the Irish TSO: Gas Networks Ireland

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 H_2 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 H_2 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.

Romania

Existing and planned gas infrastructure in Romania

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 CO_2 transport).

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.

Assessment of the impact of the storylines on the Romanian TSO: Transgaz

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 H_2 (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.

Annex C - Non gas-demand drivers for selected Member States

Table C-1 Overview of non gas-demand drivers

	Denmark	France	Poland	Italy	Ireland	Romania
Security of supply						
Access to diversified gas sources	Supply is sufficiently diversified Situation will improve with PCIs	Access to diversified gas sources via 4 terminals (expansion of LNG regasification units envisaged) and several import pipelines. Gas system resilient to possible supply crises. Short term SoS ensured by large storage capacity	Access to (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	Diversified supply sources and routes (domestic production, pipeline gas and LNG). Ongoing pipeline investments to further diversify supply and expansion of LNG regasification units is under consideration.	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 Import and network capacity is sufficient to cope with current and expected gas demand evolution	Substantial fossil gas reserves; their reduced deployment (decreasing production in medium term) will affect gas infrastructure. Investments in gas infrastructure focusing on access to diversified gas sources
Infrastructure standard N-1	Network and storage capacities are sufficient. Temporary supply security risk due to refurbishment of gas production facility.	Gas system is resilient. Conversion from L-gas to H-gas in the North of France (currently undertaken) will improve SoS	Gas infrastructure capacity is sufficient. Reverse flow investments are realised or planned to enhance SoS	Gas infrastructure capacity is sufficient. Reverse flow investments are realised or planned to enhance SoS	Twinning of the Southwest Scotland Onshore System (PCI 5.2) will allow interconnector system to be split into two separate systems, improving Ireland's N-1 infrastructure standard.	N-1 standard met. Grid extensions, adaptations and reverse flow investments are being realised/planned (PCI projects) to enhance SoS
Climate & environment						
Back-up of intermittent capacity	High share of intermittent capacity. Natural gas used for back-up power plants but expected phase out of fossil gas by 2050.	Planned expansion of intermittent capacity. Gas will be essential for back-up, at least until 2030. Networks are already sufficiently developed.	Expansion of intermittent capacity might create potential for gas as back-up source.	Planned expansion of intermittent capacity. Gas will maintain (at least until 2030) a primary role in the energy mix.	Planned expansion of intermittent capacity. Gas is essential for back-up (Ireland does not have nuclear power).	Planned expansion of intermittent capacity. Gas might become more important for back-up.
Biogas/biomethane development	Strongly support of biomethane. Biomethane and decarbonised gas will replace major part of natural gas consumption. Gas infrastructure can be used without adaptation.	Large potential for biomethane, though financial and other hurdles need to be addressed (currently relies highly on subsidies)	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 without adaptation.	Biomethane is injected into gas grid since 2017 (regulatory framework in place). Target for yearly increase of injected biomethane up to 1,1 bcm per year. Biomethane development will have major impact on gas infrastructure, possibly also for imports.	Large potential for biomethane. Development & injection has started. Gas infrastructure can be used without adaptation. Substitution of oil products with CNG in transport sector, initially from natural gas transitioning to bio-methane over time.	Large potential for biomethane production. Injection into gas grid is not yet considered
Hydrogen development	Hydrogen production (P2G), transport and storage considered. Transport of H_2 via grid requires investments if H_2 share	Hydrogen production (P2G), transport and storage considered. Transport of H_2 via grid requires investments if H_2 share exceeds technical	No installations or projects for injection of hydrogen or synthetic methane into gas grid. No major impact expected in	No installations or projects for injection of hydrogen or synthetic methane into the gas grid. No impact in short term.	Feasibility and impact assessment studies ongoing (Steam Methane Reforming of natural gas and potentially biogas with carbon neutral methane). P2G also feeding	Use of hydrogen is not yet considered

	Denmark	France	Poland	Italy	Ireland	Romania
	exceeds technical thresholds.	thresholds. Storage also to be refurbished	short/medium term.		into Hydrogen Networks	
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	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	Limited substitution of coal/oil by gas for power generation and heating. Initiative has been taken to substitute oil with CNG in transport sector, though expected limited impact in medium term	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.	Substitution of more carbon intense fossil fuels for power generation with gas. Aim to end of coal burning by 2025 and to peat by 2019. Gas fired power plants and large industry with CCS, storing CO_2 in depleted offshore gas field.	No plan to substantially reduce coal or oil use, hence no major impact
Competitiveness						
Market integration	No cross-border expansion needed to improve market integration.	No cross-border expansion needed to improve market integration, except if Spain confirms its need to have more import capacity from the North in order to rely less on LNG supplies.	Concentrated market, dominated by one company. Limited interconnection capacity. Infrastructure projects will enhance potential for full market integration	Well interconnected with neighbouring countries; ongoing investment project contributes to this objective and few projects are envisaged to expand cross-border trade capacity.	No cross-border expansion needed to improve market integration. Planned reverse flow project (PCI) will improve integration	Well interconnected, but markets are not integrated (technical and legal issues). Investments in interconnectors and reverse flows ongoing to enhance markets' integration
Enhance competition	No need for gas infrastructure investments to enhance competition	No need for gas infrastructure investments to enhance competition	Limited access to diversified supply sources to attract new suppliers and counterparts to Polish market	No need for gas infrastructure investments to enhance competition; ongoing investment project contributes to this objective.	No need for gas infrastructure investments to enhance competition	Mainly related to legal and market issues. No need for gas infrastructure investments to enhance competition

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