# Shrinking together and pulling apart: the Austrian gas grid by 2040 under declining natural gas demand and increasing domestic renewable gas generation

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## Abstract

*Keywords:*

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## Nomenclature

| Type | Description | Unit |
|---|---|---|
| Set and index | | |
| $p \in \mathcal{P} = \{1, \ldots, P\}$ | Pipeline for gas transport, index by $p$ | |
| $n \in \mathcal{N} = \{1, \ldots, N\}$ | Node of the gas grid, index by $n$ | |
| $l \in \mathcal{L} = \{1, \ldots, L\}$ | Level of pressure in the gas grid, index by $l$ | |
| $y \in \mathcal{Y} = \{1, \ldots, Y\}$ | Years, index by $y$ | |
| $m \in \mathcal{M} = \{1, \ldots, M\}$ | Months, index by $m$ | |
| Decision variables (selected) | | |
| $Capex$ | Capital cost of pipelines in the gas grid | EUR |
| $Opex$ | Operational cost of pipelines in the gas grid | EUR |
| $CoAS$ | Cost of an alternative off-grid gas supply | EUR |
| $\gamma_{p,l,y}$ | Transport capacity of pipeline $p$ at $l$ in $y$ | GW |
| $\sigma_{p,l,y}$ | Decommissioning decision of pipeline $p$ at $l$ in $y$ (binary) | - |
| $q^{fed,local}_{n,l,y,m}$ | Local gas production injected into the gas grid at $n$ and $l$ in $y$ and $m$ | Year |
| Relevant parameters | | |
| $\gamma^{pre}_{p,l,y}$ | Existing transport capacity of pipeline $p$ at $l$ in $y$ | MW, GW |
| $y^{inv}_{p,l}$ | Year a pipeline $p$ at $l$ reaches its technical lifetime | Year |

## 1. Introduction

In Europe, the most efficient way to deliver natural gas to end customers, from large industrial plants to households, has been through pipelines and gas grids for decades. There are two main reasons for this. Firstly, natural gas has been a cheap energy source due to its unlimited availability in Europe through imports from neighbouring regions. This allowed that large quantities of natural gas have been used to provide various energy services throughout the territory. As a result, the gas grids have been able to operate at high utilization rates most of the time. Secondly, the transport of natural gas through pipelines has been technically efficient and economically cheap over both short and long distances [1]. Both reasons were largely responsible for the fact that gas customers were only charged low costs for using the gas grid (historically mainly for withdrawals, less for injections). This paper aims, among other things, to analyze how these gas grid costs for end customers could develop in the course of decarbonizing the energy system.

In the context of piped natural gas supply, Austria has a long tradition. Austria was one of the first Western European countries connected to natural gas pipelines. The "Trans Austria Gas Pipeline" (TAG) started operation in 1968 and connected Austria with Slovakia [2]. The gas came from Russia. The consequences of this long history of natural gas in Austria are reflected on the one hand in a high dependence on natural gas for the provision of energy services [3] and on the other hand in a well-developed gas grid in the country [4]. However, natural gas grids face an uncertain future, as does the Austrian gas grid. European and national decarbonisation policies are pushing the use of natural gas towards renewable energy alternatives in all energy services. The consequence is a massive reduction in demand for natural gas [5] that can be expected. It is therefore unclear to what extent gas grids will still be needed and whether they can be operated economically. With reference to the first paragraph, both rationales for efficient gas grids are called into question when considering the decline in demand for natural gas, carbon pricing and the general shift towards electrification of energy services. The main objective of this paper is to contribute to this discussion by quantifying the scope and size of the Austrian gas grid by 2040 under different decarbonization scenarios. In particular, the goal it to answer the following three research questions:

- How does Austria's gas grid develop up to 2040 under different decarbonization scenarios, ranging from electrification of most of energy services to importing large amounts of renewable methane?
- Given the ageing nature of gas grids and pipelines, what is the need for replacement investment, especially in view of the expected increase in renewable gas production (e.g., biomethane and synthetic gas) and its grid injection?
- How does Austria's gas grid change in terms of grid costs for the end customer in comparison to the status quo?

The analysis of the Austrian gas grid provides relevant insights for countries with a high potential for domestic renewable gas production in the future, such as Germany, Italy, and France (see in [6]). The relevance of this case study must also be considered from a European perspective. The Austrian gas grid has historically been an important hub for the transmission and distribution of imported natural gas through Europe and provides ample storage capacities (see in [7]). Therefore, changes in the Austrian gas grid might also impact the gas grid of neighboring countries and vice versa.

A mixed-integer linear optimization approach is proposed to answer the research questions. The applied model considers the existing natural gas grid (tranmission, high-pressure and mid-pressure pipelines) as a starting point and decides whether the gas grid supplies the gas demand and collects renewable gas production. Alternatively, unmet demand and uninjected production are considered to be met by the alternative transport option of trucking. The model considers the existing pipelines' age and the necessary replacement investments if they reach their technical lifetime and the option of early decommissioning in case of no or insufficient use of pipelines to reduce grid operating costs. The four different scenarios ("Electrification", "Green Gases", "Decentralized Green Gases", and "Green Methane") ensure robustness while covering a wide range of possible future gas volume developments in demand, imports, exports, and generation. They base on scenarios developed for a decarbonized Austrian energy system 2040 by the *Environment Agency Austria* [8] and *Austrian Energy Agency* [9]. Therefore, the scenarios and work must be understood from a "what-if" perspective. The scenarios determine the shares of renewable/natural gas, hydrogen, power, and other energy carriers in the Austrian energy system. Based on that, the need for pipelines to transport and balance gas demand and generation is analyzed. No blending is considered. Explicitly, no integrated energy system modeling across energy sectors/carriers or analysis of how fossil fuel-based energy services are decarbonized is done.

The paper is organized as follows. Section 2 provides relevant literature and background information on the topic as well as the novelties of this work. Section 3 explains the applied method and the four scenarios in detail. Section 4 present the results of the work, while Section 5 provides a synthesis of key findings. Section 6 concludes and outlines future research.

## 2. State-of-the-art and progress beyond

This section discusses relevant scientific literature in the field of this work. It is divided into three parts. First, Section 2.1 deals with the global and cross-country dimension of natural and renewable gas trade. It focuses on the impact of the decarbonization on gas markets and discusses also intra-country gas supply with a high spatial granularity of a grid representation. Then, Section 2.2 examines different approaches of modeling gas grids. Section 2.3 elaborates on the regulation of gas grids and especially on gas grid charges. Finally, Section 2.4 highlights the novelties of this work.

### *2.1. Decarbonized gas markets and cross-country trade*

In 2021, the European Commission has published a proposal for a framework of renewable and natural gases and for hydrogen [10]. The aim is to support renewable and low carbon gases (i.e., biogas, biomethane, renewable and low carbon hydrogen as well as synthetic methane) in Europe and to reach a share of two-third of gaseous fuels in 2050 energy mix. Further details on the definition of renewable and low carbon gases can be found in [11]. The remaining one-third of gaseous fuels in 2050 is expected to be still fossil natural gas, but in combination with carbon capture, storage and utilization. Today, renewable and low carbon gases have only a minor contribution to Europe's energy mix. Bertasini et al. [12] give a critical overview of the contribution of renewable gases to the decarbonization of the European energy system and grids. Kolb et al. [13] focus in their work on the integration of renewable gases into gas markets. In addition, the latter study provides also a comprehensive literature review on the topic of renewable gases. Lochner [14] elaborates on the European gas market and the identification of congestions in the gas transmission grid. Gorre et al. [15] deal exhaustively with future renewable gas generation costs.

