PATHWAYS FOR RAMPING-UP HYDROGEN INTO THE NATURAL GAS SYSTEM

Roberta Cvetkovska, Peter Nagovnak, Thomas Kienberger

Montnuniversität Leoben, Lehrstuhl für Energieverbundtechnik, Franz-Josef-Straße 18, 8700 Leoben, +43 3842 402 5417, roberta.cvetkovska@unileoben.ac.at, www.evt-unileoben.at

Abstract: The Austrian government program 2020-2024 aims for climate neutrality in Austria by 2040, preferably on the basis of domestic renewable sources of energy (RES). Green hydrogen represents a link between the variable RES and the demand, independently of the time frame (day/night, summer/winter). Blending the hydrogen into the existing natural gas pipeline network is seen as an important stepping stone towards a hydrogen based gas sector. This is an approach from which both sides, the hydrogen as well as the conventional natural gas sector, can benefit from. The gas mixture offers a decrease of the greenhouse gas emissions, corresponding to the share of hydrogen. In addition, the blending could provide a significant source of demand for hydrogen producers, enhancing the scaling up of hydrogen production units.

The aim of this work is to suggest possible ramp-up curves of the share of hydrogen into the gas network. Also the cost of this ramp-up is estimated. Relations to other energy-based efforts are given. Storing and transporting hydrogen within the gas blend can help to offset the cost of building dedicated hydrogen infrastructure, particularly in the early stages of market development.

Keywords: Green Hydrogen, Blending of natural gas, Decarbonisation, Hydrogen network

1 Introduction

The European Green Deal [5] seeks to make Europe climate-neutral by 2050. This goal necessitates a comprehensive transformation of the energy system in which fossil fuels are being replaced with renewable alternatives. In many sectors, such as mobility or heating, large-scale decarbonization can be achieved via direct electrification (i.e., e-mobility, heat pumps). That is not a feasible option in the so called “hard-to-abate” sectors which mostly pertain to the metallurgical or chemical industry. They rely on renewable gases, mostly hydrogen, as a feedstock to change their processes and mitigate the CO_2 emissions. As an energy carrier, hydrogen can play a role in the longer term in storage and power generation to balance seasonal variations. Decarbonization implies that the hydrogen does not come with a heavy backpack of emissions itself. Hence, green hydrogen is of interest for this study.

Blending hydrogen into the natural gas grid has the purpose of greening the gas, meaning decarbonizing a portion of the gas flowing through the grid. In the favor of scaling-up green hydrogen production towards cost competitiveness against the natural gas, blending can play a significant role in providing a reliable source of demand. Transitional pathways in which the share of hydrogen increases by a certain share can provide learnings and incremental change towards a 100% hydrogen network.

This paper compares the cost-competitiveness of the natural gas and the hydrogen by comparing their specific costs and analyzing the future gas demand on the basis of two scenarios. It outlines transitional paths of increasing share of hydrogen in the gas grid, with a limitation that the gas mixture is not more expensive then only natural gas flowing through the grid.

2 Methodology

The methodology of this work is divided in the following three parts:

a) comparison of the specific costs of natural gas, CO_2-certificates, hydrogen and bio methane;
b) alignment of the specific costs of gas with the current and future gas demand in Austria in all sectors and
c) modeling of possible ramp-up curves in order to sketch a transition towards renewable gas network.

2.1 Framework conditions

On the basis of thorough literature research from high level sources and own calculations, the development of the gas and CO_2 prices and the gas demand in the period between 2020 and 2050 was estimated. As a leading paths for that purpose, two scenarios were defined.

The “Mitigation” Scenario (MGS) represents a more conservative approach and comprises the implementation of currently planned measures and trends in the technological development for the period from 2030 until 2050. It shows usage of the already well-established technology and infrastructure to a greater extent.

The “Decarbonisation” Scenario (DCS) represents an ambitious path towards decarbonized gas sector supported by a significant increase of the natural gas and the CO_2 prices. It considers future technologies which are currently at an early stage of technological development and extensive efficiency measures which lead to decreased gas consumption.

The production cost of green hydrogen and bio methane stay the same in both scenarios for the sake of comparison.

2.2 Cost comparison

In this section, the specific production costs of hydrogen and bio methane and the energy share of the natural gas price including the price for the carbon dioxide emissions were investigated.

