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LEGAL OPINION

Principles of the regulation of German hydrogen networks in the context of an adaptation of the European legal framework and the financing of hydrogen networks by integration into the legal framework of gas network regulation

prepared on behalf of

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Introduction

In the context of the decarbonisation of the energy industry and the implementation of the climate targets for 2050, CO_2-free gases and hydrogen in particular play a major role.[1] The existing natural gas industry is a powerful industry with enormous, but yet untapped potential for the energy transition. The existing legal framework needs to be reviewed in this respect.

A. Starting point: Regulatory considerations of GEODE

GEODE AISBL, the European association of independent electricity and gas distribution companies (hereinafter referred to as GEODE), has presented a concept paper on the regulatory framework conditions that need to be created, particularly in European law. This legal opinion takes up the considerations of GEODE and adopts its proposals. The central proposition is to use the already existing natural gas network operators to develop a future hydrogen infrastructure (so-called combined network operators), which will require an equal regulation of natural gas and hydrogen network operators.

On behalf of GEODE and Hydrogen Europe, this legal opinion examines regulatory barriers to the integration of hydrogen infrastructure into the existing German legal and regulatory framework as well as to the establishment of *combined network operators* and identifies possible solutions (Part 1). Part 2 provides an economic assessment of the investment possibilities that arise from integration into the existing regulatory regime.

The principles and general findings of this report can be applied to other member states of the European Union which are also characterised by historically developed gas networks; the following statements, however, refer primarily to Germany. The subsequent quantification of these regulatory considerations will finally show the economic potential of integrating the hydrogen infrastructure into the existing regulatory system. Wanting to unlock this potential constitutes another starting point. The regulatory proposals at hand aim at a general welfare gain, which lies in the transformation – rather than a liquidation of existing structures – (if possible without burdening the public budget).

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[1] The European Green Deal of 11/12/2019 identifies a number of measures that will bring far-reaching changes, including in particular the "supply of clean, affordable and secure energy". This includes, in particular, hydrogen networks.

B. Summary of the findings

If it is recommended – as in this legal opinion – that hydrogen networks and natural gas networks be subject to joint regulation on the basis of the provisions in place for natural gas network operators, it is, first and foremost, necessary to establish a European legal framework. The focus is on national regulations insofar as they serve the implementation of European Community law for natural gas infrastructures in national law – see for example sec. 1 subs. 3 German Energy Industry Act (EnWG).[2] The respective national implementations must be uniform to the extent that a technical-economic interconnection such as is currently ensured for natural gas also applies to hydrogen and other relevant gases.

First, Part 1 discusses how hydrogen (and other CO2-neutral gases) can be established as a *base gas* alongside natural gas – in the EnWG by means of minor changes. Based on this, it is outlined how, for example, the grid access model should be developed further in regulatory terms. The integration of hydrogen and other gases makes a *demand-oriented network expansion* possible which no longer focuses solely on the demand for natural gas networks. Furthermore, it will be shown how a rapid market ramp-up can be achieved by using *hydrogen from all production options* in line with decarbonisation, while at the same time securing the legal future of *green hydrogen* by giving technologically priority to the feed-in of green energy. Finally, the *protection of end customers* in the event of a conversion of existing gas networks, e.g. to hydrogen, is also taken into account and it is shown how the protection of *end-use applications* can be guaranteed during the necessary transformation. This would require a future regulatory regime covering all these aspects.

Part 2 of the legal opinion assesses the economic effects of integrating the hydrogen infrastructure into the existing regulatory framework. This chapter puts forward and examines the proposition that the combined network operator introduced at the beginning of this paper represents the most cost-effective option for a transformation of the gas industry with the greatest possible welfare gain. Based on different scenarios, the first step is to forecast the decreasing trend in the cost level and revenue caps of the existing natural gas networks until 2050. This would help unlock the potential for annual investments without having to increase the revenue

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[2] In this regard, see, for example, the German Energy Industry Act (*Energiewirtschaftsgesetz* – EnWG) loc.cit. The objective of this Act includes the implementation and application of European Community law in the area of grid-bound energy supply.

caps, i.e. the costs to be borne by network users, compared to the status quo. The analysis combines this potential with the volume of special depreciations which would be necessary if the networks became obsolete by 2050, but instead could be invested in hydrogen pipelines, and concludes that a considerable annual investment sum of €0.5 billion from the ongoing operation of the gas network industry would be possible – **without state subsidies and without an increase in network charges.**

Part 1 Principles of the regulation of German hydrogen networks in the context of an adaptation of the European legal framework

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A. National provisions in the context of European law

National provisions of the member states affect European law insofar as their regulatory content is also part of European law. This applies to the internal gas market whose relevant legal framework is laid down in Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 (**Gas Directive 2009**). Further provisions also result from Regulation (EC) No. 715/2009 of the European Parliament and of the Council of 13 July 2009 (**Gas Transmission Regulation 2009**) and from Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 (**RED II**). Especially with regard to the *primacy of EU law*[3], the EU regulatory framework and particularly the Gas Directive 2009 must be considered in advance in order to subsequently derive regulatory measures in national law.

The German legislator would also be free to regulate hydrogen networks alone, e.g. in the EnWG, but a common European regulatory framework has long been established. The existing legal framework is therefore considered to be sufficient as the national route for "green hydrogen".[4] Then, (renewable) gases such as hydrogen are not treated as *base gas* like natural gas, but as so-called additional gas (for blending). In addition, the existing system of the EnWG is limited to the form of production of water electrolysis. Last but not least, these considerations have already been blocked in practice by the National Regulatory Authority (although the non-binding consideration are nevertheless encouraged).[5]

However, the provisions contained in the Gas Directive 2009 refer for the most part only to **natural gas** and only in part to other gases such as hydrogen. According to Article 1(2) Gas Directive 2009, the latter are only covered by the regulatory regime in cases of admixture, i.e. when the other gas is fed into the natural gas network.

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[3] Declaration 17 to the Final Act of the Treaty of Lisbon, OJ EU 2008, No. C 115, p. 344.