A key role in the transition to renewable and low carbon gas markets has the existing gas infrastructure. On the hand, the repurposing of existing pipelines especially at the transmission grid level allow to build up a hydrogen grid, as proposed in the so-called "Hydrogen Backbone" [16]. In this context, also the recently extended terminal capacities for liquified natural gas (LNG) are worth to be mentioned. In the short-term, LNG terminals are used to support Russian natural gas import substitution by fossil LNG imports from exporter countries, such as the United States and Quatar [17]. But in the mid-term, these terminals can be used to import renewable and low carbon gases, supporting the European gas market [18]. On the other hand, the area-wide existing pipelines of the distribution grid levels (high-, mid-, and low-pressure pipelines) allow the injection of distributed renewable and low carbon gas generation [19]. Sulewski [20] explore the biomethane market in Europe. Schlund and Schönfisch [21] analyze the impact of renewable quota on the European natural gas markets. Paturska et al. [22] provide an economic assessment of biomethane supply system based on the natural gas grid. Khatiwada [23] elaborate on barriers of the decarbonization of natural gas systems. Stürmer [24] examines in detail on the potentials of renewable gas injection into existing gas grids. Padi et al. [25] study the techno-economic potentials of integrating decentralized biomethane production into existing natural gas grids.

### *2.2. Gas grid modeling approach (top-down and bottom-up)*

The following literature review focuses on the modeling of natural gas transport by grids and pipelines. There are other ways of transporting natural gas. The interested reader is referred to Thomas and Dawe [1] for a comprehensive review of the options for transporting natural gas. In general, the literature on gas grid modeling approaches can be divided based on two key dimensions: (i) modeling perspective (e.g., techno-economic) and (ii) spatial scale. These dimensions, along with others such as the sectoral dimension (whether or not hydrogen is accounted for in detail), determine the level of consideration given to various factors such as flow conditions of natural gas, pressure levels and drops in transport pipelines, and the operational energy and costs associated with compressors.

A review on optimization of natural gas transportation systems is given by Ríos-Mercado and Borraz-Sánchez [26]. It encompasses both transmission and distribution grids. Pfetsch et al. [27] elaborate in detail on the operation of gas transmission grids. Pambour et al. [28] propose an integrated transient model approach for simulating the operation of transmission grids. The transient process in transmission grids is further examined by Liu [29]. Riepin et al. [30] develop in their study an adaptive robust optimzation model for transmission grid expansion planning. Chiang and Zavala [31] investigate the interconnection between gas and power transmission grids. O'Donoghue et al. [32] examine transmission pipelines' resistance to high-pressure levels. Liu et al. [33] study aspects of supply security in detail.

With regard to the distribution grid level, Herrán-González et al. [34] provide a comprehensive review on the modeling and simulation of gas grids. Barati et al. [35] propose an integrated framework for grid expansion planning. Giehl et al. [36] examine the impact of the decarbonization on gas distribution grids. Zwickl-Bernhard and Auer [37] present alternative supply options to natural gas distribution grids. Keogh et al. [38] review technical and modeling studies of renewable gas generation and injection into the distribution grid. The same authors present also a techno-economic case study for renewable gas injection into the distribution grid in [38]. Abeysekera et al. [39] analyze the injection of renewable gas in low-pressure gas grids from a technical perspective in detail. Mertins et al. [40] examine the competition between renewable gas and hydrogen injection into distribution grids. Repurposing of natural gas pipelines for hydrogen transport is assessed by Cerniauskas et al. [41]. An overview of the modeling of hydrogen grids is given by Reuß et al. [42].

Finally, the modeling contributions of the open-source community subject of gas grids are discussed. In principle, open-source approaches are becoming increasingly important in energy system analysis [43]. This trend is also continuing in the area of gas grids. For instance, Schmidt et al. [44] provide a set of publicly available gas grid instances that can be used by researchers in the field of gas transport. Pluta et al. [45] present an approach for developing an open-source model of the gas transport grid in Europe. Nevertheless, data on natural gas grids in particular are rarely made publicly available. There are isolated exceptions, e.g. for the transmission grid (see [46] for open-source data on the European transmission gas grid) or for the Belgian gas grid in [47]. However, there is often an information advantage for those who have this information (e.g., gas grid operators) to scientific researchers, particularly with analyses at the distribution grid level.

### *2.3. Regulatory of decarbonized gas grids*

Not much has been published on how to regulate decarbonized gas grids. In particular, there is, to the best of the author's knowledge, a lack of literature on gas grid costs and end customers tariff schemes. The need for more research on the regulation of gas grids in the future is however mentioned in several studies already. Khatiwada et al. [23] emphasize that the energy system decarbonization requires new rules and regulation of gas grids as well as restructuring of gas markets. Erdener [48] reviews literature on the regulation of gas grids with focus on the blending of hydrogen. Recently, the European Commission published a proposal on markets for renewable and natural gases and for hydrogen [49]. Overall, there is a growing trend for gas grid operators and regulators to look beyond short-term forecasts of gas grid tariffs to long-term forecasts (e.g., up to 2050). In this context, the report of the French Energy Regulatory [50] deals with the French gas grid in the context of decarbonized energy systems 2030 and 2050. Bouacida et al. [51] study the impact of the decarbonization on the gas grid costs in France and Germany. Zwickl-Bernhard et al. [52] show the need for socialization of increasing gas grid costs among remaining end customers.

In addition, the literature on the design of grid tariffs in decarbonized electricity grids, for example, can provide useful information, although of course they face a fundamentally different situation with a significant increase in demand and associated end customer numbers expected. Peterson and Ros [53] provide a broad discussion on the regulation of electricity grids in the future. Fulli et al. [54] elaborate on the impact of electricity grid regulatory on electricity markets. Morell Dameto et al. [55] study electricity grid tariffs in the context of the energy system decarbonization.

### *2.4. Novelties*

The novelties of the present work in relation to the existing literature described above can be summarised as follows:

- A techno-economic high spatially resolved analysis of the Austrian gas grid up to 2040 in four different decarbonization scenarios of the Austrian energy system is carried out. In particular, the required gas grids are shown under a range of possible developments to supply gas demand and integrate domestic renewable gas production.

- Taking into account the ageing of the existing gas grid and the resulting need for replacement investment in pipelines, as well as the possibility of decommissioning parts of the grid that are no longer in use, an indication of the cost to end customers of using the decarbonized gas network in 2040 is provided based on average network costs. This provides valuable information to support end customers make the best decision on how to decarbonize their energy service needs.

- The methodological extension of an existing model to include an alternative supply option (e.g., trucks and on-site gas storage) makes it possible to investigate the techno-economic trade-off between expected oversized and thus low-utilized or even replaced gas pipelines of decarbonized gas grids and off-grid solutions. This contributes to the discussion of the economic efficiency when energy systems are decarbonized.

## 3. Method

This section describes the methodology of the paper. First, in Section 3.1, the optimization model used is explained in detail. The focus is thereby on the mathematical formulation. However, where meaningful, qualitative explanations are added to give the reader a more complete understanding of the model. These qualitative explanations are used in particular to describe the main decision made by the model between maintaining operation, decommissioning or making replacement investment in existing gas grid pipelines. In Section 3.2, the gas grid in Austria, which serves as the case study in this paper is presented. Finally, in Section 3.3, the four different scenarios are shown.

