# Future of the natural gas distribution grid in Flanders

VNR/0110

Report



#### **Contract details:**

Vlaamse Nutsregulator (VNR)

Future of the natural gas distribution grid in Flanders

Reference Number: VNR/0110

Presented by

Trinomics B.V.

Mauritsweg 44

3012 JV Rotterdam

The Netherlands

#### **Contact persons:**

Louise Aeby

T: +31 (0) 6 305 282 38

E: louise.aeby@trinomics.eu

Luc van Nuffel

T: +32 (0) 478 65 26 37

E: <u>luc.vannuffel@trinomics.eu</u>

#### Date:

Rotterdam, 12/11/2025

#### **Authors:**

Luc van Nuffel, Louise Aeby, Anna Kralli, Sara Svensson, Nina Voulis (Trinomics) Daniel Grote, Adam Madgett, Andrew Ellis, Kameh Attarian, Paul Quinn (DNV)





VNR/0110

Future of the natural gas distribution grid in Flanders

#### In association with:



# **Table of Contents**

1.	Con	text and objective of the study	1
	1.1.	Context of this assignment	1
	1.2.	Objective of the study	1
	1.3.	Structure and content of this report	1
2.	Sce	narios for possible evolution of gas distribution grid use in 2025-2050	3
	2.1.	Assumptions	3
	2.2.	Results per scenario	8
	2.3.	Phase-out planning strategies	11
	2.4.	Scenarios and phase-out strategies as basis for the cost evolution analysis	14
3.	Use	of Flemish gas distribution network for "alternative" gases	16
	3.1.	Biomethane	16
	3.2.	Synthetic methane	17
	3.3.	Hydrogen blending in distribution gas networks	19
4.	Opt	ions for repurposing the Flemish gas distribution gridgrid	21
	4.1.	Hydrogen	21
	4.2.	CO <sub>2</sub>	31
	4.3.	Water	39
	4.4.	Corridor for communication or electricity cables	40
	4.5.	Comparative analysis of adaptation costs for the four use cases	44
	4.6.	Key findings and conclusions	46
5.	Dec	ommissioning of gas distribution grid	50
	5.1.	Lessons learned and best practices in other European countries	50
	5.2.	Possible Roadmap for Decommissioning in Flanders	58
	5.3.	Summary of key findings	64
6.	Cos	t structure and drivers of gas DSOs in Flanders	65
	6.1.	Cost structure and drivers of gas DSOs	65
	6.2.	Cost structure and drivers of gas DSOs in Flanders	67
	6.3.	Conclusion	74
7.	Fut	ure evolution of gas DSO costs in Flanders in the 3 scenarios	75
	7.1.	Methodology and assumptions	75
	7.2.	Projection of CAPEX	77
	7.3.	Projection of endogenous OPEX	84
	7.4.	Future evolution of total costs of gas DSOs in Flanders	89
	7.5.	Conclusion	91
8.	Evo	lution of allowed revenues of gas DSOs based on current tariff methodology	92
	8.1.	Methodology and assumptions	92

	8.2.	Evolution of the basic component of allowed revenues for endogenous costs	94
		Comparison between total endogenous costs and basic component of allowed revenue ogenous costs	
	8.4.	Conclusion	98
9.	Evol 99	ution of the network tariffs and other components of the gas bill for households and S	MEs
	9.1.	Methodology and assumptions	99
	9.2.	Evolution of network tariffs	. 102
	9.3.	Evolution of the other components of the gas bill	.108
	9.4.	Evolution of the total gas bill for residential and non-residential end-users	111
	9.5.	Conclusions	115
10.	Mea	sures to support phase-out of gas distribution	117
	10.1.	Regulatory challenges and questions	117
	10.2.	Regulatory context and challenges in Flanders	121
	10.3.	International regulatory practices	122
	10.4.	Regulatory options to address challenges in Flanders	127
		Key findings and recommendations for adjustments of the legal and regulatory framev anders	
11.	Ove	rall key findings and recommendations	.143
An	nex A	a – Correlations between CAPEX and OPEX of gas DSOs in Flanders and cost drivers	.149
	Corr	elation between CAPEX and cost drivers	. 149
	Corr	olation between selected ODEX categories and cost drivers	1/,0

# Context and objective of the study

## 1.1. Context of this assignment

This study on the 'Future of the natural gas distribution grid in Flanders', conducted by Trinomics and DNV, has been launched by the Flemish Utilities Regulator VNR ("Vlaamse Nutsregulator") in the context of the ongoing energy transition. As stated in its Climate Strategy 2050 and the revised Flemish Energy and Climate Plan 2021-2030, Flanders has the ambition to reduce its greenhouse gas (GHG) emissions from sectors not yet subject to the ETS by 40% in 2030 and by 85% in 2050 (compared to 2005). Reaching these targets will require a gradual shift away from unabated fossil fuels use, including by reducing energy consumption and replacing natural gas with renewable and low-carbon energy. This transition will not only contribute to the climate objectives but should also allow to reduce the dependence on imported fossil fuels. In this context, the Flemish government has announced in its Coalition Agreement 2024-2029 that it will prepare the gas distribution network for the future and investigate an exit policy in coordination with Fluvius and VNR. At the EU-level, article 57 of the new Gas Directive (EU)2024/1788 foresees that Member States shall ensure that the gas DSOs develop network decommissioning plans where a reduction in natural gas demand would require dismantling (parts of) the network.

## 1.2. Objective of the study

This study aims to provide expert advice to VNR on the future development and regulation of the gas distribution grid. Advice and recommendations will be formulated after having identified and evaluated possible scenarios and options for the future use, repurposing and decommissioning of the natural gas grid in Flanders from an energy, economic and technical perspective, and after having assessed the impacts of these scenarios on grid costs, revenues for DSOs, and costs for end-users. The study focuses on scenarios up to 2050, starting from the current situation in Flanders, and takes the European context into account, and draws insights from relevant developments in other EU countries.

# 1.3. Structure and content of this report

This report presents the results of the study. It is structured as follows:

- Chapter 1. 'Context and objective of the study' provides an introduction to the context of the study and its objectives, as well as the structure of the report.
- Chapter 2. 'Scenarios for possible evolution of gas distribution grid use in 2025-2050' presents the three scenarios for the development of the gas offtake from the distribution grid and the number of connections, i.e. one medium scenario representing the most likely future development according to our view, and two alternative scenarios with a faster and slower decline of natural gas demand respectively. It also presents three different possibilities for the phase-out of the natural gas grid in Flanders, one strategy in which end-users disconnect randomly and two strategies in which policymakers implement a partial or a stronger organisation of the phase-out.
- Chapter 3. 'Possible use of gas distribution network in Flanders for other gases' discusses the potential of using the Flemish gas distribution network for other gases (i.e. biomethane, synthetic methane and hydrogen blending).
- Chapter 4. 'Options for repurposing of gas distribution grid' analyses the realistic options and expectations of repurposing (part of) the current gas distribution grid network for transport of hydrogen, CO2 or other possible use cases (such as water or as corridor for communication cables).



- Chapter 5. 'Decommissioning of gas distribution grid' presents a possible roadmap for decommissioning the gas distribution grid in Flanders based on lessons learned and best practices from other countries.
- Chapter 6. 'Cost structure and drivers of gas DSOs' explores the cost structure and drivers of gas DSOs and more specifically in Flanders. It also provides estimates for gas DSOs costs.
- Chapter 7. 'Evolution of the costs of the gas DSOs in Flanders in the 3 scenarios' builds on the previous chapter and projects the evolution of the costs of the gas DSOs in Flanders according to the 3 scenarios developed in Chapter 2.
- Chapter 8. 'Evolution of allowed revenues of gas DSOs based on current tariff methodology'. In line with Chapter 7, this Chapter projects the evolution of the allowed revenues of the Flemish gas DSOs.
- Chapter 9. 'Evolution of the gas bill for households and SMEs' analyses how the different components of the gas bill, in particular the network tariff, may evolve for representative endusers in the scenarios considered in the study.
- Chapter 10. 'Measures to support phase-out of gas distribution' describes the regulatory challenges and questions resulting from a phase-out of natural gas, analyses the international regulatory practices and assesses different regulatory options for gas distribution.
- Chapter 11. 'Key findings and recommendations' presents the main conclusions and takeaways of this study and develops a set of recommendations for VNR and the policymakers in Flanders.

# Scenarios for possible evolution of gas distribution grid use in 2025-2050

In this chapter we describe three scenarios for the possible evolution of the use of the gas distribution grid in Flanders that will serve as a basis for the assessment of the evolution of the costs and revenues of the gas DSOs in Flanders. The medium scenario is designed to align with the policy goals and can therefore be considered as the most plausible pathway. The low and high scenarios show possible pathways with respectively slower and faster phase-out of natural gas. In general, scenarios should not be considered as predictions but rather as tools to identify and understand the impacts of potential evolutions resulting from different assumptions. In this case, scenarios provide insights in the effects on costs, revenues, etc. of the distribution grid if a certain evolution in the use of the gas grid would take place. Once the effects in terms of grid costs and revenues/tariffs are better understood, policies can be designed to adapt certain regulatory aspects and steer the evolution of the gas grid, including possible repurposing and ultimate decommissioning in the most appropriate direction.

The assumptions in the scenarios described in this chapter are as much as possible grounded in available data and existing scenarios and policies. However, less data and information are available closer towards 2050. In that case we base scenarios on assumptions chosen in such a way to provide valuable insights and support decision making.

## 2.1. Assumptions

The basis for the three scenarios is the sectoral gas distribution data provided by Fluvius for 2023<sup>1</sup>. This data was filtered to include the gas off-take volumes and number of connections aggregated by sector (households, tertiary sector, and industry). The values represent approximate gas off-take volumes (consumption), calculated by Fluvius on a monthly basis and adjusted to reflect calendar year consumption<sup>2</sup>.

#### 2.1.1. Assumptions used for the residential and tertiary sectors

#### 2.1.1.1. Assumptions regarding new connections

The assumptions regarding new connections are based on the switch from fuel oil heating to natural gas in the residential and tertiary sectors. The scenarios are based on the prohibition to renew or install fuel oil boilers and the assumption that a portion of the buildings with fuel oil boilers will switch to natural gas<sup>3</sup>.

According to estimates from VEKA, approximately 600 000 residential buildings still use fuel oil as major heating source. We assume that a share of these will switch to natural gas, thereby increasing

<sup>&</sup>lt;sup>3</sup> Vlaamse Overheid (2021). Verbod op het plaatsen en vervangen van stookolieketels. Available at: <u>Vlaanderen (2021)</u> <u>Verbod op het plaatsen en vervangen van stookolieketels</u>



<sup>&</sup>lt;sup>1</sup> Fluvius – Verbruiksgegevens per statistische sector met NACE sector en NACE subsector.

<sup>&</sup>lt;sup>2</sup> In parallel with the present study, Elia and Fluxys are developing multi-energy scenarios for the entire energy system in Belgium. These scenarios are not completed yet, and the assumptions are under review by stakeholders. The goal of the multi-energy scenarios is to provide insights in different pathways Belgium can reach net-zero carbon emissions in 2050. This is a different goal as compared to the scenarios in the present study, it can therefore be expected that assumptions and results will differ.

both the number of connections and overall gas consumption. In the residential sector, projections for new connections are based on Fluvius' estimates for the period 2024–2030. Between 2023 and 2030, Fluvius anticipates 45 693 additional residential connections, representing a 2% increase by 2030 compared to 2023 in the medium scenario and 36 795 between 2030-2035<sup>4</sup>. From 2040 onwards, we assume no further new connections to the gas grid and by 2050 we assume a portion of the new connections from before 2030 will disconnect again by 2050.

For the tertiary sector, the number of buildings currently using fuel oil is estimated at 11 800. This is derived by assuming that 20% of Belgium's tertiary buildings are heated with fuel oil, applying this share to the national building stock of approximately 100 000 buildings, and adjusting for the share located in Flanders<sup>56</sup>. Projections for new tertiary connections are based on Fluvius' estimates in the "Dienstleidingen buiten >2"" category, indicating 166 new connections between 2025 and 2030 and 149 new connections between 2030-2035<sup>7</sup>. This corresponds to a modest increase of 0.08% in 2030 relative to 2023 in the medium scenario.

Table 2-1 (in Section 2.3) presents the projected relative increase in the number of connections to the natural gas grid by 2030, resulting from fuel oil to gas conversion in both residential and tertiary sectors.

#### 2.1.1.2. Assumptions regarding evolution of gas offtake

The assumptions regarding the evolution of gas offtake by existing connections in the residential and tertiary sectors are based on the increase in energy efficiency due to building and energy equipment renovation scenarios, the uptake of heat pumps, and connections to district heating.

#### Renovation

The projected decrease in gas consumption in the residential sector due to renovation is estimated based on three intermediate scenarios for EPC (Energy Performance Certificate) values in 2030, as set out in the 'Vlaamse Energie- en Klimaatplan', as well as the average EPC in 2023 and the target or expected average EPC in 2050. For 2023, an average EPC value of 400 is assumed for both residential and tertiary buildings<sup>8</sup>.

In the residential sector, the following EPC values are used for 2030:

- EPC = 325 in the low scenario
- EPC = 285 in the medium scenario
- EPC = 250 in the high scenario

By 2050, we assume an average EPC of 100 is achieved in both the medium and low scenarios. In the high scenario, it is assumed that the residential sector is entirely disconnected from the gas grid, with no remaining natural gas consumption.

For the tertiary sector, the same assumptions as for the residential sector are applied for 2023 and 2030. However, as the goal is to achieve emission-neutral buildings by 2050, it is assumed that there will be no natural gas consumption in that year across all scenarios.

Trinomics - -

4

<sup>&</sup>lt;sup>4</sup> Fluvius (2025) Forecast Number of connections Gas 2025-2029 (received from Fluvius)

<sup>&</sup>lt;sup>5</sup> Heat Roadmap EU (2017). Profile of heating and cooling demand in 2015. Available at: Heat Roadmap Europe

<sup>&</sup>lt;sup>6</sup> Federaal Planbureau (2024) Energievooruitzichten van België bij aangekondigd beleid. Available at: <u>Federaal Planbureau (2024) Energievooruitzichten van België</u>

<sup>&</sup>lt;sup>7</sup> Fluvius (2025) Forecast Number of connections Gas 2025-2029 (received from Fluvius)

<sup>&</sup>lt;sup>8</sup> VEKA (2023). Vlaams Energie- en Klimaatplan (VEKP) 2021-2030. Available at: <a href="https://www.vlaanderen.be/veka/energie-en-klimaatbeleid/vlaams-energie-en-klimaatplan-vekp-2021-2030">https://www.vlaanderen.be/veka/energie-en-klimaatbeleid/vlaams-energie-en-klimaatplan-vekp-2021-2030</a>

It is important to note that only a portion of the average reduction in energy consumption per EPC label is attributed to decreased gas demand. The remainder may be due to other factors, such as increased installation of solar panels, improved efficiency in electricity use, and other technological or behavioural changes.

#### Heat pumps

Estimates for the number of additional heat pumps installed in the residential sector are based on VEKA's projection of 41500 annual installations by 2030. For the period 2030 to 2050, we apply projections from the 'Energievooruitzichten van België bij aangekondigd beleid', adjusted proportionally to reflect Flanders' share<sup>9</sup>.

The figures are further refined to isolate heat pumps, replacing or complementing gas boilers in existing buildings, as these are the installations relevant to our analysis. This adjustment is based on "VEKA's E-peil" data, which shows that 48% of newly built homes in 2021 were equipped with a heat pump. With 23 500 new dwellings constructed in Flanders that year, and using installation data from Climafed, we estimate that approximately 70% of all heat pumps installed in 2021 were in new buildings<sup>10</sup>. Consequently, we assume that the remaining 30% were installed to replace or complement gas boilers or fuel oil in existing buildings.

We also distinguish between fully electric and hybrid heat pumps to differentiate those that lead to full disconnection from the gas grid from those that result in efficiency gains while maintaining a gas connection. Although no reliable estimates are available for Flanders, data from the Netherlands indicate that 10% of heat pumps installed in 2024 were hybrid 11. However, these figures do not differentiate between new and existing buildings. As hybrid models are more likely to be installed in existing buildings, we assume that 60% of the residential heat pumps will be fully electric in 2030, increasing to 100% by 2050.

In the tertiary sector, we use VEKA's estimate of 1250 annual heat pump installations through to 2050. We assume that 80% of these will be fully electric up to 2030, with all installations fully electric from 2030 onwards.

The decrease in gas offtake is derived from the number of hybrid heat pumps installed multiplied by the efficiency increases of hybrid heat pumps and for fully electric heat pumps, the reduction is based on the average household gas consumption per replaced unit.

#### **District heating**

Data on current levels of district heating are sourced from the 'Warmtenetrapportering 2023'<sup>12</sup>. To estimate future increases in district heating by 2030 and 2050, we use both Fluvius' projections and figures from the report 'Energievooruitzichten van België' (FPB report)<sup>13</sup>.

The FPB report projects that 760 000 households in Belgium will be connected to district heating by 2050. Adjusting this figure for Flanders results in an estimated 448 598 households, implying an average annual increase of 16 307 connections. In contrast, Fluvius' investment plan assumes that 8%

<sup>&</sup>lt;sup>13</sup> Federaal Planbureau (2024) Energievooruitzichten van België bij aangekondigd beleid. Available at: <u>Federaal Planbureau (2024) Energievooruitzichten van België</u>



\_

<sup>&</sup>lt;sup>9</sup> Federaal Planbureau (2024) Energievooruitzichten van België bij aangekondigd beleid. Available at: <u>Federaal Planbureau (2024) Energievooruitzichten van België</u>

<sup>&</sup>lt;sup>10</sup> Statistiek Vlaanderen (2025) Nieuwbouwvergunningen,

<sup>&</sup>lt;sup>11</sup> Centraal Bureau voor de Statistiek (2025) Warmtepompen; aantallen, thermisch vermogen en energiestromen

<sup>&</sup>lt;sup>12</sup> VEKA (2023) Warmtenetrapportering

of the existing buildings in Flanders will be connected to district heating by 2050, corresponding to 219 542 households which is nearly half the FPB estimate<sup>14</sup>.

As this analysis focuses exclusively on existing buildings and not on new construction, we adopt the more conservative estimates provided by Fluvius. Under the medium scenario, this results in 7 824 new district heating connections per year from existing buildings. Each new connection is assumed to offset the average annual gas consumption of a household.

For the low and high scenarios, the uptake of fully electric heat pumps and district heating is assumed to be 20% lower or higher, respectively, than in the medium scenario. Table 2-2 (in Section 2.3) presents the projected percentage reduction in gas consumption for each scenario in 2030, 2040, and 2050, relative to 2023 levels.

#### 2.1.1.3. Assumptions regarding number of disconnections

The assumptions regarding the number of disconnections in the residential and tertiary sectors are primarily based on the installation of fully electric heat pumps, connections to district heating, as well as demolished buildings.

We assume that buildings that install fully electric heat pumps or connect to district heating are fully disconnected from the gas grid. The figures for these disconnections follow the logic of the calculations to estimate the number of heat pumps and district heating and are detailed in section 2.1.1.2.

To calculate the number of buildings that will be demolished, we use the expected average rate of yearly demolished buildings estimated in the "Vlaamse Langetermijnrenovatiestrategie voor gebouwen 2050". We assume the buildings are demolished at a linear rate up until 2050 in all scenarios. In the high scenario we assume all buildings will be disconnected as there is no gas offtake in that scenario (see Table 2-1).

This results in a disconnection rate slightly lower than the overall decrease in gas offtake. The remaining connections are due to hybrid heat pumps and energy efficiency increases without complete disconnection of the gas boiler. In the high scenario, we assume that by 2050, the entire gas reduction is translated into full disconnection. The outcomes of these scenarios are presented in Table 2-1 (in Section 2.3).

#### 2.1.2. Assumptions regarding evolution of gas offtake and connections of industry

Industry that draws natural gas from the distribution grid (lower and medium pressure) is smaller scale industry and can therefore be assumed to be (a portion of) the non-ETS industry, also referred to as ESR industry. The gas demand by industry from the Fluvius distribution grid was 7.7 TWh in 2023 and is assumed to be mainly used to produce heat. Approximately 75% of the heat demand by ESR industry is satisfied through natural gas, 15% through fuel or gas oil, and the remaining 10% through biomass, LPG and other fuels combined 16.

#### 2.1.2.1. Assumptions for the evolution between 2023 and 2030

The Vlaamse Energie- en Klimaatplan<sup>17</sup> sets a GHG emissions reduction goal for the ESR industry at  $3.2 \, \text{Mton CO}_2\text{eq}$ , compared to  $4.9 \, \text{Mton CO}_2\text{eq}$  in 2005 (35% relative reduction). The main approaches to reduce energy-related GHG emissions is through decrease in natural gas and fuel/gas oil uses. We assume that 25% (**medium** scenario) of fuel/gas oil use would be replaced by biomass, heat pumps, or residual heat by 2030. Based on the Technopolis and VITO (2022) report, we assume fuel or gas oil

<sup>&</sup>lt;sup>17</sup> <u>Vlaamse overheid (2023) Ontwerp Vlaams Energie- en Klimaatplan 2021-2030 – actualisatie 2023,</u> p. 28



<sup>&</sup>lt;sup>14</sup> Fluvius (2024) Investeringsplan (2024-2033)

<sup>&</sup>lt;sup>15</sup> VEKA (2019) <u>Vlaamse langetermijnrenovatiestrategie voor gebouwen 2050</u>

<sup>&</sup>lt;sup>16</sup> Technopolis Group (2022). Economische potentieelstudie vergroening van de warmtevraag van de niet-ETS industrie in Vlaanderen. <u>Economische-potentieelstudie-vergroening-warmtevraag-niet-ETS-industrie-in-Vlaanderen-april-2022-002-8.pdf</u>

will not be replaced by natural gas. Phase out of fuel/gas oil results in 6% GHG emissions reduction. We take into account the additional decrease in GHG emissions (30%) due to the drop in economic output leading to a marked decrease in natural gas demand and number of industrial connections between 2021 and 2022. We however assume an economic rebound, resulting in a partial negation of said decrease. The remaining GHG emission reduction to be achieved through natural gas phase out between 2023 and 2030 amounts to 26% (medium scenario), corresponding to a natural gas consumption reduction of 2 TWh/year. This is achievable through replacement of natural gas use for low temperature heating by heat pumps. The technical potential found by Technopolis and VITO (2022) is between 5 and 8 TWh. In addition, other technologies such as shallow geothermal energy, use of residual heat, solar thermal energy, etc. could also be adopted. However, these technologies are at present in general less cost effective.

To differentiate between the low, medium, and high scenarios, we make the following range of assumptions. For the **low** scenario we assume that (1) the phase out of fuel/gas oil is higher (resulting in lower need for emission reductions through natural gas phase out to achieve the policy targets); (2) economic rebound is higher (resulting in higher demand for natural gas); and (3) policy goals are achieved only for 80%. For the **high** scenario, we assume the opposite: (1) lower emission reduction contribution from phase out of fuel/gas oil; (2) lower economic rebound; and (3) overshoot of policy target (120% achieved).

#### 2.1.2.2. Assumptions for the evolution between 2030 and 2050

The policy goal of the Vlaamse Klimaatstrategie <sup>18</sup> for the ESR industry is 1.2 Mton CO<sub>2</sub>eq in 2050, a 76% decrease compared to 2005 emissions as published in the VEKP. For the **medium** scenario, we assume that all fuel/gas oil will be phased out by 2050, requiring an additional 45% decrease in emissions from natural gas as compared to 2030 to meet the policy goal. We assume that additional economic growth between 2030 and 2050 will not result in additional natural gas demand, as the Vlaamse Klimaatstrategie emphasises a central role for a circular economy, which would lead to considerable changes to the overall economic activity and industrial processes.

For the **low** scenario, we assume that the ESR industry will follow the overall trend of the ETS industry, however, at a somewhat reduced level due to for instance fewer specific measures, lack of cluster effects, etc. According to the MIX-scenario of the Deloitte report conducted for VLAIO<sup>19</sup>, the natural gas demand of the ETS industry is reduced by 60% in 2050 compared to 2030. For the ESR industry we assume 50%. Note that the resulting reductions in natural gas demand in 2050 in the low and medium scenarios are close to each other. The reason is the proportion of policy goals for 2030 and 2050. The goal for 2030 from the VEKP is on a yearly basis more ambitious than the goal for 2050.

For the **high** scenario, we assume that by 2050 all natural gas use by industry on the distribution grid will be phased out. The main challenge to achieve this is not purely technical, but requires dedicated policies, financial incentives, and information and communication with the sector.

For all scenarios we assume a linear trajectory between 2030 and 2050. This is similar to the assumptions made by Deloitte for the ETS industry in its studies for VLAIO and BBL.

#### 2.1.2.3. Assumptions regarding the evolution in the number of connections

The changes in natural gas demand are not necessarily proportional to changes in the number of connections. An industrial site, also a smaller one, can use natural gas for multiple processes or applications. Phase out of natural gas for a portion of them does not necessarily mean that the entire site can be disconnected. We therefore make the following assumptions for disconnections:

- Between now and 2030, we assume that in the medium scenario 50% of the industrial sites that phase out gas, will do so entirely, the other half only partially, thus not leading to a



<sup>&</sup>lt;sup>18</sup> <u>Vlaamse overheid (2019) Vlaamse Klimaatstrategie 2050</u>, p. 17

<sup>&</sup>lt;sup>19</sup> <u>Deloitte (2020) Naar een koolstofcirculaire enCO2-arme Vlaamse industrie.</u>

disconnection of the site. For the low and high scenarios, we assume respectively 40% and 60%.

- Between 2030 and 2050 we assume that 75% of the sites that phase out gas in the medium scenario will do so entirely. The higher assumption is based on longer adjustment times, assumed improvements in technologies and targeted policies. For the low scenario, we assume 60%, for the high scenario we assume 100%, however, a share (e.g. 10%) of the connections could remain and use biomethane.

#### 2.1.3. Assumptions regarding offtake and connections of other gas users

Developing specific assumptions for the evolution of the remaining other (mainly smaller) gas users is challenging due to limited data availability and the mixed composition of categories such as *Rest*. These groups typically comprise a mix of minor or irregular users for which no distinct trend drivers can be identified. To simplify the analysis, all remaining sectors other than *residential* (*huishoudens*), *industry* (*industrie*), and *tertiary* (*tertiaire sector*) have been grouped into a single category called "Other." For this combined category, the evolution of the gas offtake has been assumed to follow the weighted average of the three main sectors, based on their respective shares in total gas offtake. Within this category "Other", the shares are as follows: *Onbekend* (1.30%), *Energiesector* (0.02%), *Landbouw, bosbouw en visserij* (7.24%), *Rest* (16.55%), and *Transport* (0.03%). The corresponding breakdown for connections follows the same approach, with the current shares distributed as follows: *Onbekend* (2.4%), *Energiesector* (0.0%), *Landbouw, bosbouw en visserij* (0.0%), *Rest* (1.4%), and *Transport* (0.0%), while *Huishoudens* (86.6%), *Industrie* (1.2%), and *Tertiaire sector* (8.3%) make up the main groups.

#### 2.1.4. Assumptions regarding local injection of gases in the distribution grid

We have not included any injection of other gases in the scenario analysis, but we describe the potential for using the gas distribution grid to transport "alternative" gases in chapter 3.

# 2.2. Results per scenario

The three tables and figures below summarise the evolution of the number of gas connections (Table 2-1 and Figure 2-1), gas consumption (Table 2-2 and Figure 2-2), and related GHG emissions (Table 2-3) under each scenario. Each table or figure presents the results for the residential, tertiary, and industrial sectors, for the years 2030, 2040, and 2050.

Figure 2-1 presents the evolution of the number of gas connections per sector and per scenario and Table 2-1 presents the relative changes compared to 2023. Disconnections result from switch to fully electric heat pumps, district heating and demolished buildings. New connections arise primarily from heating oil to gas conversions assumed until 2040 and remain marginal. By 2050, the number of disconnected buildings compared to 2023 ranges from 34% (low scenario) to no remaining connections in the high scenario, and in the medium scenario 44% of the connections are disconnected compared to 2023.

Figure 2-1 Gas grid connections per sector and scenario in 2023, 2030, 2040 and 2050

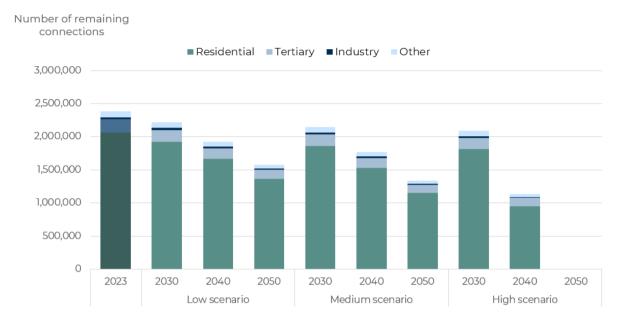


Table 2-1 Percentage change in gas grid connections/disconnections per sector and scenario in 2030, 2040 and 2050 compared to 2023

	CO	umber of nnections 2023		w scena	ario	Med	ium sce	nario	Hiç	gh scen	ario
			2030	2040	2050	2030	2040	2050	2030	2040	2050
Residential	-	2.07	-10%	-24%	-37%	-12%	-29%	-47%	-14%	-57%	-100%
Residential	+	million	3%	4%	3%	2%	4%	3%	2%	3%	0%
Tertiary	-	0.20	-8%	-20%	-32%	-11%	-26%	-41%	-15%	-37%	-100%
Tertiary	+	million	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industry	-	0.03 million	0%	-15%	-30%	-8%	-23%	-39%	-18%	-59%	-100%
Other	-	0.09 million	-7%	-19%	-34%	-10%	-26%	-44%	-13%	-52%	-100%
Total		2.39 million	<b>-7</b> %	-19%	-34%	-10%	-26%	-44%	-13%	-52%	-100%

Figure 2-2 presents the evolution of the gas offtake per sector and per scenario and Table 2-2 shows the changes in gas consumption relative to 2023. These changes reflect both the net reduction in the number of gas grid connections and efficiency gains among remaining users. The pace of gas consumption decline is faster than that of gas grid disconnections due to the installation of hybrid heat pumps, building retrofits, and sectoral energy efficiency measures. In the high scenario, natural gas use is fully phased out by 2050. In contrast, the low scenario retains approximately one-third of the 2023 gas demand by 2050.

Figure 2-2 Gas offtake per year per sector and scenario in 2023, 2030, 2040 and 2050 (TWh/year)

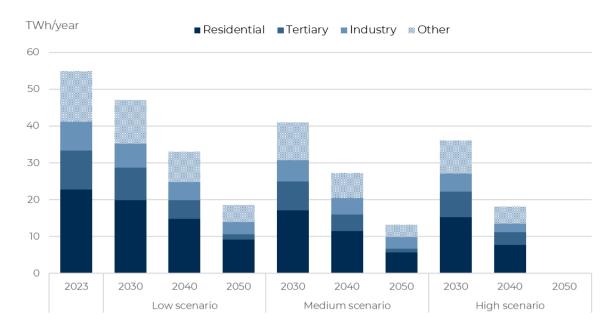


Table 2-2 Evolution in gas offtake per sector and scenario in 2030, 2040 and 2050 compared to 2023

		nsumptio in 2023	L	ow scei	nario	Med	ium sce	nario	Hig	gh scen	ario
			2030	2040	2050	2030	2040	2050	2030	2040	2050
Residential	-	22.75 TWh	-15%	-38%	-61%	-27%	-51%	-76%	-34%	-67%	-100%
Residential	+	22.75   1 1 1 1 1	3%	3%	1%	2%	2%	1%	0.9%	0.8%	0.0%
Tertiary	-	10.58 TWh	-17%	-52%	-87%	-25%	-57%	-90%	-35%	-68%	-100%
Tertiary	+	10.56 1 7711	0%	0%	0%	0%	0%	0%	0.05%	0.03%	0.00%
Industry	-	7.73 TWh	-16%	-37%	-58%	-26%	-43%	-59%	-37%	-69%	-100%
Other	-	13.79 TWh	-14%	-40%	-66%	-25%	-50%	-76%	-34%	-67%	-100%
Total		54.86 TWh	-14%	-40%	-66%	-25%	-50%	-76%	-34%	-67%	-100%

Table 2-3 presents the GHG emission reductions relative to 2005. They are driven by the above-mentioned gas demand evolutions and the phasing out of fossil gas. The residential and tertiary sectors see sharper GHG emission reductions than the industry. The high scenario achieves full decarbonisation by 2050 across all sectors.

Table 2-3 GHG emission reductions per sector and scenario in 2030, 2040 and 2050 compared to 2005

	G	HG emissions in 2005	Lov	v scena	rio	Medium	n scenar	io	High	scena	rio
			2030	2040	2050	2030	2040	2050	2030	2040	2050
Residential	-	3.82 MtCO2	-19%	-40%	-63%	-31%	-53%	-77%	-38%	-69%	-100%
Tertiary	-	1.91 MtCO2	-29%	-59%	-89%	-35%	-63%	-91%	-44%	-72%	-100%
Industry	-	1.55 MtCO2	-35%	-51%	-67%	-43%	-56%	-69%	-51%	-76%	-100%
Other	-	1.55 MtCO2	19%	-16%	-53%	4%	-31%	-66%	-8%	-54%	-100%

	G	HG emissions in 2005	Low	/ scena	rio	Medium	scenar	io	High	scena	rio
Total	-	8.82 MtCO2	-17%	-52%	-77%	-17%	-42%	- <b>67</b> %	-36%	-68%	-100%

The results presented in this section illustrate a range of possible outcomes for the evolution of gas grid connections, gas consumption, and related GHG emissions in Flanders, based on varying levels of policy ambition, ranges of behavioural changes and technological developments. The low scenario shows a gradual decline in connections and gas demand but leaves a sizeable residual gas grid and GHG emissions footprint by 2050. The medium scenario, which aligns with current policies and forecasts, results in a substantial reduction of gas use by 2050 (- 76%) and a less high decrease in number of connections (- 44%). The high scenario demonstrates the implications of a full fossil gas phase-out, with complete disconnection across all sectors by 2050. These trajectories provide a foundation for analysing future costs, tariff impacts, and infrastructure decisions in the next phases of the study.

## 2.3. Phase-out planning strategies

The scenarios estimate the potential evolution of the number of gas grid connections and offtake volumes. The phased-out connections can however be distributed in very different ways throughout the grid. Different distributions of phased-out connections have direct impact on which portions of the grid can be decommissioned, and thus on the costs of the remaining grid (e.g., maintenance and replacement costs).

This section presents three different phase-out planning strategies that have been used to estimate the evolution of costs. These strategies aim to determine how the grid length evolves over time based on the spatial pattern of disconnections, which may be systematically organised (e.g., through policies phasing out certain areas) or entirely random (e.g., unplanned disconnections of network users across different locations).

We first address the phase-out strategies for the low-pressure (LP) and medium-pressure (MP) grid. In Flanders, the operating pressure of the LP grid is up to 98 mbar, while the MP grid operates at a pressure level between 98 mbar and 14.7 bar.

#### 2.3.1. Phase-out of the low-pressure network

Phasing out the low-pressure network in practice will require a dedicated locally tailored approach. The low-pressure grid in Flanders is meshed. The degree to which it is meshed varies from location to location. The more central portions of the grid are more interconnected. They feed the more peripheral portions, which are less interconnected. In practice, a DSO can phase-out a portion of the grid if (1) it does not feed any more connected consumers, and (2) its phase-out would not impact the surrounding grid.

To develop the phase-out strategies, we adopt a probabilistic analysis assuming no coordination of phase-out of connections, and two organised phase-out strategies, with two different levels of organisation.

#### 2.3.1.1. Virtual low-pressure branches

Within the scope of this study the grid topology could not be modelled in detail. Determining the impact of phasing out a portion of the grid on the surrounding grid is therefore out of scope of this study. The present analysis focused on determining the effects of different phase-out strategies on the distribution of connections over the low-pressure grid.

To do so, we assumed a simplified model of the grid, where consumers are connected to "virtual" low-pressure branches, representing portions of the grid. Based on the key figures available for the reference year below, we assumed that an average "virtual" branch has 24 connections, 20 meters of low-pressure grid per connection:



Table 2-4 Key parameters used to assess the phase-out of the low-pressure network

Parameters	Value
Length of medium-pressure pipelines (meters)	10,137,256
Length of low-pressure pipelines (meters)	47,898,115
Number of connections to low-pressure network <sup>20</sup>	2,364,299
Number of connections to medium-pressure network <sup>21</sup>	797
Low-pressure pipeline length per connection (meters/connection)	20
Number of connections per branch	24
Length of a low-pressure branch	486
Number of low-pressure branches	98,512

The number of 24 connections per "virtual" branch is based on the analysis of the number of connections per street in the Fluvius open data<sup>22</sup>. The value 24 is the median value of connections per street. The median is used instead of an average as the distribution of the number of connections per street is highly skewed, and the median value is more representative than the average.

The results of the phase-out strategies are robust with respect to the assumed value of 24 connections per "virtual" branch. Probability of "virtual" branch disconnections with considerably lower numbers of connections (e.g., 10 or 12 per branch) remain very low. With higher number of connections per "virtual" branch the probability of phase out of portions of the grid without organisation remains negligible, and the importance of organization of phase-out only increases.

#### 2.3.1.2. Phase-out strategies

For our analysis, we define three phase-out strategies to illustrate the impact of phase-out organisation:

- 1. **Phase-out strategy 1 Random phase-out at the initiative of grid users**. This strategy assumes that the authorities do not implement any zonal planning policy for phasing out natural gas use, and that grid users disconnect on their own initiative (e.g., when switching to a heat pump).
- 2. **Phase-out strategy 2 Partially organised phase-out**. This strategy assumes that the authorities implement zonal planning policies that lead to a partially organised phase-out of natural gas use.
- 3. **Phase-out strategy 3 Strongly organised phase-out**. This strategy assumes that the authorities implement zonal planning policies that lead to a strongly organised phase-out of natural gas use per area/zone.

The strategies are built upon an analysis of the probability that all residential or tertiary network users connected to the same branch disconnect which in turn would lead to the phase-out of the concerned branch. Each individual connection has a probability p that the user will disconnect. For a branch of x connections, the probability of the phase-out of the entire branch is  $p^x$ .

The assumptions taken for each phase-out strategy are further explained below.

The phase-out strategies are simplified versions of strategies in other European countries. Studies in the UK proposed to divide the networks in sectors of approximately 2,500 consumers and disconnect those at once. This is a strategy that could be seen as an approach for a strongly organised phase-out. A number of European countries, including Germany, Switzerland and the Netherlands have adopted

— Trinomics 🦰 💳

<sup>&</sup>lt;sup>20</sup> We assume that all T1 to T4 users are connected to the low-pressure network.

 $<sup>^{21}</sup>$  We assume that only T5 and T6 users are connected to the medium-pressure network.

<sup>&</sup>lt;sup>22</sup> Fluvius, <u>Verbruiksgegevens per straat</u>, accessed online 10/07/2025

obligations for the local level (e.g. municipalities) to develop heat transition plans. The plans typically focus on providing an alternative such as district heating but could be combined with decommissioning of the gas grid. Such approaches could fit with phase-out strategy 2 or 3 and could be seen as an extension of the Local Energy and Climate Pact in Flanders. See Chapter 5 for a more detailed description of practices in Europe.

#### Phase-out strategy 1: Random phase out at the initiative of grid users, no policy

The probability of disconnection from the low-pressure grid is based on the average percentage of disconnection in the residential and tertiary sectors per scenario.

Probability of disconnection in residential and tertiary sector	Low scenario	Medium scenario	High scenario
2030	7%	10%	13%
2040	19%	26%	52%
2050	34%	44%	100%

The shares of low-pressure branches that are phased out resulting from the probability analysis are presented in the table below.

Share of low-pressure branches phased out	Low scenario	Medium scenario	High scenario
2030	0%	0%	0%
2040	0%	0%	0%
2050	0%	0%	100%

**Conclusion**: In the event of an unplanned (i.e. random) phase-out by the connected grid users, it is unlikely that low-pressure branches can be phased out until 2050 (with possibly a few exceptions).

#### Phase-out strategy 2: Partially organised phase-out

The partially organised phase-out strategy assumes that 50% of projected disconnections are random and 50% of projected disconnections are driven by policy. The probability of disconnection from the low-pressure grid resulting from this assumption is presented in the table below.

Probability of random disconnection	Low scenario	Medium scenario	High scenario
2030	4%	5%	6%
2040	10%	13%	26%
2050	17%	22%	100%

The shares of low-pressure branches that are phased out resulting from the probability analysis are presented in the table below.

Share of LD branches phased out	Low scenario	Medium scenario	High scenario
2030	3%	5%	6%
2040	9%	12%	25%
2050	16%	21%	100%



**Conclusion**: In the event of a partially planned phase-out of connections, the proportion of phased-out low-pressure branches is higher than in the case of a random phase-out. It is however considerably lower than in the case of a very strongly planned phase-out.

#### Phase-out strategy 3: Strongly organised phase-out

The partially organised phase-out strategy assumes that 10% of projected disconnections are random and 90% of projected disconnections are driven by policy. The probability of disconnection from the low-pressure grid resulting from this assumption is presented in the table below.

Probability of random disconnection	Low scenario	Medium scenario	High scenario
2030	1%	1%	1%
2040	2%	3%	5%
2050	3%	4%	100%

The shares of low-pressure branches that are phased out resulting from the probability analysis are presented in the table below.

Share of LD branches phased out	Low scenario	Medium scenario	High scenario
2030	6%	9%	11%
2040	17%	22%	45%
2050	29%	38%	100%

**Conclusion**: In the event of a very strongly planned phase-out of connections, the share of phased-out low-pressure branches is close to the share of individual disconnections in phase-out strategy 1.

In summary, the probabilistic analysis shows that it is extremely unlikely that disconnections of grid users on a **voluntary basis** (at their own initiative) will lead to a disconnection of all users connected a substantial portion of the grid (in our analysis represented by a "virtual" branch). This means that a voluntary disconnection approach would not allow to decommission or repurpose grid sections as up to 2050 some users will still be connected to each individual pipeline section in all scenarios (except the high scenario 2050 where it is assumed that in 2050 the remaining consumers would be disconnected, and the grid becomes largely obsolete). A **reduction of the grid length** before 2050 will hence only be possible if **organised phase-out plans** are developed allowing Fluvius to disconnect remaining grid users on specific grid branches, depending on predetermined criteria, e.g. x grid connections or y MWh yearly gas offtake per 1000 m grid length. If those criteria are met, the remaining users could be disconnected on a planned basis (see also chapter 5: users can be informed long enough in advance, financial stimuli can be provided, etc.). In chapter 7 we use the scenarios and phase out strategies to estimate reductions in grid length and thus associated costs.

#### 2.3.2. Phase-out of the medium-pressure grid

As the medium-pressure grid feeds the low-pressure grid, in addition to its own large consumers, it is more difficult to phase-out portions of the medium-pressure grid. We therefore assume that a major part of the medium-pressure grid will remain the same in operation up to 2050 to feed the connected low-pressure portions of the grid. With more organised phase-out strategies, we assume small portions of the medium-pressure gird (5% to 10% in phase-out strategy 2 and 3 respectively) would no longer be needed by 2050.

# 2.4. Scenarios and phase-out strategies as basis for the cost evolution analysis

The scenarios and phase-out strategies developed in this chapter are further used to determine the evolution of the main cost drivers in the future, from which the future costs for Fluvius are estimated.

The evolution of the costs of the gas DSOs in Flanders is described in Chapter 7. The next chapters focus on the possible future uses of the existing grid, and lessons learned from other European countries.

# 3. Use of Flemish gas distribution network for "alternative" gases

#### 3.1. Biomethane

#### 3.1.1. Context

Biomethane (or upgraded biogas) is produced through biomethanisation, whereby biological raw materials (e.g., manure, agricultural and garden waste) are broken down under controlled conditions through anaerobic fermentation to produce methane. The biogas produced has a methane content of 50-60% and is then purified and upgraded to a quality comparable to that of natural gas, so that it can be injected into the gas grid. The CO<sub>2</sub> released during the upgrading process can be recovered and used to accelerate the fermentation process or for other purposes (e.g., production of synthetic gas).

#### 3.1.2. Current injection of biomethane into the Flemish gas distribution network

As of 2025, Flanders has 6 operational biomethane producers, connected to the medium-pressure network of Flemish DSOs, namely Aquafin Antwerp, IOK Afvalbeheer Beerse, Bio Blue Ypres, Verko Dendermonde, Aquafin Gent<sup>23</sup> and Biogas Bree<sup>24</sup>. Collectively these facilities injected in 2024 approximately 73 GWh of biomethane. A 7<sup>th</sup> connection (Tiense Suiker) is currently being implemented. According to Fluvius, the overall injected biomethane volumes would reach 0.3 TWh in 2026.

Flanders currently has 130 to 140 fermentation plants that produce biogas.<sup>25</sup> Only a small proportion of biogas is upgraded to biomethane for injection into the gas grid, accounting for less than 1% of the gas consumption from the grid.<sup>26</sup> Most biogas is used locally for the production of green electricity and heat in CHP plants and in only a limited number of cases it is upgraded to biomethane for injection in the gas grid, or to bio-LNG or bio-CNG for transport purposes. From an economic and energy perspective, direct local use of biogas is often more appropriate than upgrading it. This is also related to regional regulation. The Flemish authorities do indeed not consider biomethane production as a priority; the Flemish Government's decision of July 8, 2022, established a phase-out path for the maximum banding factors for biogas for 2024 and 2025. Following this decision, financial support for biogas via green certificates is gradually phased out. Moreover, biomethane installations are no longer eligible for investment support granted via green calls, but they continue to be supported through a system of tradable guarantees of origin. This is in line with the vision document 'Warmteplan 2025' approved by the Flemish government in 2021.

#### 3.1.3. Potential biomethane production in Flanders

An older study by Ghent University<sup>27</sup> estimates the production potential of biomethane in Flanders based on a maximum supply of biomass waste streams at approximately 1.03 bcm (11.4 TWh). The highest potential consists of food waste streams from the agro-industry, agricultural crop residues, and manure. Manure and crop residues in particular constitute a relevant potential for biomethane

<sup>&</sup>lt;sup>27</sup> Biogas-E (2018) <u>Maximaal Productiepotentieel van Biomethaan in Vlaanderen uit Biomassarestromen</u>.



<sup>&</sup>lt;sup>23</sup> Aquafin website, Aquafin produceert groen gas uit rioolwaterzuivering, accessed online 24/09/2025.

<sup>&</sup>lt;sup>24</sup> Engie website, <u>Biogas Bree, dat als eerste in Limburg groen aardgas produceert, wordt overgenomen door ENGIE</u>, accessed online 24/09/2025.

<sup>&</sup>lt;sup>25</sup> <u>VILT (2023) Minder mest gebruikt in stagnerende biogassector</u>

<sup>&</sup>lt;sup>26</sup> <u>IEA (2024) Implementation of bioenergy in Belgium – 2024 update</u>

production, as they are currently only fermented to a limited extent but are available in large quantities.

The biomass potential in Flanders is significantly smaller than in several other European countries, both in absolute and relative terms. According to a study by the European Biogas Association<sup>28</sup>, Europe has the potential to produce approximately 111 bcm (1,221 TWh) of biomethane by 2040, of which only 0.9 bcm (10 TWh) in Belgium. Based on an estimated share of 65% for Flanders, this would translate into a potential of 0.6 bcm (6.5 TWh).

In a recent (not publicly available) study, Trinomics and VITO estimated the technical availability of suitable biomass in Belgium at 14 TWh in 2030 and 19 TWh in 2050. The latter figure is approximately six times higher than the current biogas production and represents 10-12% of total natural gas consumption in Belgium. However, the real potential is substantially lower due to the priority use of biomass for other purposes (e.g., as raw material). In addition, biomass is widely dispersed, especially in the agricultural sector, while large volumes are required to make investments in biomethane production and injection into the gas grid economically feasible. The available biomass (e.g., manure, agricultural residues) could be transported to centrally located fermentation units, but this approach would lead to higher transport costs and negative environmental impacts.

The Flemish Energy and Climate Plan does not mention a specific target for biomethane. The National Energy and Climate Plan sets a target of 1.2 TWh (0.11 bcm) of biomethane by 2030. The Netherlands, for example, is aiming for approximately 22 TWh (2 bcm).

# 3.1.4. Estimated evolution of biomethane injection in the Flemish gas distribution network

Based on the current situation and the above-mentioned potential studies, we propose to assume for the study a **limited increase in the use of the gas distribution network for biomethane, namely injection of 0.5 TWh in 2030, gradually increasing to 1 TWh in 2050**. This estimate also takes into account that part of the biomethane produced in Flanders will be injected into the Fluxys network.

The increasing injection of biomethane and gradual decline in natural gas consumption may lead to necessary investments to enable reverse flows when the biomethane injection in a particular distribution area would exceed local gas consumption, e.g. during summer months.

In addition, based on these assumptions, it can also be assessed to what extent part of the distribution network could be retained after the phase-out of natural gas as a solution to facilitate local biomethane production. This option can be compared with alternatives without biomethane injection, such as local use of biogas for CHP, or as bio-CNG or bio-LNG for transport purposes.

# 3.2. Synthetic methane

#### 3.2.1. Context

Synthetic methane, also known as e-methane or synthetic natural gas (SNG), is produced using a methanation process which combines carbon dioxide ( $CO_2$ ) with hydrogen ( $H_2$ ) to provide a synthetic gas, which has similar characteristics as natural gas and could hence be injected into the methane gas grid and used for heating, electricity generation, industrial processes and transportation. Synthetic methane could also be used as a storage option in salt caverns and in porous geological formations or in liquefied form using LNG tanks.<sup>29</sup> However, for synthetic methane to be considered as renewable, the hydrogen used for its production would have to stem from water electrolysis, using renewable electricity as input; the  $CO_2$  would have to be 'recycled  $CO_2$ ' and could be captured from industry flue gas or from air.



