Measuring the contribution of gas infrastructure projects to sustainability as defined in the TEN-E Regulation

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EXECUTIVE SUMMARY

The main objective of this study is **to define and test a comprehensive indicator for the sustainability impacts of gas infrastructure projects considering the TEN-E Regulation requirements** of Art. 4.2 (b) (iv) and Annex IV.3 (chapters 1-3). The proposed indicator improves the consideration of the projects' sustainability impacts that feed in the gas PCI selection process. The proposed indicator addresses some of the weaknesses of the current sustainability indicator as defined in the gas cost-benefit analysis (CBA) methodology, such as possible misestimation/misallocation of sustainability impacts and increase the comparability of project-specific CBAs, and thus the ranking of PCIs in the regional groups. The proposed indicator can be implemented without introducing any additional complexity in ENTSOG's model. Furthermore, we propose a methodology to calculate sustainability benefits based on the use of an interlinked model that recognises the coupling of the gas and electricity systems. Such an indicator could be calculated using the METIS model.

A secondary objective is to **analyse the (TEN-E) sustainability aspects of a wide range of gas-related infrastructure projects, as well as their eligibility as a gas PCI** (chapters 4-5). The scope of this analysis is broader than the sustainability indicator developed in the first part of the study, and covers more types of projects than those considered in either the PCI or TYNDP processes. The study allows to identify potential improvements in the current TEN-E Regulation and the gas cost-benefit analysis methodology.

Overall structure of the study

Chapters 1-3
Sustainability indicator

1 – The ENTSOG CBA 2.0 sustainability indicator
2 – Development and testing of a new sustainability indicator
3 – Indicator description and implementation plan

Chapters 4-5
Gas-related infrastructure projects

4 – Gas-related infrastructure projects and their sustainability characteristics
5 – PCI eligibility and TEN-E sustainability of gas-related infrastructure projects

A new gas sustainability indicator considering the TEN-E Regulation requirements

The first step of the study has been to review the requirements from the TEN-E Regulation and the definition of the sustainability indicator as currently defined in the cost-benefit analysis methodology developed by ENTSOG (CBA 2.0). The current indicator defined in CBA 2.0 covers two sustainability aspects. The first part of the indicator is an evaluation of the CO_2 emission savings enabled by the development of the project being assessed, the gas it brings in the downstream system allowing to reduce the consumption of other more CO_2-intensive fuels in the area. The second part is a qualitative analysis of the measures the promoter has taken to mitigate the impact of the project on the environment. In this aspect, the current indicator does not cover other sustainability impacts, in particular the effect of the project on methane emissions, on non-GHG emissions and on the integration of intermittent renewable electricity generation or synthetic gas. The computation of the indicator evaluating CO_2 savings has some important limitations, some of which being directly linked to the limitations of the gas system model currently being used by ENTSOG to assess infrastructure projects, in particular the fact that dynamic interlinkages with other vectors (including electricity) are not captured and that its temporal granularity is limited to two points a year (winter and summer). The main limitations identified are as follows:

- The calculated CO_2 emission savings are independent from the potential use of the assessed project (i.e. the value of the indicator only depends on the capacity of the project and not on its use rate).

- The allocation of CO_2 emission savings treats existing infrastructure and new projects in the same way, regardless of the possibility of achieving the same level of fuel switching without the assessed project.
- The computation cannot capture the transit effects: e.g. a project built between area A and area B allowing a fuel switching from coal to gas in area C will not be attributed any CO_2 emission savings.
- The reduced representation of the dynamics of the gas system (two representative days) does not allow to precisely capture the operational management of gas storage assets. Therefore, the evaluation of their sustainability impacts lacks robustness.

In order to address these issues, an updated indicator is proposed in this study. Beyond small refinements related to the computation of the CO_2 emission savings due to fuel switches, the main change with respect to the current indicator is the allocation key (which encodes how CO_2 savings are allocated to projects). The allocation key of the updated indicator is based on flows instead of capacities, ensuring that projects which are not used in simulations are not allocated CO_2 emission savings. Furthermore, the report recommends, for computing this updated indicator, to use simulations prioritising existing infrastructure over projects in the operation of the gas network. The latter point would ensure that projects that grant access to cheaper gas but do not decrease the use of more CO_2-emitting fuels (coal, oil) are not allocated CO_2 emission savings for decreasing gas flows in neighbour infrastructure. This updated indicator could be used with the current modelling framework available to ENTSOG and thus be used by ENTSOG to compute the sustainability indicator of projects in upcoming TYNDP cycles. Similar methodologies have been proposed to assess the effect of fuel switches on non-GHG gases emissions and on methane emissions, linked to the increased use and leakages of methane in the downstream network. Insights on the quantification of RES gases and RES electricity integrated in the network are also provided. The proposed indicator allows to reduce the weaknesses of the current indicator, and to better cover the sustainability aspects mentioned in the TEN-E Regulation.

However, some of the limitations of the current indicator remain despite the recommended updates. In particular transits between countries are not well captured, the benefits of storages cannot be assessed accurately, and direct interlinkages between gas and electricity (i.e. gas-to-power, power-to-gas and hybrid consumption technologies) are not well accounted for. For that purpose, an indicator building on an interlinked gas, heat and electricity model is proposed. This indicator would allow for a better computation of sustainability indicators on all aspects (CO_2, non GHG emissions, impact of RES integration and renewable gas integration).

As far as we are aware, ENTSOG is not currently equipped with an interlinked model. Options where another entity could be tasked with evaluating the effect of projects on the system, for instance using METIS[1], could therefore be explored.

Finally, the question of the compatibility of projects towards a 2050 net-zero emission future has also been raised. The definition of these indicators (improved indicator and interlinked model indicator) could help assess the relevance of projects for reaching a net-zero emission future but would require assessing projects at the 2050 horizon (which is not foreseen in TYNDP 2020 as far as we are aware). Scenarios reaching the European objectives, such as the Long-Term Strategy pathways 1.5TECH or 1.5LIFE, could be considered to assess whether projects are future-proof.

[1] METIS is an interlinked model developed by Artelys on behalf of the European Commission. It has been used to inform policy making in various areas (e.g. proposals of the Clean Energy Package) and is available to the Joint Research Centre. For more information on METIS, we refer the reader to https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en

Figure 1 Comparison between the different indicators

	Current Sustainability indicator	Improved Sustainability indicator	Interlinked model Sustainability indicator
Simplicity to compute the indicator	✔	✔	
Possibility to attribute a negative CO_2 impact to a project		✔	✔
CO_2 savings allocation prioritise existing infrastructure.		✔	✔
CO_2 savings are linked to expected flows in the project.		✔	✔
Evaluation of the effect of projects on CO_2 based on a marginal approach (operation of the system with/without the project similarly to the CBA)			✔
Accuracy for the evaluation of CO_2 savings of storages			✔
Cross sectoral assessment (incl. P2G)			✔
Trans-national assessment			✔

Gas-related infrastructure projects

The sustainability characteristics of eight selected gas-related infrastructure project types analysed in chapter 4, are illustrated by their impact on greenhouse gas emissions (CO_2, CH_4 and other gases), on the reduction of local pollutant emissions, and on the development of renewable electricity, biomethane and hydrogen. The projects selected for detailed analysis are related to hydrogen (pure or admixed in natural gas networks), biomethane or methane emission reduction, covering the gas supply chain stages of transport, distribution, storage and conversion.

The emission reduction impact of the different project types varies significantly, from potentially negative to neutral or strongly positive impacts. Quantitatively, the impact may vary from around under -200 to over 200 tCO_2eq of avoided GHG emissions per TJ of fossil fuel substituted due to gas projects. However, the impacts of individual projects will vary according to not only aspects considered in this study, but also characteristics specific to each project and the energy system they are integrated in.

Section 5.1 considers the PCI eligibility of the gas-related infrastructure projects according to the TEN-E criteria (general, Annex II and specific criteria). Of the eight project types analysed, half would not be eligible for PCI status, while specific projects in the other four types could potentially satisfy the eligibility criteria.

As for the sustainability impacts that gas-related infrastructure can have, these are already considered in the TEN-E regulation at a high level. However, several options for potential improvements are identified in the study. They concern the eligibility criteria mentioned in the TEN-E regulation, the gas CBA methodology and the sustainability indicator to assess the positive and negative sustainability impacts of candidate PCI-projects:

- **Asses the sustainability characteristics of PCI candidates, preferably with an integrated electricity-gas model,** in order to fully account for the benefits of projects to enable the integration of both renewable gas and electricity into the system as well as to consider the electricity-gas systems interlinkages. This substantial change could be preceded by short-term improvements in the CBA methodology, including by implementing the improved sustainability indicator developed in chapter 2;

- **Consider implementing minimum sustainability criteria for gases in the calculation of the projects' sustainability benefits**, using RED II criteria, while also including gases with comparable carbon footprints to renewable gases, such as low-carbon hydrogen;
- **Use eligibility and assessment criteria for PCIs to avoid a lock-in in unsustainable pathways**, considering the carbon footprint of the various gases facilitated by gas-related infrastructure;
- **Consider developing an integrated hydrogen-electricity-gas model if and when the scope of the TEN-E Regulation is expanded,** to include hydrogen systems when these reach significant scale and interaction with other energy infrastructure. Meanwhile, hydrogen projects can be considered through scenarios, with verified project-specific data and at the interface of methane and of electricity systems.

Finally, it is important to recognize the importance of scenarios' formulation and the subsequent choice of scenario(s) for performing the cost-benefit analysis on the resulting project assessment. In order to ensure the neutrality of scenarios, they should be aligned to general policy goals (such as the 2050 Long-Term Strategy), and reflect alternatives to infrastructure investments, such as energy efficiency measures, in line with the Energy Efficiency First principle of the Energy Union. Furthermore, there should be strong oversight and consultation of stakeholders to ensure the scenario development and project assessment are transparent and scientific, and avoid the risk of lock-in in unsustainable pathways or stranded investments.

1. THE ENTSOG CBA 2.0 SUSTAINABILITY INDICATOR

This chapter presents a description of the current approach used by ENTSOG and gas project promoters to assess the sustainability impacts of gas infrastructure projects in the context of TYNDP 2018. We then proceed to describing our assessment of the strengths and weaknesses of the approach. The description and evaluation of ENTSOG's approach are based on publicly-available documents as well as on bilateral contacts between the consultants and ENTSOG staff members. The key ENTSOG documents that have been consulted to describe ENTSOG's approach are:

- ENTSOG (2018), 2nd ENTSOG Methodology for Cost-Benefit Analysis of Gas Infrastructure Projects
- ENTSOG (2018), TYNDP 2018, Annex D – Methodology
- ENTSOG (2018), TYNDP 2018, Project-Specific Cost-Benefit Analysis

Several other documents have been consulted to assess the strengths and weaknesses of the sustainability indicators currently used by ENTSOG, for instance:

- EC, Regulation (EU) No 347/2013
- ACER, Opinion No 15/2017
- ACER, Recommendation No 02/2019
- Navigant (2019), Study on an assessment methodology for the benefits of electricity storage projects for the PCI process
- Deloitte/FSR (2017), Study on recommendable updates and improvements of the ENTSOG methodology for cost-benefit analysis of gas infrastructures
- ENTSO-E (2018), 2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects
- ENTSO-E (2019), Draft CBA 3.0
- EIB (2018), Project Carbon Footprint Methodologies

The following paragraphs present an overview of the 2nd ENTSOG methodology for cost-benefit analysis (CBA), with a focus on the sustainability indicators. We then present a detailed description of the way the sustainability indicators are calculated, the input data, and the role of stakeholders in supplying datasets and/or running calculations. Finally, the strengths and weaknesses of the current indicator are presented.

1.1. Sustainability in the current TEN-E Regulation (EC) 347/2013

Article 4 "Criteria for projects of common interest" of the TEN-E Regulation states that gas projects falling under the energy infrastructure categories (set out in Annex II.2), must contribute significantly to at least one of the following specific criteria:

- **Market integration**, inter alia through lifting the isolation of at least one Member State and reducing energy infrastructure bottlenecks; interoperability and system flexibility;
- **Security of supply**, inter alia through appropriate connections and diversification of supply sources, supplying counterparts and routes;
- **Competition**, inter alia through diversification of supply sources, supplying counterparts and routes;
- **Sustainability**, inter alia through reducing emissions, supporting intermittent renewable generation and enhancing deployment of renewable gas.

Annex IV "Rules and indicators concerning criteria for projects of common interest" to the TEN-E Regulation further specifies that "sustainability shall be measured as the contribution of a project to reduce emissions, to support the back-up of renewable electricity generation or power-to-gas and biogas transportation, taking into account expected changes in climatic conditions" (Annex IV.3).

In the TEN-E Regulation as it stands today, sustainability is only one of the four considered criteria, meaning that PCI projects do not necessarily have to meet this sustainability criterion, as the four mentioned criteria are not cumulative.

1.2. Overview of 2nd ENTSOG Cost-Benefit Analysis

Chapter IV of Regulation (EC) 347/2013 provides the regulatory reference for the energy system wide cost-benefit analysis methodology. It defines the use of the CBA methodology for the development of the TYNDP, as input for the selection of Projects of Common Interest (PCIs), as basis to investment request, and as basis to allow promoters to apply for financial assistance. The latest CBA methodology developed by ENTSOG and approved by the European Commission on 1 December 2018, aims at delivering a comprehensive assessment bringing more clarity than its predecessor with a reduced number of indicators and an easier interpretation of the results.

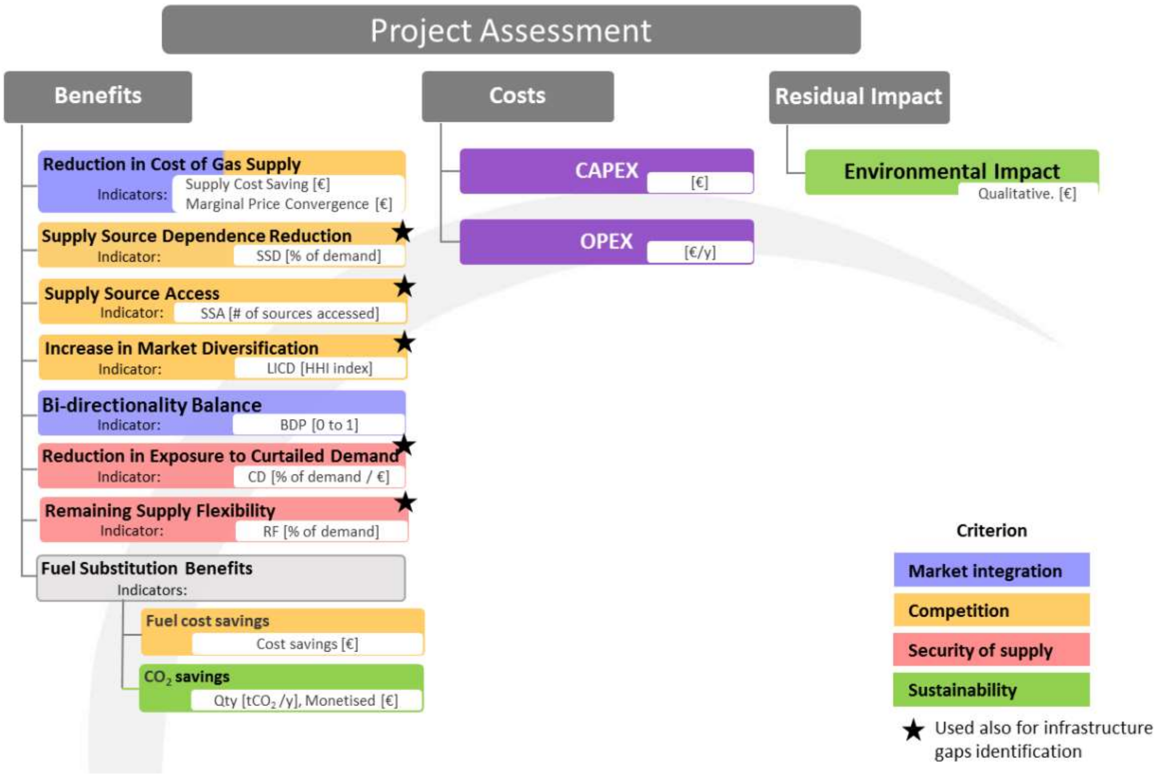
The methodology includes two steps:

- The **system assessment** aims (among others) at providing an overall assessment of the European gas system under different infrastructure levels: a reference level (current + projects having reached the final investment decision), an advanced level (with advanced non-FID projects) and a PCI level (with non-FID projects having PCI label);
- The **project-specific assessment** aims at providing an individual assessment of each of the projects submitted to ENTSOG during the TYNDP process in order to evaluate the costs and benefits associated with the project.

The CBA methodology consists in an analysis of the contribution of the project to four criteria: market integration, security of supply, competition and sustainability. Several indicators of the CBA can qualify each of these four criteria. The latest CBA methodology developed by ENTSOG to assess specific projects (PS-CBA) and approved by the European Commission[2] is structured as follows:

[2] https://www.entsog.eu/sites/default/files/2019-03/1.%20ADAPTED_2nd%20CBA%20Methodology_Main%20document_EC%20APPROVED.pdf

Figure 1-1 ENTSOG CBA - Structure of the PS cost-benefit analysis



The different benefits are quantified via simulations of the operations of the European gas system, based on a bottom-up representation of the system: the gas sources (production/imports/LNG), storage assets and interconnections are explicitly represented with a country-level spatial granularity. The operations of these assets are then simulated by enforcing a demand-supply equilibrium, in particular in periods of stress (cold winters, disruptions, etc.). The annual figures are obtained by simulating two days (one for winter, the other for summer, linked via a storage-related constraint).

For most indicators, the projects are assessed by comparing two situations: one situation without the project and another one where the project is present. The contribution of the project to the corresponding criteria is then calculated as the difference of the key indicators presented in the figure above between the two situations.

However, the way the sustainability indicators are calculated is not based on such an approach: these indicators are calculated by comparing two different time horizons. The details and motivation for choosing a different approach are presented in Section 1.3.

1.3. Sustainability in ENTSOG's Cost-Benefit Analysis 2.0

As described above, one of the four criteria defined in the TEN-E Regulation to assess gas projects is sustainability. The following paragraphs present our understanding of the methodology developed by ENTSOG to capture the sustainability impacts of a gas infrastructure project.

The current CBA methodology includes two indicators related to sustainability:

- ***CO_2 emission savings* (quantitative indicator, monetized)**: The objective of the "CO_2 savings" indicator is to quantify and monetize the impacts of the project on CO_2 emissions. The rationale is that a given gas infrastructure project can enable gas to substitute more carbon-intensive fuels;

- ***Environmental impact* (qualitative indicator, with associated costs)**: The objective of the "Environmental impact" indicator is to provide an appreciation of the mitigation measures put in place by project promoters in order to reduce the impact of the project on its surroundings.

The 2nd CBA methodology also imposes that the calculation must be performed both in CO_2 emissions (MtCO2) and in monetary value (in €) using two possible approaches for the monetization (CO_2 market price or social cost of carbon).

In the following section, we provide a description of the calculation of the "CO_2 emission savings" indicator, and illustrate this method with a virtual example based on a project with impacts in 3 countries.

As described in Annex D of ENTSOG TYNDP 2018, ENTSOG has left the final calculation of project-specific CO_2 savings to the responsibility of promoters. However, in order to facilitate this calculation, ENTSOG provides a number of indicative figures to the promoters, which are based on an analysis of the evolution of gas use over the period covered by the TYNDP scenarios. In practice, ENTSOG figures are used unless project promoters can propose alternative figures that are duly justified by them.

The key steps of the ENTSOG methodology to assess the effect of infrastructure projects between two consecutive years of the modelled scenarios (e.g. 2020 to 2025, 2025 to 2030) are the following:

- **Step 1**: Assessment of evolution of the use of gas by sector during the period
- **Step 2**: Computation of CO_2 savings from fuel switching per sector
- **Step 3**: Evaluation of CO_2 savings in each country
- **Step 4**: Allocation of CO_2 savings to projects in the country

We describe in the following sections the steps in more details.

As far as the environmental impact indicator is concerned, the promoter has to provide a table with the impacts and an overview of the mitigation measures that will be undertaken to comply with the EU Environmental acquis.

Methane emissions are not taken into account in the current ENTSOG approach (no methane emissions allocated to projects).

According to ENTSOG, in TYNDP 2020, the total GHG **non-CO_2** emissions are considered in the scenarios by taking the average of 1.5LIFE and 1.5TECH scenarios of the European Commission's Long-Term Strategy. However, these emissions are not allocated to projects during the project-specific cost-benefit analysis.

1.3.1. Step 1: Assessment of the evolution of the use of gas by sector over the period

The first step of the computation consists in the identification of the sectoral evolution of gas use between two consecutive years in the modelling (e.g. 2025 and 2030). For this purpose, ENTSOG relies on the scenario assumptions by sector.

For TYNDP 2018, since the scenarios did not cover the full energy system, the assumptions for the energy mix by sector partly rely on Eurostat 2016 datasets.

In TYNDP 2020, the full energy mixes will be provided for two top-down scenarios (Global Ambition and Distributed Energy). For the remaining bottom-up scenario (National Trends), based on NECPs, additional assumptions will have to be made on the energy mixes.

Required input: gas use in all sectors (electricity, heating, transport, industry), at country level, for the two considered years.

