Assistance to the impact assessment for designing a regulatory framework for hydrogen

FINAL REPORT

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GLOSSARY

(r)[n]TPA	**(regulated)[negotiated] Third-party access**: access to an energy transmission infrastructure by another energy provider
ATR	**Auto Thermal Reforming:** Process to create grey hydrogen from natural gas by partial oxidation and subsequent catalytic reforming. When coupled with CCS, blue hydrogen (with various CO_2 capture rates) can be generated.
BEIS	**Business, Energy and Industrial Strategy** department of the UK government
BF-BOF	**Blast furnace and basic oxygen furnace:** most commonly used steel production route, high in emissions
Brownfield	A site which has already been used for infrastructure development
CAM	(Gas) **Capacity allocation mechanism:** Cross-border capacity products at interconnection points between entry-exit zones
CAPEX	**Capital expenditures:** Initial investment required to build a piece of infrastructure
CCS	**Carbon capture and storage**
(C)CfD	**(Carbon) contract for differences**
CMA	**Competition and Markets Authority**
Consumer surplus	An economic term to describe the private benefit to consumers from a market outcome, which is defined as the difference between the price that a consumer is willing to pay and the market price.
DHC	**Depreciated historical costs**
DRI-EAF	**Direct reduction iron and electric arc furnace**: novel, low-emissions steel production route
EC	**European Commission**
EHB	**European Hydrogen Backbone:** Industry initiative focussing on the infrastructure requirements for Europe’s hydrogen future
ETS	**Emission Trading System**
FLH	**Full load hours:** Average (annual) production divided by rated power.
Greenfield	A site which not previously been used for infrastructure development
GHG	**Greenhouse gases**
ISO	**Independent system operator:** Independent system operators/regional transmission organisations provide more extensive grid reliability and transaction support services than TSOs by facilitating competition among wholesale suppliers, providing regional planning, energy and/or capacity market operation, outage coordination, transactions settlement, billing and collections, risk management, credit risk management, and other ancillary services. Across large regions, they schedule the use of transmission lines, manage the interconnection of new generation, and provide market monitoring services to ensure fair market operations for all participants.
KPI	**Key performance indicator**
LCOE	**Levelised cost of energy**
Linepack	**Linepack** refers to the volume of gas that can be stored in a gas pipeline. This stored gas can be used for short-term balancing of supply/demand.
LNG	**Liquified natural gas**
MS	**Member state** of the European Union

NBV	**Net book value**
NC	**Network codes**
Nm^3/d	**Normal cubic metres per day:** Standard unit used for natural gas pipeline flows. Normal means the flow rate was measured at a specified pressure and temperature, so as to be comparable.
NRA	National Regulatory Authorities
OPEX	**Operating expenditures:** Costs of operating a piece of infrastructure
OU	**Ownership unbundling**, one of several possible unbundling options. See also Section 3.2
PEM	**Polymer electrolyte membranes:** polymeric materials used in fuel cells
PPA	**Power purchase agreement**
Producer surplus	An economic term to describe the private benefit to producers from a market outcome, which is defined as the difference between the price they receive in the market and the minimum price they would be prepared to supply for.
RAB	**Regulatory asset base**: Compilation and summation of the assets used in providing the regulated service
RPM	**Reference price methodologies**
SMR	**Steam Methane Reforming:** Process to create blue/grey hydrogen from natural gas by letting the methane react with steam under pressure in the presence of a catalyst. The reaction produces hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide.
SNG	**Synthetic Natural Gas**
TAR	**Tariff network code:** The Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas on the transmission network.
TFEU	**Treaty on the Functioning of the European Union:** one of two treaties forming the constitutional basis of the European Union, the other being the Treaty on European Union.
TPA	**Third-party access**
TRL	**Technology readiness level:** an international system of classification for the development status of a specific technology, ranges from 1 to 9 with 9 closest to full maturity
TSA	**Temperature swing adsorber**
TSO	**Transmission System Operator:** an entity entrusted with transporting energy in the form of natural gas or electrical power on a national or regional level, using fixed infrastructure.
TYNDP	**Ten Year Network Development Plan**
WACC	**Weighted average cost of capital**

EXECUTIVE SUMMARY

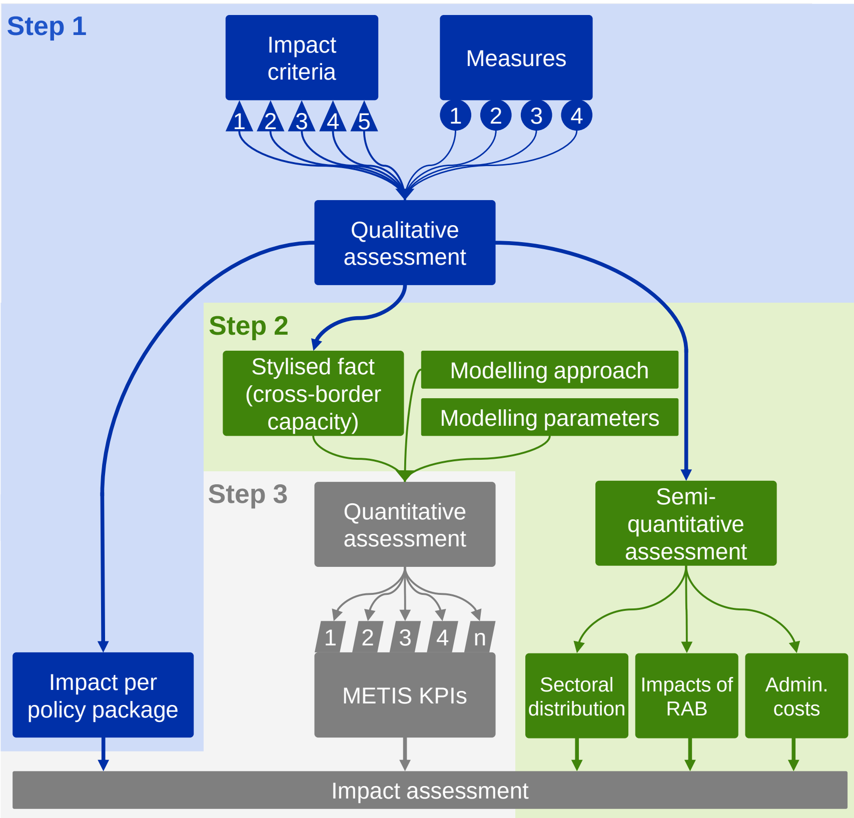
The European Union (EU) set itself a goal of creating at least 40 GW of electrolyser capacity within the EU and a goal of using up to 10 million tonnes/year of renewable hydrogen by around 2030 in line with its goal of climate neutrality by 2050 target. Much of this hydrogen is expected to be delivered through a pipeline network akin to the existing gas grid. The European Commission (EC) is considering which regulation, if any, should cover the build-out and operation of this hydrogen network, especially across EU Member States (MSs). The expected rulemaking requires the EC to publish an impact assessment before it can be adopted.

This report presents:

- An overarching framework for the impact assessment of regulations that could be used for the EU hydrogen market
- A qualitative assessment of the key regulatory measures against principal impact criteria within this framework (*hydrogen market structure, cross-border integration, administrative costs, investments incentives for new hydrogen infrastructure, repurposing of natural gas pipelines*), as well as their effect as part of example policy packages
- Several methods for quantifying or semi-quantitatively assessing indicators for the future EU energy system under various scenarios and assumptions that can be expected to differ across EU hydrogen policy packages

Figure 1-1 sets out these elements and their relationship. Steps 1 and 2 form part of this report, step 3 and the final impact assessment represent work that will follow afterwards.

Figure 1-1 Approach overview



Our findings are summarised in the following sections. Table 1-1 lays out the overall draft EU policy packages (called 'Options') and their disaggregation into four key policy measures. Note that Option 1 does not differentiate along these measures but represents a tendering approach.

Table 1-1 Overview of draft EU policy packages and regulatory measures

	BAU No additional measures	**Option 1** Competition "for the market"	**Option 2** Main regulatory principles + provision of exemptions/ derogations		**Option 3** Detailed rules at EU level	
		1: Rights for network operation tendered	2a: Light regulation	2b: Intermediate regulation	3a: ISO model	3b: EU hydrogen TSO
Individual measures per policy option						
Vertical unbundling	-	-	Accounts unbundling	Legal + functional unbundling	ISO/Ownership unbundling	EU TSO (ISO model)
TPA	-	-	nTPA	rTPA for repurposed assets	rTPA	rTPA
Tariff regulation	-	-	Cost-reflective tariffs	Cost regulation for repurposed assets	Revenue regulation	Revenue regulation
Horizontal unbundling – Default	-	-	-	Separate RAB (accounts unbundling)	Separate RAB (accounts unbundling)	Separate RAB (accounts unbundling)
Horizontal unbundling – Alternative	-	-	-	Joint RAB	Joint RAB	Joint RAB
Tendering	-	At national level	-	-	-	-

Against the same policy packages, Table 1-2 shows the results of the qualitative assessment and the structure for the quantitative results (which will be collected in a separate study in Step 3). The contents of Table 1-2 are explained in the remained of this summary.

Table 1-2 Overview of results[1] of complete impact assessment

	BAU	Option 1	Option 2		Option 3	
		1	2a	2b	3a	3b
Impacts qualitative assessment (without regulatory exemptions)[2]						
Market structure	-	0	0	0/-	++/0	+
Cross-border integration	-	0	0	+	+	++
Administrative costs	+	0	-	-	-	-
Investment incentives/barriers	+	0	0	-/0	-/0	-
Repurposing	+	-	0	0/+	0/+	0
Stylised fact used in modelling of impacts						
Cross-border transport capacity	BAU	"A constrained"				"A optimised"
Impacts – quantitative assessment						
Total energy system cost difference to BAU [Bn EUR]	n/a	-0.70				-1.34
Average cost of hydrogen delivery (incl. transmission; EU weighted average) [EUR/kg H_2 (HHV)]	2.3	2.1				1.7
Average renewable share of the hydrogen produced (EU weighted average) [%]	80	75				77
Weighted average market emission factor for electricity used for hydrogen generation (EU weighted average) [$kgCO_2eq/MWh$]	26	20				12
Weighted GHG emission intensity of the hydrogen produced (EU weighted average) [$kgCO_2eq/MWh$ H_2 (HHV)]	19	15				9
Ratio of electricity sold and bought by the electrolysers versus total electricity sourced [(%) total $Electricity_{sold+bought}$/ total $Electricity_{consumed}$]	55	57				60
Volumes of hydrogen loss of load [TWh H_2 (HHV)]	6.2	2.5				0
Hydrogen interconnection capacity:new [GW]	0	10				27
Hydrogen interconnection capacity:repurposed [GW]	0	19				44
H_2 interconnection utilisation (EU weighted average) [%]	n/a	40				54
Total electrolyser capacity [GW_{H2}]	56	49				42
Total hydrogen production [TWh H_2 (HHV)]	194	198				220
Impacts – semi-quantitative assessment (in comparison to BAU)						
Impact of transport costs on sectoral distribution	n/a	Differ by sector and depend on subsidy scheme structure				
Impacts of joint versus separate RAB on tariffs	n/a	Impacts H_2 tariffs: likely small c.f. total H_2 costs. Impacts NG tariffs: small.				
Administrative costs [EUR million]	n/a	~5	~10–25			~30–50

Legend					
	- -	-	0	+	+ +
	Very low Administrative costs: very high	Low Administrative costs: high	Neutral / No clear impact	High Administrative costs: low	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

[1] NB: The quantitative results inserted here in the middle section of the table come from separate study by Artelys using the METIS model at EU level. Therefore, the exact indicator names and units differ slightly from the table in the Synthesis section.

[2] The qualitative assessment is undertaken on the assumption that the regulatory measures in each package are applied to all pipelines. In case certain pipelines (e.g. new pipeline investments) are granted exemptions from certain measures (e.g. TPA, vertical unbundling, tariff regulation) equivalent to regulatory exemptions for gas and electricity infrastructure, the assessment may differ. For example, the negative effects on investment incentives in draft policy packages 2 and 3 can be tackled with exemptions for new pipelines, while providing long-term certainty about the regulatory regime for a significant part of the asset lifetime (e.g. 20 years). Depending on the specifics of the exemption (e.g. duration), positive effects of regulation on market structure and cross-border integration can be largely maintained with an exemption regime.

Qualitative assessment findings

The qualitative assessment scrutinised individual regulatory measures and potential packages of regulatory options as suggested by the EC (policy packages). The main findings, structured by the EC's draft policy packages, and shown in the top part of Table 1-2 ,are as follows:

An approach that does not entail regulatory measures (business as usual [BAU]) provides commercial freedom to enter into long-term agreements and secure investments at bilaterally agreed-upon terms. This may facilitate investments in an early phase of hydrogen market development. However, the no-regulation approach bears the risk of vertically integrated, monopolistic network operators, with potentially negative implications for transport tariffs, hydrogen uptake and ultimately for decarbonisation targets. Under this approach, network operators will develop pipeline networks in a bottom-up approach likely to result in a dispersed and uncoordinated network development across the EU with less cross-border capacity than the other regulatory packages.

Under a tendering approach (competition for the market), the level of investment incentives and cross-border integration depends strongly on the details of the approach and may become a politically driven decision rather than a market result. Similarly, creating appropriate repurposing investments is very challenging. Unless the concession is associated with conditions regarding Third-party access (TPA), vertical unbundling, or tariffs, the impacts of this approach bear the risk of monopolistic network tariffs with potential negative implications for the hydrogen uptake and decarbonisation targets.

A stricter regulatory approach, which includes a TPA requirement, vertical unbundling, horizontal unbundling (separate regulatory asset base (RAB)) and tariff regulation (such as Options 2b, 3a and 3b) may impede incentives to invest in hydrogen pipelines, which broadly includes incentives for repurposing investments. A (tariff) regulation imposes asymmetric risks for investors, which may render investments unattractive, but could be avoided by allowing for temporary regulatory exemptions (regulation holidays) for new investments while providing certainty for investors over the duration of the exemption (which a BAU pathway may not be able to provide given that regulation may be introduced and applied after investments have been made). While a light-touch regulatory approach (such as Option 2a) might not be sufficient to achieve the key objectives of the introduction of infrastructure regulation (e.g. increase cost efficiency, reduce infrastructure costs, enable competition in business activities upstream and downstream of the infrastructure), which has been observed in the electricity and gas markets, a stricter regulatory approach can generally help to achieve these objectives. The introduction of regulation generally also facilitates cross-border integration.