In Austria, as part of the eco-social tax reform, a CO_2 price for carbon dioxide emissions will be charged from July, 2022. This will have a significant contribution in the increase of natural gas prices in the future. The CO_2 tax is set to be 30 €/t CO2 in 2022 and 55 €/t CO_2 in 2025 [6]. These represent the minimum price which will have to be paid by all the gas customers, regardless if they belong in ETS[1] or non-ETS sector. The energy share of the price of natural gas for the year 2020 was calculated by subtracting the network charges, taxes and levies

[1] ETS - Emissions Trading System

from the total gas price as given by the E-Control [3]. Further on, until the year 2050, the prices for natural gas and CO_2 - certificates in the MGS develop according to the WEM (With existing measures) Scenario of the Environmental Agency Austria (EAA) [8]. This path is also reported by Austria in its National Energy Clime Plan (NECP) to the European Commission. In the DCS they follow the same development as the scenarios "Transition" and "WAM+" (With Additional Measures plus) of EAA [8].

Regarding the production price of green hydrogen using electrolysis, literature gives quite comprehensive overview until the year 2030. Nevertheless, the further development is still unclear. The capital costs (CAPEX) of electrolysis are estimated to decline by 40-60% based on today until 2050 [7]. This expectation is backed up with scaling-up production, increasing learning rates and technological improvements. Böhm et al. 2020 [1] and Sejkora et al. 2021 [11] have analyzed extensive range of literature, estimating a cost development curve for Austria which includes capital costs (CAPEX), operative costs (OPEX), electricity prices and H_2 transport costs.

The production price of bio methane was contemplated in accordance to the estimated potential and the possible development of the bio-methane production plants in Austria [4].

The breakeven point (BEP) is defined as a point in time at which renewable gases, especially hydrogen, becomes cheaper than fossil natural gas.

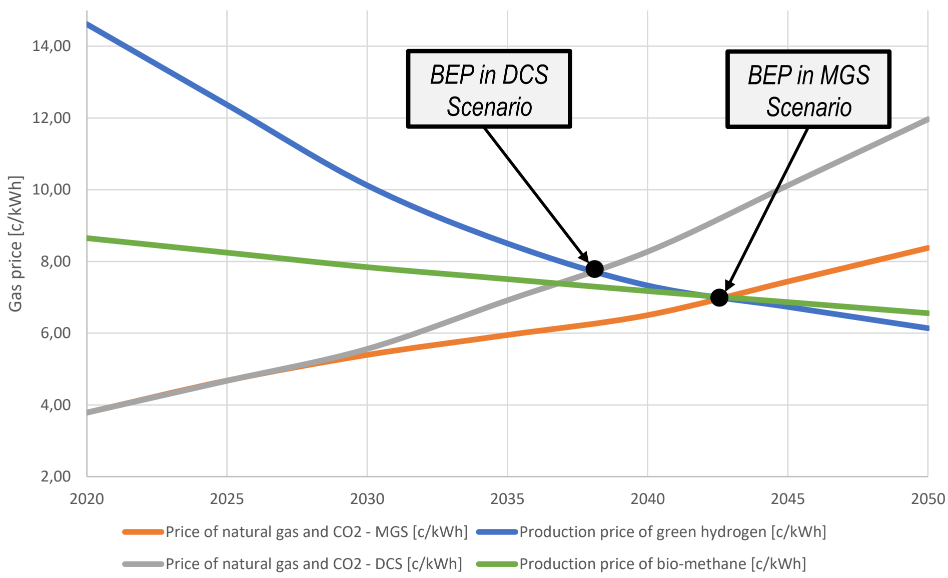

Figure 1. Comparison of the specific costs of natural gas, hydrogen and bio-methane

Two break even points are to be distinguished (Figure 1). In the MGS, hydrogen becomes cheaper then natural gas in the period between 2040 and 2045. In the DCS, this point is moved to the nearer future, between 2035 and 2040. The main drivers for achieving cost-competitiveness of the hydrogen over the natural gas are the significant decrease in the hydrogen prices and the increase of the CO_2 certificate prices. The current high prices of renewable hydrogen have a large potential for a decline as CAPEX of the electrolyser falls with scaling. Another contributor is an access to low cost power which should improve over time with RES penetration. On the other side, the natural gas loses cost-competitiveness because of the rising prices of the CO_2 emissions. The strong carbon price[2] can lead to changes in the behavior and to significant cuts in emissions. The carbon market is being seen as way to stimulate undertaking of technical interventions and efficiency improvements.