### *3.1. Optimization model*

The optimization model used is based on the model described in [52]. The original model is a graph-based linear optimization model with the objective of minimizing total system costs from the perspective of the gas grid operator. The optimal solution finds the economic trade-off between the capital and operating costs of the grid (mainly pipeline costs) and the revenues for meeting gas demand through the grid. These revenues are generated on the basis of the predefined grid charge and the volume of gas demand met. In the graphical representation of the grid in the model, gas demand is assigned to nodes and pipelines are represented by lines. The model focuses only on the supply and transport of natural and renewable gas through the grid. Other energy sources are not considered. Compared to the original model, further fundamental functionalities have been added that are necessary to answer the research questions posed here. The new functionalities relate to:

- The inclusion of alternative supply options, such as trucking and on-site storage, and their costs in the objective function. This allows the model to bypass the use of pipelines to supply very small volumes (e.g., compared to their maximum transport capacity) in the grid at the expense of the cost of the truck, including transport and storage. This change in the objective function also replaces the previously mentioned idea of revenues generated by the network charge.

- The possibility of decommissioning existing pipelines before their technical lifetime in order to save on maintenance and fixed costs, for example for the low utilized pipelines mentioned above;

- The integration and recompression of biomethane in the grid. This allows the model to transport biomethane from the mid-pressure to the high-pressure grid level and makes the use of biomethane in the grid more flexible.

Before the objective function of the model and the main functionalities and constraints are described in detail (including a more comprehensive description of the new functionalities), the Figure 1 gives a first overview of the model.

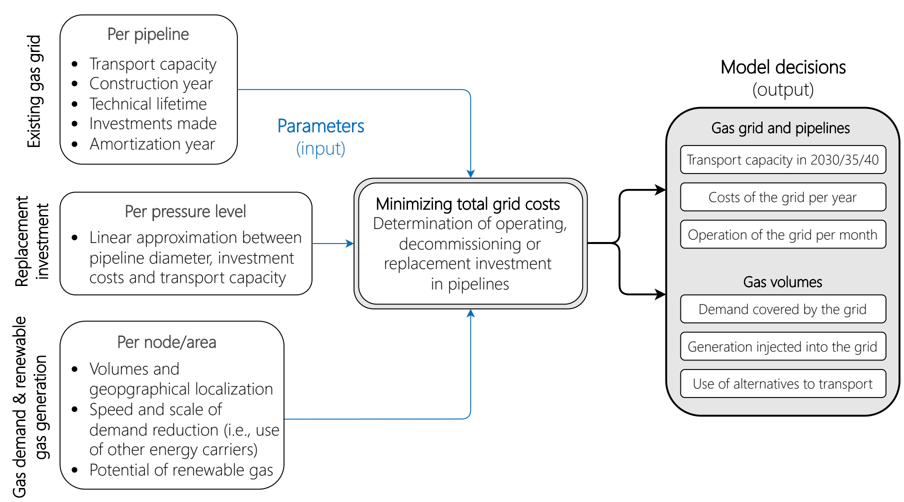


Figure 1: Overview of the model showing which parameter inputs are used to make optimal decisions about the natural gas grid.

It shows which input parameters are used to make optimal decisions about the grid. Optimality of the model's solution determines whether to operate, decommission or replace investments in the grid's pipelines. The model decisions can be divided into two categories, namely gas grid and pipelines and gas volumes. For example, the gas grid and pipelines results include pipeline transport capacity up to 2040. The parameter inputs consist of information on the existing gas grid (e.g. transport capacity and technical lifetime of pipelines), techno-economic assumptions on replacement investments and scenario-based developments in gas demand and renewable gas production.

#### *3.1.1. Objective of minimizing total grid costs*

The objective function, that aims to minimzing total grid costs from the perspective of the gas network operator is given in Equation 1. Essentially, it consits of the costs of the network supply using pipelines, and the costs of an alternative supply option ($CoAS$) and off-network supply.

$$\min_{x} \quad \underbrace{Capex + Opex}_{\text{operation of pipelines}} + \underbrace{CoAS}_{\textit{off-network supply}} \tag{1}$$

The costs of the network supply consist of capital costs ($Capex$) and operational costs ($Opex$). $CoAS$ considers the operational costs for the stand-alone supply option. All three costs components are explained in detail below:

- $Capex$ takes into account the capital cost of the gas pipelines in the network. It includes the cost of imputed interest (i.e., the book value of the gas pipelines multiplied by the weighted average cost of capital ($WACC$)) and annual depreciation of the investments made in pipelines.

- $Opex$ takes into account the fixed costs of maintaining the gas pipelines in the network. It does not include the operating costs of the compressors in the gas network.

- $CoAS$ takes into account the cost of the off-network and stand-alone supply of the gas demand. It is assumed that this alternative supply option is trucking combined with on-site gas storage. Consequently, from the perspective of the objective function, the gas demand not supplied by the network is penalized with the marginal operating costs of the stand-alone supply option. This includes the marginal cost of trucking and the marginal cost of on-site gas storage.

Essentially, the optimization model finds the optimal solution between *Capex* and *Opex* of the piped gas supply and the off-network supply. Note that the cost to be minimised in the objective function is the net present value.

#### *3.1.2. Operation, decommissioning or replacement investment in pipelines*

As indicated in the objective function, the main decision of the model is to determine how to supply the exogenously determined demand for natural gas. To be more precise, the model essentially decides whether it is worthwhile to continue operating the gas pipelines or even to invest in replacements due to ageing, against a background of significantly declining transport volumes. As an alternative to the gas pipelines, there is the option of an alternative and off-network supply through trucks and local gas storage. The mathematical formulation of this decision between network and off-network supply is described in detail below. Three different decision points or decision periods are distinguished: before, at and after a gas pipeline reaches its expected technical lifetime. Note that existing gas pipelines are considered here.

Before an existing gas pipeline reaches its technical lifetime, there is the option of either operating it or decommissioning it prematurely. In this way, if the model decides to decommission the pipeline prematurely, fixed pipeline costs (i.e. *Opex*) can be saved on the basis of the existing network and its pipelines. It is not possible to save on *Capex* because the underlying investment costs in pipelines already made have been sunk. Only from a regulatory perspective on gas networks and tariff design, it can be argued that capital costs can be saved by saving depreciation costs of existing gas pipeline investments for example. However, this has to be seen as a question of cost allocation, rather than cost savings because investments have been made already as mentioned. In addition, from a purely practical point of view, the typical relationship between the economic depreciation time of gas pipelines and their technical lifetime means that most parts of today's gas networks can be operated essentially without capital costs from existing pipelines.[1] In general, the technical lifetime of gas pipelines can be up to 100 years, with typical investments in gas pipelines being written off after 30 years. Today's investments in gas networks are often written off after 20 years. In any case, this exemplary period of 70 or 80 years is the one in which only the operating costs of existing pipelines can be saved by early decommissioning. In general, the specific situation of the capital costs of the existing network must of couse be carefully examined in general. The decision of decommissioning a pipeline before it reaches its technical lifetime is modeled as a transport capacity which reduces the available transport capacity. Equation 2 shows the available transport capacity of a gas pipeline $p$ at network level $l$ and in year $y$. This equation is valid for all years until the existing gas pipeline reaches its technical lifetime $y^{inv}_{p,l}$.

$$\gamma_{p,l,y} = \gamma^{pre}_{p,l,y} - \gamma^{early}_{p,l,y} \quad : \forall y \mid y < y^{inv}_{p,l} \tag{2}$$