[4] A blending quota of 100 % would allow de facto pure hydrogen networks, see Michael Kalis in IKEM, Rechtsrahmen für ein H2-Teilnetz, Berlin, September 2019.

[5] See Bundesnetzagentur, Bestätigung des Szenariorahmens für den Netzentwicklungsplan Gas 2020-2030, 5. Dezember 2019, p. 53f.

Pure hydrogen networks, by contrast, are *de lege lata* unregulated. Since the *status quo* does not legally permit the full integration of hydrogen into the regulated European internal gas market, it must be adapted accordingly.

This proposal adopts **GEODE's current considerations** on the framework conditions that are to be established under the regulatory regime and in particular in European law. Using the already existing natural gas network operators to develop a hydrogen infrastructure (so-called *combined network operators*) is at the core of the considerations. This will require natural gas and hydrogen network operators to be regulated on an equally footing.

In summary, modifications to the European legal framework are recommended, especially with regard to the following points: [6]

- The EU legal provisions on network development in Article 13(1)(a) Gas Directive 2009 (transmission level) and in Article 25(1) Gas Directive 2009 (distribution level) as well as those on network development planning in Article 22(1) Gas Directive 2009 (national ten-year network development plan – **NEP**) and in Article 8(3)(b) Gas Transmission Regulation 2009 (Community-wide network development plan – **TYNDP**) do virtually not permit de lege lata the expansion of a pure hydrogen network by the natural gas network operator as this would not be carried out *in line with demand*. In this respect, the above-mentioned provisions must be modified across all gas types – thus, including also hydrogen – so as to ensure that such a network expansion and the corresponding network development planning is carried out in line with demand.

- As far as the financing of the hydrogen infrastructure is concerned, the only option which is economically reasonable is to use the current income from the natural gas infrastructure for financing (see under part 2). However, such a tariff setting is not provided for de lege lata in European legislation, in particular in Article 41(6)(a) second sentence Gas Directive 2009, and must therefore be adapted to make financing possible across all gas types.

- Pure hydrogen networks, like natural gas networks, constitute natural monopolies so that network users run the risk of being denied access to the network without any objective justification in a discriminatory manner. In

6 See GEODE, Towards the New Age of Gas Networks, May 2020.

order to counteract this, the regulator must impose an obligation to contract on the monopolist, which can only be deviated from in exceptional cases. Pursuant to Articles 32 and 35 Gas Directive 2009 and Article 14(1)(1)(a) Gas Transmission Regulation 2009, the EU regulatory framework currently in place, however, stipulates such an obligation solely for natural gas networks and not for pure hydrogen networks. Therefore, the aforementioned EU legal framework conditions must be modified to apply to all gas types with regard to the granting and refusal of network access.

- Since the dual-contract model laid down by EU law for natural gas transmission system operators and the requirement for equivalent contractual conditions (Article 13(1)(2) and (4) Gas Transmission Regulation 2009) work effectively, these should apply to all types of gas and therefore also to operators of other transmission systems.

- According to Article 3(2) Gas Directive 2009, the natural gas network operator must guarantee its end customers protection of the existing gas supply, in particular with regard to the type and quality of gas. However, this provision also applies only to natural gas and should also cover other gases such as hydrogen.

The considerations of this regulatory proposal are based on the primacy of integrated European markets also for hydrogen and other renewable gases. Therefore, the principles underpinning the successful creation of uniform gas markets by way of a uniform European directive are to be adapted to the matter at hand. Accordingly, the principles governing uniform regulation in the EU must also be laid down in a corresponding directive (note: the content of which is still to be specified), if necessary in compliance with subsidiarity.

Using **Germany as an example**, the following chapter will show whether and to what extent a European legal framework tailored to hydrogen (or other gases) requires implementation and additions in national law.

B. Amendments and additions according to European law

If GEODE's proposals to amend the European legal framework were to be implemented, subsequent legislative amendments of varying scope would be necessary. In some cases, this could be achieved by recasting definitions alone. Other points, however, would require further revision. It can be assumed that natural gas-specific regulations will continue to be structurally necessary for the time being.

I. Revision of the scope of the German Energy Industry Act (EnWG)

First of all, it should be examined whether a simple adaptation of the legal definitions is sufficient here. In German law, at present only hydrogen produced by electrolysis – regardless of whether from grey electricity or green electricity (only biogas) – may be added as a so-called *additional gas*. This means, however, that the transport of hydrogen as *a* so-called *base gas* is **not subject to regulation** under the current legal provisions.

The applicability of the EnWG is therefore the starting point for determining whether and to what extent hydrogen can be integrated into the regulated, grid-bound gas supply. At present, the EnWG pursues a **technology-specific approach**:

a) Hydrogen is considered as biogas in terms of sec. 3 no. 10c EnWG if it has been produced by water electrolysis and if the electricity used for electrolysis demonstrably comes predominantly from renewable energy sources within the meaning of Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009.

b) Hydrogen is considered as gas in terms of sec. 3 no. 19a EnWG if it has been produced by water electrolysis and is fed into a gas supply network. Other production paths (steam reforming, autothermal reforming, etc.) that could make hydrogen available in large quantities are therefore currently excluded from regulation. At the same time, it becomes clear that the legislator can easily remove the restriction to water electrolysis under b) and thus simply extend the definition of "regulated gas" to hydrogen in line with the European Green Deal.

Accordingly, there are presently no plans for an integrated network for hydrogen. According to sec. 3 no. 19 EnWG, the task of the transmission networks is described (exclusively) as "transport of natural gas" through a high-pressure pipeline network; in the future this should read "**transport of gas within the meaning of this Act**". This becomes even clearer when the addressees of the regulation are considered: According to sec. 3 no. 5 EnWG, transmission network operators have the task of transporting natural gas and are also responsible for the operation, maintenance and, if necessary, the expansion of a network. This has consequences, for example with regard to network development planning (see below).

II. Network access

According to sec. 20 subs. 1 sentence 1 EnWG, a distinction must be made in the established system for natural gas between the statutory right to *network access for everyone* (sec. 20 subs. 1 EnWG) and the additional provisions governing the organisation of such access, i.e. the specification of a *network access model* (for gas: sec. 20 subs. 1b EnWG).