2.3 Ramp-up curves

The ramp-up curves describe the add-mixture of green hydrogen and bio-CH_4 in the gas grid for the period 2025-2050 with focus on decarbonisation of the gas network in 2040. Using the specific costs of each gas and the overall future gas demand, possible transitional pathways of covering a certain energy share with hydrogen were calculated.

The gas demand of the industry sector was determined based on the NEFI Scenarios [10]. For the other sectors, the calculations of the future gas demand correspond to the data provided by the Statistic Austria and the Monitoring Mechanism of Austria to the EU [9]. The share of bio-methane in the year 2030 is set to be as defined in the actual government program 2020-2024 [2] and follows a linear growth until 2050.

The costs of the mixture of gases (H_2, fossil - CH_4 and bio – CH_4) is described with the following equation:

$$C(gas\ mix) = x(H_2) \cdot C(H_2) + y(bio - CH_4) \cdot C(bio - CH_4) + (1 - x - y) \cdot C(NG) \tag{1}$$

Where: C – costs of the corresponding gas; x, y – shares of the corresponding gases

This cost will be greater than the cost for solely natural gas in the network until the threshold is reached (s. Figure 1). The higher particular H_2 and bio-CH_4 production costs relative to natural gas expenses, which include the energy portion of the end-customer price and the associated CO_2 price, are the reason for this.

The model for ramping up H_2, which we present here, is based on maximum total costs of the gas mixture (Equation 1) with upper limit equal to the fictitious cost of gas network using only natural gas and the corresponding CO_2 costs (Equation 2).

$$Total\ costs = C(100\%\ NG) \tag{2}$$

The goal is to maximize the added hydrogen amount with respect to the limitation that the total costs of the gas mixture is not higher than the costs for solely natural gas system. In order to do so, the tax revenues from the CO_2 emissions of the gas mixture containing hydrogen, bio-methane and fossil methane are used to subsidize the production of green hydrogen:

$$Total\ costs = max = C(100\%\ NG) = C(gas - mixture) - C(CO_2) \tag{3}$$

We apply non-linear optimization according to Equation 3 to obtain the maximum H_2 value at which the cost parity is achievable. This results in no additional energy-related costs for the end-customers compared to the system containing 100% fossil CH_4. The incentives for H_2 which come only from CO_2-based revenues corresponding to the residual CH_4 share, are

[2] Experts consider that the minimum at which carbon prices can initiate technology and economic changes is 30 €/t CO_2.

calculated in the range of 350 – 900 Mil. € in both scenarios, enabling the share of hydrogen in the gas network as represented in Figure 2. They subsidy the total cost of the mixture containing specific share of hydrogen to the amount of total costs of solely natural gas network.

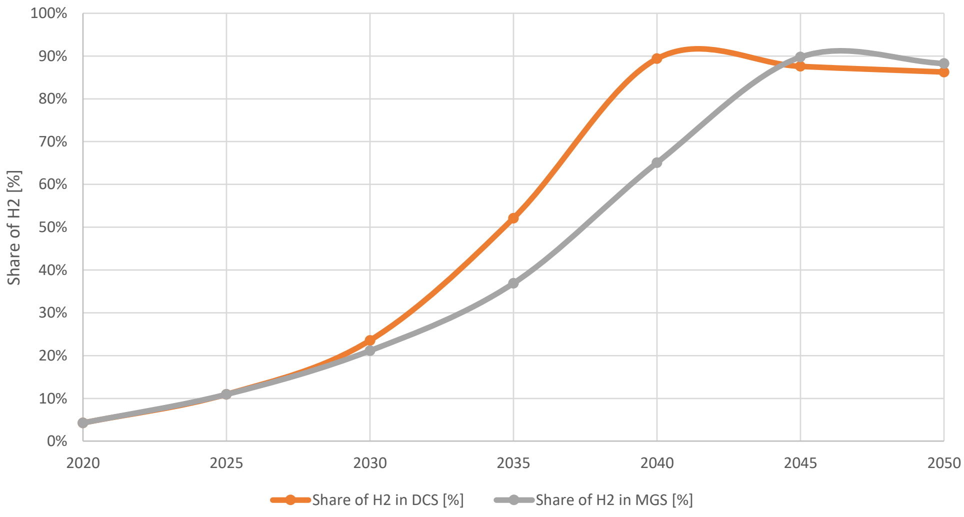

Figure 2. Transitional pathways for the possible share of hydrogen in the gas network in both scenarios

From the years 2045 in MGS and from 2040 in DCS as depicted from the BEPs in Figure 1, the gas consists only of renewable hydrogen and bio-methane. Before that, blending hydrogen gradually in the gas network could provide learnings and incremental changes towards 100% hydrogen grid.