Therein, $\gamma^{pre}_{p,l,y}$ is the transport capacity of the existing gas pipeline and $\gamma^{early}_{p,l,y}$ is the prematurely decommissioned transport capacity. As only the full pipeline can be decommissioned or not, $\gamma^{early}_{p,l,y}$ can either be equal to $\gamma^{pre}_{p,l,y}$ or 0. This is described in Equation 3, where $\sigma_{p,l,y}$ is a binary decision variable (i.e., 0 or 1).

$$\gamma^{early}_{p,l,y} = \sigma_{p,l,y} \cdot \gamma^{pre}_{p,l,y} \quad : \forall y \mid y < y^{inv}_{p,l} \tag{3}$$

Equation 4 ensures that the gas pipeline remains decommissioned if the corresponding decision is made.

$$\sigma_{p,l,y} \leq \sigma_{p,l,y+1} \quad : \forall y \mid y + 1 < y^{inv}_{p,l} \tag{4}$$

[1] The situation of no capital costs of the existing network can be particularly considered in the case study analysed here. More details can be found in the detailed description of the Austrian gas network in section 3.2.

Combining Equations 2 and 3 leads to Equation 5, where $\gamma^{early}_{p,l,y}$ is substituted.

$$\gamma_{p,l,y} = (1 - \sigma_{p,l,y}) \cdot \gamma^{pre}_{p,l,y} \quad : \forall y \mid y < y^{inv}_{p,l} \tag{5}$$

In sum, the total transport capacity of a pipeline $\gamma_{p,l,y}$ before the year where it reaches its technical lifetime $y^{inv}_{p,l}$ depends whether or not the existing transport capacity is decommissioned.

When an existing gas pipeline reaches its technical lifetime in year $y^{inv}_{p,l}$, the model determines whether or not an replacement investment in the pipeline capacity $\gamma^{ref}_{p,l,y}$ is made. Equation 6 shows that the available transport capacity in year $y^{inv}_{p,l}$ and afterwards is equal to refurbished transport capacity $\gamma^{ref}_{p,l,y}$.

$$\gamma_{p,l,y} = \gamma^{ref}_{p,l,y} \quad : \forall y \mid y \geq y^{inv}_{p,l} \tag{6}$$

From the model's viewpoint, a replacement investment in pipelines is only made if it is profitable compared to the off-network supply option. The decision is consequently determined by the volume and gas transport of the pipeline.

Once an existing gas pipeline has reached its technical lifetime, the available transport capacity remains constant. Consequently, the model does not take into account the subsequent decommissioning of rehabilitated pipelines. However, this does not have a significant impact on the results, especially in view of the time frame of this work up to 2040.

#### *3.1.3. Gas balance constraint*

The economic decision of which gas demand to meet by pipeline or by the alternative supply option is described in detail above with reference to the objective function and the transport capacities of gas pipelines. Against this background, Equation 7 shows the gas balance constraint of a node in the network. It establishes a balance between gas injections ($q^{fed}_{n,l,y,m}$), demand ($q^{dem}_{n,l,y,m}$), imports ($q^{imp}_{n,l,y,m}$), exports ($q^{exp}_{n,l,y,m}$), storage ($q^{sto}_{n,l,y,m}$) and the alternative off-grid supply option for each node.

$$q^{fed}_{n,l,y,m} - q^{dem}_{n,l,y,m} - \xi_m \cdot \left(q^{exp}_{n,l,y,m} + q^{imp}_{n,l,y,m}\right) + q^{sto}_{n,l,y,m} + q^{off-grid}_{n,l,y,m} = 0 \quad (7)$$

Note that $\xi_m$ is a scaling factor per month to respect hourly peak values at the gas pipelines. As it is assumed that supplied volumes equals the sum of discharged volumes at the gas pipelines, Equation 7 describes a stationary model. The so-called (supplied and discharged volumes together with gas pressure levels) are balanced. The gas demand $q^{dem}_{n,l,y,m}$ consits of two components, as shown in Equation 8. $q^{dem,loc}_{n,l,y,m}$ represents that gas demand that is at the node locally available. In contrast, $q^{del}_{n,l',y,m}$ is the amount of gas exchanged between different levels of the network (e.g., delivered from the high-pressure network level $l$ to the mid-pressure network level $l'$).

$$q^{dem}_{n,l,y,m} = q^{dem,loc}_{n,l,y,m} + q^{del}_{n,l',y,m} \quad (8)$$

In the original version of the model $q^{del}_{n,l',y,m}$ was restricted to positive values. Consequently, only a delivery of gas amounts from a higher pressure level to a lower pressure level was possible. This is why $q^{del}_{n,l',y,m}$ was listed as a gas demand component. However, in the work here we allow gas exchange between between gas network levels in all directions. This gives the model the flexibility in how to use biomethane generation and to transport it from the mid-pressure network level to the high-pressure network level covering its demand there. This functionality was already mentioned in Section 3.1 (third bullet point) as integration and recompression of biomethane in the network. Mathematically, this is taken into account while $q^{del}_{n,l',y,m}$ is changed to a continous variable that can be both positive and negative. In view of that, depending on the sign, $q^{del}_{n,l',y,m}$ is either a demand or, as shown in Equation 9, a source of gas from the perspective of a node. $q^{fed}_{n,l',y,m}$ is similar as $q^{dem,loc}_{n,l,y,m}$ the amount of gas production locally injected. We refer for further details of the model's equation to the detailed description made by the authors in [52].

$$q^{fed}_{n,l',y,m} = q^{fed,local}_{n,l',y,m} + q^{del}_{n,l',y,m} \tag{9}$$

### *3.2. Representation of the existing natural gas grid in Austria*

As described, the existing gas grid and its pipelines takes a key role in the optimal decision of the model. Figure 2 shows the current gas grid, which serves as the starting grid of the present study. For the reader who is not very familiar with Austria and its current gas supply, additional information can be found in Appendix A. The existing natural gas grid is represented in the model by 738 pipeline sections (lines) and 657 supply and demand points (nodes). In addition, entry and exit points connecting the Austrian gas grid with the neighboring gas grids, the Austrian gas storage capacities and the domestic fossil natural gas generation, are taken into account.

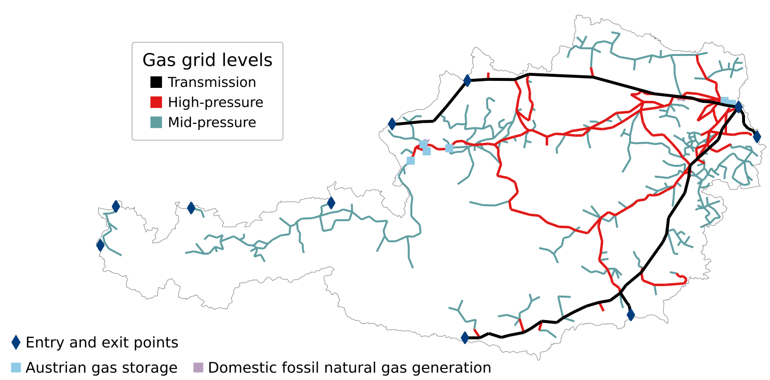


Figure 2: Representation of the existing natural gas grid in Austria in the model.