<sup>&</sup>lt;sup>28</sup> EBA (2024) Biogases towards 2040 and beyond

<sup>&</sup>lt;sup>29</sup> <u>IEA (2024) E-methane: a new gas for a net-zero future?</u>

The production of synthetic methane involves a complex industrial process involving high capital and operating costs, and high overall energy losses in the conversion processes. The costs highly depend on the availability and price of renewable electricity and the value of providing flexibility in the future electricity system. It is expected that the cost of renewable electricity will decrease when more renewable electricity will become available in the system, while the value of flexibility will increase.<sup>30</sup> Furthermore, the production costs of synthetic methane depend on the number of operating hours as well as the CAPEX and OPEX of electrolysers and methanation plants, their efficiency and the costs of capturing CO2.31 Hence, estimating the production costs of e-methane is challenging. Current estimates suggest that producing e-methane is quite expensive, ranging from €150/MWh to €600/MWh.<sup>32</sup> In comparison, the cost of biomethane ranged from €50/MWh to €110/MWh in 2022 depending on feedstock, technology used and scale of the plant<sup>33</sup>, while the wholesale price of natural gas in 2024 was around €35/MWh.<sup>34</sup> However, some sources foresee that the costs of e-methane may decrease over the coming years due the downward trend of renewable electricity prices and decreasing electrolyser CAPEX.<sup>35</sup> Specifically, models show that the production costs of e-methane will range from €50/MWh to €200/MWh in 2030 and from €30/MWh to €150/MWh in 2050, depending on electricity prices, full-load hours of electrolysis and methanation units, and capital expenditures.36

According to the white paper 'Mapping e-methane plants and technologies' released in September 2024, there were in 2024 in Europe 35 operational plants, 33 of which produce fully renewable gas. The synthetic methane production capacity in Europe has increased to about 450 GWh per year. Projections indicate that by 2027, this capacity could nearly reach 3,000 GWh per year. Finland, Germany, and Denmark are pioneering this rollout.<sup>37</sup>

#### 3.2.2. Potential production of synthetic methane in Flanders

The potential production of synthetic methane is mainly determined by the availability and costs of suitable technologies and renewable electricity.

Regarding the technologies, water electrolysis and methanation are well-established processes. Carbon capture at the stack of an industrial plant is also a well-established process. In the long run, direct air capture (DAC) and carbon capture at the stack of bioenergy production plants are more relevant options.<sup>38</sup> Renewable electricity technologies are mature, with the efficiency of some technologies expected to further increase in the future. Hence, all technological processes that are required to produce synthetic methane can be considered as (near) mature.

The availability and cost of renewable electricity are, however, more critical factors. The current and expected renewable electricity production in Flanders/Belgium is insufficient to cover the total electricity demand. In 2023, only 23% of the electricity consumed in Flanders was produced by renewable energy sources.<sup>39</sup> If 'excessive' renewable electricity production would become available, it could be used to produce renewable hydrogen, but direct use of hydrogen (e.g. as feedstock in industrial processes) is from an economic and energy efficiency perspective much more appropriate than converting it into synthetic methane. This is exemplified by the scrap of the Belgian green



<sup>&</sup>lt;sup>30</sup> EBA (2024) Mapping e-methane plants and technologies

<sup>&</sup>lt;sup>31</sup> EBA (2024) Mapping e-methane plants and technologies

<sup>32 &</sup>lt;u>IEA (2024) E-methane: a new gas for a net-zero future?</u>

<sup>&</sup>lt;sup>33</sup> Gas for climate (n.d.) Biomethane

<sup>34 &</sup>lt;u>European Commission (n.d.) Gas and electricity market reports</u>

<sup>35</sup> TES-H2 (2024) e-NG's role for net-zero future

<sup>&</sup>lt;sup>36</sup> <u>Corre et al. (2019) Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage</u>

<sup>&</sup>lt;sup>37</sup> EBA (2024) Mapping e-methane plants and technologies

<sup>&</sup>lt;sup>38</sup>Tregambi et al. (2023) Techno-economic assessment of a synthetic methane production process by hydrogenation of carbon dioxide from direct air capture

<sup>&</sup>lt;sup>39</sup> Statistiek Vlaanderen (n.d.) <u>Renewable energy</u>.

hydrogen-to-synthetic methane project (developed by Engie) due to concerns about the slow development of the European hydrogen market and the project's economic viability.<sup>40</sup>

Synthetic methane can also be produced through pyrogasification of solid waste or hydrogenation of liquid waste. Pyrogasification would enable to gasify solid waste that is currently not used in other processes, such as wood residues, waste furnishing components, plastics or solid recovered fuels. This technology is still under development. Hydrothermal gasification is another emerging technology to produce synthetic methane from liquid wet waste and biomass, such as sewage sludge or digestate from methanization plants that cannot be spread on land. Once the mineral component of the waste has been extracted, the remaining water and organic matter are converted into synthetic methane.<sup>41</sup>

Overall, the availability in Flanders of suitable waste and biomass for conversion to gas is very limited and will in principle not increase, also due to the priority for recycling and using this feedstock in other processes, where it can provide higher added value.

#### 3.2.3. Estimated injection of synthetic methane in Flemish gas distribution network

As the production potential of synthetic methane in Flanders is limited and due to the drawbacks of this option from an economic and energy perspective, it is highly uncertain that small or medium-scale production plants will in 2030-2050 be developed for injection into the gas distribution grid. The development of large-scale production plants for synthetic methane as well as the possible import of synthetic methane are also quite unlikely; both would also relate to injection into the TSO network. We hence do not deem it useful to specifically further consider this option in the study.

## 3.3. Hydrogen blending in distribution gas networks

#### 3.3.1. Context

According to the technical characteristics of the current methane infrastructure, hydrogen could be injected into the gas grid up to about 5-10% volume, without the need for major modifications to network infrastructure and end-consumer installations. In principle, the blending threshold could be increased to 15-20% volume, after making the necessary changes to the infrastructure and affected consumer installations. <sup>42</sup> Blending is to some extent facilitated in the EU legislation: blending levels up to 2% hydrogen volume into natural gas flows must be accepted and facilitated at cross-border points (Article 21, Gas Regulation) <sup>43</sup>. However, in the preamble (74) of the Regulation, it is noted that hydrogen blending should be considered a 'last resort' use case, reflecting its scarcity and therefore the importance of using it in a targeted way.

#### 3.3.2. Potential production of renewable or low-carbon hydrogen in Flanders

Renewable hydrogen can be produced via water electrolysis, which has become a well-established process, while low-carbon hydrogen can be produced from steam methane reforming (SMR) with carbon capture and storage or by methane pyrolysis.

The potential production of **renewable hydrogen** is mainly determined by the cost of electrolysers and the availability and cost of renewable electricity. The implementation of this technology at large scale is not mainly hindered by technical barriers, but rather by economic aspects (lack of competitiveness compared to grey hydrogen). Specifically, Belgium had one of the lowest grey hydrogen production costs in Europe in 2023, amounting to €3.2/kg, while the estimated production

<sup>&</sup>lt;sup>43</sup> Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen.



19

<sup>&</sup>lt;sup>40</sup> <u>Hydrogen Insight (n.d.) Engie scraps Belgian green hydrogen-to-synthetic methane project amid doubts about viability</u>

<sup>&</sup>lt;sup>41</sup> <u>Green Gas: Key for the energy transition</u>

<sup>&</sup>lt;sup>42</sup> Kanellopoulos, K., Busch, S., De Felice, M., Giaccaria, S. and Costescu, A., Blending hydrogen from electrolysis into the European gas grid, EUR 30951 EN, Publications Office of the European Union, Luxembourg, 2022, ISBN 978-92-76-46346-7, doi:10.2760/908387, JRC126763.

cost of green hydrogen was reported to be €8.4/kg, almost three times higher.<sup>44</sup> In Flanders, the availability and cost of renewable electricity are specifically critical factors. The current and expected renewable electricity production in Flanders/Belgium is insufficient to cover total electricity demand (23% in 2023<sup>45</sup>). If 'excess' renewable electricity production became available, it could be used to produce renewable hydrogen, but direct use of the produced hydrogen (e.g. as feedstock in industrial processes) is from an economic and energy efficiency perspective much more appropriate than blending it with natural gas into the network. A recent study shows that blending 20% (which is the maximum blending volume % that can be safely burned in gas boilers) of green hydrogen into Europe's gas distribution networks would increase the costs for consumers by up to 43%, while it would reduce the GHG emissions by only 6-7%. Therefore, hydrogen blending is in general not recommended and it is considered more adequate to transport hydrogen via dedicated pipelines for use in applications that cannot be substituted by electricity.<sup>46</sup> In addition, blending levels above lower threshold would require adjustments to both grid equipment and end-user applications with every change in the blending ratio, making blending a very costly (non-economic) option. Blending of hydrogen and natural gas is therefore generally not further looked at as an option in the decarbonisation plans of other EU countries and gas network operators across Europe, who favour the operation of separate methane and hydrogen network infrastructure.

**Low-carbon hydrogen** can be produced by cracking methane in SMR plants with CCS or in pyrolysis processes. Although low-carbon hydrogen could be considered as a bridging technology to facilitate rapid renewable hydrogen market ramp-up, it is in general not supported by regulation and support schemes in the EU, mainly due to the fact that it still requires fossil fuels. The production of hydrogen by using SMR with CCS is hindered by its high cost but and by the limited availability of suitable CO2 transport and long-term storage infrastructure. Next to producing low-carbon hydrogen in SMR installations, it can also be produced through pyrolysis, where methane is heated at high temperatures to break it down into hydrogen and solid carbon. This carbon can take various forms, including carbon black and graphite, which are chemical commodities, which can be used for different applications including as steel additive, filler for car tyres, graphite, dye and soil improver. CH<sub>4</sub> pyrolysis has been extensively studied and demonstrated via a variety of different experimental reactor setups. According to experts, this technology can become commercially viable within 5 to 10 years and could to some extent replace the current SMR methods of producing hydrogen.<sup>47</sup> 48

#### 3.3.3. Estimated injection of hydrogen in Flemish gas distribution network

As the production potential of renewable and low-carbon hydrogen in Flanders is limited and due to the drawbacks of blending hydrogen into the gas network from an economic and energy perspective, it is highly uncertain that small or medium-scale production plants will in 2030-2050 be developed for injection (blending) into the gas distribution grid. While the development of larger-scale production plants is more likely, such plants would be connected to a dedicated hydrogen network rather than be used for blending in the methane network. Possible imports of renewable or low-carbon hydrogen would also be injected into a dedicated hydrogen grid, and not in TSO or DSO methane grids. Due to the important drawbacks of the blending option, it is unlikely that market actors in Flanders will opt for it and that Flemish authorities will support it. We hence do not deem it useful to specifically further consider this option in the study.

🔻 Trinomics 🥷 🗕

20

<sup>44</sup> European Hydrogen Observatory (n.d.) Cost of hydrogen production

<sup>&</sup>lt;sup>45</sup> Statistiek Vlaanderen (n.d.) <u>Renewable energy</u>.

<sup>&</sup>lt;sup>46</sup> Fraunhofer IEE (2022) The limitations of hydrogen blending in the European gas grid

<sup>&</sup>lt;sup>47</sup> Methane pyrolysis: hydrogen without CO2 emissions | TNO

<sup>&</sup>lt;sup>48</sup> International Journal of Hydrogen Energy Volume 157,12 August 2025, Hydrogen production by microwave plasma CH4 pyrolysis: Characterization via optical emission spectroscopy and response surface methodology - ScienceDirect

# 4. Options for repurposing the Flemish gas distribution grid

This section presents a technical feasibility assessment of repurposing the Flemish gas distribution network for other uses. We identify and evaluate the potential impacts, technical challenges, and key requirements associated with converting existing gas network infrastructure under different use cases. The section also includes the identification of components or assets that would require modification, along with an outline of the specific needs for the following cases:

- Dedicated hydrogen use
- CO<sub>2</sub> transport
- Water distribution
- Use as a "collector" for communication or electricity cables

From an economic perspective, a comparative analysis of the relative costs of the required modifications is provided for the considered use cases.

The results are summarised in a matrix that highlights the suitability of different pipeline materials for each use case. In addition, we provide an indication of which parts of the gas distribution network in the Flemish region could potentially be repurposed, along with a high-level overview of the modifications needed to adapt the infrastructure for these alternative applications.

## 4.1. Hydrogen

The repurposing of transmission gas pipelines for dedicated hydrogen use has been widely studied at both EU and national levels, with implementation already underway or planned in several European countries.<sup>49</sup> However, due to the relatively low potential hydrogen demand at the low-pressure distribution level (e.g., for residential and small commercial buildings), this option has received comparatively less attention.

While both hydrogen (H<sub>2</sub>) and methane (CH<sub>4</sub>) are colourless and odourless gases under standard conditions, their distinct physical and chemical properties present significant challenges for adapting existing natural gas infrastructure for hydrogen use. These differences also give rise to concerns related to safety, efficiency, environmental impact, and costs. Although various mitigation measures are available, they often bring additional technical and operational complexities.<sup>50</sup>

The European Commission's hydrogen strategy highlights the potential future need for long-distance hydrogen transport across Europe. To transport hydrogen from supply sources (domestic production and import) to demand centres, two primary solutions are being considered: building new hydrogen pipelines or repurposing existing natural gas infrastructure for hydrogen transport.<sup>51</sup>

To assess these options, the European Union Agency for the Cooperation of Energy Regulators (ACER) reviewed more than 20 studies focused on the technical feasibility and cost-effectiveness of converting current gas transmission pipelines to carry pure hydrogen. The following is a summary of the key insights from this study:

<sup>&</sup>lt;sup>51</sup> ACER (2021) <u>Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing.</u>



<sup>&</sup>lt;sup>49</sup> See also DNV Whitepaper (2023) <u>Repurposing onshore pipelines for hydrogen: Guiding operators through the re-evaluation process</u>.

<sup>&</sup>lt;sup>50</sup> Paul Martin, I. B.-E. (2024) A review of challenges with using the natural gas system. SCI(DOI: 10.1002/ese3.1861).

- Repurposing existing infrastructure is technically feasible and generally more costeffective than constructing entirely new hydrogen networks.
- The future shape of hydrogen infrastructure may vary. Some projections envision a large, pan-European transmission system, primarily based on repurposed gas pipelines, while others point toward more regional or localized networks where hydrogen is produced and consumed in proximity. A few studies suggest that, given current expectations around industrial demand, technology, and cost, a continent-wide hydrogen grid may not be fully justified.

One practical example is GTS (Gasunie) in the Netherlands, which currently operates two parallel natural gas networks. The company plans to convert one of these into a dedicated hydrogen backbone by 2030, linking potential hydrogen production and import hubs with major industrial consumers<sup>52</sup>.

Several projects are currently demonstrating the use of a 100% hydrogen gas within the UK gas grid, with larger-scale trials planned under the UK Government's Hydrogen Strategy. As part of the Hy4Heat innovation program, two semi-detached houses have been constructed and are being supplied entirely with hydrogen. The UK hydrogen strategy had set out a number of key milestones. One of these was to convert an existing natural gas distribution network to hydrogen. This would have seen a village of circa 2000 homes and businesses receiving low carbon hydrogen for heating, hot water and industrial processes. However, in 2024 the UK government made a decision to not progress, with the preference to wait until the strategic policy decision on using hydrogen for heat is made in 2026<sup>53</sup>. Examples of hydrogen transmission and distribution projects in the UK include the following <sup>54</sup>:

#### Distribution

- East Coast Hydrogen: Project led by NGN, Cadent, and NGG to build off Project Union to provide a hydrogen delivery network connecting producers to end-users in northeast England.
- Cadent, HyNet: Project to construct and operate an onshore pipeline transporting hydrogen from CCUS-enabled production in northwest England to end users.

#### **Transmission**

National Gas Transmission, Project Union: Proposed hydrogen national transmission system, or hydrogen "backbone", repurposing around 25% of current gas transmission pipelines.

#### Materials' Compatibility with Hydrogen

Because of hydrogen's distinct physical properties compared to natural gas, components originally designed for natural gas service may not be inherently suitable for hydrogen applications. A material is considered compatible with hydrogen if it can operate reliably under service conditions without being negatively impacted by exposure to dry hydrogen gas.

Introducing hydrogen into infrastructure initially built for natural gas exposes system components directly to hydrogen, which can lead to absorption by certain materials. This absorption can trigger degradation processes collectively referred to as Hydrogen Embrittlement (HE). According to ASME B31.12:2023, hydrogen embrittlement is defined as a loss of metal ductility due to hydrogen uptake, which can reduce material performance by decreasing elongation, fracture toughness, and increasing susceptibility to fatigue<sup>55</sup>. The risk of embrittlement depends on factors such as material strength and hydrogen partial pressure.

– Trinomics 🦰 💳

22

<sup>&</sup>lt;sup>52</sup> Roland Berger (2024) <u>Making the Hydrogen Market: Requirements for the Netherlands to become a hydrogen</u>

<sup>&</sup>lt;sup>53</sup> UK Department of Energy and Net Zero (2024) <u>Hydrogen Strategy Update to the Market: December 2024</u>

<sup>&</sup>lt;sup>54</sup> HM Government [Government of the United Kingdom] (2024) <u>Hydrogen Net Zero Investment Roadmap</u>.

<sup>55</sup> ASME Standard B31.12-2023: Hydrogen Piping and Pipelines.

Exposure to hydrogen may alter the material's behaviour in several ways, including reduced fracture resistance, crack formation in metals, and swelling in polymers. It can also exacerbate existing material defects. Therefore, understanding how hydrogen interacts with different materials is critical before repurposing existing infrastructure for hydrogen use.

Key variables influencing HE include applied stress, hydrogen pressure, temperature, and loading cycle frequency. To assess material resistance to hydrogen embrittlement, various testing methods, outlined in ISO 11114-4, are available. These include fracture mechanics-based tests, tensile testing, and tests using disk-shaped specimens<sup>56</sup>.

To address the vulnerability of carbon steel to hydrogen degradation, ASME B31.12:2023 introduces limits on the hardness and strength of both the base material and welds. Specifically, line pipe intended for hydrogen service should have a maximum hardness of 250 HV10, and the tensile strength of both the pipe and welds must not exceed 690 N/mm<sup>2</sup>.

Historically, higher-grade carbon steels have been avoided due to their perceived increased susceptibility to hydrogen embrittlement. However, steel grade alone is not always a reliable indicator of actual material strength or behaviour. The key concern with hydrogen embrittlement in pipeline steel is the reduction in fracture toughness and the acceleration of fatigue crack growth rates (FCGR).

These considerations may necessitate re-evaluation of design parameters, including maximum allowable operating pressures, minimum detectable flaw sizes, and the criteria for selecting suitable piping materials. To guide such evaluations, ASME B31.12:2023 outlines two fracture control methodologies:

- Option A is a prescriptive approach, specifying allowable material performance parameters and setting strict limits on yield and tensile strengths for both pipes and welds.
- Option B is performance-based, allowing the use of higher-strength materials without fixed performance factors, provided the design is qualified in accordance with Article KD-10 of ASME BPVC Section VIII, Division 3. This qualification requires determining the threshold stress intensity factor for hydrogen-assisted cracking (KIH), using the procedures outlined in KD-1040 and based on ASTM E1681.

Understanding how hydrogen permeates metals versus polymers is crucial. In metals, molecular hydrogen cannot pass through directly; it must first break down into atomic hydrogen before diffusing through the metal. Polymers, on the other hand, allow molecular hydrogen to pass in its original form, enabling easier permeation.

Hydrogen moves more easily through polymers than natural gas does. This behaviour is primarily influenced by two thermodynamic properties:

- Diffusivity the speed at which hydrogen travels through a material.
- Solubility the material's capacity to absorb hydrogen.

Several factors affect how permeable a polymer is to hydrogen, including its type, grade, formulation, crystallinity, and manufacturing process. Higher crystallinity and density typically result in lower hydrogen permeability. Therefore, assessing a polymer's structure and how it's made is important.

Several field and pilot trials at distribution pressures have demonstrated the durability of PE 80 and PE 100 pipes under hydrogen exposure. However, failures in the PE network are almost linked to joints,

Trinomics 🦰 💳

.

<sup>&</sup>lt;sup>56</sup> ISO Standard 1114-4:2017 Transportable gas cylinders — Compatibility of cylinder and valve materials with gas contents — Part 4: Test methods for selecting steels resistant to hydrogen embrittlement.

with the majority resulting from defective jointing procedures on site and the leakage paths in these defects are significantly larger than the size of hydrogen molecules<sup>57</sup>.

Elastomers, in particular, are complex materials containing additives such as fillers and plasticizers that significantly impact their permeability. Because different manufacturers use distinct formulations and processes, elastomers with the same listed specifications can vary in performance across brands and even production batches.

In general, elastomers are compatible with hydrogen, though materials like Viton require additional evaluation, as noted in ISO/TR 15916<sup>58</sup>. Compared to natural gas, hydrogen permeates polymers more readily, potentially accelerating degradation mechanisms such as swelling, rapid gas decompression (RGD), and chemical incompatibility.

However, these effects are often dependent on specific conditions. For instance, RGD typically becomes an issue only when elastomers experience sudden drops in pressure. Problems like fatigue, abrasion, and wear usually occur under dynamic or cyclic conditions, which don't apply to most elastomeric seals in static environments. Still, it is vital to evaluate the potential impact of hydrogen exposure on sealing performance, as changes from swelling, chemical reactions, or ageing could compromise functionality, even without outright material failure.

A general guideline of the compatibility of different materials in hydrogen services in accordance with ISO TR 15961 and ASME B31.12: 2023 is specified in the table below. A material should be evaluated carefully before it is used for hydrogen service, and it should in general not be used unless data are available to show that the material is suitable for the intended service conditions.

Table 4-1 Materials' compatibility for Gaseous Hydrogen services

Material	Code/Standar	d	Remarks
METALS	ISO/TR 15916	ASME B31.12	
Aluminium and its alloys	Acceptable	Acceptable	Negligibly susceptible to hydrogen embrittlement.
Copper and its alloys (such as brass, bronze and copper-nickel)	Acceptable	Acceptable	Negligibly susceptible to hydrogen embrittlement.
Iron, cast, grey, ductile	Not Acceptable	Not Acceptable	Not permitted by relevant regulations and standards.
Nickel and its alloys (such as Inconel and Monel)	Evaluation needed	Not Acceptable	Evaluation needed. Susceptible to hydrogen embrittlement.
Steel, austenitic stainless with > 7 % nickel (such as 310 and 316)	Evaluation needed	Acceptable	May make martensitic conversion if stressed above yield point at low temperature.
Carbon Steel	Evaluation needed	Acceptable	Evaluation needed. Susceptible to hydrogen embrittlement.

<sup>&</sup>lt;sup>57</sup> H Iskov and S Kneck Using the Natural Gas Network for Transporting hydrogen - Ten Years of Experience' IGRC Rio 2017, IBP1057\_17.



<sup>&</sup>lt;sup>58</sup> ISO/TR Standard 15916: 2015 - Basic considerations for the safety of hydrogen systems.

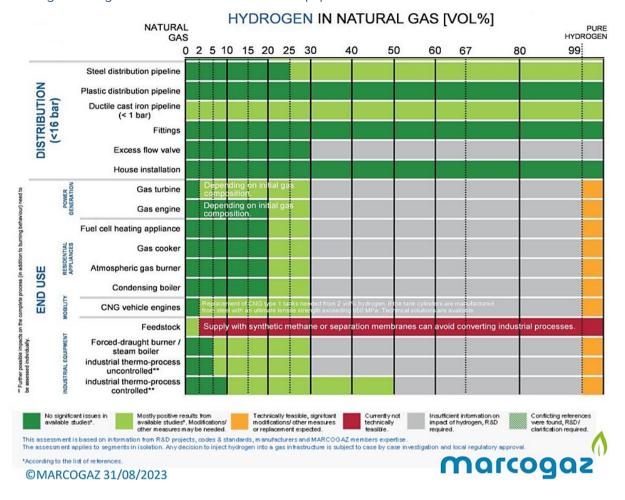
Low Alloy Steel	Evaluation needed	Acceptable	Evaluation needed. Susceptible to hydrogen embrittlement.
Martensitic Stainless Steel	Evaluation needed	Not Acceptable	Evaluation needed. Susceptible to hydrogen embrittlement.
Steel, nickel (such as 2,25; 3,5; 5 and 9 % Ni)	Evaluation needed	Not Acceptable	Ductility lost at liquid hydrogen temperature.
Titanium and its alloys	Evaluation needed	Acceptable	Evaluation needed. Susceptible to hydrogen embrittlement.
NON-METALS	ISO/TR 15916	ISO 11114-2	
Asbestos impregnated with	Acceptable	Compatibility	Avoid use because of
Polytetrafluoroethylene (PTFE)		risk	carcinogenic hazard.
	Acceptable	risk Compatible	carcinogenic hazard.
(PTFE) Chloroprene rubber	Acceptable Acceptable		- Acceptable by NASA
(PTFE)  Chloroprene rubber (Polychloroprene)			-
(PTFE)  Chloroprene rubber (Polychloroprene)  Polyester fibre (Dacron)	Acceptable  Evaluation		- Acceptable by NASA

The information about material compatibility in this report is based on published academic research and previous work by DNV, especially the H21 project<sup>59</sup>. The H21 project is a series of initiatives within the gas industry aimed at demonstrating that methane gas networks can safely transport 100% hydrogen in the future. It specifically investigated how materials and assets in the gas network can be compatible and operate effectively with pure hydrogen.

The following figure presents an overview of available test results and regulatory limits for hydrogen admission into the existing natural gas infrastructure and end use equipment as published by Marcogaz.

<sup>&</sup>lt;sup>59</sup> Energy Networks Association (2021) <u>H21 overview</u>

Figure 4-1 An overview of available test results and regulatory limits for hydrogen admission into the existing natural gas infrastructure and end use equipment<sup>60</sup>.



#### 4.1.2. Main Challenges in Converting Gas Networks to Hydrogen Service

The most critical concern in hydrogen services is its potential adverse impact on materials. In pipeline steel, the absorption of hydrogen reduces ductility, especially in areas with stress concentrations, making the material more prone to crack initiation and growth under both static and cyclic loading. Pipeline systems often experience cyclic stress due to pressure variations and operational shutdowns, which can significantly shorten fatigue life, particularly in low-cycle fatigue conditions.

Another challenge relates to capacity and energy efficiency. Since hydrogen has only about one-third the energy density by volume compared to natural gas, its volumetric flow rate would need to triple to deliver the same energy. This means compressors would have to operate much harder, using at least three times more energy.

There is also an issue with valves and meters used in hydrogen service. These components should be studied to ensure they function properly with hydrogen. Leakage is most likely at connection points between parts, especially at valves. Large pipelines often have ball valves every 32–48 km for maintenance, leak detection, or emergencies. However, hydrogen's small molecules might prevent

Trinomics -

<sup>&</sup>lt;sup>60</sup> Marcogaz (2023) <u>Overview of available test results\* and regulatory limits for hydrogen admission into existing natural gas infrastructure and end use.</u>

these valves from sealing effectively, which could impair their performance. As a result, research recommends significant modifications to valves when adapting them for hydrogen use<sup>61</sup>.

Metering stations at the pipeline's entry and exit points are crucial for tracking gas volumes and helping operators manage the system efficiently. Currently, these meters are calibrated for natural gas based on volumetric flow and energy content. Since hydrogen has different physical properties, these meters need to be recalibrated for accurate energy measurement. Most existing gas meters would require major upgrades or replacements. They need to handle about three times the volumetric flow rate of natural gas to deliver the same energy, and many common types, like diaphragm meters with large polymer or elastomer parts, tend to underestimate flow rates when measuring hydrogen-rich gases.

Additionally, the Department for Energy Security and Net Zero (DESNZ) commissioned Verian (formerly Kantar Public) to research barriers in planning hydrogen projects in the UK. The main obstacles identified include:

- A lack of resources in local authority planning departments and statutory consultees, which was seen as the biggest barrier and a priority for the UK Government to address.
- Limited experience with hydrogen among local authorities, statutory bodies, and developers.
- Public attitudes and opposition to hydrogen development.
- A shortage of published guidance for hydrogen planning.
- Challenges related to planning thresholds and regulations.
- A lack of flexibility in the planning process.
- Inconsistencies across different UK nations<sup>62</sup>.

The following table summarizes the main challenges in converting the Flemish natural gas grid for dedicated hydrogen use. It should be noted that for the materials' compatibility analysis, the study team based its assumptions on the types of materials likely to be present in the Gas Distribution Network, drawing on its industry experience.

Table 4-2 Main technical challenges in converting the Flemish natural gas grid for dedicated hydrogen

Pipelines	Material Compatibility in dedicated hydrogen use
Steel	Acceptable assuming low strength steels (<690 N mm <sup>-2</sup> ) are available. CS is susceptible to HE. Dependent on material strength and application. Facture toughness and fatigue crack rate could be impacted. However, distribution networks are generally made of relatively low strength steels. High strength steels are available in transmission networks operating at higher pressures.
PE	Compatible assuming there is no legacy grades (pre 1980s) PE in the network. Field trial evidence shows suitability of PE in hydrogen. Most PE pipelines operate at pressures significantly below their MAOP. Permeation is higher for hydrogen than for natural gas.
PVC	Compatible assuming there is no legacy grades (pre 1980s) PVC in the network. Leakage rates are like PE.

Trinomics 🦰 🗕

-

<sup>&</sup>lt;sup>61</sup> Kornel Telessy, L. B. (2024) Repurposing natural gas pipelines for hydrogen: Limits and options from a case study in Germany. International Journal of Hydrogen Energy.

<sup>&</sup>lt;sup>62</sup> Department for Energy Security and Net Zero (2023) <u>Hydrogen Projects: planning barriers and solutions</u>.

Cast Iron	Prohibited As per ASME B31.12, using Irons including Cast, Ductile, and Malleable due to their lack of ductility and their sensitivity to thermal and mechanical shock are prohibited in hydrogen.
Fiber Cement	Fiber cement is generally considered compatible with hydrogen based on available studies. However, the compatibility can depend on the jointing method used.
Valves and Meters	Material Compatibility issues in dedicated hydrogen use
Carbon Steel	Susceptible Valves with bodies, connectors, or discs made from cast carbon steel carry a risk of hydrogen embrittlement (HE), as carbon steel is inherently susceptible to HE and cast components may contain fabrication-related defects.
Cast Iron	Prohibited by ASME B31.12
Stainless Steel- Austenitic	Compatible Generally, austenitic stainless steels are not susceptible to hydrogen embrittlement. Austenitic stainless steels are currently used for hydrogen services.
Stainless Steel- Ferritic/ Martensitic	Susceptible to hydrogen embrittlement dependent on microstructure and heat treatment.
Stainless Steel- Precipitation hardening	Susceptible Valves and regulators frequently contain high strength low alloy steels used for components such as valve stems and springs, and potentially subject to Hydrogen Embrittlement (HE). There is limited test data on the compatibility of spring steels with hydrogen.
Copper	Acceptable Copper can be present in auxiliary pipework on distribution governors. There is limited literature on the mechanical performance of copper and copper alloys in the presence of hydrogen. Copper and its alloys (such as brass, bronze and copper-nickel alloys) are considered suitable in ISO 15916.
Aluminium and Aluminium Alloys	Acceptable There may be limited aluminium in the existing networks. For example, aluminium can be used in meters. ISO 15916 advises that aluminium alloys have a low susceptibility to hydrogen embrittlement and are considered suitable for hydrogen service.
Brass	Acceptable ASME B31.12 states that brass alloys are highly resistant to hydrogen embrittlement in dry gas. IGEM/H/I states that brasses with lead contents of ≤2% are hydrogen compatible. Some leaded brass may be present in fittings downstream of the meter, however the majority of leaded brass has a lead content <2% as the high strength induced by higher lead contents is not required in this application.
Non-metallic materials	Material Compatibility issues in dedicated hydrogen use
Elastomers (Diaphragm, O- Ring, and Seals)	Elastomers are commonly used in seals in valves etc. Higher permeability of smaller molecule hydrogen in polymeric materials compared to natural gas. Non-metallic materials such as NBR, FKM, and Nylon are identified to be

	acceptable for hydrogen service based on ISO 11114-2 and ISO 15916. However, their ability to mitigate leaks and maintain sealing effectiveness in hydrogen service must be confirmed with the OEMs. ISO 15916 and ISO11114-2 and H/I consider most elastomers compatible with hydrogen.
Sealants	There are a wide range of sealants and repair materials that can be used in the gas networks. Sealants are used in threaded joints and other leak repairs including sealing joint gaps, pipe joint repairs. Sealants based on epoxy are compatible with hydrogen based on its applications in underground storage and hydrogen tanks. ISO 11114-2 states polyurethane and polyacrylate sealants are compatible with hydrogen.
Regulators and Meters	Functionality issues in dedicated hydrogen use
Regulators	Hydrogen has only about one-third the energy density by volume of natural gas. This requires an increase in the gas volumetric flowrate to compensate for hydrogen's lower heating value compared to natural gas, which, in turn, increases the gas velocity through the pressure regulators and other components within the stations.
Meters	This requires an increase in the gas volumetric flowrate to compensate for hydrogen's lower heating value compared to natural gas, which, in turn, increases the gas velocity through the meters. The meters are designed for natural gas flow.

#### 4.1.3. Requirements for Converting to Dedicated Hydrogen Use

Hydrogen possesses different characteristics from pure natural gas, including a Lower Flammability Limit (LFL), which leads to increased volumetric leak rates and a higher likelihood of ignition. This necessitates extra safety measures, such as controlled venting and purging, to prevent risks like autoignition and detonation when mixed with air. It also requires thorough training for personnel involved in the handling, maintenance, and inspection of related infrastructure. A key distinction is the potential for hydrogen to degrade material properties. As a result, all materials and equipment must be verified as compatible with hydrogen under the specified operating conditions throughout their intended service life<sup>63</sup>.

Additionally, introducing hydrogen may impact the pipeline's transport capacity and alter loading conditions. Therefore, a flow analysis must be conducted using suitable modelling tools to assess the viable transport capacity and evaluate pressure and temperature profiles along the pipeline. This analysis will inform the operational adjustments needed and predict pipeline performance after requalification.

There are two major safety considerations that must be considered to determine the asset suitability of natural gas Grid for Hydrogen gas service, which are:

- 1. Asset integrity maintaining the pressure envelope of the system to prevent the release of gas.
- 2. Functionality continuing to deliver the intended engineering safety function of that asset.

Another important requirement is considering the regulatory framework for hydrogen distribution. For example, in the UK, the Energy Act 2023 (the "Act") introduced key measures to support the development of the hydrogen economy, including the establishment of a regulatory framework. The Act amends the Gas Act 1986 to explicitly include the licensing of pipelines for hydrogen transport.

Trinomics <

29

<sup>&</sup>lt;sup>63</sup> DNV (2023) <u>Service Specification for Re-qualification of pipeline systems for transport of hydrogen and carbon dioxide</u>, DNV-SE-0657.

Developers of hydrogen pipelines will now require gas transporter licences for the transmission and distribution of hydrogen, while those involved in the supply of hydrogen will need a gas shipper licence.

Although current natural gas pipelines might be able to transport 100% hydrogen, various elements of the natural gas infrastructure need to be modified for this purpose. The following table outlines the main requirements and adjustments needed to adapt the Flemish natural gas grid for dedicated hydrogen use.

Table 4-3 Key requirements for converting existing gas infrastructure

Pipelines	Key requirements for converting existing gas infrastructure
Steel	Examples of steels that have been proven for hydrogen gas service are conventional ASTM A 106 Grade B, ASTM A 53 Grade B, and API 5L Grades X42 and X52 (PSL2 grades preferred), as well as micro alloyed API 5L Grade X52.  For high strength grades, one approach is to limit the hoop stress at normal
	operating pressure to less than 30% or 40% of the minimum specified yield strength of the alloy.
DE	For applications where stresses are high, a fitness-for-service assessment will therefore be needed.
PE	May need to perform further asset assessment.  Several field and pilot trials at distribution pressures have
	demonstrated the durability of PE 80 and PE 100 pipes under
	hydrogen exposure. However, failures in the PE network are almost linked to joints, with the majority resulting from
	defective jointing procedures on site and the leakage paths in these defects are significantly larger than the size of hydrogen molecules. Additionally, hydrogen permeates PE at a rate approximately 2 to 4 times higher than natural gas.
PVC	As with other brittle legacy grades (pre 1980s) materials, PVC needs management for example 'Find and replace' This is true regardless of the gas it carries.
Cast Iron	Should be replaced, highly susceptible to HE.
Fiber Cement	Fiber cement is generally considered compatible with
	hydrogen based on available studies. However, the
	compatibility can depend on the jointing method used.
	Asbestos cement pipe is joined with either cast iron joints with rubber sealing rings or asbestos cement couplings with
	rubber O-rings and uses cast iron pipe fittings. Therefore,
	while the material itself appears suitable for hydrogen at a
	first assessment, the specific pipe configuration and joint
	materials should be verified before confirming full
	compatibility.
Valves and Meters	Key requirements for converting existing gas infrastructure
Carbon Steel	The regulator/valve body is typically made of low- to medium- strength carbon steels. These steels can be less susceptible to adverse effects from
	hydrogen. However, steel grade/specification alone is typically insufficient to determine a material's susceptibility to hydrogen embrittlement as the

	susceptibility is also determined by factors such as stress, flaws, and
	hardness.
Cast Iron	Valves having shell (body, bonnet, cover and/or end flange components)
	made of cast or ductile iron shall be replaced.
Stainless Steel-	No additional requirements.
Austenitic	
Stainless Steel-	There could be several martensitic/ferritic stainless steels present in the gas
Ferritic/ Martensitic	networks in valve and regulator internals. These materials are potentially sensitive to hydrogen embrittlement, but very little test data exist for these
Martensitic	materials in low to medium pressure hydrogen gas environments.
Stainless Steel-	The following mitigations are required:
Precipitation	- Gas facing parts which are high strength steel should be replaced.
hardening	- Increased maintenance/monitoring of their functionality.
Copper	ASME B31.12 notes that copper can be embrittled in hydrogen due to the
	reaction between dissolved hydrogen and oxygen (either in solution or from
	oxides) to form water, resulting in pores that promote failure. ASME B31.12
	recommend oxygen-free grades if copper is used for hydrogen service.
Aluminium and	ASME B31.12 A-2.6 states that aluminium alloys are highly resistant to
Aluminium	hydrogen embrittlement in dry hydrogen. It does however advise that
Alloys	aluminium alloys should be used judiciously for hydrogen gas service if
Brass	Water vapour is present.
D1 033	IGEM/H/1 suggests that evaluation is still required for brass alloys (with >2.5% lead), as the compatibility with hydrogen may depend on the lead content
	lead), as the compatibility with hydrogen may depend on the lead content.
Non-metallic	
	lead), as the compatibility with hydrogen may depend on the lead content.
Non-metallic materials	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure
Non-metallic materials Elastomers	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset
Non-metallic materials Elastomers (Diaphragm, O-	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals)	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as replacing the regulator's orifice, to allow for higher volumetric flow rates.
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as replacing the regulator's orifice, to allow for higher volumetric flow rates. Therefore, the sizing of the regulator must be thoroughly reviewed and
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as replacing the regulator's orifice, to allow for higher volumetric flow rates. Therefore, the sizing of the regulator must be thoroughly reviewed and verified with the OEMs as well as the impact of hydrogen on pressure
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/ Valves	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as replacing the regulator's orifice, to allow for higher volumetric flow rates. Therefore, the sizing of the regulator must be thoroughly reviewed and verified with the OEMs as well as the impact of hydrogen on pressure regulator noise, and potential erosion across the valve.
Non-metallic materials Elastomers (Diaphragm, O- Ring, and Seals) Sealants Regulators and Meters Regulators/	lead), as the compatibility with hydrogen may depend on the lead content.  Key requirements for converting existing gas infrastructure  For some materials (e.g. Viton) there may be a need to perform further asset assessment and seek OEM advise. Hydrogen ready elastomeric sealing products are commercially available.  Some commercial sealant products have compatibility in hydrogen blends up to 59% hydrogen. For 100% hydrogen, the OEM advise should be received. Hydrogen ready sealant is being marketed.  Key requirements for converting existing gas infrastructure  Pressure regulators size / flow capacity, specifically the valve flow coefficient (Cv or Cg), must be sufficient to manage the higher volumetric flow rates associated with hydrogen. If the required flow capacity exceeds the maximum Cv or Cg that the regulator can provide, it will be unable to accommodate the anticipated gas flow rates. In such cases, the capacity of the regulator can often be increased by modifying its components, such as replacing the regulator's orifice, to allow for higher volumetric flow rates. Therefore, the sizing of the regulator must be thoroughly reviewed and verified with the OEMs as well as the impact of hydrogen on pressure

## 4.2. CO<sub>2</sub>

As a second potential use case of gas distribution grids, we evaluate the technical and economic feasibility of  $CO_2$  transport specifically by using medium-pressure distribution pipelines in Flanders. This approach is based on the assumption that  $CO_2$  will primarily be transported between major



industrial sites and greenhouses or larger pipelines, where distribution pipelines could potentially link  $CO_2$  sources (e.g., from industrial capture processes) to end users such as other industrial facilities and greenhouses, as well as to larger transmission pipelines or ports for onward transport, export, or storage.<sup>64</sup>

There is a significant opportunity to utilize existing oil and gas pipelines for transporting captured CO<sub>2</sub> in various regions globally. The Acorn CCS project in the UK aims to convert an existing onshore pipeline for CO<sub>2</sub> transport to a storage site in the North Sea. Similarly, the Queensland Carbon Hub/Carbon Transport and Storage Company (CTSCo) project in the Surat Basin, Queensland, is considering the reuse of current pipeline infrastructure<sup>65</sup>. However, like hydrogen projects, CO<sub>2</sub> transport is primarily considered at the transmission level, not at the distribution level. Also, active gas phase CO<sub>2</sub> pipelines are uncommon compared to dense phase pipelines as transport in liquid form is more efficient in terms of achieving the maximum mass flow rate. However, there are a number of gaseous CO<sub>2</sub> pipeline projects proposed by operators in the Netherlands<sup>66</sup> and United Kingdom.<sup>67</sup> Gas TSOs in Belgium, France and Italy are also planning CO<sub>2</sub> networks, partly using repurposed natural pipelines.<sup>68</sup>

In the USA, The Trailblazer conversion project (Tallgrass Energy Partners) intends to convert 400 miles of existing natural gas pipeline for gas phase CO<sub>2</sub> transport. The customers are primarily bio-ethanol producers of Nebraska, Colorado, and Wyoming. Conversion projects in the United States requires approval from regulators, initially FERC (Federal Energy Regulatory Commission) must approve the "abandonment" of natural gas service by the pipeline before repurposing (under the Natural Gas Act). The pipeline owner must show that alternative natural gas supplies are available (or can be constructed) to serve the customers supplied by the converted pipeline. As currently there is no Federal routing or eminent domain (effectively compulsory purchase) framework, the overall planning and environmental approval process for CO<sub>2</sub> pipelines is very complex requiring separate approvals at Federal, Native American, State and County levels.

 $CO_2$  exhibits non-conventional properties and can become a supercritical fluid under typical transport conditions. Its phase behaviour has been analysed across a range of temperature and pressure conditions, particularly focusing on use cases where applicable to Flemish distribution network.

One key property is density, which significantly influences pressure drop within the pipeline. Another critical factor is impurities present in the  $CO_2$  stream, such as water, nitrogen ( $N_2$ ), and hydrogen sulphide ( $H_2S$ ). These impurities can alter the phase behaviour of  $CO_2$  and shift the conditions under which two-phase mixtures may form. The impact of impurities on both phase behaviour and mixture density has been assessed.

Water ( $H_2O$ ) is also a major consideration in  $CO_2$  pipeline operations. The presence of water can lead to the formation of ice, hydrates, or liquid phases, which may cause blockages or corrosion. Additionally, the solubility of  $CO_2$  in water is an important parameter in understanding potential operational challenges. Lastly, the effect of fluid depressurization, as may occur in the event of pipeline damage or rupture, has been examined with a focus on its influence on  $CO_2$  phase behaviour.

### 4.2.1. Phase behaviour of CO2

The phase behaviour of  $CO_2$  is complex, because the gas goes through several changes at different conditions.  $CO_2$  turns into a supercritical fluid which is neither liquid nor gas, but has properties of

<sup>&</sup>lt;sup>68</sup> JRC (2025) <u>Building Future-Proof CO2 Transport Infrastructure in Europe – Clean Air Task Force</u>



<sup>&</sup>lt;sup>64</sup> See also DNV Whitepaper (2025) Feasibility analysis of CO2 onshore pipeline infrastructure

<sup>&</sup>lt;sup>65</sup> IEA (2020) Special Report on Carbon Capture Utilization and Storage.

<sup>&</sup>lt;sup>66</sup> <u>Project - Porthos</u>

<sup>&</sup>lt;sup>67</sup> How National Gas is fast-tracking Scotland's energy transition with CCS technology | National Gas

both, above the critical pressure, but below the critical temperature a liquid like phase is created, both are referred to dense phase in the literature.

The phase behaviour of  $CO_2$  is shown in this picture. Transporting  $CO_2$  as a liquid is the most efficient in terms of achieving the maximum mass flow rate. However, it would require a means of ensuring temperatures don't exceed a specified value, and the redesign of a large proportion of the network. Given the pressure rating of the network and available materials, Flanders' distribution infrastructure is most likely to transport gaseous  $CO_2$  which is shown by purple ovel.

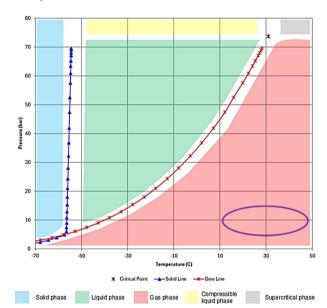


Figure 4-2 Phase diagram of pure CO2.

#### 4.2.2. Transportation of CO<sub>2</sub> - Material Compatibility

When carbon dioxide comes into contact with free water, it forms carbonic acid, which is highly corrosive to carbon steel commonly used in pipeline networks. This type of corrosion, known as sweet corrosion, only occurs if the moisture content is sufficient to produce a condensed aqueous phase, typically the case in pure  $CO_2$  streams. However, even small amounts of trace contaminants (e.g.,  $NO_x$ ,  $SO_x$ ,  $H_2S$ ,  $H_2O$ , CO) can significantly lower the corrosion threshold and accelerate the corrosion rate.

The feasibility of using carbon steel can be a critical factor in the success of a project. Gaining a clear understanding of  $CO_2$  phase behaviour, along with the effects of its composition and impurities, is crucial for identifying potential risks such as corrosion and material degradation.

The effects of  $CO_2$  on non-metallic materials must also be taken into account.  $CO_2$  absorption can cause plasticisation in polymers, altering their mechanical properties, reducing stiffness, increasing toughness, and potentially leading to issues such as part deformation or seal leakage. Therefore, understanding how  $CO_2$  interacts with various polymers is essential for ensuring the durability and reliability of materials used in  $CO_2$  transport systems.

Studies on the mechanical behaviour of engineering thermoplastics exposed to  $CO_2$  under different pressures and temperatures show that materials like PE, PTFE, and PVC experience minimal weight gain from  $CO_2$  absorption (less than 1%) and no significant reduction in tensile strength. These semi-crystalline polymers absorb less  $CO_2$  than their amorphous counterparts<sup>69</sup>. However, compatibility concerns have been identified for polymers such as CR, FKM, and NBR, as per ISO 11114-2 standards, making it important to specify material types used in the network.

33

<sup>&</sup>lt;sup>69</sup> L. Ansaloni, B. Alcock and T. A. Peters (2020) Effects of CO<sub>2</sub> on polymeric materials in the CO<sub>2</sub> transport chain: A review, International Journal of Greenhouse Gas Control, vol. 94.

The table below provides a non-exhaustive list of elastomers and engineering thermoplastics that might be found in the gas network with their typical application and CO<sub>2</sub> compatibility.

Table 4-4 Non-exhaustive list of Elastomers and Engineering Thermoplastics that might be found in the DS with their CO2 compatibility as per ISO 11114-2

Polymer Acronym		Type of Component	CO₂ Compatibility					
Elastomers								
Ethylene-propylene diene monomer	EPDM		Acceptable					
Fluoroelastomers	FKM, FFKM, FEPM		High $CO_2$ uptake and volumetric swelling due to affinity of $CO_2$ to fluorine					
Nitrile butadiene rubber	NBR	Sealants, gaskets	Moderate CO <sub>2</sub> uptake and volumetric swelling					
Polyacrylate	АСМ		Acceptable					
Chloroprene rubber	CR		Moderate CO <sub>2</sub> uptake and volumetric swelling					
Isoprene rubber	IR		Not acceptable					
Engineering Thermopla	stics							
Polypropylene	PP	Tubes, pipes	Acceptable					
Polyvinyl chloride	PVC	Tabes, pipes	Acceptable					
Polyoxymethylene	РОМ	Tubes, pipes, tanks,	Not acceptable, swelling > 15%					
Polyamides (Nylon, such as PA11 or PA12)	PA	vessels	Acceptable					
Polyetheretherketone	Polyetheretherketone PEEK		Acceptable					

CO<sub>2</sub>'s solubility characteristics vary, it is an effective solvent for non-polar and some low molecular weight polar polymers, but less so for high molecular weight polymers. To manage material degradation risks, preventive strategies such as controlled depressurization, appropriate material selection, and design optimization should be implemented. Advanced materials like PTFE-alloys and specialized elastomers offer greater resistance under extreme conditions.