An EU regulation with a common RAB (alternatives for Options 2 and 3) allows gas transmission system operators (TSOs) to cross-subsidise hydrogen network costs through natural gas consumers. This facilitates investments in hydrogen networks, particularly in early development periods where hydrogen networks based on repurposed natural gas pipelines are likely under-utilised. A joint RAB approach is expected to result in lower network tariffs for hydrogen consumers than a separate RAB approach (in the absence of other forms of support for hydrogen networks in the separate RAB approach). This may help increase incentives for consumers to switch to hydrogen, particularly in an early market ramp-up period, and thus supports the hydrogen uptake. With a joint RAB, hydrogen and natural gas network tariffs would however no longer be cost-reflective, i.e. natural gas users could end up paying for the hydrogen network. Given that natural gas users and hydrogen users will likely represent different consumer groups (primarily residential customers versus primarily industrial customers), this could lead to cross-subsidisation between these groups.

Quantitative assessment

We defined a range of parameters that are expected to have impacts on KPIs of the future hydrogen market.

- Cross-border hydrogen transport capacity
- Electrolyser operation model
- Electrolyser capacity per MS
- Hydrogen transport fees
- Hydrogen pipeline CAPEX

These parameters will be assessed quantitatively in 14 model runs using METIS. The first of these parameters, the cross-border hydrogen transport capacity, is expected to vary significantly depending on the regulatory policy package chosen (see Table 1-2).

The scenarios will be compared based on eleven key performance indicators (KPIs) from METIS which Table 1-2 describes.

Semi-quantitative assessment findings

We also created semi-quantitative, high level assessments for several impacts that could not be quantified with METIS, namely demand reach, administrative cost estimates, and considerations on joint versus separate RAB.

Sectoral distribution effects

Hydrogen regulation may have an influence over which end users can be connected to the hydrogen network. We explored which hydrogen end uses should be prioritised from a societal value perspective. A hierarchy of hydrogen uses can be defined:

1) using hydrogen where no alternatives for hydrogen exist (feedstock applications)
2) using hydrogen where it is likely the optimal technology long-term (after 2030)
3) using hydrogen in applications where alternative technologies can offer higher efficiency and better economics.

In specific situations this hierarchy might be different, and a more holistic assessment is required to prioritise hydrogen applications in policymaking.

Our analysis shows that most end uses in the first category are (in the absence of TPA regulation) more likely to be connected to the hydrogen network than end uses in the other categories, because they offer larger scale and lower risk for the pipeline operator.

The impacts on sectoral distribution are affected by whether transport costs are included in demand side subsidy schemes. If transport costs are included, a lack of regulation is expected to increase the subsidy need and if subsidies are capped, this leads to lower hydrogen uptake and an increased use of alternatives. As these alternatives are mostly electric, this might result in an even higher level of electrification which may be associated with balancing issues and higher total system costs. If transport costs are not included in subsidy schemes, an unregulated network is also expected to delay hydrogen uptake and related decarbonisation benefits.

RAB

For the discussion on joint versus separate RAB our findings include:

- Joint RAB slightly decreases natural gas tariffs compared to the starting position (before repurposing) as natural gas network utilisation increases and additional energy (hydrogen) transported is part of the same RAB. Compared to separate RAB, hydrogen tariffs are lower. This outcome might be desirable to facilitate hydrogen network ramp-up (unless other options to support hydrogen infrastructure are pursued, such as explicit subsidies); however, it leads to a (distributional) disadvantage of natural gas users cross-subsidising hydrogen end users.

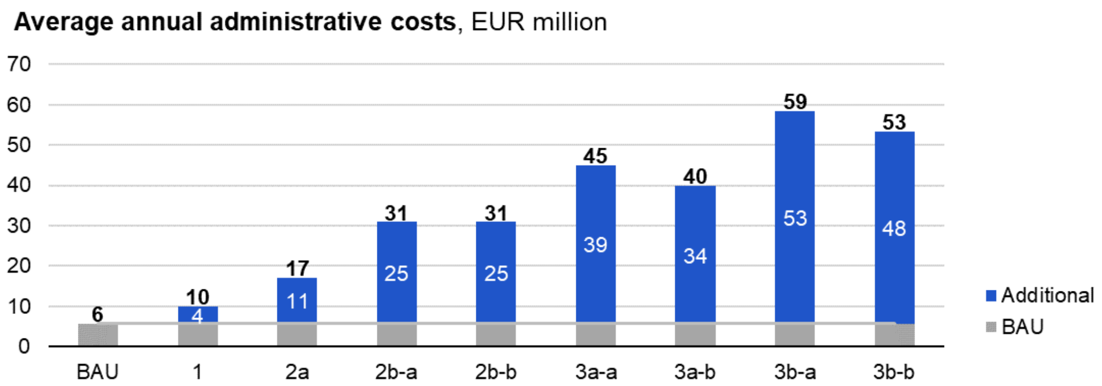
- Separate RAB decreases natural gas tariffs further (compared to joint RAB) as the network capacity utilisation increases but allowed revenues decrease. The hydrogen tariff is much higher compared to joint RAB as it is cost-reflective.
- The tariffs should be read in comparison with the expected other (especially production) costs in the hydrogen value chain. The production cost alone (especially for renewable hydrogen) will likely be between EUR 2/kg–EUR 4/kg (EUR 60/MWh–EUR 120/MWh) up to 2030. In comparison, even the highest calculated hydrogen tariff only results in ~EUR 6/MWh.

However, this picture presents just one possible interpretation of these effects and large uncertainties exist. The many regulatory and accounting details that set the RAB methodologies in different MSs drive these uncertainties. Hence a full evaluation of these effects for a given combination of regulatory principles and methodologies would have to be performed across MSs. Alternatively, the EC could consider setting a general regulatory framework for the hydrogen market (e.g. setting the need for either joint or separate RAB, standardised CBA methodology, and possibly asset valuation methodology), but leave the specific decision for either joint or separate RAB to the regulatory bodies at the MS level.

Administrative costs

Our high-level estimate of administrative costs shows that higher costs are expected for the draft policy packages under option group 2 and 3 compared to option group 1. These costs need to be compared to the overall costs or benefits from regulation which will be determined in the quantitative modelling. It is likely that the modelling will show a significant overall benefit of regulation much larger than these estimated administrative costs.

Figure 1-2 Results of administrative cost assessment by draft policy package



Next steps

Artelys will run the 14 METIS scenarios and create the quantitative results by scenario for the 11 impact indicators. These results, in combination with the findings from the qualitative and the semi-quantitative assessments, will then form the basis for the EC's full impact assessment on regulations for the hydrogen infrastructure

The 14 scenarios consist of

- 3 default scenarios which differ on the stylised fact of cross-border capacity and are expected to show the spectrum of possible impacts of the five draft policy packages (see Table 1-2 and Figure 3-2)
- 11 scenarios investigating sensitivities on various modelling parameters showing the range of possible outcomes in the KPIs (see Table 4-12 and Table 4-11).

Note that, for the sake of concreteness in the quantitative assessment, we have made specific, distilled, quantitative assumptions for the modelling parameters based on findings from the qualitative assessment. When interpreting the results of the quantitative modelling, however, the nuances of the full qualitative assessment should also be included.

1. INTRODUCTION

The European Commission's (EC's) Hydrogen Strategy signals that the EC considers renewable and low carbon hydrogen as indispensable in achieving the EU's climate neutrality by 2050 target. It targets the production of up to 10 million tonnes/year of renewable hydrogen by around 2030 and the creation of at least 40 GW of electrolysers to produce green hydrogen. The EC is considering what regulation it should propose to support the nascent hydrogen market and lay the groundwork for its future development. The EC communicated that it aims to publish a regulatory proposal during Q4 2021.[3]

As part of its rulemaking process, the EC commissioned Guidehouse and Frontier Economics to create the framework for assessing the impacts of possible regulation on the future EU hydrogen network.

The ideal regulation should serve two objectives simultaneously: to allow an efficient build-up of a hydrogen market while steering towards creating an integrated and efficient infrastructure backbone and market structure. While the immediate objectives of regulation are economic in nature, the eventual goal is to facilitate the decarbonisation of the EU economy.

In the EC's own words: "*The creation of a regulatory framework for pure hydrogen networks should lead to investment certainty that is needed for the uptake of renewable or low carbon hydrogen in the upcoming years. The final aim as stated in the European Commission's Hydrogen Strategy is to complete an open, competitive EU hydrogen market with unhindered cross-border trade and efficient allocation of hydrogen supply among economic sectors by 2030.*"

There are two key challenges in creating the impact assessment framework for the proposed rulemaking:

- **A fine balance needs to be struck between over- and underregulating**: From experience in other markets, a lower degree of regulatory intervention (e.g. allowing vertical integration) could facilitate the required coordination between infrastructure and the business structures and processes, but often at the price of a lack of competition and the related benefits. In contrast, a strong regulatory framework (e.g. explicitly setting tariffs models) has the advantage of enabling competition up- and downstream of the infrastructure but can carry the risk of decreasing incentives to invest in infrastructure and hamper market development.
- **Past experience has limited applicability in the early phase of the hydrogen market:** The objective of introducing regulation to energy markets, such as power or natural gas, was to introduce competition and to build an integrated market on the basis of an already sophisticated infrastructure and with existing players. In contrast, creating a hydrogen market in Europe in the period from 2020 to 2030 requires greenfield approaches to regulation.

1.1. Objective of this study and connection to other assignments

The purpose of this study is to create a holistic impact assessment framework for the possible regulatory measures for the creation of a hydrogen network in Europe.

The study draws on the November 2020 report by Trinomics and Ludwig Bölkow Systemtechnik titled *Sector integration – Regulatory framework for hydrogen* (van Nuffel, et al. 2020), as well as a variant of the PRIMES *MIX55 H_2* scenario that establishes a path for hydrogen development in the coming decades. The EC will use the outcomes of this study to assess the impacts of its proposed regulation, using several tools including the METIS EU energy model.

Our study focusses on 2030 as the timeframe for the EC's Hydrogen Strategy. Based on the PRIMES scenario this implies around 150 TWh (~4.5 million tonnes, LHV) of renewable hydrogen being used across the EU, i.e. not yet a mature hydrogen market. However, within

[3] As stated in the consultation document 'Gas networks - revision of EU rules on market access', published 10 February 2021, https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12766-Revision-of-EU-rules-on-Gas-

this overall picture, a maturing market may emerge within some MSs (e.g. in North-West Europe).

Although the impact assessment framework will focus on 2030, pathway considerations for the period up until 2030 and the period after 2030 need to be considered in the overall policymaking process because this is a highly dynamic moment in the development of this market. Where applicable, we have considered the outlook after 2030 in our discussion.

1.2. Structure of this report

The remainder of this report is structured into the following parts. Chapter 2 presents the overall methodology we have employed for creating the framework for the impact assessment. This methodology differentiates between a qualitative and a quantitative assessment. Chapter 3 then presents the qualitative assessment per regulatory measure and for the draft policy packages. Chapter 4 lays out the quantitative assessment approach, including three stand-alone semi-quantitative assessments. We synthesise our findings in Chapter 5 and supplement with additional considerations on technical regulation and an outlook to 2040. The report concludes with the bibliography (Chapter 6) and annexes on hydrogen purity considerations and the cross-border capacity approach in Chapter 7.

This is a joint report by Guidehouse Netherlands B.V. and Frontier Economics Limited. Frontier Economics led the qualitative assessment analysis. Guidehouse was responsible for the quantitative assessment approaches and the overall report.

2. METHODOLOGY

2.1. Assumption on market status in 2030

Our assessment will assume that the EU facilitates the scale-up of green and blue hydrogen, and **comes close to its strategic objective** as set in the Hydrogen Strategy to install at least 40 GW of renewable hydrogen electrolysers by 2030 in the EU, in addition to quantities of low carbon (e.g. blue) hydrogen.

Given this target, and considering the current and expected lack of competitiveness of renewable and low carbon hydrogen in the timeframe to 2030, we assume that there are **measures in place that foster the emergence of at least basic (national) market(s)** for green or low carbon (e.g. blue) hydrogen, or both. These measures may include supply side support mechanisms such as contract for differences (CfDs) for green or blue hydrogen generation, or demand side measures such as low carbon gas or hydrogen quota obligations. We do not assess any variations in these out-of-market measures, but instead focus on the impact of possible regulatory measures.

Although the impact assessment framework will focus on 2030, we will also reference developments before and after 2030 that should be considered in addition to this impact assessment, when devising the overall policy packages. This is important because of the nascent nature of the hydrogen market up to and immediately after 2030.

2.2. Analytical approach to creating the impact assessment framework

Our approach consists of several interlinked steps, shown in Figure 2-1. It builds on the EC's previous work on this topic and has been designed with outputs from several discussions with DG ENER as part of this project. It also aims to leverage existing energy scenarios from the EC's in-house models, which assess the impacts of the EU's climate package.

Step 1: Holistic, qualitative impact assessment framework

a. *Understand qualitative impacts of policy measures.* We assess the regulatory measures against a set of criteria (hydrogen market structure, cross-border integration, administrative costs, investments incentives, repurposing), which reflect the EC's plan for the development of a hydrogen market.
b. *Combine these to assess the expected impact of the regulatory packages.* The assessment of the individual regulatory measures against the criteria (in a.) is used to draw conclusions on the EC's draft policy packages. Where possible, strategies for quantitative assessments are outlined.

In addition, we will derive quantitative backing of those impacts where possible.