3 Results and discussion

Different developments of the future CO_2 prices and their influence were investigated. All led to the conclusion that the renewable gases will achieve cost-competitiveness in the period around the year 2040 depending on the assumptions in the scenarios. The transitional paths represent the add-mixture of hydrogen and bio-CH_4 (energy share in %) in the gas grid from the year 2025 until 2050 with focus on decarbonisation of the gas supply in the corresponding BEP (**Fehler! Verweisquelle konnte nicht gefunden werden.**). However, it is not an input point for dedicated H_2–grids which may be necessary from 2035 onwards.

By adding hydrogen and bio-methane, the costs of the mixture will be higher than the costs of only natural gas in the network, until the breakeven point is reached. This is represented by the blue line in the upper diagrams in Figure 3. It means that from economic aspect, the transition towards decarbonized gas grid will be from 0% hydrogen before the BEP to 100% hydrogen after reaching the breakeven point between the specific costs of the two gases. To avoid that and to show possible gradual addition of the green gases (Figure 2), the biggest challenge is to limit and close the cost gap (Figure 3). The cost gap represents the additional costs rising from blending the gas. This accents the need for incentivizing and supporting the scaling-up of renewable gases, especially hydrogen. The total costs of the mixture are decreased for the amount of CO_2 costs (blue line in the downer diagrams in Figure 3), which was set as a limit in this model. In that way, the cost of the gas mixture before the BEP is not higher than the cost of 100% natural gas network.

The incentives vary between of 350 – 900 Mil. € in both scenarios as already mentioned in section 2.3. This amount contemplated with the corresponding gas demand, results in specific subsidies in the range of 0,5 – 1,2 c/kWh.