It's important to note that these concerns are especially relevant for dense phase  $CO_2$ , which can act as a strong solvent for many elastomers and thermoplastics, as highlighted in DNV-RP-F104<sup>70</sup> which will be a less concern for conveying gaseous  $CO_2$  in Flemish distribution network.

#### 4.2.3. Integrity Issues in CO<sub>2</sub> transport

 $CO_2$  streams often contain various impurities, such as  $H_2O$ ,  $NO_x$ ,  $SO_x$ , and  $O_2$ , depending on the source of the  $CO_2$ . These trace components have two primary effects: first, they influence the precipitation behaviour of water, potentially leading to  $CO_2$ -induced corrosion; second, they may contribute to the

<sup>&</sup>lt;sup>70</sup> DNV (2021) Recommended Practice for Design and operation of carbon dioxide pipelines, <u>DNV-RP-F104</u>.

formation of corrosive acids that significantly increase corrosion rates. The table below outlines the key concerns associated with different impurities present in  $CO_2$  streams<sup>71</sup>.

The trace compounds can react with each other to form new, highly corrosive substances. For example, dense phase  $CO_2$  containing water, oxygen, sulphur dioxide ( $SO_2$ ), nitrogen dioxide ( $NO_2$ ), and hydrogen sulphide ( $H_2S$ ) can generate aggressive liquids such as sulfuric acid ( $H_2SO_4$ ), nitric acid ( $HNO_3$ ), and elemental sulphur, all of which can cause severe corrosion.

Achieving ultra-low impurity levels requires significant energy input and can be cost-prohibitive  $^{72}$ . As a result,  $CO_2$  captured from power plants and industrial facilities for carbon capture and storage (CCS) will likely contain some impurities. However, operational experience indicates that problems are minimal if the  $CO_2$  stream is kept relatively pure and moisture levels are tightly controlled.

To prevent internal corrosion, it is essential to dry the  $CO_2$  to below the dew point under both normal operating and upset conditions. Another important mitigation strategy is to limit the introduction of trace contaminants into the  $CO_2$  stream.

Another major concern for  $CO_2$  transport projects is the risk of low-temperature fractures, which can lead to sudden and catastrophic failure. Assessments must consider upset conditions, such as startup, shutdown, or blowdown events, during which pressure drops can cause Joule-Thomson cooling, potentially reducing temperatures to as low as -80 °C. This sub-cooling can push materials to their mechanical limits. Low-temperature embrittlement is a well-recognized hazard in pressurized systems<sup>73</sup> and must be considered in  $CO_2$  transport design. Therefore, material selection must account for fracture toughness at the lowest anticipated operating temperatures.

Trinomics - -

35 =

<sup>&</sup>lt;sup>71</sup> J. Sonke and Y. Zheng (2023) "CO2 Transport and Injection, Effect of Impurities, Understanding of Reactions and Consequences," in AMPP Annual Conference + Expo, Denver.

<sup>&</sup>lt;sup>72</sup> Barker, R., Hua, Y., Neville, A. (2017) Internal corrosion of carbon steel pipelines for dense-phase CO2 transport in carbon capture and storage (CCS) – a review. International Materials Reviews 62 (1), 1–31.

 $<sup>^{73}</sup>$  ISO Standard 17349: 2016 - Petroleum and natural gas industries — Offshore platforms handling streams with high content of CO<sub>2</sub> at high pressures.

Table 4-5 Main issues associated to various components in CO<sub>2</sub> stream, Adopted from DNV-RP-F104

	Properties										
Component	Health and safety	Pipeline capacity	Water solubility	Hydrate formation	Materials	Fatigue	Fracture	Corrosion	Operations	Comments	
CO <sub>2</sub>	•	•	•	•	•	•	•	•	•	Non-flammable, colourless, no odour at low concentrations, low toxicity, vapour heavier than air.	
H <sub>2</sub> O				•	•	•	•	•	•	Non-toxic	
N <sub>2</sub>		•	•							Non-toxic	
O <sub>2</sub>			•					•		Non-toxic	
H <sub>2</sub> S	•	•			•	•	•	•		Flammable, strong odour, extremely toxic at low concentrations.	
H <sub>2</sub>		•	•				•			Flammable, non-condensable at pipeline operating condition.	
SO <sub>2</sub>	•		•					•		Non-flammable, strong odour	
со	•		•							Flammable, toxic, oxidizer	
NO	•		•					•		Non-flammable, toxic	
NO <sub>2</sub>	•		•					•		Non-flammable, toxic	
CH <sub>4</sub>		•	•						•	Odourless, flammable	

The following table summarizes the main challenges in converting the Flemish natural gas grid for CO2 transportation use:

Table 4-6 Main challenges in converting the Flemish natural gas grid for  $CO_2$  transport

Pipelines	Integrity Issues in Gaseous CO <sub>2</sub>					
PE, PVC	PE and PVC exposed to Gaseous $CO_2$ shown minimal weight changes due to $CO_2$ absorption (< 1%) and no significant changes in tensile strength.					
Steel	Dry $CO_2$ is not corrosive. However, wet $CO_2$ can cause internal corrosion of carbon steels. Corrosion rates can be high if free water is present in the $CO_2$ . Under normal operating conditions and if the $CO_2$ is kept within the specification, water drop out and associated corrosion would be considered very low risk. Corrosion would only be expected if an upset or depressurisation occurs. An upset may include, for example if the emitter introduces $CO_2$ which is out of specification and may be insufficiently dehydrated.					
Cast Iron	Cast-Iron resists corrosion better than Carbon Steel.					
Fiber Cement	Might be compatible with gaseous CO <sub>2</sub> . Further assessment is required.					
Non-metallic materials	Material Compatibility issues in Gaseous CO <sub>2</sub>					

Pipelines	Integrity Issues in Gaseous CO <sub>2</sub>
Elastomers (Diaphragm, O- Ring, and Seals)	CO <sub>2</sub> can potentially impact polymers in the network including swelling, mechanical properties, RGD resistance due to higher solubility of CO <sub>2</sub> compared to methane and can lead to:  Increased CO <sub>2</sub> uptake and swelling  Potential for plasticisation effects  Impacts on mechanical properties  Changes in RGD resistance
General	Effect of Impurities in Gaseous CO <sub>2</sub>
Pipeline	$CO_2$ can contain many impurities. The impurities include $H_2O$ , $NO_x$ , $SO_x$ , $O_2$ which depends on the $CO_2$ sources.  Trace components have two major effects: Firstly, they can alter the tendency of water to precipitate, leading to $CO_2$ corrosion. Secondly, they can form corrosive acids that trigger corrosion rates.
	A dry CO <sub>2</sub> pipeline with no impurities in the gas will have a comparable fatigue life to natural gas pipeline, however, the presence of water or hydrogen can lead to a significant reduction in the allowable number of cycles for a given stress range.
	Material Compatibility issues in Gaseous CO <sub>2</sub>
Valves and Regulators	Due to the greater fluid density, the kinetic energy of the CO <sub>2</sub> gas flow is slightly higher at an equivalent gas velocity. Risk of increase in vibration and noise, vibration study is required.

#### 4.2.4. Requirements for Converting to CO<sub>2</sub> transporting

For repurposing natural gas networks to CO2 transport, the following approach can be followed:

#### 1. Define CO<sub>2</sub> Composition and Operating Conditions:

Identify the expected  $CO_2$  composition, including impurity limits, as well as all potential operating scenarios (e.g., pressure, temperature, and flow variations) that may occur during service.

#### 2. Assess Risk of Water Condensation:

Evaluate these conditions for the potential to cause water dropout or condensation, taking into account the role of specific impurities that may promote liquid water formation.

#### 3. Evaluate Acid and Sulphur Formation:

Examine the potential for acid or elemental sulphur formation and precipitation under the defined conditions and assess their impact on corrosion risks.

### 4. Establish a Degradation Control Strategy:

Ensure sufficient data is available to estimate degradation rates, enabling the development of a robust corrosion and materials integrity management strategy.

## 5. Verify Material Compatibility in Critical Components:

Validate the suitability of specific design components, such as seals, valves, and meters with respect to the compatibility of materials with  $CO_2$  and its impurities across the full range of operating conditions.

#### 6. Regulatory Requirements:

New standards are required for stricter limits on water content and impurities in  $CO_2$  gas compositions.

In addition to that, each emitter should be equipped with a dehydration system to maintain water content below the project-defined limit. Despite these measures, occasional water dropout during the operational life of a CO<sub>2</sub> pipeline is likely to occur. Such instances may result from dehydration unit failures, or water ingress during maintenance activities. These scenarios should be anticipated and managed within acceptable risk thresholds.

A key element of the integrity management plan is the implementation of reliable moisture detection systems, alongside the development of detailed operational procedures, as well as response and recovery plans to prevent the presence of free water and mitigate any associated impacts.

Inspection intervals should comply with regulatory standards and be adapted to the specific operational conditions of CO<sub>2</sub> pipelines. Inspection protocols must be updated accordingly. Given the unique characteristics of CO<sub>2</sub>, specialized inspection tools are required, preferably those capable of identifying even minor defects. Tool selection should also consider the configuration of the pipeline to ensure accurate and reliable data acquisition.

The following table summarizes the key requirements and modifications necessary to convert natural gas pipelines for  $CO_2$  transportation:

Table 4-7 Key requirements for converting existing gas infrastructure for CO2 transport

Pipelines	Key requirements for converting existing gas infrastructure
PE, PVC, Fiber Cement	They are not compatible with dense phase CO <sub>2</sub> as dense phase CO <sub>2</sub> acts as a solvent for them. Flanders distribution infrastructure is most likely to transport gaseous CO <sub>2</sub> .
Steel	Network CO <sub>2</sub> pipelines should be operated in the gaseous phase with a tight water specification and low impurities. Adequate moisture monitoring and controls should be in place to minimise
Cast Iron	the amount of water entering the pipelines. Maintain operating envelope of the pipeline in gaseous phase to avoid phase change and drop out of liquid.
Non-metallic materials	Key requirements for converting existing gas infrastructure
Elastomers (Diaphragm, O- Ring, and Seals)	Swelling could have a greater impact on some dynamic seals compared to static.  RGD is an issue at pressures >35bar. At operating pressure of Flemish DS, any RGD would not be expected to be significant.  The impact of CO <sub>2</sub> on polymers increases with pressure. Current proposed pipeline operating conditions <15 bar will reduce the risk of any degradation due to CO <sub>2</sub> .  ISO 11114-2 identified polymers in the network which could have compatibility issues with CO <sub>2</sub> . These are as CR, FKM, POM and nitrile.  It is recommended to perform a leak survey on the current seal inventory before converting a pipeline to CO <sub>2</sub> .  It is recommended that for seals, advice should be taken from manufacturers.
General	Key requirements for converting existing gas infrastructure
Pipeline	Required fatigue assessment Reducing the magnitude of any stress cycles also provides a significant benefit in terms of fatigue life.
	To mitigate internal corrosion, $CO_2$ must be dried to water concentrations below the dew point for both operational and upset conditions. Minimising trace components entering the $CO_2$ stream, is another strategy.

Pipelines	Key requirements for converting existing gas infrastructure
Valves and Regulators	Possibly need to be replaced It is recommended to perform a leak survey on the current seal inventory before converting a pipeline to CO <sub>2</sub> . It is recommended that for seals, advice should be taken from manufacturers.  Risk of increase in vibration and noise, vibration study is required.

#### 4.3. Water

Repurposing natural gas pipelines for water distribution is technically possible in some cases but involves significant requirements and regulatory considerations.

It is important to note that typical water distribution networks operate at pressures ranging from 1 to 5.5 bar, primarily to prevent contamination and ensure safety. As a result, the pressure ratings of the LP ( $\leq$  98.07 mbar) and MPA (98.07 – 490.35 mbar) networks are not suitable for water distribution, while the MPC sections are over-specified for such use. Therefore, only the MPB pressure tier can be considered appropriate for water distribution applications.<sup>74</sup>

#### 4.3.1. Technical Challenges in Converting gas networks for Water Distribution

While the idea of repurposing natural gas pipelines for water distribution is intriguing, its practical implementation demands thorough evaluation of material compatibility, regulatory compliance, and necessary infrastructure adaptations.

Approval from relevant water authorities and health agencies is essential, particularly when the repurposed system is intended for drinking water. Water quality must be carefully assessed, ensuring that residual contaminants such as corrosion products or sediments are fully removed.

The most critical concern is the risk of water contamination from residual odorants originally used in the gas network. Natural gas is typically odorized with sulphur-based compounds to aid in leak detection. These substances can become adsorbed into pipeline materials, especially polyethylene (PE) pipes commonly used in distribution systems (DS). Over time, these odorants may leach back into the water, causing unpleasant taste and odour, rendering the water unsuitable for human consumption unless extensive treatment or full pipe replacement is carried out.

Regarding existing materials in the DS, while standards have permitted the use of plastics and cast iron, carbon steel (CS) pipes are particularly vulnerable to corrosion. Water, especially in the presence of oxygen and certain minerals, can accelerate internal corrosion in steel pipelines.

The following table summarizes the main challenges in converting part of the Flemish natural gas grid for water distribution use.

Table 4-8 Main challenges in converting part of the Flemish natural gas grid for water distribution

Pipelines	Material Compatibility in Water
PE	According to EN 12201, PE pipes are suitable for water distribution.  Concerning residual odorants
Steel	There is risk of corrosion. Water can accelerate internal corrosion, especially with oxygen and certain minerals.  Concerning residual odorants
PVC	According to ISO 1452, PVC pipes are suitable for water distribution. Concerning residual odorants

 $<sup>^{74}</sup>$  MPC: > 4,9 bar and ≤ 14,7 bar; MPB: > 0,490 bar and ≤ 4,9 bar; MPA: > 98 mbar and ≤ 490 mbar; LP: ≤ 98 mbar



39

Pipelines	Material Compatibility in Water				
Cast Iron	According to EN 877, cast iron pipes are suitable for water supply. Concerning residual odorants				
Fiber Cement	Prohibited due to health risk				
Valves and Meters	Material Compatibility issues in Water for CS valves Concerning residual odorants Functionality issues of meters and valves as they are not designed for liquid flow.				

#### 4.3.2. Water Distribution Requirements

According to above discussion, repurposing existing gas distribution networks for water distribution, especially those containing PE and CS pipes, would require either comprehensive cleaning and water flushing, which may not fully eliminate contamination risks, or the complete replacement of affected sections with new, uncontaminated piping systems.

Also, gas valves and joints may not be watertight or suitable for water pressure regimes. Retrofitting or replacing with water-rated components is often required.

The following table summarizes the key requirements and modifications necessary to convert (part of) the Flemish natural gas network for water distribution.

Table 4-9 Key requirements for converting existing gas infrastructure for water distribution

Pipelines	Key requirements for using existing gas infrastructure for water distribution						
PE	Should be replaced due to adsorption/absorption of odorant into porous						
Steel	metal or plastic surface. Over time, these compounds may desorb into the						
PVC	water, imparting an unpleasant taste and smell.  The risk of water contamination due to residual odorants necessitates either						
Cast Iron	extensive pipe cleaning, which may not be entirely effective, or complete						
Fiber Cement	replacement with new, uncontaminated piping systems.						
	Should be replaced						
	Due to risk of corrosion for CS valves and adsorption/absorption of odorants						
Valves and	into porous metal or plastic surface of other valves. Over time, these						
Meters	compounds may desorb into the water, imparting an unpleasant taste and						
	smell.						
	Gas Meters should be replaced with suitable flow sensors for Water.						

# 4.4. Corridor for communication or electricity cables

The final potential use case involves repurposing existing gas distribution network for the installation of fibre optics or electrical cables. There are two main approaches for using the gas network as a conduit for cables:

- (1) Decommission the network and utilize it as a pre-existing duct system to house fibre optics or electrical cables.
- (2) Keep the gas network operational while "co-hosting" additional utilities, such as communication cables, within the pipeline bore.

These two approaches represent fundamentally different use cases, each with distinct levels of operational complexity and associated risks. As such, evaluations should be categorized into "live" and "decommissioned" (or "dead") use cases.



The concept of installing fibre optics within live gas pipelines has existed since the 1990s, with a notable increase in activity during the early 2000s. More recently, the drive to decarbonize the energy sector has renewed interest in repurposing out-of-service gas infrastructure for alternative uses. In some instances, fibre optic networks have already been installed in decommissioned gas pipelines, such as in parts of India. Historical examples also include the installation of telephone cables within drinking water mains in the early 20th century.

Available research and past applications provide a reasonable foundation supporting the feasibility of installing ducted infrastructure, such as fibre optics within gas pipelines, whether active or decommissioned. Companies like Alcatel and Siemens have successfully implemented systems for installing fibre optic cables inside gas pipelines.

#### 4.4.1. Fibre for Telecommunications

Fibre optic cables for telecommunications have often been installed as a secondary utility within existing utility infrastructures, including live gas networks. Below are several examples illustrating this practice.

In the 1990s, the Gas Technology Institute (GTI) launched the Global Technology Transfer Alliance, a consortium focused on the exploration of emerging technologies, including the concept of fibre-ingas. Initially, this idea received limited support from gas distribution operators. However, interest surged in the early 2000s as utilities sought ways to generate additional revenue from existing gas infrastructure.

In 2002, the GTI consortium funded multiple international studies to assess the viability of fibre-ingas systems. These included a trial by Sempra Fiber Links (a subsidiary of Sempra Broadband) in Dallas, USA, and another by Alcatel in Paris, France<sup>75</sup>.

Additionally, some companies have leveraged gas pipeline routes and associated wayleaves to support fibre network development. One example is the Lattice Group<sup>76</sup>, which included both 186k (a fibre-optic telecommunications business) and Transco (then the main operator of Great Britain's gas transmission network). 186k strategically followed Transco's gas trunk line routes to deploy its fibre network.

Although interest in fibre-in-gas applications declined after the early 2000s, it has seen renewed attention in recent years, particularly in relation to the use of decommissioned gas mains. Since 2014, CloudExtel has installed over 200 km of fibre optic cable using disused gas pipelines in the South Bombay network<sup>77</sup>.

These cases demonstrate that deploying fibre networks through both live and abandoned gas pipelines is not only feasible but has already been successfully implemented in various contexts.

#### 4.4.2. Electricity

There has been ongoing discussion about the potential for using gas pipelines to carry electricity as a secondary utility. However, a number of regulations and standards may pose challenges to this application. Most of these standards primarily address the installation of gas and electrical systems within commercial buildings, but similar considerations are likely to apply across the wider gas transmission and distribution networks.

For instance, BS 7671:2018<sup>78</sup> section 528.3.3 (equivalent to IEC 60364), stipulates that when electrical services are installed near non-electrical services, they must be arranged to avoid damage during foreseeable maintenance or operation of either service. The standard further requires that:

<sup>&</sup>lt;sup>78</sup> BSI Standards Limited (2018) BS 7671:2018 Requirements for Electrical Installations.



 $<sup>^{75}</sup>$  M. Fuller (2002) <u>Live gas lines to carry energy and information</u>.

<sup>&</sup>lt;sup>76</sup> Lattice Group (2001) Lattice Group Annual Report and Accounts 2000

<sup>&</sup>lt;sup>77</sup> CloudExtel <u>website</u>, accessed online 24/09/2025.

- The electrical wiring must be adequately protected against potential hazards arising from nearby non-electrical services during normal use.
- Fault protection must comply with Section 411.

Additionally, it refers to BS 6891 for guidance on the separation of low-pressure gas systems and electrical equipment. The European standard that covers similar aspects of gas installations is EN 1775:2007.

In BS 6891:2015<sup>79</sup> clause 8.4.2 specifies minimum separation distances when there is no insulating enclosure or barrier between gas pipes and electrical components. These include a gap of at least 150 mm from electricity supply equipment and at least 25 mm from switches, sockets, and distribution cables.

However, if a gas pipeline is no longer in active use, many of the safety standards applicable to live gas mains would no longer be relevant. In such cases, repurposing disused gas infrastructure for electrical distribution becomes significantly more viable. This repurposed network could be used to facilitate the distribution of electricity or potentially support direct current (DC) distribution for applications such as electric vehicle (EV) charging infrastructure, offering opportunities for faster and more widespread charging solutions.

#### 4.4.3. Installation and Deployment of Payload

The use of a decommissioned, or "dead," gas network presents a simpler use case due to the lack of active gas flow. In such cases, modifications are generally minimal and focus on ensuring the internal bore of the pipe is clean, smooth, and free from obstructions that could damage any inserted cables or ducts, particularly important for aging iron pipelines. It may also be necessary to install access points, such as draw pits or junction boxes, especially at changes in pipe direction. These access points help facilitate payload installation, as sharp bends increase friction and make pushing or pulling cables more difficult and potentially harmful.

Although this approach is less technically demanding than working with a live gas system, it still requires consistent oversight and maintenance of the repurposed infrastructure to meet the needs of the new utility. This is not a "fit and forget" solution; ongoing management is essential.

By contrast, working with a "live" gas network introduces additional complexities and necessitates thorough analysis and planning. While gas supply must be temporarily shut off during the installation process, the overall impact on pipeline operation is minimal.

To enable the repurposing of the pipe for a new utility, a structured payload installation process must be followed. The key steps include:

- 1. Gaining access to the pipe
- 2. Inserting and securing the payload
- 3. Routing the payload through the pipeline
- 4. Retrieving it at the end of the section

Each of these steps must be carried out with care to ensure safety, structural integrity, and compliance with regulatory standards. There are several established techniques in the gas industry for accessing live pipelines, many of which could be adapted, with minor modifications, for installing payloads. Various propulsion methods have been explored, with a hybrid push/pull technique between access points showing the most promise.

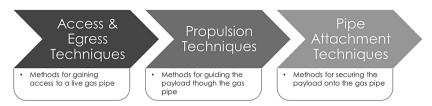
— Trinomics 🦰 💳

42

<sup>&</sup>lt;sup>79</sup> BSI Standards Limited (2015) BS 6891:2015 Specification for the installation and maintenance of low-pressure gas installation pipework of up to 35 mm on premises.

Design considerations will be crucial, both for how the payload is secured within the pipe and the specific design of the payload itself. These considerations will vary based on the payload's purpose. For instance, fibre-optic sensing applications require effective coupling with the pipe. However, design insights and technologies from other sectors can be leveraged to expedite decision-making around payload content and configuration.

Figure 4-3 Installation Process Steps for Research Focus



The following table summarizes the key requirements and modifications necessary to convert part of the Flemish natural gas network for use as collector for communication or electricity cables.

Table 4-10 Key requirements for converting existing gas infrastructure for use as collector

Pipelines, Fittings, Valves	Key requirements for using existing gas infrastructure as collector
Option 1: Dead Network	In this case, modifications are generally limited to ensure the internal bore is clear, smooth, and free of obstructions that could damage cables or pipes during installation, especially important in older iron networks. It may also be necessary to create access points, such as draw pits or junction boxes, to allow third-party connections. These access points are typically located at changes in pipe direction to facilitate payroll installation, as sharp bends can make cable or pipe pulling/pushing more difficult and potentially damaging due to increased friction. Excluding pipes that are less than 50 mm in diameter.
Option 2: Live Network	The installation of ducted infrastructure within a gas network is technically feasible. There are a range of different installation techniques that can be explored further and potentially be specialised. The risks such as gas leakage can be managed with reasonable mitigations, such as robust designs, updates to existing procedures and operational training. Excluding high pressure pipelines and pipes that are less than 50 mm in diameter
Valves and Meters	Need for Valve Modification or Bypass. To allow fibre installation, either: Valves must be modified or removed, or fibre must be routed externally around the valve using side connections or splice enclosures.
Regulatory aspects	In addition to requiring modifications to the gas network operator licences and codes, there are health and safety regulations that must be observed.  For live networks, standards like BS 7671 (equivalent IEC 60364) and BS 6891 (equivalent EN 1775:2007) define minimum separation distances and protective requirements. These are meant to prevent interaction or damage between electrical and non-electrical services.  However, in the case of disused gas mains, these restrictions no longer apply.

# 4.5. Comparative analysis of adaptation costs for the four use cases

Repurposing existing natural gas (NG) pipelines is significantly more cost-effective than constructing new hydrogen or CO<sub>2</sub> pipelines.

For instance, according to the ACT Acorn Project, supported by the European Commission under the Horizon 2020 Programme, adapting hydrocarbon pipelines for CO<sub>2</sub> transport could cost as little as 1–10% of the expense of new builds. While this highlights strong economic advantages, various technical and safety challenges must be resolved before such conversions can be implemented<sup>80</sup>.

The European Hydrogen Backbone (EHB) study estimates that retrofitting costs for dedicated hydrogen use are roughly one-third of new pipeline construction. While building new hydrogen pipelines incurs capital expenditures (CAPEX) between 110% and 150% of those for comparable NG pipelines, converting existing infrastructure typically costs only 10–35% of the expense of new hydrogen pipelines<sup>81</sup>.

To perform a comparative analysis of the adaptation costs required for each use case, based on the key requirements discussed in previous sections, a representative pipeline with average characteristics is selected. This approach is considered practical and feasible for estimating the conversion of gas pipelines across different use cases, and it helps provide meaningful and generalizable insights for decisions-making.

#### 4.5.1. Cost estimation methodology

For the four use cases outlined in previous sections, the costs associated with introducing new fluids into the existing gas infrastructure can be estimated using the methodology described below:

#### 1. Selection of Representative Pipeline Sections

Rather than attempting a comprehensive quantification of the entire gas network —which is a complex task and not necessary at this project stage, a more strategic approach involves selecting representative pipeline segments for each material type and intended use. These segments are then used to estimate the number of relevant assets.

#### 2. Assessment of Asset Suitability and Required Adaptations

A technical evaluation of each repurposing use case identified the suitability of existing assets for the new service. This process helps determine which mitigation or adaptation measures are necessary to safely and effectively transport the new fluids.

#### 3. Estimation of Specific Costs for Adaptation Measures by Section and Use case

The required mitigation actions for each evaluated use case are then translated into cost estimates. Due to the complexity and variability of retrofitting or renewing specific components, driven by market conditions and other factors, detailed cost figures are not provided at this stage. Instead, cost assumptions are described qualitatively.

#### 4. Assumptions Underpinning the Cost Estimation Approach

The following average values (based on the Marcogaz<sup>82</sup> study of the European gas grid) are used to estimate key components in the Distribution Infrastructure per kilometre:

----- Trinomics 🥐 💳

 $<sup>^{80}</sup>$  Caroline Kenton and Ben Silton (2020) Repurposing Natural Gas Lines: The CO2 Opportunity.

<sup>&</sup>lt;sup>81</sup> ACER (2021) <u>Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing.</u>

<sup>&</sup>lt;sup>82</sup> Marcogaz (2023) <u>Methodology description for the cost estimation of hydrogen admission into existing natural gas infrastructure and end use.</u>

- Valves: 1 per km
- Pressure Regulators: 9 per km
- Gas meters: 54 per km

#### 4.5.2. Representative Facilities

The following table presents representative pipeline sections based on the materials used in the Flemish distribution grid, along with the required modifications for each repurposing case. Based on the table, asset replacement costs are highest for water distribution and lowest for the transport of gaseous CO<sub>2</sub>.

Table 4-11 Representative Pipeline Segments and Case-Specific Adaptation Requirements

Pipeline	Assets	No. of Assets	Asset Replacement Needs for Repurposing Cases					
Section	Assets	per km	100% Hydrogen	CO2 transport	Water Distribution			
	Pipe	1 km	Likely to be Replaced	No need to replace	Required Replacement			
	Valve	1	Likely to be Replaced	Likely to be Replaced	Required Replacement			
Steel	Regulator	9	Likely to be Replaced	Likely to be Replaced	Required Replacement			
	Meter	54	Required Replacement	Required Replacement	Required Replacement			
	Pipe	1 km	Required Replacement	No need to replace	Required Replacement			
Cast Iron	Valve	1	Required Replacement	Likely to be Replaced	Required Replacement			
Cast Iron	Regulator	9	Required Replacement	Likely to be Replaced	Required Replacement			
	Meter	54	Required Replacement	Required Replacement	Required Replacement			
	Pipe	1 km	No need to replace	No need to replace	Required Replacement			
Plastic	Valve	1	Likely to be Replaced	Likely to be Replaced	Required Replacement			
	Regulator	9	Likely to be Replaced	Likely to be Replaced	Required Replacement			
	Meter	54	Required Replacement	Required Replacement	Required Replacement			

It is important to note that for the 4<sup>th</sup> use case, repurposing the natural gas grid as a collector, the adaptation costs are not directly comparable to those of the other three use cases. This is because the primary costs in this case relate to the installation of communication or electrical infrastructure, such as fibre optic or power cables, rather than the replacement of pipeline components.

Installing fibre optics or electrical cables typically involves accessing the pipeline, inserting and securing the payload, routing it through the pipeline, and retrieving it at the endpoint. In cases where valves are present, the fibre must exit the pipeline, turning these valve locations into access points for the cable. Special welded fixtures should be done to ensure gas-tight seals at both entry and exit points.

Another important factor influencing the cost of repurposing is the network topology, which plays a critical role in determining project expenses. Different configurations such as tree or star topologies can significantly impact investment requirements. More complex networks with numerous branches

typically demand more extensive modifications. In such cases, efficient routing algorithms become essential for optimal design and effective supply-demand balancing. While the impact of topology is likely consistent across all the use cases we evaluated, it remains a key consideration for future planning and decision making.

A critical element affecting repurposing is the interdependency between different sections of the gas grid, which directly impacts both the feasibility and timing of repurposing efforts. In highly interconnected networks, repurposing one segment can affect the operational viability of adjacent sections. For instance, converting a pipeline without ensuring alternative flow paths may isolate downstream consumers and disrupt the overall system performance. Therefore, the complexity and connectivity of the network must be carefully assessed, ensuring that any changes to one section are evaluated in the context of their broader system implications.

Repurposing existing natural gas pipelines is only feasible if the new demand (e.g., for hydrogen or CO<sub>2</sub>) exists in similar or overlapping regions. If not, large sections of the gas network may become underutilized or obsolete, making repurposing economically or logistically unviable. Pipelines located in areas with no alternative demand for hydrogen, CO<sub>2</sub>, or water may become stranded assets. Repurposing in these cases would not be economically justified. Thus, successful repurposing strategies will need to consider location-specific demand and infrastructure adaptability.

# 4.6. Key findings and conclusions

To summarize the key findings from the review of various use cases for repurposing existing natural gas distribution networks, the following matrix highlights the components or assets requiring modification and outlines the main requirements for each use case.

Table 4-12 Matrix of Required Modifications and Key Needs for natural gas infrastructure Repurposing

_	Technical Requirements	Regulatory Requirements	Adaptation Costs
Use case 1: Pure Hydrogen	To perform further asset assessment for fiber cement and plastic pipeline. High strength steel grades are susceptible to HE.  Cast iron parts should be replaced.  Compatibility of elastomers/sealants should be checked with OEMs. CS valves bodies can be susceptible to HE. High strength steels in valves and regulators should be replaced.  The sizing of the regulator and capacity and functionality of meters for 100% Hydrogen must be verified with the OEMs. Extra safety measures, such as controlled venting and purging, to prevent risks like autoignition.	Challenges related to planning and regulations.  There are standards that specify material requirements such as ASME B31.12 and IGEM/H/1 and IGEM/TD/1 S.2.	Replacement Cost for: Cast iron pipeline Additional costs for extra safety measures
Use case 2: Gaseous CO₂	Adequate moisture monitoring and controls should be in place to prevent CO <sub>2</sub> corrosion. Maintain operating envelope of the pipeline in gaseous phase to avoid phase change and drop out of liquid. It is recommended to perform a leak survey on the current seal inventory before converting a pipeline to CO <sub>2</sub> . For seals compatibility, advice should be taken from manufacturers. Calibration and manufacturer approval for meters.	New regulatory standards are required to mandate stricter water content limits and reduce impurities in gas composition.	Additional costs for installing moisture detectors
Use case 3: Water distribution	Pipelines should be replaced due to adsorption/absorption of odorant into porous metal or plastic surface. Over time,	Regulatory Approval is required.	Replacement Cost for: All pipelines

these compounds may desorb into the Water authorities and water, imparting an unpleasant taste and health agencies must smell. All valves and meters should be approve any replaced as they are not designed for repurposing, liquid fluid. especially for drinking water use. Installation Process: accessing the pipe, Use case 4: inserting and securing the payload, Replacement Cost Strict regulations and Collector for routing it, and retrieving it at the endpoint. safety standards for communication Removing valves and turning these valve Removing valves installing electricity or electricity locations into access points for the cable. and installation cables. cables Gas-tight seals at both entry and exit payload points for live scenario. Colour Code: Very high technical, regulatory and cost barriers High technical, regulatory and cost barriers

Table 4-13 summarizes the feasibility of repurposing the Flemish gas distribution network across four pressure tiers (LP, MPA, MPB, MPC)<sup>83</sup> for the considered potential use cases. The materials assessed include Carbon Steel, Cast Iron, Ductile Cast Iron, PE (Polyethylene), Fiber cement and PVC (Polyvinyl Chloride). Each cell indicates the level of suitability using the following terms:

Medium technical, regulatory and cost barriers

- **AP** (Applicable)
- **ER** (Evaluation Required)
- RR (Replacement Required)
- NA (Not Applicable)

Key insights drawn from the table include:

The LP tier is not applicable for Use Case 3 (Repurposing for water transport) across all materials, indicating limitations in using low-pressure systems for water-related applications. However, LP is mostly applicable or requires only evaluation for Use Case 2 (CO<sub>2</sub> transport) and Use Case 4 (Collector), especially for plastic materials like PE and PVC. In Use Case 1 (Hydrogen), Cast Iron and Ductile Cast Iron components require replacement, while other materials such as Carbon Steel, Fiber cement and plastics can be repurposed with minimal evaluation or adjustments.

Like LP, MPA systems are not applicable for Use Case 3 (Water). However, Carbon Steel sections are applicable for the Use Cases Hydrogen, CO<sub>2</sub>, and Collector. Plastic materials like PE and PVC require evaluation (ER) for Use Cases 1, 2, and 4, but they do not necessitate replacement, indicating moderate repurposing feasibility. MPA systems overall offer better flexibility than LP but still fall short in repurposing for water transport.

MPB systems show greater adaptability across all four considered Use Cases. For Use Case 3 (Water), while replacement is often required, repurposing is at least considered feasible. Carbon Steel remains applicable, especially for Use Cases 1, 2, and 4. However, Ductile Cast Iron requires replacement for both Hydrogen and Water Use Cases. PE and PVC are generally suitable with evaluation or replacement, indicating that MPB systems offer a more adaptable section for repurposing, particularly for non-metallic materials.

MPC systems show the highest degree of repurposing potential. Both Carbon Steel and PE are either applicable or require only evaluation across all considered Use Cases, including Water. Use Case 3 (Water) is viable here with replacement required, unlike in LP and MPA, making this tier the most versatile for repurposing efforts across all Use Cases.

<sup>&</sup>lt;sup>83</sup> **MPC:** > 4,9 bar and ≤ 14,7 bar; **MPB:** > 0,490 bar and ≤ 4,9 bar; **MPA:** > 98 mbar and ≤ 490 mbar; **LP:** ≤ 98 mbar

Table 4-13 Feasibility of repurposing the Flemish gas distribution system across four pressure tiers (LP, MPA, MPB, MPC) for different Use Cases

Pressure Tier	Material of distribution system	Dineline Length		Repurposing for CO <sub>2</sub> transport	Repurposing for Water transport	Repurposing as Collector for Cables
LP	Carbon Steel	2,599	АР	АР	NA	АР
LP	Cast Iron	201	RR	AP	NA	AP/ER
LP	PE	44,247	AP/ER	AP/ER	NA	AP
LP	PVC	548	AP/ER	AP/ER	NA	AP
LP	Fiber Cement	324	AP/ER	AP/ER	NA	AP/ER
МР	Carbon Steel	6,293	AP/ER	AP	AP/RR	AP
МР	PE	3,780	AP/ER	AP/ER	AP/RR	AP

Derived from the table above, the estimated repurposing feasibility of the Flemish gas distribution system for the different use cases, is outlined as follows:

**Repurposing for Hydrogen Transport**: ~5% of the Flemish gas distribution network could be repurposed meeting the discussed requirements, while ~94% would need further evaluation. It is important to note that this study represents only a high-level review. Similar studies and pilot projects have shown the compatibility of PE80 and PE100. A more detailed investigation, however, could reveal that the Flemish network's readiness for hydrogen is significantly higher.

Next to evaluating the technical feasibility of repurposing gas distribution pipelines for dedicated hydrogen transport and the related adaptation costs, the potential market demand for such services should also be properly considered. According to the latest developments and studies, it is not expected that hydrogen will be used at large scale by residential and small commercial end-users currently connected to the gas distribution grid.<sup>84</sup> Only a limited number of larger commercial or industrial end-users connected to the MP network could be interested to switch to low-carbon or renewable hydrogen, depending on its cost and availability. At present, the focus of policy makers and industry is on the use of hydrogen for processes for which electrification is not a suitable option. As most of the end-uses covered by natural gas taken off from the distribution grid can be electrified, repurposing distribution gas pipelines for dedicated hydrogen use is expected to be limited to specific network sections, for instance to deliver hydrogen to industrial end-users that will use hydrogen as feedstock or for (heavy-duty) transport purposes.

**Repurposing for CO<sub>2</sub> Transport**: ~16% of the Flemish gas distribution network could be repurposed for CO<sub>2</sub> transport meeting the discussed requirements, while most non-metallic parts would need further assessment.

Assessment of using hydrogen in gas distribution grids - ScienceDirect

(2024) Distinct roles of direct and indirect electrification in pathways to a renewables-dominated European energy system <u>Distinct roles of direct and indirect electrification in pathways to a renewables-dominated European energy system - ScienceDirect</u>

(2024) Comparative review of hydrogen and electricity as energy carriers for the energy transition

International Journal of Hydrogen Energy Comparative review of hydrogen and electricity as energy carriers for the energy transition - ScienceDirect

<sup>84</sup> See e.g. (2023) Assessment of using hydrogen in gas distribution grids

- Total Applicable (AP):
  - Carbon Steel (LP, MP): 8,892 km
  - Cast/Ductile Iron (LP, MPB): 210 km
- Evaluation Required (AP/ER):
  - Fiber Cement, PE & PVC across all tiers: 48,899 km

While most sections of the Flemish gas distribution grid could technically be repurposed for CO<sub>2</sub> transport, the market demand for such services at distribution level is expected to be very limited. The potential for carbon capture is mostly situated in large energy and industrial companies, which are in general connected to the transmission network, and most (potential) CO<sub>2</sub> users and storage sites would also be connected to large (cross-border) transmission pipelines, rather than to repurposed distribution pipelines. Some potential CO<sub>2</sub> users could be connected to repurposed distribution pipelines (e.g. greenhouses, smaller industrial enterprises), but the volumes to be transported may be too limited to justify dedicated pipeline infrastructure at distribution level, and other transport means (road, rail) may in these cases be more appropriate.

**Repurposing for Water Transport:** Only 17% of pipelines under MPB and MPC can be repurposed, which require full replacement, primarily due to integrity and contamination concerns.

- Total Not Applicable (NA):
  - LP: 47,920 km
- Replacement Required (RR):
  - MP Carbon Steel and PE: 10.073 km

As Flanders has already a dense water distribution network, it is unsure to what extent there would be a market demand for using converted gas distribution pipelines for water transport. This option could be interesting if the water quality would be different depending on the use, e.g. if separate networks would be considered for drinking water and water for other purposes. In such a scenario, two parallel pipelines could be developed, making use of decommissioned sections of the gas distribution network for distributing water that is not used for drinking purposes. In that case, replacement may not be required as contamination would not be an issue.

**Repurposing as Collector Network:** This use case is applicable with the existing gas distribution infrastructure, needing an installation process.

- Widely Applicable (AP):
  - o Most materials across LP, MPA, MPB, MPC are applicable: ~57,467 km
- Evaluation Required (AP/ER):
  - o Fiber Cement & Cast/Ductile Iron (LP): 525 km

This option could in particular be interesting in urban areas, where the available public domain for utilities is limited. In rural areas, this option could also be attractive if otherwise unused pipelines would have to be removed from the underground.

# 5. Decommissioning of gas distribution grid

In the event that continued use or immediate repurposing of the gas network is deemed unviable, decommissioning must be considered. This is driven by the EU Directive 2024/1788 (on common rules for the internal markets for renewable gas, natural gas and hydrogen)<sup>85</sup> and the accompanying Regulation EU 2024/1789 (on the internal markets for renewable gas, natural gas and hydrogen)<sup>86</sup>. The Directive (Article 57) states that "where a reduction in natural gas demand requiring the decommissioning of natural gas distribution networks or parts of such networks is expected", DSOs must develop and maintain a decommissioning plan. The new provisions of the Directive are required to be adopted into EU Member States' law by August 2026.

# 5.1. Lessons learned and best practices in other European countries

A literature review has been undertaken, encompassing existing regulations, standards, studies and reports in neighbouring countries in order to outline what progress has been made and what challenges have been encountered in planning to decommission their gas networks.

#### 5.1.1. The United Kingdom (UK)

The UK government has set in law that the country will be net zero by 2050. The current approach to reach this target is through large scale electrification. In this context, a new government task force, called 'Mission Control', has been set up. The aim is to have an electricity mix in 2030 consisting of 95% electricity from clean energy sources and about 5% unabated gas-based electricity for essential back up. In addition to this, the UK has set up an independent National Energy System Operator (NESO) to develop local and regional energy plans that can deliver net zero. In 2024, NESO published its Future Energy Scenario (FES<sup>87</sup>), which provides various pathways for the transition to net zero. The holistic pathway is one that UK regulator Ofgem referenced in its original guidance for the current regulatory period. This pathway forecasts small amounts of natural gas demand in 2050 compared to the current demand.<sup>88</sup>

While the UK is targeting to achieve net zero GHG emissions by 2050, there is currently no overarching directive from the Government Department for Energy Security and Net Zero (DESNZ) or the energy regulator (OFGEM) to the DSOs to have full network decommissioning plans in place. A number of studies and projects around conversion to hydrogen, biomethane scale-up and other green initiatives are being undertaken by the DSOs with a view to continuing their role as energy transporters in a net zero future.

The only relevant regulation or legislation that references decommissioning is the Pipelines Safety Regulations (1996), which states: "14.— (1) The operator shall ensure that a pipeline which has ceased

<sup>&</sup>lt;sup>88</sup> DNV publishes each year its Energy Transition Outlook for the UK. The model looks at the UK's pathway to net zero based on current policy trends and predicts that the UK will not meet the legally binding 2050 Net Zero target. Based on current trends, almost half of the homes in the UK are expected to still use natural gas in 2050. According to current policy trends and without the significant adoption of low carbon technology, the UK gas grids would hence still be essential to meet consumers' energy demand in 2050. DNV (2025) Energy Transition Outlook UK 2025.



50 =

<sup>&</sup>lt;sup>85</sup> Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen

<sup>&</sup>lt;sup>86</sup> Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen

<sup>&</sup>lt;sup>87</sup> National Energy System Operator (2025) <u>Future Energy Scenarios 2025.</u>

to be used for the conveyance of any fluid is left in a safe condition. (2) The operator of a pipeline shall ensure that work done in discharge of the duty contained in paragraph (1) is performed safely"89.

The UK industry standards, from the Institute of Gas Engineers and Managers (IGEM), do outline decommissioning options and considerations for transmission pipelines<sup>90</sup> and distribution mains<sup>91</sup>. The options are to either:

- Utilise the pipeline for another purpose,
- Remove the pipeline or sections of it,
- Leave it in-situ but rendered permanently safe.

No option is given priority over another, but they go on to state that the decision should be made with consideration to the following factors:

- Public safety,
- Environmental protection,
- Future land use,
- Legal duties and residual liabilities,
- Practical difficulties and financial considerations,
- Maintenance requirements, i.e. to prevent corrosion and/or ingress of water or other gases.

Costs for decommissioning the UK gas networks have not been looked at in great detail, in part due to there not being a government or regulator-led strategy around this. OFGEM is currently reviewing business plans from the DSOs and adopting some first regulatory measures as part of the next 5 year "RIIO" price control period due to commence in April 2026. The UK government has also recently initiated a public engagement process with the objective to review the implications of the gas transition and possible policy options.<sup>92</sup>

In 2023, a report by ARUP, commissioned by the National Infrastructure Committee (NIC) and OFGEM, was published that included cost estimates of decommissioning the UK gas networks in a high, medium and low hydrogen scenario based on various National Energy System Operator future scenarios. Cost estimates ranged from £17-74 billion (excluding any remuneration to the gas network operators), but with a high degree of uncertainty stated  $^{93}$ . Coupling this with the overall UK gas network length of approximately  $280,000 \text{km}^{94}$  would give a potential decommissioning cost of between £60,714 and £264,285 per km (approx. €71,000-€309,000 per km). This is for the physical costs of decommissioning only, not including depreciation of residual RAB value, remuneration, or other incentives to the gas network operators and end users as part of the transition.

Another indicative measure of potential decommissioning costs can be estimated by looking at the cost of gas mains and service replacement, as the overlap in activities required is large. The UK gas DSOs have been conducting a proactive replacement programme of 'at-risk' iron mains within 30 meters of a property to improve safety. This major infrastructure programme commenced in 2002

Trinomics —

<sup>89</sup> The Pipelines Safety Regulations 1996

<sup>&</sup>lt;sup>90</sup> <u>IGEM/TD/1</u> Edition 6 with amendments May 2024 - Steel pipelines for high pressure gas transmission | The <u>Institution of Gas Engineers and Managers (IGEM)</u>

<sup>91</sup> JGEM/TD/3 Edition 6 - Pipelines for gas distribution | The Institution of Gas Engineers and Managers (IGEM)

<sup>&</sup>lt;sup>92</sup> Department for Energy Security & Net Zero (2025) <u>Policy paper - Midstream gas system: update to the market</u>. Published 30 June 2025.

<sup>93</sup> Watt-Logic (2024) Gas Network Decommissioning

<sup>(</sup>a third-party paper is referenced here rather than the actual report as the original government report is no longer available online).

<sup>&</sup>lt;sup>94</sup> Cadent (2024) The future of the gas network.

and is due to be completed in 2032<sup>95</sup> 96. The largest proportion of costs is in excavating, preparing and isolating the pipe, as well as reinstating afterwards. The labour and materials cost in installing a new pipe make up a relatively small percentage of the overall costs. OFGEM publishes the volumes and costs of Tier 1 (<8" iron pipe) mains replacement and associated service replacements (accounting for approximately 80% of all 'at risk' iron pipes)<sup>97</sup>, which for 2024 indicates an average cost of £161,466 per km mains (approx. €189,000 per km), and £613 per service replacement (approx. €717). This is comparable to the range highlighted in the ARUP report above, giving an overall UK cost of £59.3 billion based on 23 million gas consumers. Overall, in the current regulatory period Ofgem figures suggest that over 15,000 km of Tier 1 pipelines will have been replaced by April 2026, at a cost of just under £2.4 Billion. The UK gas DSOs have recently submitted their business plans for the next regulatory period to OFGEM, for which they expect to spend approximately £4 billion to replace/decommission over 15,000 km of Tier 1 mains and services. As such, looking at historic mains and service replacement costs in Flanders if available, may also be a useful indicator of future decommissioning costs.

The UK DSOs can charge consumers for gas service disconnections; however, this is only where a direct request is made to them by the consumer. In 2024, the average cost of this was £1950<sup>99</sup>. Disconnections can be free of charge when the supplier removes the meter and caps the supply (a separate, typically £0-£100 cost) as the DSO then requires to fully decommission the incoming service 12 months after this in line with the Gas Safety (Management) Regulations (1996). There are government incentives in place to replace gas boilers with heat pumps which may drive up gas disconnection numbers, uptake is accelerating but still well behind the 2028 target of 600,000 per year (note that this target also includes new properties and installations transferring from other energy sources, in addition to those transferring from gas).

Whilst there are no public methodologies for network-wide decommissioning in the UK, several studies have been carried out focusing on potential conversion to hydrogen, which contain some useful planning strategy that could be used in a decommissioning-only scenario as well. This involves carrying out a detailed survey of the network and dividing it into sectors of around 2,500 consumers apiece, which is deemed to be an achievable area to convert at once without consumers being without gas supply for more than 5 days. In a conversion scenario, the order in which these sectors are converted is dependent on how the new hydrogen supply is being brought in, as well as interdependency of neighbouring sectors, however where only decommissioning needs to be considered, this becomes a simpler exercise of starting from the extremities of the network and working upstream from there, and the installation of alternative heating technologies such as heat pumps would not typically be dependent on the gas decommissioning works, meaning this could mostly be carried out well ahead of the cut-off date, and potentially allow larger sectors to be decommissioned at once.

#### 5.1.2. Germany

Germany has set a net zero GHG emission target to be achieved by 2045. The green paper published in March 2024 by the Federal Ministry for Economic Affairs and Climate Protection (BMWK) sets out the options around conversion or decommissioning of the gas networks, whilst aiming to balance

🔻 Trinomics 🥷 💳

<sup>&</sup>lt;sup>95</sup> Health and Safety Executive (UK regulator for workplace health and safety) – <u>Enforcement policy for the iron mains risk reduction programme 2021-2026</u>.

 $<sup>^{96}</sup>$  In 2002 the HSE estimated that there was approximately 100,000 km of at-risk mains that needed to be replaced by 2032.

<sup>97</sup> Ofgem (2025) RIIO-2 Gas Distribution: Annual Report 2023 to 2024 supplementary data file.

<sup>&</sup>lt;sup>98</sup> An average of the accumulated spending and forecasted length of mains to be replaced in the next regulatory period suggests a cost of k£226 per km of pipeline. This a very speculative figure as the geographical differences in the networks are huge. For example, decommissioning cost of tier 1 mains in central London vs rural locations in Yorkshire will be significantly different.