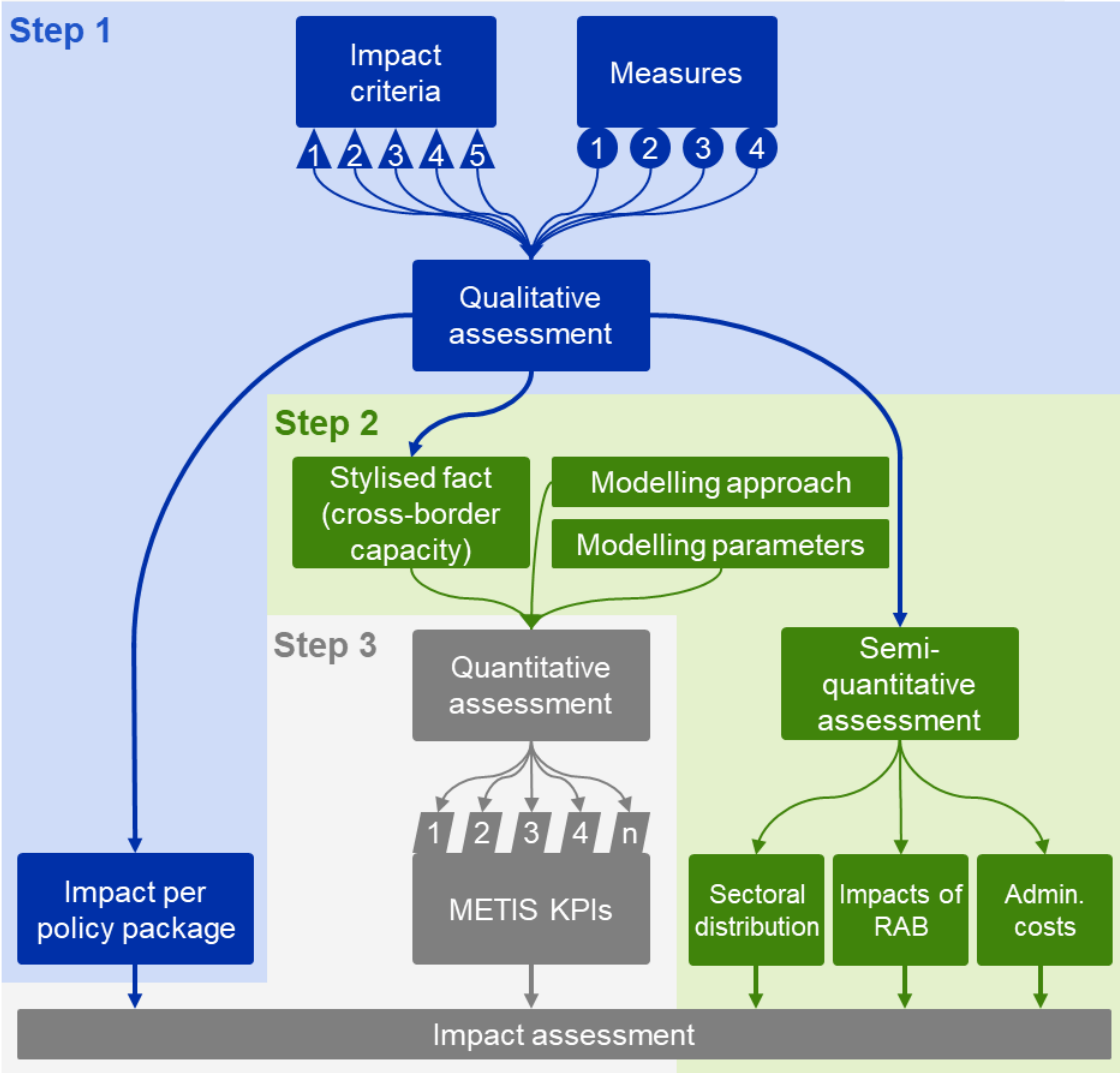
Step 2: Quantitative impact assessment using the METIS power and gas model

a. *Translate qualitative impacts into expected effects on the hydrogen markets (stylised facts).* The stylised facts are used to create comparative scenarios to illustrate possible hydrogen market developments with enough distinction so that the effects of Step 1 can be analysed in the quantitative modelling.
b. *Develop a modelling approach to model the quantifiable system implications.* A modelling approach is developed in collaboration with the METIS team.
c. *Derive semi-quantitative observations where direct modelling is not feasible.* In parallel to the METIS modelling, we perform additional analysis of the expected effects in several specific areas to complement the results of the modelling.

Step 3: *Full impact assessment [out of scope of this study]*

a. *Explore indicative impacts post-modelling.* Finally, the impacts of the quantitative, semi-quantitative, and qualitative analyses are combined to develop the impact assessment for hydrogen regulatory framework.

Figure 2-1 Overall study approach



The following sections outline the approach to each of the steps above. The remainder of the report is structured into the same sections with a Synthesis chapter at the end.

2.3. Holistic, qualitative impact assessment framework

The EC's impact assessment framework will rely on a qualitative assessment of the regulatory options and will, where possible, be substantiated by quantitative analyses. The main regulatory measures used for the assessment in this report include:

- Third-party access (TPA)
- Vertical unbundling
- Horizontal unbundling
- Tariff regulation

We assess the regulatory measures against criteria reflecting the EC's intention for the development of a hydrogen infrastructure. These criteria cover the impact of the regulatory measures on the following items:

- Hydrogen market structure
- Cross-border integration
- Administrative costs
- Investments incentives for new hydrogen infrastructure
- Repurposing of natural gas pipelines

The assessment of the regulatory measures against the criteria then informs conclusions on the EC's draft policy packages, which is a central output of the assessment framework.

We build on the qualitative assessment framework to define approaches for a quantitative assessment. This involves the discussion of relevant parameters and the definition of an effective methodology.

2.4. Quantitative assessment

To quantify the impacts of the regulatory packages as much as possible, existing EC models are used: PRIMES outputs of scenarios developed for the "Fit for 55 Package" are used to define the overall hydrogen demand level for all modelling as well as the pathway for renewable capacity deployment in 5 year steps.

METIS is subsequently used to model the interplay between the nascent hydrogen, gas, and electricity markets under different hydrogen market setups for one model year around the target year of 2030 for the Hydrogen Strategy. Section 4.1.3 describes key indicators from the METIS modelling. The first model runs will show which of the other METIS indicators show significant differences between regulatory packages.

To quantify the qualitative impacts, we translate them into expected changes in the market (stylised facts), using available literature and databases. We construct scenarios where relevant.

To enhance the modelling, we also review key input parameters of METIS and suggest modifications to model parameters where relevant. For uncertain (or arbitrary) inputs we propose several sensitivity analyses to analyse their impact on the modelling outcomes.

Chapter 4 describes the approach in detail.

2.5. Semi-quantitative assessment

In addition to the overarching impact assessment framework, two questions arose during discussions with the EC that cannot be answered through our full qualitative and quantitative approaches and so merit an independent discussion.

2.5.1. Sectoral distribution effects

One question not answered by the METIS modelling is which share of demand for hydrogen per sector would be served depending on the scale of network build-out, and what the value is of serving more (or other) sectors with additional transport infrastructure.

In the PRIMES scenarios that form the basis for the overall demand assumption for our assessment, no explicit restrictions are applied to hydrogen grid build-out, i.e. a well-integrated hydrogen market is assumed.[4] In that scenario, by 2030 most clean hydrogen would be delivered to users in the transport sector and a smaller amount is delivered to industrial consumers.

However, when considering network optimisation, including economies of scale, it could be that most clean hydrogen is transported to large offtakers that are near supply centres and near existing natural gas infrastructure that can be repurposed for hydrogen transport. This leads to a more concentrated network in certain regions. More distributed consumers (e.g. transport) would not have access to hydrogen.

We quantify (in directional terms) which sectors may be served best in a restricted hydrogen infrastructure situation (i.e., situation in which it might not be cost effective to connect all

[4] Note that PRIMES does account for the costs of building hydrogen network infrastructure. The model also distinguishes between the "direct" use of hydrogen and the injection / blending of hydrogen in the gas grids. Costs of expanding the network infrastructure are included for all energy carriers but not in an explicit pipeline by pipeline manner.

potential end-users to the dedicated hydrogen infrastructure), and how that can deliver or limit societal value from clean hydrogen.

2.5.2. Indicative impacts of the Regulatory Asset Base models on natural gas and hydrogen tariff structures

Decisions on the RAB models and related aspects, such as depreciation methodology, level of unbundling, cross-subsidisation, or cost-reflectivity will have major impact on determining future tariff structures for both natural gas and hydrogen (assuming that a strong horizonal unbuilding is not required). Additionally, RAB models (along with the other elements mentioned previously) will likely impact gas TSOs' ability to finance development of the hydrogen infrastructure, be it repurposed or new.

Our understanding is that the EC wishes to incentivise the development of the hydrogen transmission level infrastructure as efficiently (e.g. repurposing of NG pipelines) and effectively (e.g. extensive network) as possible. In that context, it is important to remember that different national regulatory regimes for gas TSOs exist across the EU. Consequently, there is no fit-for-all conclusion regarding the suitability of one RAB model over another. Rather, we focus on explaining the possible indicative impacts of different RAB models and various starting conditions on the natural gas and hydrogen tariffs. Such high-level analysis can help the EC understand what level of regulation regarding RAB needs to be set on a European versus national level.

3. HOLISTIC, QUALITATIVE IMPACT ASSESSMENT FRAMEWORK

This section sets out a holistic approach to assesses the impact of different forms of regulation. It is structured into the following three steps:

1. We discuss the inputs to the assessment framework (3.1), which include the **individual regulatory measures** (3.1.2) in the context of an evolving hydrogen infrastructure and the **key criteria** (3.1.3) for the assessment. We then provide a **qualitative assessment** (3.2) of the regulatory measures against the key criteria.
2. Based on the mapping of the key regulatory measures to the EC's draft policy packages and the discussion in Section 3.2, we apply the qualitative assessment to these draft **policy packages** (3.3).
3. Based on the identified implications for each of the draft policy packages we outline **approaches for a quantification** (3.4) of the different implications.

3.1. Approach and inputs to the assessment framework

3.1.1. The qualitative assessment framework must draw on analogies and experiences from existing regulated markets

As the Introduction describes, the key challenge of an impact assessment for a regulatory framework for hydrogen is that most elements of such a framework only have been implemented in more mature markets to date. Therefore, although ample experience is available from, for example, natural gas and power markets, their effects on a nascent sector such as hydrogen often have not yet been tested.

This section develops a qualitative impact assessment framework, which suggests the following:

- Draw on analogies to existing markets where possible
- Highlight potential caveats and limitations where the hydrogen market (in 2030) likely will require an individual assessment

The discussion of a regulatory framework for hydrogen infrastructure covers many aspects that were deliberated over the past two decades during the evolution of the regulatory framework for natural gas. This is because, especially with respect to the transmission network, there are **significant similarities between the characteristics of the (expected) hydrogen market and existing energy markets**, such as those for gas and electricity. Similar to gas and electricity, hydrogen is going to be an infrastructure-based commodity market. There are other strong analogies with natural gas, which requires a similar infrastructure and is also sourced across long distances.

Today, the gas and electricity markets are characterised by a large number of producers and consumers that need access to infrastructure and liquid trading of the underlying commodities. The infrastructures for gas and electricity are interconnected, both within and across countries, allowing the commodities to be transported across markets and geographies. In contrast, the **hydrogen market within the EU is still at an early stage** with few consumers and producers, low trading volumes, and little interconnected infrastructure compared to the gas and electricity environments in the EU.

Although there are strong parallels between the characteristics of such infrastructure-based commodity markets, a **simple transposition of the existing natural gas market regulation to the hydrogen market might not be appropriate** as there is no mature (hydrogen) market to build on. The hydrogen market is nascent in that there are only a limited number of big producers with mainly point-to-point connections to large consumers, but there is not yet a substantial number of producers and consumers needing access to a reliable meshed network. The impact assessment must examine which regulatory elements are justified in the case of such a nascent market. For example, regulatory elements of the framework for natural gas such as detailed balancing rules might not be relevant for today's largely non-interconnected hydrogen infrastructure. Other regulatory elements could also hamper investments in this nascent market and make it difficult to reward risk-taking. On the contrary some form of regulation will be crucial to provide clarity to market participants. A balanced assessment will need to be undertaken to identify the relevant regulatory measures.

Time is a key consideration given the likely highly dynamic development of this market over the coming years. **In the long term, a large part of existing natural gas regulation could be made applicable to hydrogen and hydrogen infrastructure**. However, until we observe mature hydrogen markets across the EU, regulation will have to reflect the local market maturity. The design of the hydrogen regulation will depend on the market maturity while simultaneously enabling and supporting the market to become more mature and competitive.

The regulatory measures under deliberation for the future hydrogen regulation are similar to the existing regulatory measures in other markets. To date, there is no experience on what these regulatory measures imply precisely for hydrogen markets or for nascent markets. Instead, there is a significant amount of **knowledge and experience that built up throughout the different regulatory phases for other markets**, such as electricity and gas.

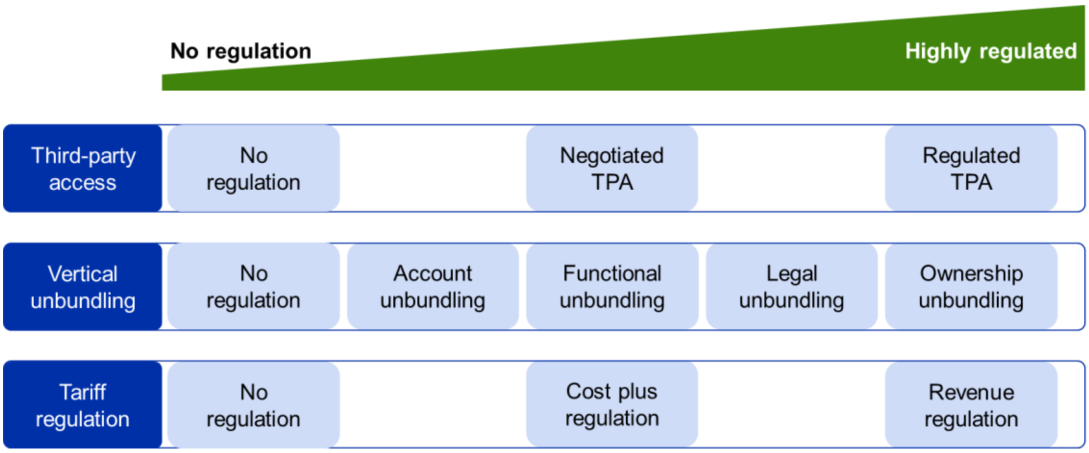
As a result, the EC can and should draw on this knowledge and experience when preparing a regulatory framework for hydrogen but also reflect on the differences between the market maturities and characteristics of hydrogen and other infrastructure-based commodity markets. In the following impact assessment framework, we will draw on the existing experience to outline the potential implications for hydrogen regulation, covering potential analogies and shortcomings for transferring knowledge between the regulatory approaches.