In total, the existing natural gas grid, serving as the starting gas grid, consits of transmission, high-pressure and mid-pressure pipelines that have in total a length of around 6700 km. Below is a brief description of how the authors of the study determined the existing Austrian gas grid in their model as a third party. The fact is that data about gas grids, especially at the distribution grid level, is scarcely accessible to the public. However, data is available for the transmission grid level and for gas storage, for example, published by ENTSO-G [46]. At the distribution grid levels, data was partly provided in the form of shapefiles (which is a digital vector storage format for storing geographic location and associated attribute information, such as transport capacities in the context here) upon request (see [52]). Where data on the distribution grid was not available, the location of the high-pressure and mid-pressure pipelines is determined manually (i.e., by comparison with publicly available maps and illustrations from the Austrian energy regulator [56]) and transport capacities are estimated. This includes the age structure of gas pipelines, for which some information is available on the Internet. The latter can be found, for example, on the websites of the distribution grid operators. The resulting Austrian gas grid, consisting of gas pipelines at the transmission, high-pressure and mid-pressure grid levels, is then overlaid on the map of Austria at the level of municipalities. Those of the municipalities, there are 2095 Austrian municipalities in total according to the NUTS nomenclature, with natural gas demand and crossing the resulting gas grid are a node in the gas grid graph. As mentioned, there are 657 of such nodes building the existing Austrian gas grid in the model. The connection between two of these nodes are one of the 738 pipeline sections in the model. If a municipality with natural gas demand does not have an intersection with a gas pipeline of the existing grid (e.g. because only a low-pressure pipeline connects is available, which is not considered in the existing gas grid), the demand (or production) is assigned to the nearest node with the shortest distance.

### *3.3. Scenarios*

In the absence of a holistic modelling view of the energy system across all energy sectors and sources in this study, the scenarios are of particular importance. The scenarios and their underlying narrative define the degree of electrification, the use of renewable natural gas and hydrogen in the process of decarbonising the energy system when replacing fossil natural gas. Typically, it is precisely this level of energy source use that is modelled in an optimal way in these holistic modelling approaches. Based on the degree of electrification, natural gas and hydrogen, the scenarios provide estimates particularly for the development of the amounts of natural gas demand and production (incl. import and export from and to neighboring countries). Consequently, this study here does not guarantee, as it is also not the focus, optimality regarding the use of the different energy carriers in a decarbonized Austrian energy system. The scope is much more on: if we have these amounts and localization of natural gas demand and production in Austria given, which gas grid is required for balancing both.

With this in mind, four different scenarios are defined. They are called "Electrification", "Green Gas", "Decentralized Green Gas" and "Green Methane" and span a wide range of the development of gas demand and production in Austria. All the four scenarios base on published national decarbonization scenarios for the Austrian energy system. For example, the scenario Electrification is based on the recently fundamentally in 2023 updated *Transition Szenario* published by the *Environment Agency Austria* [8]. Figure 3 gives a characterization of the four scenarios by in total eight dimensions, allowing a qualitiative comparison regarding natural gas demand, production and its spatial concentration. Based on this qualitative overview of the four scenarios, Table 1 and 2 give the quantitative numbers of natural gas demand and domestic production in the four scenarios in 2040 respectively. For instance, the natural gas demand is the lowest in the scenario Electrification (Elec) with 7.2 TWh. The highest natural gas demand is in the scenario Green Methane (GM) with 84.2 TWh. Latter, for instance, accounts for 91.9 % of the natural gas demand in Austria 2022.

For the interpretation of the study results, three aspects in the scenario definition are crucial. Therefore, they are highlighted here in particular:

- By the target year 2040, only renewable gases are used to supply Austria's natural gas demand in all the four scenarios. This applies to both the domestic production (i.e., biomethane based on biogas and synthetic natural gas based on renewable energy) and the imports of natural gas.

- In three of the four scenarios (Electrification, Green Gases and Decentral-

| Scenario | Elec | GG | DGG | GM |
|---|---|---|---|---|
| Natural gas demand in 2030 | 49.8 TWh | 60.3 TWh | 63.4 TWh | 79.4 TWh |
| in 2040 | 7.2 TWh | 9.5 TWh | 20.3 TWh | 84.2 TWh |
| 2040's share of 2022's demand | 9.0 % | 11.0 % | 23.5 % | 91.9 % |
| Reference for the demand | [8] | [9] | [9] | [9] |

Table 1: Natural gas demand in Austria the four scenarios in 2030 and 2040 and comparison with the demand in 2022. Values taken and build on decarbonization scenarios developed and published by the *Environment Agency Austria* [8] and *Austrian Energy Agency* [9]. Abbreviations: Electrification (Elec), Green Gases (GG), Decentralized Green Gases (DGG), Green Methane (GM).

ized Green Gases), the renewable domestic natural gas production supplies the complete demand. There is thus a national balance between production and demand in Austria 2040. Consequently, no imports are needed.

- In these three scenarios, where no imports are needed, the transmission and distribution grids are physically and economically separate. Accordingly, the transmission grid only transports gas across Austria and is not used to meet demand in Austria. The separation of the two grids is reflected in the results in that the costs of the transmission grid are borne by Austrian consumers only when imports are needed. This is only the case in the Green Methane scenario.[2]

[2]Whether or not the physical separation of the transmission and distribution grids in such case where there is no need for imports is reasonable for energy security reasons is beyond the scope of this paper.

| Scenario | Elec | GG | DGG | GM |
|---|---|---|---|---|
| Natural gas production in 2030 | 4.0 TWh | 5.0 TWh | 5.0 TWh | 5.0 TWh |
| in 2040 | 7.2 TWh | 9.5 TWh | 20.3 TWh | 30.2 TWh |
| 2040's share of biomethane | 7.2 TWh | 9.5 TWh | 9.5 TWh | 9.5 TWh |
| 2040's share of synthetic gas | 0 TWh | 0 TWh | 10.7 TWh | 20.6 TWh |
| 2040's share of fossil gas | 0 TWh | 0 TWh | 0 TWh | 0 TWh |
| 2040's share of the demand | 100 % | 100 % | 100 % | 35.9 % |
| Reference for the generation | [8] | [9] | [9] | [9] |

Table 2: Domestic renewable natural gas production in Austria 2030 and 2040. Three of the four scenarios consider a complete supply of the national natural gas demand by renewable domestic production. Values taken and build on decarbonization scenarios developed and published by the *Environment Agency Austria* [8] and *Austrian Energy Agency* [9]. Abbreviations: Electrification (Elec), Green Gases (GG), Decentralized Green Gases (DGG), Green Methane (GM).

## 4. Results

This section shows the main findings of the Austrian case study. As described above, results for the four scenarios Electrification (Elec), Green Gases (GG), Decentralized Green Gases and Green Methane (GM) are presented. It is structured in three parts. First, Sections 4.1 and 4.2 present the Austrian gas grid in 2030 and 2040 respectively. The quantitative results for grid length, operating and investment costs are presented for both target years in detail. Building on this, Section 4.3 focuses on the costs of the grid and elaborates on the grid charges for customers in 2040.

### *4.1. Austrian gas grid in 2030*

The Austrian gas grid in 2030 is shown in Figure 4. It is the same in all four scenarios and is very similar to the initial grid in 2025, only slightly smaller.
The main reason for the slight reduction of the grid length is the use of redundancies and duplicate structures in the grid as a result of declining gas demand.