Output example: In country A, the gas use will increase by 10 TWh in the heating sector and by 25 TWh in the industry sector. The gas use will decrease by 5 TWh in the electricity generation sector, and will remain constant in the transport sector between 2025 and 2030.

1.3.2. Step 2: Computation of CO_2 emission savings from fuel switching per sector

The objective of this step is, for sectors for which an increase in gas consumption is expected (as assessed in step 1), to compute CO_2 emission savings that are expected in the concerned sectors by fuel switching.

For that purpose, for each sector, the current methodology assumes that the additional gas consumption replaces consumption of more carbon-intensive fuels such as oil and coal, up to the volume of oil and coal present in the energy mix in the starting year of the period. In this sense, the case of a nuclear phase-out leading to an increase of gas consumption for electricity is not accounted as an increase of CO_2 in the methodology.

The CO_2 content of the fuel(s) replaced is estimated on the basis of the energy mix in the given sector at the starting point of the period for TYNDP2020 or of the energy mix in 2016 (based on Eurostat data) for TYNDP2018.

For instance, in a given sector, if the share of oil is 9% and the share of coal 1%, a unit of gas replaces 9/10 unit of oil and 1/10 unit of coal. The savings associated to this switch are thus 9/10 oilCO2content + 1/10 coalCO2content – 1 gasCO2content.

Although it is not fully clear in the methodology, the difference in efficiencies of gas-based or coal/oil-based technology can also be accounted for in the computation.

The savings computed are thus:

$$\mathrm{CO_2Savings_{sector}} = \mathrm{gasConsumptionIncrease_{sector}}(\mathrm{fuelReplacedCO2content} - \mathrm{gasCO2content})$$

Required input: fuel mix in all sectors (Residential & Commercial, Power, Industry, Transport), at country level, for the starting year of the period or the reference year (year 2016 for TYNDP 2018). Efficiencies of gas-based, coal-based and oil-based technologies used in each sector.

Output example: in country A, in sector S, the substitution of coal by gas has led to saving of 0.5 MtCO2.

1.3.3. Step 3: Estimate the CO_2 emission savings in each country

In each country the CO_2 emission savings of each sector are simply added. This leads to a figure of total CO_2 emission saving per country during the period.

Required input: CO_2 emission savings per sector from step 2.

Output example: in country A, CO_2 emissions have decreased by 0.75 MtCO2 during the period.

1.3.4. Step 4: Allocation of CO_2 emission savings to projects in the country

The CO_2 emission savings in a country are allocated to projects in this country via a pro-rata allocation of the different projects' capacity compared to the total capacity (including projects and existing or planned infrastructure).

$$\text{CO2savings allocated to project} = \sum_{\text{Countries}} [\text{CO2savings(country)} * \frac{\text{Project Capacity}}{\text{Total Capacity(country)}}]$$

In the above formula, "Countries" stands for the countries that host the considered project (i.e. a single country for LNG terminals and gas storage assets, two countries for an interconnector), and "Total Capacity" is the sum of the capacities of the gas infrastructure (including all projects) in each of the hosting countries.

1.3.5. Fictional examples of application of the methodology

CO_2 emission reduction in the power sector in country A between two scenarios for 2025 and 2030

- Gas consumption increases by 3.9 TWh/y between 2025 and 2030 in the power sector (i.e. there is an increase of 2.34TWh of electricity from gas-based electricity generation – with 60% efficiency)
- The reference electricity mix contains respectively 14% and 1% of coal and oil used for power generation and the volume of coal-based and oil-based electricity generation is higher than 2.34 TWh.
- The CO_2 content of the fuel replaced is 14/15 coal Content + 1/15 oil Content = 0.344 t/MWh
- The carbon intensity of natural gas is 0.2 t CO_2/MWh.
- The efficiency ratio of gas-based generation (60% for a CCGT) and coal-based or oil-based generation (around 40-45% for coal and oil plants) is 60% /45% =1.33
- The yearly carbon emission savings are computed as 3900*(0.344*1.33-0.2) = 1004 tCO_2 per year.
- The total carbon emission savings are computed as 1004*5 = 5020 tCO_2 over the period
- This calculation is then undertaken for the other concerned sectors in order to obtain the total carbon emission saving per country which is then allocated to the considered gas infrastructure.

Allocation of CO_2 emission savings in the case of a 1 GW LNG terminal

- The project is a 1 LNG terminal connected to the gas grid in country A.
- During the period considered, A has allowed for 0.75 $MtCO_2$ of CO_2 emission savings
- A has some existing or planned (FID) capacities: 2 GW of LNG terminals and 4 GW of interconnectors
- A has no other gas infrastructure projects
- The benefit allocated to the project is thus 0.75 $MtCO_2$ * 1 GW / (2+4+1 GW) = 0.11 $MtCO_2$ for the period.

Application to the case of a 1 GW interconnector between two countries

- The project is a 1 GW interconnector connecting two countries A and B.
- CO_2 emission savings would in practice only occur in country B: 3 $MtCO_2$ savings

- Existing capacity in country A is not relevant in this computation.
- Existing capacity in country B: 4 GW of interconnectors (including a 1.5 GW interconnection with A)
- The benefit allocated to the project is 3 $MtCO_2$ * 1 GW / (4 + 1 GW) = 0.6 Mt CO_2

1.4. Evaluation of the current sustainability approach used by ENTSOG for TYNDP projects

As discussed in the previous section, the methodology currently used by ENTSOG to compute the sustainability impacts of gas infrastructure projects primarily relies on computing the CO_2 emission savings in each country during a given period of time and allocating part of these emission savings to projects. We provide below our assessment of the strengths and weaknesses of the current approach.

The main strength of the indicator is that its objective is clear: *computing the CO_2 emission savings enabled by the changes in the fuel mix, allowed by the new project.* The indicator is also relatively easy to compute. Its computation is not based on simulations (unlike other indicators such as those relative to security of supply) but on data of the fuel mix per sector, and requires as input the capacities of projects and existing infrastructure (both characteristics are directly available in the TYNDP).

Its simplicity is however also its main **weakness**. The approach currently used by ENTSOG leads to several aspects being difficult to capture, for instance:

- **The results of CO_2 emission savings are independent from the potential use of the project**. Indeed, the allocation key is solely based on capacity and not on flows. The potential use of a project could be estimated by considering the gas flows obtained in the simulations performed for other indicators of the CBA analysis for the considered scenarios. Flows could then be used as an allocation key to reflect the fact that CO_2 emission savings can only be allocated to projects if these projects are actually used.
- **The current allocation key based on installed capacities treats existing infrastructure and new projects in the same way** in terms of their effect on fuel switching. While this could be valid for an *ex post* calculation (allocation of CO_2 savings to elements of an existing system assuming the project is already installed), we consider it is not well adapted for an *ex ante* analysis (calculation of CO_2 savings for an investment option). The benefits of a project should be measured by its contribution to sustainability, and not by the average contribution of the gas infrastructure.
- **Its geographic scope is limited**: for each project, fuel switches are assessed only for one (in case of LNG terminal or UGS facilities) or two countries (for cross-border pipelines). This approach cannot capture the transit effects: e.g. a project built between A and B could help bring gas from A to C and reduce emissions in C. The current approach would not attribute such savings to the project while it clearly enables the reduction of GHG emissions. This is critical for large projects that would incur significant imports of gas transiting through a large number of countries.
- Another weakness of the indicator is that **it only focuses on CO_2 and especially on CO_2 avoided by fuel switch**. As such, it does not capture other sustainability characteristics of the project, in particular its effect on methane emissions or other GHG and non-GHG emissions.
- Also, the methodology does not capture cross-sectoral dynamics. In particular, it does not account for the additional benefits from integrating more **renewable electricity or gas** or **synthetic gas** into the network.

The computation of CO_2 emission savings as currently defined is relatively straightforward but presents limitations. Some of these limitations could be addressed in the current modelling framework:

- For each sector, increases in gas consumption are assumed to reduce the use of fuels with higher specific CO_2 emissions. This is a key assumption that requires to be validated, for instance by checking the feasibility of the switch (depth of the fuel switch). This work seems to be done by ENTSOG but could benefit from more clarity and transparency to be enable stakeholders to check the plausibility of the results.
- The evolution of the energy mix and its effect on the fuel switching opportunities are not well captured in the TYNDP 2018: its assumptions only cover gas and electricity but no other fuels. This limitation is currently addressed by using as a reference the energy mix of 2016 as a proxy. In the TYNDP 2020, scenarios cover all fuels, so we understand that this proxy will not be required, except for the 'National Trends' scenario, which reflects Member States' draft National Energy and Climate Plans[3] (NECPs).
- CO_2 emission savings are computed only for sectors for which an increase in gas consumption is expected. In a country where the overall gas consumption is decreasing, there still can be CO_2 emission savings linked to the switch of other fuels.

In order to address the other limitations, the use of an interlinked electricity-gas model for project-specific cost-benefit analysis is required.

[3] Most NECPs have now been published. They are available at: https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en

2. DEVELOPMENT AND TESTING OF A NEW SUSTAINABILITY INDICATOR

The objective of this section is to present the characteristics of an updated sustainability indicator.

Based on discussions with the European Commission and with ENTSOG, and given the current modelling capabilities of ENTSOG, it has been agreed to focus first on improving the current CO_2 savings indicator, trying to address its main identified drawbacks, and in a second time, to propose a framework to compute a more complete sustainability indicator that could be implemented with an interlinked model such as METIS[4].

Finally, in Sections 2.2 and 2.3, we propose sub-indicators to capture the impacts of a project on methane emissions and non-GHG emissions.

2.1. Development of a sustainability indicator

2.1.1. Proposed improvements to the current CO_2 emission savings indicator

In this section we present possible improvements in the existing indicator calculation by addressing its key weaknesses and proposing (a) an updated way of calculating CO2 emission savings and (b) an updated allocation of CO_2 emission savings to projects. The proposed adapted CO_2 indicator methodology is similar to the current version, and aims at computing the potential CO_2 emission savings brought by a new project which leads to a growth of the gas demand while reducing the consumption of other more carbon-intensive fuels.

In particular, similarly to the CO_2 indicator currently used by ENTSOG:

- CO_2 emission savings are computed by looking at **potential fuel switches for each period**. The same assumptions are made on the replacement of fuels: **gas replaces coal, oil and other more carbon-intensive fuels in priority**.
- The computation of savings still relies on the **evaluation of the energy mix in each sector for each period**. In each country, the gas consumption increase in each sector will be assumed to replace other carbon-intensive fuels up to their volume in the energy mix.
- An assumption is made on the **average efficiency of technologies** relative to gas and more carbon-intensive fuels to be able to compute the CO_2 emission savings per sector taking into account the efficiencies.
- The **approach remains mostly national**, thus not capturing the supra-national effects of projects. A project solving a bottleneck between A and B will not see benefits from the fuel switching happening in C even if there are any (these benefits are captured by the interlinked approach we propose in Section 2.1.2).

The main changes are the following:

- The updated approach does not associate CO_2 emission savings to new infrastructure when there is no increase in net gas demand (local gas demand minus

[4] METIS is an interlinked model developed by Artelys on behalf of the European Commission. It has been used to inform policy making in various areas (e.g. proposals of the Clean Energy Package) and is available to the Joint Research Centre. For more information on METIS, we refer the reader to https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en

the local gas production). With this approach, **fuel switches are thus only assessed when there is an increase of gas demand** compared to the reference year (e.g. 2020). This choice is made to prevent infrastructure projects to claim part of the CO_2 emission savings when the consumption in the future scenario (e.g. 2030) is lower than today's consumption and could be covered by the existing infrastructure.

- The increase of gas demand results in fuel switches only when there is a **corresponding decrease of the demand for other carbon-intensive fuels**. In each sector, if the expected gas demand increase exceeds the reduction in demand for other carbon-intensive fuels, the excess gas demand is counted as an increase of CO_2. This allows to better account for the increase of gas demand either when there is an overall increase of consumption in the sector, or a switch from other fuels (e.g. a nuclear phase out replaced by gas).
- Instead of using capacities to allocate the CO_2 emission savings resulting from fuel switches, **the allocation key uses flows in the infrastructure**. This is to account for the fact that CO_2 emission savings are linked to the use of the project: a project that is not expected to be used in the future gas system should not be able to claim to contribute to CO_2 emission reductions.
- Additionally, the evaluation of flows in the infrastructure, either obtained with a modelling approach or a proxy based on demand curves (more detail in chapter 3) assumes that the existing infrastructure is used first and new infrastructure is used only if necessary from a security of supply perspective: **the CO_2 emission savings that could be made without the infrastructure projects are not attributed to infrastructure projects**.
- **RES gases are also accounted for in the approach**. CO_2 emission savings associated to production and use of RES gases (biogas/biomethane and P2G projects) are assessed by taking into account the benefits of having "carbon-neutral gas" compared to natural gas. These savings are added to the savings a non-renewable gas production project would be allocated (with the approach described above. CO_2 emission savings associated to infrastructure such as interconnections enabling integration of RES gases are also assessed.
- The methodology obtained with these changes can also be applied to **evaluate the effects of fuel switching on emissions of other gases** (NO_x, SO_2)

The implementation of this indicator is described in more detail in chapter 3.

To validate the proposed approach, **the indicator has been tested** for 10 projects of different types (LNG, pipelines, storage, ETR projects) from the TYNDP. For that purpose, ENTSOG has provided us confidential data from the TYNDP2020 and TYNDP2018.

The results show that the proposed methodology avoids certain of the limitations of the previous indicator. In particular, CO2 savings are not allocated to projects that would not be used. Also, CO2 savings from ETR projects are adequately captured.

Some drawbacks from the methodology however remain: the CO2 savings of storages are not well captured due to the temporal structure of the model (with only two periods). Also, the approach remain national, and does not allow the capture of savings enabled by a project in countries not directly connected to the project.

2.1.2. Proposal of an indicator computable with an interlinked electricity/gas model

The proposed improvements to the current sustainability indicator allow to remove or reduce some of the flaws of the existing indicator but still has some limitations that are difficult to address without a substantial improvement of the modelling approach. In particular, the main limitations of the updated indicator are that:

- The computation of CO_2 emission savings per country is based on considered impacts on energy consumption only and remains independent from projects. In this sense, the computation of the effects on sustainability is not consistent with the CBA approach which evaluates the benefits of a project by comparing the situations with/without the project.
- Trans-national CO_2 emission savings (e.g. situations where a project between country A and country B enable CO_2 savings in country C) are not captured.
- The evaluation of CO_2 emission savings associated to seasonal gas storage is not well captured since the approach relies on yearly figures.
- Cross sectoral dynamics, and in particular the link between the development of gas infrastructure projects and the development of renewable electricity, are not accurately taken into account.

These limitations mostly result from the existing limitations of the modelling framework used by ENTSOG in the context of the TYNDP, indeed it does not capture entirely the interactions between gas and electricity, in particular in situations where gas and electricity interlinkages are important, i.e. when gas-to-power, power-to-gas or hybrid consumption technologies represent a non-negligible part on the energy mix[5].

We describe below the gas modelling used for the TYNDP, the benefits of an interlinked model, and the indicators that could be computed with such an interlinked model.

Since, as far as we are aware, the ENTSOs do not yet have such an interlinked model at their disposal, it is likely that another entity would have to carry out these calculations for the assessment of the projects for the establishment of the fifth PCI list. The Joint Research Centre could be considered for such an assignment, as they have access to the METIS model and to important calculation capabilities.

Synthetic description of the gas modelling used for the TYNDP

[5] The focus study from ENTSOG and ENTSOE on gas/electricity interlinkages provides more detail on these phenomena.

The main characteristics of the gas modelling used for the TYDNP are the following:

- The model features one node per country.
- The year is represented with **one day in summer** and **one day in winter**, multiplied by 182/183 days.
- The **interactions between gas and electricity are fixed**: the consumption of gas for power generation, the gas generation via P2G and the consumption of hybrid technologies are an input of the gas model, coming from the electricity simulations carried out by ENTSO-E.
- The **current modelling approach does not allow to switch to other fuels** (e.g. if a gas pipeline is congested, the gas consumed by CCGTs cannot be lowered to reduce the congestion level). In previous exercises, ENTSOG had defined a limited flexibility of the demand for gas coming from the electricity sector (called the thermal gap) that allowed gas consumption for power to decrease, at a given cost. Now that gas consumption for electricity comes from the electricity modelling from ENTSO-E, this flexibility has been removed from the ENTSOG model.
- **Sources of gas** are modelled with **cost curves** (piecewise linear costs)
- Domestic production is always taken as priority over imports, with Norway considered as import.
- There is no distinction between natural gas, hydrogen, biomethane, methane from P2G units.

With this modelling, simulations are performed for different levels of infrastructure: existing, low, advanced and high corresponding to set of projects that are at different statuses of development. Simulations are also done incrementally for the CBA evaluation of projects. As flows are very sensitive to grid tariffs, simulations are performed three times, for the current tariff levels, for -50% on the tariffs and for +100% on the tariffs.

Output of these simulations are in particular:

- The yearly volume of gas imported by source,
- The yearly gas production in each country,
- The yearly flows in every infrastructure

In the CBA evaluation of project, different indicators relative to security of supply or to supply source dependence are also computed with and without the project being assessed.

Benefits of an interlinked electricity/gas model

As described above, the current gas modelling used by ENTSOG does not capture the flexibility linked to direct interlinkages between gas and electricity (i.e. gas-to-power, power-to-gas and hybrid consumption technologies). In addition, its time resolution is too low to capture the dynamics of these interlinkages, which would require an hourly modelling (with virtual storage assets to represent the impact of linepack storage), and even the dynamics of gas storages, which would benefit from a granularity higher than two days in the year.

These limitations affect the assessment of gas projects, especially in countries (and scenarios) where gas and electricity interlinkages are important, i.e. when gas-to-power, power-to-gas or hybrid consumption technologies represent a non-negligible part on the energy mix. In particular, instances of bottlenecks in the gas system due to a high gas consumption for G2P identified in a gas-only approach could sometimes be avoided if there are alternatives to G2P in the electricity system, e.g. electricity storage or demand response. The dynamics of P2G (related with the overall carbon content of electricity) would also be better captured.

To reduce or remove these limitations, an interlinked model, representing simultaneously the gas and electricity systems, could be used. Key features of the modelling would have to include:

- **Modelling of gas, electricity and heat** – as presented above, interlinkages between gas and electricity are significant, and with the increasing electrification of heat, this interlinkage is also significant with heat. The operation of gas-based heat generation is very likely to depend on the electricity system (e.g. electricity prices for combined heat and power).
- **Hourly time step** – evaluating the operation of gas-based electricity generation, P2G, and hybrid consumption technologies requires to capture the variability of renewable electricity production and of the electricity demand and the use of flexibilities in the electricity system.
- **CO_2 emissions** – in order to assess accurately the CO_2 emission savings linked to a given project, CO_2 emissions of the energy system have to be well accounted for. For the electricity system, it requires having a detailed model of the thermal generation, with for instance several age classes for assets. For the gas system, it requires differentiating between types of gas: natural gas, hydrogen, biomethane, synthetic gas from P2G, and their respective impact on CO2 emissions.
- **EU-wide modelling** – the modelling has to account for exchanges of energy between countries at the same temporal granularity as the rest of the system.

Sustainability indicators compatible with an interlinked gas/electricity model

With such an interlinked gas/electricity model, sustainability indicators for gas projects would be evaluated by comparing simulations with and without the assessed project, for the different scenarios and timeframes covered by the TYNDP scenarios. The two situations would then be compared in terms of CO_2 emissions, RES integration, etc, similarly to what is done in the current CBA methodology for security of supply or supply source dependence. In particular, the following indicators could be produced:

- **CO_2 savings** – the comparison of the two situations would allow to evaluate the reduction of CO_2 emissions linked to the installation of the infrastructure. In particular, a gas infrastructure could enable the use of CCGTs for electricity production, thus avoiding the use of coal-based generation, thus providing CO_2 savings. These computations would require the interlinked model to include a sufficiently detailed model of the thermal generation in each country, with for instance several age classes for assets.
- **Emissions of other gases** – if included in the modelling, the emissions of other gas linked to fuel combustion could be included as an indicator. The scope of these emissions could for instance include methane, NOx and SO2.
- **Integration of RES-e** – The interlinked model will allow to assess the effect of a P2G project in terms of quantity of RES integrated by comparing the curtailments of RES-e in each situation. The model would also allow to study the effect of different operational modes for P2G on the integration of RES-e and on the overall emissions. In particular, the effect of a power-to-gas infrastructure on CO_2 emissions is very different between an operation in baseload or an operation following (and limited to) the curtailment of RES-e.
- **Integration of RES gases** – Similarly, the effect of projects in terms of the integration of RES gases can also be evaluated by comparing the two situations. Competition between sources (bio-methane, hydrogen from P2G, methane from

P2G, natural gas) will be more accurate with the explicit modelling of power-to-gas which captures the limitations of the gas and electricity systems.

This proposed methodology for computing sustainability indicators would be consistent with the current definition of the other indicators included in the CBA (which aims at assessing, in given scenarios, how a project brings benefits in a given system configuration) than the current indicator that focuses on the benefits from fuel switches along a trajectory.

A summary of the characteristics of the approaches for the computation of CO_2 emission savings is presented in the figure below.