3.1.2. The regulatory measures

The discussion of a regulatory framework for hydrogen infrastructure includes many aspects deliberated on during the evolution of the regulatory framework for natural gas over the past 2 decades. These largely include measures that address the tendency towards insufficient competition, which results from the existence of natural monopolies. The main measures include vertical unbundling, third-party access, and tariff regulation, which all aim to enable well-functioning markets with effective competition on upstream and downstream markets. Each of these measures include a number of possible manifestations, which Figure 3-1illustrates:

- **Third-party access (TPA)** aims to allow all companies that pursue related activities (e.g. hydrogen producers or suppliers) to have non-discriminatory access to the infrastructure. Manifestations include:
  - **Negotiated TPA**
  - **Regulated TPA**
- **Vertical unbundling** separates activities of an economic operator on different levels of the value chain, differentiating between regulated and unregulated activities. Vertical unbundling can be implemented in different ways, including:
  - **Account unbundling**
  - **Functional unbundling**
  - **Legal unbundling**
  - **Ownership unbundling**
- **Tariff regulation** implies that the regulator determines the allowed or target revenues for regulated activities and provides the methodology or sets principles for the determination of the network tariffs. This can be done based on various principles, such as:
  - **Cost plus regulation**
  - **Revenue regulation**

Figure 3-1 Illustration of the spectrum of regulatory intensity for three of the four measures



Beyond these conventional regulatory measures (with a track record from natural gas and electricity regulation) there are other elements to consider for the design of the regulatory framework for hydrogen infrastructure. In light of the similarities between the infrastructures for natural gas and hydrogen, the potential to repurpose natural gas pipelines and the increasing coupling between different sectors (e.g. electricity, mobility, heating, industry), the key additional regulatory dimension to consider for hydrogen infrastructure regulation refers to:

- **Horizontal unbundling** captures the question to what extent and under which framework companies will be allowed to pursue activities in different regulated fields (such as the operation of natural gas and hydrogen infrastructure). This includes the debate of whether these regulated activities can be kept within the **same asset base** (with potential for common tariffs for natural gas and hydrogen network users) or whether they will have to be kept in **separate asset bases** (accounting unbundling).[5]

3.1.3. Assessment criteria

This section summarises the criteria for assessing possible measures for the design of the regulatory framework, which the previous section developed. Criteria is derived from the objectives for the overall market development as outlined in the Introduction.

The regulatory measures are assessed against the following criteria:

1. **Hydrogen market structure (with given transport capacity)**: Regulatory measures are predominantly introduced to avoid monopolistic market outcomes, which are likely to occur in infrastructures such as gas and hydrogen networks. These monopolistic market outcomes would likely manifest themselves through the emergence of (higher) prices or (lower) quantity settings, which affect the overall hydrogen market structure (competitive vs monopolistic) across the EU. Such monopolistic market outcomes have allocative implications (lower than optimal social welfare) and distributional implications (higher producer surplus and lower consumer surplus compared to competitive market outcome). This criterion probes the ability of the regulatory measure to avoid these adverse market outcomes.
2. **Cross-border integration**: One quantifiable output of different regulatory regimes is the cost impact of (physical) cross-border integration. To assign this potential benefit of physical integration to regulatory measures, we will assess the ability of different manifestations of a particular measure (e.g. no TPA vs. nTPA vs. rTPA) to lead to (physical) cross-border integration. Such effects could in turn allow

[5] See for example the current discussion in Germany, where the government has proposed a system with separate RABs and faces strong opposition by natural gas TSOs (energate 2021). ACER and CEER recently also published their view, arguing for separate RABs (ACER and CEER 2021).

realisation of the net-benefits of cross-border integration (in case we identify net benefits).

3. **Administrative costs**: Regulations carry administrative burdens, for regulated companies and for regulatory authorities on a national and an EU level. These administrative costs include resources that can be closely assigned to the regulation such as a TSO's resources for reporting and implementing regulatory requirements and National Regulatory Agencies' (NRAs') costs for regulating and monitoring. The costs are likely to be higher with tighter regulation (i.e. closer to the Full+ framework outlined by (van Nuffel, et al. 2020)). In the analysis of the regulatory measures we discuss what each regulatory measure means for the accompanying administrative costs. We provide evidence on regulatory administrative costs from related sectors such as the natural gas and electricity sectors and evidence of the size of administrative costs relative to the market supplied. This data can be used as an estimate for a future hydrogen regulation.
4. **Investment incentives/barriers:** Although many assessment criteria likely show a positive benefit of regulation, in the context of a future hydrogen market, there are potential downsides of a strong regulatory environment that have to be evaluated—particularly the willingness-to-invest. Historically, regulation has been imposed on already developed mature sectors (e.g. power and gas); however, for hydrogen, most of the infrastructure and processes have yet to be developed. It is likely that stronger investment incentives encourage more players to engage in the development of new hydrogen infrastructure, which will also trigger additional market players in upstream and downstream markets. As a result, more hydrogen transport capacity in the form of new pipelines and more supply (upstream) and demand sources (downstream) could be part of the interconnected hydrogen network. We outline the possible advantages and drawbacks of the different regulatory options with regards to investment incentives and barriers.
5. **Repurposing of natural gas pipelines**: Various studies have identified repurposing of natural gas pipelines to hydrogen to be the most cost-effective means of providing a dedicated hydrogen network for the majority of potential future hydrogen demand.[6] We assess each regulatory measure's ability to foster repurposing of natural gas pipelines. We expect this to be qualitative in nature but are confident that it provides extra value to the policy question at hand, particularly in the light of the discussion about the role of gas TSOs in the development of hydrogen networks.

The five assessment criteria are not equally important. A weighting of the criteria also partly depends on the priorities of the regulator.

Note that we do not look into alternative options to promote hydrogen network investments (such as direct subsidies).

While the immediate objectives of regulation are of economic nature, the eventual goal is to facilitate the decarbonisation of the EU economy

A regulatory framework for the hydrogen infrastructure operators does not in itself support the objectives for the hydrogen market development and decarbonisation in any direct way as support schemes for low carbon hydrogen production (e.g. Carbon Contracts for Differences, or CCfD) would do. Rather, the regulation seeks to avoid market outcomes that would hinder the development of a hydrogen market and so facilitates the uptake of (blue or low carbon) hydrogen. With that objective of facilitating the development of an EU hydrogen market in mind, the regulatory design is informed by the assessment of the impact of regulation on the hydrogen market structure, on the development of cross-border transport capacities, on administrative costs, and on the incentives for repurposing and new investments into hydrogen infrastructure. A regulatory design that is in line with these criteria will enable the uptake and

[6] See e.g. EU Hydrogen Backbone Study by Guidehouse (Guidehouse 2020)

use of green or low carbon hydrogen.[7] The eventual impact of a strong and efficient uptake of green or low carbon hydrogen will be a contribution to the decarbonisation of the EU economy.

We base our analysis on the assumption that dedicated hydrogen transmission and distribution in 2030 is characterised by a natural monopoly

The foundation for enforcing regulation on network operators is that infrastructure constitutes a natural monopoly, which is characterised by a sub-additive cost curve where total costs of production (here: provision of transport or distribution services) are lower for a single firm than for two or more companies with the same total production because high initial investments create economies of scale.[8] By granting third parties regulated access to this monopolistic bottleneck (or essential facility), competition should be enabled on potential merchant value stages preceding or succeeding transport and distribution, such as energy production, trading, or retail. This can enable competitive pricing and innovation on all value stages that are not characterised by a natural monopoly. Such competition lowers total supply prices[9] and increases supply volumes compared to a situation where the monopolistic bottleneck network can only be used by the party owning and operating it, and so has the market power to request monopolistic prices throughout the entire vertical value chain (including production and retail). This has a positive welfare effect (higher total rents because all consumers are served where willingness to pay exceeds marginal supply costs) and a distributional effect (higher consumer surplus), and so supports the decarbonisation of the EU economy.

Although a natural monopoly is a typical motivation for regulating networks, there is uncertainty as to whether dedicated hydrogen transmission and distribution will be characterised by a natural monopoly in the time horizon we are looking at in this study, i.e. by 2030:

- Today there is no natural monopoly for hydrogen transmission and distribution, given a small number of sellers and a limited number of buyers.[10]
- Once pure hydrogen becomes a traded commodity, meaning that in a defined space, a large number of buyers start to compete to acquire it and a certain number of producers compete for access to transport means, hydrogen is similar to natural gas in terms of natural monopoly characteristics.[11]
- Whether and when the transition will happen from today's situation to a liquidly traded hydrogen market with dedicated hydrogen networks being characterised by a natural monopoly is uncertain, and the timing depends on many factors. Van Nuffel et al (2020) indicate the transition is likely to coincide with Phase 2 (2025–2030), and more broadly Phase 3 (2030 towards 2050), as defined in the European Commission Hydrogen Strategy. [10]

This report assumes that dedicated hydrogen transmission and distribution is a natural monopoly by 2030, despite the uncertainties on the market structure.

We use evidence from the regulation of existing networks to discuss corresponding impacts on hydrogen networks

So far there is neither empirical evidence on the specific impacts of regulation for hydrogen, nor a hydrogen network in place that would allow reliable empirical analyses. We rely on evidence from the regulation of existing networks, if we consider them to be transferable. In doing so, we

[7] This is reflected in the approach for the assessment of the regulatory options: To assess the regulatory options an assumption on the development of the hydrogen market until 2030 needs to be taken. This study focusses on the market development as defined in the EC's Hydrogen Strategy, which implies around 150 TWh of renewable hydrogen being used across the EU. Thus, the assessment of the regulatory options focusses on an effective design to facilitate the development of a hydrogen market as defined in the EC's Hydrogen Strategy (which might indirectly affect the uptake of hydrogen volumes and thereby decarbonisation), but does not attempt to define schemes which directly increase the uptake of hydrogen volumes or directly trigger decarbonisation efforts.

[8] There are further characteristics that may lead to an infrastructure constituting a natural monopoly, such as the need for integrated network planning and operation, see Trinomics et al (2020), Sections 2.2.2 to 2.2.4.

[9] Empirical evidence supports this, for example (Growitsch and Stronzik, Ownership Unbundling of Gas Transmission Networks – Empirical Evidence 2011) show that TPA requirements reduce end-user prices, in particular retail prices for gas consumers.

[10] See (van Nuffel, et al. 2020), page 36.

[11] As, for example, highlighted by (Frontier Economics 2018)

explain what may differ in a hydrogen network, and which requirements must be met so hydrogen regulation (i) is similar in its effect and (ii) can be implemented.

When considering transferability of the experiences in existing energy networks to the future hydrogen network, and following competition theory, networks that are natural monopolies face similar challenges in terms of market failures (as outlined in the previous section). This enables us to use the general insights on advantages and disadvantages of various regulatory measures in existing networks, especially gas and electricity, as an empirical basis for hydrogen. We expect the hydrogen pipeline network to be similar to the gas network, albeit less branched and with more scattered supply and production centres from which the hydrogen is transported to the end user (e.g. electrolysers can be installed almost anywhere, even though there are location advantages in certain regions).

Regarding regulation, however, the starting point is different for hydrogen compared to other energy networks. Electricity and gas networks were already widely developed, mature networks before liberalisation was imposed. As economic theory predicted, empirical evidence confirmed a statistical link between market opening and sectoral performance in network industries.[12] Therefore, regulatory steps always relate to reducing or controlling market power of a central operating company with the goal of enabling competition. In contrast there is an opportunity to impose regulatory measures that enable competition in upstream and downstream markets from the beginning when setting up the hydrogen network, preventing structures that developed before the liberalisation of our natural gas networks.

3.2. Assessment of impacts of individual policy measures

This section summarises the key regulatory measures (outlined in Section 3.1.1) against the key criteria (outlined in Section 3.1.3). As we are analysing an evolving technology and infrastructure without any international precedence at a large-scale, the degree of thoroughly quantifiable impacts of different regulatory measures is naturally limited. Where possible, we provide quantification approaches in Section 4.

We develop an **assessment matrix** for the regulatory measures and their manifestations based on the discussions. The assessment is structured as follows:

- Third-party access (TPA) (Section 3.2.1)
- Vertical Unbundling (Section 3.2.2)
- Horizontal Unbundling (Section 3.2.3)
- Tariff Regulation (Section 3.2.4)

The discussion of individual regulatory measures against the five assessment criteria summarizes the spectrum of regulatory options. For each of the four regulatory categories listed above, all five assessment criteria (Section 3.1.3) are discussed in a separate subsection to note how different forms of regulation (e.g. no TPA, regulated TPA) affect a criterion (e.g. high or low investment incentives). An assessment matrix summarises the results from the discussion, adding a rough evaluation for each individual combination of regulatory measures and assessment criteria. The evaluation scale of the ranges from "– –" (very low; or in the case of administrative cost very high) to "++" (very high; or in the case of administrative cost very low) and describes an absolute valuation, not a valuation relative to the status quo (no regulation). This general evaluation of regulatory measures serves as a basis to subsequently evaluate the combination of measures in policy packages in Section 3.2.

The general **assessment approach in the following sections is based on the assumption of ceterus paribus**, or all else equal, which means that a certain regulatory measure is only considered and assessed individually, and not in interdependence with other regulatory measures. This approach helps isolate the impacts of a single regulatory measure and identify relevant tendencies. An approach that considered all possible combinations with other regulations would weaken the general assessment. However, since a regulation usually consists of several elements, we apply the general assessment approach on explicit combinations of regulatory measures in Section 3.3, which reviews EC draft policy packages.

[12] See for example Copenhagen Economics (2005) for an overview of major network industries.

3.2.1. Third-party access (TPA)

TPA aims at allowing all companies that pursue related activities (e.g. hydrogen producers or suppliers) to have non-discriminatory access to the infrastructure.

We assess three manifestations of TPA:

- **No TPA**: In absence of explicit TPA rules, network operators are free to decide whether and under which conditions third parties can access the infrastructure (or not).
- **Negotiated TPA (nTPA)**: In this soft form of TPA, infrastructure operators and users negotiate (bilaterally) the terms for access to the infrastructure based on dedicated regulatory requirements (e.g. non-discriminatory terms).
- **Regulated TPA (rTPA)**: In this stricter form of TPA, the regulator sets or approves the terms of access to the infrastructure (in particular, tariff setting methodology). These terms can also include other explicit conditions including how the infrastructure capacity is allocated and restrictions on the duration of capacity contracts.

This ranking might be less clear in practice. For example, a very strict nTPA regime with strong regulatory requirements versus a very relaxed rTPA regime.[13] For the following section, we assume that a rTPA regime provides a stronger disciplining effect.