1) Network access for everyone

According to sec. 20 subs. 1 sentence 1 EnWG, operators of energy supply networks must grant everyone non-discriminatory network access on the basis of objectively justifiable criteria. According to sec. 3 no. 4 EnWG, operators of energy supply networks include operators of electricity supply networks and operators of gas supply networks. Due to its open formulation, this provision can be applied not only to natural gas but also to other gases such as hydrogen.

2) Handling network access

The situation is different, however, as regards the more specific provisions for handling network access.

a) Abandonment of the distinction between base gas and additional gas

Section 20 subs. 1b EnWG itself does not specify the type and quality of the transported gas. It only sets out that any gas fed into the network has to be *compatible with the network* within the meaning of sec. 19 subs. 2 of the Gas Network Access Ordinance (*Gasnetzzugangsverordnung* – **GasNZV**) and must comply with the generally accepted engineering standards within the meaning of sec. 49 subs. 2 and 3 EnWG. According to sec. 49 subs. 2 EnWG, there is a rebuttable presumption of compliance with the generally accepted engineering standards if the technical regulations of the DVGW (*Deutscher Verein des Gas- und Wasserfaches e.V. – Technisch-wissenschaftlicher Verein* – German Technical and Scientific Association for Gas and Water) have been complied with in the case of systems for the production, transmission and distribution of gas. In practice, however, both mean natural gas as *base gas*.

A common feature of the above provisions is that hydrogen produced from electrolysis is to be integrated (blended) into a natural gas network *de lege lata* only as an *additional* gas. However, the classification of natural gas as a base gas and hydrogen as an additional gas means that hydrogen *will not be able to establish itself alongside natural gas de lege lata*, particularly with regard to decarbonisation and the achievement of the climate targets for 2050. In view of the European and national objective of a uniform energy market that covers all types of gas, **a distinction between base gas and additional gas should be abandoned**.

Such a distinction is also not necessary with regard to network compatibility, because the technical regulations, such as the admixture limits, must be complied with irrespective of whether a base gas or an additional gas is present. This is because it does not play any role for network compatibility whether, for example, hydrogen is fed into the natural gas network or – assuming the above-mentioned differentiation is abandoned – natural gas is fed into a hydrogen network. In both cases, the technical regulations and thus the relevant admixture limits must be observed.

b) Entry-/Exit-system and two-contract model also for hydrogen?

The entry/exit-system or two-contract model stipulated in Article 13(1)(4) Gas Transmission Regulation 2009 was transposed into German law by sec. 20 subs. 1b EnWG.[7] However, this model, which is laid down in sec. 20 subs. 1b EnWG, was created for the natural gas grid.

For pure hydrogen networks, on the other hand, independent regulations would certainly be necessary, which may partly fit into the network access model for natural gas, but may partly also follow different rules. It is therefore necessary from a regulatory point of view to issue a gas-type-specific regulation for access to (pure) hydrogen networks, which, among other things, defines a network access model taking up, for example, the principles of the well-known two-contract model. The GasNZV, which is tailored to the specific characteristics of natural gas, would, for consistency, have to be renamed "*Natural Gas* Network Access Ordinance". The authorisation for issuing such downstream gas-type-specific regulations is provided for in sec. 24 EnWG, which does not even distinguish between electricity and gas.

III. Network expansion and network development planning

As the regulatory system *de lege ferenda* combines different types of gas, an integrated network development planning process is required. This process is

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[7] The national legislator even goes beyond the stipulation in Article 13(1)(4) Gas Transmission Regulation 2009. According to sec. 20 subs. 1b sentence 1 EnWG, not only the (natural gas) transmission system operators but also the distribution system operators are obliged to apply the two-contract model.

primarily subject to national law, although European preparatory work is helpful for the development across Europe.

Section 11 subs. 1 sentence 1 EnWG is authoritative for the network expansion in Germany and, as regards hydrogen as biogas within the meaning of sec. 3 no. 10c EnWG, the following provisions also apply: sec. 33 subs. 2 sentence 1, subs. 6 sentence 4 and sec. 34 subs. 2 sentence 2 GasNZV. In order to satisfy the EU legal requirements (Article 13(1)(a) Gas Directive 2009 at the transmission level and Article 25(1) Gas Directive 2009 at the distribution level), the above-mentioned national provisions oblige the network operator to *expand the network in line with demand*. In accordance therewith and to implement Article 22(1) Gas Directive 2009, the planning of the network expansion is also subject to the requirement that it must be *demand-based*. Therefore, sec. 15a subs. 1 sentence 2 EnWG stipulates that the NDP (Network Development Plan) must contain all effective measures for the demand-based optimisation, reinforcement and expansion of the network.

Since the demand-based criterion only applies within the regulatory framework, it can also only apply to regulated gas networks. [8] Just like European law, national law de lege lata refers only to natural gas. According to the European legislation to be adapted *de lege ferenda*, the above-mentioned national provisions must be amended across all types of gas (i.e. including hydrogen and green hydrogen as biogas within the meaning of sec. 3 no. 10c EnWG) in such a way that such a network expansion and the related network development planning are also tailored to meet the demand.

IV. Green hydrogen – a special approach?

Hydrogen as biogas within the meaning of sec. 3 no. 10c EnWG generally enjoys all privileges regarding the feed-in of biogas according to chapter 6 GasNZV. Therefore, the *priority feed-in* according to sec. 36 subs. 1 sentence 1 GasNZV is already applicable to hydrogen within the meaning of sec. 3 no. 10c EnWG. However, biogas must be conditioned to be compatible with natural gas, which means that it is always a gas that is mixed together with other gas(es).