Figure 2-1 Comparison between the different indicators

	Current Sustainability indicator	Improved sustainability indicator	Interlinked model Sustainability indicator
Simplicity to compute the indicator	✔	✔	
Possibility to attribute a negative CO_2 impact to a project		✔	✔
CO_2 savings allocation prioritise existing infrastructure.		✔	✔
CO_2 savings are linked to expected flows in the project.		✔	✔
Evaluation of the effect of projects on CO_2 based on a marginal approach (operation of the system with/without the project similarly to the CBA)			✔
Accuracy for the evaluation of CO_2 savings of storages			✔
Cross sectoral assessment (incl. P2G)			✔
Trans-national assessment			✔

Compatibility with a net-zero emissions future

Given the ambitious objectives of the European Commission in terms of CO_2 emissions reduction at the 2050 horizon, the question of the compatibility of projects with a climate neutral future has to be raised, in particular to avoid investing in projects that are not likely to be used in a decarbonised economy (potential stranded assets). The European Commission's Long-Term Strategy, in particular in the pathways complying with a limitation to a 1.5°C temperature increase objective, 1.5TECH and 1.5LIFE, envisions a high electrification of demand, usually accompanied with a reduction of the gas demand and a diversification of the sources and types of gas being consumed. In this context, the development of new infrastructure faces two main risks:

- The infrastructure could be useless for the operation of the system in 2050, with lower levels of gas demand in Europe, and structurally different flows.
- The infrastructure could be incompatible with a network with high shares of hydrogen.

One way to identify the first situation is to extend the scope of the cost-benefit analyses to be performed in the TYNDP to climate neutral scenarios for 2050 (we understand that there will be no project-specific simulations for 2050 in TYNDP 2020). In this case, the "standard" application of the CBA will identify which projects are useful for the system in 2050, both from an economical and an environmental perspective. The extension of the TYNDP to pathways produced by the European Commission could be considered to be able to ensure that assets are assessed on situations meeting the European objectives. This could also be relevant for the 2030 time horizon, for which the ambition levels are likely to be revised upwards.

The second situation (incompatibility with high shares of hydrogen) is related to the type of infrastructure itself. Project promoters should describe whether their project is compatible with high shares or 100% share of hydrogen.

2.2. Dealing with methane emissions

2.2.1. Methane emissions

Methane emissions are emissions (fugitive or from venting and incomplete combustion) coming from different sources all along the natural gas value chain, from exploration to end-consumption of the gas. The precise levels of methane emissions are complicated to evaluate due to several factors, including the lack of measurements and the low level of transparency.

In its methane emissions tracker[6], the IEA quotes several mitigation measures for downstream gas, including:

- **Leak detection and repair** (LDAR) refers to the process of locating and repairing fugitive leaks. LDAR encompasses several techniques and equipment types. One common approach is the use of infrared cameras, which make methane leaks visible.
- **Replace with instrument air systems:** Pumps and controllers are used at well sites and across the oil and natural gas supply chains for a variety of purposes. Commonly, they are pneumatic, using pressurized natural gas as a power source. These pumps vent natural gas in the ordinary course of business. They can be replaced by instrument air systems, which pressurize ambient air to perform the same functions without emitting methane.
- **Vapour Recovery Units (VRUs):** VRUs are small compressors designed to capture emissions that build up in pieces of equipment across the oil and natural gas supply chains. For instance, VRUs can pull off gases that accumulate in oil storage tanks and that are otherwise periodically vented to the atmosphere to prevent explosion.
- **Install flares if relevant**
- **Replace compressor seal or rod:** Maintenance of the seal and rods over the time can significantly reduce the methane emissions.

In their report « Potential ways the gas industry can contribute to the reduction of methane emissions » presented during the 32nd Madrid Forum in June 2019, GIE and MARCOGAZ present the Best Available Techniques in transmission, LNG terminals, storage and distribution to reduce the methane emissions:

- LDAR programmes;

[6] https://www.iea.org/reports/methane-tracker-2020/methane-abatement-options#abatement-technologies-and-costs

- Minimise venting of hydrocarbons from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas;
- Replacing natural gas pneumatic valves with electric or air equipment or mechanical controls;
- Implement minimising vents programmes;
- Recompression instead venting;
- Recover boil off gas during ship loading and eliminate – to the extent practicable – flaring;
- Implement excess flow valve;
- Use of vacuum pressure pumps during commissioning of distribution networks;
- Replacing natural gas starters with electric engine starters at compressors, hence reducing operational venting;
- Hot tapping techniques procedures.

2.2.2. Sub-indicators related to methane emissions

We propose that two sub-indicators related to methane emissions are introduced in the sustainability indicator:

- **Indicator relative to project-level emissions (S-ME1):** The first sub-indicator is an indicator presenting the efforts the project promoter is making to take appropriate measures to reduce the level of methane emissions directly linked to the construction and operation of its project.
- **Indicator relative to system-wide emissions (S-ME2):** This second sub-indicator is an indicator that aims at capturing the impact of the project on methane on the overall system due to the additional gas consumption enabled by the project.

In the following paragraphs, we describe our approach for these two sub-indicators:

Indicator relative to project-level emissions (S-ME1)

This indicator shall be based on a benchmarking approach. The objective of the comparison is to assess whether the project promoter proposes technologies or processes that reach state-of-the-art quality levels. The project promoter shall also be able to provide comments to explain what mitigation measures are being taken to ensure that only the lowest possible levels of methane emissions will materialise (only for the emissions directly linked with the project). The costs of these measures should be mentioned by the project promoter.

In addition, the project promoter is encouraged to propose mitigation measures should its project cause methane emissions that are not in its direct control.

The definition of the parameters and corresponding values to be considered in the benchmark is beyond the scope of the project. We recommend that they are defined by ENTSOG's specialists. The indicator should at least capture the following steps of the life of a project:

- **Construction** – Ensuring the technology installed is state-of-the-art in terms of methane emissions.
- **Inspection and measure of the emissions or leakages** – Ensuring the emissions are tracked and reported.

- **Maintenance and renovation** – Ensuring proper maintenance is planned, and pieces of the infrastructure are replaced with the adequate timing.

We recommend that ENTSOG is tasked with the definition of project characteristics that should be benchmarked and of the value of the benchmarking parameters. These values should be updated at least for each TYNDP exercise (i.e. at least every second year).

Indicator relative to system-wide emissions (S-ME2)

Estimating the total methane emissions caused by the modifications of the structure of gas flows that can be linked with the presence of a new project is a complex task. Indeed, several facts complicate the analysis:

- The methane leaking factors of all infrastructure should be measured and reported.
- The structure of the gas flows and how a new infrastructure may impact them depends on commercial arrangements between market participants. Most of these arrangements are not publicly available.
- In the case of LNG terminals, the analysis is even more complicated since the source of LNG might have very different methane leaking factors (depending on the gas extraction methods)

Based on this, we propose to only include the additional volumes of methane emissions at the national level (i.e. due to the additional consumption of gas in the country/countries that host the project). The approach thus includes potential increase in emissions on the transportation and distribution networks. The proposed procedure is as follows:

1. Use the IEA methane emissions tracker[7] (or a similar source) to obtain the volume of methane emissions from downstream gas for each country (for the latest year available), measured in ktCH4.

2. Divide these methane emissions by the gas consumption in the country during the same year. The result is a methane emission factor for each country in ktCH4/MWh representing the emissions from downstream gas.

3. Multiply this methane emission factor by the level of gas consumption allocated to the assessed infrastructure projects. For this last step, use the same allocation key as for CO_2 emissions (see Section 3.1.2 for more details).

2.3. Non-GHG emissions (PM, SO_x, NO_x)

In the European Union, the National Emission ceilings directive sets national emission reduction commitments for 5 different pollutants:

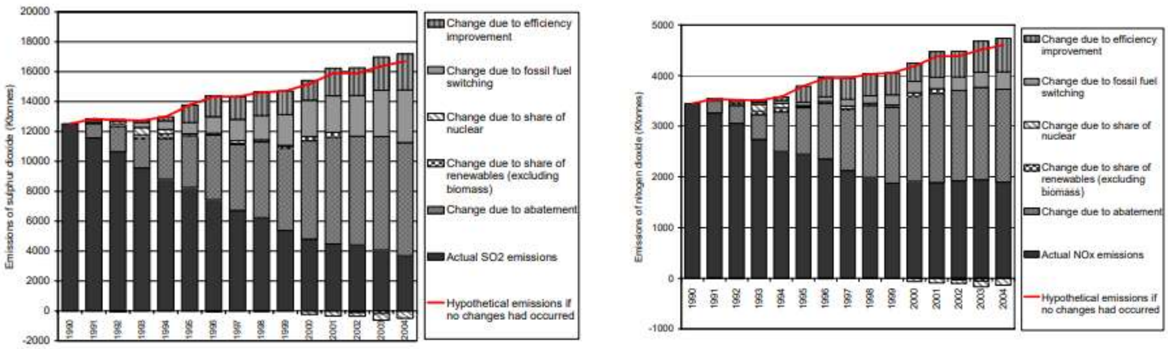
- nitrogen oxides (NO_x)
- sulphur dioxides (SO_2)
- fine particulate matter (PM2.5)
- non-methane volatile organic compounds (NMVOCs)
- ammonia (NH3)

[7] https://www.iea.org/reports/methane-tracker-2020/interactive-country-and-regional-estimates

These pollutants contribute to poor air quality, leading to significant negative impacts on human health and the environment. Energy use in transport, industry and in power and heat generation are major sources of emissions especially for NOx and SO2.[8]

Figure 2-2 Estimated impact of different factors on the reduction in emissions of SO2 and NOx from public electricity and heat production between 1990 and 2004, EU-25

SO_2 **NO_x**



Source: European Environmental Agency[9]

Following the same approach as the one developed for CO_2 (and detailed in sections 2.1.1 and 3.1), a **sub-indicator for non-GHG emissions** could be built, based on emission factors by types of fuel for each pollutant. The computation of emissions would rely on the evaluation of fuel switches and the use of emission factors per fuel and per sector for each gas.

The limit of such an approach is that the emissions factors greatly differ depending on the use of the fuel, and in particular depending on the combustion techniques and abatement techniques. This is already true today and will be even more visible if more constraints are set on the emission of these pollutants. The use of this methodology would thus require corresponding detail on the consumption of fuel by sub-sector, with the corresponding abatement techniques used with each fuel, for each scenario. This would help compute the benefits in terms of emissions due to fuel switches in each sub-sectors.

For that purpose, we thus suggest that ENTSO-E and ENTSOG construct, for their TYNDP works, a joint database of emissions factors of non-GHG, with a decomposition by fuel and by sector and sub-sector and by country. Those emissions factors should also take into account the expected decrease of the specific emissions over the years to come, with the improvement of abatement techniques. This would be a prerequisite for a reliable computation of these emissions.

Sources for these sector-specific emission factors could be the IPCC database[10], which follows a methodology they developed to calculate those emissions for different sources of energy and different usages. The UNFCCC national inventory report, gathered in the Greenhouse Gas Inventory database[11], could also be exploited. For each of the Annex I Parties to the Kyoto Protocol, this database contains all greenhouse gas (GHG) emissions and removals, implied emission factors and activity data. However, the required level of precision in order to be used for the sustainability indicator, is only available for CO_2, CH_4 and N_2O. For the other non-GHG gases such as NOx, SO_2 and NMVOC, the emissions are

[8] https://www.eea.europa.eu/data-and-maps/indicators/main-anthropogenic-air-pollutant-emissions/assessment-6
[9] https://www.eea.europa.eu/data-and-maps/indicators/en09-emissions-co2-so2-and/emissions-co2-so2-and-nox
[10] https://www.ipcc-nggip.iges.or.jp/EFDB/find_ef.php?ipcc_code=1&ipcc_level=0
[11] https://di.unfccc.int/flex_annex1

aggregated and are not imputed to specific fuels. One possibility is to directly use the IPPC database[12] to obtain default values for emissions factors of NOx and NMVOC (for other gases the availability of the data is not systematic). An important drawback of the IPCC database is that the default data are rather old and do not take into account abatement measures that enabled a clear decline of non-GHG emissions over the past few years[13].As far as PM are concerned, the level of emissions and the size of the particles are very complicated to compute given that they depend on the sector, on the fuel properties, but also on the technologies and emission process, which is highly dependent on the quality of the combustion[14]. Therefore, the same issues are applicable here. As PM pollution is a local issue rather than a global issue, it is difficult to compare sources of emissions because these emissions are far more problematic if they reach inhabitants.

As an exercise the proposed methodology has been used without differentiating the type of technologies inside each sector, and using the emission factors by fuel provided in Box 4.1 (see below on section 4.2.3). With this level of detail, the approach shows that the fuel switch from coal or oil to gas tends to reduce significantly the emissions of these pollutants, since emissions factors remain significantly lower (or nil) when burning gas.

[12] https://www.ipcc-nggip.iges.or.jp/EFDB/find_ef.php?ipcc_code=1&ipcc_level=0
[13] https://www.eea.europa.eu/data-and-maps/dashboards/air-pollutant-emissions-data-viewer-2

[14] M. Guevara, Emissions of Primary Particulate Matter , in *Airborne Particulate Matter: Sources, Atmospheric Processes and Health*, 2016, pp. 1-34 DOI: 10.1039/9781782626589-00001

3. INDICATOR DESCRIPTION AND IMPLEMENTATION

In this section, we present in more details the proposed indicator for CO_2 emission savings, step by step, with proposals of datasets to use for the input data.

3.1. Description of the indicator implementation

The proposed indicator is a two-steps indicator, similarly to the indicator currently used by ENTSOG:

- **CO_2 emission savings assessment step:** In this step we compute the reduction of CO_2 emission enabled by the evolution of the gas infrastructure to support the growth of the gas demand, if this gas consumption increase can be associated to a fuel switch.
- **CO_2 allocation step:** In this step, the CO_2 emission savings computed in step 1 are allocated to the different infrastructure projects.

These steps are performed for each scenario and each year of the scenario, for each country.

3.1.1. CO_2 emission savings assessment step

3.1.1.1. Phase 1: Fossil fuel consumption assumptions

The first phase consists in gathering the consumption by fossil fuel in the different sectors for the different scenarios.

The consumption is divided into 4 demand sectors:

- Residential & Commercial demand
- Industrial demand
- Transports
- Power

The fossil fuels taken into account are gas, coal and oil.

Required inputs

Gas, coal and oil consumption in each sector (Residential & Commercial, Industrial, Transports, Power generation), at country level, for each time step.

Possible sources: For two of TYNDP2020 scenarios, fuel mixes by sector will be available. For the third scenario, based on NECPs, using this approach will be less reliable given the fuel mixes are not available. A solution would be to use the fuel mixes of the closest scenario.

3.1.1.2. Phase 2: Assessment of the evolution of energy consumption.

In this phase, we compute the variation of demand by sector and fuel compared to a predefined reference year. For TYNDP 2020 this reference year could be 2020.

For each scenario and year, the difference in consumption compared to the reference year is computed. For non-gas consumptions (oil and coal), we only compute the expected reductions in consumption since the objective is to identify years where gas increases and coal/oil decreases.

3.1.1.3. Phase 3: Assessment of the evolution of end-use consumption

In this phase, we compute the corresponding consumption change in terms of end-use consumption. Converting primary energy consumption to end-use consumptions allows to compare the amount of fuels used in each sector when assessing if there has been a switch or not.

For instance, for the electricity sector, a 150 TWh gas consumption increase will correspond to an increase of 150*60% = 90 TWh of electricity produced with gas, assuming the electricity is produced with a CCGT.

This computation requires an assumption for the average efficiency of technologies functioning with the different fuels in each sector. To convert the previously computed variation of primary energy consumption into variation of end-use consumption, we multiply the primary energy consumption by the corresponding average efficiency.

For the indicator, we use one standard efficiency level[15] per sector and per fuel for each year and scenario.

$$\Delta \mathrm{EndUseConsumption}_{sec\quad s}(\mathrm{fuel}_f) = \Delta \mathrm{PrimaryEnergyConsumption}_{sector}\,(\mathrm{fuel}_f) * \mathrm{efficiency(fuel\_f)}$$

Required inputs

Average efficiencies for each fuel (gas, oil and solid fuels) and for the 4 sectors (Residential & Commercial, Industrial, Transports, Power generation), at country level, for each time step.

Possible sources: Assumptions should be taken from the TYNDP2020 if available. If not, these might be completed with inputs from public sources (ASSET database, IEA, ETRI, cf. footnote).

3.1.1.4. Phase 4: Computation of the switches in terms of end-use consumption

In this step, for each sector and each fuel, we allocate the increase of end-use consumption supplied with gas to either fuel switches (if there has been enough reduction of coal and oil) or to a pure increase of gas.

A **sectoral fuel switch potential** is used to allocate the increase of end-use consumption supplied with gas. For each sector, this potential corresponds to the sum of the decreases of end-use consumption supplied with the other fuels (oil and solid fuels). This correspond to the maximum fuel switch potential.

The assumption is made that the increase in gas consumption is made first to replace oil and gas technologies, filling the fuel switch potential. The excess gas increase (if there is any) is considered as a pure increase of gas.

If the increase in end-use consumption supplied with gas is not sufficient to replace the whole "sectoral fuel switch potential", we assume that gas replaces coal and oil, with a pro-rata decrease of oil and coal in the concerned sector.

After this repartition of the sectoral gas demand increase resulting from a fuel switching or from other developments, the end-use consumption is converted to primary energy consumption that is used to compute the CO_2 emission savings (if any).

[15] Assumptions for technology parameters could rely for instance on the ASSET database (2018), the IEA-ETSAP database, or the European Technology Reference Indicator (2014). https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf, https://iea-etsap.org/index.php/energy-technology-data, https://setis.ec.europa.eu/system/files/ETRI_2014.pdf

Outputs

For each sector and each time step: the fuel corresponding to each fuel (coal and oil) and the pure gas increase.

3.1.1.5. Phase 5: Conversion into CO_2 emissions

The objective of this step is to compute CO_2 emission savings that are expected in each concerned sector by the fuel switching from coal or oil to gas. For each fuel (coal, oil and gas), an emission factor EF is used, in $kgCO_2/kWh$.

The CO_2 computation is performed as follows:

- The increase of gas consumption which corresponds to a fuel switch from coal leads to a change in CO_2 emissions of: $\mathrm{IncreaseGasToReplaceCoal} * \mathrm{EF}_{gas} - \mathrm{DecreaseCoal} * \mathrm{EF}_{\mathrm{coal}}$
- The increase of gas consumption which corresponds to a fuel switch from oil leads to a change in CO_2 emissions of: $\mathrm{IncreaseGasToReplaceOil} * \mathrm{EF}_{gas} - \mathrm{DecreaseOil} * \mathrm{EF}_{\mathrm{oil}}$
- The pure increase of gas leads to a **pure increase** of CO_2 emissions of:

  $\mathrm{RawIncrease} * \mathrm{EF}_{\mathrm{gas}}$

The total variation of CO_2 emissions for each sector is thus:

$$\begin{aligned}\mathrm{CO_2Variation}_{\mathrm{sector}} &= \mathrm{IncreaseGasToReplaceCoal} * \mathrm{EF}_{gas} - \mathrm{DecreaseCoal} * \mathrm{EF}_{\mathrm{coal}} \\ &+ \mathrm{IncreaseGasToReplaceOil} * \mathrm{EF}_{gas} - \mathrm{DecreaseOil} * \mathrm{EF}_{\mathrm{oil}} + \mathrm{RawIncrease} * \mathrm{EF}_{\mathrm{gas}}\end{aligned}$$

Required inputs

CO_2 emission factor ($kgCO_2/kWh$) for each fuel (coal, oil, gas), each country. The gas emission factors should not include a potential reduction from RES gases as these impacts are handled separately.

Possible sources: Assumptions for emission factors should be taken from TYNDP2020 if available. If not, CO_2 contents from the IPCC database could be taken.

Outputs

For each time step, total CO_2 emission savings per sector in ktCO2/y.

3.1.1.6. Phase 6: Final computation of the CO_2 emission savings to be allocated to gas infrastructure

The previous computations allow to compute the emission savings per sector linked to the increase of gas consumption in each sector. In this step, we compute the CO_2 emission savings linked with the overall increase of gas demand, which is not necessarily the sum of the previous figures, e.g. if there is another sector where the gas demand decreases.

For instance, we consider a case where 2 sectors have an increase and one has a decrease.

	Sector 1	Sector 2	Sector 3	Total
Change between reference year and the considered scenario	+10 TWh	+20 TWh	-15 TWh	+15TWh
CO_2 savings per sector	8 Mt	10 Mt	N/A	N/A

The CO_2 benefits associated to the increase of 15 TWh are computed pro-rata the volume of increase in each sector:

$$\mathrm{CO_2Savings_{total}} = \mathrm{GasIncrease_{total}} * \frac{\mathrm{CO_2Savings_{sector1}} + \mathrm{CO_2Savings_{sector2}}}{\mathrm{GasIncrease_{sector1}} + \mathrm{Gas_{increase_{sector2}}}} = 15 * \frac{18}{30} = 9\ \mathrm{Mt}$$

The general formula is:

$$\mathrm{CO_2Savings_{total}} = \mathrm{GasIncrease_{total}} * \frac{\sum_{SectorsWithGasincrease} \mathrm{CO_2Savings_{sector}}}{\sum_{SectorsWithGasincrease} \mathrm{GasIncrease_{sector}}}$$

3.1.2. CO_2 allocation step

This second step of the indicator aims at allocating the previously calculated CO_2 savings to the gas infrastructure (both existing infrastructure and projects). The allocation depends on flows in the existing infrastructure and on projects, as obtained in the simulations from ENTSOG. We also propose a way of assessing the flows in the case simulations are unavailable.