Even in regimes with TPA, exemptions can be granted if certain criteria are met.[14] We incorporate these exemptions under the no TPA case. In practice, allowing for exemptions may be an opportunity to combine the advantages of TPA and no TPA regimes (see Section 3.2.1.4).

The following sections discuss the impact of different TPA manifestations on each assessment criterion before an assessment matrix summarises the results in Section 3.2.1.6.

3.2.1.1. Market structure: TPA enables merchant third parties to access hydrogen networks which increases market liquidity

This section discusses the impact of TPA measures on the assessment criterion hydrogen market structure. We assume that network investments will take place and the dedicated hydrogen network will be developed irrespective of the form of TPA rules. In other words, we assume that in case TPA rules had a negative impact on investment and repurposing incentives (which we analyse in Sections 3.2.1.4 and 3.2.1.5), there would be alternative policy measures to incentivise investments in hydrogen networks.

Based on such a like-for-like analysis, the EC could assess the effect of the introduction of TPA to a given dedicated hydrogen network similarly to its assessment of introducing TPA for existing electricity and natural gas networks (European Commission 2009):

- **In the absence of TPA rules (no TPA)**, the natural monopolistic nature of the network is likely to lead to a more monopolistic, more vertically integrated market outcome. Such an outcome implies higher prices for network access and lower volumes transported by the network, which could lead to a lower overall hydrogen uptake—e.g. if hydrogen demand is responsive to hydrogen prices (i.e. demand is elastic). This has a negative welfare effect as well as distributional effects from hydrogen consumers to network operators.
  - The case for TPA is particularly strong without effective vertical unbundling rules (see Section 3.2.2) because the negative impacts of missing TPA rules would not be restricted to the prices for network access (which constitute only a comparably small part of overall hydrogen supply costs). Instead, the negative impacts would extend to total prices of hydrogen supply, i.e. prices would also include monopolistic rents for non-monopolistic parts of the

[13] A strict nTPA regime could severely restrict the negotiating leeway of the two parties with requirements from the regulatory side; a minimum rTPA only imposes a tariff setting but no potential additional measures (such as short term quotas). Differences in restrictions imposed by the two different regulations can therefore be quite small.

[14] This could be an exemption for new pipelines.

hydrogen supply chain,[15] if vertical integration combined with a lack of TPA lead to market foreclosure in these potentially competitive upstream and downstream markets.
    - This concern of a more monopolistic and vertically integrated market outcome without any TPA rules holds, even in the case of strict vertical unbundling (i.e. where the network operator has neutral incentives as to which network users use the network). The vertical bundling could potentially be replicated by the design of transport contracts. For example, a large hydrogen producer could conclude a long-term contract (e.g. 20 years) with a pipeline operator for the full pipeline capacity and thereby extent the pipeline monopoly to the producer market. TPA rules could prevent such an outcome by providing pipeline (and thereby downstream customer) access for competing producers.
    - There is a risk of low market liquidity if the infrastructure owner fully controls access to it, so third parties might be denied access. Again, this is particularly severe where there is no vertical unbundling, as the opportunities and incentives for upstream and downstream market foreclosure would be particularly high with vertically integrated companies operating the networks.
- A requirement for **nTPA** reduces the monopolistic power of the network operator so prices tend to be lower and transported volumes higher. However, the experience in electricity and natural gas network regulation has found the disciplining effect of nTPA to be limited[16] and hence has subsequently moved towards a system of regulated TPA.[17] It could be argued, that the circumstances of a newly formed hydrogen sector might be different to the situation in other markets as there would be significantly fewer legacies of vertical integration and hence the disadvantages of a nTPA regime observed in other markets might not be fully transferable to a new hydrogen market. The market structure in up- and downstream hydrogen markets will also have to be considered as the number of hydrogen consumers in such markets (e.g. industrial consumers of hydrogen) might be limited, which improves their bargaining power and could hence render nTPA effective.
    - As a working hypothesis we nevertheless suggest assuming in an impact assessment, that the disciplining effect of a nTPA regime is somewhat lower than that of a regulated TPA with overall market effects lying between no TPA and rTPA.
- A requirement for **regulated TPA (rTPA)** potentially strengthens the disciplining effects of nTPA on network operators, because it further improves the rights for (potential) third party network users and increases transparency, which facilitates market entry of up- or downstream market parties.[18] As a result, competition on the related up- and downstream markets (H_2 production and H_2 supply) is likely to be higher (with lower market concentration), which in turn supports a stronger hydrogen uptake overall (for a given network). Other indirect effects might include more innovation in related up- and downstream markets.

3.2.1.2. Cross-border integration: TPA helps facilitating European hydrogen network integration

The creation of an internal energy market has been another cornerstone of EU energy policy in the past two decades. Since the introduction of key regulatory measures including (rTPA)—

[15] I.e. hydrogen production and retail

[16] For example, Growitsch and Wein (2005) find that under nTPA, observable upward price adjustments happened over time that could serve as an indicator of tacit collusion.

[17] This is different for infrastructures that are not characterised by a natural monopoly, which depends inter alia on the maturity and connectivity of the relevant market. For instance, LNG terminals have been characterised by natural monopolies in the 2000s, but that is no longer necessarily the case in mature markets such as North Western Europe, where there is competition between LNG terminals and between gas imports via LNG or pipelines. As a consequence, in these markets nTPA solutions may yield better economic results than rTPA solutions (Frontier Economics 2020)

[18] For example green hydrogen producers that ask for network connection or suppliers that want to supply consumers with hydrogen.

accompanied by rules for more efficient cross-border capacity allocation and for more coordinated cross-border infrastructure planning for electricity and natural gas networks in the Third Energy Package in 2009—cross-border integration of electricity and natural gas markets has increased substantially. Again on a like-for-like comparison based on a given capacity (later sections consider the effects of TPA regime on investment incentives) the TPA effects on the degree of cross-border integration of a hydrogen network could be assessed based on experience in other markets:

- **In the absence of TPA rules (no TPA)** unharmonised access rules are likely to develop in different MSs. The lack of standardised rules for the allocation of cross-border capacity (which might foster the development of transparent capacity booking platforms) may significantly hinder cross-border trade. This is especially true for transport of hydrogen over long distances, for example, for transit-flows that seek to connect low cost hydrogen regions with high hydrogen demand regions. According to Jones (2016, 70), experience in the gas market has shown that *"a lack of (non-discriminatory) access to the infrastructure […] constituted an important obstacle to cross-border trade and further market integration*". For example, long-term contracts could prevent access of new joiners to cross-border pipelines (European Commission 2007, 89): "*New entrants are unable to secure primary transit capacity on key transit routes due to the predominance of long-term contracts signed between incumbent TSOs.*" As already explained, the starting point for the hydrogen network is different compared to natural gas, but we nevertheless expect that the lack of rules for discrimination-free access will lead to barriers in the European integration of the hydrogen network.
  The relevance of standardised access rules increases with a larger, interconnected hydrogen infrastructure across the EU. In a very nascent hydrogen market, private hydrogen networks may effectively facilitate cross-border flows; however, this likelihood will diminish as the hydrogen market and infrastructure expands.
- If the EC mandates a **nTPA** then this will facilitate TPA. However, this might not fully alleviate the difficulties around unharmonised access rules, which is particularly relevant for hydrogen flows across multiple borders. For an impact assessment, we suggest (in line with our finding in Section 3.2.1.1) the assumption that an nTPA regime's market effects fall in-between the effects of no TPA and rTPA.
- Assume the introduction of **rTPA** to provide a higher degree of transparency and clearer access requirements across borders, facilitating transport of hydrogen across European borders with a given hydrogen network. At the same time, a regulatory approach with rTPA and an explicit role for NRA could facilitate the planning and coordinated development of hydrogen infrastructure across EU MSs, as it allows policymakers and NRAs to demand network operators to coordinate across borders, for example by providing Ten Year Network Development Plans (TYNDPs).

3.2.1.3. Administrative costs: modest cost for TPA requirements

A TPA requirement for network operators means that companies and regulators incur administrative costs. Companies need to invest time and resources to ensure that access requirements comply with the regulatory requirements; regulators need to regularly confirm companies abide by the requirements.

Although nTPA leaves companies some flexibility to agree on access requirements with upstream or downstream customers (e.g. to reflect national or local conditions), negotiations might take up further resources. By contrast, an rTPA regime requires fewer resources for negotiations, but also little room for aligning access requirements with national or local conditions. An rTPA regime bears another risk that could increase administrative costs as it requires that the regulator has good knowledge of the (local) conditions, the operators' costs, and the market structure.

3.2.1.4.Investment incentives: Higher incentives for new build hydrogen infrastructure likely related to weaker TPA requirements

The preceding sections discussed the effects of a TPA regime based on a given network capacity for clarity. In practice, the TPA regime is expected to have a strong effect on the incentives to invest in such capacities (note that we discuss incentives for repurposing further below):

- **The absence of TPA rules (no TPA)** grants investors in dedicated hydrogen networks commercial flexibility in their contractual agreements. Investors are free to engage in long-term capacity contracts with hydrogen generators and consumers to secure their investments. From an economic perspective, this commercial flexibility and investment certainty is one of the key drivers why investors in new electricity and gas infrastructure (such as interconnectors, cross-border pipelines, or liquified natural gas [LNG] terminals) often apply for exemptions from EU energy regulation (including TPA). Any TPA regime can be expected to reduce the availability of hydrogen network capacities, all else being equal. [19]
- **nTPA and rTPA** limit the commercial flexibility to market network capacity (e.g. in long-term contracts with single parties) and so risk reducing incentives for new investments into hydrogen infrastructure. Regulated TPA typically means that there are conditions for infrastructure operators that requires fewer resources for negotiations with individual shippers. Negotiated TPA regimes usually provide more room for network operators in their contractual agreements. Empirical evidence shows that stronger TPA requirements such as rTPA have a negative impact on investments, as determined by a lower level of investment in such a regime (Gugler, Rammerstorfer and Schmitt 2013).

Box 3-1 Reflections on the role of exemptions

Exemptions from regulatory measures provide commercial flexibility and investment certainty, which can incentivise investments into new infrastructure. In the gas and electricity sectors, EU regulation allows for regulatory exemptions to enable risky investments that could not be implemented if the usual rules were applied.[20] Investors regularly apply for exemptions from EU energy regulation (including TPA) for infrastructure such as interconnectors, cross-border pipelines, or LNG terminals. For example, approximately 70% of the LNG import terminal capacity in North-West Europe is operating under exemptions from regulation, with the remainder stemming mostly from the period before the introduction of exemption options in the Second Energy Package in 2003.[21]

3.2.1.5.Repurposing: Strong TPA requirements could hinder repurposing unless joint RAB is allowed

In contrast to the regulation of natural gas and electricity markets, hydrogen infrastructure regulation needs to consider an alternative to building new pipelines. For example, the repurposing of existing natural gas pipelines that will become idle with the continuing decarbonisation progress and other developments such as the L-gas phaseout. Because the repurposing of natural gas pipelines to hydrogen pipelines comes with significantly lower cost than the new build of hydrogen pipelines,[22] one objective for the impact assessment of the regulatory framework should be for the EC to scrutinise the incentives for repurposing natural gas to hydrogen pipelines to minimise overall infrastructure cost.

[19] We assess individual regulatory measures under the “ceterus paribus” assumption. Nevertheless, it is worth noting that a regulation without TPA requirements particularly benefits incentives to invest in hydrogen networks in case vertical integration is allowed (see Section 3.2.2). This means that companies operating networks can also operate in upstream hydrogen production, trading or downstream hydrogen distribution.

[20] See https://ec.europa.eu/energy/topics/markets-and-consumers/wholesale-energy-market/access-infrastructure-exemptions-and-derogations_en

[21] See (Frontier Economics 2020), page 28. See also https://ec.europa.eu/energy/sites/default/files/documents/exemption_decisions2018.pdf for an overview of exemption decisions for new energy infrastructure taken by the European Commission.

[22] According to (Guidehouse 2020), repurposed pipeline CAPEX are around 10-20% of new pipeline CAPEX

Under an assumption of separate RABs (i.e. assuming natural gas operators are not allowed to operate natural gas and hydrogen networks under the same accounts and thus allow for common tariffs for hydrogen and natural gas; see Section 3.2.3), the impacts of the type of TPA on repurposing pipelines should be similar to that of TPA on incentives to invest in new builds (see Section 3.2.1.4).

The EC should also consider the alternatives to using CH_4 pipelines for H_2 transport. Although there may be a strong use case for synthetic natural gas (SNG) or biomethane in the future, it is possible that decommissioning is the alternative to repurposing to hydrogen infrastructure. In that case, it is likely that there are much stronger incentives to repurpose for network operators, which would potentially decrease the relevance of the type of TPA employed on hydrogen infrastructure.

See Section 3.2.3 for a discussion of how this assessment may change if horizontal unbundling of natural gas and hydrogen accounts are not mandated.

3.2.1.6. Summary on TPA

Table 3-1 summarises how an impact assessment might evaluate the effects of various manifestations of TPA in a hydrogen regulation.