<sup>&</sup>lt;sup>99</sup> Ofgem (2025) <u>Call for Input - Exercising Consumer Choice: A review of the gas disconnections framework.</u>

meeting climate goals with security of energy supply and costs<sup>100</sup>. It highlights that under current German law, DSOs may have to remove decommissioned assets or compensate landowners for continued concession to allow the asset to remain, either on an ongoing or permanent basis.

The Association of German Gas Transmission System Operators (FNB Gas) provided a statement in response to the green paper cited above, setting out its position on several of the questions raised by BMWK<sup>101</sup>. Among these it is highlighted that should dismantling be required, this could drive up charges for the remaining gas users connected to the network at that point and suggests that in most instances there are no harmful effects from leaving the asset in-situ.

The Heat Planning and Decarbonisation of Heat Networks act<sup>102</sup> obliges municipalities that have >100,000 residents to develop heat plans by June 2026, while municipalities with <100,000 residents should develop such plans by June 2028. The plans should include a strategy for the existing gas network. Whilst this planning obligation focuses heavily on heat network expansion, there is also consideration given to gas network conversion and decommissioning.

The Buildings Energy Act<sup>103</sup> is intertwined with the Heat Planning act, requiring since the start of 2024 new properties heating systems to use at least 65% renewable energy, which basically excludes oil and natural gas heating. Existing oil and gas systems can be replaced subject to alignment with the respective municipalities' heat plans, up until the 2026/2028 deadlines. These regulations are accompanied by financial support of up to 70% of the costs of installing a new compliant system, including a 20% climate acceleration bonus for switching before the end of 2028. There are also subsidies for installing energy efficiency measures in properties, which may make technologies such as heat pumps more appealing as they could improve their performance relative to installing technologies without supporting improvements. Where consumers still cannot afford to change over, they may be exempted from these requirements, but heat plans would still need to account for how to support their eventual switchover in the long term should the gas network in that area be planned for decommissioning rather than converted.

In 2021 the city of Mannheim announced plans to phase out its gas network by 2035, becoming the first German city to announce such plans. To encourage the switchover, subsidies of up to €10,000 euros per property have been offered 104105, with an expansion of district heating and upgrading the electricity network to support heat pump installations. Some commercial and industrial consumers may remain connected to the network where these alternatives are not suitable, with a view to converting the remaining network to hydrogen or another renewable energy option. Hamburg is analysing what areas may be able to be disconnected from the gas network, with more detailed plans expected in 2026. Augsburg is planning to decommission its gas network by 2045, and Munich has a non-binding plan to do the same, both in line with Bavaria's net zero GHG emissions target date.

A report conducted on behalf of the German association of gas transmission network operators FNB¹06 provided cost estimates for decommissioning and dismantling transmission pipelines, pressure regulating stations (PRSs) and small and large compressor stations, as well as distribution pipelines and small and large distribution PRSs. This report estimates the cost of only decommissioning pipelines (no removal or filling afterwards) at €20,000/km, filling pipelines with

🔹 Trinomics 🥷 💳

53

<sup>&</sup>lt;sup>100</sup> Bundesministerium für Wirtschaft und Klimaschutz (2024) <u>Green Paper Transformation Gas Wasserstoff</u> Verteilernetze.

<sup>&</sup>lt;sup>101</sup> Association of German gas transmission network operators FNB Gas (2024) <u>Schriftliche Stellungnahme zum</u> <u>"Green Paper Transformation Gas-/Wasserstoff Verteilernetze" vom 14.03.2024</u>.

<sup>&</sup>lt;sup>102</sup> <u>Gesetz für die Wärmeplanung und zur Dekarbonisierung der Wärmenetze</u>.

<sup>103</sup> Gebäudeenergiegesetz (GEG)

<sup>&</sup>lt;sup>104</sup> MVV website, I<u>nformationen zum Rückzug aus dem Gasnetz</u> and <u>Wärmewende</u>, accessed online 24/09/2025

<sup>&</sup>lt;sup>105</sup> J. Rosenow and C. Kemfert (2025) <u>A future without gas: How German cities are managing the transition to</u> climate-neutral energy

<sup>&</sup>lt;sup>106</sup> Frontier Economics, IAEW, 4Management, and Emcel (2018) <u>The importance of the gas infrastructure for Germany's energy transition</u>.

bentonite or similar once decommissioned at €200,000/km, and fully dismantling pipelines at €280,000/km. It estimates the cost of removing large distribution PRSs at €75,000 per unit, and small PRSs at €10,000 per unit. The cost of decommissioning pipelines of only €20,000/km appears extremely low compared to the UK estimates.

#### 5.1.3. Switzerland

Switzerland has set a net zero GHG emission target to be achieved by 2050, however several towns, cities and regions (cantons) have set more ambitious dates, and some are already enacting gas network decommissioning plans in order to help achieve this.

Zurich targeted an expansion of its existing district heating networks, allowing its gas network to be mostly decommissioned by 2040. It was announced in 2011, with the first area due to be fully transferred in 2016, however this was postponed to 2021 due to resistance from residents about the short timeframe and lack of financial support for those who had recently invested in new gas appliances<sup>107</sup>. Any remaining gas network pipework is planned solely for the transport of biogases rather than "fossil" gas. This strategy of prioritising areas with large proportions of alternative heating technologies first draws parallels with targeting areas with the fewest consumers to be decommissioned first. In order to better inform consumers, Zurich has developed a GIS map<sup>108</sup> that details individual properties current heating source, and recommends the most suitable renewable option (district heating, air or ground source heat pump), as well as buildings' suitability for solar panels, highlighting where renovations would be beneficial before changing heating technology (installing energy efficiency measures such as improved insulation) and an individual energy report for the resident's property.

Winterthur, near Zurich, plans to decommission 80% of its gas network by 2040, with an interim target of 50% decommissioning by 2033<sup>109</sup>. Reduction in investment in the gas networks due to moving into a maintenance & safety only model, with no new connections going forward, frees up funding to instead invest in new district heating networks. Consumers are given 10 years notice of the switchover in their area, and they are partially compensated based on a residual value calculation for replacing their heating system where it is less than 20 years old. The remaining pipeline will be used to transport biogas or synthetic gas, for industrial use or meeting peak demands on heat networks, but no longer for direct residential heating <sup>110</sup>.

Basel-Stadt canton voted on a net zero GHG emission target to be achieved by 2037, and in early 2024 declared that the gas distribution network would be decommissioned by this date, with domestic demand being met predominantly by district heating<sup>11</sup>. From 2028, approximately 1000 users per year will be disconnected, with around 5800 of the 9000 gas heating users being moved onto district heating, and the remainder utilising alternative systems such as heat pumps. There are a further 2000 properties that utilise gas only for non-heating purposes such as cooking. Partial subsidies for installing new heating systems are provided, with additional compensation for those with newer gas appliances tapering down as they get to their expected service life end. As with Zurich, the DSO, IWB, provides a GIS map showing a recommended replacement system option<sup>112</sup>.

#### **5.1.4.** France

France has set a net zero GHG emissions target to be achieved by 2050. A report by the Energy Regulatory Commission (CRE) looks at the role of the gas network in meeting the national 2030 and

<sup>&</sup>lt;sup>112</sup> Map for district heating expansion and gas decommissioning Basel-Stadt | IWB



<sup>&</sup>lt;sup>107</sup> Energie360 (municipal utility owning and operating gas distribution in Zurich) website, Gasnetz Stillegung in Zürich, accessed online 24/09/2025.

<sup>&</sup>lt;sup>108</sup> EnerGIS - Energy Map of the City of Zurich

<sup>&</sup>lt;sup>109</sup> Stadtwerk Winterthur, <u>Zukunft Winterthurer Gasnetz</u>, accessed online 24/09/2025.

<sup>&</sup>lt;sup>110</sup> Decarb city pipes 2050 (2022) <u>H/C Plan Winterthur</u>.

<sup>&</sup>lt;sup>111</sup> IWB website, <u>Gasstilllegung in Basel-Stadt</u>, accessed online 24/09/2025

2050 GHG emissions targets<sup>13</sup>. The considered approach involves maintaining the bulk of the gas network, with a view to transitioning mainly to green gas, predominantly biomethane with potential utilisation of hydrogen and synthetic methane as well. The motivations for this include the significant level to which the distribution network has been renewed recently, the geographic disconnect between green gas production sites and demand, and the role the gas network can continue to play as an interconnector to its surrounding neighbours whilst aiding their own energy security and winter peak balancing. Another factor is that in areas such as Le Havre, an 89% drop in number of consumers who move across to heat networks leads only to 34% of the grid being freed up. It is viewed as more productive to look at a local level where full decommissioning may be supported if alternative heating systems are deemed more viable, rather than banning natural gas use at a national level and hampering future options.

#### 5.1.5. Austria

Austria has set a net zero GHG emissions target to be reached by 2040, although following recent elections where the previous government coalition including the Green party was replaced by a more centrist coalition, this may be relaxed<sup>114</sup>. Heat planning is carried out at a regional level with little central regulation leading to a lack of standardisation across areas. The number of consumers connected to the gas network has started to fall in recent years, possibly driven by increasing gas costs coupled with financial incentives to replace gas systems with renewable alternatives, including an up to 100% subsidy for the lowest 20% income households<sup>115</sup>. Gas pipelines are considered permanent fixtures in Austria and as such are not subject to removal in the event of decommissioning. AGGM, the Austrian Gas Grid Management company, has a hydrogen roadmap<sup>116</sup> that looks to repurpose significant sections of the gas network, but still works alongside the remainder of the network operating with biomethane by 2040. It is unclear what proportion of the grid may be decommissioned as part of this, as some areas are also considering building new or expanding existing heat networks. The Austrian regulator E-Control expects that gas distribution networks will be largely decommissioned in the long-term with limited potential for repurposing. As a result, the gas network tariffs would significantly increase from the mid-2030s onwards.<sup>117</sup>

#### 5.1.6. Denmark

Denmark has a net zero GHG emissions target to be achieved by 2045, but furthermore also has targeted removing natural gas as a heat source for domestic buildings by 2030, and conversion of the gas network to 100% biomethane by 2035<sup>118</sup>. This phase out is helped by natural gas only making up around 9% of their total energy consumption as of 2021,<sup>119</sup> with district heating accounting for around 70% of residential properties as of 2025<sup>120</sup>. Denmark has a long history of heat planning driven by the Heat Supply Act enacted in 1979. New buildings are no longer permitted to connect to the gas networks. The gas DSO, Evida, has carried out modelling of the gas networks<sup>121</sup> in order to inform decommissioning plans and priorities. Approximately 750 km of pipelines planned or already



<sup>&</sup>lt;sup>113</sup> Synthèse du Rapport Avenir des infrastructures gazières aux horizons 2030 et 2050, dans un contexte d'atteinte de la neutralité carbone.

<sup>&</sup>lt;sup>114</sup> Politico (2025) <u>Austria walks back support for EU's 2040 climate target.</u>

<sup>&</sup>lt;sup>115</sup> Bundesministerium für Klimaschutz, Umwelt, Energie, Mobilität, Innovation und Technologie (2023) <u>Evaluierung</u> <u>des Förderprogramms "Sauber heizen für Alle"</u>.

<sup>&</sup>lt;sup>116</sup> AGGM website, <u>H2 Roadmap</u> 2.0, accessed online 24/09/2025.

<sup>&</sup>lt;sup>117</sup> E-Control (2025) <u>Die Gasnetze – ein Blick auf die aktuelle Situation</u>.

<sup>&</sup>lt;sup>118</sup> Klima-, Energi og Forsyningsministeriet (2022) Klimaaftale om grøn strøm og varme 2022.

<sup>&</sup>lt;sup>119</sup> Energistyrelsen (2023) Data, tables, statistics and maps - Energy Statistics 2023.

<sup>&</sup>lt;sup>120</sup> RAP (2025) <u>Making Europe's homes 'Hygge': Danish lessons on district heating - Overview of Danish district heating policy and regulation</u>.

<sup>&</sup>lt;sup>121</sup> Evida (2022) <u>Konverteringskortlægning II</u>.

decommissioned has been highlighted as potentially suitable for hydrogen conversion in order to supply industrial users within reach of this corridor.

Alongside the Swiss examples discussed earlier, this appears to be the most advanced decommissioning project underway, underpinned by detailed planning and commitment to scaling up alternative heating solutions to enable it.

#### 5.1.7. The Netherlands

The Netherlands has set a net zero GHG emissions target to be achieved by 2050. The 2019 Climate Agreement sets out that no homes or other buildings should be heated by natural gas by 2050, and that by 2030 there should be 1.5 million homes out of approximately 8 million heated by means other than natural gas.<sup>122</sup> Natural gas supplies heat to 77% of homes in 2024<sup>123</sup>, and accounts for around 35% of the country's energy consumption.<sup>124</sup> Each municipality is responsible for developing its own heat plan, including planning for a natural gas free future. This also involves neighbourhood level plans for alternative heating technologies (with the cheapest feasible option preferred) and timelines to implement these. In addition to the 2018 nationwide ban on new buildings being connected to the gas networks, municipalities can also zone areas to prevent new gas connections to existing buildings. This municipal level planning means entire districts are to be transferred off gas at one time, preventing issues around uneconomic operation when consumer numbers become low. This is allowed by law to be carried out within as little as 8 years of publishing the heat plan. The government intention is for no consumer to be worse off due to the switch. Subsidies to cover part of the cost of a heat pump installation, solar water heater or heat network connection are available<sup>125</sup>, along with lowinterest rate loans for energy-saving measures like heat pumps, insulation, solar panels, and connection to heat networks and 0% interest for households with an annual income below € 60,000.126

In 2018 the PAW (Programme for Natural Gas Free Districts) programme was launched, providing support to districts planning the earliest transitions away from natural gas, providing funding mechanisms and preferential loans to enable measures towards the natural gas free target. <sup>127</sup> This allowed the districts to feedback and share their experiences, and the challenges faced with the Dutch government. To date, this programme is behind schedule with lower numbers being switched off gas than anticipated, due to unexpected complexity in the financial, technical and organisational aspects of the works.

Reduction in gas demand is driven by high recent uptake of heat pumps, with over 350.000 installed per year since 2020. This is further incentivised by the removal of gas network disconnection charges since February 2024<sup>128</sup> and the compensation of DSOs for the costs of decommissioning and dismantling of gas distribution networks.

There are plans underway to develop a 1200 km hydrogen transmission network consisting of 85% converted gas pipelines. Around one third of consumers are considered to be best supplied by biomethane in a net zero scenario, necessitating the retention of a significant portion of the distribution network.

<sup>&</sup>lt;sup>128</sup> ACM (2023) <u>Adjusted working method for the safe removal of gas connections.</u>



**=** 56 **===** 

<sup>122 &</sup>lt;u>National Climate Agreement – The Netherlands.</u>

<sup>&</sup>lt;sup>123</sup> Centraal Bureau voor de Statistiek (2025) <u>Hoofdverwarmingsinstallaties woningen, 2022-2024</u>

<sup>&</sup>lt;sup>124</sup> Centraal Bureau voor de Statistiek (2024) The Netherlands in Numbers - <u>How much energy is consumed in the Netherlands?</u>

<sup>&</sup>lt;sup>125</sup> Rijksdienst voor Ondernemend Nederland – <u>Investeringssubsidie duurzame energie en energiebesparing:</u> <u>Warmtepomp woningeigenaren</u>, accessed online 24/09/2025.

Nationaal Warmtefonds, accessed online 24/09/2025

<sup>&</sup>lt;sup>127</sup> Government of the Netherlands (2022) <u>Evaluatie Programma Aardgasvrije Wijken</u>.

The textbox below presents the results of a recent study conducted by Dutch gas DSOs on the costs of decommissioning of their gas networks according to 4 scenarios.

#### Textbox 5-1 Study about the cost of gas distribution network decommissioning in the Netherlands

De regionale gasnetbeheerders in Nederland hebben in een recente studie <sup>129</sup> een raming gemaakt van de kosten voor ombouw of verwijdering van hun gasnetten in 4 scenario's. In twee scenario's voorzien ze voor de gebouwde omgeving een ombouw van een gedeelte van het bestaande aardgasnetwerk naar een waterstofnetwerk. Daar waar in de gebouwde omgeving geen gebruik meer zal worden gemaakt van gas voor verwarming, zijn de kosten geraamd voor het verwijderen van het gasnet en de aansluitingen. Zoals blijkt uit de grafiek, lopen de geraamde kosten zeer hoog op, van bijna € 200 miljoen per jaar (van 2035 tot 2050) in het scenario INT (Internationaal georiënteerd, ruimte voor import) tot ca € 500 miljoen per jaar in de scenario's DEC (Decentrale initiatieven) en NAT (Nationaal leiderschap). In het scenario EUR (Europese integratie) zijn de totale kosten voor ombouw en verwijdering het laagst. Als beslist wordt om de leidingen buiten gebruik te plaatsen en op een natuurlijk moment te verwijderen, dan kunnen de kosten substantieel lager zijn dan deze ramingen. Een meer uitgebreide beschrijving van de scenario's is beschikbaar in de studie.

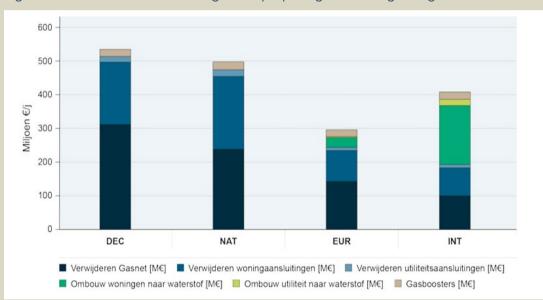


Figure 5-1 Annual decommissioning and repurposing costs of regional gas networks

De lengte en het aantal aansluitingen van de regionale gasnetten in Nederland zijn substantieel hoger dan deze van de Vlaamse distributienetten: 116.000 km regionale gasnettten in Nederland (2023) tegenover 58.000 km distributienetten in Vlaanderen, en ruim 7,2 miljoen aansluitingen (2023) in Nederland tegenover 2,4 miljoen aansluitingen in Vlaanderen.

<sup>&</sup>lt;sup>129</sup> Netbeheer Nederland (2023) <u>Integrale infrastructuurverkenning 2030-2050</u>.

# 5.2. Possible Roadmap for Decommissioning in Flanders

#### 5.2.1. Planning considerations

In Flanders, the learnings from the progress and plans in other countries can enable a well-informed decommissioning plan to be developed and enacted, if the reuse and repurposing options presented and assessed in the previous chapter of this report are not being taken up.

The first step in this roadmap is identifying the date by which the network is to be decommissioned, on or ideally before the net zero GHG emissions target date. Based on this, modelling of the network can be undertaken alongside operations planning to identify how far ahead of this date the decommissioning process would have to start. This modelling should highlight best available alternative heating systems in each area, and the network should be sectorised at a neighbourhood, town, locality and regional level.

In Flanders, the Local Energy and Climate Pact (LEKP)<sup>130</sup> is an agreement that local authorities sign up to committing to develop heat plans and implement varying levels of other green initiatives depending on the level they have signed up to (LEKP 1.0, 2.0 or 2.1). The vast majority of local authorities have committed to at least the first iteration of this. Part of this pact involves developing local heat plans by the end of 2030 as well as setting targets around the number of collective (10+ properties) reduced-carbon and fossil-free renovation projects that must be carried out. These heat plans should outline the most viable path to a renewable heating solution for the properties within their respective localities, taking account of existing infrastructure, such as district heating systems that can be expanded and potential waste heat sources to be utilised such as industrial processes or data centres, as well as assessing the building stock to evaluate the suitability of each heating solution. This is supported by a demolition plan which identifies where it is economically and environmentally unsuitable to retrofit an existing older building and instead a demolition and rebuilding with a modern renewable heating solution should be considered. These local heat plans should be considered and utilised to shape gas distribution network decommissioning plans, particularly around setting (and potentially adjusting) timelines based on each locality's planned progress in moving consumers to renewable heating solutions. The expansion of heat networks in particular may also lead to a medium-term increase in gas network connections for hybrid district heating systems, which combine large electric or geothermal heat pumps with a gas boiler system, which in the longer term would either need to be decommissioned or transitioned to an alternative green fuel such as biomethane. There is a risk however that some local authorities may drop out of the LEKP once funding from the Flemish government stops in 2026<sup>131</sup>. Furthermore, Article 25, 6 of the Energy Efficiency Directive EU/2023/1791<sup>132</sup> also states that municipalities with populations exceeding 45.000 shall prepare local heating and cooling plans, however this legal provision has not yet been transposed into Flemish legislation.

For each of the sectors defined in the plans, viability limits should be defined based on a number of criteria at which point decommissioning plans would then be enacted. This includes financial and engineering viability based on a minimum number of consumers or gas demand remaining. The financial aspect in particular could be driven by the way rising costs may be passed on to the shrinking consumer base, which would likely have an increased proportion of low-income, vulnerable or fuel-poor consumers as they are least likely to be able to afford to switch to an alternative heating solution. In this case, a maximum tolerable consumer cost should be set, likely driven and dictated by the regulator, but this may require public research and further study to define due to the range of socio-economic factors that feed into it. Conversely, if consumer costs are capped to prevent this, the point at which it becomes uneconomical for the DSO to operate a network in certain areas becomes

<sup>&</sup>lt;sup>132</sup> Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency.



<sup>&</sup>lt;sup>130</sup> Vlaamse overheid (n.d.) <u>Het Lokaal Energie- en Klimaatpact</u>.

<sup>&</sup>lt;sup>131</sup> Vereniging van Vlaamse Steden en Gemeenten (2025) <u>Lokaal Energie- en Klimaatpact</u>.

a tipping point, which would require agreement between the DSO and regulator. Again, this requires a range of factors to be considered, such as the proportion of consumers forecast to still be connected at the point, and the level of unprofitability that may be sustained in one area being offset by areas operating more profitably. In some cases where non-viable sections trigger decommissioning being undertaken, the potential to create stranded assets should also be considered. This could be a pipeline linking two areas but not defined under either of their specific plans, or downstream sectors fed by now-unviable upstream sectors, which then need to be assessed for what is best between decommissioning and the implications of maintaining a feeder main to the downstream sector until it reaches its own defined decommissioning trigger point.

In all cases, the decommissioning plan will need to work around the longest of 3 timelines at a minimum - the length of time required to decommission the network, the length of time to roll out adequate alternatives (heat networks, heat pumps etc), and a timescale that the consumers themselves feel is fair to transition, which will be influenced by the options and incentives available to them. All of these need to be set around a backstop of achieving this in line with the net zero goal date. This backstop schedule can be built in line with the local heating plans to prioritise areas with greater existing or planned transition progress in order to best spread-out resource over the coming years and creating a last-minute overburdened workload. Incentives to disconnect gas consumers may enable the acceleration of this process. This has been carried out in different ways across Europe, with some removing disconnection fees, and others providing grants or subsidies for installing alternative heating technologies or even tapered refunds for those who have invested recently in new gas appliances. These schemes especially need to cater for low-income or vulnerable households, as they could otherwise shoulder the burden of rising costs, whereas those better off have already disconnected and the costs of gas network charges may increase to account for the fewer remaining consumers. For these groups, as they are likely to be some of the last connected consumers in place, sufficient support must be put in place, defined in such a way that it goes where it is most required, and not to those who can afford to transition their heating solution to renewable energy but have chosen to hold on as late as possible in the hope that a greater incentive may exist later in the process. For all incentives, a balance between utilising public funds, where the burden is shared across all taxpayers, and increasing costs to gas consumers specifically to fund this must be maintained to prevent conflict between the overlapping, but different interest groups, especially early adopters that may feel aggrieved that they "done the right thing" without assistance while those who waited later were rewarded for their perceived inaction.

Adequate notice to consumers is another key consideration, with around 10 years appearing to be the average in decommissioning projects reviewed here. Furthermore, making available the data behind best alternative heating technologies to consumers, as Zurich has done, allows them to make well informed decisions in a timely manner.

Another learning from some of the Swiss projects is taking the opportunity to decommission areas earlier, where for example early adoption rates of gas disconnections are high, as this will help spread the cost and labour effort over a longer period, making the remaining decommissioning workload lighter. This would potentially require additional consumer acceptance as it is before the date they were initially told, and additional incentives or support may be required to disconnect the last consumers. It can only be done where decommissioning would not affect surrounding sectors and could result in only main "spines" being left live to feed downstream areas or maintain interconnections required for adequate wider system pressure, but this would still ease the burden down the line. As another element the distance of the area to be disconnected from the connection point with the transmission network should be considered in the decommissioning plans, which would reduce the risk that network infrastructure is to be kept in operation to transport gas to downstream areas through parts of the network where customers have already been disconnected.

#### **5.2.2.** Decommissioning Extent

The Flemish legislation (VLAREM and VLAREMA) outline what should be done with decommissioned pipelines, in a descending priority order:

- 1. The pipeline or parts thereof is reused for the original purpose or for another purpose, possibly at another location;
- 2. Various substances or materials that make up that pipeline are reused;
- 3. The pipeline that is visible in the dug-up trench is removed and then treated in accordance with the rules applicable to waste management;
- 4. The pipeline is left in place after taking all necessary measures to prevent damage and contamination resulting from the pipeline or its presence;
- 5. The pipeline shall be removed if none of the previous initiatives is appropriate.

The relevant sections are shown in Textbox 5-2 (in Dutch). 133

#### Textbox 5-2 Relevant extracts from Flemish legislation

Relevante bepalingen in de Vlaamse wetgeving betreffende buitengebruikstelling van gasleidingen:

#### Artikel 4.1.6.3.

Onverminderd andere wettelijke bepalingen, milieuvoorwaarden uit dit reglement of bijzondere milieuvoorwaarden, moeten de definitief door de exploitant buiten bedrijf gestelde installaties of onderdelen ervan, binnen de 36 maanden na de buitengebruikstelling zo zijn aangepast dat schade aan het milieu of hinder uitgesloten zijn.

#### Artikel 5.3.8.1.

Deze onderafdeling is van toepassing op alle infrastructuur die bestemd is voor de transit, het transport, de transmissie of de distributie van vaste, vloeibare of gasvormige stoffen, energie of informatie, hierna genoemd kabels en leidingen, die zich bevinden onder, op of boven het openbaar domein. Ze geldt evenwel niet als de kabels of leidingen deel uitmaken van een ingedeelde inrichting of activiteit zoals vermeld in artikel 5.1.1, 8°, van het decreet van 5 april 1995 houdende algemene bepalingen inzake milieubeleid (artikel 5.1.1, 8° ingedeelde inrichting of activiteit: één inrichting of activiteit en de aanhorigheden ervan op een bepaalde locatie of, in voorkomend geval, meerdere inrichtingen of activiteiten en de aanhorigheden ervan op een bepaalde locatie die voor hun exploitatie als een samenhangend technisch geheel moeten worden beschouwd. Het feit dat verschillende inrichtingen en activiteiten een verschillend eigendomsstatuut hebben belet niet dat ze door hun onderlinge technische samenhang als één ingedeelde inrichting of activiteit kunnen worden beschouwd). Ze geldt eveneens niet voor vervoersinstallaties die vallen onder de wet van 12 april 1965 betreffende het vervoer van gasachtige producten en andere, door middel van leidingen.

#### Artikel 5.3.8.2.

Met behoud van de toepassing van andere wettelijke bepalingen neemt de kabel- en leidingbeheerder die een kabel of leiding definitief buiten dienst stelt volgens afnemende prioriteit, de volgende initiatieven voor het beheer van die kabel of leiding:

1° ze hergebruikt de kabel of leiding of delen ervan voor het oorspronkelijke doel of voor een ander doel, eventueel op een andere locatie;

— Trinomics 奏 💳

60

-

<sup>&</sup>lt;sup>133</sup> Besluit van 23 mei 2014 van de Vlaamse Regering tot wijziging van het besluit van 6 februari 1991 houdende vaststelling van het Vlaams reglement betreffende de milieuvergunning, het besluit van 1 juni 1995 houdende algemene en sectorale bepalingen inzake milieuhygiëne, het besluit van 14 december 2007 houdende vaststelling van het Vlaams reglement betreffende de bodemsanering en de bodembescherming, het besluit van 12 december 2008 tot uitvoering van titel XVI van het decreet van 5 april 1995 houdende algemene bepalingen inzake milieubeleid en het besluit van 17 februari 2012 tot vaststelling van het Vlaams reglement betreffende het duurzaam beheer van materiaalkringlopen en afvalstoffen

- 2° ze hergebruikt de onderscheiden stoffen of materialen waaruit die kabel of leiding bestaat;
- ze neemt de kabel of leiding weg die zichtbaar is in de opgebroken sleuf en beheert ze vervolgens volgens de regels die gelden voor het beheer van afvalstoffen;
- 4° ze laat de kabel of leiding ter plaatse nadat ze alle nodige maatregelen heeft genomen om schade en verontreiniging ten gevolge van de kabel of leiding of de aanwezigheid ervan te voorkomen;
- 5° ze neemt de kabels en leidingen weg wanneer geen van de vorige initiatieven aangewezen is.

Het bepalen van de te nemen maatregelen en de uitvoering ervan gebeurt met toepassing van de best beschikbare technieken. Daarbij houdt men in het bijzonder rekening met de gevaarseigenschappen van de kabels en leidingen of van de stoffen of materialen waaruit ze bestaan, zowel in eigen beheer als in de onmiddellijke nabijheid.

De kabel- en leidingbeheerder informeert de beheerder van het openbaar domein over de initiatieven en maatregelen die overeenkomstig het eerste lid worden genomen en over de termijn waarbinnen die worden uitgevoerd. De termijn mag, als de kabels en leidingen overeenkomstig het eerste lid, 3° en 5° weggenomen worden, niet meer dan 36 maanden bedragen na het definitief buiten dienst stellen van de kabel of leiding, tenzij de openbaar domeinbeheerder verzoekt de termijn te verlengen.

#### Artikel 5.3.8.3.

Kabels en leidingen die met toepassing van artikel 5.3.8.2, eerste lid, 4°, ter plaatse worden gelaten, worden geïnventariseerd overeenkomstig het KLIP-decreet van 14 maart 2008.

De kabel- en leidingbeheerder blijft verantwoordelijk voor het beheer van die kabels en leidingen.

The potential for option 1, to reuse the pipeline, is covered in sections 3 and 4 of this report. Option 2 seems to refer to the reuse of pipeline materials that have been removed as part of option 3 or 5. Option 3 is potentially applicable, especially to sections removed during decommissioning operations, whereby small sections may be removed during flow-stopping or similar tasks, but this only accounts for a small amount of the total pipeline length. In line with article 4.1.6.3, where actions are required in line with the chosen option, these should be carried out within 36 months of decommissioning.

Options 4 and 5 will be the basis for large scale decommissioning comparison, and are further outlined below:

- Option 4.1 (Air/Nitrogen Fill) The competent authorities could allow gas DSOs to leave decommissioned methane pipelines in the underground as long as there is a potential to reuse them for other purposes, e.g. as collector for cables or as transport pipeline for hydrogen or CO2. In this scenario, the deadline of 36 months would not apply, and the concerned assets would remain part of the RAB and be maintained in the DSO accounts. The principles for their valuation and eventual transfer price to another operator should be agreed upon with VNR.
- Option 4.2 (Grout/Concrete Fill) As above, but decommissioned pipeline filled with grout, concrete or similar, rendering it unusable in the future but permanently safe. The assets would likely no longer be part of the RAB.
- Option 5 If there is no potential reuse of decommissioned methane pipelines, the competent
  authorities could stimulate the concerned gas DSOs to remove the pipelines from the
  underground when technical interventions on other networks (e.g. electricity, water,
  communication cables, heat, ...) take place in the concerned underground section. The
  maximum deadline (36 months) could exceptionally be prolonged if such coordinated
  interventions cannot take place within that time period for technical or legal reasons. The



planning and split of the costs of coordinated interventions between the concerned network operators can be agreed upon via the "Vlaamse Raad van Netwerkbeheerders" (VRN); the principles should be agreed upon with the regulator VNR.

Table 5-1 below compares the 3 scenarios against various factors to be considered.

Table 5-1 Decommissioning Option Considerations

	Scenario		
Considerations	Option 4.1 – Air/Nitrogen	Option 4.2 – Grout/Concrete	Option 5
Environment	Minimal impact	Significant carbon emissions from grout/concrete production, transport and installation time	Most carbon intensive due to excavation and reinstatement works to expose and remove entire pipeline, as well as more associated emissions from the longer works timeline such as additional vehicle emissions
CAPEX Cost	Low CAPEX	Medium-High CAPEX	High CAPEX
OPEX Cost	High OPEX	Low OPEX	No OPEX
Legal duties	No change over existing obligations	Possibly able to discharge legal duties dependent on regulator and government position	Legal duties can be discharged once pipeline fully disposed of
Practical Difficulties	Low impact and difficulty	Requires significant volumes of grout/concrete, may require more excavation points to fill than required for decommissioning alone	Huge public disruption, scale of removal works far exceeds practical difficulties
Maintenance Requirements	Maintenance required to preserve pipeline integrity. Records to be maintained as per KLIP Decree	Minimal maintenance.	No future maintenance requirements

#### **5.2.3.** Decommissioning Costs

Estimated costs have not been a common feature of the available literature around decommissioning gas networks in Europe. Where costs have been put forward, there is a high degree of uncertainty around them due to the number of assumptions and other variable factors they are subject to. The costs presented below are for the physical costs of decommissioning only, not including depreciation of residual RAB value, remuneration, or other incentives to the gas network operators and end users as part of the transition.

Table 5-2 shows a summary of estimated or comparable costs for only technical decommissioning of pipelines (no grout fill or pipeline removal).

Table 5-2 Decommissioning Cost Estimates (Option 4.1)

Source	Cost per km	Comments
UK ARUP Decommissioning (High)	€309.000	
UK ARUP Decommissioning (Low)	€71.000	
UK ARUP Decommissioning (Average)	€190.000	
UK Mains Replacement Comparison (Actual Cost)	€189.000	
Germany Frontier Decommissioning	€20.000	
Average	€133.000	UK ARUP average value used for calculation

Whilst the report on behalf of the German gas TSOs by Frontier Economics provides a value much lower than the other two – and is already 7 years old - it has still been included in the average calculation due to the low number of available data points, the high uncertainty in the ARUP estimations, the use of a comparison against mains replacement and 2 of the 3 costs being UK focused.

Fluvius has provided cost estimates for the removal of LP & MP pipelines of €5,7 billion and €1,7 billion respectively. This does not include the cost of the initial decommissioning. Based on 2023 network lengths, this equates to €119.000/km for LP pipelines and €169.000/km for MP pipelines. Table 5-3 below compares these against the costs mentioned in the Frontier Energy report, where the average decommissioning value from Table 5-2 **Fout! Verwijzingsbron niet gevonden.** has been added to the Fluvius values to account for the initial decommissioning cost as well as the removal. The costs for pipeline removal estimated by Fluvius and Frontier Economics align well, however it should again be cautioned that the lack of data points and high degree of uncertainty in the estimates found in the literature mean these should only be used as a rough indicator.

Table 5-3 Decommission + Removal Cost Estimates (Option 5)

Source	Cost per km	Comments
Fluvius LP	€252.000	Average
Fluvius LP	€302.000	decommissioning value of €133.000/km
Fluvius Average	€261.000	from table 52 added to Fluvius removal-only cost to compare directly with Frontier cost. Fluvius average based on total pipeline length/total cost estimate (LP + MP).
Germany Frontier Removal	€280.000	

The Frontier Economics report also estimates the Option 4.2 at €200.000/km, but there are no other data points to compare this against.

# 5.3. Summary of key findings

Plans to phase out natural gas use for heating and ultimately decommission gas distribution networks vary across European countries. The EU and UK are targeting to achieve net zero GHG emissions by 2050 at the latest. The GHG emissions targets are generally linked to the proportion of homes connected to the natural gas network, policies and subsidies for replacing natural gas appliances with renewable energy options such as the use of biomethane. In the EU, plans to decommission gas grids will increasingly be driven by the EU Directive 2024/1788, which includes a specific provision to develop a network decommissioning plan if a reduction in natural gas is foreseeable, which would require the decommissioning of the natural gas distribution network or parts of such networks. At present, there is not yet information available on how EU Member States will transpose this provision in national law and intend to implement it. In the UK there is no overarching direction from Ofgem or DESNZ to develop such plans.

The future use of the natural gas grid in **Germany** is affected by the implementation of heat planning and decarbonisation of heat introduced under the heat networks act. Heat plans should be in place by June 2026 for large municipalities and 2028 for smaller municipalities. In addition to this, the heat networks act legislates that new properties must have heating systems that use at least 65% renewable energy. Supporting measures are put in place such as up to 70% reimbursement of costs for the installation of such systems. In Switzerland, there are national plans to be net zero by 2050 but several towns and regions have set more ambitious targets. For example, Winterthur, near Zurich, plans to decommission 80% of its natural gas network by 2040. Consumer engagement is central to their approach with 10 years notice given to natural gas users and subsidies to support replacement of appliances that are less than 20 years old. France has adopted the net zero GHG emissions target to be achieved by 2050 but sees its natural gas grid contributing to the climate target with most of it still utilised to transport biomethane and potentially hydrogen and synthetic methane. Austria has set a net zero GHG emissions target to be reached by 2040, but this could be relaxed by the new coalition government. Subsidies to replace natural gas appliances with renewable energy alternatives have been introduced. Austrian gas market area manager AGGM has set out plans to repurpose sections of the natural gas grid to hydrogen, operating alongside biomethane. Denmark aims to achieve a net zero GHG emissions target by 2045; to reach this target Denmark is aiming to disconnect domestic buildings from the gas grid by 2035. As the role of natural gas for heating in buildings is quite low in Denmark, the challenge is lower than in most other European countries. The phase out of natural gas has been enabled by policy in 1979 banning connections to the gas network. Finally, the **Netherlands** has set a net zero GHG emissions target to be achieved by 2050. The country has also set specific targets to eliminate natural gas for heat in buildings. To support the phase out of natural gas, disconnection from the grid has become free of charge since February 2024. DSOs are also compensated for the costs of decommissioning and dismantling gas distribution networks.

The aspiration of European countries to implement policies to gradually phase out natural gas use for heating and to consider options for decommissioning (or repurposing part of) the gas grid is clear. However, there are only a small number of practical examples where widespread decommissioning plans have been introduced, for example in Denmark. The technical challenges, costs and disruption to consumers are clear barriers in reducing the number of connections to the gas grid. However, with the right policies, stakeholder engagement and optionality for consumers in place these challenges can be reduced.

The **decommissioning cost estimates** vary significantly depending on the technical solution (removing or leaving in situ) and approach. Based on the current legislation in Flanders, it would not be required to remove decommissioned pipelines from the underground if adequate measures are taken to prevent damage and contamination resulting from abandoned pipelines.

# 6. Cost structure and drivers of gas DSOs in Flanders

This chapter provides an overview of the cost structure of gas DSOs and explains how these costs are expected to evolve based on different cost drivers. It starts by providing an introduction on the cost structure and drivers of gas network operators in general and then analyses the cost structure and main cost drivers of the Flemish gas DSOs.

## 6.1. Cost structure and drivers of gas DSOs

This first section explores the cost structure and drivers of gas DSOs in general. It serves as a basis to have a common understanding of the cost structure and main cost drivers of the Flemish gas distribution network.

#### 6.1.1. Cost structure of gas DSOs

#### Fixed and variable costs

Most of the costs for building and maintaining gas distribution networks are largely fixed. They vary with the length of the grid and the number and complexity of its components, but do not vary with the grid users' consumption and hence do not (substantially) decrease with natural gas use reductions resulting from the energy transition. **Fixed costs** include for example, depreciation costs, debt costs, return on equity, property taxes, insurance expenses as well as all non-gas operation and maintenance costs associated with gas distribution infrastructure (e.g. cost of fixed assets, personnel remuneration). <sup>134</sup>

**Variable costs** are costs that are linked to the peak system utilisation and/or transported volumes, such as energy use for compression, connection of network users, reinforcement of existing network components (e.g. due to increasing injection or off-take peaks), implementation of smart technologies.

#### Main components of the cost structure

The main components of the gas network costs are operations and maintenance costs (O&M or OPEX), depreciation and capital remuneration costs (CAPEX) and system service costs. These costs are generally controllable (endogenous) and therefore the level of revenues from periodic distribution network tariffs that DSOs can collect to recover these costs is determined in advance by the regulator.

- Operations and maintenance costs (or OPEX) comprise the costs of physical network assets for gas distribution and maintenance. OPEX are not capitalised and thus not included in the DSOs' Regulatory Asset Base (RAB). Energy losses incurred in gas distribution grids are also considered. The cost for services provided by third parties is included, when within the scope of operation & maintenance. OPEX are partly fixed (e.g. administrative costs), partly correlated to physical infrastructure (e.g. network maintenance) and partly correlated to capacity and/or transported volumes (e.g. energy used for compression).
- Investment costs (or CAPEX) comprise costs for network planning, construction and ownership for new network assets as well as major refurbishment (renovation) or replacement of existing assets. All investment costs, including related overhead costs, are capitalised (after deduction of one-off payments by the concerned grid users) and recovered through depreciation costs included in the tariffs. In this study, only network related

<sup>&</sup>lt;sup>135</sup> Trinomics (2020) Energy costs, taxes and the impact of government interventions on investments – Final report: Network Costs.



65 =

<sup>&</sup>lt;sup>134</sup> Catalyst Consulting (2016). Straight Fixed Variable Rate Design.

investment costs (recovered through regulated network tariffs) are considered. Financial investments, e.g. participations (shares) in other network operators or services' companies, are out of scope.

• **System service costs** are costs incurred to ensure the reliable operation of gas systems, such as balancing costs. These include among others ancillary services contracted to third parties. As the balancing of the gas system is in general ensured by TSOs, the system service costs of DSOs are limited. Costs incurred to guarantee the safety and operability of the physical infrastructure assets are considered as operational and maintenance costs.

Both OPEX and CAPEX can be endogenous or exogenous. As exogenous costs cannot be controlled or influenced by the DSO, they are in general not considered in benchmarking studies. They are in principle recovered without any margin via the grid tariffs or another mechanism. <sup>136</sup>

#### 6.1.2. Main cost drivers

There is limited literature on the cost drivers for gas distribution networks. The CEER study on cost drivers for gas transmission networks<sup>137</sup> may in this context be interesting, as similar technical and economic principles apply to both the transmission and distribution levels. The **main cost drivers for gas transmission networks as identified by CEER** are:

- Normalized asset base of the network operators (with assets such as pipelines, compressors
  and control centres): this parameter was found to be an important cost driver. The most
  relevant environmental factor influencing the asset base costs is topography, affecting both
  the costs of construction (due to new build, reinforcements, site access) and operation (due
  to maintenance access) as represented by a cost proxy using average component costs and
  corrected for topography);
- **Number of connection points:** the different connection points, all of which associated with certain costs of operation, metering, monitoring, etc, represent another important cost driver;
- **Installed compressor power** (representing the transport capacity) was found to also be a relevant cost driver;
- Length of pipelines.

The actual cost drivers for gas distribution networks vary between different grid operators and countries depending on factors such as their network topology, injection of biomethane, network capacity and constraints, and end use demand profiles.

Based on the study of CEER and our analysis of the existing data of Flemish gas DSOs, **three cost drivers are considered as most relevant** for this study:

- **Number of grid connections**, which determines specifically some cost categories, e.g. metering CAPEX and OPEX and to some extent billing costs);
- **Grid length**: this parameter reflects the network asset base (pipelines, compressors, meters, connections, other equipment) and is considered as an important cost driver that determines both CAPEX (investments in building and replacing pipelines and related equipment) and OPEX (grid maintenance);
- **Gas offtake volume**, which determines for example the odorization costs. This cost driver does in general not affect CAPEX (unlike electricity where offtake volumes drive investments while in the gas grid more spare capacity and flexibility is available due to line pack) and only affects a very limited OPEX share.

Other cost drivers, e.g. gas peak offtake capacity could be considered, but the related data is not readily available. Local biomethane injection volumes and peaks can affect CAPEX (investments in

<sup>&</sup>lt;sup>137</sup> CEER (2019) "Project CEER-TCB18 Pan-European cost-efficiency benchmark for gas transmission system operators: main report"



66

<sup>&</sup>lt;sup>136</sup> CEER (2024). <u>Report on Regulatory Frameworks for European Energy Networks 2024</u>.

reinforcement or reverse flows), but the related share in the net overall CAPEX will be very limited and this driver is therefore not specifically considered in this study.

# 6.2. Cost structure and drivers of gas DSOs in Flanders

This section first presents the principles behind the current cost structure of gas DSOs in Flanders, as described in the tariff methodology covering the period from 2025 to 2028.<sup>138</sup> Then, it quantifies the current cost structure and main cost drivers.

#### 6.2.1. Description of cost structure of gas DSOs in Flanders

There are three types of costs incurred by Flemish gas DSOs:

- **Endogenous costs** (or controllable costs) are the costs (CAPEX and OPEX) incurred by DSOs for network and data management on which they have an influence and that are considered in determining the revenue cap based on benchmark regulation.
- Exogenous costs (or non-controllable costs) are costs on which the DSOs have no influence.
   As these costs cannot be reduced through efficiency improvements, they are fully recovered from the distribution network users and are as such part of the allowed income determined by the VNR.
- **Remaining costs** are costs incurred by the DSOs which are not considered in the determination of the allowed income. They are referred to as "other costs" in the tariff methodology.

The table below presents how each of these cost categories is considered in the current tariff methodology for 2025-2028.

Table 6-1 Consideration of different cost categories in the current tariff methodology 2025-2028

Exogenous costs	Endogenous costs	Remaining/other costs
Full recovery of costs via	Compensation of costs based	Fully incurred by the DSO. No
periodic distribution network	on periodic distribution network	compensation of costs via
tariffs (or other financing	tariffs via <b>revenue cap</b>	periodic distribution network
source e.g. subsidy)	regulation	tariffs.

#### **Endogenous costs**

For endogenous costs, the tariff methodology aims to promote the efficiency of the DSOs and encourages them to manage their network and data in a sustainable and cost-conscious manner. The endogenous costs are used to determine the DSOs' allowed income.

There are two main groups of endogenous costs:

- Investment-related costs (CAPEX) which are determined based on the depreciation period (i.e. period over which assets are recognized as expenses) and method (i.e. rhythm at which assets are depreciated, e.g. linear, degressive or progressive) for the different types of regulated assets (sites, buildings, pipelines, connections, cabins/stations, measuring equipment, digital meters, etc.). The CAPEX also include capital costs.
- **Operational costs** (OPEX) are net costs (= operational cost operational revenues<sup>139</sup>) incurred by the DSO in the context of its regulated activities.

Trinomics —

**—** 67 **—** 

<sup>&</sup>lt;sup>138</sup> Vlaamse Nutsregulator (2024). <u>Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de reguleringsperiode 2025-2028</u>.

<sup>139</sup> Excluding operational revenues collected via (periodic) network tariffs

#### **Exogenous costs**

As the DSOs cannot influence their exogenous costs, VNR does not apply regulatory incentives on this cost category. They are hence as such recovered by the DSOs via periodic distribution network tariffs, without any margin.

Exogenous costs include for example:

- Taxes (excl. any corporate income tax) and levies;
- Charges for non-capitalized additional pensions or public sector pensions paid to staff members;
- Net costs incurred for public service obligations related to minimum supply of natural gas, promotion of energy efficiency and deployment of renewable energy sources (e.g. costs related to green certificates);
- Regulatory accounts arising from differences between expected (ex-ante) and actual (expost) costs and revenues, or to account for the impact of inflation;
- Capital cost allowance for guaranteed assets (for instance, total value of green electricity and cogeneration certificates held by the DSOs and amounts on the regulatory balances).

Exogenous costs are not specifically considered in the further analysis.

#### **Remaining costs**

Remaining costs include eventual criminal, administrative and civil fines; depreciation and impairment losses on goodwill; addition and reversal of impairment losses on financial fixed assets. These costs are in general quite low and not further considered in the context of this study.

#### 6.2.2. Analysis of the current cost structure and drivers of gas DSOs in Flanders

This section provides an overview of the current cost structure of the gas distribution in Flanders, differentiated between CAPEX and OPEX, and identifies the main cost drivers. Only endogenous costs are considered in this overview and analysis. Annex A of this report presents the results of the regression analyses undertaken to calculate the correlation between specific cost categories of the Flemish gas DSOs and selected cost drivers.

Throughout this report, 2023 is used as the reference year, as data from 2024 is not yet complete and available for all datasets. However, data for 2024 is included when the concerned dataset is complete and available.

#### 6.2.2.1. Endogenous costs of gas DSOs in Flanders

#### **CAPEX**

#### **Cost structure of CAPEX**

The most important CAPEX incurred by the Flemish gas DSOs are related to the following asset types, which account for more than 95% of total CAPEX:

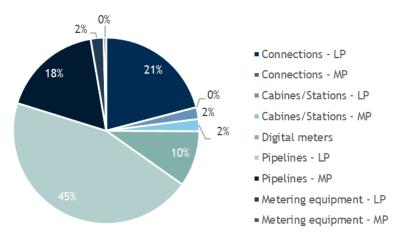
- Pipelines (low- and medium-pressure);
- Cabins/stations (low- and medium-pressure);
- Connections (low- and medium-pressure);
- Metering equipment (low- and medium pressure);
- Digital meters.

Only these asset categories are considered in the further analysis; other asset categories, e.g. buildings or financial participations, are out of scope.

Figure 6-1 presents the **share of the net book value in 2023** (i.e. investment cost minus depreciation) **of each asset category in the total asset value** of the gas DSOs in Flanders. Pipelines (low- and

medium pressure) accounted for 63% of the total net book value. Connections represent the second most important category (21% for low pressure).