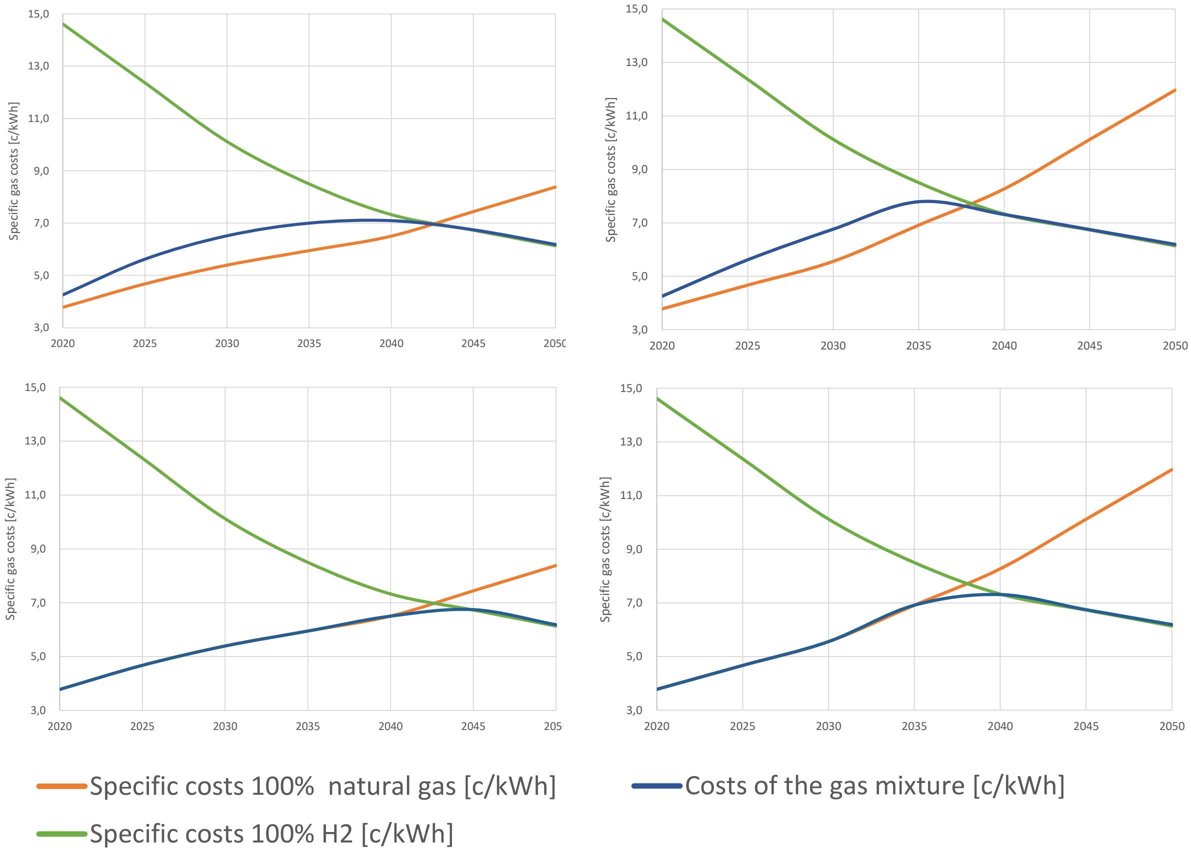

Figure 3. Specific costs of the gas mixture for different shares of hydrogen according to the ramp-up curves (upper diagrams) and reduction of the additional cost by H_2 incentives (lower diagrams) in two cases: a) Mitigation Scenario; b) Decarbonization Scenario

The inducement of the blending of natural gas can be of an important meaning in the early stages of larger-scale hydrogen production units by providing a stable demand for hydrogen. This could pave the way for future scenarios in which some systems convert entirely to hydrogen.

4 Outlook

This study analysis the transformation of the gas network from the view of cost-competitiveness between the renewable and fossil gases. However, it doesn't consider the limitations of the gas network and the end consumers towards certain share of hydrogen. It doesn't apply to specific applications of the green hydrogen.

Further work might pursuit detailed analysis of the saved emissions when blending hydrogen on the one side, and when using it directly on the other side. In other words, to investigate if it offers better advantages in a sense of costs and CO_2 emissions when burning it as a mixture of gases for the purpose of space heating, or using it as a feedstock for direct reduction of steel.

5 References

[1] Böhm, H., Zauner, A., Rosenfeld, D. C., and Tichler, R. 2020. Projecting cost development for future large-scale power-to-gas implementations by scaling effects. *Applied Energy* 264, 114780.

[2] Bundeskanzleramt Österreich. 2020. *Regierungprogram 2020-2024*. *Aus Verantwortung für Österreich*, Wien.

[3] E-Control. 2021. *Zusammensetzung des Gaspreises*. https://www.e-control.at/industrie/gas/gaspreis/preiszusammensetzung.

[4] Energieinstitut an der Johannes Kepler Universität Linz and Energieverbundtechnik Lehrstuhl an der Montanuniversität Leoben. Mai, 2020. *Erhöhung des Einsatzes von erneuerbarem Gas im österreichischen Energiesystem*. *Potential-Kosten-Effekte*.

[5] European Comission. 2019. *The European Green Deal COM (2019) 640 Final*. Brussels, Belgium.

[6] finanz.at. 2021. *CO2-Preis-CO2-Steuern in Österreich 2022*. https://www.finanz.at/steuern/co2-steuern/. Accessed 10 November 2021.

[7] IEA International Energy Agency. June/ 2019. *The Future of Hydrogen*. *Seizing today's opportunities*.

[8] Krutzler, T., Zechmeister, A., Stranner, G., Wiesenberger, H., Gallauner, T., Gössl, M., Heller, C., Heinfellner, H., Ibesich, N., Lichtblau, G., Schieder, W., Storch, A., and Winter, R. 2017. *Energie- und Treibhausszenarien im hinblick auf 2030 und 2050*. *Synthesebericht* ISBN 978-3-99004-445-2. Umweltbundesamt Österreich.

[9] Müller, A., Fritz, S., and Kranzl, L. 2017. *Energieszenarien bis 2050: Wärmebedarf der Kleinverbraucher*. Energy Economic Group; Technische Universität Wien; E-think energy research.

[10] Nagovnak, P., Kienberger, T., Geyer, R., and Hainoun, A. 2021. Dekarbonisierungsszenarien für das industrielle Energiesystem in Österreich. *Elektrotech. Inftech.* 138, 4-5, 258–263.

[11] Sejkora, C., Lindorfer, J., Kühberger, L., and Kienberger, T. 2021. Interlinking the Renewable Electricity and Gas Sectors: A Techno-Economic Case Study for Austria. *Energies* 14, 19, 6289.