3.1.2.1. Description of the allocation method

This method allocates the CO_2 emission savings to projects pro rata the flows obtained in simulations of the scenario.

In order to prioritise the use of existing infrastructure, simulations used should consider a high tariff for the studied infrastructure projects and a lower tariff for existing infrastructure.

For the project p, the allocation factor is simply given by the formula:

$$\mathrm{allocationFactor_p} = \frac{\Phi_p}{\sum_{\mathrm{infrastructure_i(existing\ or\ new)}} \Phi_i}$$

where ϕ_p is the gas flow in MWh that passes through the infrastructure during the year.

This allocation factor is then multiplied by the CO2 savings computed in the CO2 savings assessment step.

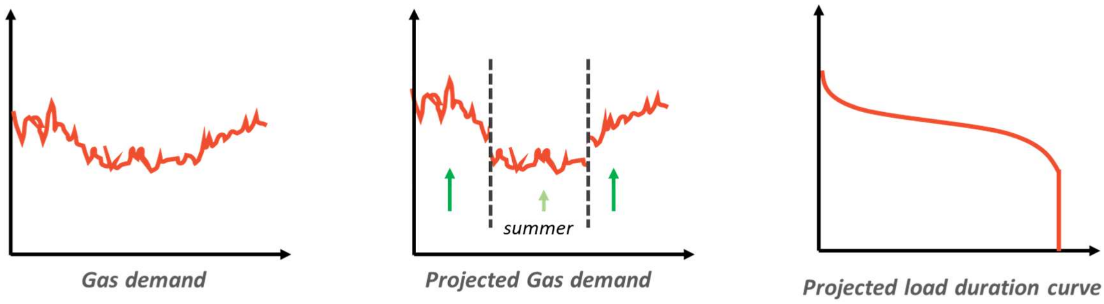
Required inputs
ENTSOG simulation results. Simulation of the scenario with the existing infra (low tariff) and infrastructure projects (high tariffs)

3.1.2.2. Alternative to flows from simulations

If the simulations are not available, flows could be approximated using the following approach:

- We build a load duration curve for the country corresponding to the scenario. This can be done by using a historical gas demand curve for the country (obtainable on the ENTSOG website), and scaling it upwards or downwards to obtain the adequate yearly consumption. When possible, this scaling can be done with a different ratio for winter and summer as illustrated in Figure 3-1.

Figure 3-1 Construction of an approximated demand curve

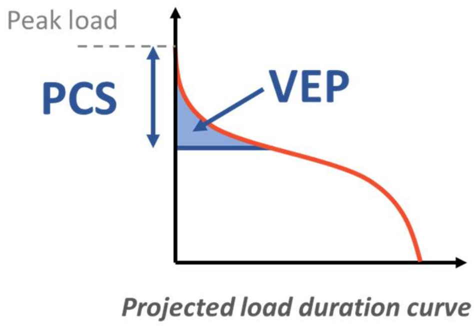


- We compute the "Project Capacity Share" (PCS): the ratio between the capacity of projects and the total capacity of the infrastructure (existing and new). This has to be based on the capacities of projects and infrastructure from TYNDP.

$$\mathrm{PCS} = \frac{\sum_{\mathrm{projects}} \mathrm{Capacity}}{\sum_{\mathrm{infrastructure\ (projects+exist\ \ )}} \mathrm{Capacity}}$$

- We consider that without the new projects, the existing infrastructure covers only (1-PCS)*peakload. This means that the part of the curve below (1-PCS)*peakload can be covered by existing infrastructure, while the remainder requires the new projects. We then compute the "Volume enabled by projects" (VEP): the volume of gas above (1-PCS)*peakload, which is call the "Volume enabled by projects" (VEP).

Figure 3-2 Estimation of the volume of gas enabled by projects



- CO_2 emission savings for the country are allocated to new projects and existing infrastructure pro rata these volumes of energy.

$$\mathrm{CO_2Savings_{projects}} = \mathrm{CO_2Savings_{total}} * \frac{VEP}{totalDemand}$$

- Finally, this CO_2 emission saving for all projects can be allocated to all projects (no existing infrastructure) pro rata their respective capacity.

$$\mathrm{CO_2Savings_{project\ p}} = \mathrm{CO_2Savings_{projects}} * \frac{\mathrm{Capacity_{project\ p}}}{\sum_{\mathrm{projects}} \mathrm{Capacity}}$$

Required inputs

A demand curve for the reference year.

Gas consumption for the scenario (possibly with winter/summer).

Possible source: the demand curve can be extracted from the ENTSOG Transparency platform.

3.1.3. CO_2 emission savings resulting from RES gas projects

The savings associated to RES gas projects (biogas, biomethane or P2G projects) can be divided in two parts:

- Following the previously presented approach, these projects are contributors to fuel switches from more CO_2-intensive fuels to gas, and can be allocated a CO_2 emission saving.
- Additionally, these projects can be allocated another benefit in terms of CO_2 emissions since the RES-gas produced avoid consumption of non-RES gas.

Both benefits can be accounted for in the indicator.

The first part can be computed with a similar approach to what was proposed above, by considering the RES gas project as any other project (like a LNG terminal or gas production facility).

The additional benefits can be computed with the following equation:

$$\mathrm{AdditionalCO_2Savings} = \mathrm{V_{RESgas}} * (\mathrm{EF_{gas}} - \mathrm{EF_{RESgas}})$$

Where EF is the emission factor and V_{resgas} the volume of RES gas that is produced per year by the project, based on the scenario assumption.

3.1.4. Accounting for benefits linked to the integration of RES gases

In some cases, interconnection projects might allow to integrate more RES gases in the system. This can be the case when the local generation of RES gas exceeds the local demand and the existing export capacity, which is expected to only occur rarely in the coming years but might occur more frequently as of 2040. Except for this case, interconnections should not be allocated CO_2 benefits resulting from RES gas integration since these benefits are already counted for the RES gas projects themselves (see above).

The benefits related to RES integration come in addition to the benefits from fuel switching and can be computed with the following equation:

$$\mathrm{AdditionalCO_2Savings_{projects}} = \mathrm{AdditionalVolume_{RESgas}} * (\mathrm{EF_{gas}} - \mathrm{EF_{RESgas}})$$

Where $\mathrm{AdditionalVolume_{RESgas}}$ is the additional volume of RES gas integrated in the system thanks to the considered projects, i.e. the sum of all flows in the projects.

4. GAS-RELATED INFRASTRUCTURE PROJECTS AND THEIR SUSTAINABILITY CHARACTERISTICS

The key objective of this chapter is to identify different types of imaginable gas-related infrastructure projects and assess their overall sustainability characteristics. For this the chapter is composed of two sub-sections:

- Gas-related infrastructure projects
- Overall sustainability characteristics of selected projects

The main added-value of the chapter is to provide an overview of the sustainability aspects of a wider range of potential gas-related infrastructure projects than the range of projects eligible under the current TEN-E criteria, and to guarantee that the configurations that are being tested in the development of the sustainability indicator are relevant and likely to appear in projects promoters submit to ENTSOG for inclusion in the TYNDP. A number of technologies are becoming more widespread for the production, storage and transport of biomethane, synthetic methane and hydrogen, but may not yet be eligible for gas PCI status. This despite potentially being able to contribute not only to the sustainability of the EU energy system but also to competition, market integration and/or security of supply. The chapter furthermore supports the definition of the fictional project configurations to be used for the testing of the new sustainability indicator.

This chapter does not cover the following projects, which are addressed by the TYNDP or PCI selection processes but which are out of scope of the present analysis:

- Conventional transport and storage of natural gas;
- Conventional LNG terminals;
- Biogas production;
- Other networks, such as for CO_2 and heat;
- Vehicle conversion for the use of alternative fuels.

4.1. Gas-related infrastructure projects

This sub-section first presents the long-list of individual gas-related infrastructure projects and categorizes them according to a customized typology. Next, individual projects in this long-list are grouped into the most likely cluster of projects, as some may be more sensible as a group of projects than as a stand-alone project.

The long-list of individual gas-related infrastructure projects was developed based on existing literature related to the decarbonization of the gas sector as well as on existing projects being currently developed in the gas sector. Main information sources for the exercise comprised multiple recent studies, as well as the list of ETR projects of the 2020 gas Ten-Year Network Development Plan.[16]

The long-list of gas-related infrastructure projects (which excludes conventional gas infrastructure projects) is divided according to the main project function as follows:

[16] Including Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and of the hydrogen potential on trans-European infrastructure; Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets; Artelys - Investigation on the interlinkage between gas and electricity scenarios and infrastructure projects assessment (2019); DNV GL (2018) Hydrogen as an energy carrier – an evaluation of emerging hydrogen value chains; GIE and Marcogaz (2019) Potential ways the gas industry can contribute to the reduction of methane emissions; Frontier Economics et al. (2019) Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU

- **Transport**
  - to allow reverse gas flows from the distribution to the transport network, to enable large-scale injection of biomethane at distribution level, where local injection might (mainly in the summer period) exceed local demand;
  - to adapt existing gas transmission or distribution grids, to make them suitable for hydrogen admixtures up to a certain threshold (e.g. 10 vol%), both intra-EU and for import pipelines from foreign countries;
  - to adapt existing gas transmission or distribution grids, to make them suitable for 100% hydrogen;
  - to build new transmission or distribution grids suitable for hydrogen transport;
  - to build offshore infrastructure for the transport of renewable hydrogen produced from offshore wind generation;
- **Storage**
  - to adapt existing underground gas storage facilities, to make them suitable for hydrogen, pure or admixed with methane up to a certain threshold (e.g. 10 vol%);
  - to build new underground (admixed) hydrogen storage facilities;
  - to build new hydrogen storage facilities in cross-border or TSO-DSO connection points to regulate the hydrogen admixture content to respect regulatory limits, technical standards and the tolerance of sensitive end-users;
- **Liquefied gas terminals**
  - to build new / adapt existing LNG terminals to make them suitable for importing hydrogen (either renewable electricity based or fossil gas based via SMR with CCU/S);
- **Injection in gas networks**
  - to build facilities injecting biomethane into the methane transmission/distribution network;
  - to build terminals for injecting hydrogen into the transmission/distribution network;
- **Network interfacing**
  - to separate hydrogen from methane in H_2-admixed methane networks (deblending);
- **Hydrogen / methane production**
  - to build power-to-gas installations with electrolysers using (renewable) electricity;
  - to build new methanation facilities for the conversion of hydrogen into synthetic methane;
  - to build new facilities for the production of methane by purifying biogas;
  - to build new facilities for the production of hydrogen by gasification of biomass;
- **Transversal projects**
  - To reduce methane emission in gas infrastructure (detailed below)
- **CCS/U**

    - to capture, transport, store and/or utilize carbon (CCU/S) from the production of hydrogen through steam methane reforming;
    - to capture, transport, store and/or utilize carbon (CCU/S) from the upgrading of biogas into biomethane;
- **Secondary infrastructure**
    - To build infrastructure for utilization of methane / hydrogen in transport, in particular refuelling stations for compressed or liquefied methane / hydrogen (for the use in automotive, inland and maritime shipping).

Methane emission reduction projects are transversal and may take place in any part of the methane supply chain and thus all infrastructure components, from gas production, liquefaction, regasification, storage, transmission & distribution, and secondary distribution (refuelling). Methane emissions may occur due to fugitive emissions (in the various components such as valves, flanges, connectors), venting (in compressors, due to maintenance, failures or emergencies, and others) or incomplete combustion (e.g. in gas-based compressors or during flaring).[17] Methane emissions are a result not only of the specific components in gas infrastructures, but also of operation practices of this infrastructure. This diversity of origins for methane emissions makes it diffuse and also complexifies its sustainability assessment.

The projects in the long-list have been categorized according to the customized typology presented in Table 4-1 (with a short project name). This typology of projects uses the following parameters for categorization:

- **Facility type,** that is, the main type of the project physical assets, i.e.
- **Main function** of the project within the gas system;
- **Location** of the project, either onshore or offshore;
- **Network level** of the project, namely transmission and/or distribution, or the interface of the two levels;
- **Energy carriers** at the entry and exit of the projects;
- **Asset type,** whether the projects are new, adapted (slight modifications for e.g. hydrogen blending) or converted for the entry/exit of a new energy carrier (e.g. from methane to hydrogen).

[17] GIE and Marcogaz (2019) Potential ways the gas industry can contribute to the reduction of methane emissions.

Table 4-1 Individual gas-related infrastructure projects

Short name	Facility type	Main function	Location	Network level	Carrier - entry	Carrier - exit	Asset type
Gas networks adaptation for H2 admixture	Integrated network components	Transport	Onshore	Transm./dist.	Hydrogen	Hydrogen	Converted
Gas networks adaptation for H2 transport	Integrated network components	Transport	Onshore	Transmission	Natural gas + hydrogen	Natural gas + hydrogen	Adapted
Reverse D-T methane compressors	Reverse compression	Transport	Onshore	Transm./dist. interface	Natural gas	Natural gas	New
Hydrogen injection	Injection terminal	Production	Onshore	Transm./dist.	Hydrogen	Natural gas + hydrogen	New
Methane refuelling	CNG terminal	End-use supply	Onshore	Distribution	Natural gas	Natural gas	New
Hydrogen refuelling	LNG supply facility	End-use supply	Onshore	Distribution	Hydrogen	Hydrogen	New
LNG terminal adaptation to hydrogen	LNG terminal	Transport	Onshore	Transmission	Hydrogen	Hydrogen	Adapted
New liquefied hydrogen terminal	LNG terminal	Transport	Onshore	Transmission	Hydrogen	Hydrogen	New
Hydrogen from biomass gasification	Biomass gasifier	Production	Onshore	Distribution	Biomass	Hydrogen	New
Biogas upgrading	Biogas upgrader	Conversion	Onshore	Transm./dist.	Biogas	Synthetic methane	New
Regulating hydrogen storage	Storage	Storage	Onshore	Transm./dist.	Hydrogen	Natural gas + hydrogen	New
Hydrogen methanation	Methanation facility	Conversion	Onshore	Transm./dist.	Hydrogen	Synthetic methane	New
Onshore hydrogen pipelines	Integrated network components	Transport	Onshore	Transm./dist.	Hydrogen	Hydrogen	New
Offshore hydrogen pipeline	Integrated network components	Transport	Offshore	Transmission	Hydrogen	Hydrogen	New
Admixed hydrogen storage	Storage	Storage	Onshore	Transmission	Natural gas + hydrogen	Natural gas + hydrogen	New/adapted
Hydrogen storage	Storage	Storage	Onshore	Transmission	Hydrogen	Hydrogen	New/converted
Metering	Metering equipment	Transport	Onshore	Transm./dist.	All gases	All gases	New
Power-to-gas	Electrolyser	Production	Onshore	Transm./dist.	Electricity	Hydrogen	New
Biomethane injection	Injection terminal	Production	Onshore	Transm./dist.	Biomethane	Biomethane	New
Methane emission reduction	Transversal	Transversal	Transversal	Transm./dist.	Natural gas	Natural gas	New/adapted
Hydrogen deblending	Deblender	End-use supply	Onshore	Transm./dist.	Natural gas + hydrogen	Hydrogen	New

Note: integrated network components include pipelines, compressors, metering stations and other integrated components.

The individual gas-related infrastructure projects above may be combined to form coherent project clusters which serve a specific function within the gas system (e.g. the combination of projects to allow reverse flows from the distribution to the transmission grid and for the deblending of hydrogen from natural gas flows). Frequently gas-related infrastructure projects will only be sensible (and hence potentially viable from an economic stand-point) if combined with others. Clusters of gas-related infrastructure projects may also require conventional infrastructure projects such as network capacity expansion due to e.g. increased network demand at the transmission or distribution level.

As discussed in the next section, the sustainability impact of certain projects will also be dependent on the implementation of other projects, as per se specific gas-related infrastructure such as hydrogen storage is only able to reduce greenhouse gas emissions or increase the deployment of biomethane or hydrogen indirectly.

Table 4-2 Illustrative project clusters identified

Short cluster name	Project 1	Project 2	Project 3	Project 4
Hydrogen electrolysis and injection	Electrolyser	Hydrogen pipeline(s)	Hydrogen injection (blending) facility	
Biogas collection and upgrading	Biogas production	(biogas pipeline)	(central) biogas upgrader	Biomethane injection facility
Liquid hydrogen refuelling	Hydrogen pipeline	Hydrogen liquefaction facility	Hydrogen refuelling station	
Offshore hydrogen production	Offshore electrolyser	Offshore hydrogen pipeline		
Biogas methanation post-upgrading	Electrolyser	Biogas production	Biogas CO_2 separation	Hydrogen methanation
Biogas production and reverse flow	Biomethane production	Methane distribution pipeline(s)	Dist.→ transm. compressor station	
Hydrogen distribution network	Hydrogen injection facility	Hydrogen underground storage	Hydrogen distribution pipeline(s)	

4.2. Overall sustainability characteristics of the selected projects

The objective of this section is to present an overview of the overall sustainability characteristics of selected gas-related infrastructure projects, that is, the project characteristics which may potentially contribute (or deter) sustainability. This overview aims at providing a broader perspective than the sustainability benefits covered in the ENTSOG CBA 2.0, and even the proposed indicator of chapter 1.

The sustainability characteristics assessed here indicate the potential contribution of each project type, rather than actual sustainability benefits, which will vary from project to project. The characteristics of specific projects (such as the location in the network) or system aspects such as the electricity carbon footprint will strongly affect the exact sustainability characteristics of individual projects.

4.2.1. Structuring the sustainability analysis

The analysis of the potential sustainability benefits focuses on the operational phase of the projects and applies the following methodology, summarized in the steps below:

1. **Define potential sustainability characteristics**: projects may contribute to (climate) sustainability through the mitigation of greenhouse gas emissions or through enabling the deployment of renewable energy (electricity or gas);
2. **Define mechanisms through which projects have a sustainability impact:** the projects' sustainability contributions may occur through a number of mechanisms. It is thus necessary to identify the main mechanisms in order to provide the overview of the sustainability characteristics;
3. **Assess the sustainability impact of the mechanisms for the selected projects:** the mechanisms are described for selected gas-infrastructure related projects, in order to assess their sustainability characteristics and mechanisms.

Potential sustainability characteristics

Sustainability impacts will depend on the horizon under consideration. In combination with the selection of specific scenarios, the horizon will affect the level of deployment of renewable energy, the economy-wide and sector GHG emission reduction, and the level of gas demand in the EU and Member States, which will impact the sustainability characteristics of specific projects. The potential sustainability contributions of the gas-related infrastructure surveyed in this chapter will occur only in certain horizons and scenarios.

The potential sustainability contributions of the projects analysed here comprise the:

- Reduction in emissions of greenhouse gases (CO_2, methane, and other gases);
- Reduction in emissions of local pollutants (NO_x, SO_x, particulate matter);
- Facilitation of the integration of renewable electricity;
- Facilitation of the integration of hydrogen and biomethane.

Mechanisms of sustainability impacts

The mechanisms through which these benefits may arise are indicated in Table 4-3. The potential sustainability benefits of the selected projects may arise directly from the operation of the project (e.g. by reducing methane emissions or energy consumption of the facility) or indirectly from the investment and operation in other parts of the energy system.

When effectively assessing the sustainability benefits of gas-related infrastructure projects, it is important to understand the various benefits and any overlaps which might exist, for example between the reduction of greenhouse gases emissions and the facilitation of renewable energy deployment. Although any reduction in emissions should not be double counted, there is an argument for separately analysing how gas projects enable renewable energy, due to the specific EU renewable energy targets (complementary to the emissions reductions target) and for dynamic efficiency considerations, as the deployment of renewable energy technologies should lead to cost reductions which in turn will reduce the cost of the energy transition and thus the costs of future emission mitigation efforts.

Table 4-3 Main mechanisms affecting the sustainability characteristics of gas-related infrastructure projects

	CO_2 reduction	CH_4 reduction	Other GHG reduction	Local pollutant reduction	Renewable electricity integration	Biomethane and hydrogen integration
Substituting/ reducing natural gas consumption in transport / buildings / industry / power generation	✓	✓				
Substituting/ reducing coal consumption in transport / buildings / industry / power generation	✓		✓	✓		
Substituting/reducing liquid fossil fuels consumption in transport / buildings / industry / power generation	✓		✓	✓		
Reducing methane emissions in gas transmission/distribution		✓				
Storing and/or utilizing CO_2	✓					
Enabling the deployment of renewable / decarbonized gases by increasing or adapting transport, conversion or storage capacity	✓				✓	✓
Increasing the flexibility of the energy system, thus facilitating RES-e deployment and/or reducing the need for fossil fuel-based dispatchable electricity generation capacity	✓				✓	

4.2.2. Sustainability characteristics summary

Based on the consideration of sustainability aspects summarised in this chapter, the sustainability of gas infrastructure projects could be evaluated to cover most of their sustainability impacts. Section 4.2.3 provides a detailed discussion of the sustainability characteristics, which are summarised here in tables 4-9 and 4-10.

Summary of sustainability impact mechanisms per supply chain stage

Table 4-4 summarizes the aspects that would need to be examined in order to assess the sustainability impact of a project. It covers the supply chain stages (upstream, transport/storage and consumption), as well as the three categories of described sustainability impacts – substituting more carbon-intensive fuels usage (or reducing their consumption), enabling the deployment of renewable gases and enabling the uptake of renewable electricity.