Figure 6-1 Distribution of the total net book value in 2023 per asset category

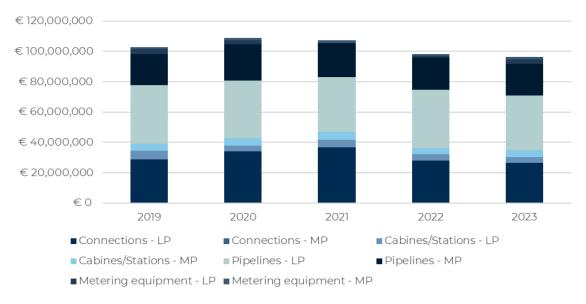


Legend: LP = Low Pressure; MP = Medium Pressure

Source: Trinomics calculations, based on data received from Fluvius

As gas DSOs are in Flanders since 2021 no more allowed to connect new large allotments and buildings, **investments** in grid extensions and new grid connections have decreased, from  $\leqslant$  102 million in 2019 to  $\leqslant$  96 million in 2023 (see Figure 6-2). Investments will be further affected by the prohibition since 1 January 2025 to connect new buildings. The total investment levels are however still quite high (i.e.  $\leqslant$  196 million in 2023) mainly due to the roll-out of smart gas meters, which represented 39% of the total investments in 2019 - 2023 (see Figure 6-3). As a gradual disconnection of grid users is not expected to allow a decommissioning of major grid sections and components (only the concerned individual connections and meters can be dismantled), the overall investment levels are expected to remain at a high level, due to the need to ensure a high safety and operational reliability of the gas system. The projected future investment levels per scenario are presented in Chapter 7.

Figure 6-2 Annual investments per asset category in 2019 - 2023 (excl. digital meters)



Legend: LP = Low Pressure; MP = Medium Pressure

€ 250,000,000 € 200,000,000 € 150,000,000 €100,000,000 € 50,000,000 €0 2019 2020 2021 2022 2023 ■ Connections - LP ■ Connections - MP ■ Cabines/Stations - LP Cabines/Stations - MP ■ Digital meters ■ Pipelines - LP ■ Pipelines - MP ■ Metering equipment - LP ■ Metering equipment - MP

Figure 6-3 Annual investments per asset category in 2019 - 2023 (incl. digital meters)

Legend: LP = Low Pressure; MP = Medium Pressure

Source: Trinomics calculations, based on data received from Fluvius

Table 6-2 presents **the depreciation** period (years), **weighted technical average age**<sup>140</sup>, and **net book value** (end 2023) of the gas distribution assets per type. Due to the long depreciation period and high current non-depreciated asset value (net book value), the depreciation costs are expected to remain high in the coming decades, even with decreasing investment levels. This will affect future network tariffs, which will still have to recover historic costs. Moreover, the long depreciation period (in particular for pipelines) increases the risk of stranded assets, in particular in a scenario where natural gas use would be phased out before their complete depreciation. Some gas distribution assets may hence lose their economic value before the end of their expected life cycle, typically because of shifts in energy demand. Infrastructure built in recent years may not generate sufficient returns over its planned lifespan if natural gas demand declines faster than anticipated, leaving gas DSOs with sunk costs, also due to limited options for repurposing. Based on the current depreciation rules, around 13% of the net book value in 2023 would still not be depreciated in 2050.

Table 6-2 Depreciation period, weighted average technical age and net book value in 2023 per asset category

Asset category	Depreciation period	Weighted average technical age (end 2023)	Net book value (end 2023) <sup>141</sup>		
Connections - LP	33	19	€ 655,786,034		
Connections - MP	33	N.A.	€0		
Cabins/Stations - LP	33	16	€ 63,773,114		
Cabins/Stations - MP	33	17	€ 66,714,272		
Digital meters	15	2	€ 303,330,114		

<sup>&</sup>lt;sup>140</sup> The weighted average technical age of assets is determined based on the annual Regulated Asset Base (RAB) of the Flemish gas DSOs for each type of asset since 1900, taking into account all replacements and decommissioning of assets.

— Trinomics 🥷 💳

<sup>&</sup>lt;sup>141</sup> These figures have been calculated based on the historical investment amounts in tangible fixed assets.

Asset category	Depreciation period	Weighted average technical age (end 2023)	Net book value (end 2023) <sup>141</sup>		
Pipelines - LP	50	22	€ 1,409,500,453		
Pipelines - MP	50	25	€ 548,396,811		
Metering equipment - LP	33	18	€ 69,986,921		
Metering equipment - MP	33	12	€ 13,995,839		
Total			€ 3,131,483,557		

To prefinance their investments and working capital, gas DSOs need capital (equity, loans or bonds). The next table presents the capital costs in 2023, estimated based on a WACC level before corporate tax of 5.2%, as per the current tariff methodology, applied to the net book value. The actual capital costs are slightly different and also include the remuneration of the working capital, which amounts on average to  $\leq$  20.5 million in 2021 - 2024.

Table 6-3 Estimated capital costs for 2023

Asset category	Capital costs in 2023
Connections - LP	€ 34,100,874
Connections - MP	€0
Cabins/Stations - LP	€ 3,316,202
Cabins/Stations - MP	€ 3,469,142
Digital meters	€ 15,773,166
Pipelines - LP	€ 73,294,024
Pipelines - MP	€ 28,516,634
Metering equipment - LP	€ 3,639,320
Metering equipment - MP	€ 727,784
Total	€ 162,837,145

Source: Trinomics calculations, based on data received from Fluvius

The future capital costs will depend on the actual investment levels, depreciation rules, WACC level determined by VNR based on developments in the financial market, funding structure and financial rating of the DSOs/Fluvius. In the current tariff methodology (2025-2028), the allowed revenues are based on capital costs calculated by using a fixed normative WACC determined by VNR for all DSOs, independently of their actual capital costs.

#### Cost drivers of CAPEX

Table 6-4 summarises the relevant cost drivers per asset category. As presented in Annex A of this report, the correlations we found between the annual investments in 2020 - 2024 and changes in the assets (per asset type) in the same period were in general quite low. This may be due to the limited time period considered in the regression analysis. Notwithstanding these results, we deem it reasonable to assume that future investments in pipelines and cabins/stations will largely be driven by the grid length while investments in connections and metering equipment will be correlated to the number of connections.

Table 6-4 Cost driver per asset category

Asset category	Cost driver
Connections - LP & MP	Number of connections

Asset category	Cost driver
Cabins/Stations – LP & MP	Length of gas grid
Digital meters	Number of connections
Pipelines – LP & MP	Length of gas grid
Metering equipment – LP & MP	Number of connections

#### **Endogenous OPEX**

#### Cost structure and cost drivers of endogenous OPEX

The endogenous OPEX can be broken down into fixed and variable costs. While fixed costs are expected to remain to some extent stable and will only decrease depending on the overall size of the assets and activities, variable costs vary with their respective cost driver. As described in section 6.1.2, three cost drivers have been selected for this analysis: number of connections, grid length and gas consumption volumes. Annex A of this report presents the results of the regression analysis undertaken between selected OPEX categories in 2020 - 2024 and these three cost drivers. The correlations between the selected OPEX and the cost drivers were high for all OPEX categories. Therefore, we assume that these variable OPEX will evolve in a similar manner as their cost driver. Based on detailed data and information provided by Fluvius, we have identified the different variable endogenous OPEX items that are driven by respectively the number of connections, grid length and gas consumption. These variable OPEX account for about 77% of the total endogenous OPEX, with the OPEX category driven by the number of connections accounting for the largest share.

Table 6-5 presents the total endogenous OPEX of the gas DSOs in Flanders in 2023 per category. The fixed OPEX represent about 23% of the total.

The total endogenous OPEX calculated on the basis of the detailed Fluvius data and presented in this table are closely aligned with the costs reported by the Flemish gas DSOs in their ex-post reporting for 2023 (the difference amounts to 6% only) and can hence be considered as a reliable basis to estimate future costs (see next chapter). The endogenous OPEX considered in this table do not include financial operational costs and revenues (these are included in the analysis of the capital costs); depreciation costs (included in the analysis of CAPEX); operational costs and revenues related to the purchase and sale of energy (DSOs as supplier of last resort) and internal transfers of costs and revenues.

Table 6-5 Total annual endogenous OPEX in 2020-2024 considered in the analysis (in million €, 2023 prices)

Type of OPEX	Variable/ fixed	OPEX in 2023
OPEX driven by number of connections	Variable	€89,829,418
OPEX driven by grid length	Variable	€27,826,246
OPEX driven by gas consumption	Variable	€10,750,399
Other OPEX	Fixed	€39,063,613
Total		€167,469,677

Source: Trinomics' calculations, based on Fluvius data received from VNR

The evolution of the endogenous OPEX of the Flemish gas DSOs in 2020 - 2024 is presented in Figure 6-4. The overall endogenous OPEX have decreased by 27% between 2020 and 2024, from € 187 million to € 138 million, and mainly consist of variable costs (60 to 90%).



€200,000,000 €180,000,000 €160,000,000 €140,000,000 €120,000,000 €100,000,000 €80,000,000 €60,000,000 €40,000,000 €20,000,000 €0 2020 2021 2022 2023 2024 ■ OPEX driven by number of connections ■ OPEX driven by grid length

Figure 6-4 Evolution of endogenous OPEX of Flemish gas DSOs in 2020 - 2024 (in €, 2023 prices)

OPEX driven by gas consumption

#### Total endogenous costs (CAPEX + OPEX) of gas DSOs in Flanders

Figure 6-5 presents an overview of the evolution of the total endogenous costs of gas DSOs in Flanders in 2020 - 2024. Whereas the share of OPEX has decreased from 44% in 2020 to 30% in 2024, the share of depreciation costs and capital costs (incl. costs of working capital) have both increased, from 25% in 2020 to 32% in 2024 and from 31% in 2020 to 38% in 2024 respectively. The total endogenous costs have remained relatively constant between 2020 and 2024.

Fixed OPEX

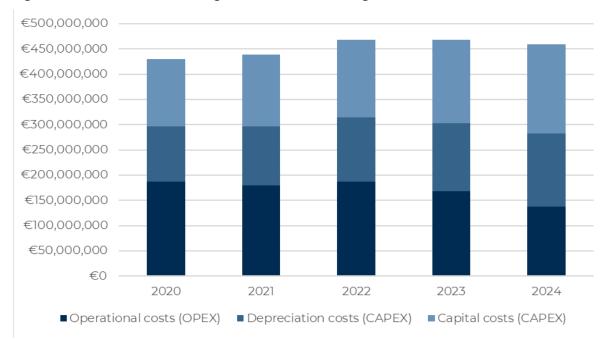


Figure 6-5 Evolution of total endogenous costs of Flemish gas DSOs in 2020 - 2024

#### 6.2.2.2. Exogenous costs of the Flemish gas DSOs

According to the ex-post reporting of the Flemish gas DSOs, the exogenous costs accounted for around 4% of their total costs reported in 2019 - 2023. This means that in 2023, the exogenous costs amounted to about  $\leqslant$  19 million.

#### 6.3. Conclusion

The total costs of the Flemish gas DSOs mainly consist of endogenous costs (96%); the exogenous costs accounted in 2019-2023 for only 4% of total costs. The endogenous costs have remained relatively constant since 2020, amounting to about € 450 million. Whereas depreciation and capital costs (CAPEX) accounted together for 60% of the total endogenous costs on average in 2020 - 2024, operational costs (OPEX) accounted for the remaining 40% of the total endogenous costs over the same period.

The analysis suggests that the **future depreciation and capital costs of the gas DSOs in Flanders will remain at a relatively high level**. This is partially due to the current high residual (non-depreciated) asset value (about € 3.1 billion per end 2023); moreover, even with decreasing offtake volumes and connection numbers, important investments will still be required in the coming decades due to the ongoing need to ensure the safety and operational reliability of the gas distribution networks. In this study, it is assumed that investments in **pipelines and cabins or stations** are mainly proportionate to the **grid length**, while investments in **connections and metering equipment** are primarily driven by the **number of connections**.

The **endogenous OPEX** of the Flemish gas DSOs consist of **fixed and variable costs**. The fixed costs accounted on average in 2020 - 2024 for about 30% of the total endogenous OPEX, while the variable cost represented the remaining 70% and are assumed to evolve with changes in the number of connections, grid length and gas consumption volumes. From 2020 to 2024, the total endogenous OPEX decreased by 27%. It is important to note that not all operational costs have been included in this analysis. However, the selection of OPEX considered in this study results in an overall amount that is close to the OPEX reported by the DSOs according to the current tariff methodology.

-



<sup>&</sup>lt;sup>142</sup> Operational costs not considered in this analysis are exogenous OPEX; financial costs and revenues (included in the capital costs' analysis); depreciation costs (separately considered in the CAPEX analysis); operational costs and revenues related to the purchase and sale of energy and internal transfers of costs and revenues.

# 7. Future evolution of gas DSO costs in Flanders in the 3 scenarios

In this chapter the future evolution of the costs of the gas DSOs in Flanders is estimated according to the three scenarios and, where relevant, the phase-out strategies as developed in Chapter 2. The first section presents the methodology and assumptions used to calculate the evolution of the costs. The second and third section present respectively the estimated evolution of the endogenous costs (CAPEX and OPEX) of the Flemish gas DSOs in 2030, 2040 and 2050.

#### 7.1. Methodology and assumptions

#### 7.1.1. Methodology and assumptions used to estimate the evolution of CAPEX

#### Reference year

The data from 2023 is used as reference to compare the future costs of the Flemish gas DSOs. As mentioned earlier, data from 2024 is not yet complete and available for all datasets.

#### **Cost drivers**

Although no strong correlations were found between the investment costs of the Flemish gas DSOs in 2021-2024 and the selected cost drivers (as presented in Chapter 6 and shown in Annex A), we assume that the investments will mainly evolve in the future with the number of connections and grid length. It is assumed that the level of gas offtake does not influence DSOs' investments in gas distribution assets. This assumption is based on the rationale that the gas grid should be maintained as long as end-users remain connected to it, regardless of their individual consumption level.

#### **Projected annual investments**

The projected annual investments for 2030, 2040 and 2050 have been estimated based on the average level of investments made by Flemish DSOs between 2021 and 2024 per asset category. These figures were extrapolated until 2050 and adapted based on the expected evolution of the concerned cost drivers in the different scenarios and phase-out strategies.

#### Projected annual investments for digital meters

A different methodology was used to estimate the future investments in digital meters. While the current rollout is expected to be finalised by 2029,  $^{143}$  around 1.7 million digital gas meters have been installed by end 2024, which represents 71% of the total rollout.  $^{144}$  This means that about 700,000 digital gas meters will still need to be installed in 2025 - 2029. Based on an average investment cost of around  $\leqslant$  260 in 2019 - 2024, the annual remaining investments are estimated, assuming a constant number of smart meters will be installed each year.

In addition, since digital meters have an expected technical lifetime of 15 years, they will need to be replaced as of 2034. For the further calculations in this study, the replacement cost is estimated at 50% of the initial investment cost, i.e.  $\in$  130 (in  $\in$  2023) on average, assuming that only the electronic device would have to be replaced and not the whole equipment. This assumption could however not be verified based on publicly available information. The replacement costs assumed in this study might hence be underestimated.



<sup>&</sup>lt;sup>143</sup> Vlaamse overheid (n.a.). <u>Digitale meter</u>.

<sup>&</sup>lt;sup>144</sup> VNR (2025) <u>Installatie digitale meters in Vlaanderen</u>.

#### 7.1.2. Methodology and assumptions used to estimate the evolution of OPEX

#### Reference year

The data from 2023 is used as reference to compare the future costs of the Flemish gas DSOs. As mentioned earlier, data from 2024 is not yet complete and available for all datasets.

#### **Cost drivers**

Based on the correlations found between the selected OPEX categories of the Flemish gas DSOs in 2020 - 2024 and the three identified cost drivers (as presented in Chapter 6 and shown in Annex A), it is reasonable to assume that the **variable** endogenous OPEX will evolve in the future with the number of connections, grid length and gas consumption volumes. A smaller share of the endogenous OPEX is, however, to some extent **fixed** and will thus not decrease to the same extent as the network assets. The next sections describe the assumptions taken to estimate the evolution of the different categories of the variable and fixed endogenous OPEX.

#### Variable OPEX driven by number of connections

The average variable OPEX driven by the number of connections is estimated at  $\leq$  21.3 per connection, based on the related costs and number of connections in 2020 - 2024. As disaggregated OPEX data per grid users' segment or tariff group (T1 to T6) are not available, the same average cost per connection is assumed for all segments to estimate the future OPEX per connection. Finally, the calculations assume that there will be no remaining grid connections by 2050 in the high scenario, as described in Chapter 2.

#### Variable OPEX driven by grid length

The average variable OPEX driven by the grid length is estimated at  $\leq$  0.42 per meter pipeline based on the related costs and pipeline length in 2020 - 2024.

#### Variable OPEX driven by gas consumption

The average variable OPEX driven by the gas consumption is estimated at  $\leqslant$  0.19 per MWh offtake based on the related costs and gas consumption volumes in 2020 - 2024. As disaggregated OPEX data per grid users' segment or tariff group (T1 to T6) are not available, the same average cost per MWh is assumed for all segments to estimate the future OPEX per MWh. Finally, the calculations assume that there will be no remaining gas consumption by 2050 in the high scenario, as described in Chapter 2.

#### **Fixed OPEX**

The fixed endogenous OPEX, that are not specifically influenced by a cost driver, amounted to around € 39 million in 2023. In line with the expected decreasing overall operational activities (requiring less building space, fewer vehicles, less staff personnel, smaller data and client management systems), it is assumed that the fixed OPEX will slightly decrease over time. The expected decrease is assumed to be more rapid in the high scenario (by -15% every 10 years), than in the medium scenario (by -10% every 10 years) and in the low scenario (by -5% every 10 years), as shown in Table 7-1.145

Table 7-1 Expected evolution of fixed OPEX in 2030, 2040 and 2050 compared to 2023

Mediu	m scenario		Low scenario			High scenario			
2030	2040	2050	2030	2040	2050	2030	2040	2050	

<sup>&</sup>lt;sup>145</sup> As most of the fixed costs are related to assets and activities that also cover electricity and heat distribution operated by the DSOs/Fluvius, it can be assumed that a decreasing share of the fixed costs will be allocated to gas activities. While the fixed costs do not directly vary with the number of gas connections, a structural decrease can hence be assumed in the context of a phase-out of the natural gas distribution.



76

Me	dium scenario	Low scer	nario		High scenario			
Evolution of fixed -109 OPEX	% -20%	-30%	-5%	-10%	-15%	-15%	-30%	-45%

#### **Decommissioning costs**

The costs for decommissioning and/or repurposing of the gas distribution network have not been included in this analysis. The actual future costs of the Flemish gas DSOs will hence be higher than the cost estimates presented in this study.

#### 7.2. Projection of CAPEX

#### 7.2.1. Projected future investments in tangible fixed assets in the three scenarios

The future investments will be affected by the prohibition since January 2025 to connect new buildings. As a gradual disconnection of grid users is not expected to allow a decommissioning of major grid sections and components (only individual connections and meters concerned can be dismantled as the pipeline will have to serve the remaining users), the overall investment levels are expected to remain at a relatively high level, due to the need to ensure high safety and operational reliability of the gas distribution system.

Figure 7-1 presents the evolution of future annual investments in the three scenarios (low, medium and high) and phase-out strategies. The methodology used to estimate future investments in tangible fixed assets is explained in section 7.1.1. Depending on the scenario and phase-out strategy, the annual investments would decline from around  $\in$  196 million in 2023 to  $\in$  91 - 97 million in 2030. The sharp reduction in investments in 2030 in all scenarios is due to the full roll out of smart meters by 2029, which accounted for about 50% of the total investments in 2021 - 2023.

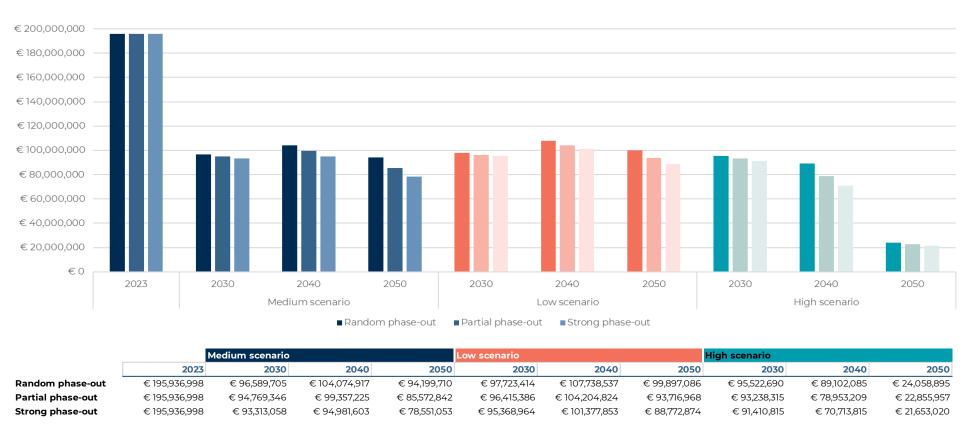
From 2040 onwards, the investment trajectories diverge by scenario. In the low and medium scenarios, the annual investments rise slightly compared to 2030, reflecting the need to replace digital meters after their 15-year lifespan. In the high scenario, however, the decline in connections reduces the volume of replacements required, leading to a continued decrease in annual investments.

The replacement of digital meters will start as of 2034 with the replacement of the first batch of digital meters rolled out in 2019. As most of the digital meters were installed in 2019 - 2023, their replacement would mainly take place in 2034 - 2038. This means that the annual investments are likely to rise between 2030 and 2040 and then fall to a lower level in 2040.

In the medium and low scenario, the annual investments in 2040 and 2050 would remain only slightly below the 2030 level, depending on the evolution of the number of connections and network length. In contrast, in the high scenario the investments would fall sharply by 2050 reflecting the large phaseout of natural gas use and low remaining number of connections.



Figure 7-1 Estimated annual investments of the Flemish DSOs in 2030, 2040 and 2050 (in € 2023), compared to the investments in 2023



Fluvius' draft Investment plan  $2026-2035^{146}$  also foresees that the investment levels would substantially decrease after the roll-out of digital meters (yellow bars in Figure 7-2). The budget for regular investments is expected to almost halve by 2033 compared to today's levels, and would amount to  $\leqslant$  60-70 million annually, which is lower than the amounts estimated in our analysis (except for 2040 in the high scenario, with a strong phase-out strategy). These investments are deemed necessary to ensure the safety and reliability of the gas distribution network. The figure below also shows an increase in investments from 2034, reflecting the replacement of digital meters installed as of 2019.



Figure 7-2 Gross investments in the gas grid, based on Fluvius' draft investment plan 2026-2035

Source: Fluvius (2025) – Investeringsplan 2026-2035

#### 7.2.2. Projected depreciation costs in the three scenarios

#### Depreciation costs related to the residual accounting asset value in 2023 of the Flemish DSOs

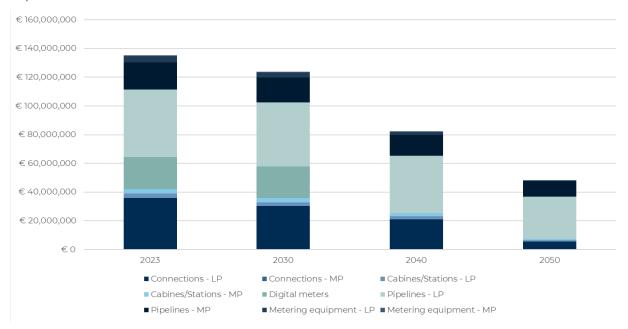
The depreciation costs are expected to remain high in the coming decades, even with decreasing investment levels in the future. This is due to the long depreciation period and the high non-depreciated asset value (net book value) in 2023. revaluation amounts and intangible fixed assets.

Figure 7-3 presents the evolution of the remaining depreciation costs related to the residual accounting asset value of the Flemish DSOs in 2030, 2040 and 2050, compared to 2023. These costs decrease from  $\leqslant$  135 million in 2023 to  $\leqslant$  124 million in 2030,  $\leqslant$  82 million in 2040 and  $\leqslant$  48 million in 2050. These estimates do not include depreciation costs of RAB revaluation amounts and intangible fixed assets.

\_

<sup>&</sup>lt;sup>146</sup> Fluvius (2025). Investeringsplan 2026-2035. <u>Investeringsplan 2026-2035</u>

Figure 7-3 Evolution of the depreciation costs in 2030, 2040 and 2050 (in  $\leq$  2023) related to the residual accounting asset value in 2023 (from historic investments) of the Flemish DSOs, compared to the depreciation costs in 2023

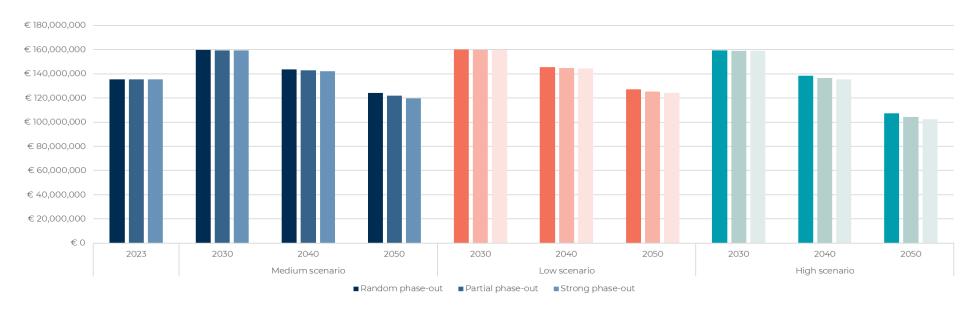


#### Projected overall depreciation cost estimates in the 3 scenarios

Figure 7-4 presents the projected total depreciation costs for the Flemish DSOs in 2030, 2040 and 2050, compared to 2023. These figures include both the future depreciation costs from past investments (up to 2023) as well as those related to future investments. The overall depreciation costs would remain high in all scenarios until 2050 and range from  $\leqslant$  102 to 127 million depending on the scenario and phase-out strategy, compared to  $\leqslant$  135 million in 2023 (as shown in Figure 7-4).

These estimations do not consider any future policy measure (e.g. review of depreciation rules, anticipated depreciation of stranding assets).

Figure 7-4 Projected total depreciation costs (from historic and future investments) of the Flemish DSOs in 2030, 2040 and 2050 (in € 2023) compared to 2023



	Medium scenario				Low scenario			High scenario			
	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050	
Random phase-out	€ 135,251,689	€ 159,597,028	€ 143,603,956	€ 124,054,150	€ 159,959,171	€ 145,367,065	€ 127,049,946	€ 159,264,208	€ 138,227,254	€ 107,201,093	
Partial phase-out	€ 135,251,689	€ 159,444,300	€ 142,729,748	€ 121,725,856	€ 159,849,428	€ 144,722,185	€ 125,350,659	€ 159,072,549	€ 136,636,010	€ 104,497,292	
Strong phase-out	€ 135,251,689	€ 159,322,117	€ 141,957,787	€ 119,716,711	€ 159,761,633	€ 144,206,281	€ 123,991,230	€ 158,919,222	€ 135,348,496	€ 102,278,815	

#### 7.2.3. Projected capital costs in the three scenarios

The cost of capital invested, considered to determine the revenues allowed, does not reflect the actual remuneration of equity and cost of debt capital but is based on a fixed weighted average cost of capital (WACC), which is uniformly determined by VNR for all DSOs independently of their actual cost and financing structure. The WACC level is determined considering a representative market remuneration level taken into account the specific risk level of gas DSOs. By applying this methodology, VNR has greater certainty that the capital cost compensation is proportionate to the appropriate risk. This helps prevent over- or under-investment in the network. The DSOs' management and board members are responsible for adequate risk management and the search for capital at competitive terms, as well as for the choice of the DSOs' capital structure.<sup>147</sup>

In the current tariff methodology, the WACC before corporate tax is determined at 5.2% for 2025.

As mentioned in Chapter 6, the WACC level of 2025 (i.e. 5.2%) is used to estimate the future capital costs in the 3 scenarios. In line with the tariff methodology, the WACC is applied on:

- the estimated non-depreciated accounting value of the fixed assets in 2030, 2040 and 2050 in the 3 scenarios;
- the net working capital in 2030, 2040 and 2050 in the 3 scenarios. The projected networking capital is calculating by multiplying the average net working capital over the 2020- 2024 period with the projected decrease in the amount of connection.

As it is not possible to precisely estimate the future net working capital requirements per scenario, we have used the average net working capital level in 2020 - 2024 as a basis (i.e. € 20.5 million) and assume it will evolve proportionately to the number of connections.

Figure 7-5 presents the total projected capital costs for the Flemish DSOs in 2030, 2040 and 2050, compared to 2023. The projected capital costs are expected to remain relatively high in 2030 (around  $\\ilde{\\em}$  157-159 million in all scenarios and phase-out strategies) due to the investments in digital meters and then decrease over time. The projected capital costs are also expected to remain above  $\\em}$  80 million in 2050.

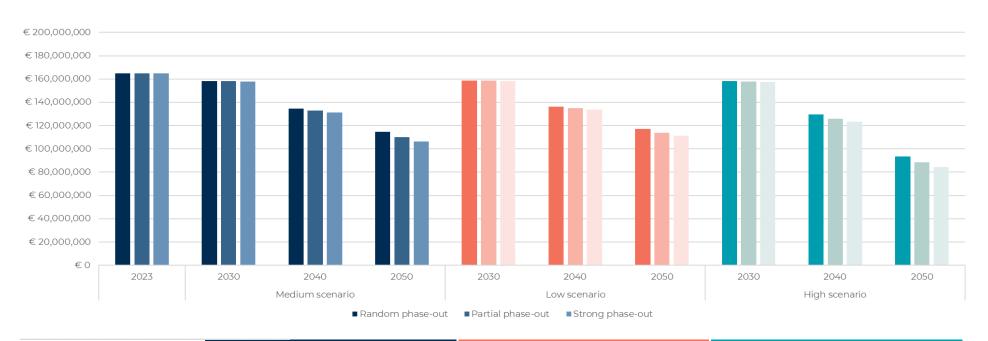
82 =

Trinomics 🦰 💳

.

<sup>&</sup>lt;sup>147</sup> Vlaamse Nustregulator (2024). <u>Tariefmethodologie reguleringsperiode 2025-2028 Bijlage 2:</u> <u>Kapitaalkostvergoeding</u>.

Figure 7-5 Projected total capital costs of the Flemish DSOs in 2030, 2040 and 2050 (in € 2023) compared to 2023



	Medium scenario				Low scenario			High scenario			
	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050	
Random phase-out	€ 164,825,964	€ 158,396,702	€ 134,645,292	€ 114,755,713	€ 158,772,433	€ 136,245,874	€ 117,204,066	€ 158,048,790	€ 129,459,970	€ 93,521,854	
Partial phase-out	€ 164,825,964	€ 158,044,606	€ 132,777,466	€ 110,151,467	€ 158,519,433	€ 134,866,090	€ 113,842,784	€ 157,606,943	€ 126,009,434	€ 88,578,977	
Strong phase-out	€ 164,825,964	€ 157,762,929	€ 131,126,284	€ 106,199,422	€ 158,317,032	€ 133,762,263	€ 111,153,758	€ 157,253,466	€ 123,217,621	€ 84,514,454	

#### 7.3. Projection of endogenous OPEX

This section presents the estimated OPEX levels in 2030, 2040 and 2050, based on the scenarios and phase-out strategies developed in Chapter 2.

#### 7.3.1. OPEX driven by number of connections

In the medium scenario (most plausible trajectory), the number of connections is expected to decrease from 2.3 million in 2030 to 1.3 million in 2050. The OPEX driven by this parameter would decline from approximately  $\leqslant$  45.8 million in 2030 to  $\leqslant$  37.7 million in 2040 and  $\leqslant$  28.5 million in 2050. This decrease is driven by a gradual reduction in the number of active connections across all sectors, particularly in the residential sector. As the low scenario assumes a slower decline in connections, the concerned OPEX would be slightly higher,  $\leqslant$  47.2 million in 2030 decreasing to  $\leqslant$  33.6 million in 2050. The high scenario leads to the steepest drop in the concerned OPEX, from  $\leqslant$  44.4 million in 2030 to  $\leqslant$  24.2 million in 2040, and ultimately to zero by 2050, as all grid users would by then be disconnected.

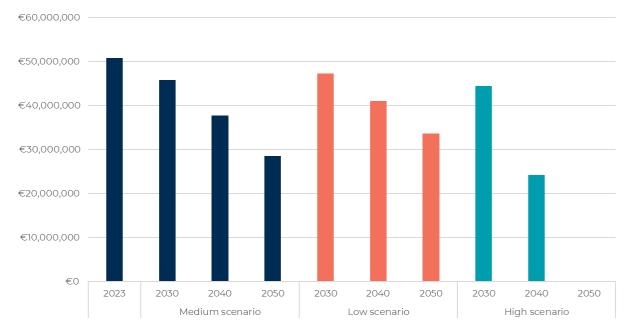


Figure 7-6 Projected levels of connections driven OPEX, per scenario and year, all sectors

Source: Trinomics calculations, based on data received from Fluvius

#### 7.3.2. OPEX driven by grid length

#### Phase out strategy 1 - Random phase out at the initiative of grid users, no specific policy

If the phase out of gas connections occurs in a random manner, it is unlikely that low-pressure branches can be decommissioned before 2050, with possibly a few exceptions. In that case, both low-and medium-pressure networks would have to remain largely operational until the complete phase-out in 2050. Assuming an average grid length correlated OPEX of  $\leqslant$  0.42 per meter pipeline (2023 value), the annual OPEX driven by network length is projected at  $\leqslant$  24.3 million throughout most of the period, of which  $\leqslant$  20.0 million is attributable to the low-pressure network. This means that no meaningful OPEX reductions are realised before the very end of the period.

#### Phase-out strategy 2 - Partially organised phase-out

This strategy represents a partially controlled transition, with half of the disconnections being coordinated and half occurring randomly at the initiative of grid users. As a result, low-pressure branches' decommissioning progresses more slowly than in a strongly policy-driven scenario, but faster than in the random phase-out case. Regarding the medium pressure branches, this strategy assumes that 2.5% of the branches will be phased out in 2050 in the medium scenario and 5% in the high scenario.

In the medium scenario, the OPEX driven by the network length is projected at  $\leqslant$  23.3 million in 2030 and would decrease to  $\leqslant$  19.6 million in 2050. In the low scenario, the OPEX driven by the network length is projected at  $\leqslant$  23.6 million in 2030 declining to  $\leqslant$  21.1 million in 2050. Finally, in the high scenario the OPEX correlated to the network length will decrease from  $\leqslant$  23.1 million in 2030 to  $\leqslant$  18.8 million in 2040 and  $\leqslant$  3.2 million in 2050.

€25,000,000 €20,000,000 €15,000,000 €10,000,000 €5,000,000 €0 2030 2050 2030 2050 2030 2050 2040 2040 2040 Medium scenario High scenario Low scenario ■ LP network ■ MP network

Figure 7-7 Projection of OPEX driven by network length assuming 50% policy phase out, per scenario and year

Source: Trinomics calculations, based on data received from Fluvius

#### Phase out strategy 3 - Strongly organised phase-out

In this strategy, the phase-out of gas grid connections is strongly policy-driven, with a high level of control over the network decommissioning planning. In this case, the share of phased-out LP branches is close to the share of individual disconnections. Under this strategy, it is also assumed that 2.5% in 2040 and 5% in 2050 of the MP branches in the medium scenario will phase out, while in the high scenario the share of phased-out branches remains at 5% both for 2040 and 2050.

In the low scenario, the OPEX driven by network length will decline from  $\leqslant$  23.1 million in 2030 to  $\leqslant$ 18.5 million in 2050. In the medium scenario, the decline is forecasted to be steeper from  $\leqslant$  22.6 million in 2030 to  $\leqslant$  15.7 million in 2050. In the high scenario where all gas use is expected to be phased out, the OPEX correlated to the network length will fall from  $\leqslant$  22.1 million to  $\leqslant$  2.2 between 2030 and 2050.

€25,000,000 €20,000,000 €15,000,000 €10,000,000 €5,000,000 €0 2030 2050 2030 2040 2050 2030 2040 2040 2050 Medium scenario Low scenario High scenario

Figure 7-8 Projection of OPEX driven by network length assuming 90% policy phase out, per scenario and year

#### 7.3.3. OPEX driven by gas consumption

Figure 7-9 presents the evolution of OPEX driven by gas consumption, assuming an average cost of  $\in$  0.187 per MWh. In the medium scenario, the OPEX driven by gas consumption is projected at  $\in$  7.7 million in 2030 and would decrease to  $\in$  2.5 million in 2050. In the low scenario, the OPEX driven by gas consumption is projected at  $\in$  8.8 million in 2030 declining to  $\in$  3.5 million in 2050. Finally, in the high scenario the OPEX correlated to the gas consumption will decrease from  $\in$  6.8 million in 2030 to  $\in$  3.4 million in 2040 and zero in 2050.

■ LP network ■ MP network

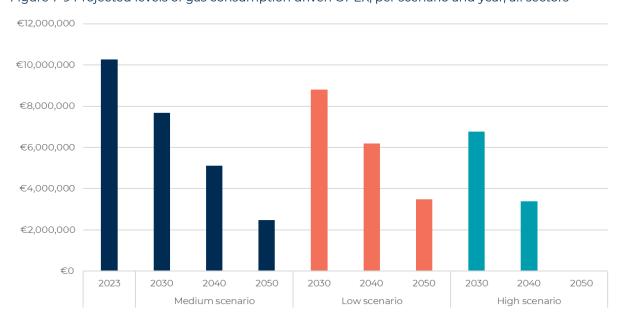
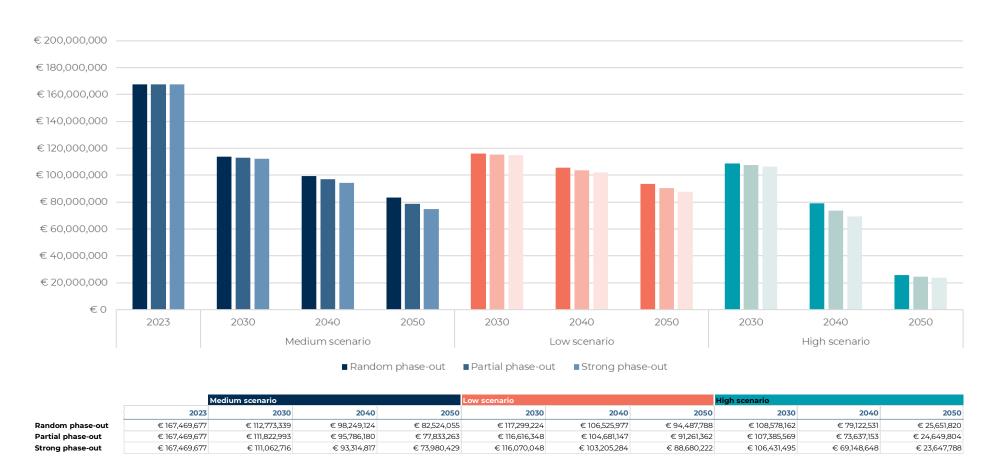


Figure 7-9 Projected levels of gas consumption driven OPEX, per scenario and year, all sectors

#### 7.3.4. Total endogenous OPEX

Figure 7-10 presents the evolution of total OPEX for 2030, 2040 and 2050 per scenario and phase-out strategy. These costs include both the variable OPEX driven by the number of connections, by the length of the grid and by gas consumption as well as the fixed OPEX. In 2030, the costs are expected to range between  $\in$  106 million and  $\in$  117 million depending on the scenario and strategy. This represents a 31 to 36% drop in costs compared to 2023. The total OPEX continue to fall until midcentury. In the low and medium scenario, they remain at a high level in 2050, between  $\in$  75 million and  $\in$  93 million. The total OPEX remain around  $\in$  23-25 million in the high scenario in 2050 due to remaining operations of assets that have not yet been decommissioned.

Figure 7-10 Projected total (variable + fixed) endogenous OPEX for the Flemish gas DSOs in 2030, 2040 and 2050 (in € 2023) compared to 2023



#### 7.4. Future evolution of total costs of gas DSOs in Flanders

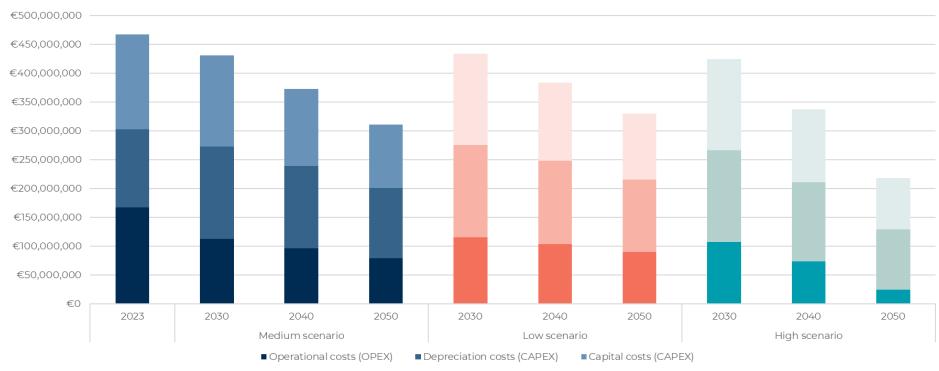
Figure 7-11 illustrates the projected evolution of total costs for gas DSOs in Flanders, in 2030, 2040 and 2050 compared to 2023. The figure presents average values for both endogenous operational expenditures (OPEX) and capital expenditures (CAPEX), including depreciation and capital costs, across three phase-out strategies. These strategies have only a marginal influence on overall DSO costs, primarily because the portion of costs directly linked to grid length is relatively small compared to the total cost structure.

In 2023, the total costs for Flemish gas DSOs are estimated at approximately €468 million. Across all scenarios, this figure is expected to decline to around €430 million in the near term. However, from 2040 onward, the cost trajectories begin to diverge depending on the scenario:

- In the **low scenario**, total costs will remain the highest, evolving from € 371 million in 2040 to € 310 million in 2050;
- In the medium scenario, total costs will decrease from € 384 million to € 330 million in 2050;
- The **high scenario** shows the most significant reduction in total costs, with a drop from € 337 million in 2040 to € 218 million in 2050.

Even in the high scenario – where the number of gas connections is projected to reach zero by 2050 – costs of DSOs remain substantial. This is largely due to ongoing depreciation of existing infrastructure and the operational expenses required to manage and decommission remaining assets. These residual costs highlight the long-term financial implications of the phase-out of the distribution infrastructure, even in the absence of active connections.

Figure 7-11 Projected total costs (endogenous OPEX + CAPEX) of the Flemish gas DSOs in 2030, 2040 and 2050 (in € 2023) compared to 2023



		Medium scenario			Low scenario			High scenario			
	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050	
Operational costs (OPEX)	€167,469,677	€111,886,349	€95,783,374	€78,112,582	€116,661,873	€104,804,136	€91,476,457	€107,465,075	€73,969,444	€24,649,804	
Depreciation costs (CAPEX)	€135,251,689	€159,454,482	€142,763,830	€121,832,239	€159,856,744	€144,765,177	€125,463,945	€159,085,326	€136,737,254	€104,659,067	
Capital costs (CAPEX)	€164,825,964	€158,068,079	€132,849,681	€110,368,867	€158,536,299	€134,958,076	€114,066,869	€157,636,399	€126,229,008	€88,871,762	
Total endogenous costs	€467,547,330	€429,408,910	€371,396,885	€310,313,688	€435,054,917	€384,527,389	€331,007,272	€424,186,801	€336,935,706	€218,180,632	

#### 7.5. Conclusion

The analysis presented in this chapter shows that the **annual investments of the Flemish DSOs are expected to decline significantly in the coming decades,** falling below € 100 million per year as of 2030 in most scenarios and phase-out strategies. However, **both the depreciation costs and operational expenditures will remain at relatively high levels until 2050**.

Given the high residual asset value in 2023 that should still be depreciated, the depreciation costs will remain substantial, even in the context of lower future investment needs, ranging between  $\leqslant$  102 million and  $\leqslant$  127 million in 2050 across scenarios. This underlines the **long-lasting financial burden of past investments** in infrastructure, particularly given the long depreciation periods associated with gas distribution assets.

A large share of the endogenous OPEX of Flemish gas DSOs are fixed (65% in 2023) and most of the variable OPEX are closely linked to the number of connections in the network. Consequently, the total endogenous OPEX will remain high in most scenarios until 2050, except for the high scenario, where a sharp reduction in connections leads to a more pronounced decline.

As a result, the **total costs of Flemish gas DSOs are expected to remain high**; i.e. around  $\le$  430 million in 2030; between  $\le$  336 and 384 million in 2040 (depending on the scenario) and between  $\le$  218 and 331 million in 2050 (depending on the scenario).

If no regulatory adjustments are introduced, these dynamics have **significant implications for the future network tariffs**. Although investment needs will decrease, tariffs will need to remain high and increase further, to enable the gas DSOs to fully recover their costs. This raises important questions about the affordability of gas distribution services for consumers, the fairness of cost allocation in a shrinking customer base, and the potential need for alternative regulatory or policy measures to manage the financial sustainability of the gas distribution sector during the energy transition.

# Evolution of allowed revenues of gas DSOs based on current tariff methodology

In this chapter we assess the evolution of the allowed revenues of the Flemish gas DSOs, based on the endogenous costs estimated in the previous chapter. This analysis will allow to compare the evolution of the costs which gas DSOs have an influence on with their expected revenues from network tariffs. The first section presents the methodology and assumptions used to estimate the evolution of the allowed revenues. The results of the analysis are presented in the second section.

#### 8.1. Methodology and assumptions

#### 8.1.1. Methodology used to estimate the basic component of the allowed revenues

#### Allowed revenues according to the current tariff methodology

As mentioned in Chapter 6, the tariff methodology<sup>148</sup> for 2025-2028 considers both endogenous and exogenous costs to calculate the allowed revenues. The formula used is as follows:

$$AR_{y,x} = AR_{end,y,x} + AR_{ex,y,x}$$

#### Where:

- y is the concerned year y in the regulatory period;
- x is the concerned DSO;
- $AR_{y,x}$  is the total allowed revenues which serves as starting point to determine the network tariff for the concerned year and DSO;
- AR<sub>endy,x</sub> is the allowed revenues from distribution network tariffs to cover endogenous costs of the gas DSO;
- AR<sub>ex,y,x</sub> is the allowed revenues from distribution network tariffs to cover exogenous costs of the gas DSO.

As mentioned in Chapter 6, the exogenous costs represent on average 4% of the total endogenous and exogenous costs (OPEX and CAPEX) incurred by the Flemish gas DSOs in 2019 - 2023. To have a consistent approach across the study, this section only focuses on allowed revenues from distribution network tariffs to cover endogenous costs.

#### Components of allowed revenues for endogenous costs

The allowed revenues from distribution network tariffs to cover endogenous costs consist of a basic component and additional endogenous components, such as:

- Costs of revaluation gains (ex-ante/ex-post);
- Correction of corporation tax (ex-ante/ex-post);
- Quality incentive, i.e. financial impact of quality indicators (Q factor);
- Advances, i.e. temporary adjustments to the basic component.

<sup>&</sup>lt;sup>148</sup> Vlaamse Nutsregulator (2024) <u>Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de</u> reguleringsperiode 2025-2028.



This study assesses the evolution of the basic component, which is composed of:

- Depreciation costs;
- Endogenous OPEX;
- Costs of capital invested.

The basic component that covers endogenous costs is adjusted based on three factors:

- Historic evolution of aggregated endogenous costs of all gas DSOs in Flanders;
- Evolution of costs with inflation throughout the regulatory period;
- Efficiency factor called 'frontier shift' that aims to encourage productivity improvement of gas DSOs. The frontier shift is however equal to 0.0% for productivity improvements of gas DSOs per year in the 2025-2028 period.<sup>149</sup>

In this study, the estimated allowed revenues are revised based on the first adjustment factor, i.e. historic evolution of aggregated endogenous costs. The two other adjustment factors are not considered.

### 8.1.2. Methodology to determine the first adjustment factor (historic sectoral evolution)

As per the current tariff methodology, the allowed revenues for endogenous costs are adjusted based on the so-called "x-factor" which considers the historic evolution of the aggregated endogenous costs of all gas DSOs in Flanders. This adjustment reflects how various recent external and internal factors, whether counteracting or reinforcing each other, influence the evolution of the endogenous costs for gas distribution networks.

The x-factor for each regulatory period of 4 years is determined based on the endogenous costs incurred during a historical reference period of 5 years. To discourage manipulative behaviour, the last year of the historical reference period for a regulatory period is always the starting year of the historical reference period for the subsequent regulatory period. Figure 8-1 illustrates this mechanism.

Figure 8-1 Illustration of the alignment of historical reference periods and regulatory periods

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	etc.
					1									
									<b></b>					
													$\color{red} \color{red} \color{red} \color{red}$	

To calculate the x-factor for a given regulatory period, the trend of total endogenous costs of the associated historical reference period is linearly extrapolated to the first year  $(y_1)$  and the last year  $(y_4)$  of the regulatory period. The x-factor is then calculated based on the following formula:

$$x = 1 - \sqrt[3]{\frac{TC_{trend, year 4}}{TC_{trend, year 1}}}$$

Where:

• TC<sub>trend, year 4</sub> is the total endogenous costs of the associated historical reference period linearly extrapolated to the last year of the regulatory period;

---- Trinomics 🥷 💳

93

<sup>&</sup>lt;sup>149</sup> The frontier shift was determined based on a study from Europe Economics, as described in the tariff methodology 2025-2028.

• TC<sub>trend, year 1</sub> is the total endogenous costs of the associated historical reference period linearly extrapolated to the first year of the regulatory period.

The assumed historical reference periods and regulatory periods as well as the resulting x-factors calculated for this study are presented in Table 8-1. The x-factors are calculated based on the estimated total endogenous costs that are presented in section 8.2.4. Positive x-factors indicate a decreasing trend in total endogenous costs.