Table 3 shows the reduction in the grid length at the high-pressure and mid-pressure levels in the four scenarios.

| | 2025 | 2030 | | | |
|---|---|---|---|---|---|
| Pressure level | Initial grid | Elec | GG | DGG | GM |
| High-pressure | 1449 km | −172 km (−11.9 %) | −142 km (−9.8 %) | −142 km (−9.8 %) | −131 km (−9.0 %) |
| Mid-pressure | 3218 km | −283 km (−8.8 %) | −200 km (−6.2 %) | −186 km (−5.8 %) | −208 km (−6.5 %) |

Table 3: Absolute and relative reduction in the length of the gas grid at the high-pressure and mid-pressure levels by 2030 compared to the initial grid in 2025. Abbreviations: Electrification (Elec), Green Gases (GG), Decentralized Green Gases (DGG), Green Methane (GM).

The reduction in the grid length at the high-pressure level varies between −131 km and −172 km in the GM and Elec scenarios respectively. The reduction in the grid length at the mid-pressure level varies between −186 km and −283 km in the DGG and Elec scenarios respectively. Removing redundant gas pipelines reduces the operating costs of the grid.[3] The operating costs of the gas grid, which are mainly fixed pipeline costs, decrease compared to the initial grid in 2025 and are around 110 MEUR in all four scenarios in 2030. Note that energy costs for the compressor are not included. By 2030, virtually no gas pipelines are decommissioned due to ageing or because the pipeline is no longer used to transport gas. The rather young Austrian grid age also leads to very low replacement investments into the gas grid. In total, those investments vary by 2030 between 15 MEUR and 18 MEUR in the Elec and GM scenarios respectively. Note that in the model presented in this paper, replacement investment is necessary when a pipeline reaches its technical lifetime of 75 years. At this point, the model decides whether to invest in replacing the pipeline or to decommission it age-related.

[3]In reality, these gas pipelines, especially at the transmission and high-pressure levels, can form the core of a hydrogen network. For further details, see for example, the plans for the Austrian hydrogen grid by 2030 published by the Austrian gas network operator [57].

### *4.2. Austrian gas grid in 2040*

The Austrian gas grid in 2040 differs significantly between the four scenarios. Four different gas grids emerge, which are mainly determined by the assumptions of the underlying scenarios. Figures 5 (Elec scenario) and 6 (GM scenario) show the smallest and largest gas grids in terms of grid length.

The smallest grid is in the Elec scenario and the largest in the GM scenario. The gas grids of the remaining two scenarios GG and DGG are shown in Appendix B. They lie between the two extreme grids in terms of size. Table 4 quantifies the size of the gas grids in 2040 in all the four scenarios by comparing the absolute length of the grids as well as the absolute and relative reduction of grid lengths compared to the initial grid in 2025. In absolute numbers, the reduction of grid length at the mid-pressure level is more significant than at the high-pressure level. In particular, the reduction in the grid length at the mid-pressure level is equally greatest in the two scenarios Elec and GG with −1316 km (−40.9 % compared to the initial grid in 2025). The smallest reduction in length at the mid-pressure level among the four scenarios is with −811 km (−25.2 % compared to the initial grid in 2025) in the DGG scenario.

The main reason here for the relatively small reduction in the mid-pressure grid length is the significant decentralized production and injection of domestic renewable gas.

| | | 2040 | | | |
|---|---|---|---|---|---|
| Pressure level | Indicator | Elec | GG | DGG | GM |
| High-pressure | Abs. grid length in 2040 | 964 km | 965 km | 974 km | 1105 km |
| | Abs. reduction to 2025 | −485 km | −484 km | −475 km | −344 km |
| | Rel. reduction to 2025 | −33.5 % | −33.4 % | −32.8 % | −23.7 % |
| Mid-pressure | Abs. grid length in 2040 | 1902 km | 1902 km | 2407 km | 2331 km |
| | Abs. reduction to 2025 | −1316 km | −1316 km | −811 km | −887 km |
| | Rel. reduction to 2025 | −40.9 % | −40.9 % | −25.2 % | −27.6 % |

Table 4: Absolute length of the grids 2040 in the four scenarios as well as the absolute and relative reduction of grid lengths compared to the initial grid in 2025 at the high-pressure and mid-pressure levels. Abbreviations: Electrification (Elec), Green Gases (GG), Decentralized Green Gases (DGG), Green Methane (GM).

The domestic injection leads to an increased use of mid-pressure pipelines. Figure 7 shows the grid length in the two extreme scenarios Elec (top) and GM (bottom) at high-pressure (left) and mid-pressure (right) levels. It highlights the reduction in grid length by 2030 and 2040. The grid length in 2025 is shown on the far left and in 2040 on the far right.

The operating costs of the gas grid decrease compared to 2025. They vary between 87.5 MEUR and 93.0 MEUR in the Elec and GM scenarios respectively. 50.0 MEUR (the same in all four scenarios) are accounted for the transmission level. The remaining costs are accounted for the high-pressure and mid-pressure level. Figure 8 shows the total replacement investments in the gas grid in the four scenarios. It includes the replacement investments in 2030 mentioned in Section 4.1 above. The lowest total replacement investments are in the scenarios GG and Elec with 143.0 MEUR and 146.0 MEUR respectively. The highest replacement investments are in the GM scenario with 185.0 MEUR.

### *4.3. Grid charges for customers in 2040*

This section presents an analysis of the cost-effectiveness of the gas grid in four different scenarios. The average grid costs are calculated by dividing the total annual grid costs by the gas demand supplied. These average grid costs serve as a basis for estimating grid charges for customers in 2040. It should be noted that determining grid charges based on minimizing system costs must be viewed with caution, as a grid charge regulation process must also be take other considerations into account. Nevertheless, regulatory mechanisms often rely on approaches that aim to minimize system costs. Therefore, it is important to consider and interpret the following results from this perspective. In particular, the different grid costs provide a different perspective on comparing the four scenarios.

Figure 9 shows the (average) grid costs in 2040 in the four different scenarios. Note that the horizontal axis is the renewable gas demand supplied by the grid in TWh. The Elec scenario is therefore on the far left, as it has the lowest gas demand of the four scenarios. At the same time, the GM scenario, which has the highest gas demand among the scenarios, is on the far right.

It is shown that the grid costs are the highest in the Elec scenario with 7.0 EUR/MWh and the lowest in the GM scenario with 1.3 EUR/MWh. The grid costs and its components of operating costs at the different pressure levels and gas demand supplied are summarized in Table 5.

| | 2040 | | | |
|---|---|---|---|---|
| Components for calculating grid costs | Elec | GG | DGG | GM |
| Transmission operating costs in MEUR | 0 | 0 | 0 | 50 |
| Distribution operating costs in MEUR | 37.5 | 39.3 | 40.2 | 43.0 |
| Capital costs per year in MEUR | 13.0 | 13.1 | 15.0 | 18.3 |
| Gas demand supplied in TWh | 7.2 | 9.5 | 20.3 | 84.2 |
| Grid costs in EUR/MWh | 7.0 | 5.5 | 2.7 | 1.3 |

Table 5: Average grid costs and their components of operating costs and capital costs. The distribution operating costs encompass the high-pressure and mid-pressure levels. Separation between the transmission and distribution grids result in accounting no transmission operating costs for the customers.

Note that the three scenarios Elec, GG and DGG assume a separation between the transmission and distribution grids (i.e., high and medium pressure levels). Therefore, the transmission operating costs accounted for customers in these scenarios are zero. Consequently, it is assumed that customers requesting gas transport through Austria at the transmission level bear these costs.