The distinction per supply chain stages is mainly useful to analyse the sustainability impact of fuel substitution, to separate its emission impacts per stage. Assessing the impacts on renewable gases integration and renewable electricity production separately per supply chain stage might pose a risk of double counting of benefits - for example energy storage might be beneficial from the perspective of avoiding RES-E curtailment, as well as enabling renewable energy consumption in time of insufficient renewable energy supply (even though the resulting reduction of emissions can be counted only once). However, this analysis can discover additional benefits, such as the fact that avoiding curtailment of renewable electricity sources will positively influence their profitability, making further investments in the sector more attractive. Assessing the impacts on renewable gases integration and renewable electricity production separately per supply chain stage might pose a risk of double counting of benefits - for example energy storage might be beneficial from the perspective of avoiding RES-E curtailment, as well as enabling renewable energy consumption in time of insufficient renewable energy supply (even though the resulting reduction of emissions can be counted only once). However, this analysis can discover additional benefits, such as the fact that avoiding curtailment of renewable electricity sources will positively influence their profitability, making further investments in the sector more attractive.

Summary of sustainability impact due to due to fuel substitution, methane emission reduction and CCU/S

The sustainability impacts due to fuel substitution is more easily quantifiable than the impacts of enabling renewable energy, through the use of the emission factors of the substitute and substituted fuels. Methane emission reductions and CCU/S impacts can also be more readily quantified For the analysis of the sustainability impact of new infrastructure projects, a short list of gas-related infrastructure projects was selected from the long list based on their likely positive sustainability characteristics, cross-border relevance and likely large-scale deployment in specific scenarios (e.g. scenarios with high hydrogen or biomethane development).

The short-list of projects for the sustainability assessment comprise:

- New or converted pure hydrogen onshore pipelines;
- Onshore natural gas pipelines with hydrogen admixture
- Pure hydrogen storage facilities;
- Hydrogen electrolysis facilities;
- Biomethane injection terminals;
- Hydrogen methanation facilities
- Methane emission reduction projects;

- Reverse distribution ➔ transmission compressors.

Table 4-5 presents the quantitative assessment of the impact due to the substitution (or consumption reduction) of fossil fuels of the selected gas-related infrastructure projects. The sustainability impact characteristics of projects due to the substitution of fossil fuels represent the maximum potential contribution of the projects to reducing GHG emissions, calculated as:

$$Emission\ reduction = emission\ factor_{fossil\ fue} \ - emission\ factor_{biomethane/hydrogen}$$

The emission factor of fossil fuels is related to fuel combustion, whereas the emission factor of substituting fuels is related to emissions in the "upstream" production phase, as the combustion does not result in additional GHG emissions (in case of hydrogen), or has neutral GHG emission effect (in case of biomethane). Detailed calculation of these factors is presented in Annex B.

Emissions in the upstream production of natural gas (or other fossil fuels) are not included for as the available data lack coherence and reliability. These could improve the sustainability characteristics of biomethane and hydrogen from electrolysis, while affecting that of hydrogen from SMR or coal gasification combined with CCS either negatively or positively depending on specific system and project characteristics.

Fossil fuel emission factors employ data by the IPCC, and biomethane emission factors are derived from the RED II.[18] For example, the IPCC emission factor for natural gas is 56.15 tCO_2eq/TJ, and the RED II emission factor for biomethane from wet manure is -100 tCO_2eq/TJ (with close digestate and off-gas combustion), leading to a emission reduction of 156.2 tCO_2eq/TJ if natural gas is substituted for biomethane.

The sustainability characteristics for reducing methane emissions in gas infrastructures are presented as the maximum reduction possible if leakage, venting and incomplete combustion could be entirely eliminated, based on the data on methane emission reductions presented in the previous section.

[18] IPCC Emission Factor Database. Available at https://www.ipcc-nggip.iges.or.jp/EFDB/find_ef.php
Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources.

Table 4-4: Overview of sustainability impact mechanisms of gas-related infrastructure projects

	Upstream/Production	Transport/storage	Consumption

Substituting/ reducing fossil fuel consumption	• Emissions related to the energy required for the upstream process;
	• Emissions inherent to the upstream process (e.g. from chemical processes, flaring etc);
	• Emissions related to the fuel production process feedstocks:
	  ○ Can be negative, if CO_2 feedstock is transformed in different chemical compound
	  ○ Can be neutral, if CO_2 feedstock is equivalent to emissions released during fuel combustion
	  ○ Can be positive, if e.g. natural gas is used as feedstock
		• Switching to gases with no greenhouse impact (e.g. hydrogen) reduces/eliminates emissions of e.g. CO_2 or methane;
		• Alternative modes of transport to pipelines may cause additional emissions;
		• Distributed sources might require larger amounts of energy for transport.
			• Fuel switch has direct impact on end-use GHG emissions;
			• Process switch accompanying fuel switch may increase efficiency of electricity production, waste heat recovery, energy end-use.

CO_2 storage or utilization	• CO_2 storage or utilization reduces the emission factor of the substitute fuel		
Enabling biomethane and hydrogen	• Biogas upgrading enables its injection in methane infrastructure; • Renewable gas production can employ renewable electricity which would be otherwise curtailed.	• Gas infrastructure refurbishment/ conversion/ new investments enable the transport of admixed/pure hydrogen, directly or by eliminating network congestion/increasing overall transport capacity.	• Distribution projects enable the end-use of biomethane and hydrogen; • Specific projects may enable the end-use in hard-to-decarbonise / sensitive applications.
	• Facilitating renewable gases leads to learning effects and economies of scale across the supply chain.		
Enabling renewable electricity	• Power-to-gas may reduce the curtailment of RES-E; • Power-to-gas may provide flexibility services to the electricity system.		• Enable interlinked use of gas and renewable electricity (e.g. hybrid heating or transport)
	• Gas-infrastructure projects may increase the overall system flexibility through sector coupling, enabling RES-E integration and reducing flexibility needs from carbon-intensive providers		

Table 4-5 Range of potential greenhouse gases emission reductions for selected project types

	Reducing greenhouse gases emissions				
Project	Substituting / reducing natural gas use	Substituting / reducing coal use	Substituting / reducing liquid fossil fuels use	Reducing methane emissions	Storing and/or utilizing CO_2
Unit	tCO_2eq per TJ substituted (range or maximum)			tCO_2eq/parameter (maximum)	tCO_2eq/TJ of fuel
New or converted pure hydrogen pipelines **Pure hydrogen storage facilities** **Hydrogen electrolysis facilities** **Pipelines with hydrogen admixture**	• Electrolysis: ○ EU electricity mix: -72.2 ○ RES: 56.2 • SMR+CCS: 47.9 • CG+CCS: 38.7 • Methane pyrolysis: 38.4-56.2	• Electrolysis: ○ EU electricity mix: -27 ○ RES: 101.4 • SMR+CCS: 93.1 • CG+CCS: 83.9 • Methane pyrolysis: 83.6-101.4	• Electrolysis: ○ EU electricity mix: -54.1 ○ RES: 74.3 • SMR+CCS: 66 • CG +CCS: 56.8 • Methane pyrolysis: 56.5-74.3	• 28 tCO_2eq per tCH4 substituted	NA
Hydrogen methanation facility	• -205.9 to 56.2	• -160.7 to 101.4	-187.8 to 74.3	No methane emission reductions	• 10 tCO_2eq/TJ (if coupled with biogas upgrade)
Biomethane injection terminals **Reverse D->T methane compressors**	• -16.8 to 156.2	• 28.4 to 201.4	• 1.3 to 174.3		NA
Methane emission reduction projects	NA			• Transm. pipelines: 5.0 tCO_2eq/km. • Compressor: 146.8 tCO_2eq/MW • Pressure Regulating and Reduction stations: 294.8 tCO_2eq/station • Dist. mains: 37.9 tCO_2eq/km	

Notes: Positive values denote an emission reduction. Coal is equivalent here to lignite, and liquid fossil fuels to gasoline / diesel.
NA: not applicable; CCS: Carbon capture and storage, CG: Coal gasification, SMR: Steam Methane Reforming.

4.2.3. Detailed analysis of sustainability characteristics

Substituting/reducing fossil fuel consumption

One of the most direct paths for reducing greenhouse gas emissions is to switch from fossil fuels such as coal, gasoline or diesel to less emission-intensive energy carriers, such as natural gas, hydrogen or biomethane. Gas infrastructure projects can contribute to this fuel switch in various ways, in particular:

- By building or upgrading projects that serve to substitute or reduce fossil fuel usage in a particular end-use sector (for example converting methane distribution networks to hydrogen, or building hydrogen refuelling stations for transport applications);
- By contributing to the development of gas markets, and thus enabling greater market participation and increasing the market efficiency, resulting in increased competitiveness of methane gases or hydrogen against more emission-intensive fuel alternatives;
- By supplying new consumers in areas with no or inadequate gas supply which force consumers to choose other more emission-intensive or less efficient fuel alternatives;
- By enabling the provision of flexibility resources to the energy system which allow the increased integration of intermittent renewable energy sources or which reduce the need for flexibility resources using fossil fuels (elaborated in more detail in following sections).

However, since most of these effects bring an indirect contribution to the emissions reductions and act more as an enabler for the actual fuel switches taking place in intermediary and end-use applications, it is difficult to estimate their contribution ex-ante. Since energy supply and demand is subject to market forces, the impact of any infrastructure project will thus be influenced by external factors such as energy and technology prices and availability, as well as the carbon price.

For the same reason it is possible that a new gas infrastructure project might even contribute to increasing the emission of greenhouse gases. More competitive energy markets might lead to lower energy prices and thus increase the energy demand, resulting in more fossil fuels consumed (the rebound effect). Developing new infrastructure projects might also lock in the economy on certain energy pathways and limit (crowd-out) the amount of resources available for investment in assets with greater emission reduction potential (such as energy efficiency or renewable energy sources).

In particular the infrastructure enabling the integration of biomethane might have a significantly different sustainability impact depending on the origin of the feedstock and the process used for the production of biogas. Apart from the different emissions factors of different biomass feedstock used, a significant determinant of emissions to be considered is the potential land use change resulting from increased demand for biomass.

Another major pathway of emission reduction is increasing the efficiencies in energy production and end-use, which will directly result in lower consumption and thus emissions, as well as lower leakages and other emissions occurring along the fossil fuel supply chain. As an example of the effect the switch to a more efficient process can have, the Energy Efficiency Directive (EU) 2012/27 indicates that the default power-to-heat ratio of combined cycle gas turbines with heat recovery is 95%, against e.g. 55% for simple gas turbines with heat recovery.

The avoided emissions due to the realization of a gas infrastructure project can be estimated on the basis of fossil fuel emission factors and the estimate of the amount of avoided fossil fuel energy production. The emission factors due to the combustion of fossil fuels for the main greenhouse gases (CO_2, CH_4 and N_2O) are summarized in Table 4-6. Alternatives to fossil fuels such as biomethane, or renewable or low-carbon hydrogen, have the potential for achieving lower emissions, but as mentioned this will depend on the biomass/electricity sources as well as the production process. The net emissions factors for the production of hydrogen and biomethane using various energy sources and processes are summarized in Table 4-7, based on current technology and inputs.

For the purpose of comparison, an emission factor of hydrogen produced via water electrolysis using the 2017 EU27 electricity mix was included as well. This value is notably higher than the emission factors of fossil fuels combustion, largely due to high energy losses of water electrolysis. It can be however presumed that the emission factor of the EU electricity mix will decrease in the future and that the electrolysis efficiency will increase. Thus, this emission factor can be regarded as a maximum. It must be noted that while the emission factors from the combustion of fossil fuels depend on their chemical properties and will not change significantly in the future, there is still potential to reduce the net emissions resulting from the production of biomethane and hydrogen (as well as upstream emissions in the fossil fuel supply chain).

For hydrogen methanation facilities, the emission factor of production has been calculated as 0 – 262.1 tCO_2/TJ, depending on the carbon footprint of the hydrogen production inputs (0 tCO_2/TJ for electrolysis using renewable electricity, 262.1 tCO_2/TJ using 2017 EU27 electricity generation mix). This value was derived from the assumptions used by IEA in the Future of Hydrogen[19] project, taking into account the efficiency of methanation process and related own consumption of electricity. Additional emissions might arise in relation to the feedstock CO_2 extraction – using CO_2 arising from the upgrading of biogas would for example not require additional energy input, whereas direct air capture would require additional electricity consumption that cannot be covered by e.g. using surplus heat from the methanation reaction[20]. These additional emissions are thus very variable and hard to quantify, and since their relative impact in comparison to the emissions related to hydrogen production is negligible, they are not taken into account.

[19] IEA (2019), IEA G20 Hydrogen report: Assumptions. Available at: https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

[20] Meylan et al (2017). Power-to-gas through CO_2 methanation: Assessment of the carbon balance regarding EU directives. In: Journal of Energy Storage 11 (2017). Available at: https://doi.org/10.1016/j.est.2016.12.005.

Table 4-6: GHG emissions from combustion of fossil fuels[21]

Fuel	tCO_2/TJ	$kgCH_4/TJ$	kgN_2O/TJ	tCO_2eq/TJ
Gaseous Fossil Fuels				
Natural gas	56.1	1	0.1	56.2
Refinery gas	57.6	1	0.1	57.7
Liquefied Petroleum Gases	63.1	1	0.1	63.2
Blast furnace gas	260.0	1	0.1	260.0
Coke oven gas	44.4	1	0.1	44.5
Liquid Fossil Fuels				
Gas/Diesel oil	74.1	3	0.6	74.3
Crude oil	73.3	3	0.6	73.5
Refinery feedstocks	73.3	3	0.6	73.5
Motor gasoline	69.3	3	0.6	69.5
Aviation/jet gasoline	70.0	3	0.6	70.2
Jet kerosene	71.5	3	0.6	71.7
Naphtha	73.3	3	0.6	73.5
Shale oil	73.3	3	0.6	73.5
Residual fuel oil / HFO	77.4	3	0.6	77.6
Other kerosene	71.9	3	0.6	72.1
Solid Fossil Fuels				
Anthracite	98.3	1	1.5	98.7
Bitumen	80.7	3	0.6	80.9
Lignite	101.0	1	1.5	101.4
Other bituminous coal	94.6	1	1.5	95.0
Sub bituminous coal	96.1	1	1.5	96.5
Brown coal briquettes	97.5	1	1.5	97.9
Peat	106.0	10	1.4	106.7
Coking coal	94.6	1	1.5	95.0
Petroleum coke	97.5	3	0.6	97.7
Coke oven coke	107.0	1	1.5	107.4

Source: EIB (2018)[22]

[21] With a 100-year global warming potential for methane of 28 and for nitrous oxide of 265. TJ in lower heating values where applicable (i.e. net calorific content).
See IPPC (2013) Fifth Assessment Report. Chapter 8 - Anthropogenic and Natural Radiative Forcing.

[22] EIB (2018). Methodologies for the Assessment of Project GHG Emissions and Emission Variations. Available at: https://www.eib.org/attachments/strategies/eib_project_carbon_footprint_methodologies_en.pdf

Table 4-7 GHG emissions from hydrogen production, hydrogen methanation and biomethane production

Fuel and process	tCO_2eq/TJ_{LHV}	tCO_2/TJ_{LHV}
Hydrogen production		
Water electrolysis using renewable electricity [a]	0	0
Water electrolysis using 2017 EU27 electricity mix[23]	NA	128.4
Natural gas reforming [a]	74.2	74.2
Natural gas reforming with carbon capture [a]	8.3	8.3
Coal gasification [a]	168.4	168.4
Coal gasification with carbon capture [a]	17.5	17.5
Biomass gasification (corn stover) [b,24]	16.8	16.7
Methane pyrolysis using natural gas as process fuel [d]	NA	9.2
Methane pyrolysis using 30%-35% of output hydrogen as process fuel [d]	NA	0
Methane pyrolysis using 2017 EU27 electricity mix as process fuel [e]	NA	17.8
Hydrogen methanation		
using renewable electricity as process fuel	NA	0
using 2017 EU27 electricity mix as process fuel	NA	262.1

[23] Based on emission factor of 295.74 g/kWh_e and electrolysis efficiency of 64%.
See: EEA (2020), CO2 Intensity of Electricity Generation. Available at: https://www.eea.europa.eu/data-and-maps/data/co2-intensity-of-electricity-generation. and IEA (2019), IEA G20 Hydrogen report: Assumptions. Available at: https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

[24] CH4 emissions of 0.19 kgCH4/TJ and N2O emissions of 0.19 kgN_2O/TJ

Fuel and process			tCO_2eq/TJ_{LHV}	tCO_2/TJ_{LHV}
Biomethane production [c]				
Feedstock	**Digestate**	**Off-gas combustion**	**tCO_2eq/TJ_{LHV}**	**tCO_2/TJ_{LHV}**
Wet manure	Open	None	22	
		Yes	1	
	Close	None	-79	
		Yes	-100	
Maize whole plant	Open	None	73	
		Yes	52	
	Close	None	51	
		Yes	30	
Biowaste	Open	None	71	
		Yes	50	
	Close	None	35	
		Yes	14	

Sources: a: adapted from IEA (2019)[25]; b: adapted from E4tech (2018)[26]; c: adapted from Directive (EU) 2018/2001[27]; d: adapted from Parkinson et al (2019)[28]; e: based on Machhammer et al (2016)[29]. Negative emissions are due to the manure credits. For the breakdown of emissions by biogas production steps see Annex A.

[25] IEA (2019), IEA G20 Hydrogen report: Assumptions. Available at: https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

[26] E4tech (2018), H2 Emission Potential Literature Review. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/798243/H2_Emission_Potential_Report_BEIS_E4tech.pdf

[27] European Commission (2018), Directive (EU) 2018/2001 of the European Parliament and of the Council on the promotion and use of energy from renewable sources. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN

[28] Parkinson et al (2019), Levelized cost of CO_2 mitigation from hydrogen production routes. In: Energy & Environmental Science 1/2019. Available at https://doi.org/10.1039/C8EE02079E.

[29] Machhammer et al (2016), Financial and Ecological Evaluation of Hydrogen Production Processes on Large Scale. In: Chemical Engineering & Technology 6/2016. Available at: https://doi.org/10.1002/ceat.201600023.

Box 4-1 Emission of air pollutants due to fuel combustion

Although the TEN-E Regulation is focused on climate sustainability, the specific sustainability criteria for gas projects set in article 4(2b) broadly refer to emissions, which may also include air pollutants such as particulate matter (PM), nitrous oxides (NO_x) and sulphur dioxide (SO_2). Moreover, the methodology for the energy system-wide cost-benefit analysis of Annex V of the Regulation indicates that the 'common electricity and gas market and network model' should allow for the assessment of external costs such as 'conventional air pollutant emissions'.

The substitution of coal or liquid fossil fuels (e.g. gasoline or diesel) by natural gas would bring the most significant benefits in the reduction of air pollutant emissions. Analysis of data from the fuel use and air pollutants emissions of large combustion plants in Europe indicates that natural gas presents the lowest emission factor for total suspended particles, NO_x and SO_2, as indicated below. Moreover, the implied pollutants emission factor from the combustion of fossil fuels has generally been falling continuously since 2007.[30]

Direct combustion of biogas has been more frequently studied.[31] However, less attention has been given to the biomethane combustion and eventual differences to natural gas in the emission of air pollutants. The air pollutant impact of hydrogen combustion (or oxidization in a fuel cell) is regarded as much more limited.

The emissions of air pollutants from transport have fallen significantly in the 30 years in the EU but this decrease has decelerated significantly in the last few years, with SOx emissions even increasing from 2016 to 2017.[32] Natural gas, biomethane and hydrogen use in transport can contribute further to the reduction of emission of pollutants from transport.[33] Section 2.3 further discusses of the use of emission factors for air pollutant (and the caveats).

Implied emission factors for large combustion plants, 2017

t/TJ	Total suspended particles	NOx	SO_2
Natural gas	0.000	0.029	0.000
Liquid fuels	0.008	0.268	0.188
Solid fuels	0.005	0.082	0.090

Reducing methane emissions in gas transmission/distribution[34]

Methane emissions from natural gas operations within the EU amounted to slightly under 30 $MtCO_2eq$, equivalent to 6% of the total EU methane emissions, or 0.6% of total EU

[30] EEA (2017) Evolution of the environmental performance of large combustion plants in the EU-28, expressed as implied emission factors for sulphur dioxide, nitrogen oxide and dust, by fuel type.
[31] See for example Paolini et al. (2018) Environmental impact of biogas: A short review of current knowledge. Journal of Environmental Science and Health, Part A, 53(10), and the DG Energy study 'Study on energy costs, taxes and the impact of government interventions on investments in the energy sector'.
[32] EEA (2019) Emissions of air pollutants from transport - TERM 003.
[33] US Department of Energy (2019) Alternative Fuels Data Center. See
https://afdc.energy.gov/vehicles/natural_gas_emissions.html
https://afdc.energy.gov/fuels/hydrogen_benefits.html

[34] This section, unless specified, is based on GIE and Marcogaz (2019) Potential ways the gas industry can contribute to the reduction of methane emissions.

greenhouse gas emissions in 2016.[35] The IEA on its turn has estimated European[36] methane emissions from downstream gas operations (including refining) at 1.317 $MtCH_4$ in 2017, or 32.9 $MtCO_2eq$, comparable to the GIE and Marcogaz estimations.[37] The first EU strategy for reducing methane emission was published in 1996, and the EU is working on a 2nd strategy as required in the EU Governance Regulation,[38] for publication in 2020.