Table 8-1 Historical reference and regulatory periods, and resulting x-factors considered in this study, per scenario and phase-out strategy

	Historical reference period (5 years)	Regulatory period (4 years)	Medium scenario	Low scenario	High scenario
Random p	hase-out strategy				
Period 1	2023-2027	2029-2032	0.0085	0.0068	0.0101
Period 2	2027-2031	2033-2036	0.0183	0.0162	0.0210
Period 3	2031-2035	2037-2040	0.0105	0.0090	0.0161
Period 4	2035-2039	2041-2044	0.0184	0.0156	0.0303
Period 5	2039-2043	2045-2048	0.0174	0.0149	0.0392
Period 6	2043-2047	2049-2050	0.0060	0.0052	0.0172
Partial pha	ase-out strategy				
Period 1	2023-2027	2029-2032	0.0089	0.0071	0.0107
Period 2	2027-2031	2033-2036	0.0191	0.0167	0.0222
Period 3	2031-2035	2037-2040	0.0114	0.0097	0.0185
Period 4	2035-2039	2041-2044	0.0199	0.0166	0.0345
Period 5	2039-2043	2045-2048	0.0194	0.0163	0.0419
Period 6	2043-2047	2049-2050	0.0069	0.0057	0.0176
Strong ph	ase-out strategy				
Period 1	2023-2027	2029-2032	0.0093	0.0073	0.0111
Period 2	2027-2031	2033-2036	0.0197	0.0172	0.0231
Period 3	2031-2035	2037-2040	0.0124	0.0102	0.0206
Period 4	2035-2039	2041-2044	0.0214	0.0175	0.0383
Period 5	2039-2043	2045-2048	0.0213	0.0174	0.0444
Period 6	2043-2047	2049-2050	0.0077	0.0062	0.0180

# 8.2. Evolution of the basic component of allowed revenues for endogenous costs

This section presents the evolution of the basic component of allowed revenues for endogenous costs (called "allowed revenues' in the rest of this report), which is composed of the depreciation costs (section 8.2.1), costs of capital (section 8.2.2) and endogenous operational costs (section 8.2.3).

#### 8.2.1. Future depreciation costs

The future **depreciation costs** estimated for the 3 scenarios and presented in Chapter 7 are summarised in the table below. The depreciation costs account for about 35% of the allowed revenues

in most scenarios and phase-out strategies. An exception arises in the high scenario in 2050, where their share increases to around 50% as the operational costs approach zero. This outcome illustrates that the overall depreciation costs remain largely fixed and do not adjust in line with a declining number of connections or network phase-out.

Table 8-2 Future depreciation costs in 2030, 2040 and 2050 (in million €, 2023 prices)

	Medium	scenario		Low scenario			High scenario		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€ 159.6	€ 143.6	€ 124.1	€ 160.0	€ 145.4	€ 127.0	€ 159.3	€ 138.2	€ 107.2
Partial phase-out	€ 159.4	€ 142.7	€ 121.7	€ 159.8	€ 144.7	€ 125.4	€ 159.1	€ 136.6	€ 104.5
Strong phase-out	€ 159.3	€ 142.0	€ 119.7	€ 159.8	€ 144.2	€ 124.0	€ 158.9	€ 135.3	€ 102.3

Source: Trinomics calculations, based on data received from Fluvius

#### 8.2.2. Future costs of capital

The **future costs of capital** invested estimated for the 3 scenarios and presented in Chapter 7 are summarised in the table below. They represent about 35% across all scenarios and phase-out strategies. However, in the high scenario, their share would rise to around 40% of total allowed revenues in 2050.

Table 8-3 Future costs of capital in 2030, 2040 and 2050 (in million €, 2023 prices)

	Medium scenario			Low scenario			High scenario		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€ 158.4	€ 134.6	€ 114.8	€ 158.8	€ 136.2	€ 117.2	€ 158.0	€ 129.5	€ 93.5
Partial phase-out	€ 158.0	€ 132.8	€ 110.2	€ 158.5	€ 134.9	€ 113.8	€ 157.6	€ 126.0	€ 88.6
Strong phase-out	€ 157.8	€ 131.1	€ 106.2	€ 158.3	€ 133.8	€ 111.2	€ 157.3	€ 123.2	€ 84.5

Source: Trinomics calculations, based on data received from Fluvius

#### 8.2.3. Future endogenous OPEX

The future **endogenous OPEX** estimated for the 3 scenarios in Chapter 7 are summarised in the table below. The endogenous OPEX are the smallest cost component, representing about 25% of the allowed revenues, except in the high scenario in 2050, where they account for only 10%.

Table 8-4 Future OPEX total costs in 2030, 2040 and 2050 (in million €, 2023 prices)

	Medium	scenario		Low scer	nario		High scenario		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€ 112.8	€ 98.2	€ 82.5	€ 117.3	€ 106.5	€ 94.5	€ 108.6	€ 79.1	€ 25.7
Partial phase-out	€ 111.8	€ 95.8	€ 77.8	€ 116.6	€ 104.7	€ 91.3	€ 107.4	€ 73.6	€ 24.6
Strong phase-out	€ 111.1	€ 93.3	€ 74.0	€ 116.1	€ 103.2	€ 88.7	€ 106.4	€ 69.1	€ 23.6

#### 8.2.4. Total basic component of allowed revenues for endogenous costs

The sum of the endogenous costs presented in sections 8.2.1, 8.2.2 and 8.2.3 provides the total allowed revenues. In line with the methodology discussed in section 8.1.2, the basic component of the allowed revenues for endogenous costs has been adjusted to consider the historical evolution of the sector's total endogenous costs.

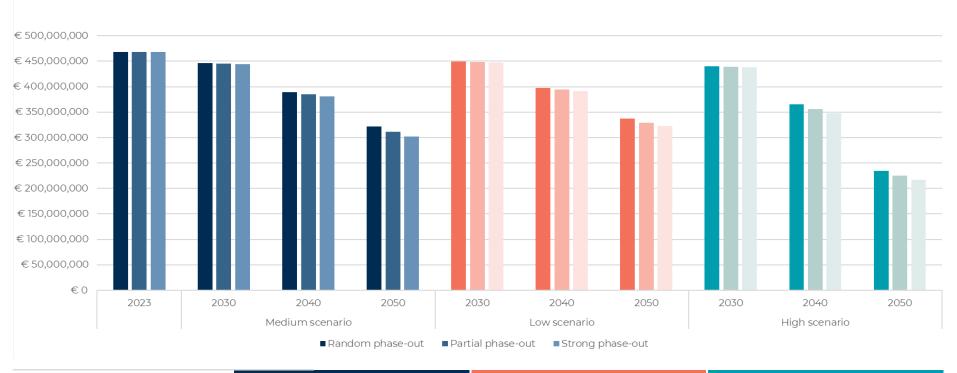
In 2023, the allowed revenues were equal to € 468 million (unadjusted). The resulting adjusted allowed revenues are presented in Figure 8-2. The allowed revenues will decrease between 2023 and 2030, by 4% in the low scenario, 5% in the medium scenario and 6% in the high scenario. This decrease can mainly be attributed to the expected decrease in OPEX, namely -31% in the low scenario, -33% in the medium scenario and -36% in the high scenario. The depreciation costs are expected to increase in 2030 compared to 2023, due to the roll out of smart meters. Capital costs would remain relatively constant in 2023 - 2030.

A larger decrease in allowed revenues is expected between 2030 and 2040. In 2040, the allowed revenues decrease by 16% in the low scenario, 18% in the medium scenario and by 25% in the high scenario (compared to 2023).

Between 2040 and 2050, the allowed revenues would further decrease. This decrease is again lower in the low and medium scenarios (between -30% and 33% compared to 2023, depending on the scenario and phase-out strategy). In the high scenario, the decrease in allowed revenues is important (around -50% compared to 2023).

The results also show that the phase-out strategy has a limited impact on the changes in allowed revenues of the gas DSOs.

Figure 8-2 Future adjusted basic component of allowed revenues for endogenous costs in 2030, 2040 and 2050 (in million €, 2023 prices)



	Medium scenario				Low scenario			High scenario		
	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€ 467,547,330	€ 446,203,435	€ 389,685,395	€ 322,094,271	€ 449,069,066	€ 397,821,768	€ 336,976,299	€ 440,340,339	€ 364,995,916	€ 234,502,106
Partial phase-out	€ 467,547,330	€ 444,952,121	€ 384,884,484	€ 311,128,749	€ 448,170,215	€ 394,265,006	€ 329,135,255	€ 438,769,039	€ 355,634,940	€ 224,930,058
Strong phase-out	€ 467,547,330	€ 443,950,949	€ 380,407,647	€ 301,782,147	€ 447,451,074	€ 391,419,597	€ 322,862,256	€ 437,511,799	€ 348,018,938	€ 216,928,056

# 8.3. Comparison between total endogenous costs and basic component of allowed revenues for endogenous costs

This section presents a comparison between the evolution of the total endogenous costs and the basic component of allowed revenues for endogenous costs (adjusted for the historical evolution of the sector's costs). This analysis allows to check whether and to what extent the current methodology used to determine allowed revenues for gas DSOs is suited to cover future costs. Table 8-5 presents the difference between the projected adjusted allowed revenues to cover the endogenous costs (as presented in section 8.2.4, Figure 8-2) and the projected total endogenous costs of Flemish gas DSOs (as presented in section 7.4, Figure 7-11). The results show that overall, the current methodology still allows gas DSOs to cover their costs up to 2050. A small negative gap between allowed revenues and total endogenous costs is identified in the low and medium scenarios.

Table 8-5 Evolution of the gap between adjusted allowed revenues and total endogenous costs in 2030, 2040 and 2050 (in million €, 2023 prices)

	Medium	scenario		Low sce	nario		High scenario		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€14.3	€12.1	-€0.2	€14.2	€10.8	-€0.8	€14.4	€18.2	€8.1
Partial phase-out	€14.5	€12.5	€0.4	€14.3	€11.1	-€0.3	€14.7	€19.4	€7.2
Strong phase-out	€14.7	€12.9	€0.9	€14.4	€11.3	€0.0	€14.9	€20.3	€6.5

Source: Trinomics calculations, based on data received from Fluvius

#### 8.4. Conclusion

The allowed revenues to cover the endogenous costs are composed of **depreciation costs**, **costs of capital** and **endogenous OPEX**, which respectively account for around 25%, 30% and 45% of the total costs. The adjusted allowed revenues would decrease by 2030, which is mainly attributable to an expected decrease in operational costs during that period. The allowed revenues would then continue to decline at a slow pace until 2050, except in the high scenario, where a sharp drop is expected between 2040 and 2050 due to the number of connections falling to zero by 2050.

Overall, the analysis indicates that the current methodology to calculate the allowed revenues still allows gas DSOs to cover their costs up to 2050.

## Evolution of the network tariffs and other components of the gas bill for households and SMEs

In this chapter we estimate the possible evolution of the network tariffs for the representative enduser profiles in the three scenarios and assess the possible evolution of the other components of the gas bill. The random phase-out strategy is used as a basis to determine the evolution of network tariffs as this would lead to the highest costs and therefore require the largest increase in network tariffs.

#### 9.1. Methodology and assumptions

#### 9.1.1. Network tariffs

As per the current tariff methodology 2025-2028, the gas distribution tariffs comprise a fixed component, a variable offtake related component, and for large users also a component related to their offtake peak. The current structure is presented in Table 9-1.

Table 9-1 Current network tariffs structure

	π	T2	Т3	T4	T5	Т6
Basic tariff		Fixe kWł				V <sub>cap</sub> (h <sub>con</sub>
Data management			Fixed	data	•	
Public service obligation		kWh <sub>con</sub>				
Surcharges			kWh	1 <sub>con</sub>		

Source: Vlaamse Nutsregulator (2024)<sup>150</sup>

#### Where:

- Fixed<sub>net</sub> is the fixed tariff for distribution via the grid (EUR/year)
- kWh<sub>con</sub> is the gas volume withdrawn from the grid, expressed in kWh
- kW<sub>cap</sub> is the maximum amount of gas withdrawn within one hour (capacity), expressed in kW
- Fixed<sub>data</sub> is the fixed tariff for data management (EUR/year), the tariff consists of a fixed amount per year and depends on the type of the metering device

The network tariffs are based on the allowed revenues (i.e. estimated budget for endogenous and exogenous costs). As it is not possible to estimate the future network tariff levels per consumer type based on the available data, we have used the network tariffs for 2023 as a basis. By comparing the tariff revenues according to the 2023 tariffs with the evolution of allowed revenues, we have estimated the gaps to cover the allowed revenues per scenario in 2030, 2040 and 2050. These gaps represent the necessary tariff increases per consumer type compared to the 2023 levels.

Trinomics —

<sup>&</sup>lt;sup>150</sup> Vlaamse Nutsregulator (2024) <u>Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de</u> reguleringsperiode 2025-2028.

To improve the representativeness of the figures used as input, we have calculated the weighted average tariffs applied by the 9 gas DSOs in 2023. These weighted average tariffs have been increased by 13.52% to ensure that revenues from network tariffs in 2023 match the allowed revenues defined by the tariff methodology for the same year. Table 9-2 presents the weighted average network tariffs for 2023, that are used as reference in our analysis.

Table 9-2 Weighted average network tariffs in 2023

	Unit	п	T2	Т3	T4	T5	T6
Basic tariff – Fixed term (Fixed <sub>net</sub> )	€/year	15.1	78.1	529.3	5,062.7	0.0	0.0
Basic tariff – Proportional term (kWh <sub>con</sub> )	€/kWh	0.020819	0.007943	0.004879	0.000382	0.000336	0.000319
Basic tariff – Proportional term (kW <sub>cap</sub> )	€/kW <sub>cap</sub>	0.0	0.0	0.0	0.0	2.1	0.5
Data management (Fixed <sub>data</sub> )	€/year	14.34	14.34	104.36	104.36	104.36	104.36
Public service obligation (kWhcon)	€/kWh	0.000489	0.000479	0.000487	0.000000	0.000000	0.000000
Surcharges (kWh <sub>con</sub> )	€/kWh	0.000403	0.000415	0.000409	0.000082	0.000071	0.000016

Source: Trinomics calculations, based on data received from Fluvius

#### 9.1.2. Total allowed revenues for endogenous and exogenous costs

In the analysis presented in this chapter, the allowed revenues comprise the revenues related to both the endogenous costs (see Chapter 8) and the exogenous costs, estimated as 4% of total endogenous costs in 2030, 2040 and 2050. The total allowed revenues used as basis to calculate the grid tariff impacts are presented in Table 9-3<sup>15</sup>.

Table 9-3 Future allowed revenues for endogenous and exogenous costs in 2030, 2040 and 2050 (in million €, 2023 prices)

	Medium scenario			Low scenario			High scenario		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Random phase-out	€463.5	€404.8	€335.0	€466.5	€413.3	€350.5	€457.4	€378.9	€243.6
Partial phase-out	€462.2	€399.8	€323.6	€465.5	€409.6	€342.3	€455.7	€369.1	€233.6
Strong phase-out	€461.1	€395.1	€313.8	€464.8	€406.6	€335.8	€454.4	€361.1	€225.3

Source: Trinomics calculations, based on data received from Fluvius

— Trinomics 🦰 💳

<sup>&</sup>lt;sup>151</sup> Additional endogenous terms as per the current tariff methodology are not included in these amounts.

### 9.1.3. Evolution of connections, off-take volumes and peak load per tariff group in 2030, 2040 and 2050

#### **Evolution of the number of connections**

We assume that the split of the number of connections per tariff group in each sector will remain constant until 2050. Table 9-4 shows the split of the number of connections per tariff group in each sector in 2023. This share is then multiplied by the number of connections per sector, as estimated in Chapter 2.

Table 9-4 Split of the number of connections per tariff group and per sector in 2023

	П	T2	Т3	T4	T5	Т6	Total
Residential (share)	17%	83%	0%	0%	0%	0%	100%
Tertiary sector (share)	20%	73%	5%	1%	<1%	<1%	100%
Industry (share)	21%	73%	4%	1%	<1%	1%	100%
Other (share)	48%	50%	1%	<1%	<1%	<1%	100%

Source: Trinomics calculations, based on data received from Fluvius

#### **Evolution of gas offtake volumes**

The split of the volumes consumed per tariff group and per sector is also assumed to be constant until 2050. The current split (2023) is presented in the table below.

	П	T2	Т3	T4	T5	Т6	Total
Residential (share)	5%	95%	0%	0%	0%	0%	100%
Tertiary sector (share)	1%	35%	27%	23%	3%	10%	100%
Industry (share)	0%	6%	4%	14%	4%	71%	100%
Other (share)	1%	7%	3%	5%	3%	81%	100%

Source: Trinomics calculations, based on data received from Fluvius

#### **Evolution of offtake peak capacity**

To estimate the evolution of the peak load of the T5 and T6 consumer profiles, we first calculated their average load factor in 2023 (i.e. total offtake volumes divided by the total number of hours in a year, 8,760 hours). Then, we calculated the ratio between peak capacity and average load (see Table 9-5) for 2023 and assume that this ratio will remain constant until 2050. To estimate the future peak load, we multiplied the estimated evolution of the average load of each scenario (based on total volumes consumed in each scenario) with the calculated ratio for T5 and T6.

Table 9-5 Ratio between peak capacity and average load in 2023

	T5	Т6
Average load factor (kWh/h)	140,279	1,887,530
Peak capacity (kW <sub>max</sub> )	864,005	4,700,761
Ratio	6.2	2.5



Finally, the ratios are slightly adjusted in each scenario based on expert judgment to account for a lower future decrease in peak capacity than in average load. The reasoning behind this adjustment (see Table 9-6) is that the average load factor will decrease faster, resulting in a faster decrease of the average demand, while the peak capacity demand is expected to decrease at a slower rate:

- An adjustment factor of 1 implies that the ratio between peak capacity and average load equals the current ratio. We assume this for the low scenario as this scenario represents the least deviation from the status-quo.
- An adjustment factor higher than 1 implies that the peak offtake is decreasing slower than the average load.

For the medium and high scenario, the adjustment factors are respectively 10% and 25% higher than for the low scenario.

Table 9-6 Adjustment factor per scenario

	Medium scenario	Low scenario	High scenario	
Adjustment factor	1.1	1	1.25	

#### 9.1.4. Consumer profiles

In section 9.2, the future network tariffs are estimated for representative end-users. These consumer profiles have been defined based on the average annual volumes consumed and offtake peak capacity per tariff group, for a defined sector or mix of sectors (e.g. for T1 and T2). The average annual volumes and offtake peak capacity per consumer profile are considered to remain fixed until 2050. In practice, it is likely that energy efficiency measures, such as building renovation or the transition towards more efficient processes, are likely to drive the average consumption and peak capacity down. However, to provide a useful comparison, the impact of such measures has not been considered in the second part of this study which assesses the impacts of the three scenarios (developed in Chapter 2) on grid costs, revenues for DSOs, and costs for end-users.

Table 9-7 Consumer profiles considered in this study

	π	T2a	T2b	T3	T4	T5	Т6
Sector	Mixed	Residential	Non- residential	Tertiary	Industry	Industry	Industry
Annual volumes consumed (kWh/year)	3,622	13,021	25,138	301,095	2,928,844	4,520,346	40,764,476
Annual peak capacity (kW <sub>max</sub> )	-	-	-	-	-	2,354	10,708

Source: Trinomics calculations, based on data received from Fluvius

#### 9.2. Evolution of network tariffs

This section provides an analysis of how current tariffs should be adjusted to ensure that the future allowed revenues are covered by the revenues from network tariffs.

#### 9.2.1. Evolution of revenues from network tariffs

The revenues from network tariffs are calculated by multiplying the reference weighted average network tariff (shown in Table 9-2) with the projected offtake volumes, connections and offtake peak capacities per tariff group in 2030, 2040 and 2050. To estimate the required adjustment of network tariffs, we have calculated the gap between the allowed revenues and the revenues collected on the basis of the 2023 network tariffs, per scenario and phase-out strategy. Figure 9-1 presents the relative differences between the allowed revenues and the 2023 tariffs-based revenues. Across all scenarios, the revenues generated based on the 2023 network tariffs fall short of covering the overall allowed revenues (and hence costs) of the Flemish gas DSOs. The gap increases over time, underscoring the growing structural imbalance between allowed revenues and revenues based on 2023 network tariffs. The impact of the phase-out strategy is very limited, as the gap between revenues remains more or less constant across the different phase-out strategies.

In the high scenario, the gap between allowed revenues and revenues from tariffs in 2050 is equal to 100% as there are no remaining end-users who are paying network tariffs.

0% -10% -20% -30% -40% -50% -60% -70% -80% -90% -100% 2030 2040 2050 2030 2040 2050 2030 2040 2050 Medium scenario Low scenario High scenario ■ Random phase-out -10% -25% -45% -2% -14% -30% -16% -47% -100% ■ Partial phase-out -10% -24% -43% -2% -13% -29% -16% -45% -100% Strong phase-out -10% -23% -2% -13% -27% -15% -100%

Figure 9-1 Relative differences between allowed revenues and revenues based on 2023 tariffs in 2030, 2040 and 2050, per scenario and phase-out strategy

Source: Trinomics calculations, based on data received from Fluvius

■ Random phase-out

The analysis highlights the risk of a mismatch between the revenues according to the 2023 tariff structure and the allowed revenues (based on the expected costs) and underlines the importance of developing timely regulatory measures to prevent gas DSOs from being unable to recover their costs. Substantial tariff increases (per MWh) may be required to ensure the long-term financial sustainability of the DSOs. In addition, the cost estimates in this study do not include costs for decommissioning of connections and pipelines; the ultimate cost burden may hence be substantially higher, depending on legal provisions and technical solutions.

■ Partial phase-out

■ Strong phase-out

### 9.2.2. Estimated adjustment of network tariffs per consumer profile in 2030, 2040 and 2050

As presented in the previous section, the Flemish gas DSOs will not be able to recover the allowed revenues (and underlying costs) through the 2023 network tariffs. To estimate the required adjustment, we first projected the evolution of the network tariff component of the gas bill per consumer profile in 2030, 2040, and 2050, assuming the tariffs remain unchanged. We then adjusted the tariff component to reach the allowed revenues for the gas DSOs.

Our analysis indicates that, to recover the allowed revenues across the three scenarios and phase-out strategies (the latter have only a marginal effect on costs and thus on allowed revenues), the network tariff would need to be substantially increased, as presented in Table 9-8. In the high scenario, network tariffs would need to rise by 19.1% in 2030 and by 87.1% in 2040. As there would in this scenario be no more grid connections in 2050, the tariff revenues would fall to zero. Tariff increases are also required in the other two scenarios: in 2030, tariffs would need to rise by 2.3% in the low scenario and by 11.6%

in the medium scenario. By 2040, the required increases amount to 16.7% and 33.2% respectively and climb further to 43.7% in the low scenario and 80.8% in the medium scenario in 2050.

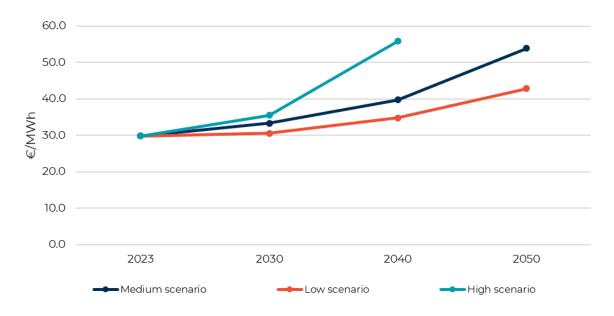
Table 9-8 Necessary changes in the network tariff component of the gas bill (compared to 2023 levels) to ensure coverage of gas DSOs' allowed revenues in 2030, 2040 and 2050, per scenario

	Medium scenario			Low scenario		High scenario			
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Network tariff change (compared to 2023 levels)	+11.6%	+33.2%	+80.8%	+2.3%	+16.7%	+43.7%	+19.1%	+87.1%	NA

The graphs below present for each consumer profile the evolution of the network tariff component of the gas bill in 2030, 2040 and 2050. The tariffs have been adjusted as per the percentages presented in Table 9-8 to ensure that total revenues collected from tariffs cover the allowed revenues. As mentioned earlier, these calculations do not consider potential additional costs the DSOs will have to face for the decommissioning of their connections and pipelines. The necessary increases in the network tariffs may hence be higher than estimated in this section. To simplify the analysis, future network tariffs are shown as an approximate value in  $\in$ /MWh. In practice, network tariffs include both a fixed and a variable component, but only the variable component changes based on the amount of gas consumed.

Based on our assumptions and calculations, small consumers in the **T1 tariff group** would face important increases in their network tariffs. In the three scenarios, the network tariffs would increase from 30 €/MWh in 2023 to about 31-36 €/MWh in 2030. In 2040, network tariffs would further increase to 35 €/MWh in the low scenario, 40 €/MWh in the medium scenario and to 56 €/MWh in the high scenario. In 2050, the network tariffs would increase by 44% in the low scenario (compared to 2023 levels), up to 43 €/MWh and almost double in the medium scenario, up to 54 €/MWh.

Figure 9-2 Evolution of network tariffs for T1 consumers (in €/MWh, without VAT)



Source: Trinomics calculations, based on data received from Fluvius

A similar evolution is expected for **T2 consumers from the residential sector**. The adjusted network tariffs would steadily increase up to 2050 in the low and medium scenario, reaching respectively 23

€/MWh and 29 €/MWh (compared to 16 €/MWh in 2023). In the high scenario, network tariffs would have to increase up to 30 €/MWh in 2040.

35.0
30.0
25.0
25.0
10.0
10.0
5.0
0.0
2023
2030
2040
2050
High scenario

Figure 9-3 Evolution of network tariffs for T2 consumers – Residential (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

In all scenarios, **non-residential T2 consumers** are expected to face a much higher relative increase in network tariffs between 2023 and 2030 than residential consumers (T1 and T2). The adjusted network tariffs would reach 12.8 €/MWh (low scenario), 14.0 €/MWh (medium scenario) and 14.9 €/MWh (high scenario) in 2030 compared to 8.3 €/MWh in 2023, representing a 50% average increase. The increase would then slow down up to 2050, where tariffs will be around 18.0 €/MWh and 22.6 €/MWh in the low and medium scenarios respectively.

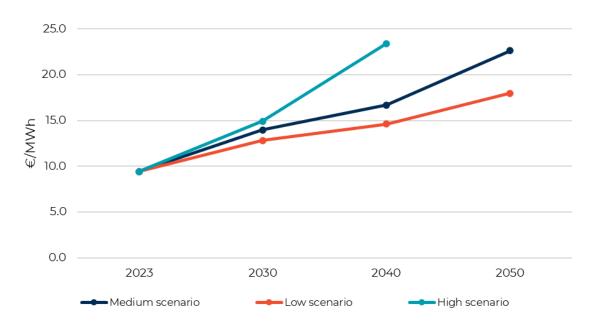


Figure 9-4 Evolution of network tariffs for T2 consumers - Non-residential (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

Tertiary consumers in the **T3 tariff group** are expected to face similar tariff increases as T1 and T2 tariff groups, with high increases of network tariffs in the low and medium scenarios between 2040 and 2050. The adjusted network tariffs would respectively reach 11.3  $\leq$ /MWh and 14.2  $\leq$ /MWh in 2050 compared to 9.2  $\leq$ /MWh and 10.5  $\leq$ /MWh in 2040, representing a 30% average increase.

16.0

14.0

12.0

10.0

8.0

4.0

2.0

0.0

2023

2030

2040

2050

High scenario

Figure 9-5 Evolution of network tariffs for T3 consumers – Tertiary (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

The network tariffs for **T4 end-users in the industry sector** are expected to rise to about 2.3-2.7 €/MWh in 2030 for all scenarios. They will then further increase to 2.6 and 3.0 €/MWh in 2040 respectively in the low and medium scenarios, compared to 4.2 €/MWh in the high scenario. Finally, the network tariffs would amount to 3.2 and 4.0 €/MWh in 2050 respectively in the low and medium scenarios.

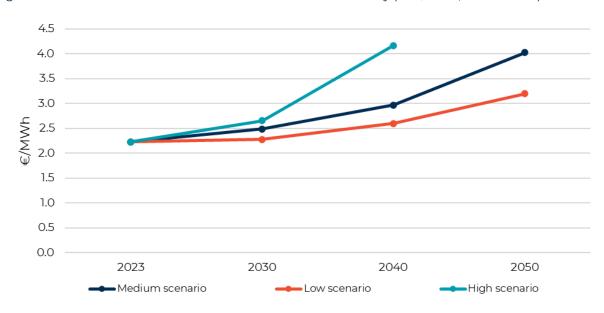


Figure 9-6 Evolution of network tariffs for T4 consumers – Industry (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

In the high scenario, the adjusted network tariffs for average large industrial consumers in the **T5** tariff group in the industry sector would rise from  $1.54 \in /MWh$  in 2023 to  $2.88 \in /MWh$  in 2040. In the low and medium scenarios, an increase from  $1.54 \in /MWh$  in 2023 to  $2.21-2.79 \in /MWh$  in 2050 is expected.

3.50

3.00

2.50

1.50

1.00

0.50

2023

2030

2040

2050

High scenario

Figure 9-7 Evolution of network tariffs for T5 consumers – Industry (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

Finally, the adjusted network tariffs of large industrial consumers in the **T6 tariff group** will rise to around 0.48- $0.56 \le$ /MWh in 2030 (compared to  $0.47 \le$ /MWh in 2023). As for other tariffs groups, the adjusted network tariffs would then increase up to 0.68- $0.85 \le$ /MWh in 2050 for the low and medium scenarios, and a peak at  $0.88 \le$ /MWh is expected in the high scenario in 2040 before the complete phase-out of the grid in 2050.

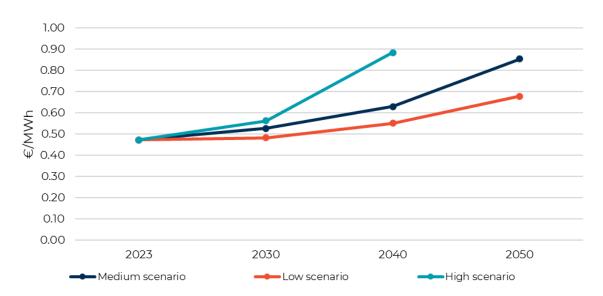


Figure 9-8 Evolution of network tariffs for T6 consumers – Industry (in €/MWh, without VAT)

Source: Trinomics calculations, based on data received from Fluvius

# 9.3. Evolution of the other components of the gas bill

In this section, we analyse the evolution of the other components of the gas bill for different consumer profiles (as defined in section 9.1.4). The gas bill is composed of the natural gas retail price, network tariffs (transport and distribution), taxes and levies (including VAT). The data for all components, except for the distribution network tariffs, were taken from the 2023 and 2025 PwC studies on the 'European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers' In addition, we also provide an estimation of the additional costs resulting from the implementation of the EU-EST2 based on a study conducted by Trinomics in 2025 for the European Commission on the impact of the EU-ETS2 on residential consumers and SMEs.

# 9.3.1. Evolution of gas commodity prices

The evolution of the **natural gas (commodity) price** is highly uncertain, mainly due to different geopolitical developments and the unsure evolution of global natural gas supply and demand:

- Natural gas prices have since 2020 become much more volatile, both on the spot and forward markets, with a significant surge in 2022 due to supply constraints caused by the Russia-Ukraine war. As of 2023, prices declined but did not return to their pre-crisis levels. Geopolitical tensions and political decisions will continue to affect natural gas' prices. Following the energy crisis, cheap pipeline gas supply mainly sourced from Russia has in Europe partly been replaced by more expensive LNG sourced from different countries and continents, including the USA. The future gas price is hence expected to be determined to a large extent by the (full) cost of the marginal (most expensive) LNG source, rather than by the lower cost of pipeline gas.
- Notwithstanding the expected decrease and ultimate phase-out of natural gas use in the EU, global natural gas demand would remain high in the coming decades. In March 2025, the Gas Exporting Countries Forum (GECF) forecasted a 32% increase in global natural gas demand, rising from 4,018 bcm in 2023 to 5,317 bcm by 2050, reflecting an average annual growth rate of 1%.<sup>153</sup> According to IEA's World Energy Outlook, global natural gas demand would until 2050 remain at the current level, with slightly decreasing demand in the advanced economies, offset by further increasing demand in emerging and developing economies.<sup>154</sup>
- Taken into account the sustained global natural gas demand, and the shift to more expensive supply sources, most experts expect an increase in gas commodity prices. While analysts typically remain cautious about providing long-term outlooks due to market volatility, recent forecasts and data offer relevant insights into potential future trends. Fitch Ratings' updated long-term natural gas price forecast, released in March 2025, expects Henry Hub to average \$3.89 per MMBtu in 2026, while the Dutch TTF would average \$4.20/MMBtu in 2026. In 2027-2028, gas prices may slightly decrease in Europe (and Asia) due to abundant supply of LNG. However, Deloitte's latest natural gas price forecast, published in December 2024, anticipates Henry Hub trading at \$5.40/MMBtu in 2030, compared to \$3.89 in 2026. For 2041, Deloitte projects Henry Hub to trade at \$6.50/MMBtu. Deloitte does not provide a specific forecast for 2050 but maintains its projection of a 2% annual increase in Henry Hub prices after 2041. The U.S. Energy Information Administration (EIA) forecasts Henry Hub prices to reach

<sup>&</sup>lt;sup>155</sup> Reuters (2025) <u>The US LNG industry risks becoming victim of its own success | Reuters</u>



<sup>&</sup>lt;sup>152</sup> PwC (2025). <u>A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers</u>; PwC (2023). <u>A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers</u>.

<sup>&</sup>lt;sup>153</sup> Gas Exporting Countries Forum (2025) Global Gas Outlook 2050.

<sup>&</sup>lt;sup>154</sup> International Energy Agency (2022) Global natural gas demand, 2010-2050.

\$3.80/MMBtu by 2030, \$4.20/MMBtu by 2040, and \$4.95/MMBtu by 2050 in its reference case scenario.  $^{156}$ 

• The retail gas price is not only affected by the wholesale price evolution but also by the suppliers' margin, which is expected to increase per connection and per MWh supplied, as the overall market will shrink while the administrative costs (e.g. IT, customer service and billing system) are to some extent fixed.

As there is no consensus in the literature on the future evolution of gas prices, it is generally impossible to provide reliable projections. Therefore, we have assessed the evolution of the gas retail price in the total gas bill based on three different evolutions of the gas retail prices:

- Constant prices;
- Annual increase of 2%;
- Annual increase of 4%.

Given the exceptionally high gas prices in 2023 as a consequence of the energy crisis, we have used the gas prices of 2025 as reference. In 2025, the average gas retail prices amounted in Flanders to **56.0** €/MWh for residential consumers and **49** €/MWh for non-residential consumers <sup>157</sup>. The projected future gas prices for 2030, 2040 and 2050 are presented in the table below for the two consumer types. The future gas prices shown in the table below are illustrative assumptions, not predictions, and their actual evolution will **depend on global market developments and mark-ups** applied by retailers depending to some extent on local developments.

Table 9-9 Projected evolution of gas retail prices in 2030, 2040 and 2050

	Residential consumers			Non-residential consumers		
	2030	2040	2050	2030	2040	2050
Constant prices	€56.0	€56.0	€56.0	€49.0	€49.0	€49.0
2% annual increase	€61.8	€75.4	€91.9	€54.1	€65.9	€80.4
4% annual increase	€68.1	€100.9	€149.3	€59.6	€88.2	€130.6

#### 9.3.2. Evolution of transport network tariffs

The average transport tariff applied by Fluxys in 2025 amounted to **1.56 €/MWh**. For the analysis of the evolution of the total gas bill in 2030-2050 (section 9.4), we assumed that this tariff would remain constant up to 2050. It is likely that the TSO tariff will increase in a shrinking gas market, but there is no study that provides an estimate of the possible evolution. Therefore, we did not consider a tariff increase in our calculations, also taking into account that the impact on the overall gas bill would be limited.

## 9.3.3. Evolution of taxes and levies

There are two taxes and levies at the federal level:

- An energy contribution of 0.9978 EUR/MWh, or 0.54 EUR/MWh for holders of an EBO or sector agreement. In this study, we included the first amount in our calculations.
- A special excise duty (see rates in the table below).

<sup>&</sup>lt;sup>157</sup> PwC (2025). <u>A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers</u>; PwC (2023). <u>A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers</u>.



**—** 109 **——** 

<sup>&</sup>lt;sup>156</sup> NAGA (2025) <u>Natural Gas Forecast & Price Predictions 2025</u>: <u>Prices Rebound Amid Tightening Supply-Demand</u> Balance.

Table 9-10 Special excise duty rates

Special excise duty (in EUR/MWh)	Residential	Non- residential
Up to 20 000 MWh	0.54	0.66
Between 20 000-50 000 MWh	0.46	0.56
Between 50 000-250 000 MWh	0.44	0.54
Between 250 000-1 000 000 MWh	0.34	0.42
Between 1 000 000-2 500 000 MWh	0.18	0.22
Above 2 500 000 MWh	0.15	0.15

Source: PwC (2025)

The VAT on natural gas was temporarily reduced to 6% as of April 2022 in response to the energy crisis. This measure was definitively implemented as of April 2023 for residential consumers.

Specific policies and measures at federal or regional level, such as possible **taxes and levies'** shifts to make electricity more competitive for heating compared to fossil fuels, may affect the gas bill. In the analysis of the evolution of the total gas bill, we have assumed that the federal energy contribution, the special excise duty and VAT (6%) will remain constant. However, these levies may as of 2028 slightly increase as the Flemish minister for energy has in July 2025 announced that a tax shift will be implemented in 2028: the levies on natural gas and heating oil use would be increased by  $\in$  362 million per year, while the levies on electricity would decrease by the same amount. This tax shift can, depending on its implementation, either increase the exogenous cost to be recovered by the DSOs via their grid tariffs, or lead to higher fees on the gas bill.

## 9.3.4. Impact of ETS2 on consumer's gas bill

The **ETS2 carbon pricing** will increase the natural gas bill for use in the residential and tertiary sectors as gas suppliers will as of 2027 have to buy carbon allowances to cover the GHG emissions caused by the fossil gas they sell. While the exact price increase is uncertain and depends on the future carbon allowance price and market dynamics, studies estimate that the natural gas costs could rise by a significant percentage, potentially increasing the annual gas bills for average households by around  $145 \ \text{e/year}$  with a carbon allowances price of  $30 \ \text{e/tCO}_2$  and  $290 \ \text{e/year}$  with a price of  $60 \ \text{e/tCO}_2$  158. The cost resulting from ETS2 will likely be fully passed on to end-users, but the Social Climate Fund is intended to mitigate these impacts, especially for vulnerable households.

In this study, we have estimated the additional cost from ETS2 for residential and non-residential endusers based on fictive carbon prices of  $30 \le /tCO_2$  in 2030,  $50 \le /tCO_2$  in 2040 and  $60 \le /tCO_2$  in 2050. The emission factor used to estimate the additional cost from ETS2 is 264 kgCO<sub>2</sub>/MWh. The resulting additional cost from ETS2 are presented in the table below.

Table 9-11 Estimated additional cost from ETS2

	Carbon price (€/tCO2)	Additional cost from ETS2 (€/MWh)
2030	30 €/tCO2	8€/MWh
2040	50 €/tCO2	13 €/MWh
2050	60 €/tCO2	16 €/MWh

<sup>&</sup>lt;sup>158</sup> Trinomics (2025). <u>Support to the Preparation of Social Climate Plans - Deliverable 2: Report on the impacts of ETS2, the identification of vulnerable groups and stakeholder engagement plans.</u>



# 9.4. Evolution of the total gas bill for residential and nonresidential end-users

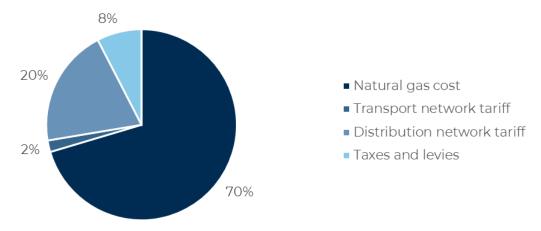
This section presents the possible evolution of the total gas bill for residential and non-residential end-users, based on the results of sections 9.2 and 9.3. The consumer profiles used to illustrate the possible evolution of the total gas bill are respectively the T2 residential consumer type and the T4 professional consumer type.

# 9.4.1. Evolution of the total gas bill for residential consumers

# **Current gas bill for residential consumers**

The gas bill for residential consumers (i.e. for an average residential consumer in the T2 tariff group with an annual consumption of 13 MWh) was about  $1,000 \in$  per year in 2023. As shown in Figure 9-9, the cost of natural gas is the largest component of the gas bill, representing 70%. Distribution network tariffs are the second largest component (20% of the total gas bill), followed by taxes and levies (8%) and transport network tariffs (2%).

Figure 9-9 Distribution of the components of the total gas bill in 2023 for residential consumers



# **Constant gas prices**

The figure below presents the evolution of the total gas bill for residential consumers in the three scenarios, at constant gas prices and for an annual consumption of 13 MWh (as shown in Table 9-7). In all scenarios, the gas bill increases in 2030 and 2040 compared to 2025, mainly due to the additional costs resulting from ETS2 as of 2027 as well as increases in distribution network tariffs. The average share of natural gas costs in the total gas bill decreases to 58% across the three scenarios, while the share of the distribution tariffs increases to an average of 22%. The additional costs from ETS2 account for around 12% of the total gas bill, increasing from 103 €/year in 2030 to 206 €/year in 2050.

At constant gas prices, the total gas bill of an average residential consumer would increase by 29% between 2023 and 2050 in the low scenario and by 37% in the medium scenario.

€1,600 €1,400 206 172 206 € 1,200 172 172 103 103 103 € 1,000 375 388 298 276 232 212 €.800 € 600 729 729 729 729 729 729 729 729 729 €.200 €0 2023 2030 ■ Natural gas cost ■ Transport network tariff ■ Distribution network tariff ■ Taxes and levies ■ETS2

Figure 9-10 Evolution of the total annual gas bill for residential consumers per scenario, at constant gas prices (in €/year, 2023 prices)

Source: Trinomics calculations, based on data received from Fluvius

#### Moderate increase in gas prices

Figure 9-11 presents the evolution of the total gas bill for residential consumers in the three scenarios, with a moderate annual increase (2%) in gas prices. The total gas bill rises by 77% and 85% between 2023 and 2050 in the low and medium scenarios respectively, mainly due to the increase in natural gas prices. Natural gas cost represents on average 64% of the total gas bill between 2030-2050 and across all scenarios, and distribution network tariffs account on average for 19%.

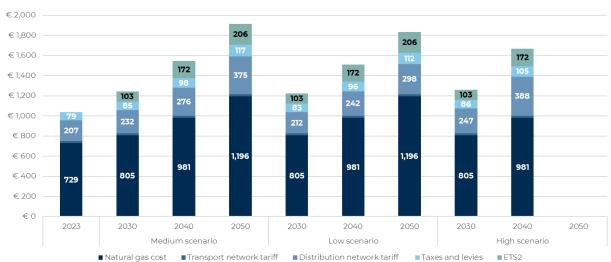


Figure 9-11 Evolution of the total annual gas bill for residential consumers per scenario, with a moderate annual increase (2%) in gas prices (in €/year, 2023 prices)

Source: Trinomics calculations, based on data received from Fluvius

#### High increase in gas prices

Figure 9-12 presents the evolution of the total gas bill of residential consumers in the three scenarios, with a high annual increase (4%) in gas prices. The rise in the total gas bill of residential consumers be substantially higher than with constant and moderate gas prices increases (by 154% and 161% between 2023 and 2050 for the low and medium scenarios). The increase of the total bill is mainly due to the increase in the natural gas cost component which accounts for 69% of the total gas bill on average across scenarios and years.

€ 2.500 206 € 2.000 172 € 1,500 242 103 212 €1000 1,313 1,313 1,313 € 500 887 887 887 €0 2023 2050 High scenario ■ Natural gas cost ■ Transport network tariff ■ Distribution network tariff ■ Taxes and levies ■ETS2

Figure 9-12 Evolution of the total annual gas bill for residential consumers per scenario, with a high annual increase (4%) in gas prices (in €/year, 2023 prices)

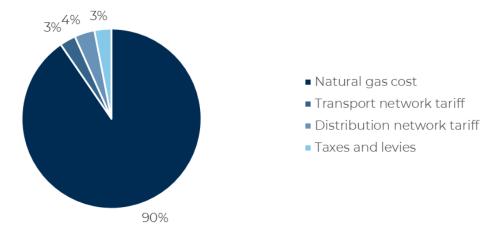
Source: Trinomics calculations, based on data received from Fluvius

#### 9.4.2. Evolution of the total gas bill for non-residential consumers

#### **Current gas bill for non-residential consumers**

The gas bill of non-residential consumers (i.e. for an average professional consumer in the T4 tariff group with an annual consumption of 2,900 MWh) amounted in 2023 to about € 160,000. Figure 9-13 presents the distribution of the different components of the energy bill for this consumer type. Like for residential consumers, the cost of natural gas is the largest component of the gas bill, accounting for 90% in 2023. The distribution network tariff represents a much lower share in the total gas bill, compared to residential consumers (only 4% in 2023). Taxes and levies (excluding VAT) as well as transport network tariffs each represent around 3% of the total gas bill.

Figure 9-13 Distribution of the components of the total gas bill in 2023 for non-residential consumers (excluding VAT)

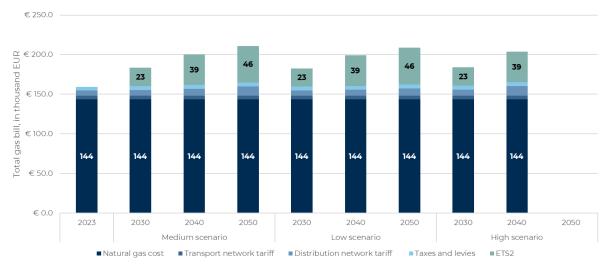


#### **Constant gas prices**

Figure 9-14 presents the evolution of the total gas bill for non-residential consumers in the three scenarios, at constant gas prices. As for residential consumers, the increase in the total gas bill can mainly be attributed to the additional costs arising from the implementation of ETS2. The latter account for 13% of total costs in 2030, 19% in 2040 and 22% in 2050 in all scenarios.

The largest component of the gas bill remains the cost of natural gas, which represents on average 73% of total gas bill on average across scenarios, but decreases over time as carbon prices increase. The share of distribution network tariffs in the total gas bill remains constant (at 4% of the total gas bill), except in 2050 where it reaches 6% of the total gas bill.

Figure 9-14 Evolution of the total annual gas bill for non-residential consumers per scenario, with constant gas prices (in 1,000 €/year, 2023 prices) (excluding VAT)

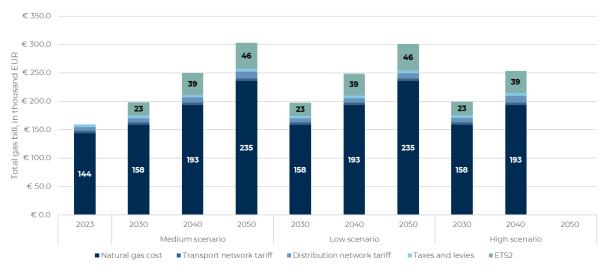


Source: Trinomics calculations, based on data received from Fluvius

## Moderate increase in gas prices

Figure 9-15 presents the evolution of the total gas bill for non-residential consumers in the three scenarios, with a moderate annual increase (2%) in gas prices. The total gas bill of this consumer group will almost double by 2050 in all scenarios. Due to rising gas prices, the gas bill will increase from  $\leq$  159,000 in 2023 to at least  $\leq$  300,000 (low scenario).

Figure 9-15 Evolution of the total annual gas bill for non-residential consumers per scenario, with a moderate annual increase (2%) in gas prices (in 1,000 €/year, 2023 prices) (excluding VAT)



Source: Trinomics calculations, based on data received from Fluvius

#### High increase in gas prices

Figure 9-16 presents the evolution of the total gas bill for non-residential consumers in the three scenarios, with a high annual increase (4%) in gas prices. Unsurprisingly, the total gas bill of average

non-residential consumers will rise substantially across all scenarios until 2050, to at least € 448,000 (low scenario), compared to € 159,000 in 2023.

€ 450.0 ⊈ € 400.0 € 350.0 € 300.0 € 250.0 <u>=</u> € 200.0 23 383 383 gas € 150.0 258 258 € 100 O 175 € 50.0 € 0.0 2023 2040 2050 2040 2050 2030 2050 Medium scenario Low scenario High scenario ■ Natural gas cost ■ Transport network tariff ■ Distribution network tariff ■Taxes and levies

Figure 9-16 Evolution of the total annual gas bill for non-residential consumers per scenario, with a high annual increase (4%) in gas prices (in 1,000 €/year, 2023 prices) (excluding VAT)

Source: Trinomics calculations, based on data received from Fluvius

# 9.5. Conclusions

The total gas bill for most residential and non-residential end-users connected to the distribution grid is expected to rise in the coming decades, mainly driven by higher gas commodity price but also due to a potential increase in network tariffs - if adjusted to fully recover distribution expenses - and the implementation of ETS2 carbon pricing as of 2027. Announced increases in levies on natural gas use (tax shift) are also likely to affect the total gas bill, but this impact has not been included in the present analysis.

The table below summarises the share of each gas bill component in the current total gas bill (in 2025) and how these components may evolve in the future.