If the existing legal framework is transferred to a future system that regulates hydrogen networks on an equal basis with natural gas networks, the question arises

[8] cf. BNetzA (*Bundesnetzagentur* – Federal Network Agency), confirmation of scenario framework 2020-30 of 05/12/2019, page 48: "However, a distinction must be made between such [note: addition of electrolytic hydrogen] measures and the rededication and, above all, the construction of a pure hydrogen infrastructure, since the latter are not subject matter of the expansion planning regarding the transmission network."

if it is permissible to differentiate between hydrogen production methods. EU legal requirements are only contained in Article 20(1) RED II, which stipulates that Member States shall examine the necessity to extend the existing gas infrastructure in order to facilitate the feed-in of gas from renewable sources. Accordingly, the national legislator is allowed *flexibility* in the specific implementation of the priority feed-in.

However, decarbonisation and the climate targets for 2050 can only be implemented in practice if, in the end, green hydrogen actually flows through the hydrogen network. For this reason, green hydrogen should have priority feed-in over blue hydrogen as "bridge energy". There are different options for implementing the priority feed-in of green hydrogen in regulatory terms, e.g.

- by enshrining the priority feed-in in the EnWG in a central and technologically neutral manner or
- by establishing a parallel provision – modelled after the priority feed-in of biogas into the natural gas network in accordance with sec. 36 subs. 1 sentence 1 GasNZV – for the priority feed-in of green hydrogen into the pure hydrogen network in a hydrogen-specific downstream regulation[9].

However, it is recommended that the priority feed-in is enshrined in the EnWG as the primary law in order to give due consideration also from a legislative point of view to the pivotal role that green energy plays in ensuring a sustainable and, in the long-term, carbon neutral energy supply. Thus, individual provisions may in the future both favour green hydrogen and replace the priority feed-in of biogas, which has so far been governed by various downstream regulations. The details may then be worked out in an ordinance regulating the access to the hydrogen network

V. Protection of end-use customers

Finally, framework conditions for the type and quality of gas must also be established with regard to how new and existing customers of network operators are to be treated.

End-use customers are in need of protection to the extent that they have made long-term investments (e.g. in heating systems or industrial applications) in reliance on a specific gas supply. This applies not only to cases of admixture, if the quota does not remain constant, but particularly also to the use of pure hydrogen networks by final

[9] See the comments on the handling of network access in chap. II sec. 2 lit. b).

consumers. Therefore, a corresponding *inventory protection* is highly relevant for end-use customers.

Generally speaking, each network connection is based on *technical conditions* (in Germany for medium and high pressure according to sec. 17 subsec. 1 EnWG in conjunction with a grid connection contract and according to sec. 18 EnWG or according to the supplementary conditions of the network operator according to the Low Pressure Connection Ordinance). Accordingly, end-use customers are thus entitled to continuity and to a supply of consistent quality, which also serves the implementation of Article 3(2) Gas Directive 2009. The above-mentioned national provisions refer to both electricity and gas supply networks, so that due to their open formulation they can also be applied to (pure) hydrogen networks under the premise that a low-pressure level as well as higher pressure levels exist in hydrogen networks.

This right of end-use customers, i.e. to be supplied with a specific type of gas, should therefore be restricted by law in return for a (partial) passing-on of the costs incurred by the conversion of the customer's applications. Costs are to be passed on to gas consumers nationwide – provided that they were incurred as a result of climate protection considerations. Experiences from the conversion from L-gas to H-gas in Germany (sec. 19a EnWG) or the current considerations regarding hydrogen conversion in Great Britain may be taken into account here.

C. Financing hydrogen networks

I. Enhancement of existing assets

In its European Green Deal of 11 December 2019, the European Commission calls not only for the application of new innovative technologies in order to achieve the climate targets, but also, where possible, for the modernisation and continued use of *existing* infrastructure and assets.[10] This request has been taken up by the present legal opinion, and an approach aiming at the highest possible welfare gain – ideally without the use of state subsidies – has been sought.

Accordingly, the creation of a *combined network operator* also provides for existing natural gas assets to be used and for the necessary investments, depending on the speed of expansion, to be financed from the current income from the natural gas infrastructure. In this way, the chicken-and-egg problem and the *first-mover disadvantage* of an infrastructure-based market ramp-up can be avoided. After a

[10] European Green Deal of the European Commission, 11/12/2019 COM(2019) 640 final

brief explanation on the regulatory implementation with regard to cost allocation, this is dealt with in more detail in Part 2.

II. Regulatory implementation; cost allocation

The existing legal framework offers two possibilities of allocating costs associated with the integration of hydrogen in the natural gas networks to the parties causing them. Both mechanisms, for which sufficient experience is available in Germany, have specific advantages and disadvantages:

According to sec. 20b indent 1 Gas Network Charges Ordinance (*Gasnetzentgeltverordnung* – **GasNEV**) in conjunction with sec. 33 subs. 10 GasNZV, the costs for the feed-in of biogas are factored into the network charges nationwide. However, sec. 20b GasNEV could be supplemented by a further indent providing for the nationwide passing-on of costs in order to finance the expansion of hydrogen networks. This would make the investment costs transparent and network operators willing to invest could anticipate them but separate accounting would be necessary. However, distributing the costs equally to the network charges for the use of natural gas networks would become meaningless at the latest when natural gas customers gradually drop out as the natural gas network is transformed into a pure hydrogen network, which at the same time increases the surcharge for the remaining natural gas network users.

It follows from the above that a finalisation and transfer to the system of network charges is necessary in the end. In this respect, it can be concluded that the financing should be arranged directly within the network charges system without the intermediate step of a surcharge.

Finally, the expansion of the hydrogen network could be financed within the framework of the incentive regulation pursuant to sec. 21a EnWG by means of a uniform network charge with a common revenue cap for natural gas and hydrogen networks. This would have the advantage that the system of charges remains the same from the beginning of the transformation, the costs are reviewed in a uniform manner and that the equity capital bears a uniform interest rate.

However, such a tariff setting is less transparent and leads to regionally varying charges. As a uniform network charge with horizontal cost shifting has been in force in the transmission network since 2020, it is irrelevant to the network user in which region hydrogen structures are required. Unfortunately, however, there is a risk here that distribution networks – which, following the transformation of upstream networks also have to be transformed – would have to carry a particular burden due to the lack of a shifting mechanism. Therefore, different mechanisms would be required depending on the network level.