EU methane emissions in gas operations arose from production (16%), processing (2%), transmission and storage (23%) and distribution (59%). Therefore, although methane emissions are spread across the entire gas chain, gas transmission, storage and distribution was responsible for 82% of the EU methane gas operation-related emissions in that year. However, data must be considered with care due to the data gaps and quality. Complementary data from Marcogaz indicates that emissions from LNG terminals, gas storage, transmission and distribution amounted to 14.4 $MtCO_2eq$ in 2015.

Gas methane emissions may be categorized as fugitive, due to venting or due to incomplete combustion. Table 4-8 presents the categorization used by GIE and Marcogaz to identify the components responsible for methane emissions arising from the gas supply chain directly related to the gas infrastructure projects addressed in this chapter: gas regasification, transmission, storage, distribution as well as biomethane and biogas production.

Table 4-8 Categories for identification of methane emissions across the gas chain

		Categories of methane emissions		
		Fugitives	**Venting**	**Incomplete combustion**
Gas chain links	**Biomethane/ biogas production**	Open digestate storage; Separator; Storage of solid fraction; Biofilter; Valves	Flaring Closed digestate storage; Reactor Maintenance	Flaring; CHP
	Transmission & storage[39]	Components (valves, flanges, connectors, etc.)	Compressors; Maintenance; Failure/Emergency; Pneumatic controllers; Devices for on-line gas quality sampling	Stationary combustion devices (e.g. engines, boilers) ; Engines/Turbines for gas compression ; Flaring
	Regasification	Components (valves, flanges, connectors, etc.)	Flaring; Vessels and truck loading; Vessels unloading; Maintenance; Failure/Emergency; Pneumatic controllers	Stationary combustion devices (e.g. engines, boilers); Vaporisers; Flaring
	Distribution	Components (valves, flanges, connectors, etc.); Permeability of materials	Maintenance; Failure/Emergency; Operational	Stationary combustion devices (e.g. boilers)

Source: GIE and Marcogaz (2019) Potential ways the gas industry can contribute to the reduction of methane emissions.

[35] Calculated using a 100-year global warming potential.
[36] Including non-EU countries

[37] IEA (2020) Methane tracker. Available at https://www.iea.org/reports/methane-tracker/country-and-regional-estimates
[38] Regulation 2018/1999 on the Governance of the Energy Union and Climate Action

[39] Only above ground installations. Includes compressor stations, regulation and measurement stations, pipelines, underground storage.

Marcogaz published specific studies identifying the origin of emissions in the various sections of the gas infrastructure using 2015 data. Fugitive emissions are identified as the main emission source for LNG terminals (83% of emissions) and for underground storage (57%). For transmission, fugitive and venting emissions are responsible for 40% each, followed by pneumatic gas use (20%). At the distribution level, steel pipes are responsible for 50% of total methane emissions, followed cast iron (23%) and polyethylene pipes (17%).

The Marcogaz calculated methane emissions scaled per the transmission network length was 0.57 tCH_4/km. The emissions for the distribution level depend on the pipe material, varying from 1.39 tCH_4/km for cast iron mains to 0.20 tCH_4/km for steel and 0.03 tCH_4/km for PVC. These and further emissions scaled per pipeline length, compressor power or number of pressure regulating and reduction stations are presented in Table 4-9.

Table 4-9 GHG emissions from gas networks

Infrastructure type	Source	Scaling	tCH_4	tCO_2	tCO_2eq
Transmission					
Aggregated gas network emissions	Marcogaz	Per km	0.57		15.9
Pipelines			0.18	-	5.0
Compressors		Per MW	5.24	-	146.8
Pressure regulating and reduction stations		Per station	10.53	-	294.8
Pipelines (CH_4 leaks)	API	Per km	2.24	-	62.58
Pipelines (CO_2 oxidation)			-	0.13	0.13
Distribution					
Cast iron pipeline	Marcogaz	Per km	1.39	-	38.9
Steel pipeline			0.20	-	5.5
Polyethylene pipeline			0.06	-	1.7
PVC pipeline			0.03	-	0.8
Pipelines (CH_4 leaks)	API		1.00	-	28.1
Pipelines (CO_2 oxidation)			-	0.41	0.41

Source: Marcogaz (2018), API (2009) in EIB (2018)[40]. Marcogaz data refers to Europe, while API data is based on US and other data.

Methane emissions are not covered under the Emission Trading System (ETS), but are part of the Effort Sharing Decision (ESD). The ESD covers the sectors outside of the ETS, including gas transport, which is not within the ETS scope. The current target for emissions reduction in the ESD is 30% by 2030, compared with 2005 levels.

Mitigation measures to address the identified methane emissions vary according to the emitting source. Fugitive emissions on the one hand are addressed by leak detection and repair (LDAR). Venting and incomplete combustion emissions on the other hand are addressed through the use of best available techniques (BAT) for the various gas chain elements and processes. It must also be noted that besides emission identification and mitigation, a number of improvements should be made in the quantification and reporting of these emissions, as well as in the validation of methane emission reductions due to mitigation measures.

[40] Marcogaz (2018) Survey Methane Emissions for Gas Transmission in Europe. WG-ME-17-09.
Marcogaz (2018) Survey Methane Emissions for Gas Distribution in Europe. WG-ME-17-25.
API (2009) Compendium of Greenhouse Gas Emissions Methodologies for the oil and natural gas industry.

The IEA has in 2017 estimated the methane emission abatement potential for the European downstream gas supply chain, already mentioned in sec.[41] Available measures applicable to gas infrastructures are presented section 2.2.1, and are recapped in Table 4-10 along with their estimated abatement potential and cost.

Table 4-10 Estimated EU gas supply chain abatement potential and weighed abatement cost in 2017

	Estimated abatement potential ($ktCH_4$)	Weighed abatement cost (EUR/TJ)[42]
Blowdown capture	23.3	-4.13
Downstream LDAR	831.1	2.14
Install flares	0.2	1.48
Replace compressor seal or rod	59.5	-0.33
Replace with instrument air systems	4.1	-4.23
Vapour recovery units	1.3	2.20

Note: The downstream gas supply chain data includes refining.
Source: IEA (2020) Methane tracker.

Considerations on upstream emissions for natural gas imports

Next to emission of greenhouse gases in the European transmission and distribution infrastructure and upstream activities, the emissions arising from upstream activities outside of the EU could be considered as well, since a substantial part of the EU natural gas demand is covered by imports from third countries. Not only are these emissions not considered in the existing EU regulatory framework, but the actual emissions arising from natural gas extraction and supply might vary across the exporting countries due to different technology performance and practices as well as environmental protection standards.

Depending on the production location and method, the upstream methane emissions might range from 0.2% to 10% of the produced natural gas. The majority of estimates are however located within the range of 0.5% to 3%[43]. If the CO_2 emissions in the supply chain are taken into account as well, the total GHG emissions range from 3 to 36.4 tCO_2eq/TJ[44], which equals to 5% - 65% of the GHG emission from the combustion of a TJ of natural gas. The GHG emission estimates for the European natural gas production are lower, ranging between 2.3 - 15.3 tCO_2eq/TJ[45] (due to, among others, shorter transport routes). Also, the LNG supply chain has a greater emission impact than gas pipeline supply[46].

Although the emissions connected to the supply chain can potentially have a significant effect on the overall environmental performance of natural gas, the literature suggest that a major part of these emissions is connected to only a small number of facilities. Therefore, the emission reduction efforts can be more focused and therefore more effective. Among

[41] IEA (2020) Methane tracker. Available at https://www.iea.org/reports/methane-tracker/country-and-regional-estimates

[42] Using a 2019 exchange rate of 1.1195 USD/EUR
[43] Sustainable Gas Institute (2015). Methane and CO2 Emissions from the Natural Gas Supply Chain. Available at https://www.sustainablegasinstitute.org/wp-content/uploads/2015/09/SGI_White_Paper_methane-and-CO2-emissions_WEB-FINAL.pdf?noredirect=1.
[44] Ibid (note that the values were converted to high heating values)
[45] E4tech (2018). H2 Emission Potential Literature Review. Study commissioned by the Department for Business Energy and Industrial Strategy (BEIS). Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/798243/H2_Emission_Potential_Report_BEIS_E4tech.pdf
[46] Stern (2019). Challenges to the Future of LNG: decarbonisation, affordability and profitability.

the identified key "super emitters" are for example well-completing activities, liquids unloading (removal of liquids in well), and leaking pipework, pneumatic devices and compressors[47].

Further reasoning for how to best address this extra-EU methane emissions is presented in sections 2.3 and 5.2.

Storing and/or utilizing CO_2

Gas-related infrastructure projects are not an essential part of carbon capture, storage and utilization projects (CCU/S), but may indirectly enable such projects. As such, gas-related infrastructure may indirectly lead to the storage or utilization of CO_2 from fossil or biological origin, and thus have a positive sustainability impact.

The influence of gas-related infrastructure occurs because CCU/S technology can be combined with a number of gas production technologies, with the following being the focus of this section:

- Biogas upgrading + CCS;
- Hydrogen from methane reforming + CCU/S;
- Hydrogen from coal gasification + CCU/S;
- Biogas methanation with hydrogen.

The impact on final CO_2 emissions will depend on the source of carbon (fossil, biological, from air capture) and the carbon capture rate. On the one hand, the capture of carbon originating from the combustion or gasification of coal, natural gas or oil may lead to a strong reduction of emissions, although the final emission factor of the combined gas production and carbon CCU/S project will still be positive as technologies are not able to capture all carbon emissions. On the other hand, the capture of carbon from biological origin (such as from the upgrading of biogas to biomethane) or from air would allow to achieve net negative emissions.

Biogas upgrading + CCS is a particular combination of bioenergy and CCS (BECCS), a lead candidate to achieving negative emissions, if the stored CO_2 emissions are greater than those arising from biomass production, transport, conversion and utilization. Although the individual technologies for upgrading biogas and capturing CO_2 are mostly mature (with the exception of biomass gasification), only one out of 18 BECCS plants worldwide produce biogas (the Biorecro/EERC project in the US). Moreover, an important constraint to the large-scale development of BECCS in general is the availability of sustainable biomass.[48]

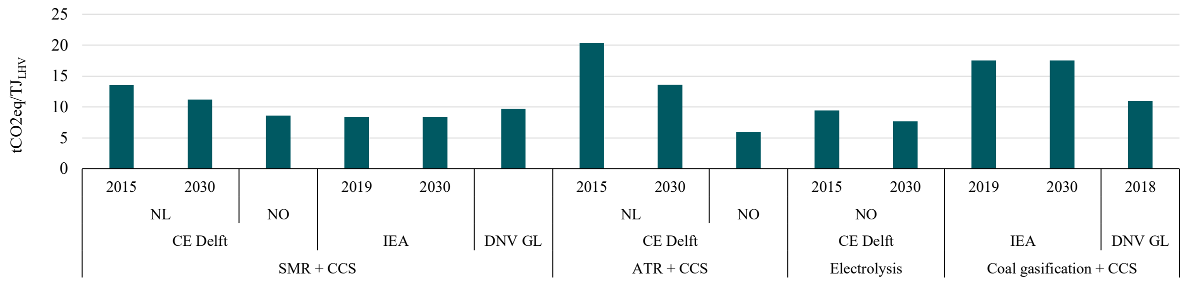
CCS may be combined with hydrogen production from either natural gas through methane reforming (either steam methane reforming, SMR, or autothermal reforming, ATR) or from coal gasification. DNV GL estimates the emission factor of hydrogen production from SMR + CCS at around 1.2 $kgCO_{2eq}/kgH_2$, and for hydrogen produced from coal gasification + CCS at 1.3 $kgCO_{2eq}/kgH_2$. With a carbon capture efficiency of 87% for SMR + CCS, hydrogen production from electrolysis would have to use electricity with a carbon footprint of 75 $kgCO_{2eq}/MWh$ or lower to have a lower emission impact. Thus, only hydrogen produced from hydrolysis with electricity from predominantly renewable or nuclear sources would have a lower emission impact. CE Delft estimates the emission factor of hydrogen production from SMR + CCS at 1.62 tCO_{2eq}/tH_2. All estimates are presented in Figure 4-1 (with year of estimate when available, and with the carbon footprint of the natural gas or

[47] Sustainable Gas Institute (2015). Methane and CO2 Emissions from the Natural Gas Supply Chain. Available at https://www.sustainablegasinstitute.org/wp-content/uploads/2015/09/SGI_White_Paper_methane-and-CO2-emissions_WEB-FINAL.pdf?noredirect=1.

[48] Global CCS Institute (2019) Bioenergy and Carbon Capture and Storage

coal supply not shown for comparability). Here, differences on emissions between the Netherlands and Norway are caused by the cleaner electricity carbon footprint in the latter.

Figure 4-1 Greenhouse gas emissions in hydrogen production due to process emissions and electricity input carbon footprint



Source: CE Delft (2018), DNV GL (2018), IEA (2019)[49]

The production of biogas and hydrogen offers an additional synergy if the CO_2 present in biogas is used in the methanation of renewable hydrogen. Methanation can be direct, with hydrogen mixed with the biogas, or occur after the biogas upgrading (separation of the biomethane and the CO_2). Methanation can be biological (using microorganisms called archea) or catalytic. Biogas methanation with hydrogen can achieve negative emission factors depending on the emissions in the biogas supply chain and the footprint of the electricity used in the hydrogen production.

Different biogas methanation projects in Germany and Denmark in 2017 exhibited a CO_2 content going from trace amounts up to 6% CO_2.[50] Moreover, in 2019 as part of the STORE&GO project a methanation plant opened in Germany using CO_2 from bioethanol production, which is subsequently injected in the gas grid.[51] Collet et al. indicate that the emission factor for this biogas methanization could decrease to around 13 tCO_{2eq}/TJ in France (excluding the electricity carbon footprint). This indicates there could be an additional reduction in emissions of over 10 tCO_{2eq}/TJ compared to the simple upgrading of biogas, if the CO_2 could be utilised for methanation of hydrogen produced exclusively with renewable electricity.[52] However, further analysis of the impact of biogas methanation is necessary.

Enabling the deployment of biomethane and hydrogen by increasing or adapting transport, conversion or storage capacity

Gas-related infrastructures can increase the deployment of biomethane and hydrogen either directly or indirectly. Directly, some gas-related infrastructures may be themselves responsible for the production of biomethane or hydrogen, such as hydrogen electrolysers, or be responsible for the connection of gas production projects to the network and injection of the gases. Indirectly, the capacity to deploy and connect biomethane or hydrogen projects to the network may increase with gas transport, conversion or storage projects.

Gas-related infrastructures thus may first themselves **enable the connection of renewable/decarbonized gas projects**, either through the development of connectors and/or injection terminals (possibly collecting gases from multiple producers) for gas production projects. Here, the infrastructure projects are responsible for the full increase in deployment of renewable / decarbonized gases.

[49] CE Delft (2018) Feasibility study into blue hydrogen; DNV GL (2018) Hydrogen as an energy carrier; IEA (2019) The Future of Hydrogen.
[50] PlanEnergi (2017) FutureGas – D1.1.1 - Upgrading of Biogas to Biomethane with the Addition of Hydrogen from Electrolysis
[51] STORE&GO (2019) The German demonstration site at Falkenhagen
[52] Collet et al. (2017) Techno-economic and Life Cycle Assessment of methane production via biogas upgrading and power to gas technology. Applied Energy, 192.

Second, gas-related infrastructure projects may **develop and integrate gas markets** which would be otherwise (partially) separated due to limited interconnection capacities or operational limitations (e.g. due to gas technical specifications), facilitating in this way the deployment of gases such as biomethane or hydrogen.

Future large-scale production of renewable gases could take place either close to where the renewable energy resources are located, or renewable energy could be transported closer to consumption centres before being converted to gas. Biogas production from biomass would logically be located close to biomass sources, while power-to-gas capacity could be located close to either renewable electricity sources or demand centres.

However, regardless of the location of the gas production facilities, the location of renewable energy sources (and carbon sources for e.g. methanation) will be an important determinant to the EU gas infrastructure needs per transmission corridor and consequent cross-border gas flows in the long-term.[53] Therefore, **cross-border methane or hydrogen transmission capacity** in specific corridors (e.g. from solar, wind or biomass-rich regions to large energy demand centres) will play an important role in facilitating the deployment of renewable gases.

One option for deploying decarbonized/renewable gases is **admixing hydrogen to methane networks**. The biomethane and hydrogen study[54] indicates that this question has to be analysed separately for the transmission and distribution levels. Hydrogen admixture at the transmission level carries considerably greater challenges due to the need to avoid temporal and regional variations in the hydrogen content and due to the requirement that the entire gas system be compatible with such admixture, unless (de)blending capacities are set at the cross-border and transmission-distribution interfaces. However, deblending capacity at cross-border points could lead to considerable additional investment costs, and is unlikely to be deployed at large scale. Hydrogen admixture at the distribution level is comparatively less challenging, as it is possible to maintain any hydrogen admixture within a specific distribution system (in the absence of reverse flows from distribution to transmission). Hence, for 2030 the study assumes there may be hydrogen admixture (up to 10%) in certain distribution networks, while for 2050 hydrogen admixture will not be relevant in any scenario due to several arguments, such as the limited interest compared to the alternatives of dedicated (bio)methane/hydrogen networks and the limited contribution to emission reduction targets.

Therefore, in the short-term the deployment of hydrogen may be facilitated by the admixture in specific methane distribution networks, and in the long-term by the development of dedicated hydrogen networks. Such scenario could change if (de)blending technologies advance significantly, which would make possible varying levels of hydrogen admixture in different network sections (such as distribution networks with reverse-flow capabilities), but this would not change many of the arguments in favour of the development of dedicated hydrogen networks, as opposed to admixing hydrogen in methane networks.

There are few technical limitations for the **injection of biomethane** in methane networks, in comparison to hydrogen.[55] The European Gas Research Group (GERG) is nonetheless conducting a project assessing the impact of trace compounds of biomethane (such as siloxanes and H_2S) when injected in methane networks, with the aim of reviewing the biomethane European standards.[56]

[53] Trinomics, LBST and E3M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure
[54] Ibid.

[55] Ibid.

[56] Standards EN 16723-2 and EN 16723-2

Gas-related infrastructure projects for methane networks may thus enable the **deployment of biomethane projects by increasing the network capacity** in specific sections of the network. Analysis has shown that the need for reverse flow projects from distribution to transmission networks will be restricted even in the long-term to specific network sections. Nonetheless, reverse flow projects in the short-term (to 2022) are highlighted in multiple initiatives by methane network operators.[57] Dedicated biomethane pipelines could be developed in specific sections of the gas network, and although forming part of the transmission or distribution network (that is, forming part of the regulatory asset base of network operators) still having as main purpose connecting biomethane projects.[58]

Many of the gas-related infrastructure projects are associated with the deployment of new gas networks (either methane or hydrogen ones) and the connection of new gas users. **New hydrogen infrastructure** (through new investments or the conversion of methane infrastructure) would clearly enable the production and consumption of hydrogen. Moreover, the first such networks would provide significant experience and potentially learning effects, thus resulting in benefits to hydrogen deployment which would go beyond the specific sustainability impacts of one specific hydrogen network. For example, there is still significant uncertainty on the operation & maintenance costs of hydrogen networks,[59] which have a relevant effect on the total costs and which could be reduced with further experience in hydrogen networks.

There is still significant uncertainty on the future deployment levels of dedicated hydrogen infrastructure. In case hydrogen becomes an important energy carrier, dedicated hydrogen infrastructure should be developed,[60] by the conversion of natural gas infrastructure and/or through new investments. Increasingly, there is an agreement that the gradual increase of hydrogen admixture levels in natural gas networks beyond e.g. 20% would be impractical, and that conversion to dedicated hydrogen networks is more likely in a high hydrogen deployment scenario. In this case, important cross-border EU hydrogen transport could develop. Cross-border transport would be necessary to move hydrogen to demand centres, if it is produced for example in Southern and Northern European countries with a large renewable energy potentials.[61] Also, initially localised networks could develop, and as a sufficient density of local or regional networks is reached, these could be connected by a transmission network.

Transport by pipelines, ships and trains are the main options for long-distance cross-border hydrogen transport. Trains would be an inland option for some regions, and still most likely more expensive than pipeline transport. Likewise, transport by ships (maritime or fluvial) would be constrained by geography, and still often require pipelines for inland transport. Moreover, considering the conversion and eventual reconversion costs of liquid hydrogen, liquid organic hydrogen carriers (LHOCs) and ammonia, long-distance transport by pipelines is competitive vis-à-vis the alternatives up to at least 1000 km (especially considering the lower costs of converting natural gas pipelines versus new investments). Transport of liquid hydrogen, liquid organic hydrogen carriers (LHOCs) and ammonia become increasingly competitive with hydrogen pipeline transport as distance increases. However, as generally, for all options, the cost of hydrogen transport increases, the share

Juge (2019) GERG Biomethane project – Biomethane trace components and their potential impact on European gas industry

[57] See Gas for Climate (2019) Action Plan 2050 (update 2019) and Green Gas Initiative (2017) Biomethane – Naturally Green Gas.