A comparison of the average grid costs with the current grid charges in Austria shows that these are increasing significantly in three of the four scenarios. The current grid charges at the mid-pressure level in Austria are around 1.7 EUR/MWh [58]. Only in the GM scenario, where the supply depend on massive renewable imports, do the grid costs remain around or slightly below this value. In the results of the other three scenarios, the increase in grid costs is driven by the high operating costs of the distribution grid with comparatively low demand volumes and capital costs. The (annual) capital costs in 2040 result essentially from the replacement investments made by then, which are necessary due to the aging of the (otherwise already fully depreciated) existing grid. As mentioned, a technical lifetime of the pipelines of 75 years is assumed. A possible window for reducing grid costs opens, as a more extended operation of pipelines (e.g., technical lifetime between 90 and 100 years) could reduce the share of capital costs in the grid costs; in extreme cases even go towards zero. Such a measure of a longer operating life of pipelines is certainly considered in practice, especially against the background of declining transport volumes. This is because transport volumes determine the operating pressure levels, which determine the pipelines' wear and tear. Lowering the operating pressure levels compared to today's could extend the technical lifetime[4]. Replacement investments due to aging could be saved. Figure 10 shows the impact on the grid costs if an extension of the pipelines' technical lifetime to 90-100 years is taken into account. The lifetime extension leads to no replacement investments and the current pipelines can remain in operation. The grid costs are consequently going down in all the four scenarios. The highest reduction in grid costs is with −1.8 EUR/MWh in the Elec scenario. The latter is the one with initially the highest grid costs. The smallest reduction in grid costs is with −0.2 EUR/MWh in the GM scenario.

## 5. Synthesis

[4]In addition, lowering the operating pressure levels also affects and supports domestic renewable gas generation. On the one hand, generation plants require less energy to compress their gas, and on the other hand, their connection costs are reduced, as the costs are highly dependent on the pressure levels in the grid. For more information from the field, see [59].

## 6. Conclusions

was es wert diese analyse durchzuführen: nicht nur mengen, sondern auch einspeisung und deren verortung.

die zukunft von erdgasnetzen bleibt eine der spannendsten fragen die sich durch die umsetzung der dekarbonisierung ergibt.

unbestritten, wird es zu einer verkleinerung der erdgasnetze kommen.

auf der fernleitungsebene sehr eindeutig, dass eine umwidmung zu wasserstoff möglich ist, weil kapazitäten vorhanden sind. parallelstränge erlauben es

auf der verteilnetzebene nicht mehr so eindeutig.

doppelstrukturen herauslösen weil netz oft redundanzen hat.

setzt man auf biomethane große netze weiter gebraucht.

dabei kommt es weniger auf die absoluten mengen an, sondern die verteilte einspeisung ist eher eine ja/nein entscheidung

teurere netze, selbst im elektrifizierung noch ein großes netz

schaffen regional/lokal biomethan, genau abgestimmt wo weiterhin verbrauch bleibt

zukünftige arbeiten, diese regionalen cluster zu identifizieren weitere technische details berücksichtigen, wie die druckentwicklung in schwächer ausgelasteten netzen, energie die gebraucht wird um druckhertzstellen, etc.

## Declaration of interests

None.

## Data availability

The original data used in this study are publicly available. The compiled dataset is published on Zenodo at Link einfügen!.

## Code availability

The code is published under an open license on GitHub at Link einfügen!.

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## Appendix A. Details on Austria and its natural gas supply 2023

## Appendix B. Detaillierte Gasnetz im Szenario A und B 2040

| Target year: 2040 | Electrification (Elec) | Green Gases (GG) | Decentralized Green Gases (DGG) | Green Methane (GM) |
|---|---|---|---|---|
| Natural gas displacement | Almost complete | Very high | High | Low |
| Main energy source/carrier | Electricity | Hydrogen | Hydrogen | Renewable natural gas |
| Sectoral concentration of natural gas demand | Small use in industry and tertiary sector | In addition to industry and tertiary sector, increasingly in transformation and transport sector; partly in stone/earth and glass industry | In addition to industry and tertiary sector, increasingly in transformation and transport sector; partly in stone/earth and glass industry | In addition to industry and tertiary sector, increasingly in transformation and transport sector; partly in stone/earth and glass industry |
| Spatial concentration of natural gas demand | High | High | Low to moderate | Low |
| Domestic production of renewable-based natural gas | Low (biomethane) | Low (biomethane) | Moderate (biomethane and synthetic) | Moderate (biomethane and synthetic) |
| Spatial concentration of renewable-based natural gas production | Low | Low | Low | Low |
| Imports of renewable-based natural gas | No | No | No | Yes |
| Balance between national natural gas demand and production | Yes | Yes | Yes | No |

Figure 3: Overview of the most relevant dimensions characterizing the four scenarios. Storylines and narratives of the scenarios build on decarbonization scenarios developed and published by the *Environment Agency Austria* [8] and *Austrian Energy Agency* [9].

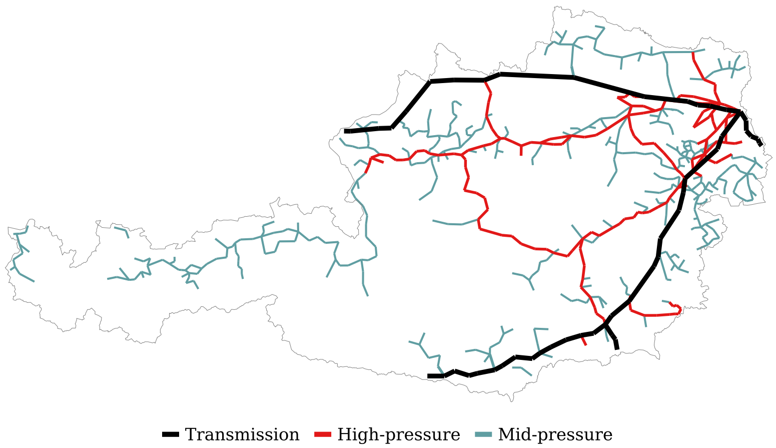



Figure 4: Austrian gas grid in 2030 at the transmission (blue), high-pressure (red) and mid-pressure (green) pressure levels in all four scenarios.

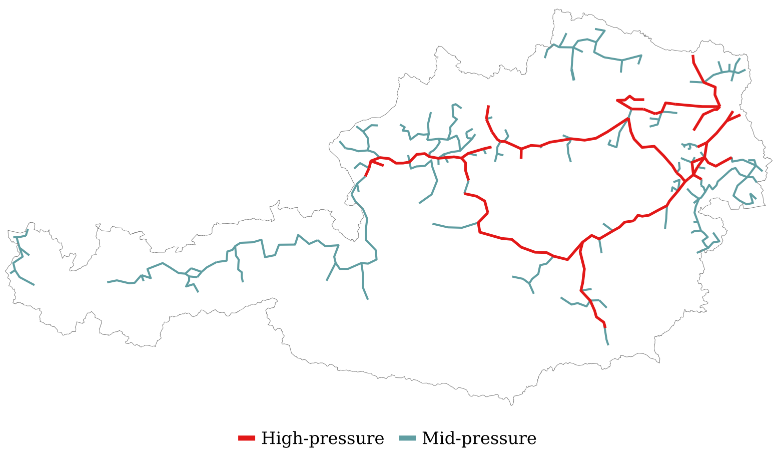



Figure 5: Austria's smallest gas network by 2040 in the scenario Electrification (Elec). Colours: transmission (blue), high-pressure (red) and mid-pressure (green).