Share in the current gas bill (2023)			Potential evolution up to 2050
	Residential end- users	Non-residential end-users	
Natural gas cost	70%	90%	The evolution will <b>depend on</b> global <b>market developments</b> . Impossible to provide reliable projections.
Transport network tariff	2%	3%	Likely to <b>increase.</b> The actual level will depend on the scenario and regulatory adjustments
Distribution network tariff	20%	4%	Most likely to <b>increase substantially</b> , in particular for small gas consumers; the actual level will depend on the scenario and regulatory adjustments. As decommissioning and stranding costs have not been included in our cost calculations, future distribution network tariffs may be higher than estimated in this chapter.
Taxes and levies	8%	3%	Evolution will <b>depend on political decisions</b> .

	Share in the curr	Potential evolution up to 2050		
ETS2	Not yet in place in 2023	Not yet in place in 2023	Will increase gas bill as of 2027. Actual impact will depend on carbon emission cost:  • At carbon prices of 30 €/tCO2 and 60 €/tCO2, additional costs from ETS2 will equal to about € 100 and € 200 respectively for a residential consumer with an annual consumption of 13 MWh.  • At carbon prices of 30 €/tCO2 and 60 €/tCO2, additional costs from ETS2 will equal to about € 23,000 and € 46,000 for a non-residential consumer with an annual consumption of 2,900 MWh.	

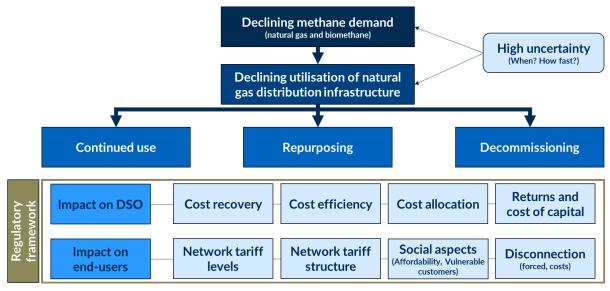
# 10. Measures to support phase-out of gas distribution

With methane demand expected to permanently decline, both the utilisation of the natural gas distribution infrastructure and the number of users connected to it are going to decline. This poses a number of challenges and questions related to the continued use and eventually the repurposing and decommissioning of gas distribution network assets, which have to be addressed in the regulatory framework (10.1). Like in most other countries, many of these regulatory challenges are not yet addressed within the regulatory framework of Flanders (10.2). Different regulatory measures addressing the implications for DSOs and network users are however already adopted in EU legislation and in the regulatory frameworks of other European regulatory jurisdictions (10.3). Additional measures have been discussed in other publications and the scientific literature. Based on these examples and conceptual considerations, different regulatory options can then be evaluated (10.4) and recommendations for adjustments of the regulatory framework in Flanders related to the phase-out of gas distribution be provided (10.5). Within this chapter a focus will be on regulatory measures under the control of the regulatory authority VNR as well as regulatory decisions, which can already be taken in the upcoming regulatory periods. In addition, measures to be taken by policymakers will be analysed; some of which will be a precondition for further regulatory measures to be taken by VNR. Finally, also measures to be considered with regards to long-term developments will be discussed.

# 10.1. Regulatory challenges and questions

The regulatory questions related to the phase-out of gas distribution, but also the different options to address them, can be best grouped according to the future use of the network assets, being it a continued use for the distribution of methane, a repurposing for alternative uses or a decommissioning of assets. For each of these cases the regulatory design will essentially determine the ability of the DSO to recover its costs, the incentives for cost efficiency, the allocation of the costs between different stakeholders, as well as the cost of capital and returns of the DSO. For the network users, it will influence the development of network tariff levels over time and the tariff structure, which can have implications for the affordability of gas (in particular for heating). In addition, the process of disconnection and the allocation of the associated costs will have a key impact on methane network users. Several of these challenges and questions are closely linked to policy measures and require adjustments to the legal framework by policy makers. Hence, several regulatory measures can only be taken by VNR, when appropriate decisions have been made and policies adopted by the government. For all of these areas a high uncertainty will remain, when and how fast methane demand and utilization of the gas distribution infrastructure will actually decline, and whether the policy targets will be met. It will be important that this uncertainty is adequately reflected in the regulatory framework.

Figure 10-1 Regulatory Questions for Gas Distribution



Source: DNV

# 10.1.1. Regulatory Questions on Continued Use

As the overall volume of gas transported through the distribution network decreases, also the network capacity requirements will be reduced. The remaining gas demand will in the future likely also increasingly be concentrated around industrial clusters and CHPs, which are generally connected at higher pressure distribution or transmission levels. As the capacity of individual gas pipelines cannot be easily adjusted, they will increasingly be oversized, and their utilization will further decline. Besides the transported volumes also the number of users connected to the network will significantly decline. Consequently, the network costs will have to be recovered from a smaller number of remaining gas users, which would result in a continuous increase in gas network tariffs. When the DSOs costs continue to be fully recovered via network tariffs, this effect could lead to a self-reinforcing circle or "death spiral", as ever more gas network users decide to disconnect from the gas grid. To the extent that natural gas network assets are not yet fully depreciated, this could provide a challenge for the recovery of the DSO's costs from network users but also raises questions of affordability and protective measures for the remaining (vulnerable) customers as well as questions for adjustments to the tariff structure.

For existing gas network assets in operation, it must also be decided whether maintenance is conducted in a way that enables a potential longer use or a repurposing of the distribution assets, or whether the maintenance policy already anticipates an earlier decommissioning at a fixed date. Eventually however a decision for either maintenance approach (preventive or corrective) will have to be taken at some point. This could be based on regulatory determinations or left to the DSO. In the latter case it should however be considered that the eventual phase out date for individual assets may be outside of the control of the DSO. The timing of the future use and eventual phase-out of individual assets is uncertain, unless disconnection and decommissioning for specific grid areas is based on fixed plans. The expansion of district heating networks may be delayed as could be the replacement of oil and gas boilers with heat pumps due to a lack of skilled workers, and bottlenecks in the supply chain or electricity system. When a disconnection from the gas grid is not mandated but driven by rising CO2 emission costs, the economics of gas use by households, industry and for heat and power

generation (CHP plants) may also continue to favour the use of natural gas compared to alternative renewable uses as CO2 prices would need to increase by more.<sup>159</sup>

When a phase out of gas is expected, it could be more efficient to extend the life of existing assets beyond their regulatory asset lifetime, instead of replacing them (re-investments). This however raises the question of the financial incentive of the DSO to do so, as the DSO does only receive a return on the residual RAB and not on its OPEX. This does not only provide a CAPEX bias but may also provide a challenge for the asset owner, as he would only receive limited returns on a gas distribution network that is already largely depreciated.

It also needs to be reflected in the regulatory framework how investments into the gas network, which may still be necessary in future years, are to be treated. Such investments could be caused by shifts in gas flows, the injection of biomethane, the need to keep the remaining grid operational and safe, or to enable a repurposing of assets.<sup>160</sup>

More generally, the suitability of the current regulatory model to address uncertainty is to be considered. While the regulatory framework should be flexible to cater for alternative developments in gas demand and policy, it should also provide clear signals for the DSOs based on which they can take investment and operational decisions. As mentioned above for the case of maintenance, it could be efficient or necessary to take an assumption on the future evolution of the gas sector, based on which different elements of the regulatory framework are defined. While the long-term development may be more uncertain, more certainty is to be expected for the next regulatory period(s). As such, it should also be easier to reflect the shorter- to medium-term implications of gas decarbonisation in the specific regulatory framework of the next regulatory period. When uncertainty on future developments is high, also the duration of the regulatory period may be looked at. Furthermore, when the utilization of the gas network and the number of gas network users significantly and permanently decline, the historic or actual costs may be less relevant for forecasting efficient future costs. When determining allowed revenues, it could therefore be considered to move from a backward-looking approach (assessing and benchmarking actual costs) to a forward-looking approach (where the regulator assesses expected future costs forecasted by the DSO).

### 10.1.2. Regulatory Questions on Repurposing

Where repurposing is a technically feasible option for gas distribution assets, it needs to be determined within the regulatory framework in which cases individual assets can be repurposed. In addition to the technical feasibility and the actual need for alternative uses, this should also reflect the operational feasibility, ensuring that remaining gas users are still securely supplied with gas. When the utilization of individual gas network assets is very low and there is an economic case for a repurposing of these assets, it could be considered to discontinue their further use for the distribution of methane. In this case, it needs however to be determined how the remaining gas users are to be treated and how their disconnection can be conducted. Should the DSO have the ability to disconnect such remaining gas users and how does this comply with obligations of the DSO for connection? If disconnection can be enforced by the DSO or follows a structured approach, financial compensations or support mechanisms may be considered for the remaining gas users. When disconnection is only allowed to happen by request of an individual user, who is switching to an alternative technology based on increasing costs for the use of natural gas, a repurposing of these assets would only be feasible once the last gas user in a grid area has been disconnected.

When gas distribution assets are to be transferred for other purposes, it also needs to be specified at which asset value individual assets are to be transferred. The asset transfer value has an impact for

Trinomics —

119

See for example the cases of Germany and the UK, where DNV forecasts relevant natural gas use in 2050, despite national targets for full decarbonisation by 2045 and 2050 respectively. <u>Energy Transition Outlook Germany 2025</u>. <u>Energy Transition Outlook UK 2025</u>.

<sup>&</sup>lt;sup>160</sup> There may possibly also be cases where it is beneficial to keep temporarily non-utilized assets available for a potential future use or later repurposing. Should these assets still be kept in the RAB for gas distribution? How should the additional costs to keep non-utilized assets available be treated.

both the remaining gas network users (benefitting from a higher value) as well as the users of the repurposed asset in case this is also regulated or on the business case for repurposing (in both cases benefitting from a lower value). By not allowing any cross-subsidies between gas, hydrogen and electricity networks, the EU legislation already specifies the residual asset value in the gas distribution RAB as the asset transfer value for these purposes. For other repurposing options the allocation of costs and revenues from a deviation of the residual asset value needs to be defined.

Finally, also the procedures for the transfer of individual assets are to be looked at. A decision among alternative repurposing options may be biased by a transfer to an affiliated or competing company of the gas DSO. The transfer of assets could furthermore also require in many cases a split of joint facilities and services. The separation and transfer of assets may also cause additional costs for the gas DSO, for which their allocation needs to be determined.

#### 10.1.3. Regulatory Questions on Decommissioning

Like for repurposing, it also needs to be determined how and in which cases individual gas distribution assets can be decommissioned. Should the use of individual gas distribution assets be discontinued when their utilisation is low or should they be kept in operation as long as there is a last user? Should they maybe even be kept available for potential future changes in gas flows or for security of supply reasons? When the utilisation of the gas distribution network is low, a recovery of costs to keep assets in operation from remaining users may be challenging. Eventually residual users would request their disconnection due to the high costs of the associated network tariffs, resulting in a decommissioning of the gas distribution assets. There will also be cases where the DSO has to take decisions between alternative decommissioning options, e.g., by decommissioning parallel pipelines or choosing between alternative routes. In this case, criteria and procedures for these decisions should be defined in the regulatory framework.

When the DSO is enabled to disconnect remaining users or disconnection is enforced, the treatment and potential financial compensation of remaining gas users is to be determined. Furthermore, it also needs to be defined in the regulatory framework, if and how the disconnection costs are recovered from users requesting a disconnection or whether they should be recovered from the remaining gas network users, the DSO or the government. This relates to disconnection costs for equipment on the user's property, the actual network connection and possibly also impacts in the wider distribution network.

Another key question for decommissioning is how stranded assets, and the costs of stranded assets are to be treated within the regulatory framework. This includes on the one hand regulatory measures that prevent or limit the occurrence of asset stranding ex-ante (linked for example to the obligation to connect or the depreciation policy) and on the other hand regulatory provisions for determining the value of stranded costs and their allocation when stranding has occurred. The latter should particularly reflect the ability of different stakeholders to influence the occurrence of asset stranding. Should the DSO for example bear the risk of asset stranding when it had conducted its investment into the gas grid in the past based on a regulatory framework requiring the connection of users and the expansion of its network and based on a phase-out following a political decision to do so? In these cases, it may be seen as adequate that the network users or the government rather than the DSO recover these costs. On the other hand, the DSO should have possibly anticipated a potential risk of asset stranding when it took its investment decisions. Should maybe a distinction been made between assets which have been invested before and after a certain point of time? In addition, it is also to be reflected to what extent the risk of asset stranding and a potential decommissioning of assets is reflected in the cost of capital and considered in the return on capital of the DSO.

Furthermore, the physical decommissioning and dismantling of gas distribution network assets is associated with significant costs. As explained in Chapter 5, these may be particularly high, when pipelines are to be removed from the ground, but costs will also arise in the long-term, when assets are left in the ground. To whom should these costs be allocated and from whom should they be recovered? As a consequence of increased decommissioning, the number of gas network users will significantly decline, which will make it increasingly difficult to recover the decommissioning costs from the smaller number of remaining gas users. As such these costs will either to be covered by the

government, the DSO's owners or from electricity or hydrogen network users through dedicated surcharges, so long as it complies with the restrictions on cross-subsidies within the EU legislation. In addition, also the decision among alternative decommissioning options is to be reflected in the regulatory framework. While a physical removal of assets will cause high one-of costs, keeping the assets in the ground may cause operational expenditures for ensuring their safety that arise over a long period of time.

# 10.2. Regulatory context and challenges in Flanders

In line with the policy targets, some measures have already been taken to reduce the risks for stranded assets and the barriers to disconnecting from the gas distribution grid, for instance:

- New gas grid extensions and connections are legally constrained.<sup>161</sup>
- The cost for the removal of unused gas connections is recovered from the concerned grid
  users, except if the removal is initiated by the DSO/Fluvius as part of necessary works on an
  unused connection to avoid further investments. For example, in the context of roadworks,
  network renewal, or leakages on the connection, the DSO may remove the gas connection at
  its own expense.
- Application of a nominal WACC and an unindexed RAB, which has been suggested as a regulatory measure to front-load depreciation for countries that apply a real WACC and an indexed RAB in several other studies.<sup>162</sup>

The current regulatory framework in place for gas distribution does however not yet address the anticipated long-term challenges resulting from a gradual phase out of natural gas use:

- Gas distribution assets are depreciated linearly over a long period (e.g. 50 years for pipelines), which will lead to challenges to recover the depreciation costs in a context with a decreasing number of end-users and declining gas offtake. Moreover, even without grid extensions and new connections in the future, large investments will still be needed for safety and operational reasons. Grey cast iron pipelines (still 9.7 km in use) must for instance be replaced in the coming years, and fibre cement pipelines (333.6 km) should also to a large extent be replaced.¹63 According to our projections, the annual investments required in 2030-2040 will range between € 70.7 and 104 million depending on the scenario and would still exceed € 20 million in 2050. If no measures are taken, the net accounting value of the gas grid assets will still be quite high in 2050.
- A coordinated approach to disconnections is not yet available and should not necessarily
  be developed in the very short-term. However, it should timely be prepared for
  implementation when gas users will progressively shift to electric heat pumps (or district
  heating). Legal provisions would also be needed allowing gas DSOs to disconnect remaining
  grid users when certain criteria are met. As illustrated in the previous chapters, lack of

See the example for the Netherlands in chapter 10.3.5, as well as DNV and Trinomics (2022): <u>Future regulatory decisions on natural gas networks: repurposing, decommissioning and reinvestments.</u>



<sup>&</sup>lt;sup>161</sup> While new gas grid connections for existing homes (e.g. switch from heating oil to natural gas) are still possible in Flanders, gas grid connections for new large residential projects are prohibited since 2021, and since January 2025 this prohibition applies also to any new built home. In addition, also the fees for new connections of existing homes have recently been increased, discouraging such new connections.

<sup>&</sup>lt;sup>162</sup> Under nominal WACC with non-indexed RAB, the real value of the RAB declines over time due to the impact of inflation, whereas compensation for inflation is reflected via the capital costs in the respective year. Under real WACC and an indexed RAB, the RAB is increasing in line with inflation. As a consequence, the application of a nominal WACC with non-indexed RAB leads to higher capital costs and gas network tariffs in early years and lower capital costs and gas network tariffs in later years.

<sup>&</sup>lt;sup>163</sup> Fluvius (2025) <u>Investeringsplan 2026-2035</u>.

coordination of disconnections may lead to high costs for DSOs and hence for the remaining grid users.

- A large majority of the revenues of gas DSOs are received from energy (or commodity) charges) based on gas offtake volumes. With decreasing offtake volumes per end-user (e.g., due to more energy efficient use and/or implementation of hybrid solutions where an increasing share of users is accessing the grid in a more limited number of hours), it can be considered to adjust the allocation and structure between energy and capacity charges. This could bring network tariffs more in line with the DSOs' cost drivers and hence improve cost reflectivity.
- The future role of biomethane in the Flemish energy system is not yet fully clear but is expected to remain limited. As mentioned in Chapter 3, the suitable biomass potential is limited, and it can be used for different competing purposes. Upgrading biogas to biomethane for injection into the natural gas grid can be an appropriate option if there are no more favourable alternative uses of the biomass and biogas. It is also not expected that significant biomethane volumes will be imported from other European countries. However, maintaining a dedicated part of the grid specifically to transport biomethane between local producers and off-takers, after the full phasing out of natural gas, should further be evaluated, although depending on the distance this might be a very expensive option.
- Low coordination between gas grid and district heat planning: Local heat plans are increasingly being developed by municipalities and should increasingly be considered in network planning and decommissioning plans for gas distribution. Gas networks may still be necessary although in a much smaller and different grid configuration if district heat networks rely on CHPs using (renewable) gas.

# 10.3. International regulatory practices

# 10.3.1. Relevant EU legislation

With the adoption of Directive (EU) 2024/1788 and Regulation (EU) 2024/1789 several provisions relevant for the future regulation of gas distribution in the context of a natural gas phase-out have or will be implemented, influencing also the relevant regulatory framework for Flanders.

A key element of **Directive (EU) 2024/1788**, 164 which has to be implemented into national regulation by 5.8.2026, is the development of decommissioning plans by the gas DSOs, where a decline of gas demand is expected requiring the decommissioning of the natural gas distribution network or parts of such networks (Article 57). These decommissioning plans will have to be submitted every 4 years by all gas DSOs with more than 45,000 connections. They are subject to review and approval by the regulatory authority (e.g., VNR) and shall be based on a 10-year outlook of gas demand and supply, considering also relevant local heating and cooling plans. The plans will be subject to a public consultation and identify required infrastructure adaptations as well as list infrastructure to be decommissioned in the future. Based on the decommissioning plans, access and connection to gas distribution networks can be refused by the DSO, whereas the NRA shall provide a regulatory framework for refusal of connection and disconnection that is based on objective, transparent and non-discriminatory criteria (Article 38). Member States can furthermore decline the construction and operation of gas grids in areas for which decommissioning has been specified in an approved decommissioning plan (Article 8). For assets to be decommissioned before the end of their regulatory asset life, the NRA shall establish guidelines for the depreciation of such assets and the tariff setting in such cases (Articles 57 and 78). Gas users are to be consulted and informed sufficiently in advance of any disconnection on the procedure, the steps, the timeline, the sustainable heating options, and available financial support (Article 13). The European Commission shall provide further guidance on the protection of vulnerable customers and customers affected by energy poverty (Article 27). Several

Trinomics 🦰 💳

<sup>&</sup>lt;sup>164</sup> Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen.

articles also require a legal, operational and accounting unbundling of gas, hydrogen and electricity networks and prohibit cross-subsidies between gas, hydrogen and electricity activities (Articles 46, 75, 78).

Regulation (EU) 2024/1789, 165 in force since 5 February 2025, implements a number of provisions relevant for the repurposing of natural gas assets. According to Article 5, separate regulatory asset bases (RAB) are to be kept for natural gas and hydrogen (and electricity) networks, whereas revenues and costs are only to recover the OPEX and CAPEX of the respective RAB. In case of an asset transfer, no cross-subsidies between different RABs are allowed, which limits the asset transfer value basically to the residual asset value of the gas network operator. Temporary<sup>166</sup> financial transfers between unbundled regulatory services via a dedicated charge paid by end-users (at exit points) is however possible, if the NRA sees that the network tariffs are not viable to finance the network infrastructure and the NRA has approved the methodology and level of the charge. While such temporary exemptions for cross-subsidies are intended for the early phase of hydrogen networks, the Regulation is not explicit in limiting its application to this case, but also transfers from electricity to gas users may in principle not be excluded so long as they are limited in time (see footnote 166). DSOs are furthermore also required to ensure the availability of firm capacity for the feed-in of renewable and low carbon gases into their network based on transparent and non-discriminatory procedures, as well as to conduct the necessary investments to ensure reverse flow from the distribution network to the transmission network (Article 36).<sup>167</sup>

# 10.3.2. Relevant regulatory developments in the UK

The UK gas distribution networks, owned and operated by 4 DSOs, are regulated by the Office for Gas and Electricity Markets (OFGEM). Ofgem determines the funding the gas DSOs receive to maintain existing and invest in new gas assets. In 2013 Ofgem started discussions on a new regulatory framework called RIIO (Revenue=Incentives + Innovation + Outputs), with the aim of encouraging the DSOs to operate efficiently, invest in new technology and meet customer valued outputs<sup>168</sup>. The regulatory framework is based on a detailed regulatory review of the business plans (forecasts) of the gas DSOs for the next regulatory period (currently 5 years). Outputs include security of supply, reliability, quality of service and "infrastructure fit for a low-cost transition to net zero", which is assessed via Environmental Action Plan and Reporting, Advanced Leakage Detection and Digital Analytics, Regional Energy Strategic Plan, and standards for methane leakage repairs. Adjustments by UK regulator Ofgem within the regulatory period are possible in specific pre-defined cases via "reopeners" to address uncertainty. Re-openers allow Ofgem to adjust of allowances, outputs, and delivery dates. In the current regulatory period among others two net zero reopener funds to support projects' design and pre-construction phases, and another to allow amendments in case of changes to the heat and decarbonization policies. <sup>169</sup>

Under the current framework, gas DSOs charge customers requesting a gas disconnection (voluntary disconnection) a reasonable and cost reflective charge relating to the disconnection. Gas disconnection works required under health and safety legislation, including the disconnection and capping of pipes 12 months after any meter has been removed, are ultimately passed onto remaining

Trinomics —

123

<sup>&</sup>lt;sup>165</sup> Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen.

<sup>&</sup>lt;sup>166</sup> The temporary limitation is no longer than 1/3 of the remaining depreciation period of the concerned infrastructure benefiting from the transfer.

<sup>&</sup>lt;sup>167</sup> As part of the development process for Network Codes for natural gas also a dedicated Network Code on network connection rules that includes renewable and low carbon gas production and procedures for connection requests is to be developed (Article 71). The European Commission may furthermore adopt rules for determining the value of transferred assets and the dedicated charge.

<sup>&</sup>lt;sup>168</sup> Ofgem website, Energy network price controls, accessed online 24/09/2025.

<sup>&</sup>lt;sup>169</sup> In addition, different incentive mechanisms for the reduction of carbon emissions by the DSOs are adopted, including innovation funding via the Network Innovation Allowance (NIA) and targeted support for Net Zero technologies.

gas users through network charges. According to information collected by Ofgem, the latter form of disconnection accounts for most of the connections in the UK.<sup>170</sup> As the current framework has been perceived as rather complex and unfair, Ofgem is currently consulting a new disconnection policy, final proposals of which are to be expected in early 2026.<sup>171</sup>

Ofgem has been exploring changes to the regulatory framework for the next regulatory period (2026 – 2031), addressing a few items related to natural gas transition, including an accelerated depreciation of the Regulated Asset Value  $(RAV)^{172}$ .

The following four options were put forward to the UK DSOs as part of the sector specific methodology:

- 1) Sum-of-digits with RAV returned by the government's net zero target date. In this option, the asset lives (depreciation period) would be set such that the RAV is fully depreciated by the target date.
- 2) Sum-of-digits, variable declining balance with RAV returned by government's net zero target date. As with the option above, but with an acceleration factor determined for each price control period and applied to the depreciation amount for that period to accelerate recovery as required.
- 3) Straight-line, variable declining balance profile with RAV returned by government's net zero target date. As with Option Two above but with a straight-line depreciation profile rather than sum-of-digits.
- 4) For existing assets retaining the existing depreciation profile and asset life assumptions; for new investments sum-of-digits with investment returned by government's net zero target date.

The basis for this approach is twofold. Ofgem sees a decline in gas usage and wants to accelerate the RAV depreciation to reduce the risk of stranded assets. Secondly, Ofgem has based its approach on the holistic pathway developed by the National System Energy Operator. As mentioned previously, the holistic pathway sees a steep decline in natural gas usage aligned to the 2050 net zero target.

The UK DSOs responded to Ofgem's proposed changes with various options, unsurprisingly none of them was in favour of accelerated RAV depreciation. The DSOs arguments were based on the actual slow decline in natural gas users compared to the FES scenarios of the National Energy System Operator. They argue that accelerated RAV depreciation on all assets would have a significant impact on consumers' bills in the short term and potentially the long term too if assets are used beyond 2050.

Ofgem's draft determination issued in July 2025 has produced a "cautious but proactive stance" where the current RAV deprecation rules will remain in place for existing assets and an accelerated depreciation in line with the government's net zero date for new assets. The latter is particularly important with regard to the significant replacement of iron mains with polyethylene pipes for safety reasons described in the section 5.1.1. With replacements taking place until 2032, this could otherwise potentially result in significant stranded assets at current regulatory depreciation periods for pipelines of 45 years. Existing depreciation rules already apply a front-loaded approach with the use of the sum of years' digits depreciation method; only the regulatory asset lifetimes for the existing asset would not change.

# 10.3.3. Relevant regulatory developments in Germany

Reflecting the target of the German government for greenhouse gas neutrality for Germany in 2045, the German regulatory authority Bundesnetzagentur (or BNetzA) has adopted an accelerated

\_



<sup>&</sup>lt;sup>170</sup> OFGEM (2025) <u>Summary of Responses: Gas Disconnections Framework Review.</u>

<sup>&</sup>lt;sup>171</sup> OFGEM website, <u>Exercising consumer choice: a review of the gas disconnections framework</u>, accessed online 24/09/2025.

<sup>&</sup>lt;sup>172</sup> OFGEM (2025) RIIO-3 Draft Determinations - Finance Annex.

depreciation policy for natural gas networks (KANU 2.0).<sup>173</sup> Applying from 2025 onwards, it enables DSOs to depreciate all of their assets until 2045 by (optionally) applying shorter regulatory asset lives. In exceptional cases, i.e., if a phase-out before 2045 has been decided on municipal or regional level, also a depreciation up to 2035 is feasible. In an earlier determination from 2022 such faster depreciation was limited to assets capitalised from 1.1.2023 onwards. In addition, also a declining balance depreciation at a rate of 8-12% is allowed in particular cases, whereas the rate should be in "reasonable proportion" to the remaining useful life, which requires justification by the DSO (or TSO) towards the BNetzA.<sup>174</sup> Figures recently published by BNetzA show that 86% of all gas DSOs subject to regulation by BNetzA apply shorter depreciation timelines. This will result in a one-off increase of gas network tariffs for those DSOs applying faster depreciation the first time (according to BNetzA network tariffs will increase for these DSOs by around 23% in 2026).

Regulatory provisions for the disconnection and decommissioning of gas networks are however still largely missing for Germany, although renewable heating systems are required for new build areas since January 2024, while oil and gas boilers outside these areas and in existing buildings can only be replaced with fossil heating systems until the end of June 2028 (2026 for municipalities with more than 100,000 inhabitants), unless the local heat transformation plan would foresee the use of hydrogen in the future. In general, gas DSOs in Germany are still obliged to connect new users (including industrial users) to the gas network on their request. Refusal of a connection request is only possible in line with the general provisions, if this is technically or economically not feasible. Accordingly, DSO are only able to disconnect gas users in Germany on their request.<sup>175</sup> No common regulation applies with regards to the allocation of the disconnection costs (decommissioning and dismantling of gas network connections) in Germany. While some DSOs leverage these costs on all remaining gas network users, others charge the full costs to the network user requesting the disconnection (and some DSOs share the costs between the concerned user and the remaining network users). There is no legal requirement for physical decommissioning or dismantling in Germany. Current concession agreements, which DSOs need to possess to operate the gas network in a specific concession area, can however oblige DSOs to dismantle their gas networks in case the network assets are not further used.

# 10.3.4. Relevant regulatory developments in Denmark

Reflecting the political target to phase out natural gas for heating, no new connections to the gas distribution network are allowed in Denmark. Buildings situated within district heating areas are only permitted to be heated by district heating or by renewable energy sources. Where sufficient biogas production exists, the network users may be exempted from the disconnection obligations, but with a target to convert that local network to 100% biomethane by the deadline. As a result of long-term

Trinomics - -

125 =

<sup>&</sup>lt;sup>173</sup> Determination proceedings for the adjustment of imputed useful lives and depreciation arrangements for natural gas pipeline infrastructure (KANU 2.0)

<sup>&</sup>lt;sup>174</sup> BNetzA has also approved a plan for a hydrogen core network of around 9,000 km in Germany, which to a small extent (470 km) also includes gas DSOs. According to the plan, 60% of the assets of the core network will be repurposed natural gas assets, while 40% will be new build assets. The financing of the hydrogen core network will be done by an intertemporal cost allocation mechanism ("amortisation account"), by which initially lower network tariffs for the use of the hydrogen network (when the number of users of this network is still small) will be compensated via higher network tariffs in later years (up to 2055), when it is expected that the number of users and their willingness to pay has increased.

<sup>&</sup>lt;sup>175</sup> A new version of the Energy Industry Act, which would implement the provisions of Directive (EU) 2024/1788 into German legislation, including the development and approval of decommissioning plans and the rejection of new connections for parts of the network for which a decommissioning is foreseen in the plan, is currently in a draft stage. According to the draft law customers will also have to be informed at least 10 years in advance on a planned decommissioning of parts of the network.

policy plans, already 40% of the methane consumption in Denmark of 2025 is covered by biomethane and around 70% of the homes in Denmark use communal heating.<sup>176</sup> <sup>177</sup>

Denmark has also adopted a disconnection scheme (*Afkoblingsordningen*)<sup>178</sup> funded by the Danish state that provides financial assistance to end-users for the removal of gas pipes used for households switching to an alternative for space heating (e.g., heat pump or district heating). The funding is provided based on application by the end-user, subject to availability of funds and meeting eligibility criteria. The funding is used, disconnections can still be carried out but for a fee, until the next funding pool is made available. In addition, support for biomethane, district heating and heat pumps is provided via a number of schemes that include subsidies, certificate of origin schemes overseen by the regulator, and a right to inject policy. National gas DSO Evida is however not allowed to impose a disconnection of users. Denmark does still apply a linear straight-line depreciation for natural gas distribution with regulatory asset lifetimes for distribution pipelines of 30-40 years.

The Danish Ministry of Climate, Energy and Utilities has also published in March 2024 guidelines for the conversion from natural gas to district heating. Among others, they specify that municipalities should analyse the technical feasibility and economic viability of a conversion, the customer commitment, the available power grid capacity to supply heat pumps, the environmental impacts and the land requirements for new infrastructure.

National gas DSO Evida was tasked by the Ministry of Energy with conducting a screening of local distribution areas where decommissioning of gas distribution would be feasible and economic viable for the DSO as well as parts of the distribution network that cannot be decommissioned due to biogas production or the supply of companies using gas for their production processes.<sup>181</sup>

## 10.3.5. Relevant regulatory developments in the Netherlands

According to the Gas Act (*Gaswet*) gas DSOs in the Netherlands are prohibited to connect new users to their gas network since July 2018 (i.e., users with a connection of less than 40m³ of gas per hour). Municipalities may grant exemptions in case alternatives to gas are technically infeasible or only feasible at disproportionate costs. Municipalities are also obliged to develop local heat transition plans to phase-out the use of natural gas for heating at district level. In areas designated for alternative heating existing gas users can be disconnected from the gas network by the DSO within an 8-year transition window, provided the alternative is cost-effective. DSOs are furthermore required due to safety considerations to remove gas connections that are no longer in use.

Following an appeal to the earlier regulatory determination for the current regulatory period (2022-2026), a variable declining balance depreciation (instead of the previous linear depreciation) with an acceleration factor of 1.2. is applied. Under this method a fixed percentage of the remaining value of the asset is depreciated each year. The percentage is equal to the percentage of a straight-line

<sup>&</sup>lt;sup>182</sup> For gas transmission the same framework of an accelerated depreciation had already been adopted in the initial regulatory determination for the period 2022-2026.



<sup>&</sup>lt;sup>176</sup> The Danish Energy Agency (2025) <u>Biogas in Denmark</u>.

<sup>&</sup>lt;sup>177</sup> Dansk Fjernvarme <u>website</u>, accessed online 24/09/2025.

<sup>&</sup>lt;sup>178</sup> Evida website, Afkoblingsordning, accessed online 24/09/2025.

<sup>&</sup>lt;sup>179</sup> The disconnection scheme is established by the Danish Energy Agency with operational responsibility delegated to natural gas DSO (Evida). Applications are processed on a first-come, first-served basis until the annual budget is exhausted. The customer has to be a private household or a landlord with rental properties heated with natural gas and an annual gas consumption of an annual gas consumption between 100 m<sup>3</sup> and 6,000 m<sup>3</sup>.

<sup>&</sup>lt;sup>180</sup> Klima-, Energi og Forsyningsministeriet - Regeringens nationale energikrisestab (NEKST) (2024) <u>Konvertering</u> <u>fra naturgas til fjernvarme</u>.

<sup>&</sup>lt;sup>181</sup> Evida (2022) Konverteringskortlægning II.

depreciation of the initial asset value multiplied by an acceleration coefficient.<sup>183</sup> The acceleration factor enables a flexible adjustment of depreciation in the future based on the progress of gas decarbonization. The Dutch regulatory authority ACM did however not change the regulatory asset lifetimes for gas distribution (45 years for low pressure pipelines).

As another measure to front-load the recovery of costs, also a shift from real WACC with an indexation of the RAB, to a nominal WACC with no-indexation of RAB was adopted for the current regulatory period. Under nominal WACC with non-indexed RAB, the real value of the RAB declines over time due to the impact of inflation. As a consequence, this leads to higher capital costs and gas network tariffs in early years and lower capital costs and gas network tariffs in later years. All of these measures prevent future gas network users from having to bear an unreasonably large share of the costs of the network that was partly constructed for the benefit of current gas network users.

Disconnection fees previously charged by DSOs to users (for removing gas connections in buildings) were abolished. Disconnection and decommissioning costs are now socialised via network tariffs from the remaining gas network users. Assets no longer in use are to be removed from the RAB in one go.

ACM did furthermore implement an ex-post adjustment based on the actual costs both for disconnection and decommissioning, while it also concluded that it does not have robust enough data yet, to set a dedicated efficiency incentive for decommissioning costs.

While ACM did not expect any significant removals to take place during the current regulatory period, it expects a sharp decline in in the number of users and the utilisation of the gas networks until 2050, resulting in the removal of both gas connections and gas networks. ACM however also expects that there will still be a partial need for gas networks in 2050. As a consequence, ACM assumes that gas network assets will remain in use long enough to recover their costs through tariffs paid by remaining users.

With the aim to better align regulation with the energy transition, it is also planned to shift from expost to ex-ante costs assessments for the next regulatory period starting in 2027.

# 10.4. Regulatory options to address challenges in Flanders

A large number of regulatory options to address potential challenges related to the phase-out of natural gas have been discussed in the scientific literature, several studies and publications of various stakeholders. In addition, as presented in the previous chapters, several European countries have already adopted some of these regulatory measures in practice.

The regulatory options can be structured in relation to the future utilisation of the assets – continued use, repurposing and decommissioning – as well as the point in time at which regulatory measures are applied. The latter includes regulatory measures

- A) applied ex-ante to avoid or reduce the occurrence of certain implications, such as the risk of asset stranding;
- B) relevant for the process of phasing out natural gas, such as disconnection policies and the allocation of disconnection costs;
- C) applied ex-post when assets are repurposed or decommissioned, such as the recovery of stranded costs or the regulatory efficiency assessment of physical decommissioning costs.

A further dimension are additional regulatory measures or provisions that address the high uncertainty of the future development of natural gas demand, i.e., where, when and how fast the utilisation of natural gas distribution infrastructure will decline.

Trinomics —

127 =

 $<sup>^{183}</sup>$  If for example 4% (or  $^{1}/25^{th}$  with depreciation over 25 years) would be depreciated under straight line depreciation in a specific year, an acceleration factor of 1.2 would result of a depreciation of 4.8% (= 4% x 1.2) for that specific year.

Several of these regulatory measures are to be decided on policy level or require adjustments to the legal framework by policy makers first, before further measures can be taken by VNR. Measures requiring adjustments at policy level relate in particular to connection obligations, disconnection and decommissioning processes (including the ability of the DSO to disconnect users) and the allocation of disconnection, stranded and decommissioning costs to different stakeholders. When discussing the different options in the following sections, we will also give an indication on whether the decision to implement these will primarily be taken on policy level or whether they relate to measures to be implemented by VNR.<sup>184</sup>

As part of this study, we cannot provide a detailed analysis of all options but instead focus our analysis and assessment on key regulatory measures addressing the specific situation in Flanders, which are under the control of VNR, and relate to regulatory decisions to be taken for upcoming regulatory periods. While repurposing and decommissioning may still be limited in the next years, expectations of the DSOs for the future evolution of regulatory measures in category C will still influence the operational and investment decisions, the DSOs are already taking now. Based on the quantitative analysis of the previous chapters, we also expect limited repurposing for the gas distribution network in Flanders, which puts particular focus on questions around the continued use under declining gas demand, the disconnection of users and the decommissioning of assets. In addition, some measures will already apply with the implementation of the EU legislation, such as the development and review of distribution decommissioning plans, which we will not further assess here in detail. A quantitative assessment of individual options and the drafting of detailed regulatory provisions to be adopted in Flanders are not part of the scope of this study. We suggest studying these in further details in a separate study based on the findings of this study.

Figure 10-2 provides an overview on the relevant regulatory options along the above categories, which are further discussed in the following sections.

128 -



<sup>&</sup>lt;sup>184</sup> This only provides an indication whether the decision is to be <u>primarily</u> taken on policy level or by VNR, as no detailed legal analysis on individual measures has been conducted as part of this study. As both are also closely interlinked, it may also be the case that additional legislation or policy decisions are required for measures where we indicated that VNR could primarily implement these measures.

Figure 10-2 Regulatory options to address a phase-out of natural gas distribution

A Ex-ante	B Process	C Ex-post
Regulatory measures aiming to avoid / reduce the impact of a phase out	Regulatory measures relevant for the process of phasing out gas	Regulatory measures applying when decommissioning and repurposing takes place
Regulatory measures avoiding / reducing the risk of asset stranding  • Accelerated depreciation  - Shorter regulatory asset lifetimes  - Changing the depreciation policy to front-loaded depreciation  • Reflection of the stranding risk in the regulatory cost of capital  • End obligation of DSOs to connect / apply deep connection charges P  • Regulatory approval for individual new (replacement) investments  • Limit the capitalization of opex  • Incentives to utilize assets beyond their regulatory asset lifetime	Process for decommissioning and disconnection  Implement distribution decommissioning plans* P  Enable DSO to disconnect users* P  Information/consultation of users on disconnection, protection of vulnerable customers* P  Financial compensation / support of residual gas users P  Maintenance policy Reflection in efficiency assessments Asset Management Plan  Treatment of disconnection costs Recovery from connectee, remaining gas users, DSO, government/taxpayer P  Changes of tariff structure Higher share of fixed / capacity tariffs	Treatment of stranded costs  • Allocation of costs to DSO, asset owner, remaining gas network users, or government/taxpayer P  • Differentiation of recovery by date of investment and type or investment  Determination and treatment or (physical) decommissioning costs  • Separate cost assessment and approval of efficient physical decommissioning costs by regulator  • Allocation of costs to DSO, asset owner, remaining gas network users, or government/taxpayer P
Reg	ulatory measures addressing uncert	tainty
Re-openers / ex-post adjustmen     Length of regulatory period		of allowed revenues based on cost d of actual / historic costs

- \* To be implemented with Directive (EU) 2024/1788
- <sup>P</sup> Primarily policy measures

Source: DNV

#### **Accelerated depreciation**

One option to avoid the risk of asset stranding is to either **shorten** the **standard regulatory asset lifetimes** below their technical lifetimes or to enable a depreciation until a **fixed end-date** that ensures full depreciation in line with the political decarbonisation targets. Another option to accelerate depreciation is to apply a **non-linear depreciation method** that front-loads depreciation such as the (variable) declining balance method or the sum of years' digits method. To the extent that the risk of asset stranding is under the control of the DSOs or is already being compensated by a higher rate of return, it could also be considered that the costs of stranded assets should at least partially be covered by the DSOs, in which case regulatory measures to avoid asset stranding would

<sup>&</sup>lt;sup>185</sup> The year for which a binding target for full decarbonisation ('net zero') is to be achieved in Flanders, should also mark the year until which natural gas pipelines are to be operated at the latest, unless specific policy targets for the use of natural gas are defined for Flanders or the natural gas is used as a feedstock and not as a fuel.



be less needed. Shifting part of the risk and burden of stranded assets to the municipal owners of the Flemish DSOs may however not be possible, as the municipalities face a number of other financing requirements which limit their financial leeway, including significant investments related to the energy transition and climate change.

#### Textbox 10-1 Accelerated depreciation methods

As alternative to the currently applied **linear (straight-line) depreciation method**, which simply divides the asset value at the point of construction evenly across the asset's expected useful life, two alternative accelerated depreciation methods are generally considered: the **Sum-of Years' Digits method** (applied in the UK regulation) and the **Variable Declining Balance method** (applied in the Dutch regulation).

Under the Sum-of Years' Digits method, the annual depreciation is determined by multiplying the depreciable cost by a fraction, whose numerator is the remaining life of the asset in years and whose denominator is the sum of the remaining asset's life every year through the asset's entire life. It allocates larger depreciation amounts in the early years of an asset's useful life and lower amounts in later years.

The variable declining balance method applies a constant depreciation factor to an asset's declining book value but applies a straight-line depreciation when this yields a higher depreciation value than the declining method. It allocates a larger depreciation amount in the first years of its application, whereas a constant depreciation value below the straight-line depreciation value will apply in later years.

The following figure illustrates the impact of the three depreciation methods on the annual depreciation values for an investment of EUR 1,000,000, depreciated over a period of 20 years.

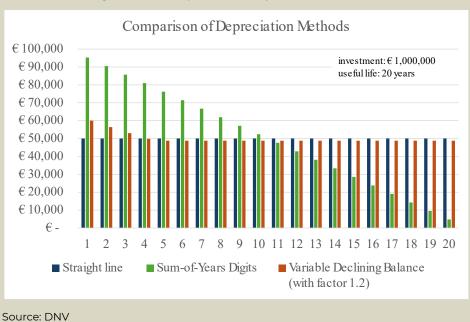


Figure 10-3 Comparison of depreciation methods

With regards to asset stranding, it may be considered to differentiate between assets, which are expected to be fully depreciated in line with their asset lifetime or which will likely be repurposed, and assets for which a decommissioning before the end of their regulatory lifetime is to be expected. In this case, it could be considered to limit the accelerated depreciation to assets constructed after a certain point of time. As the declining number of natural gas network users will make it however more difficult to recover the costs in later years – and also from the point of fairness that the current network assets have been constructed for the supply of the current gas users – it could be seen as more adequate to apply the accelerated depreciation method to all assets independent of their age. Even

more so, when the level of repurposing is expected to be quite limited and most assets will eventually be decommissioned. Different energy transition forecasts predict that the energy policy decarbonisation targets, including the decarbonisation targets for the heating sector, will likely not be met by the actual developments in several European countries due to a number of practical and economic challenges. As a result also the phase-out and disconnection from natural gas may take place over a much longer period. With high uncertainty on the speed of the phase-out of natural gas, it could be beneficial to apply a variable declining balance depreciation, like in the Netherlands, which allows to adjust the depreciation factor in line with actual developments.

While shorter regulatory asset lifetimes provide a better safeguard against the risk of asset stranding, front-loaded depreciation methods may have the advantage of recovering even higher shares of the RAB in earlier years, when the number of gas users still remains high. Applying a fixed end date could also have the risk that assets are fully depreciated before the end of their actual use, in case phase-out dates are further moved into the future. In this case the DSOs would have an incentive to replace these assets before the end of their lifetime, as they only receive a recovery of their opex but no return. Besides being inefficient this would also increase rather than lower the risk of asset stranding. The decision for shorter asset lifetime should be strongly influenced by the expected risk of asset stranding and the ability of the DSOs to recover stranding costs from remaining users, which is influenced by the residual asset age of the current assets, the expected speed of disconnection, and the expected level of future investments.

Depending on whether a voluntary "cost-based" or a planned phase-out of natural gas is foreseen in Flanders, the scenarios developed in this study forecast a reduction in the number of connections between 3%-34% (low scenario) and 4%-44% (medium scenario) by 2050, resulting in a decommissioning of 0%-38% of the low-pressure pipeline branches (see chapter 2). While a stranding risk for individual assets was not calculated as part of this study, the numbers seem to indicate that asset stranding may be more limited in these two scenarios. Only in the high scenario, which foresees a complete phase-out by 2050, significant asset stranding may occur. The same holds also true for any new investments, which may for example be needed for safety reasons. Both cases (high scenario and new investments) would provide a strong argument to shorten the regulatory asset lifetimes. Still considering the decarbonisation policies in place, the current regulatory asset lifetimes for pipelines on low and medium pressure level of 50 years applied in Flanders could be seen as long, also compared to other European countries. Even if significant gas network connections and parts of the gas distribution network remain in 2050, as forecasted in the medium and low scenarios, it could still be considered to apply regulatory asset lifetimes more in the direction of 30 years. A combination of shorter regulatory asset lifetimes and front-loaded depreciation methods should in particular be considered for any new investments.

Front-loading depreciation has the implication that network tariffs will increase in the short-term, which will increase the incentive for the remaining users to disconnect from the gas network, which would increase the upward pressure on network tariffs as the costs would be allocated among a smaller number of network users. Implementing measures that ensure that network tariffs do not jump significantly from one year to another and ensure that vulnerable and customers affected by energy poverty are sufficiently protected in this process will be important. This is further discussed in sections 10.4.1 and 10.4.4.

As the DSOs have the best overview on the condition, the expected residual use of individual assets (including the potential risk of stranding) and a potential later repurposing, the decision of the application of an accelerated depreciation for an individual asset could also be left to the DSOs. As the regulator does not have granular insight on state and potential use of individual assets, different speeds of depreciation could only be applied for all assets or differentiated by asset category, when the application is determined within the regulation or by the regulator. This would however likely

Trinomics —

**—** 131 **———** 

<sup>&</sup>lt;sup>186</sup> See for example the Energy Transition Outlooks of DNV for Germany and the UK, which both forecast relevant natural gas use in 2050, despite national targets for full decarbonisation by 2045 and 2050 respectively. Energy Transition Outlook Germany 2025. Energy Transition Outlook UK 2025.

result in situations where some assets are depreciated too early while other assets may face an increased risk of stranding. When the decision on the application of an accelerated depreciation is left to the DSO, it is however important to ensure that such decisions are linked to the expected timeline of natural gas decarbonisation (i.e., based on the politically defined decarbonisation targets) and do not result in increased investments (and thereby increase the risk of stranding). To avoid this, a number of measures could be considered:

- attribute (part of) the risk of stranding to the DSO, if stranding of assets was avoidable or driven by over-investments of the DSO; cost-sharing of stranded costs would need to be defined ex-ante
- ensure opex-capex neutrality when assessing cost efficiency (e.g., via a benchmarking of total expenditures) and determining the regulatory cost of capital
- require the DSO to submit further explanation on the application (and non-application) of accelerated depreciation
- require an ex-ante regulatory approval of the accelerated depreciation suggested by the DSO, based on a robust analysis. It could also be considered to only apply a regulatory approval, if accelerated depreciation increases annual allowed revenue by more than a set threshold (e.g., 2–3%)
- require the regulatory approval for individual new (replacement) investments (see further below for more details)

#### Reflection of the stranding risk in the regulatory cost of capital (WACC)

The risk of asset stranding can be seen as asymmetric, as the allowed revenues provide an upper limit that cannot be exceeded by the DSOs, while an under-recovery of allowed revenues, in case stranded costs are allocated to the DSOs, cannot be excluded by the regulator, unless specific government guarantees or a socialisation of stranding costs are in place. This may provide a case to reflect this risk in the regulatory rate of return (which could potentially at least partially be done by applying an uplift to the regulatory cost of capital), although it could also be argued that the remuneration above the risk-free rate already reflects a potential risk that the investment may not be fully recovered. In its assessment on this topic UK regulator Ofgem has concluded that shorter asset lives and a more aggressively front-loaded depreciation profile are better suited to mitigate any perceived asset stranding risks, as higher regulatory returns on capital would increase returns to investors at the expense of increased consumer bills, when the long-term risk of asset stranding remains uncertain.<sup>187</sup> In a report for the Ofgem<sup>188</sup> evidence from UK debt markets was provided that markets price a higher risk for gas networks compared to electricity networks and that this difference has been increasing over time when the risk of a potential stranding has been gaining further attention in the market. Besides a higher debt risk premium also equity holders are expected to demand a higher return. In fact, in the same report for Ofgem evidence from Italy and Spain was provided that reported asset betas of gas network companies are in general above the betas of electricity network companies in the same country. Important in this regard is the market perception on the risk of asset stranding and the potential non-recovery of costs by the DSO. If regulatory and policy measure are in place mitigating the asset stranding risk (such as an accelerated depreciation) that credibly protect the investor or owner from the risk of stranding and non-recovery of costs related to the energy transition, it would not be adequate to apply higher asset betas and regulatory cost of capital.<sup>189</sup> If the risk of asset stranding is not sufficiently addressed in the regulatory and policy framework, it seems at least adequate to apply a higher regulatory return for gas networks than for electricity networks, which do not face a similar risk of asset stranding. Different to the previous measures, a higher regulatory cost

<sup>&</sup>lt;sup>189</sup> See also Brattle (2025) The WACC for the Flemish DSOs for the regulatory period starting in 2025.