Part 2 Financing the development of hydrogen networks through integration into the legal framework for the regulation of gas networks

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A. Background and assumption

The background to this analysis is the decarbonisation of the gas industry. On the one hand, gaseous energy transport will still be necessary in the future, but on the other hand, it is evident that natural gas will have to be replaced by CO_2-neutral gases beyond 2050. In this respect, the future may lie in hydrogen. Various framework conditions are currently being discussed in the industry. One assumption in this context is that the greatest welfare gain lies in a **regulated hydrogen infrastructure**, which would be developed based on the existing (regulated) natural gas network operators.

I. Starting point of the analysis

The task of establishing a hydrogen infrastructure should be assigned to the existing gas network operators. The necessary investments can then be financed from the current income of the natural gas infrastructure.

In addition to other benefits for the transformation of the gas industry, this approach would avoid the risk of special depreciation for the existing natural gas infrastructure, which could become a necessary alternative. This is because energy networks in general do not have a final amortisation period or investment cycle. Regulated energy networks are characterised by a mixed calculation of fully depreciated and new infrastructure. As a result of the ever shorter periods of use – if an end date is set – network charges would have to increase accordingly towards the end of the natural gas industry. Furthermore, by using the existing organisational structures of the current gas network operators, a parallel development of similar structures for the hydrogen infrastructure and the costs associated therewith would be systematically avoided. However, this does not only apply to the construction. Due to economies of scale, it also applies to the ongoing operation.

A quantification of this starting point can show the economic potential of integrating the hydrogen infrastructure into the existing regulatory system.

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II. Working hypothesis to be tested

It is assumed that a "combined network operator" for natural gas and hydrogen, which is bound by a common regulatory regime comparable to the current one, constitutes the most cost-effective option for the transformation of the gas industry. The potential of this working hypothesis will be quantified and/or economically substantiated below (economic and business justification). We will do so in the following by comparing the costs prior to the expansion of the regulatory framework to include hydrogen investments while considering the special depreciation of the existing natural gas network with the costs to be incurred taking into account these investments being made by a "combined network operator". This "combined network operator" should be able to successively rededicate the assets and thus avoid special depreciation allowances.

For networks in Germany, the effects can best be identified by looking at the development of the costs for network users; ideally, **the network charges will remain the same despite investments in hydrogen infrastructure**. In this context, it must be taken into account that the level of the specific network charges combines two effects: on the one hand, the costs in form of a revenue cap for network operators and, on the other hand, the development of the sales volumes. The confirmation and/or quantification of the hypothesis is therefore carried out in two steps. In economic terms, the costs to be borne by the current network users but also the costs to be borne by the state, should remain the same as without investments in the hydrogen infrastructure.

B. Economic analysis

The quantification of the costs for network operators or the change thereof without taking into account the effects resulting from changes in sales volume can be considered in isolation and is analysed **under 2.** below.

The combination with effects resulting from changes in sales volumes requires a differentiated approach. This is because, against the background of decarbonisation, "pure natural gas network operators" are expected to suffer significant decreases in sales volume even if there is no change in costs.; Therefore, if they continue operating these natural gas networks, sharp increases in specific network charges can be expected. This means that existing gas network customers will switch to an alternative energy supply and network users who continue to use natural gas will be burdened with significantly higher network charges. In order to determine whether the investments in hydrogen – which will lead to more gas being sold in the network and will cause comparatively lower specific network charges –

will not result in an additional economic burden, the costs of alternative energy supply must also be taken into account (see further on this **under III.**).

I. Basis for assumptions on sales development

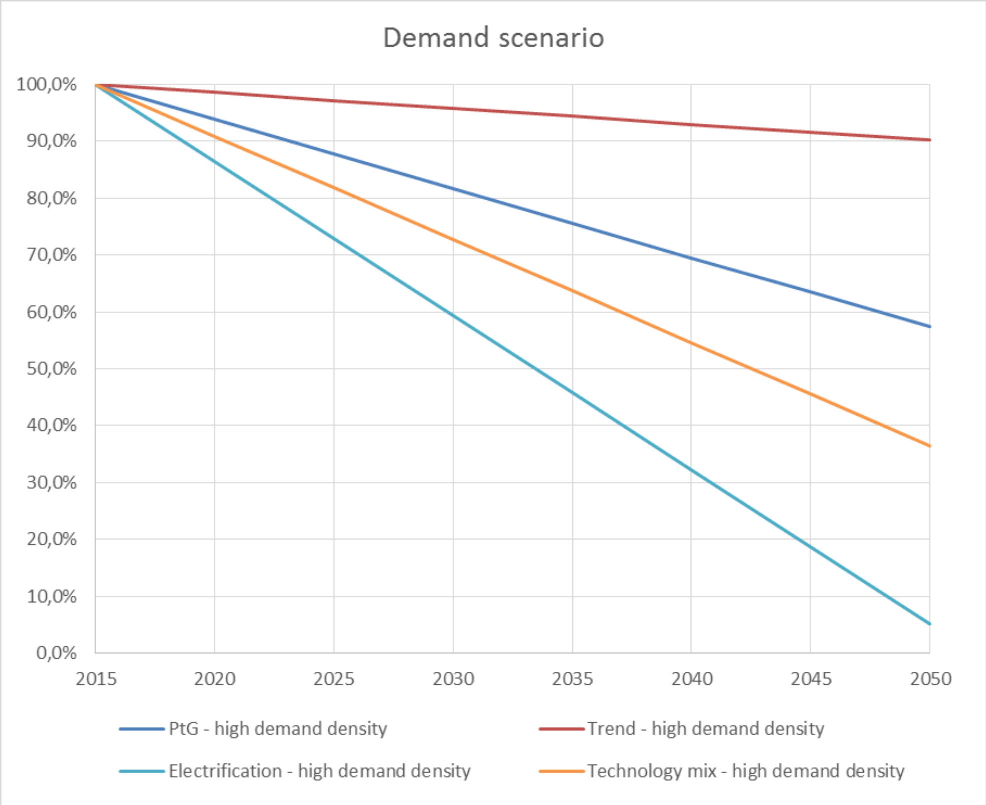
To examine and quantify the above working hypothesis we have relied on preliminary studies regarding gas distribution networks. In the so-called heat transition study ("*Wärmewende-Studie*")[11], we examined the effects on different network models taking into account the changing demand due to decarbonisation. In particular, the impact on network operators and their possible reactions to changing demand volumes were investigated.