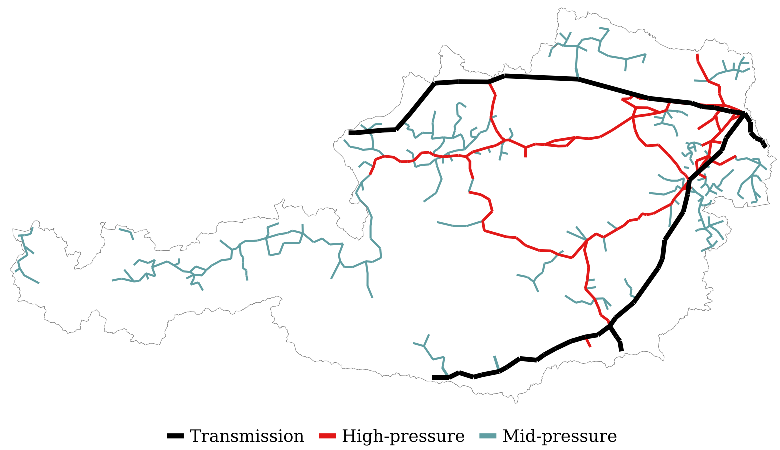
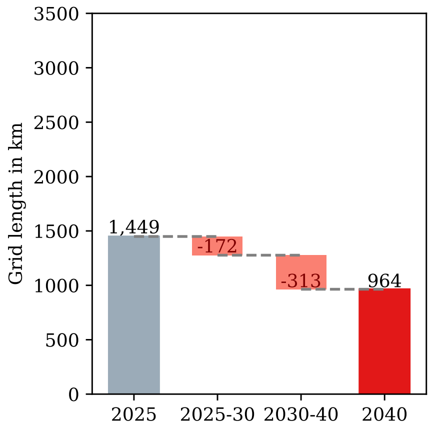
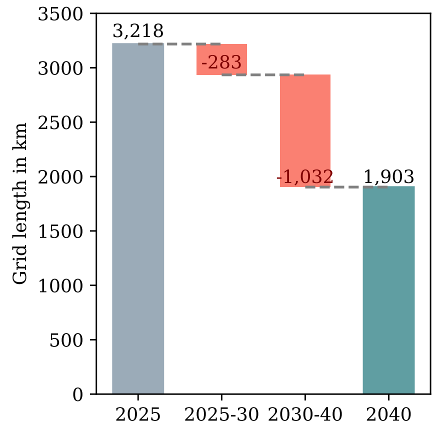


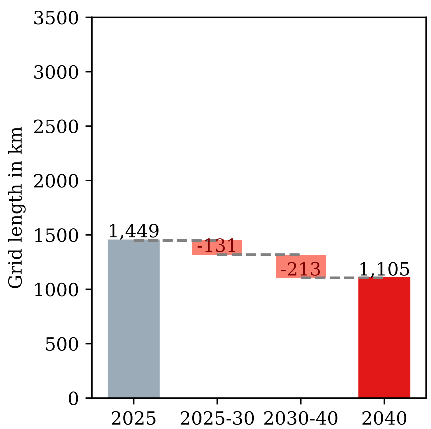

Figure 6: Austria's largest gas network by 2040 in the scenario Green Methane (GM). Colours: transmission (blue), high-pressure (red) and mid-pressure (green).



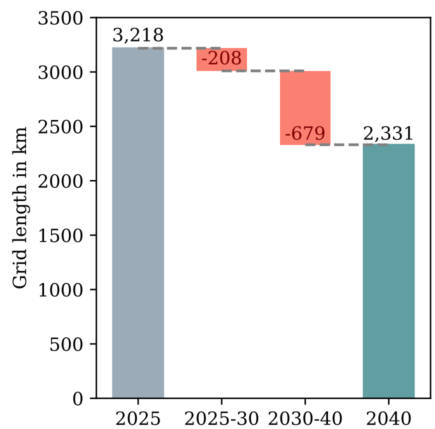

(a) Elec | High-pressure




(b) Elec | Mid-pressure




(c) GM | High-pressure




(d) GM | Mid-pressure

Figure 7: Comparison of the Austrian gas grid in 2025 and 2040 in the extreme scenarios Electrification (Elec) and Green Methane (GM) at high-pressure and mid-pressure levels. In the Elec and GM scenarios, the smallest and the largest gas grids are obtained in terms of the size of the grids.

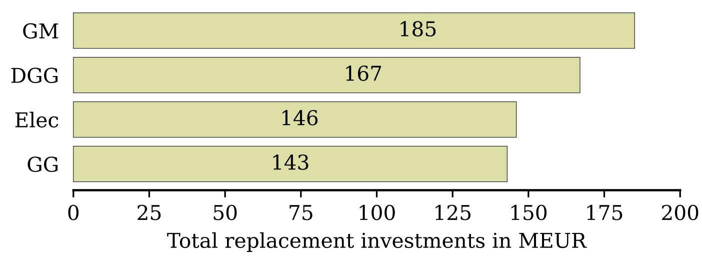



Figure 8: Total replacement investments in the Austrian gas grid until 2040 in the four scenarios.

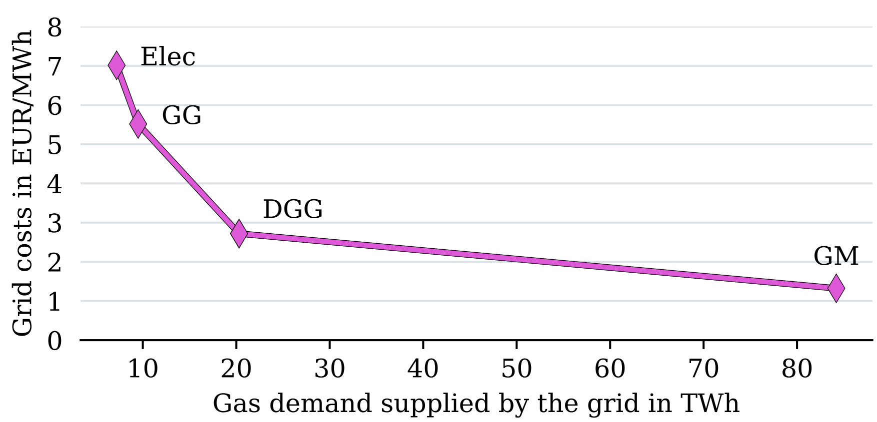



Figure 9: Grid costs in the four scenarios Electrification (Elec), Green Gases (GG), Decentralized Green Gases (DGG) and Green Methane (GM).

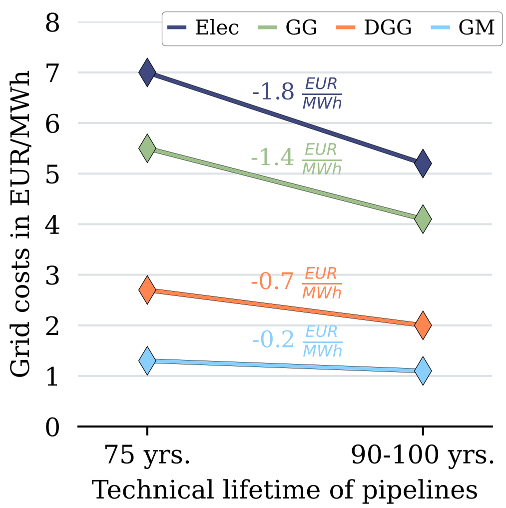



Figure 10: Comparison of grid costs in 2040 for a technical lifetime of pipelines of 75 years (left) and 90-100 years (right).