Table 3-1 Summary of assessment of TPA options

Regulation	Impact on...									
	Hydrogen market structure, liquidity, and sector reach (distribution of rents, with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers for new infrastructure		Repurposing of natural gas infrastructure	
No TPA (or TPA with high degree of exemptions)	Risk that monopolistic pricing or market foreclosure (restricted by competition law) of network use leads to low hydrogen uptake Risk of low market liquidity if pipeline capacity is booked in long-term capacity contracts (particularly severe in absence of vertical unbundling)	–	Lack of non-discriminatory access and unharmonised access rules could lead to a substantial obstacle in cross-border trade	– –	Low administrative costs *[additional cost for case-by-case exemption applications in the case of exemption regime]*	+	Market based incentives; more commercial flexibility for network investors, e.g. long-term capacity contracts possible that provide investment certainty	+	Market based incentives; more commercial flexibility for hydrogen network investors, e.g. long-term capacity contracts possible that provide investment certainty	+
Negotiated TPA (+ transparency requirements?)	nTPA reduces end user prices and increases market liquidity Effect may be limited as operators of (natural monopoly) networks have higher bargaining power than network users	+	Easier third-party access, but negotiated TPA still means a potential barrier to cross-border trade Increases costs for x-border flows, in particular for flows across multiple border (e.g. south to north)	0	Additional cost for TPA negotiations (for network operators and network users)	–	Low investment incentives since pipelines cannot be used freely More flexibility than rTPA to get contract conditions (e.g. long-term) which support long-term investment decisions	–	Further reduces commercial flexibility and weakens incentives (if no opportunity for joint RAB) More flexibility than rTPA to get contract conditions (e.g. long term) that support long-term investment decisions	–
Regulated TPA (without exemptions)	Easier access for new upstream/downstream entrants, higher competition in upstream/downstream markets: lower market concentration, lower prices, more innovation upstream/downstream	+ +	High transparency and clear access requirements across countries/borders Facilitates infrastructure planning in coordination with NRAs	+ +	Lower transaction cost compared to negotiated TPA But higher costs for regulators as well as for network operators to ensure rTPA compliance	–	Lower transaction cost compared to negotiated TPA but no flexibility of contracts Empirical evidence shows negative effects on investments	–	Further reduces commercial flexibility and weakens incentives (if no opportunity for joint RAB)	–

Legend
- - - Very low / Administrative costs: very high
- - Low / Administrative costs: high
- 0 Neutral / No clear impact
- + High / Administrative costs: low
- + + Very high / Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

3.2.2. Vertical unbundling

Vertical unbundling has the objective to separate activities of an economic operator on different levels of the value chain. It differentiates between activities that are characterised by a natural monopoly (as assumed for hydrogen, see Section 3.1.3) and so need to be regulated, and competitive activities that can be left to competition of non-regulated market parties. In the context of dedicated hydrogen networks, vertical unbundling aims at separating the regulated activity of network operation from merchant activities that allow for competition such as hydrogen production, trading, or retail. Vertical unbundling can be implemented in different ways, including:

- **No unbundling:** Without explicit rules for vertical unbundling, regulated and unregulated activities can be owned and operated by vertically integrated companies without conditions on the vertical split of activities. Under this regime, a vertically integrated company is allowed to produce, trade, transport, sell, and use hydrogen. This is the current framework for most hydrogen suppliers who provide vertically integrated (grey) hydrogen services to industrial consumers through self-owned infrastructure.[23]
- **Account unbundling:** In this more light-touch unbundling regime, regulated and unregulated activities can be owned by the same company and can be operated within one single legal entity, but regulated activities must be captured in separate accounts from the unregulated activities. This e.g. prohibits cross-funding of non-regulated activities through (regulated) tariffs.
- **Functional unbundling:** The same company can own regulated and unregulated activities, but the operation of the activities has to be separated (e.g. strict rules on separate human, technical, physical, and financial resources). We assess this form of unbundling together with legal unbundling.
- **Legal unbundling:** Regulated and unregulated activities can be owned by the same group of companies but there must be separate legal entities with separate corporate identities and separate accounts, among others.
- **Ownership unbundling:** In this strictest form of vertical unbundling, a company is not allowed to own interests in regulated and unregulated activities simultaneously (restrictions on interests in other regulated activities are covered under horizontal unbundling in the next section).

Unbundling involves the trade-off between synergies and discrimination of competitors

The absence of unbundling regulation enables synergies typically leading to stronger business cases and a fast network expansion, which could be particularly advantageous in the early phase of the hydrogen market ramp-up. This is increasingly relevant in situations where the upside potential from regulation for an investor in infrastructure is small (e.g. because a small customer base does not allow for socialisation of risks), but downside risks (e.g. stranding risk) are comparably large.

However, the absence of vertical unbundling might lead to welfare losses through less vivid competition. Fully integrated firms might discriminate against their competitors, causing inefficient investment decisions and hampering competition. A potential consequence of discrimination could be the construction of competing infrastructure, which is inefficient from a welfare perspective as long as the market could be served by an existing pipeline with sufficient capacity. This could become increasingly important with an advanced hydrogen market. The impact assessment might want to focus particularly on the assumed status and degree of maturity of the hydrogen market affected by regulation.

The following sections detail the impacts of different unbundling measures, focussing on the five assessment criteria. Section 3.2.3.6 summarises the results in an assessment matrix.

[23] Under current unbundling rules in methane networks, a vertically integrated model for hydrogen could mean that methane TSO are not allowed to own hydrogen infrastructure.

3.2.2.1. Market structure: Vertical unbundling aims to create fair conditions for all participants and prevents market failures

According to economic theory, a fully vertically integrated company does not necessarily hinder the functionality of a market and can also lead to lower end user prices as integration often brings along efficiency advantages. However, integration can become a problem if there is a market within the value chain in which, due to its structure, market failure occurs without regulation. Transport and transmission networks are a general example of such a market, as the infrastructure often represents a natural monopoly. We also assume the hydrogen network represents a natural monopoly (as Section 3.1.3 elaborates). Without considering potential impacts on the availability of network capacities, which should be assessed separately (see Sections 3.2.2.4–3.2.2.5), the hydrogen market sphere can be expected to benefit from higher degrees of unbundling:

- In the case of **no vertical unbundling**, unregulated network operators can use their monopoly to favour their upstream and downstream entities over competitors. Regulators can implement TPA requirements to guarantee everyone access to the transmission network, but the risk of discriminatory behaviour and asymmetrical information remain as long as firms are fully integrated. Therefore, the absence of vertical unbundling contributes to market foreclosure that decreases market liquidity and hampers competition. With less competitive pressure, firms can realise higher profits, which implies a redistribution of surplus away from consumers and towards firms. These mechanisms could be observed and confirmed empirically in electricity and gas networks in the past.[24] With specific reference to the hydrogen market, we expect market failures due to fully integrated firms become increasingly relevant with advanced network maturity. Market failures due to a natural monopoly arise when it is efficient to transport hydrogen over existing pipelines instead of building new pipelines (possibly parallel to existing ones). Then competitors of fully integrated companies could be discriminated against regarding network access. If hydrogen transmission pipelines only exist sporadically at the beginning, the mechanisms of the natural monopoly are less relevant.
- **Accounts unbundling** is the weakest unbundling measure and might not enforce fair competition by itself, as firms can remain vertically integrated. Evidence from gas regulation shows that incomplete management unbundling lays the foundation for discriminatory behaviour in favour of the operator's own upstream or downstream operating arm (European Commission 2007). Currently, hydrogen and methane downstream markets are different in structure, which is why the findings from methane cannot be transferred one-to-one. Nevertheless, the economic mechanisms are also valid for hydrogen: Under accounts unbundling, firms still have an incentive to discriminate against competitors to maximise their overall profit, which limits market access for competitors and leads to a more monopolistic market structure.
- With respect to **legal and functional unbundling**, literature shows clearer evidence on competition and prices when assessing existing energy networks. Growitsch and Stronzik (2011) find that legal unbundling results in lower end user prices in gas markets. According Heim et al. (2019), legal unbundling of the network stage significantly decreases grid charges in electricity markets. Höffler and Kranz refer to legal unbundling as the "golden mean between vertical integration and ownership separation" (Höffler and Kranz 2011, 576) as consumer surplus will be largest under legal unbundling. However, it may still be insufficient to prevent discrimination (Jones 2016, 96). Consequently, legal unbundling decreases market failures caused by integrated companies to a large extent and increases competition—a key finding that may extend to hydrogen regulation. A distinction must be made, however, that in the gas market prior to regulation there were already fixed structures of fully integrated firms making a stronger separation between network and upstream/downstream business necessary. The relevance of discrimination against competitors in the hydrogen network could be significantly

[24] See for example European Comission (2007) for natural gas.

smaller if structures of monopolistic firms serving all parts of the supply chain are prevented.

- **Ownership unbundling** fully removes incentives for preferential treatment and creates optimal conditions for a discrimination-free market in the non-regulated hydrogen markets. As for the additional effect on competition and prices (compared to legal unbundling), there are mixed results from the literature. Filippini and Wetzel (2014) evaluate the impact of ownership unbundling for electricity distribution companies in New Zealand and find evidence that ownership unbundling has a positive effect on the cost efficiency. Nillesen and Pollitt (2011) assess the effect of ownership unbundling in electricity markets and suggest that it did not facilitate greater competition in the electricity supply industry but did lead to lower costs and higher service quality. Growitsch and Stronzik (2011) find no evidence for a price-decreasing effect in gas transmission networks when switching from legal to ownership unbundling. In relation to the hydrogen market, the additional impact of ownership unbundling on prices in the market cannot be predicted precisely. However, the experience that ownership unbundling is the most consistent regulatory measure when competition and non-discriminatory market access are prioritised is transferable from other markets as the same economic principles apply.

Finally, with respect to a future hydrogen market structure, without the introduction of unbundling rules the topology of the resulting hydrogen network could be different as fully integrated firms expand the network primarily where it is most beneficial for them. In particular, the focus could be on connections between consumption and production centres relevant to industries, in which an integrated firm is active.

3.2.2.2. Cross-border integration: Lack of vertical unbundling could complicate coupling of national networks

Vertically integrated firms might have fewer incentives to develop integrated markets as long as this is not for their own benefit, for example, if an integrated firm owns assets in multiple countries. If integrated companies are mainly active in national markets, increased integration of national markets could lead to higher competition in an integrated firm's domestic market, threatening profits in upstream and downstream markets of the hydrogen supply chain. The EC identified the protection of domestic markets for natural gas networks (European Commission 2007, 6). We expect this to be less relevant for the hydrogen market, since the starting point for the network is not fully integrated national monopolies, but companies could operate internationally from the start (and this is also necessary to transport hydrogen from supply to demand centres).

The Impact Assessment on Gas (European Commission 2007) showed that fully unbundled TSOs reinvest a higher share of their congestion revenue in new capacity. According to the EC, this is because "vertically integrated companies have an interest to protect their supply business in their home market by limiting cross-border capacity" (European Commission 2007, 34). Ownership unbundling increases incentives for network operators to integrate markets by removing these conflicts of interest. Nevertheless, findings in mature markets need to be assessed carefully, as in a more nascent hydrogen market (starting without vertically integrated national champions) other effects (e.g. on investment incentives, see below) might outweigh potential advantageous effects of stronger unbundling.

3.2.2.3. Administrative costs: depend on the regime but could be lower for hydrogen than for electricity and gas

Vertical unbundling implies administrative costs for companies and regulators from administrative requirements as well as oversight and reporting. This effect is well known in more mature energy markets. For electricity and gas, monitoring of existing unbundling regulations consists of several components that vary with the unbundling regime (for more details, see CEER 2019). A major cost burden is generally incurred with the implementation of a change in the unbundling regime. NRAs continuously monitor an unbundling implementation and the EC evaluates the implementation of the unbundling provisions and tries to identify potential gaps. Continuous monitoring costs are usually limited, but where the transmission operator is completely independent (ITO), it is legally mandatory to have a compliance officer check the application of the unbundling rules within the firm.

We expect the monitoring for hydrogen to be similar to existing vertical unbundling regulations. Structurally, however, the starting point for unbundling is different than it was for electricity and gas so there are advantages in the hydrogen market. The hydrogen market is in the process of being set up, there are no fully integrated companies that operate an extensive network. Electricity and gas networks were already well developed and operated by integrated firms before unbundling began. Therefore, the administrative costs of vertical unbundling in the hydrogen market are likely lower than in electricity or gas markets.

Administrative costs vary with the type of regulation. Accounts and legal unbundling still allow interdependencies between activities at different levels of the hydrogen supply chain within a company or parent company. Ownership unbundling, on the other hand, completely separates all activities and is easy to monitor. Therefore, in an impact assessment, the unbundling costs for oversight and reporting of accounts (as well as legal and functional) can be assumed to be higher than for ownership unbundling.

3.2.2.4. Investment incentives: Vertical unbundling might remove synergies and could decrease incentives to build new hydrogen infrastructure

With the high degree of investments required for the hydrogen network, potential effects of an unbundling regime on the incentives to invest in further capacity are of particular significance:

The **absence of vertical unbundling** would allow for fully integrated firms to be active in all parts of the hydrogen supply chain from production and storage to transport to distribution (and potentially consumption). Combining the entire hydrogen value chain in a single owner potentially creates strong investment incentives—e.g. through minimising risks for the investor (because of full control of upstream and downstream elements of the value chain)—and allows the network operators to optimise the use of storage (which might be less relevant for hydrogen systems with different sources of hydrogen as opposed to natural gas) and network planning. Vertical integration in such cases might enable synergies between the individual parts of the hydrogen supply chain, making construction of infrastructure more cost-efficient.

Synergies from coupling different parts of the supply chain might disappear with stronger regulation. Transaction costs for the coordination of the hydrogen supply chain increase with stronger barriers between transmission and upstream and downstream markets. This finding is supported by empirical evidence in other energy markets (Gugler, Liebensteiner and Schmitt 2017). While accounts unbundling still allows for vertical integration within one company and the positive effects of risk management, legal and functional unbundling requires a complete separation of business areas and further reduces such synergies.

As the strongest form of unbundling, **ownership unbundling** implies a maximum of lost synergies but also fully removes distorted investment incentives of vertically integrated companies. There is mixed evidence regarding the impact of ownership unbundling on investments in energy markets. Gugler et al. (2013) find that in electricity markets, full unbundling decreases aggregate investments in the network. On the other hand, the *Impact Assessment for the 2009 Gas Directive* (European Commission 2007) suggests that TSOs constantly increased their investment spending after ownership unbundling. This empirical evidence can only be transferred to the hydrogen market to a limited extent in the short term for the following reasons:

- The investigations in gas and electricity refer to networks that have already been developed
- Empirical research for these networks always investigates into the effects, breaking existing structures of integrated firms by imposing a stronger unbundling regulation (which does not have to be the case for hydrogen)

In the hydrogen market, we would primarily rely on principles of economic theory, according to which stronger unbundling increases transaction costs, weakens synergies, and tends to lower investment incentives for market participants. We suggest the assumption of a negative correlation for the impact assessment framework, with more strict vertical unbundling regimes leading to lower investment incentives. Unbundling rules in the future might have a similar incentive effect at present. The regulatory framework should provide certainty for a sufficient planning period (this holds for many regulatory measures).

3.2.2.5. Repurposing: Vertical unbundling plays a subordinate role

As previous sections about other regulatory measures describe, investments into new infrastructure and repurposing of existing natural gas infrastructure often follow similar mechanisms. Investment primarily describes the construction of new infrastructure while repurposing refers to the modification of existing gas infrastructure.