[58] Already in 2017 the Ontras TSO (DE) indicated two of its pipelines were dedicated to biomethane transport. See Green Gas Initiative (2017) Biomethane – Naturally Green Gas.

[59] Trinomics, LBST and E3M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

[60] European Commission (2018) A Clean Planet for All. In-Depth Analysis in Support of the Commission Communication COM(2018) 713

[61] Trinomics, LBST and E3M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

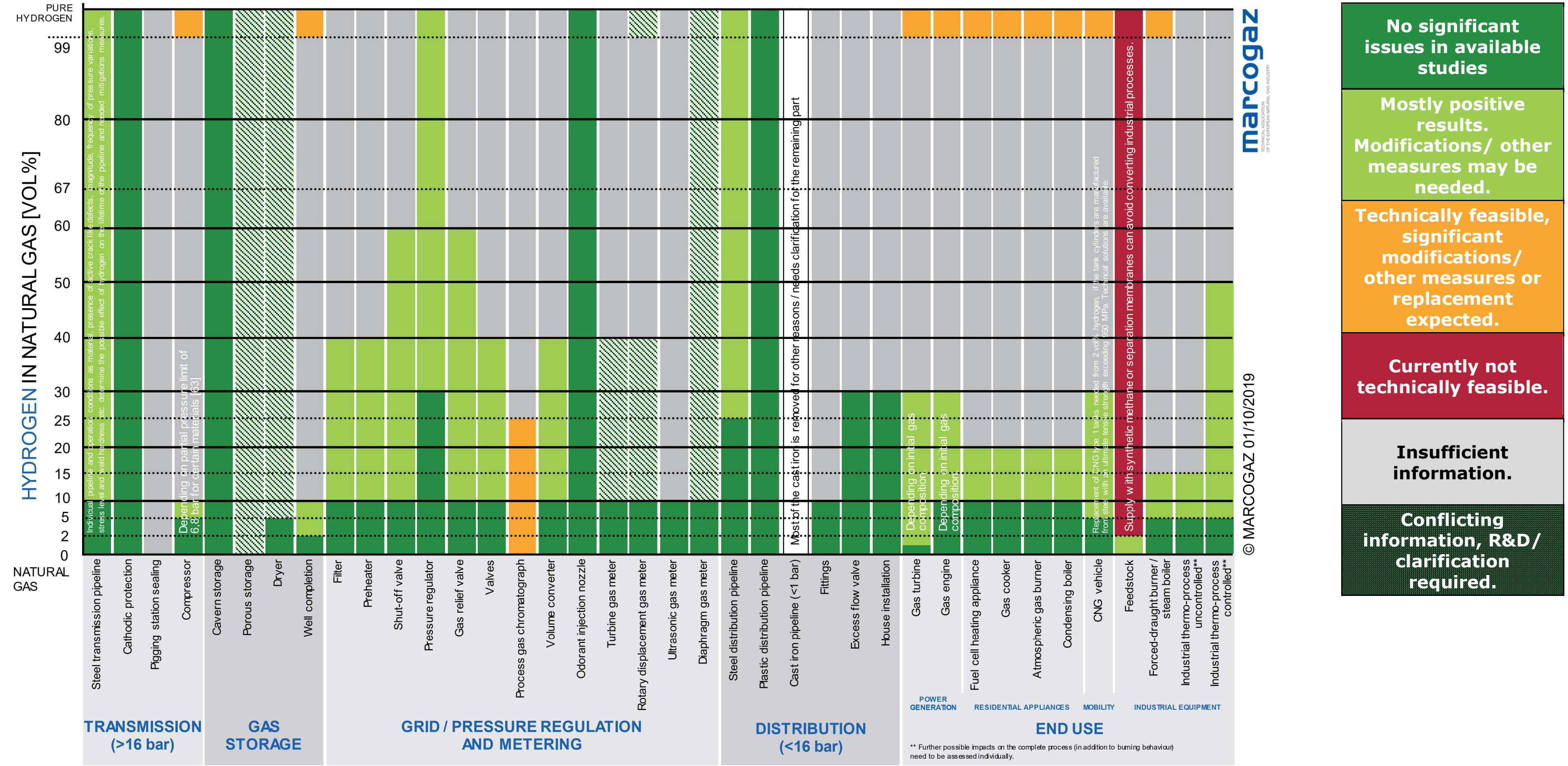
of hydrogen transport and distribution costs to the final hydrogen cost may become significant and affect the overall competitivity of hydrogen against other energy carriers.[62]

Hence, there is still much uncertainty on the future need for cross-border hydrogen transport and its competitivity versus other energy carriers. It is out of the scope of this study to assess the likelihood of the development of hydrogen infrastructure in general and cross-border transport pipelines in particular, but they should not be excluded at the moment.

Potential adaptation / conversion of infrastructure and end-use appliances will be necessary in the case of either pure or admixed hydrogen. Figure 4-2 presents a Marcogaz summary of test results on the tolerance for hydrogen admixture in natural gas infrastructure and end-use applications. At relatively low concentration levels (from 5 to 10%), investments may be needed for the adaptation of gas storage (porous storage and well completion), gas turbines, chemical industry equipment using natural gas as feedstock, and reservoirs for CNG vehicles. Concentrations above 10% require further investigations among others in transmission and distribution, including for pressure regulation and metering, as well as the adaptation of end-use equipment and appliances.

[62] IEA (2019) The future of hydrogen.

Figure 4-2 Test results and regulatory limits for hydrogen tolerance of natural gas infrastructure and end-use



Source: Marcogaz (2019) Overview of available test results and regulatory limits for hydrogen admission into existing natural gas infrastructure and end use

Enabling the deployment of renewable electricity by increasing the flexibility of the energy system

In order for the EU to achieve full net decarbonization by 2050, electricity demand is forecasted to grow in all scenarios of the 2050 Long-Term Strategy (LTS),[63] along with renewable electricity production, which would represent in 2050 about 80% of the electricity supply in all scenarios.

This electrification of the EU energy system is seen across most sectors, while in comparison consumption of natural gas is poised to decrease in all LTS scenarios. Nonetheless the Long-Term Strategy acknowledges that despite the uncertainty surrounding the role of natural gas in the long-term, the use of renewable/decarbonized hydrogen and (bio)methane could support the decarbonization of the energy system and make best use of the existing gas infrastructure. Multiple other studies do indicate scenarios combining the use of the gas and electricity systems allow to achieve full net decarbonization at least cost.[64]

Besides gas serving to satisfy specific end-uses which may be hard to electrify due to technology limitations or the required level of investments in electricity generation and transport/distribution (especially space heating with its high peak winter demand), gas-related infrastructures can facilitate the deployment of renewable electricity by increasing the overall flexibility of the energy system, which enables a higher penetration of intermittent renewable electricity sources while maintaining the security of supply.

The interlinkages study for the ENTSOs[65] mapped both direct and indirect potential interactions between the electricity and gas systems. Direct interactions are those where gas and electricity are involved for the same technological application, as either energy inputs or outputs. Indirect interaction are those where gas and electricity are in competition as alternative energy sources for a specific use, such as transportation or heating. More specifically, these potential interactions concern:

- Energy conversion
  - Gas-to-power
    - Open and combined-cycle gas turbines (OCGT and CCGT)
    - Gas combined heat and power (CHP)
  - Power-to-gas
    - Power-to-hydrogen
    - Power-to-gas (hydrogen or methane injection into gas network)
- Interlinked use
  - Electricity-driven gas compressors
  - Hybrid heating technologies
    - Industrial gas furnaces with electric boilers
    - Hybrid heating (residential & tertiary sector, district heating)

[63] European Commission (2018) A Clean Planet for All. In-Depth Analysis in Support of the Commission Communication COM(2018) 713

[64] For example Trinomics, LBST and E3M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure; Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets; Frontier Economics (2019) The Value of Gas Infrastructure in a climate-neutral Europe; Navigant (2019). Gas for Climate - The optimal role gas in a net-zero emissions energy system.; European Climate Foundation (2019). Towards fossil-free energy in 2050; ICCT (2018). The potential for low-carbon renewable methane in heating, power, and transport in the European Union.

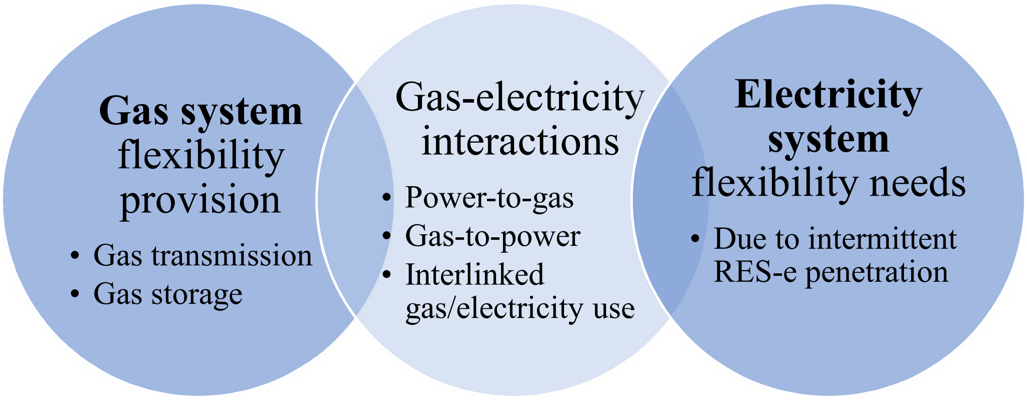
[65] Artelys (2019) Investigation on the interlinkage between gas and electricity scenarios and infrastructure projects assessment

      - Hybrid transport technologies (if any)
- Competition for energy uses (indirect interaction)
  - Mobility
  - Heating
  - Biogas use (for electricity production or as end-use gas)

Therefore, a number of interactions are possible, although they do not all have the same importance to interlinking the electricity and gas systems. Moreover, increased gas use in competitive applications (mobility, heating, biogas as end-use gas) will likely reduce electricity demand (and thus not positively enable the deployment of renewable electricity sources). Moreover, some of the gas-electricity system interactions involve infrastructure elements themselves (such as gas compressors), although most do not. However, whether gas infrastructure elements are responsible or not for such interactions, they may add flexibility to the gas system, which in its turn may support the deployment of renewable electricity.

In summary, gas-related infrastructures which increase the flexibility of the gas system may further enable the deployment of renewable electricity due to the direct interaction between the gas and electricity system (power-to-gas, gas-to-power and interlinked electricity/gas use), as indicated in Figure 4-3. In contrast, indirect, competitive interactions between electricity and gas such as hybrid heating devices will not act as a channel for the gas system flexibility to facilitate RES-e deployment.

Figure 4-3 Flexibility provision from the gas to the electricity system



Therefore, the main gas-related infrastructures which may provide flexibility to the electricity system include gas transmission, storage and conversion to/from electricity. The exact flexibility contributions of the gas system (and of specific gas-related infrastructure projects) will vary per system and depend on the other existing flexibility resources, which may be complementary (to varying degrees), as e.g. gas transmission and storage projects.

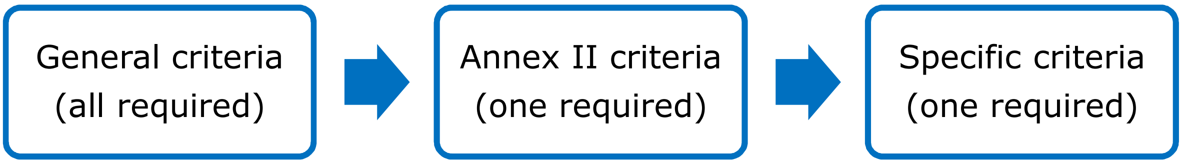
5. PCI ELIGIBILITY AND TEN-E SUSTAINABILITY OF GAS-RELATED INFRASTRUCTURE PROJECTS

The key objective of chapter 5 is to analyse which of the gas-related infrastructure projects discussed in chapter 4 could potentially meet the PCI eligibility criteria (section 5.1), and which of the sustainability aspects foreseen in TEN-E would be addressed by these projects (section 5.2). By conducting this assessment, the chapter makes recommendations for possible improvements in the TEN-E Regulation and the associated gas CBA methodology for the assessment of gas-related infrastructure projects.

5.1. PCI eligibility of gas-related infrastructure projects

As indicated in Figure 5-1, the TEN-E Regulation specifies both general and specific eligibility criteria, while its Annex II determines the categories of gas projects that are eligible for PCI status. While all general criteria need to be met, only one Annex II and specific criteria each need to be satisfied for eligibility.

Figure 5-1 Eligibility criteria structure of gas PCI projects



The provisions determined in Article 4 "Criteria for PCIs" of the TEN-E Regulation define the following **general criteria**:

a) The project is necessary for at least one of the gas infrastructure priority corridors and areas listed in Annex I;
b) The potential overall benefits of the project outweigh its costs, including in the longer term; and
c) The project meets any of the following criteria:
    i. involves at least two Member States by directly crossing the border of two or more Member States
    ii. is located on the territory of one Member State and has a significant cross-border impact
    iii. crosses the border of at least one Member State and a European Economic Area country.

Annex II of the TEN-E Regulation determines the **eligible categories** for gas projects:

a) Transmission pipelines for the transport of natural gas and biogas that form part of a network which mainly contains high-pressure pipelines, excluding high-pressure pipelines used for upstream or local distribution of natural gas;
b) Underground storage facilities connected to the above-mentioned high-pressure gas pipelines;
c) Reception, storage and regasification or decompression facilities for liquefied natural gas (LNG) or compressed natural gas (CNG);
d) Any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations.

Article 4 of the TEN-E Regulation furthermore defines the **specific eligibility criteria** (detailed in Annex IV)**:**

i) Market integration, inter alia through lifting the isolation of at least one Member State and reducing energy infrastructure bottlenecks; interoperability and system flexibility;
ii) security of supply, inter alia through appropriate connections and diversification of supply sources, supplying counterparts and routes;
iii) competition, inter alia through diversification of supply sources, supplying counterparts and routes;
iv) sustainability, inter alia through reducing emissions, supporting intermittent renewable generation and enhancing deployment of renewable gas.

It is considered that all gas-related infrastructure projects have the potential to satisfy the following eligibility general criteria, which are not further analysed in this section:

1. Necessity for at least one gas infrastructure priority corridors and areas (article 4(a));
2. Benefits outweighing costs (article 4(b)).

For the remaining eligibility criteria, the analysis on whether the projects could potentially satisfy them is indicated in Table 5-1, and discussed next. There could be very specific projects which whose eligibility would differ from the one shown above, as the objective here is to assess the eligibility of the project types, rather than address exceptions.

Table 5-1 PCI eligibility of gas-related infrastructure projects

	General criteria	Eligible categories (Annex II)	Specific criteria (Annex IV)				PCI eligibility
Project type	**Cross-border relevance**	**Applicability to one gas category**	**Market integration**	**Security of supply**	**Competition**	**Sustainability**	
New or converted pure hydrogen pipelines	✓	✗	⇔	✓	✓	✓	**No**
Pipelines with hydrogen admixture	✓	⇔	✗	✓	✓	✓	**Yes**
Pure hydrogen storage facilities	✓	✗	⇔	✓	✓	✓	**No**
Hydrogen electrolysis facilities	⇔	✗	⇔	✓	✓	✓	**No**
Biomethane injection terminals	⇔	⇔	✓	✓	✓	✓	**Yes**
Hydrogen methanation facility	⇔	✗	✓	✓	✓	✓	**No**
Reverse D->T methane compressors	⇔	✓	✓	✓	✓	✓	**Yes**
Methane emission reduction projects	⇔	✓	✗	✗	✗	✓	**Yes**

✓*: Meets the criteria in most cases;* ⇔*: Potentially meets the criteria for some cases;* ✗*: Does not meet the criteria.*

Eligible infrastructure categories

The list of PCI eligible infrastructure projects in the Annex II of the TEN-E Regulation state clearly that only natural gas (or biogas) pipelines on the transmission level are allowed to become a PCI. Similarly, the facilities for reception, storage and decompression or regasification of liquefied and compressed gases are limited to natural gas. The underground storage facilities are not limited with regards to the type of gas used, but they have to be connected to the natural gas transmission network.

All facilities dealing purely with hydrogen are thus not allowed in the current framework, although a combination in a cluster could be possible – e.g. hydrogen underground storage combined with a methanation facility that is connected to the natural gas transmission system. Natural gas pipelines with hydrogen admixture might be eligible according to this criteria since they still transport natural gas, but infrastructure conversion to enable higher level of hydrogen admixture are not eligible, since they effectively do not add new transport capacity (according to Annex IV, see paragraphs on cross-border impact below).

With regards to biogas, the high-pressure transport pipelines on transmission level are explicitly allowed. Since biomethane is similar to natural gas from a technical perspective, a biomethane injection facility (on the transmission system level) could potentially be included in the category of reception facilities of liquefied or compressed natural gas.

The types of facilities falling under the article 2(d) of the Annex II are defined very generally, but could include methane emission reduction projects, as they improve the efficient operation of networks. It could also include the reverse compressors on the transmission/distribution interface.

The Annex II does not differentiate between onshore and offshore infrastructure. However, the article 2(a) excludes upstream pipelines.

The criteria in Annex II also do not explicitly cover facilities for conversion between energy carriers (electrolysers, methanation facilities). Since they can be hardly included in any of the defined categories, they are not eligible for the PCI status.

Cross-border impact

From all the analysed infrastructure types, only the transmission pipelines can cross the border of at least two Member States (or a Member State and a European Economic Area country). All the other projects can only be located on a territory of one MS and thus need to have significant cross-border impact according to paragraph (1) of Annex IV:

(1) A project with significant cross-border impact is a project on the territory of a Member State, which fulfils the following conditions:

> (c) for gas transmission, the project concerns investment in reverse flow capacities or changes the capability to transmit gas across the borders of the Member States concerned by at least 10% compared to the situation prior to the commissioning of the project;
>
> (d) for gas storage or liquefied/compressed natural gas, the project aims at supplying directly or indirectly at least two Member States or at fulfilling the infrastructure standard (N-1 rule) at regional level in accordance with Article 6(3) of Regulation (EU) No 994/2010 of the European Parliament and of the Council

This criterium is thus foremost a question of the scale of the project. The considered facilities would have to be large enough to either increase the cross-border capacity by 10% (in case of transport projects) or supply at least two countries (in case of storage and liquefied/compressed gas infrastructure). This criterium might effectively exclude projects that aim to refurbish or upgrade natural gas infrastructure to enable hydrogen admixture, since they would most likely not be coupled with an increase of transport capacity.

Given the fact that most of the considered gas-related infrastructure projects are innovative and did not yet reach market-ready level of development, it is questionable that they could be implemented on such a scale in the foreseeable future. This criterium would thus exclude many projects, such as biomethane injection, reverse flow on the distribution/transmission interface, or the methane emission reduction projects. However, these types of infrastructure could be included in wider project clusters that could together achieve the required cross-border impact.

Specific criteria

Market integration

Since many of the analysed infrastructure categories aim at integrating indigenous production of alternative gases, it is not possible to argue that they could contribute to the market integration through lifting the energy isolation of a Member State (notwithstanding the fact that the problem of single-supplier dependency has been largely solved in the EU).[66] However, enabling decentralised domestic production of gases could relieve cross-border infrastructure bottlenecks by supplying part of the domestic demand.

Some of the analysed projects can clearly contribute to the system flexibility, such as enabling reverse flow of gases. Other projects, such as hydrogen electrolysis facilities, have however flexibility benefits that are apparent only when analysing electricity and gas infrastructure in combination, since they provide flexibility by coupling those two systems, albeit they do not bring any direct flexibility benefits to the gas system alone.

It is also questionable if building hydrogen infrastructure can be considered as enhancing the natural gas market integration. Moreover, there is currently no regulatory framework for hydrogen markets on the European level and it is thus not clearly defined what form of hydrogen markets integration is desired.

Competition

It can be argued that the analysed types of infrastructure aim at integrating either indigenous sources of gas, or enabling import of gases from alternative supply sources. Because of the lack of integration of hydrogen and natural gas markets, it is questionable if pure hydrogen infrastructure can contribute to the increase of market diversification and supply source access indicators used in the current gas CBA methodology[67]. However, hydrogen can directly substitute part of the natural gas demand and can therefore contribute to lowering the single supplier dependency.

Security of supply

The infrastructure projects aimed at integrating domestic gas production have clear benefits for enhancing the security of supply and also contribute to the long-term resilience of the European gas system, since they aim at developing modern infrastructure that can be part of a low-emission energy system. It is however questionable if the new types of infrastructure can have a significant impact in the short- and medium-term future – for example, their contribution to fulfilling the N-1 criterion can be limited by their scope and scale.

[66] EC (2019). Fourth report on the State of the Energy Union. Available at https://ec.europa.eu/commission/sites/beta-political/files/fourth-report-state-of-energy-union-april2019_en_0.pdf

[67] ENTSOG (2018): 2nd CBA Methodology. Avaliable at: https://www.entsog.eu/methodologies-and-modelling#2nd-cba-methodology.

Discussion of potential changes in the TEN-E Regulation

The clarification of which infrastructure projects are eligible for PCI status is a no-regret option. The Regulation currently includes explicitly only natural gas and “biogas”. Biogas is however not defined in the Regulation and the definition section refers to outdated European legislation, such as the 2009 Renewable Energy Directive. Similarly, “power-to-gas” is mentioned in the article 3(d) of Annex IV, potentially excluding other forms of low-carbon hydrogen (such as production via steam-methane reforming combined with CCS). An updated definition of eligible infrastructure is thus, at least, necessary to ensure coherence with the Clean Energy Package and future gas decarbonisation package.