The findings on the decreasing sales volumes are based on numerous studies on the development of natural gas demand considering the development of decarbonisation. These findings were summarised and the main transformation paths were derived therefrom. These include the following demand scenarios relating to the natural gas-based heating market:

- Trend (approximately constant sales volumes; climate targets are not met);
- Power to gas (synthetic gaseous fuels, such as hydrogen and synthetic methane, are becoming increasingly important);
- Technology mix (mix of different technologies or power to gas and electrification) and
- Full electrification (gas-based technologies will be replaced by electricity-based technologies by 2050).

This results in the following decrease in sales volumes per demand scenario for space and process heating supply:

[11] The heat transition and its impact on gas distribution networks; Becker Büttner Held Part-GmbB, Becker Büttner Held Consulting AG; Berlin/Munich 2018 (summary).



The above diagram and the heat transition study do not include the supply of natural gas for the transportation sector or for power generation.

II. Development of revenue caps for natural gas networks (without hydrogen)

In a first step, we examined to the development of the revenue caps of the network operators over the period up to 2050 if no new investments are made. We compared this development with the current supply situation of the network operators without taking into account the effects of decarbonisation (status quo). If the revenue caps were to be lowered, investments in hydrogen networks or the rededication of existing natural gas networks could be carried out without the total costs for extended network operation including hydrogen rising. If the costs for network users remain unchanged, this amount could be used to finance the investments in hydrogen pipelines.

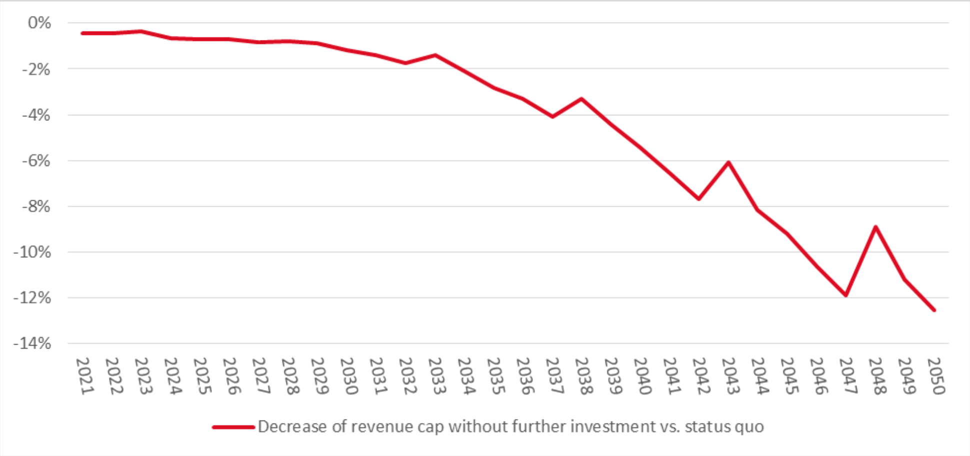
a) Investment potential within the revenue caps

In order to assess the development of the revenue caps, we first derived their current level for all gas network operators (transmission system and distribution system). The basis for this was the Monitoring Report of the Federal Network Agency (*Bundesnetzagentur*) and the Federal Cartel Office (*Bundeskartellamt*) of November

2019 with the information on the approved starting level for 2015 as well as the current applications of the network operators regarding the revenue caps for the year 2019, which are published in accordance with sec. 31 of the Incentive Regulation Ordinance (*Anreizregulierungsverordnung* – ARegV). The revenue cap applications show an average increase of approx. 15% compared to the original revenue cap from the cost approval of 2015. This is probably due to the comparatively high level of investments compared with the base year, which is why the underlying initial level was increased accordingly. This results in adjusted network costs for 2019 of €7.1 billion for all network operators. However, the network costs also include upstream network costs (especially transmission system operators), which must be deducted in order to calculate the cost burden of all network users; otherwise these costs would be taken into account twice. The adjusted network costs less the costs of the upstream network amount to €5.9 billion.

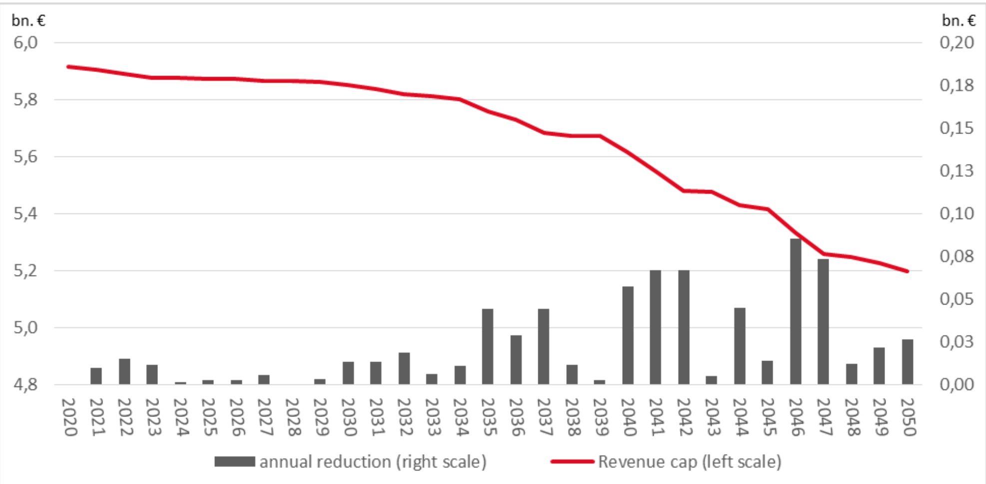
The development for all gas network operators was analysed in the framework of the heat transition study on the basis of the calculated effects, taking into account the currently applicable regulatory requirements. In this context, the original model networks were used as a simple average, assuming that further investments in the gas pipeline network were avoided. However, the planning of the model networks is still based on the assumption of a secure gas network operation, which means that reinvestments and also higher maintenance costs due to the increasing average useful life of the pipelines are taken into account to ensure the security of supply in other types of infrastructure.