If investment cases are stronger for integrated companies, willingness to pay also increases for the repurposing of pipelines. The absence of vertical unbundling could encourage repurposing. A difference between incentives for repurposing or new investments could be within the concerned actors and their motivations. While repurposing automatically includes a starting advantage for methane TSOs to continue the business model with hydrogen, new investments would likely be driven primarily by demand from larger hydrogen consumers. Generally, the impact of vertical unbundling on repurposing is limited since this criterion depends more on the horizontal ownership structure than on the vertical.

In an impact assessment, various vertical unbundling measures might be assumed to behave neutrally towards repurposing incentives.

3.2.2.6. Summary on vertical unbundling

Table 3-2 summarises the preceding discussions on how an impact assessment might evaluate the effects of various manifestations for vertical unbundling in the hydrogen market:

Table 3-2 Summary of assessment of vertical unbundling options

Regulation	Impact on… Hydrogen market structure (with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers (for new infrastructure)		Repurposing (existing infrastructure)	
No unbundling	Contributes to market foreclosure and hampers competition Market power of integrated firms leads to higher profits and a redistribution of surplus away from consumers and towards the firm	–	National regulatory authorities are unable to monitor cross-border related unbundling. Companies can undermine integration and unbundling Fully integrated firms have few/no incentives to develop network for overall benefit of the market	–	No need for oversight or reporting around unbundling	+	Integration could facilitate vertical synergies: higher incentives for infrastructure operators Stronger investment cases and predictability if entire hydrogen chain can come from a single owner and can be set up and used by one company	+ +	Repurposing of large pipelines pays off faster if vertically integrated companies expand the whole hydrogen value chain Disadvantage for unbundled gas operators versus vertically integrated hydrogen operators	+
Accounts unbundling	Incomplete unbundling: discriminatory behaviour of vertically integrated operators in favour of their own upstream or downstream operating arm	0	Incentives for TSOs to increase capacity of interconnectors are low when congestion benefits the vertically integrated company	0	High costs for oversight and reporting as division of accounts must be warranted within network operator and proven to regulator	–	Economies of scale remain within firm but are weakened due to accounts unbundling	+	Business cases for repurposing under accounts unbundling similar to no unbundling, albeit slightly weakened	+
Legal and functional unbundling	Evidence that legal unbundling results in lower end-user prices and decreases grid charges Insufficient to fully prevent discrimination	+	(similar incentives as with accounts unbundling, e.g. asymmetric information issue)	0	High costs for oversight and reporting as strong division between gas and hydrogen operations must be warranted within network operator and proven to regulator	-	H_2 value chain can no longer be planned via an integrated company, lower investment incentives	-	No clear impact	0
Ownership unbundling	Eliminates incentives for preferential treatment, positive effect on competition No evidence for price-decreasing effect in gas transmission network	+ +	Increased share of congestion revenue reinvested	+	Modest cost due to strict unbundling requirements that are easy to monitor No oversight is needed within a firm	0	Disintegration decreases synergies Higher transaction cost for coordination of hydrogen supply chain Mixed evidence of impact on investments	0	No clear impact	0

Legend										
	- -	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	+ +	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

3.2.3. Horizontal unbundling

Horizontal unbundling determines to what extent and under which framework companies will be allowed to pursue activities in different regulated fields (such as the operation of natural gas and hydrogen infrastructure, but also other energy infrastructure). This will be an important aspect of the regulatory framework, particularly for hydrogen. With respect to network expansion, the hydrogen sector is distinguishable from other energy sectors in that existing natural gas assets can be repurposed. This activates the potential synergies for pipeline network operators to become active in the hydrogen sector. We suggest an impact assessment with a dedicated focus on horizontal unbundling.

Similar to vertical unbundling, horizontal unbundling can be implemented in different ways, including:

- **No horizontal unbundling (joint RAB):** Regulated activities can be kept within the same asset base (with potential for common tariffs for natural gas and hydrogen network users).
- **Horizontal accounts unbundling (separate RAB):** Regulated activities across markets can be owned by the same company and can be operated within one single legal entity but have to be kept in separate asset bases. This implies different tariffs for hydrogen and natural gas networks.
- **Legal and functional horizontal unbundling:** Activities in different regulated fields can be owned by the same company but there must be separate legal entities with separate corporate identities and separate accounts, among others.
- **Horizontal ownership unbundling:** In this strictest form of horizontal unbundling, a company is not allowed to own regulated activities across different fields, such as hydrogen (if regulated) and natural gas networks.

Regarding the economic incentive structures for market participants, the key question is whether the horizontal unbundling rules allow for unrestrained interactions between a hydrogen network and other network activities of the owning company or whether these must be kept separate. We suggest focusing the impact assessment on the question of whether to mandate horizontal accounts unbundling (separate RAB) or allow for a joint RAB, i.e. no obligation for horizontal unbundling.

In contrast to vertical unbundling, there is only limited economic reasoning to demand stricter horizontal unbundling than accounts unbundling. The main argument for horizontal unbundling is a separation of gas and hydrogen networks ensuring that costs are borne where they arise to prevent cross-subsidisation between markets and between consumer groups.[25] This argument is already fulfilled with unbundling of accounts. A further unbundling might even create negative effects. In the case of horizontal ownership unbundling, for example, gas pipelines cannot be repurposed within the same company but would have to be sold to be repurposed to hydrogen. Synergies might be lost if gas TSOs are completely banned from activities in the hydrogen network. All of this will likely result in higher transaction costs and additional barriers to investments and would endanger the development of the hydrogen network.

Since the considerations regarding horizontal unbundling for hydrogen are new, there is no empirical evidence to evaluate impacts of regulatory measures on investment or repurposing barriers and cost allocation. Consequently, we focus on considerations based on economic theory. The following sections discuss the influence of horizontal unbundling on each assessment criterion before an assessment matrix summarises the results (Section 3.2.3.6).

[25] The structure of the demand side is currently very different for gas and hydrogen and may remain so in the medium term. While gas demand is also driven by private households, hydrogen is mainly demanded by large industrial consumers today.

3.2.3.1. Market structure: Horizontal unbundling allows for cost separation between different markets and consumers, but could lead to initially higher hydrogen prices

It is uncertain what effects horizontal unbundling might have on the development of the hydrogen market (this analysis should be based on an everything else equal basis, in this case same availability of hydrogen transport capacity):

- **Horizontal unbundling (separate RAB) prevents distributional effect of cross-subsidisation**: The degree to which the activities in gas and hydrogen networks are separated determines to what extent cost-reflectivity can be maintained. Without a horizontal unbundling requirement, network operators can operate gas and hydrogen networks under a common asset base (i.e. the asset base for gas networks is extended to include hydrogen networks). This implies that the costs for both networks is also spread across the customers of both networks. During the hydrogen ramp-up phase, it is likely that there will be a large number of gas consumers and a relatively low number of hydrogen consumers. In this initial period, gas users (e.g. residential gas users) will likely end up paying for the hydrogen grid development (e.g. to supply industrial consumers with hydrogen).[26] This is beneficial for network users with higher unit costs and so has a clear distributional impact (cross-subsidisation). Although overall redistribution will likely be towards hydrogen in the beginning, in some cases, cross-subsidisation could also happen in opposite directions, from hydrogen to natural gas. For example, this could arise when parallel pipelines are repurposed and are no longer used for the transport of natural gas and so do not create any revenue, but still have a value in the asset base of the network operator. Section 4.2.2 includes the distributional impacts of a joint RAB.
- **Horizontal unbundling (separate RAB) could lead to high hydrogen network costs in a ramp-up phase**: The unbundling requirement entails a differentiation between cost and revenue allocation between the gas and hydrogen networks. This means that initially the costs for building the hydrogen network might have to be borne by a small number of hydrogen users on a low utilisation of the hydrogen networks, while natural gas customers might experience slightly lower tariffs. This implies a high cost burden for these early adopters in the hydrogen market (or a huge volume risk for the hydrogen TSO in the absence of direct subsidies to support hydrogen networks). These risks discourage potential hydrogen consumers from switching to hydrogen and could slow down hydrogen uptake. Section 4.2.2.3 elaborates on this impact.
- **Absence of horizontal unbundling (joint RAB) could lead to competitive distortion:** The absence of horizontal unbundling, which allows for a joint RAB across gas and hydrogen networks and accordingly cross-subsidisation of hydrogen network costs by natural gas consumers, could entail an unlevel playing field between investments from gas network operators and other parties with interest in investing in and operating hydrogen networks. A joint RAB regime between gas and hydrogen infrastructure could mean, depending on the specifics of the regulatory regime, that gas network operators that also operate hydrogen networks would be able to offer hydrogen network services for lower tariffs than other investors, which would distort competition and create barriers for private investments outside gas network operators.

3.2.3.2. Cross-border integration: Potentially more complicated with horizontal unbundling

Although early cross-border interconnections for gas pipelines were built by vertically integrated national gas companies prior to liberalisation, today, European gas infrastructure is being planned in a more regionally integrated manner with instruments such as the Ten Year Network Development Plan (TYNDP). The process of creating this cross-border integration has shown

[26] The direction of redistribution could switch in the future if the hydrogen network is more expanded, natural gas demand decreases and the average network costs for hydrogen are below those of natural gas.

that a strong coordination, often in cooperation with national regulatory agencies, between various (often national) TSOs is necessary.

If existing gas operators are allowed to operate both gas and hydrogen pipelines, these companies might be able to build on existing relationships between natural gas network operators and on existing knowledge and experience to strengthen the cross-border integration for a hydrogen network. While this benefit may also materialise with horizontally unbundled accounts (i.e. separate RABs), a joint RAB approach may improve the development of cross-border integration of hydrogen networks because additional costs can be spread across a larger client base (with potentially few hydrogen users in the beginning, but still many gas users). Accounts unbundling would still allow gas TSOs to own and operate hydrogen networks, but investment risks would no longer be as widely distributed due to different accounts.

Strong forms of unbundling (e.g. ownership unbundling) would mean that existing network operators cannot build on the resources that have accumulated around the development of cross-border integration. Rather, unbundled hydrogen network operators will have to build up the knowledge and cooperation between themselves anew. There is also little economic reason to demand stricter horizontal unbundling than accounts unbundling (see Section 3.2.3.1).

Horizontal unbundling is likely only creating a minor effect on cross-border integration.

3.2.3.3. Administrative costs: Likely higher with a clear separation of business activities

We expect the key effects of horizontal unbundling on administrative costs to be:

- Additional costs for NRAs and network operators because structures and tasks have to be replicated. For example, the introduction of accounts unbundling requires a separate tariff system for hydrogen networks (with own rules) and the administration of separate accounts for network operators that also operate natural gas networks. This loss of synergies is likely to be more significant for stricter forms of horizontal unbundling. In the case of horizontal ownership unbundling, for instance, know-how, personnel and other overhead costs cannot be shared between natural gas and hydrogen networks at all.
- The effect of horizontal accounts unbundling on the complexity of regulatory oversight is ambivalent. On the one hand, an obligation to keep natural gas and hydrogen network accounts separate increases transparency and may facilitate regulatory prevention of undesirable outcomes (such as "over-repurposing" of natural gas pipelines to hydrogen, see Section 3.2.3.5). On the other hand, both with and without separate accounts there will be a requirement to install a mechanism where any repurposing decision needs NRA approval (equivalent to new build decisions).

In summary, as with other aspects of regulation for an impact assessment it is reasonable to assume that stronger forms of horizontal unbundling lead to higher administrative costs.

3.2.3.4. Investment incentives: Horizontal unbundling might disincentivise hydrogen investments into new build hydrogen infrastructure

The degree of horizontal unbundling affects investment incentives primarily through the opportunity to refinance investments and the associated risk. A common asset base for gas and hydrogen networks means that the risks and costs associated with an investment are smaller as they are shared between the two commercial sides, gas and hydrogen transport. In addition, a common asset base might enable integrated investment planning by the network operators. This allows optimisation at company level but may also cause inefficient investment decisions when network operators seek to maximise rents and try to avoid any cannibalisation effect between gas and hydrogen networks.

In a regulatory environment requiring horizontal unbundling, network operators can not cross-subsidise between gas and hydrogen consumers. As a result, network operators face higher investment burdens and risks for hydrogen investments as they must be entirely refinanced by hydrogen consumers (everything else equal, i.e. no alternative support scheme).

Overall, in an impact assessment, the option of the joined RAB is likely to be associated with higher investment incentives for new build hydrogen infrastructure.

3.2.3.5. Repurposing: Horizontal unbundling likely has a strong impact

The degree to which methane network operators are allowed to operate hydrogen networks – and under which conditions – is likely to have substantial influence for the incentives and options to repurpose infrastructure. A strong unbundling requirement (e.g. horizontal **ownership unbundling**) means that methane network assets need to be removed from the methane asset base. There are several uncertainties associated with such an asset transfer, e.g. around how these assets are valued, how gas operators are remunerated and how these assets are captured within a new hydrogen asset base (with regards to depreciation, asset value). So, while it is still possible to repurpose gas network assets, a lot of new regulatory and economic arrangements must be made potentially creating risks and disincentives.

A weaker measure of unbundling, such as horizontal **account unbundling**, would require the network assets to be captured within separate asset bases, but would allow them to be operated under the same ownership. The option for a company to transfer assets within different asset bases facilitates repurposing and increases speed of implementation as it allows the company to use internal resources and knowledge. A network operator might use the asset within the regulated sphere (gas or hydrogen) where it provides the highest value for the operator in the specific regulatory setting.[27] Although it allows the operator to consider the different value (and lifetime and risks) of the same asset in either the natural gas or hydrogen asset base, this evaluation is also bound to the regulatory setting and potential inefficiencies arising from that.

The option to operate gas and hydrogen networks in a joint asset base ("**no horizontal unbundling**") is likely to facilitate repurposing. A common asset base would avoid the need to take assets out of and (in the case of a regulated hydrogen infrastructure) back into asset bases and allows network operators to finance the networks across users of both energy infrastructures, gas and hydrogen. This is of particular relevance during the hydrogen market ramp-up phase over the coming decade, where utilisation of hydrogen pipelines is likely to be relatively low, and consequently separate hydrogen network tariffs can be expected to be high. A common RAB approach would enable operators to spread these early adopter costs to the larger group of natural gas network users (see Section 4.2.2 for a detailed discussion and illustration of these effects).For a qualitative impact assessment framework, we recommend linking the possibility of joint RAB to strong incentives for repurposing existing natural gas pipelines.