Dedicated (100%) hydrogen infrastructure is expected to function in the future in parallel with the natural gas infrastructure. This raises a question whether the TEN-E Regulation should address hydrogen infrastructure as a separate category. Natural gas markets and infrastructure in the EU are well developed, while hydrogen markets and dedicated infrastructure are still very limited and largely inexistent in most EU Member States. Furthermore, natural gas infrastructure projects are also currently divided into four regional groups with different regional needs that do not necessary apply to hydrogen as well.

Forming a special priority thematic group that would take into account the present phase of incipient renewable and low-carbon hydrogen market and specific infrastructure development (similar to CO_2 transport networks and smart grids) could be a simpler solution than setting a set of eligibility criteria that would treat all types of gases equally. This solution has however the negative effect of not directly comparing the benefits of all gas projects and consequently obscuring the holistic perspective that takes into account the complex interdependence of energy infrastructures (including electricity infrastructure).

The acceleration of cross-border infrastructure build-up and refurbishment in order to ensure functioning of the internal energy market is one of the main goals of the TEN-E Regulation. For that reason, the Regulation is aimed at supporting the selection of the most important projects while the number of PCIs should remain “manageable”. The article 23 of the preamble states that the number of projects should not significantly exceed 220, 50 of them for gas projects.

Even with the current number of projects, significant delays in their implementation are occurring and the efficient oversight and regulatory support based on the TEN-E Regulation is in question[68]. The possible broadening of the scope of the Regulation should thus also be considered taken into account its contribution and efficacy to achieve its objectives. However, a more detailed analysis of the desirability to include hydrogen infrastructure within the TEN-E Regulation is out of the scope of this study.

5.2. TEN-E sustainability of gas-related infrastructure projects

In order to complement the analysis of sustainability characteristics conducted for Task 4.2, the sustainability aspects specific to TEN-E of the gas-related infrastructure projects are assessed, considering the possibilities defined by the gas CBA methodology and the new sustainability indicator developed in chapter 2. The aim is to understand to which extent the gas-related infrastructure projects could contribute to present TEN-E sustainability aspects, and how future contributions could be considered beyond what can be captured by the new indicator.

Combined with the eligibility analysis of section 5.1, this may support long-term improvements to the sustainability indicator, the gas CBA methodology and the TEN-E

[68] ACER (2019). Consolidated Report on the Progress of Electricity and Gas Projects of Common Interest. Available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/CONSOLIDATED%20REPORT%20ON%20THE%20PROGRESS%20OF%20ELECTRICITY%20AND%20GAS%20%20PROJECTS%20OF%20COMMON%20INTEREST%20-%202019.pdf.

Regulation in general. Additional considerations are discussed for this purpose, such as the complementarity and substitutability of gas-related infrastructure projects.

Contributions to TEN-E sustainability aspects by gas-related infrastructure projects

Table 5-2 summarizes which of the sustainability characteristics of the selected projects in section 4.2 could contribute to the TEN-E sustainability aspects. The contributions are detailed on whether it would be possible to consider those contributions with the new sustainability indicator developed in chapter 2, or whether further changes to the CBA methodology or sustainability indicator would be necessary. There are discussed in detail next.

Regarding the **substitution of fossil fuels**, it can be considered for most selected project types, employing the specific emission factors of the gases and the displaced consumption volumes of natural gas, coal and liquid fossil fuels. This is detailed in section 3.1. In the case of hydrogen projects, considering the benefits of the substitutions of fossil fuels would be possible for the share of hydrogen which is admixed in the gas system. Considering the benefits of projects within a hydrogen system would require a hydrogen-methane interlinked model. In other words, the impact of hydrogen projects on the substitution of fossil fuels can presently be considered only if they are located within the methane system or at most at the interfaces with electricity and methane systems. Likewise, for the reduction in greenhouse gases due to the **storage and/or utilisation of CO_2** the same possibilities and limitations apply.

The reduction of methane emissions by projects targeting specifically this aspect can be accounted through verified project-specific data. Other projects which lead to hydrogen admixture in the methane system can also lead to the reduction in methane emissions. This could be accounted for by considering the specific volumetric gas emissions due to leakage, venting and incomplete combustion and the admixture rate. However, at low admixture rates the benefits are likely to be marginal. It must be noted that an increase in methane gases consumption could lead to increased methane emissions and thus a negative sustainability impact, as indicated in section 2.3.

The enabling of admixed hydrogen for projects directly contributing to the production and/or injection in the methane system can be assessed by verified project-specific information. The inclusion of hydrogen networks within the scope of TEN-E would allow to consider the benefits of enabling pure hydrogen due to infrastructure projects in the hydrogen system (pipelines, regasification terminals, storage). This should be combined with a modelling of hydrogen systems, and of the interfaces with electricity and methane systems (as indicated above), in order to allocate sustainability benefits to specific projects. Otherwise, the impact of the development of hydrogen supply and demand which remains outside of the methane system can be considered through reduced demand for other energy carriers in joint scenarios, but the sustainability benefits cannot be allocated to specific projects.

The enabling of biomethane is comparatively more straightforward than for hydrogen, and could be assessed by verified project-specific information. For example, a biomethane injection terminal promoter could corroborate its planned capacity and expected yearly utilisation rate.

The benefits of enabling renewable electricity requires the development of an integrated gas-electricity systems model, or at least of strongly interlinked gas and electricity models. Defining the impacts to enabling renewable electricity is arguably easier for hydrogen electrolysis projects (and injection terminals for electrolytic hydrogen), as promoters can more easily provide direct evidence of the project's impact on the flexibility of the energy system and consequently on the enabling of electricity from renewable sources.

Table 5-2 Consideration of the TEN-E sustainability contributions of selected projects

<table>
<tr><th rowspan="2">Project</th><th colspan="5">Reducing greenhouse gases emissions</th><th colspan="2">Enabling renewable/decarbonized energy</th></tr>
<tr><th>Substituting natural gas</th><th>Substituting coal</th><th>Substituting liquid fossil fuels</th><th>Reducing methane emissions</th><th>Storing and/or utilizing CO_2</th><th>Enabling hydrogen and biomethane</th><th>Enabling RES-E</th></tr>
<tr><td>Pure hydrogen pipelines</td><td colspan="3" rowspan="7">Possible, specific emission factor of admixed gas and displacement of coal and liquid fossil fuels. Only for gas system impact of admixed hydrogen, not for pure H_2 remaining in hydrogen system, unless a hydrogen-methane interlinked model is developed.</td><td rowspan="2">NA</td><td rowspan="3">NA</td><td rowspan="2">Only for gas system impact of admixed hydrogen.</td><td rowspan="2">Requires a hydrogen-methane-electricity model.</td></tr>
<tr><td>Hydrogen storage facilities</td></tr>
<tr><td>Admixed hydrogen pipelines</td><td>Possible, with calculation based on admixture %.</td><td>Possible, using verified project-specific data / calculation based on admixture %.</td><td>Requires a methane-electricity model.</td></tr>
<tr><td>Hydrogen electrolysis facilities</td><td rowspan="2">Possible, with calculation based on admixture % (for admixed hydrogen only)</td><td rowspan="2">Possible, through specific emission factor for injected gas.</td><td rowspan="2">Possible, using verified project-specific data.</td><td>Using verified project-specific data</td></tr>
<tr><td>Hydrogen injection terminal</td><td>Requires a methane/hydrogen-electricity model.</td></tr>
<tr><td>Biomethane injection terminals</td><td>NA</td><td rowspan="3">NA</td><td rowspan="2">Using verified project-specific data.</td><td rowspan="3">NA</td></tr>
<tr><td>Reverse D->T methane compressors</td><td>NA</td></tr>
<tr><td>Methane emission reduction projects</td><td colspan="3">NA</td><td>Possible, using verified project-specific data</td><td>NA</td></tr>
</table>

Complementarity of the sustainability impacts of different project categories

Section 5.1 indicates that many gas-related infrastructure projects would not be eligible for PCI status at the moment. Nonetheless, if new project categories eventually become eligible for PCI status, the complementarity or substitutability of gas-related infrastructure projects regarding the sustainability characteristics will be a central aspect, as e.g. power-to-gas and hydrogen pipelines may need to be assessed side-by-side to currently eligible gas transmission, storage and LNG projects.

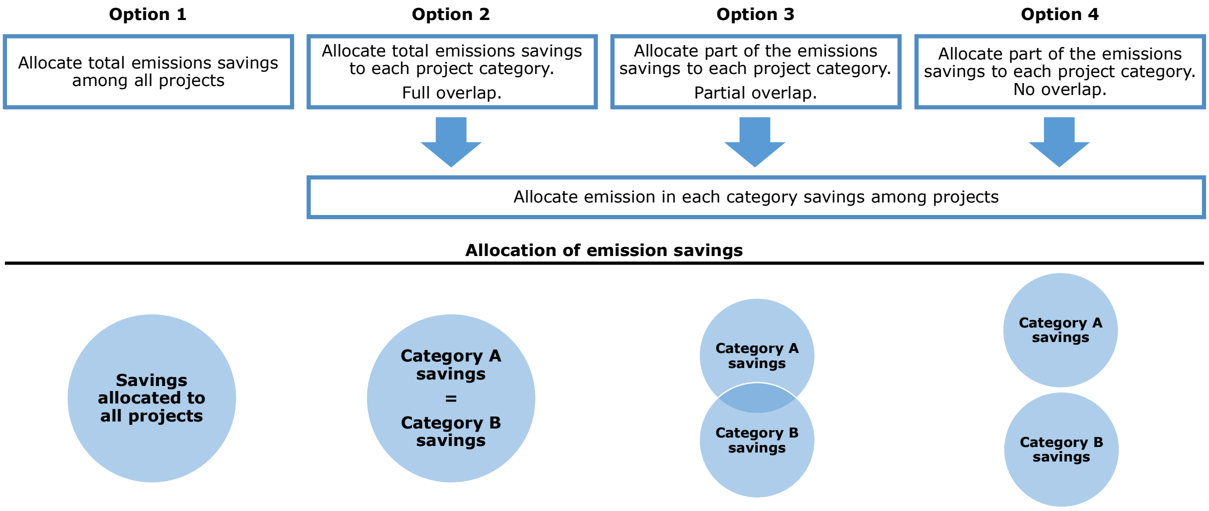
Under the TEN-E regulation, gas projects of different categories (e.g. a gas pipeline and an LNG terminal) do not compete in the same ranking. However, in the sustainability indicator of the current gas CBA methodology, total CO_2 emissions savings per scenario are divided among all considered projects, according to their capacities (in MW). Hence, a gas pipeline and an LNG terminal would compete to some extent under the current indicator, in the allocation of the CO_2 emissions savings.

However, this does not reflect that projects of different categories such as a pipeline and an LNG terminal may be complementary, rather than substitutes, regarding their contributions to sustainability. In another example, a hydrogen injection facility and a methane pipeline adapted admitting admixed hydrogen both contribute to enable the consumption of hydrogen, even in the case of independent projects which cannot be clearly grouped into a project cluster.

Figure 5-2 presents the different options for the allocation of sustainability impacts such as emission savings among projects of the same or different categories. Overlaps should be avoided within each project category, but for some sustainability benefits there could be an overlap in allocation between different project categories. Independently of the approach selected, the (eventual) inclusion of further gas-related infrastructure project categories in the TEN-E scope would require the consideration of how to allocate the different sustainability benefits between projects.

Option 1 represents the approach for allocating emission savings of the current sustainability indicator in the gas CBA methodology, and of the new indicator when using a flow-based allocation without an interlinked model. Option 2 allocates the full scenario benefits to each category, and thus has a full overlap of benefits, while option 4 has no overlap. Either option 2 or 4 could potentially not reflect the fact infrastructure projects can be complementary or substitutes. A partial overlap of the sustainability impacts of different project categories as in option 3 could better reflect the partial complementarity of some projects, but would increase the complexity of the allocation step. As, in the framework of the TEN-E regulation, the objective is to rank the projects within a same category, option 1 may still achieve that with greater simplicity.

Figure 5-2 Options for the allocation of emission savings among project categories



It can nonetheless be worthwhile to adopt different approaches to allocate the benefits to the TEN-E sustainability aspects due to the substitution of fossil fuel use, the reduction of methane emissions and the enabling of renewable energy. For example:

- **Allocation of benefits due to the fossil fuel substitution:** use option 1, with the partition of the benefits based on a clear criteria (such as additional utilised capacity), avoiding double-counting, may be adequate for a group of projects of the same type. This as long as the criteria considers the actual contribution of the project to the substitution of fuels, by allocating benefits based on e.g. the load curve or flow-based modelling as presented in chapter 3.
- **Direct benefits of enabling biomethane, hydrogen and renewable electricity:** use option 3, using specific project characteristics, based on verified data from promoters and agreed procedures for accounting for these benefits. Due to the project complementarity and the qualitative nature of the benefit, double counting may be accepted, as the objective is to define the sustainability characteristics to rank the candidate PCIs, rather than accounting for the achievement of targets such as for GHG emission reduction or RES – these can be tracked at the scenario level.
- **Indirect benefits of enabling biomethane, hydrogen and renewable electricity:** use option 3. Due to the coupling of the methane and electricity systems: may be calculated using an integrated energy systems model, and allocated similarly as for fossil fuel substitution benefits, avoiding double-counting. Alternatively, due to the partially qualitative nature of the benefit, double counting may be accepted.

The use of PINT (put in one at a time) or TOOT (take out one at a time) approaches could better reflect the complementarity and substitutability of (a cluster of) gas projects to a reference gas grid. The use of a robust CBA methodology (i.e. a min-max regret approach selecting the projects which show the highest minimum benefits across all scenarios) could represent a further step and better reflect the impacts of the projects considering future uncertainty.

Box 5-1 Linking sustainability benefits to specific projects

As discussed in this study, while the sustainability benefits of a certain scenario can be allocated to a pool of projects, others could be directly (and exclusively) assigned to a specific project. This could be the case of e.g. a new transmission pipeline connecting a biomethane producer to the natural gas system, which could be thus assigned the full emissions saving arising from the biomethane consumption as well as the benefits from enabling biomethane. However, the issue of accepting or not overlap with the benefits allocated to other projects would need to be addressed per sustainability benefit type.

Potentially, sustainability benefits could be linked to a specific project only for the benefits where overlap between project categories is acceptable. The impacts could be directly assigned to a specific project if, in the absence of the project, they would not occur or be significantly reduced. For example, if a gas-related infrastructure project was essential for the injection of biomethane or hydrogen from a production facility. Generally, projects within a meshed, interconnected gas system could not be directly linked to specific sustainability impacts.

Direct sustainability impacts of specific projects would also have to be defined based on project characteristics and supported by verifiable project data from the promoters. A parallel can be made to the 3rd electricity CBA methodology recently submitted by ENTSO-E to ACER. The ENTSO-E draft includes project-level indicators, "designed to address the instances where it is not possible for ENTSO-E to assess certain benefits at a pan-European level within the TYNDP process."[69]

No sustainability benefit is considered at the project level for the ENTSO-E 3rd CBA methodology, but it provides a potential approach for considering the direct sustainability impact of gas-related infrastructure projects. Promoters are required to provide a copy of a study supporting the project-level benefit(s), along with the assumptions, data sources, tools used and demonstration of the alignment of the used methodology to the electricity CBA.

In the case of direct sustainability benefits of gas-related infrastructure projects, other supporting evidence could include project plans or letters of intent from e.g. biomethane producers demonstrating the contribution to a TEN-E sustainability aspect. These would need to demonstrate the alignment with the TEN-E gas-related infrastructure eligibility requirements as well as the sustainability indicator scope (regarding, for example, eventual maximum carbon footprints of low-carbon gases).

Further issues concerning the TEN-E sustainability of gas-related infrastructure projects

End-users take their equipment and appliances investment decisions based on comparative prices and availability of different energy carriers, and (potentially) the sustainability characteristics of e.g. natural gas, heat, biomethane, hydrogen and electricity. While the configuration of energy systems plays a direct role in determining those factors, it is unlikely that (most) individual projects will alter decisions of end-users significantly, as these decisions are influenced by a multitude of factors.

Therefore, these investment decisions of end-users and their impact on the TEN-E sustainability aspects can be addressed in project-specific CBAs through scenarios, and if needed additional considerations for specific projects. Thus, investment decisions most

[69] ENTSO-E (2020). 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. Draft Version, January 28.

likely do not need to be modelled in project-specific CBAs. If a project directly affects an investment decision (e.g. an injection terminal for collection of hydrogen produced in a specific region), this can be adequately measured from (verified) project data. Likewise, peripheral regions with poor gas supply may benefit from specific projects, which may also be measured through project-specific considerations.

Another issue is that of infrastructure lock-in. Logically, the award of PCI status to projects which contribute to lock-in in unsustainable pathways should be avoided. An eventual provision in the TEN-E Regulation could consider as an example the provisions for transition activities in the Taxonomy Regulation. The political agreement of the Taxonomy Regulation[70] defines near-zero and transition activities in article 6(1a) as:

an economic activity for which there is no technologically and economically feasible low carbon alternative, shall be considered to contribute substantially to climate change mitigation as it supports the transition to a climate-neutral economy consistent with a pathway to limit the temperature increase to 1.5 degrees Celsius above pre-industrial levels including by phasing out greenhouse gas emissions, in particular from solid fossil fuels, where that activity:

- I. has greenhouse gas emission levels that correspond to the best performance in the sector or industry;
- II. does not hamper the development and deployment of low-carbon alternatives; and
- III. does not lead to a lock-in in carbon-intensive assets considering the economic lifetime of those assets.

The Taxonomy Expert Group[71] considers furthermore that "activities related to dedicated storage and/or transportation of any fossil fuels, including gaseous or liquid fossil fuels, should not be considered as making a substantial contribution to climate change mitigation, as this risks leading to lock-in which would undermine Article 6(1a)" and that "energy generation from gaseous or liquid fossil fuels should only be considered to make a substantial contribution to climate change mitigation where it meets the technical screening criteria, which we recommend be set at <100 gCO_2e/kWh reducing in five-year increments to 0 g CO_2e/kWh by 2050."

A final issue to consider is the greenhouse gases footprint of extra-EU gas imports. Upstream emissions exist not only for imported gas but also other imported fossil fuels, imported biomethane/hydrogen/synthetic hydrogen.

Member States may import renewable fuels which do not comply with the sustainability criteria of the recast Renewable Energy Directive, but are not allowed to count those towards their renewable energy targets - a similar approach could be applied to the assessment of PCI candidates. The GHG footprint of energy imports could be addressed by a separate measure such as a carbon border tax. Nonetheless the TEN-E sustainability assessment could consider the GHG footprint to some extent. The Regulation could establish minimum eligibility criteria for gases in the quantification of the sustainability benefits of the gas-related infrastructure projects, possibly in alignment with the RED II criteria for biogas and renewable fuels of non-biological origin.

[70] European Council (2019) Proposal for a Regulation on the establishment of a framework to facilitate sustainable investment - Approval of the final compromise text. COM (2018) 353 final.
[71] Technical Expert Group (2020) Taxonomy: Final report on Sustainable Finance. Available at https://ec.europa.eu/info/sites/info/files/business_economy_euro/banking_and_finance/documents/200309-sustainable-finance-teg-final-report-taxonomy_en.pdf

Options for possible improvements

In June 2020 European energy regulators have published a position paper on the revision of the TEN-E Regulation.[72] Concerning aspects affecting gas-related infrastructure projects, the following proposals are of note:

- Sustainability criteria need to be strengthened so gas projects need to demonstrate positive benefits in terms of sustainability of the energy system;
- To create a carbon dioxide and hydrogen networks group;
- Maintain the cross-border impact requirement for PCI status, and the list of PCIs at a manageable number;

Our analysis supports especially the first and last recommendations of ACER and CEER. We propose that the following options for improvement should be considered in the TEN-E Regulation, gas CBA methodology and the sustainability indicator, but should be weighed against practical considerations, such as the modelling requirements:

- **Asses the sustainability characteristics of PCI candidates preferably with an integrated electricity-gas model** in order to fully account for the benefits of projects to enable the integration of both renewable gas and electricity into the system as well as to consider the electricity-gas systems interlinkages.
    - This should be preceded by short-term improvements in the CBA methodology, including by implementing the improved sustainability indicator developed in chapter 2;
- **Consider minimum sustainability criteria for gases in the calculation of the projects' sustainability benefits**, using RED II criteria, while also including gases with comparable carbon footprints to renewable gases, such as low-carbon hydrogen;
- **Use eligibility and assessment criteria for PCIs to avoid a lock-in in unsustainable pathways**, considering the greenhouse gases footprint of the various gases facilitated by gas-related infrastructure;
- **Consider developing an integrated hydrogen-electricity-gas model if and when the scope of the TEN-E Regulation is expanded,** to include hydrogen systems when these reach significant scale and interaction with other energy infrastructure. Meanwhile, consider hydrogen projects:
    - Through scenarios;
    - With verified project-specific data; and/or
    - At the interface of methane and of electricity systems.

[72] ACER-CEER (2020). Position on revision of the Trans-European Energy Networks Regulation (TEN-E) and Infrastructure Governance

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