This analysis shows the following decrease in revenue caps over time compared to the status quo:



The reduction in network costs over time shown above is significantly stronger from 2034 onwards. In addition, it is also evident that in the first year of a regulatory period after a new base year the reduction starts again at a lower level. The background to this is the rising maintenance costs while avoiding grid-bound investments. In 2050, the reduction reaches its highest level at 12.5%.

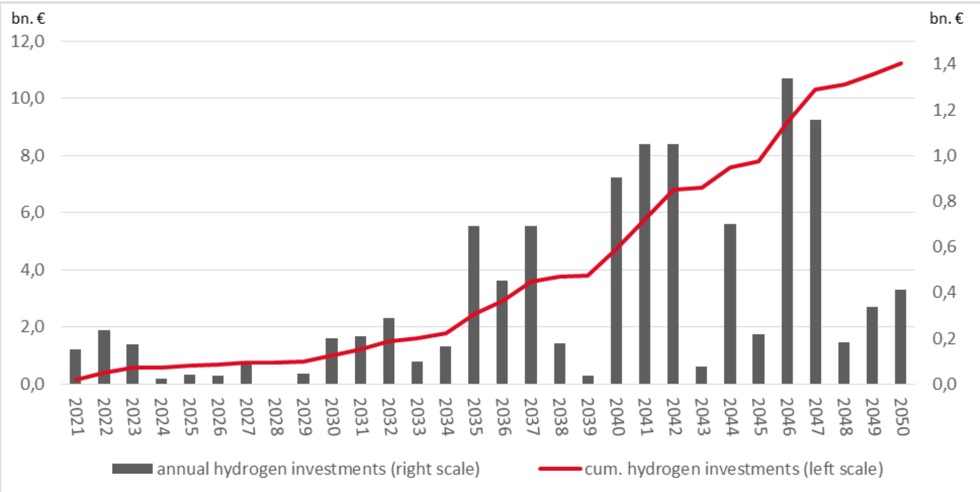
Taking into account a smoothing of the cost reductions within a regulatory period with corresponding period-specific increases, the following annual revenue caps of all network operators in Germany and the resulting annual reductions have been derived, which can be "filled up" by corresponding capital costs from hydrogen investments:



The reason for the comparatively small decrease compared to the original expectation is that the main part of the capital costs included for existing infrastructure until 2034 – the imputed depreciation – will remain almost unchanged. Only after 2034, the existing infrastructure of the older model networks will be fully depreciated and the revenue caps will decrease accordingly.

b) Added value of a combined natural gas/hydrogen network operation

In principle, the above mentioned reductions in the revenue caps would result in the following potential for annual investments in hydrogen networks, which could be refinanced under the same regulatory regime, so that the revenue caps and consequently the costs for network users would remain constant at €5.9 billion:



The reductions in the revenue caps correspond to the potential capital costs of the hydrogen infrastructure. Based on these costs, the annual investment amounts were derived retroactively.. To derive the investment amounts from the capital costs, average useful lives of 45 years were taken into account for the hydrogen pipelines. In addition, we have based this calculation on the imputed rates of return on equity from the heat transition study of 6.8% for the equity-financed assets of up to 40% plus imputed trade tax and an average of 1.7% for the remaining financing (total cost of capital including trade tax 4.1%).

Preliminary result: In total, €11.2 billion can be invested in hydrogen pipelines in the period from 2021 to 2050 (Ø €0.4 billion p. a.) while maintaining the cost level in the status quo.

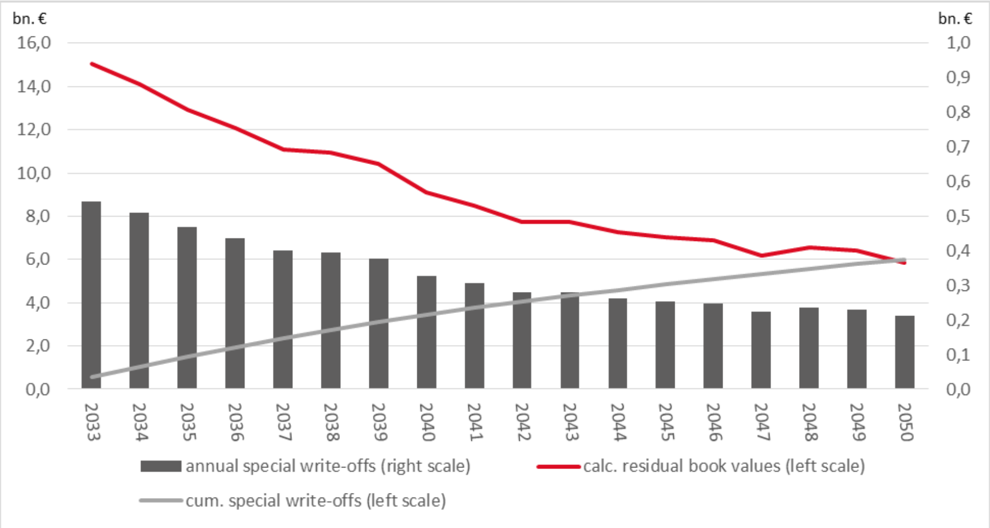
So far, it has not been taken into account in this analysis that towards the end of the period under review before 2050 – in case of a finite natural gas supply – (parts of) the network will have to be dismantled that have not yet been refinanced. It remains open whether it will be the "last" customer or the state that will have to refinance the special depreciation for the asset disposal of other parts of the network. The latter consideration is based on ownership-related considerations in the case of state-initiated decommissioning. If the finite supply of natural gas remains unchanged, these costs will be additional.

The time of decommissioning or dismantling will differ. This also depends on how high the specific network charges of the respective network will be compared to the supply with alternative energy sources (see also below under b.).