**=** 132 **====** 

<sup>&</sup>lt;sup>187</sup> Ofgem (2023) <u>RIIO-3 Sector Specific Methodology Consultation – Finance Annex</u> and Ofgem (2024) <u>RIIO-3 Sector Specific Methodology Decision – Finance Annex</u>.

<sup>&</sup>lt;sup>188</sup> Risks and investability of the GB gas distribution sector – Report of oxera prepared for GB gas distribution networks, 1 March 2024.

of capital would not mitigate the asset stranding risk but would compensate the DSOs for the asset stranding risk.

## **Grid connection policy**

To reduce the risk of stranding assets and to mitigate the challenges around the disconnection of the last residual users, it should be considered to **end the obligation of the DSOs to connect new users** to the gas grid. While new gas grid connections are prohibited for new built homes, new connections for existing buildings (e.g., switching from oil to natural gas) are still possible in Flanders. Reflecting the average useful lifetimes of heating systems, it is likely that these newly connected users will be among the last ones to switch from natural gas to renewable energy options. A connection of new users to the gas network should therefore be limited to exceptional cases, where no alternative heating option is feasible or available or where methane is used as feedstock for processes. Changes to the obligation of the DSO to connect new users will require adjustments in the relevant Flemish legislation.

Alternatively, it could also be considered to charge new users the full costs of their connection, by applying deep connection charges that also reflect network capacity needs beyond the customer connection. This would reflect that the connection of new users requiring grid capacity expansions does in particular increase the risk of stranding. This may especially apply for larger industrial users or gas-fired power plants (e.g. combined-heat power plants) connected at distribution level. Natural gas use in industry and for power and heat generation may however take place as part of a transition to hydrogen, in which case higher (deep) connection charges could be seen as working against this transition. Deep connection charges could also be an option for biomethane producers, but this would create an additional unintended barrier for a biomethane uptake. The recent increase of connection charges in Flanders could already be seen as a first step in incentivising potential new users to reflect their full costs when requesting a new connection, discouraging the connection of new users.<sup>190</sup> Deep connection charges have the general challenge that it is very difficult to determine the individual network (expansion) costs that are caused by an individual connection. Cost reflective deep connection charges would require extensive modelling, which itself would already be cost intensive. While convincing in theory, deep connection charges, reflecting also the wider system costs, have therefore only been applied in a limited number of cases for gas and electricity networks. As such it seems adequate to only allocate the costs directly attributable to the user requesting the connection as part of the connection charges.

#### Regulatory approval for individual new (replacement) investments

Another option is to apply a stricter regulation for the conduction of new investments, requiring the regulatory approval of individual investments. This may require the DSOs to submit a justification for each (major) individual investment project to VNR, also reflecting on the risk of stranding, potential non-capex alternatives (including an extension of the asset life of existing assets or demand-side measures), and its impact for a later decommissioning. It could also be considered to limit any new investments to safety requirements and investments which facilitate a repurposing or decommissioning of parts of the network. To limit the administrative effort for both the DSO and VNR, the regulatory review and approval of individual investments could be done as part of the decommissioning plans, whereas only investments above a certain threshold would be subject to such review and to be included in the distribution decommissioning plans.

133



<sup>&</sup>lt;sup>190</sup> With the amendment of the Flemish Energy Decree in 2023, the cap on connection costs of €250 for new natural gas connections to existing residential units or buildings was abolished as of January 1, 2025. This limit had already been abolished for connections to new-build homes since July 1, 2022. This measure ensures that a new grid user must pay a flat rate that covers the average actual connection cost (approximately €1,600 for domestic users), meaning that connection costs above the previous flat rate of €250 are no longer socialised via the network tariffs. For current connection tariffs of Fluvius, see also ansluitingstarieven aardgas 2025.

#### **Limit the capitalization of OPEX**

One additional element could also be to limit the capitalization of own work respectively OPEX related to investments and instead keep it as OPEX. As part of the planning and construction of asset replacements and network expansions, a number of activities are conducted by staff of the DSO which are typically capitalized and thereby included in the RAB. Keeping them as OPEX and recovering them in the year of their occurrence would lower the RAB and thereby also lower the risk of stranding. Depending on the level of investments to be conducted in future years, which could in particular relate to replacement investments necessary for safety reasons, this could be an interesting measure to be implemented. The non-inclusion of own work in the RAB could however on the other hand set an incentive to procure a larger share of these activities from external providers, which could potentially be less efficient and result in overall higher costs.

#### Incentives to utilize assets beyond their regulatory asset lifetime

Furthermore, the adoption of specific regulatory measures could be considered, which incentivize the DSOs to utilize their assets beyond the regulatory lifetime rather than replacing them by new assets, which would increase the risk of asset standing. Enabling the DSO to keep assets in operation after the end of their regulatory lifetime and only account for higher maintenance and operational costs in the allowed revenue, would - depending on how the risk of asset stranding for new investments is allocated - be financially unattractive for the DSO compared to more capex intensive solutions. In this case the DSO would not receive a return on these assets (equal to the product of the regulatory asset base for these assets and the allowed rate of return). To the extent that an inefficient preference by the DSO of replacement investments over asset life extensions could not accordingly be detected by the regulator in a benchmarking of the total expenditures of the DSO, an explicit financial incentive to utilize assets beyond their regulatory asset lifetime could be considered. This could take the form of a premium on OPEX (OPEX mark-up), which the DSO would receive in addition to the OPEX allowance. Such measure has for example been adopted for gas transmission in Spain for the current regulatory period. 191 When applying such measure, it is important to ensure that the additional maintenance costs to keep the existing asset in operation plus the costs of the financial incentive are lower than the replacement investment, which should particularly be the case when a replacement is expected to result in significant stranded costs. Determining the OPEX mark-up at a level which sets efficient incentives is therefore an important element when considering such mechanism. Additional regulatory reviews and monitoring may be considered to ensure that the stranding risk and the cost implications of either decision are adequately reflected by the DSO. In addition, quality of supply regulation should be adopted which guarantees the reliability and safety of the assets in operation, which should include a regular monitoring and inspection of the respective assets. The relevance of such mechanism will be limited, when investments into the gas distribution network are primarily limited to replacements related to safety considerations, where extension of the asset life is not an option.

# 10.4.1. Process for decommissioning and disconnection

Three key elements facilitating the process of disconnection and decommissioning will already be implemented with the transposition of Directive (EU) 2024/1788 into Belgian and Flemish legislation. This includes in particular the requirement to implement **distribution decommissioning plans** linked to local heat plans, which would facilitate a structured disconnection and decommissioning rather than a "voluntary" disconnection of users that decide to disconnect from the gas network based on rising gas end-user prices (reflecting increasing CO2 emission costs) and rising gas network tariffs. As described earlier, Article 57 of the Directive lists a number of elements to be included in the decommissioning plan. In addition, it could also be beneficial to include all relevant investment projects in the decommissioning plan. Investment and decommissioning projects included in the

<sup>&</sup>lt;sup>191</sup> For a more detailed description of the relevant regulatory mechanism for gas transmission in Spain, please see also DNV / Trinomics (2022): <u>Future regulatory decisions on natural gas networks: repurposing, decommissioning and reinvestments.</u>



reviewed and approved decommissioning plan, should in general be not subject to an additional separate regulatory approval (unless significant changes occur), and accordingly be included in the RAB. Once implemented such decommissioning plan could be a central element guiding a number of further measures related to disconnection and decommissioning as is laid out in Directive (EU) 2024/1788.

To avoid situations where the DSOs would be required to keep gas network segments and branches in operation as long as there is one last (smaller) gas user connected to this part of the network, although this would not be economic, it will be important to adopt provisions that **enable DSOs to disconnect users**. As part of the implementation of decommissioning plans also provisions will apply, which enable the DSOs to refuse access and connection to their network on the basis of these plans (Article 38 of Directive (EU) 2024/1788).

The EU Directive, furthermore, defines a number of requirements with regards to the information and treatment of gas users to be disconnected or effected by decommissioning in line with the decommissioning plan (Article 13). This includes the consultation and information of gas network users (e.g. gas suppliers) and end-users sufficiently in advance on the planned date of disconnection, the procedure for disconnection, the planned steps, the relevant timeline, sustainable heating options, and available financial support. The Directive also requires that the special needs of vulnerable customers and customers affected by energy poverty are taken into account in the planning and carrying out decommissioning process. All of these are important elements to ensure that the interests of end-users are properly reflected in the disconnection and decommissioning process. While further guidelines on the protection of these customers are to be provided by the European Commission, it will also be useful to define the information and consultation of users in further detail. Once implemented, it will also be important to monitor all of these steps as well as the compliance of the DSOs with the general requirement of ensuring a secure and reliable supply of the network users, which should in the context of disconnection and decommissioning in particular focus on the secure and reliable supply of the remaining gas users. Depending on the transposition of the European legislation into the Flemish legislation, these monitoring tasks could be assigned to VNR. It would be beneficial to define specific quality of supply indicators for the interaction with customers to be disconnected and in relation to the secure and reliable supply of the remaining gas users and to include these parameters in the existing quality of supply regulation in Flanders.

#### Financial support for gas users to be disconnected

Achieving sufficient public acceptance of a phase-out of natural gas will be important for the transition and decommissioning process. To protect residual customers that lack the financial sources to switch to sustainable options for the heating of buildings and hot water supply, it will be important to ensure that adequate financial support by the government is made available. Otherwise, a disconnection in line with the decommissioning plan may conflict with provisions to protect vulnerable customers and could potentially only be realised with delay. The provision of such funding will need to be evaluated by policy makers; the provisions adopted in Denmark could serve as an example here (see section 10.3.4).

#### 10.4.2. Maintenance policy

Effective maintenance planning, analysis, and execution are vital for the reliability and longevity of natural gas distribution assets. Inadequate maintenance can trigger premature equipment failures and service interruptions. By shifting from a reactive to a proactive maintenance approach – whether preventive, scheduled, or predictive – the DSOs can possibly extend the service life of an asset and defer costly capital replacements for infrastructure expected to be decommissioned in the mid- to long-term. For assets which are to be decommissioned in the short-term or before the end of their expected technical and regulatory lifetime, it could on the other hand be beneficial to adjust maintenance in line with the expected residual use of that asset following a reactive approach and focussing maintenance in particular on safety considerations.

Given the information asymmetries between the DSOs and the regulator, both on the conditions and the likely future (residual) use of individual assets, the regulator will not be able to determine the

adequate maintenance policy for individual assets. It will however be important for the regulator to reflect the maintenance policy implications in the regulatory cost efficiency assessments. Keeping assets in operation after the end of their regulatory lifetime will likely require higher maintenance efforts or could result in rising maintenance costs in the final years before the decommissioning of that asset, which would however be efficient if the alternative is a replacement of the asset with only a short period of use due to decommissioning. Rising maintenance costs may also not be sufficiently reflected when allowed revenues are determined based on historic costs. When a significant share of assets in operation is already fully depreciated, it should also be reassessed whether an explicit financial incentive for maintaining fully depreciated assets in operation (e.g., as discussed in a previous section) should be implemented, as the DSO would otherwise only receive an allowance for the recovery of its OPEX.

In addition, it could be beneficial that the natural gas DSOs develop and publish a comprehensive **Asset Management Plan**<sup>192</sup> that:

- outlines the DSO's overall approach to maintaining and upgrading its distribution network;
- presents forecasts for investment programs and upcoming construction activities;
- defines a maintenance strategy that balances the cost of ongoing upkeep against the expense of full asset replacement;
- favours condition-based assessments over strictly age-based replacements when technically and economically feasible;
- details the required inspections, condition-monitoring techniques, specific maintenance tasks, and the frequency of each activity.

Moreover, incorporating monetized risk assessments ensures that every intervention is driven by a clear understanding of the current and future risks, quantified in terms of failure frequency and potential impact in monetary terms. This risk-informed approach helps DSOs prioritize interventions where they deliver the greatest value and safety benefits, while keeping overall costs in check.

#### 10.4.3. Treatment of disconnection costs

Recovering disconnection costs from end-users via a one-off exit fee will significantly reduce the incentive for users to disconnect from the gas distribution network and hamper the phase-out of natural gas. To avoid this, disconnection costs could be **recovered from the remaining gas users**, i.e. by socializing them via the network tariffs. This will however only be possible as long as there are sufficient remaining gas network users to recover these costs from. When the disconnection of users will have advanced significantly, it will only be possible to recover these costs from the **government respectively taxpayers** via subsidies towards the DSOs or a **dedicated fund** covering (part of) the disconnection costs. As these costs will be quite significant, particularly in the later stages of the phase-out, it could be beneficial to already set up a dedicated independent regional fund which is provided with the necessary financial resources over the next years to finance the disconnection costs arising in the mid- to long-term (possibly resembling some of the features of the Hedera fund for nuclear waste). Allocating disconnection costs to the DSOs without the ability to recover them via one of the previous options would not be adequate, as the DSOs have realised the connection on behalf of grid users in line with the legislation in place at that point in time.

## 10.4.4. Changes of tariff structure

With decreasing offtake volumes per end-user (e.g., due to more energy efficient use and/or implementation of hybrid solutions), an increasing share of users may access the grid during a smaller

Trinomics —

**—** 136 **—** 

<sup>&</sup>lt;sup>192</sup> We take note that some financial data is included in the investment plan of Fluvius submitted to and approved by VNR. This does however not include comprehensive details on its maintenance policy as characterized by the following bullets.

number of peak hours. Also, the utilisation of the existing infrastructure will decline so that volume (offtake) based network charges may increasingly be less suitable to reflect the costs caused by an individual user. Therefore, it could be appropriate to apply a **higher share of capacity or fixed charges** also on lower pressure levels, which better aligns with the cost causality principle, and which sets stronger incentives for network users to reflect their network capacity needs in their gas usage patterns. For household consumers, where the effective peak consumption is not metered, the capacity charges could be based on the nominal capacity of the connection.

Disconnection and decommissioning can vary quite significantly from year to year and as a consequence, if timely reflected, also the allowed revenues. To avoid that network tariffs vary significantly from year to year in line with these costs, mechanisms should be adopted in the midterm to balance these impacts over several years. This could be done in a similar way like the current regulatory balance (*regulatoire saldi*) that accounts for volume risks. However, instead of dissolving the regulatory balance over the following two years, it could be considered to dissolve it over a longer period of time, although when decommissioning has further progressed this may provide the challenge that with declining numbers of network users it will also be more difficult to recover costs in future years.

Network tariffs will likely increase in the future, when CAPEX and OPEX cannot be adjusted in line with the declining number of network users and distributed volumes while at the same time additional costs may be allocated to remaining gas network users relating to disconnection costs, stranded costs and decommissioning costs. As discussed in chapter 10.1.1 this could result in a feedback loop of increasing network tariffs and increasing disconnection numbers. When cross-subsidies from other energy networks are generally excluded by EU Directive 2024/1788, gas distribution network costs can only be recovered from the remaining gas network users via network tariffs, the government via subsidies or a dedicated fund, or by the DSO and its owners/shareholders. These options are further analysed in relation to the costs of disconnection, decommissioning and asset stranding in separate sections (10.4.3, 10.4.7, and 10.4.6 respectively). The costs for the construction and operation of the gas distribution network should in general be recovered from its users. Front-loading depreciation and taking a careful approach on new investments (see section Fout! Verwijzingsbron niet gevonden.) will ensure that these costs are to a larger extent recovered via network tariffs, when the number of network users is still high, and avoid situations in later years, where a small number of remaining gas users would struggle to pay high network tariffs.

#### 10.4.5. Additional measures addressing uncertainty

With high uncertainty on the future development of disconnections from the natural gas network, and the policy, market and technological parameters driving it, also the development of the efficient future costs of the DSO will be increasingly uncertain. In addition, also the number of end-users and transported volumes to allocate these costs will become more uncertain. In the longer-term it may further be more challenging to balance an under-recovery of allowed revenues resulting from a lower actual gas demand than forecasted for the determination of network tariffs by an according upward adjustment of network tariffs in future years. As a consequence, both the ability of the current regulatory model to address uncertainty and the adoption of additional regulatory measures should be investigated. This includes among others the **determination of allowed revenues on forecasted** rather than historic **costs**, a **shortening of the regulatory period** or the implementation of **reopeners** or **ex-post adjustments**.

The allowed revenues of the Flemish DSOs are primarily determined based on their historic costs, as it is the case in most other regulatory jurisdictions in Europe. When past costs become a less reliable predictor of future costs, it could be considered to switch to an approach where the allowed revenues are based on the efficient costs forecasted by Fluvius/DSOs for the upcoming regulatory period (resembling the approach applied in the UK). <sup>193</sup> As part of such approaches, DSOs are required to

\_

<sup>&</sup>lt;sup>193</sup> Such approach would also allow to include output-based parameters in the regulation, defining what the DSO must deliver, like it is the case in the RIIO approach in the UK.

submit detailed cost forecasts before the start of the regulatory period (e.g., based on detailed business plans), which are subject to strong regulatory scrutiny and validation by the regulator, ex-post reconciliation and incentive mechanisms.<sup>194</sup> The main challenge is to ensure an efficient forward-looking forecast and to avoid inflated cost projections by the network operators. This requires extensive reviews of the regulator and can be associated with significant costs, in particular if external engineering and economic consultants are involved. As such, longer regulatory periods are generally applied for regulatory frameworks based on explicit forward-looking assessments.

Shorter regulatory periods provide the benefit of faster alignments between allowed revenues and efficient actual costs. They come however at the expense of higher administrative costs and possibly less strong incentives as the DSOs have less time to benefit from efficiency gains above the regulatory targets. A longer regulatory period on the other hand does provide more stability on the future regulatory framework and sufficient time for DSOs to improve their efficiency.

Re-openers enable the NRA to determine new or adjusted allowed revenues for the DSOs during the regulatory period in case of specific external events or the occurrence of particular pre-defined changes in circumstances. This could provide the NRA with an effective tool to accommodate unforeseen changes and developments, as the NRA does not need to wait until the end of the regulatory period to adjust the allowed revenues. As such re-openers reduce the risk of the DSOs from the occurrence of certain types of unexpected events. Depending on the details on when and how re-openers could take place, it either provides stability and protection for DSOs or introduce some instability and uncertainty in the regulatory process and reduce the incentives for cost efficiency (as the incentive of DSOs to prevent or minimise costs related to events triggering a re-opener would be limited). In the context of this study, it could particularly relate to unexpected changes of relevant decarbonisation policies and policies affecting the phase-out of natural gas. The re-opener may consist of a full cost review or only consider costs related to a specific investment or event. It could relate to both upwards adjustments of allowed revenues, in case the (earlier) occurrence of a predefined event causes an increase of costs, as well as to downward adjustments of allowed revenues, in case specific cost relevant events do not occur or are delayed. A specific version of a re-opener is a trigger mechanism, which results in an automatic adjustment of regulatory components following a mechanistic formula, if certain parameters deviate from a pre-determined threshold. Finally, for cost items which are particularly uncertain, but under the control of the DSO, also ex-post reviews of actual costs and parameters could be considered. To the extent that these relate to cost items forecasted by the DSO, also an incentive mechanism could be adopted as in the UK, which provides a financial benefit to the DSO to provide forecasts as close as possible to actual values.

# 10.4.6. Treatment of stranded costs

Stranded costs are best determined based on the residual asset value in the natural gas regulatory asset base. This ensures that any re-valuations, which have occurred, been recognised, and approved at the time by the NRA, are already factored in the current natural gas RAB. Adjusting this value retrospectively would be difficult but also not desirable as this would undermine the regulatory principle of stability and predictability. When a decommissioned asset has become stranded, it should be removed from the RAB, and the DSO should no longer earn a regulatory rate of return as the asset is no longer in use and needed.

The key question is hence how stranded costs should be allocated and who should be liable to pay these. Stranded costs could be fully or partially be allocated to the **DSOs or their owner (municipalities)**, they could be considered in the allowed revenues and allocated to the **remaining** 

— Trinomics 🦰 💳

**—** 138 **———** 

<sup>&</sup>lt;sup>194</sup> See also the DNV study from 2023 for the Dutch regulatory authority ACM, which analysed the regulatory practice and experience in a number of countries, including explicit forward-looking forecasts of costs and measures to deal with uncertainty: <u>Study on the regulation of electricity and gas system operators</u>.

**gas users**, or be recovered from the **government** (i.e., **taxpayers**) via subsidies or a dedicated fund. <sup>195</sup> A decision on these options will have to be made by policymakers.

It can be argued that based on equity and fairness considerations, the natural gas DSOs should not be penalized when the investments had been approved by the NRA in the past based on the investment need and justification at the time of making the decision. Even if the policy changes relating to the energy transition could have been (partially) anticipated and could have already been factored into investment decisions in the past, it would be difficult to question these investments, when they were taken decades ago also based on legal obligations. An allocation of all stranded costs to the natural gas DSOs could also jeopardize their financial stability, and as a consequence could also have significant financial implications for their owners (i.e., municipalities in Flanders), when decommissioning has further increased and significant stranded costs occur. As such it could be argued to allocate the stranded costs to gas network users, as the assets have initially been constructed by the DSOs based on obligations and requests for connection and requirements of the DSO to expand the network in line with gas demand levels.

On the other hand, it could also be questioned whether the full costs of stranding should be allocated to the remaining network users, when assets are not further used and needed and at least some of the users for which the assets have originally been constructed have already been disconnected in the past. For more recent investments, it could also be argued that the natural gas DSOs should, to some degree, have already considered alternative measures reducing the risk of being stranded, such as conducting smaller investments or by extending the life of existing assets. Furthermore, it should also be taken into account to what extent the DSOs have already partially been compensated for the potential risk of stranding within the previous regulatory framework (e.g., by receiving a regulatory remuneration above the market based risk-free rate).

If the stranding of assets is caused by the decarbonisation policy and regarded as largely outside of the control of the natural gas DSOs, it could be argued that the government or taxpayers should bear all or part of the stranded costs. The risk of asset stranding will also be particular high when already a significant number of users have disconnected from the network and network tariffs (as well as gas end-user prices) have already significantly increased, which would make it difficult to recover the stranded costs from these residual users and thereby endanger the financial stability of the natural gas DSOs. Recovering the stranded costs via government funding would represent a one-off transfer of risk from current users of the gas network, or the asset owners, to current (and potentially future) taxpayers.

Finally, the recovery of stranded costs could also be differentiated by date and/or type of investment, reflecting that the degree to which the stranding risk could be seen as under the control of the DSO depends on the investment date and type. Such differentiation is also an option that has been discussed for gas distribution in a study commissioned by Brugel for the Brussels Capital Region.<sup>196</sup> It could for example be considered to expose the asset owner only to the stranding risks for future investments, unless they have been conducted on the basis of legal requirements or safety requirements or they facilitate the repurposing or decommissioning of other assets, whereas the burden of proof should be with the DSO.

As a compromise of the above options, the stranded costs could also be shared between the asset owner and the users of the network via a sharing mechanism, in which case stranded costs would only be partially recovered within the regulatory framework. This could in particular be an approach for earlier years. At a later stage also a sharing of stranded costs between the asset owner and the regional government budget could be considered.

Trinomics - -

<sup>&</sup>lt;sup>195</sup> In case an asset transfer value different from the residual asset value of the gas distribution network would be allowed in case of repurposing, similar considerations would also need to be made for these additional revenues or partial stranded costs.

<sup>&</sup>lt;sup>196</sup> Brugel (2023): Studie over het risico op stranded assets in het gasdistributienet tegen 2050 (BRUGEL-STUDIE 44-20230113).

#### 10.4.7. Determination and treatment of physical decommissioning costs

As explained in Chapter 5, the decommissioning costs can be very significant. Regulatory measures should therefore be adopted to ensure that the decommissioning process is as efficient as possible. In addition, it will also need to be determined how these costs are allocated and can be recovered.

#### Regulatory assessment of physical decommissioning costs

Following the regulatory approval to decommission an asset, the DSO should submit an estimation of the physical decommissioning and if relevant dismantling cost to the regulator. To ensure that only the efficient decommissioning and dismantling costs are recognised within the regulatory framework, a separate cost assessment on their efficiency should be conducted by the regulator outside of the general efficiency assessment of the natural gas DSO. To facilitate the assessment, a detailed disaggregated approach, listing the activities and associated costs for each activity related to the decommissioning of the respective assets could be requested. A benchmarking of these costs may be challenging, as the decommissioning costs may be quite asset and location specific, influenced by environmental factors, which may require the application of some adjustment factors. External advisors can support the NRA in assessing these costs. A further option could also be to request that the DSO conducts a public tender or get competing offers for the decommissioning work. This could facilitate the decision-making process and the assessment of the decommissioning costs.<sup>197</sup> In addition, the DSO should provide a justification for its decision, when alternative decommissioning options are feasible, e.g., removing or leaving the assets in the ground. Where leaving the assets in the ground would be a more cost-efficient option, provisions that require a dismantling and removal of assets from the ground – unless there are specific safety considerations - should accordingly be adjusted.

#### Allocation of decommissioning costs

Similar to the options discussed for the allocation of stranded and disconnection costs, also the costs of a physical decommissioning could be allocated to the asset owner (DSO or its shareholder), the remaining gas network users, or the regional government respectively taxpayers. The properties and implications of the alternative options are similar to the discussion on the allocation of stranded costs, although the case here may be stronger for a (partial) recovery of these costs by the government. The need to decommission is largely outside of the control of the DSO but driven by policy decisions. If the gas distribution network will also be widely decommissioned in the long-term, the costs would be so significantly high that a recovery from the asset owner or the remaining users in later phase-out phases would not be feasible. A decision on the allocation of physical decommissioning costs will have to be made by policymakers.

As relevant decommissioning is only expected to occur further in the future, an up-front payment prior to the actual decommissioning to cover the expected decommissioning costs could be considered. This could either take the form of a (partial) recovery of the expected decommissioning costs via network tariffs during the utilisation of the assets to be decommissioned, or an exit fee from users disconnecting from the distribution network. This option would however be associated with a number of disadvantages, including the uncertainty on when and under which conditions assets may be decommissioned or be repurposed. If the full decommissioning costs are to be recovered over the lifetime of an asset, it would also implicitly assume that a later decommissioning of the asset was already to be expected when the investment decision was made and that these costs had been factored into that decision. If decommissioning costs would only be recovered during the final years of an asset, it would also be an argument of intertemporal fairness to not allocate these costs only to the remaining users, who represent only a fraction of the decommissioned distribution network capacity. In addition, network tariffs are already expected to increase if disconnection costs and stranding costs as well as fixed costs are allocated to a smaller number of network users.

<sup>&</sup>lt;sup>197</sup> For a more detailed discussion of this topic, please see also DNV / Trinomics (2022): <u>Future regulatory decisions on natural gas networks</u>: <u>repurposing, decommissioning and reinvestments</u>.



### 10.5. Key findings and recommendations for adjustments of the legal and regulatory framework in Flanders

Based on the above analysis and practices implemented or considered in other regions or countries, VNR could consider the following regulatory measures to reduce the risk of stranded assets, to ensure cost efficiency and to mitigate the impact of increasing grid costs per connection and per MWh gas offtake. The implementation of some of these recommended measures may require prior changes in the regional legal framework.

- Consider changing the depreciation method: apply variable declining balance method (instead of linear) for all assets.
- Review of shorter regulatory asset lifetimes: 50 years for pipelines are at the upper end in Europe; shorter depreciation periods should in particular be considered for all new assets.
- Reflect the impact of the stranding risk on the WACC calculation: review whether higher cost
  of capital (debt and equity) are expected from capital markets in relation to the perceived
  stranding risk and the recovery of decommissioning costs.
- Consider revising the rules regarding the inclusion of new investments in the RAB, e.g. treat overhead costs related to investments as OPEX rather than including them in the RAB.
- Reflect the implications of the network maintenance policy in the regulatory assessments of
  cost efficiency: preventive maintenance enabling extension of asset lifetimes to avoid
  replacement of assets and extension of asset lifetimes result in higher maintenance costs;
  maintenance for assets expected to be decommissioned fast possibly to be reduced. Consider
  submission of Asset Management Plans by DSOs.
- Review of tariff structure: higher fixed and lower volume-based tariff components.
- Account for disconnection and decommissioning costs in regulatory balance (regulatoire saldi).
- Consider determination of allowed revenues based on forecasted rather than historic costs.
- Review implementation of re-opener mechanisms and additional ex-post adjustments to account for increasing uncertainty.

In addition, a number of policy measures addressing the disconnection and decommissioning process and costs can be considered in regional legislation:

- Implement gas distribution decommissioning plans.
- Enable DSOs to disconnect users and end obligation to connect users.
- Adopt measures related to the information and treatment of gas users to be disconnected and the protection of vulnerable customers.
- Provide financial support for (vulnerable) residential end-users to be disconnected.
- Consider (partial) recovery of disconnection costs from remaining gas users in the short-term and through government or taxpayers (e.g., via a dedicated fund or subsidies) in the mid- to long-term.

As the number of residual users will be very low when larger parts of the grid will be decommissioned and to provide clarity for the Flemish DSOs/Fluvius on the long-term perspective based on which they can optimise their investment and operational decisions, it might be appropriate to timely start creating specific **provisions for stranded assets and decommissioning costs**. This includes in particular:

- Review (partial) allocation of stranding costs to the remaining gas users or the regional budget (i.e., taxpayers) via subsidies or a dedicated fund, if full recovery by the gas DSOs is not feasible.
- Adopt regulatory measures to assess the efficiency of physical decommissioning costs.
- Consider a framework for a partial recovery of physical decommissioning costs via a regional fund, if a full recovery by the gas DSOs is not feasible.

# 11. Overall key findings and recommendations

#### According to the medium scenario considered in this study, about 1.3 million energy users would in 2050 still be connected to the gas distribution grid in Flanders.

The study has defined 3 scenarios (high, medium, low) of which the medium scenario is based on current policies. In this scenario, the number of grid connections would decrease from 2.4 million in 2023 to 1.3 million in 2050. The related gas consumption would decrease more significantly, from 55 TWh in 2023 to 13 TWh in 2050. The gas consumption is expected to decrease to a larger extent than the number of connections because of energy efficiency impacts and partial transition to other energy vectors (e.g. electricity), amongst others by using hybrid solutions. Both the number of connections and average use would significantly decrease in the coming decades, but based on current policies, natural gas use in the distribution sectors would not be phased out by 2050.

### Biomethane injection is expected to cover an increasing but still limited share of gas consumption.

The injection of biomethane in the gas distribution grid is currently quite low (73 GWh in 2024). Based on different potential studies, a limited increase is projected: 0.5 TWh in 2030 and 1 TWh in 2050. Biomethane injection is hence not expected to cover a substantial share of the methane demand in Flanders. The slightly increasing injection of biomethane and gradual decline in natural gas consumption may require specific investments to enable reverse flows. To continue facilitating local biomethane production and its use, the Flemish authorities should timely assess whether and to what extent part of the distribution network could (or should) be retained for biomethane transport and distribution after the phase-out of natural gas. This decision should be taken on the basis of a thorough evaluation and comparison with alternative options, such as local use of biogas for CHP, or as bio-CNG or bio-LNG for transport purposes.

### Using the gas distribution grid as such for blending synthetic methane or hydrogen with natural gas is for economic and energy efficiency considerations not recommended.

Using hydrogen for production of synthetic methane to be injected into the existing natural gas distribution grid would not be an adequate option from an economic and energy efficiency perspective and was hence not further considered in this study. Blending (clean) hydrogen into the natural gas network is also not a recommended option, as its dedicated use as such (not blended) for specific purposes should be prioritised. Due to the important drawbacks of the blending solution, it is unlikely that market actors in Flanders would opt for it, and Flemish authorities do hence not need to facilitate it.

### Repurposing sections of the gas distribution gas grid for dedicated hydrogen use is technically feasible, but the actual potential at distribution level is expected to be very low.

About 5% of the Flemish gas distribution network meets the technical requirements for repurposing for dedicated hydrogen use, while ~94% would need further evaluation. However, the potential market demand for such services should also be properly considered. According to the latest developments and studies, it is not expected that hydrogen will be used at large scale by residential and small commercial end-users currently connected to the gas distribution grid. Only a limited number of large end-users would in the medium- to long-term switch to low-carbon or renewable hydrogen, depending on its cost and availability. As most of the end-uses covered by natural gas taken off from the distribution grid can be electrified, repurposing distribution gas pipelines for dedicated hydrogen use is expected to be limited to specific medium pressure sections, to deliver hydrogen to industrial end-users that use it for processes than cannot be electrified, e.g. as feedstock or for heavy-duty transport purposes. Due to the meshed topology of the gas distribution networks, the majority of medium pressure distribution pipelines is expected to remain operational until the last users will

have been disconnected. The potential to already repurpose specific pipeline sections before the complete phasing-out of natural gas distribution will hence be limited.

### Repurposing parts of the gas distribution gas grid for CO<sub>2</sub> transport is technically feasible, but the expected potential is very low.

About 16% of the Flemish gas distribution network could be repurposed for  $CO_2$  transport meeting the technical requirements, while most non-metallic parts would need further assessment. However, the market demand for such services at distribution level is expected to be very limited. Potential sites for carbon capture, re-use and storage will mainly be connected to large transport pipelines. Some potential  $CO_2$  capturers or re-users could be connected to repurposed distribution pipelines, but the volumes to be transported will likely be too limited to justify dedicated pipeline infrastructure at distribution level, and other transport means (road, rail, waterway) may in these cases be more appropriate.

#### Repurposing parts of the gas distribution grid for water transport or as collector for cables could be considered, but the business case is unclear.

17% of the medium pressure pipelines in Flanders are technically suitable for water transport, but would require full replacement, primarily due to integrity and contamination concerns. This option would hence require considerable investments, and the economic benefits of re-using existing infrastructure would be very low. Moreover, it is unclear to what extent there would be a market demand for using repurposed (in most cases replaced) gas distribution pipelines for water transport. This option could be interesting if the water quality would be different depending on the use, e.g. if separate networks would be considered for drinking water and water for other purposes. In such a scenario, two parallel pipelines could be developed, (partially) utilising decommissioned sections of the gas distribution network for transporting non-drinking water.

Existing gas distribution infrastructure could partially be repurposed as a collector for cables. This use case is widely applicable for most of the materials currently used but would need an installation process. This option could in particular be considered if unused pipelines would otherwise have to be removed from the underground.

# As potential re-use or repurposing of gas distribution network assets will be limited to smaller parts of the gas distribution network in Flanders, larger parts will eventually have to be decommissioned.

The decommissioning of pipelines could either be done by leaving them in the ground and (a) filling them either with air / nitrogen or (b) filling them with grout / concrete, or (c) by removing and disposing the pipelines. A decision on the preferred technical solution should be made based on the likelihood of a potential future repurposing (a), safety considerations (b), future land uses and legal/landowner obligations (c). While the CAPEX increase from options (a) to (c), the OPEX related to continued maintenance are highest with option (a), low with option (b) and no future OPEX or infrastructure liabilities are associated with option (c). The descending priority order defined in the Flemish environmental regulations provides a good starting point.

# Detailed asset- and area-specific decommissioning cost studies should be conducted to have accurate cost estimates, as decommissioning costs do vary significantly depending on the chosen technical solution, site, asset and network specificities.

Only rough indicative ranges of around EUR 133,000 per km on average for the decommissioning (when leaving the pipeline in the ground) and EUR 250,000 – 300,000 per km (when also removing the pipeline from the ground) can be given from existing publications. As decommissioning of gas distribution networks have not yet been conducted at large scale in practice and estimates can be quite country and situation specific, these numbers should be treated with particular care. Aligning gas pipeline decommissioning with technical interventions in other networks could contribute to lower the decommissioning costs.

Comprehensive long-term plans for the future use of natural gas and biomethane in Flanders should be developed and aligned with politically defined regional and local decarbonisation

targets, local heating plans, and reflect the necessary duration of decommissioning works, the roll-out of alternative heating options, consumer acceptance/transition timelines, residual shares of gas use in a specific area, as well as the distance to the connection point with the gas transmission network.

Dedicated incentives for gas users to disconnect may enable the acceleration of the decommissioning process. Across Europe, different approaches have already been applied ranging from removing disconnection fees to the provision of grants or subsidies for installing alternative heating technologies or even refunds for those who have invested recently in new gas appliances. Such schemes should especially focus on low-income or vulnerable households as they would otherwise be likely among the last users to disconnect, facing also the burden of potentially rising gas network tariffs. Based on the practical experience from the limited decommissioning projects across Europe an adequate advance information of gas users on the decommissioning (around 10 years in advance) and the provision of detailed data and information on alternative heating technologies have shown to be important. Conducting pilots in a mix of urban, suburban and rural parts of Flanders to test the practicalities of different technical decommissioning solutions and the communication with local gas users could provide useful learnings for decommissioning at larger scale.

# Although grid extensions and new connections are expected to be very limited in the future, investment needs and depreciation costs (CAPEX) will remain high, independently of the considered scenario and phase-out strategy.

Based on our assumptions, future investments required to ensure safe and reliable operation of the gas distribution network will still be important and would, depending on the scenario and phase-out strategy, amount to € 91 – 98 million in 2030 (compared to € 197 million in 2023). Annual investments would slightly decrease in the high scenario to € 70 – 89 million in 2040, or increase in the low and medium scenarios to € 94 – 107 million in 2040, due to the roll out of smart meters up to 2029. In 2050, annual investments would still be between € 22 – 100 million.

Due to the high current non-depreciated accounting value of the distribution grid assets, the depreciation costs related to existing assets will remain high in the coming decades. Based on the current depreciation rules, the annual depreciation costs for the asset base in 2023 will amount to  $\in$  124 million in 2030,  $\in$  82 million in 2040 and  $\in$  48 million in 2050. If the current depreciation rules are maintained, around 13% of the net book value in 2023 would still not be depreciated in 2050. Based on the above-mentioned future investment levels, the overall depreciation costs will, depending on the scenario and phase-out strategy, amount to 159 – 160 million in 2030 (versus  $\in$  135 million in 2023),  $\in$  135 – 145 million in 2040 and  $\in$  102 – 127 million in 2050.

#### As an important share of the operational expenses (OPEX) of gas DSOs is variable and driven by the number of connections, gas consumption or grid length, the OPEX is anticipated to evolve proportionally to these cost drivers.

A large share of the OPEX is variable (i.e. around  $\leqslant$  128 million in 2023, accounting for about 60% of total OPEX) and will therefore evolve proportionally to the number of connections, the length of the grid or gas consumption. The remaining part of OPEX (40%) is fixed and is expected to decrease to a lesser extent than variable costs. Depending on the scenario and phase-out strategy, the overall OPEX will amount to  $\leqslant$  106 – 117 million in 2030 (compared to  $\leqslant$  168 million in 2023) and will further decrease to  $\leqslant$  69 – 106 million in 2040 and  $\leqslant$  24 – 95 million  $\leqslant$  in 2050. It is important to note that these figures do not include the eventual decommissioning and stranding costs.

Although the number of grid connections and gas offtake will in the different scenarios substantially decrease in the coming decades, it will not be possible to dismantle the grid to the same extent. The technical infrastructure (grid and related components) will hence not substantially decrease during the transition period, and maintenance (and related OPEX) will further be required. Only in a strategy with planned or mandatory disconnections, decommissioning can be faster. This explains why a certain proportion of OPEX will still remain in 2050, even when there are no more active connections and gas consumption would equal to zero.

### As the allowed revenues according to the current tariff methodology would decrease less than the gas offtake, substantial increases in grid tariffs would be required per connection and per MWh gas offtake.

According to our calculations for the medium scenario, the allowed revenues (i.e. estimated budget for endogenous and exogenous costs) are expected to decrease from around  $\in$  486 million in 2023, to  $\in$  462 million in 2030,  $\in$  399 million in 2040 and  $\in$  324 million in 2050. The overall revenues' decrease in 2023 – 2050 will hence amount to 33%, while the decrease in gas offtake will be much higher, namely 76% in the medium scenario. The grid tariffs would hence need to be adjusted to ensure that the costs incurred by the DSOs can be fully recovered by the network tariffs.

#### Two major components in the gas bill, namely grid charges and gas retail prices, are expected to further increase in the coming decades.

As the overall costs and related allowed revenues will decrease to a lower extent than the gas offtake, the **network tariff** would need to be substantially raised. In the high scenario, network tariffs would increase by 19.1% in 2030 compared to 2023 and by 87.1% in 2040. As there would not be any more grid connections in 2050, tariff revenues would in this scenario be zero; the remaining costs could hence not be covered by grid tariffs. Substantial tariff increases are also required in the other two scenarios: in 2030, tariffs would rise by 2.3% in the low scenario and 11.6% in the medium scenario. By 2040, the required increases amount to 16.7% and 33.2% respectively and climb further to 43.7% in the low scenario and 80.8% in the medium scenario in 2050. The relative tariff increases in €/MWh are similar across the different consumer profiles. It is important to note that these figures do not include the eventual decommissioning and stranding costs.

The evolution of the second important component of the gas bill, namely the **gas retail price**, cannot be predicted as it is based on wholesale prices which depend on geopolitical developments and the evolution of the global natural gas supply and demand. As of 2027, the gas retail bill is expected to increase by the implementation of ETS 2, which will lead to an annual increase of the natural gas bill. This increase will depend on the CO2 emission allowance price and consumer profile. As estimated in this study, the additional annual costs for a residential consumer with an annual consumption of 4 MWh would range between  $\in$  103 and  $\in$  206. The additional annual costs for a non-residential consumer with an annual consumption of 2,900 MWh would range between  $\in$  23,000 and  $\in$  46,000. In a future scenario with decreasing gas offtake and number of connections, the suppliers' margin may also slightly increase to recover their fixed costs.

Finally, the gas bill level also comprises **levies and taxes**; their evolution will depend on political decisions. The future gas bill is in this study estimated based on the current levies and taxes. Changes can be expected resulting from political decisions. The Flemish minister for energy has for instance in July 2025 announced that a tax shift will be implemented in 2028: the levies on natural gas and heating oil use would be increased by  $\in$  362 million per year, while the levies on electricity would decrease by the same amount. This measure should stimulate the switch from fossil fuel heating to electric heat pumps.

# Adequate measures should be considered by VNR to reduce the risk of a stranding of assets, the impact of a high increase of network tariffs for the remaining gas users after 2035-2040 and to ensure an efficient operation by the DSOs.

To avoid a high grid tariff impact on the remaining gas users in a situation with a decreasing number of connections, a declining gas offtake and to reduce the risk of asset stranding, a change of the depreciation policy should be further investigated. Applying a variable declining balance method and shortening the regulatory asset lifetimes, at least for new assets, should be further evaluated. It should also be further reviewed whether the depreciation method and asset lifetimes should differ between assets for which a repurposing or a longer-term use (e.g. for biomethane) is to be expected and assets which will likely be decommissioned. Furthermore, whether and under which conditions the DSOs/Fluvius could take a decision for an accelerated depreciation of assets should be further examined. Changes to the depreciation policy should be carefully analysed as they can have

significant implications on the network tariff levels in the short- and long-term as well as other side effects, while uncertainty on the speed of the phase-out of natural gas remains high.

Moreover, we recommend reflecting the impact of the stranding risk in the WACC determination. It should in particular be reviewed whether higher costs of capital are expected from capital markets in relation to the perceived stranding risk and the recovery of decommissioning costs. As the network maintenance policy should reflect the expected further use of an asset, including the extension of its technical lifetime, it is important to reflect the implications of the maintenance policy in the regulatory cost assessments. To ensure an efficient conduction of maintenance, the development and submission of Asset Management Plans by the DSOs could possibly be considered.

To reduce uncertainty and to determine regulatory allowed revenues better reflecting the expected efficient cost levels, a change to determine the allowed revenues based on forecasted rather than historic costs should be considered as well as the implementation of re-opener mechanisms and additional ex-post adjustments.

Following the decline of distributed volumes, VNR should also further review a change of the tariff structure applying higher fixed (capacity) and lower volume-based tariff components.

Additional analysis should be conducted in follow-up work of this study to determine the details of individual regulatory measures for Flanders, to assess the impact of different measures, and to work out a consistent and effective regulatory framework that potentially combines different regulatory measures.

Several of these challenges and questions are closely linked to policy measures and require adjustments to the legal framework by policy makers. Hence, several regulatory measures can only be taken by VNR, when appropriate decisions have been made and policies adopted by the government. For all of these areas a high uncertainty will remain, when and how fast methane demand and utilization of the gas distribution infrastructure will actually decline, and whether the policy targets will be met. It will be important that this uncertainty is adequately reflected in the regulatory framework.

# To facilitate an efficient disconnection and decommissioning process and to ensure the recovery of disconnection and decommissioning costs, a number of measures should timely be taken by policy makers.

The decommissioning costs will be higher if the phase-out is based on voluntary disconnection initiatives from gas grid users only rather than on a coordinated or planned phase-out strategy. Three key measures addressing the decommissioning process will have to be implemented with EU Directive 2024/1788 into Belgian and Flemish legislation: gas distribution decommissioning plans, provisions that enable gas DSOs to disconnect users in line with these plans, and measures related to the information and treatment of gas users to be disconnected and the protection of vulnerable customers. Together with these disconnection measures, also legislation ending obligations of the DSOs/Fluvius to connect new users to the gas grid should be considered. Another key item is the recovery of the disconnection costs: While in the short-term a recovery from remaining gas users is possible, a (partial) recovery from the government or taxpayers (e.g., via a dedicated fund or subsidies) may be considered in the mid- to long-term. As some of these measures are a precondition for further regulatory measures to be implemented by VNR, it is important that decisions on the alternative options are timely taken by policy makers.

### Even if stranded costs could largely be avoided through the above measures, the regulatory treatment of the expected large physical decommissioning costs should timely be addressed.

If a full recovery of the physical decommissioning costs by the DSOs is not feasible, a (partial) recovery via a regional fund could be further investigated. Likewise, a (partial) allocation of stranding costs to the remaining gas users or the regional government via subsidies or a dedicated fund should be reviewed. Regulatory measures for both cost categories should be analysed in further details and widely consulted with relevant stakeholders. To ensure that only efficient physical decommissioning

costs are to be recovered, a separate regulatory assessment of these costs (based on a disaggregated approach of the individual cost components) should be adopted.			

# Annex A – Correlations between CAPEX and OPEX of gas DSOs in Flanders and cost drivers

#### Correlation between CAPEX and cost drivers

The regression analysis of the correlations between the annual investments in 2021 - 2024 and the evolution of assets (changes in grid length, in number of connections or number of assets, i.e. cabins/stations, metering equipment) presented mixed results. High correlation coefficients (R-square) were found between annual investments and new/replaced LP connections, MP metering equipment and cabins/stations. However, low correlation coefficients were observed between annual investments and LP and MP pipelines and LP metering equipment. The R-squares resulting from the analysis are presented in Table 0-1.

Table 0-1 Results of the regression analysis

Variable Y	Variable X	Resulting R <sup>2</sup>
Investments in connections (LP) between 2021 and 2024	Replaced/new connections between 2021 and 2024 (number of connections)	0.988
Investments in pipelines (LP) between 2021 and 2024	Replaced/new LP pipelines between 2021 and 2024 ( <i>meters</i> )	0.241
Investments in pipelines (MP) between 2021 and 2024	Replaced/new MP pipelines between 2021 and 2024 ( <i>meters</i> )	0.461
Investments in metering equipment (LP) between 2021 and 2024	Replaced/new LP equipment between 2021 and 2024 (number of equipment)	0.311
Investments in metering equipment (MP) between 2021 and 2024	Replaced/new MP equipment between 2021 and 2024 (number of equipment)	0.724
Investments in cabins and stations (LP/MP) between 2021 and 2024	Replaced/new LP/MP cabins and stations between 2021 and 2024 (number of cabins/stations)	0.934

Notwithstanding the relatively low correlation coefficients for some investment categories, the analysis is based on the following assumptions:

- Investments in pipelines and cabins/stations are largely driven by the grid length;
- Investments in connections and metering equipment are mainly driven by the number of connections.

### Correlation between selected OPEX categories and cost drivers

As mentioned in Chapter 6, operational costs can be divided into fixed and variable costs. Whereas the fixed costs remain to some extent constant, the variable costs vary with factors such as number of connections, grid length and gas consumption. To better understand the relationship between selected cost drivers and the OPEX of the Flemish gas DSOs, we performed a correlation analysis using:

- Data per gas DSO for the period 2020-2024, including costs, offtake volumes and network data (e.g. network length);
- Aggregated OPEX data (per cost type) for the period 2020-2024.

For the analysis, some categories of operational costs were excluded, i.e. all non-endogenous OPEX; financial costs and revenues (as they are included in the capital costs analysis); depreciation cost (as they are included in the CAPEX analysis); all operational costs and revenues related to the purchase and sale of energy and internal transfer costs and revenues. The excluded costs represented in total about  $\in$  -248 million in 2023, compared to  $\in$  167 million for costs included in the analysis (i.e. total OPEX in 2023 were negative).

Based on a linear regression analysis ( $R^2$ ) for the selected OPEX categories and the corresponding cost drivers, a high correlation coefficient was found between the concerned endogenous OPEX and gas consumption. The R-squares resulting from the analysis are presented in Table 0-2.

Table 0-2 Results of the regression analysis

Variable Y	Variable X	Resulting R <sup>2</sup>
OPEX driven by the number of connections between 2021 and 2024	Number of connections	0.811
OPEX driven by grid length between 2021 and 2024	Grid length	0.504
OPEX driven by gas consumption between 2021 and 2024	Gas consumption	0.716



Trinomics B.V.

Mauritsweg 44

3012 JV Rotterdam

The Netherlands

T +31 (0) 10 3414 592

www.trinomics.eu

KvK n°: 56028016

VAT nº: NL8519.48.662.B01