The imputed special depreciation for all gas network operators in Germany is estimated on the basis of a simplified derivation. This is based on the respective values from the heat transition study. We have made various estimates, which all arrive at approximately the same level of special depreciation for all gas network operators in Germany. The decisive factor here, however, is the timing of the decommissioning or the special depreciation. The findings of the heat transition study suggest that the decommissioning will start from 2033. The decommissioning will be evenly distributed over the time period from 2033 to 2050. Since the residual book values will decrease over time, the resulting special depreciation will also decrease over time.

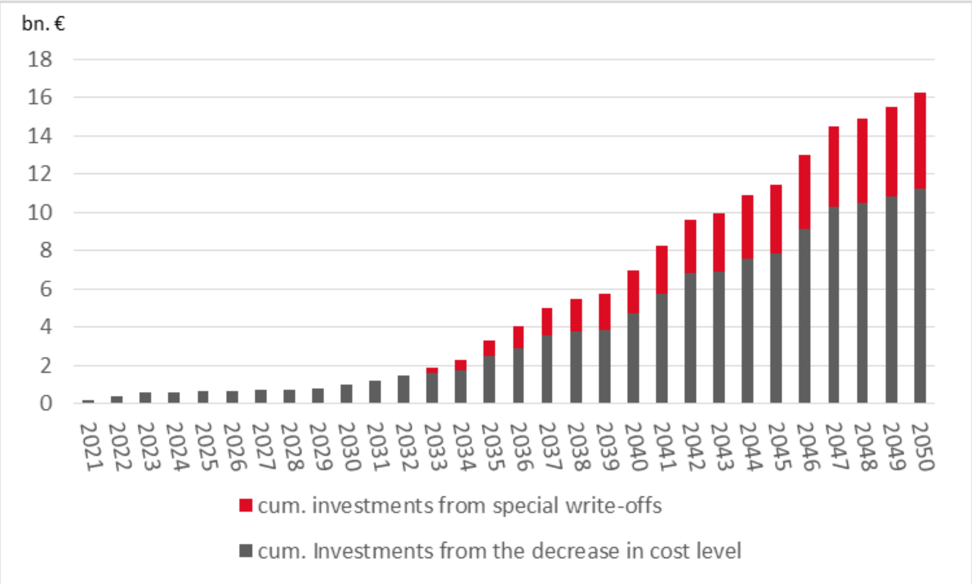
In addition, the proportion of networks that will be decommissioned is also decisive. In particular the transmission networks are unlikely to be decommissioned because, in addition to the pure supply of (space and process) heat, which will largely decline, the power generation and transport will still have to be supplied at certain locations. In our analysis, we have estimated that 65% of the calculated residual values indicated below constitute pipelines that will have to be decommissioned.

This results in the following imputed special depreciation for the period under review:



Thus, the accumulated special depreciation allowances will amount to €6.0 billion. In principle, it is also possible to make investments in hydrogen pipelines in this amount instead of refinancing these special depreciation allowances. However, the potential is slightly overestimated in this context, especially when considering the effects of the cost and revenue cap development described above. This is because after the special depreciation is carried out, no more capital costs are included in the revenue caps. We have also roughly adjusted this effect. As a result of the special depreciation, investments in the amount of €5.0 billion can be made in hydrogen networks. Spread over the period from 2033 to 2050, this amounts to €0.3 billion in investments per annum.

Finding: Taking into consideration the cumulative potential of the decrease in costs and the special depreciation allowances, the following annual investments in hydrogen pipelines can be carried out and financed without causing any additional burden:



The cumulative investment in hydrogen infrastructure amounts to €16.2 billion. In simplified terms, for the 30-year period under review, this results in an annual investment amount of €0.5 billion if the investments are evenly distributed.

III. Sales volume effects

In addition to the effect mentioned above which only relates to the costs of the gas network operators, there is also a sales volume effect which becomes apparent when analysing the specific network charges for the gas network operators. The reason for this is that for pure natural gas network operators (taking decarbonisation effects into account) a significant decrease in sales volumes can be assumed. The cost side can be ignored for the moment.

The findings on the decreasing sales volumes are based on numerous studies on the development of natural gas demand in light of decarbonisation. When assessing the natural gas networks without taking hydrogen into account, it is reasonable to take the demand scenario of full electrification as a basis in relation to the development of sales, since a large part of the gas volumes are currently consumed in the heat supply. In this context, it becomes clear that the specific network charges multiply over time as the demand for gas declines sharply. The reduction in costs over time as described under 1. above will also lead to a huge increase of the network charges.

The decreasing demand is caused by a multitude of individual effects. Some of these effects will be temporary efficiency gains in the heat supply. However, these sales volume effects are irrelevant for the purpose of this analysis, as the costs of the network will remain essentially unaffected thereby and basically the same customers will bear the same costs. In the long term, however, the reason for the decline in sales volumes will be the change in the number of gas customers who will have switched to alternative energy sources. In order to be able to carry out an economic, comparative cost analysis for the envisaged hydrogen supply, it would have to be investigated how many customers can be kept at which marginal prices in the grid-bound supply and how much the total sales volume per year would increase. In economic terms, the investments in alternative energy sources that would have been avoided if customers were not to switch to an alternative supply would have to be systematically included in the analysis. The switching to an alternative energy supply is also dependent on other charges or requirements imposed by the state.

Assuming simply that all customers who could switch to an alternative supply are potentially supplied by hydrogen, our statements under 1. above on the analysis without consideration of sales volume effects apply accordingly.

In other cases, a more in-depth analysis would have to be carried out. Compared to the analysis of the isolated effect of the cost development (result under 1. above) the advantage of such in-depth analysis would probably be that it would lead to a somewhat higher financing potential for investments in hydrogen.

C. Conclusion

As a result, our analysis could confirm the proposition that a combined regulatory framework for natural gas and hydrogen can unlock a considerable financial potential from regulation compared to the status quo. . A rough quantification at the level shown above is possible, at least in relation to the cost volume in the network area. In addition, further effects can be qualitatively assessed.

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