While incentives to repurpose are generally beneficial given that providing hydrogen networks is substantially less costly with repurposed assets compared to new builds, these incentives come with the risk that too many assets are repurposed. This would happen, for example, if natural gas network operators repurpose to hydrogen networks (because this allows additional revenues and returns), even though decommissioning of the pipeline would lead to lower system costs (for example because hydrogen demand is expected to be limited). However, this risk can be addressed by the implementation of a mechanism where each repurposing investment has to be approved by the NRA similarly to new build investments today. Such a mechanism is required in a regulatory regime with any form of horizontal unbundling anyway, because even in a regime with separate natural gas and hydrogen accounts (and even in a horizontal ownership unbundling), there is a risk of incentives to "over-repurpose". One example is the case where valuation principles would allow the owner of a natural gas asset to re-valuate marginally used natural gas pipelines to a "use value" above the book value in the RAB account to incentivise the sale of these natural gas assets so that a third party can repurpose and operate it as hydrogen pipeline.

3.2.3.6. Summary on horizontal unbundling

Table 3-3 summarises the preceding discussions on how an impact assessment might evaluate the effects of horizontal unbundling in a hydrogen regulation.

[27] Here we focus on the regulatory setting and abstract from technical differences between the gas and hydrogen systems such as a lower transport capacity for hydrogen as opposed to gas with a given pipeline.

Table 3-3 Summary of assessment of horizontal unbundling options

Regulation	Impact on...									
	Hydrogen market structure (with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers (for new infrastructure)		Repurposing (existing infrastructure)	
No unbundling (joint RAB)	No cost-reflectivity: (Residential) natural gas users could end up paying for hydrogen grid for industry customers *[distributional impact]* No level playing field as companies without gas assets have a competitive disadvantage → high barriers to market entry But: Cross-subsidisation could decrease hydrogen network tariffs and thus increase incentives for consumers to switch to hydrogen	-	Repurposing spillovers as gas infrastructure is already integrated Hydrogen grid development can benefit from natural gas experience/knowledge	+	Reduced administrative burden for oversight and reporting Common RAB would imply same depreciation profile -> lack of room for regulator to adapt natural gas/hydrogen profile individually Cost allocation not transparent	0	Allows sharing of risks and costs Integrated planning of natural gas and hydrogen infrastructure	+	Facilitates repurposing by NG operators via cross-subsidisation of hydrogen by NG consumers May incentivise inefficient decisions if techno-economic parameters are fundamentally different (but can be addressed by approval requirement of NRA)	+ +
Accounts unbundling (separate RAB)	Cost-reflectivity can be maintained *[distributional impact avoided]* Level playing field, no starting advantage for gas TSOs But: Higher initial tariffs for hydrogen may decrease incentives for consumers to switch to hydrogen	0	Higher hydrogen network tariffs in early years due to low utilisation Allows to reflect different drivers of sector development (usage of assets, new networks) Hydrogen grid development can benefit from natural gas experience/knowledge	0	Costs for additional oversight and reporting (loss of synergies)	–	No scope for cross-subsidization, higher burden for hydrogen investments Possibility of higher investment returns if hydrogen pipelines are removed from the gas regulation Vested interests between methane/hydrogen divisions within same company	0	Difficult repurposing NG operators can still use knowledge from NG infrastructure Unbundling allows to reflect different value of NG/ H_2 assets, lifetime & risks	-

Legend	- -	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	+ +	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

3.2.4. Tariff regulation

Tariff regulation implies that the regulator determines the allowed or target revenues for regulated activities and provides the methodology or sets principles for the determination of the network tariffs. Three types of tariff regulation may be assessed as part of the impact assessment:

- **No tariff regulation:** Network operators can set tariffs individually, without ex-ante regulatory restrictions (while of course competition law still allows for ex-post investigations and measures)
- **Cost plus regulation:** Tariffs are set directly for each network operator with reference to individual costs. This usually includes a rate of return on both debt and equity, i.e. allows the network owner a profit margin in addition to the pure cost compensation.
- **Revenue regulation**: Tariffs are set indirectly; for example, through revenue or tariff caps. In electricity and gas markets, the caps are set using cost benchmarking that compares the efficiency of various network operators within a market. This form of regulation favours dynamic over static efficiency, which means that firms can make and keep temporary profits if they manage to reduce their costs between so-called 'photo years', where revenue or tariff caps are adjusted to actual individual costs.

These tariff regulation options were developed to regulate networks that are characterised as natural monopolies and have been applied in existing energy networks. We use empirical evidence from existing or past tariff regulation schemes to gain insights for the hydrogen network. Although general economic incentive mechanisms should be fairly transferable to the hydrogen market, the network structure of hydrogen will likely be different from other networks, especially in early market stages, which limits the applicability of some tariff regulations.

We discuss the impact of regulatory measures on the assessment criteria in the next sections and conclude with a summary of results in an assessment matrix (Section 3.2.4.6).

3.2.4.1. Market structure: Regulated network tariffs can prevent monopoly rents but could be a barrier in an early hydrogen market phase

The tariff structure for using a future hydrogen network is likely to have a strong impact on the resulting market structure:

- Markets with **no tariff regulation** do not set any rules on price setting behaviour. According to economic theory, profit-maximising tariffs of network operators with no explicit regulatory barriers become a problem in relation to market attributes when a mature hydrogen network corresponds to the character of a natural monopoly (see Section 3.1.3). Monopolistic tariffs and quantities develop at the expense of consumers and non-integrated upstream and downstream firms. Accordingly, a market with free pricing may lead to higher hydrogen end user prices and lower market penetration or liquidity. Tariff regulation creates price transparency through the regulator's monitoring of activities and prevents an excessive redistribution of the benefits towards network operators (monopoly rents). All market participants pay the same price for the same product and no price discrimination based on willingness to pay is possible.
- **Cost plus regulation** sets an upper limit for profits and helps address the adverse impacts of market power in a natural monopoly: Firms cannot charge excessive prices but need to get regulatory confirmation for their tariffs. However, as long firms are reimbursed for all occurring costs, there are no market incentives for them to increase efficiency (i.e. minimise cost at equal output and quality). Under a cost-plus regulation there is a stronger risk that construction and operation of hydrogen networks are inefficient. Especially overinvestments (gold plating) are a potential risk, where a network that is expanded too much leads to increased end user costs (Section 3.2.4.4.).

- **Revenue regulation**, which is also used in the electricity and gas network, is particularly suitable for increasing efficiency by mimicking competition between network operators. Evidence shows that the introduction of revenue regulation has decreased tariffs and increased productive efficiency in different networks, e.g. gas and telecoms.[28] Controlling market participants by regulating tariffs is necessary in an advanced market where the hydrogen transmission network represents a natural monopoly. However, it could be difficult and unfavourable to implement it in the early market ramp-up. In a hydrogen network that is currently being established, the market structure is quite dynamic, and the efficiency criterion may be of lower priority than a rapid network expansion. The efficiency in operation of a network becomes important after the network construction progresses. If an expanded hydrogen network has structures similar to the current gas network, revenue regulation could have a corresponding effect. In the next sections we elaborate further on this.

3.2.4.2. Cross-border integration: Tariff regulation at EU level might facilitate cross-border integration

In principle, transparent and uniform tariffs at EU level ensure better conditions for integrating the hydrogen network. **Without any form of tariff regulation**, network operators set up tariffs individually. Different tariff structures could arise across the EU, making transport of hydrogen across borders more complicated.[29] According to ACER (2020, 13), "*inconsistent tariff structures across MSs impacted effective cross-border gas transportation*" in the gas market. This experience also applies for the hydrogen network. Applying cost-reflectiveness, avoidance of cross-subsidisation and non-distortion of cross-border trade at the EU level could simplify integration (ACER 2020, 15).

Cost-plus regulation makes costs transparent and standardises tariff schemes (under the assumption that alongside cost-plus regulation, general principles of cost-reflectiveness, no cross-subsidisation and no distortion of cross-border trade apply to tariff schemes) but does not guarantee a socially optimal network integration across borders. The reason behind this is that there is no incentive mechanism that rewards companies for making efficient decisions. However, as cost-plus regulation tends to lead to increasing and (in some cases) to high investments, this could include some expansion of cross-border connections. But without additional coordination, misdirected hydrogen network expansion could be a risk under cost-plus regulation.

On the other hand, **revenue regulation** could create incentives for an efficient integration of national hydrogen markets. Economies of scale and lower production cost of green hydrogen in southern Europe could lead to a demand for large transit capacities across multiple borders. With revenue regulation, operators have a stronger incentive to construct pipelines efficiently and utilise them as much as possible to reduce costs. The goal of using pipelines as much as possible could promote the integration of a European hydrogen network. For networks to be well-integrated at the European level, however, the infrastructure must first be set up at national level. Since revenue regulation works primarily for mature markets it might be effective to promote integration only after the ramp-up phase.

3.2.4.3. Administrative costs: Revenue regulation is potentially costly and difficult to implement in the market development phase

Assuming the administrative costs are directly related to the degree of tariff regulation:

- **Revenue regulation** offers many advantages for establishing dynamic efficiency in the network. However, the regulatory implementation is complex and costly. To define tariffs, cost benchmarking must control for all factors that potentially

[28] See for example Heim, Krieger und Liebensteiner (2019) for evidence from gas networks and Resende (2000) for the telecommunication network.

[29] However, in particular cases, the absence of tariff regulation could also facilitate cross-border connections, because without regulation there are fewer barriers to operation – for example, when a point to point connection between a production and demand centre runs across a border between two or more countries.

influence efficiency results. Benchmarking is generally sensible with a relatively high number of comparable networks, which is found in few electricity and gas markets across the EU MSs. In the hydrogen market, the number of participants and the size of the pipeline network will be limited, especially in the early ramp-up phase. Implementing robust cost benchmarking is unlikely to be feasible during this period.

- A **cost-plus regulation** is likely easier to apply in an early market phase. In contrast to revenue regulation, the regulator can set a certain rate of return that does not need to be substantiated by an efficiency benchmarking. Cost monitoring of TSOs still requires a certain amount of effort compared to the case without any tariff regulation, where there are no administrative costs.

3.2.4.4. Investment incentives: The option to agree on unregulated tariffs may facilitate investments in new infrastructure

Generally, the introduction of tariff regulation faces the risk of impeding incentives to invest in hydrogen pipelines. This may appear counterintuitive, because tariff regulation is generally understood to reduce revenue risks which may facilitate investments. However, a revenue risk-reducing effect of tariff regulation requires captive customers, i.e. a secure customer base that covers the occurring cost of investments (and operation) of the regulated infrastructure irrespective of tariff levels. This is observed in many regional electricity and natural gas networks, where consumers carry the cost of the networks, which are regional natural monopolies. They are "captive customers", i.e. they cannot escape tariff increases, as they cannot switch to other network operators. Some electricity and gas customers may reduce their consumption or even switch energy carriers in case of increased network tariffs (e.g. followed by new investments in networks), but:

- This effect is likely to be small given that electricity and gas consumers are comparably price-insensitive
- The residual costs can be reallocated to the remaining customers (by increasing tariffs).

As a result, costs of new network investments can in any case be socialised to the aggregate of network users and ultimately consumers, and tariff regulated companies rarely face cost recovery risks.[30]

For new investments that cannot rely on captive customers, however, tariff regulation can have the opposite effect on investment incentives. If there is uncertainty about the size of the likely customer base for a new infrastructure asset, even a tariff regulation cannot guarantee cost recovery as it relies on customers carrying the cost via tariffs. In this case, tariff regulation imposes asymmetric risks for investors, which may render investments unattractive. Although investors face the downside risk of incomplete cost recovery if the infrastructure asset is not or hardly used, the upside chances of high returns are capped by the tariff regulation, because these restrict revenues to sustainably exceed cost recovery (plus a reasonable margin).

In the absence of strict regulatory conditions with tariff regulation, investors can enter into long-term agreements with infrastructure users such as producers, consumers, or wholesale traders (or integrate that supply chain in one vertically integrated undertaking) with commercial freedom to bilaterally agree on tariffs. This opportunity to secure the commercial risk of capital-intense infrastructure investments closes once strict tariff regulation is applied.

The asymmetric risk of (tariff) regulation compared to the commercial leeway in an unregulated setting without tariff regulation (and other regulatory measures such as TPA and vertical unbundling) is why many investors in new electric and gas infrastructure apply for regulatory exemptions (regulation holidays). This is an opportunity the EC introduced in the 2nd Energy Package in 2003. The option to apply for exemptions is restricted to investments in major new infrastructure without captive customers, namely LNG terminals and cross-border gas pipelines

[30] Note that we are simplifying here and abstracting from issues regarding a decreasing customer base in the natural gas market, which also imposes challenges for future cost recovery. We also abstract from revenue recovery risks associated with efficiency benchmarking (in the case where incentive regulation schemes compare efficiency of different network operators and reduce allowed tariffs for those operators that are identified as not fully efficient).

and electricity interconnectors. Applicants have to demonstrate that they meet a set of conditions. Of particular relevance here is the condition that "*the level of risk attached to the investment must be such that the investment would not take place unless an exemption was granted*" (Art. 36 no. 1b Gas Directive 2009/73/EC).

An example is an investment in an LNG import terminal where there are not necessarily any captive customers, as there are both pipeline and other LNG terminal alternatives to source gas, and so customers are not relying on the new terminal alone. As a consequence of these rules, approximately 70% of the LNG import terminal capacity in North-West Europe operates under exemptions from regulation, with the remainder stemming mostly from the period before the option of exemptions was introduced in 2003.[31]

Transferring this logic to hydrogen implies that the risks of investments in new hydrogen pipelines may be too high to be pursued under a standard regulation scheme with tariff regulation as long as the hydrogen market development is in an early phase with significant uncertainty about the future uptake. There is no substantial hydrogen customer base yet, and potential consumers can still choose between a number of options (such as decarbonising with other technologies and energy carriers). Thus, there are no captive customers that the investment cost could be socialised to.

In summary, early investments in hydrogen networks are likely to be pursued without strict tariff regulation to avoid asymmetric risks. In a regime without explicit regulation, however, there is a risk that at a later stage tariff regulation is introduced and applied to the pipeline of an investor, unless this is explicitly ruled out, for example in the form of regulatory holidays for a certain duration.

There are some nuances in the assessment of investment incentives for two key tariff regulation schemes:

- **Cost-plus regulation**. Economic theory suggests that among the various regulatory approaches cost-plus regulations tend to incentivise a growth of the RAB and provide comparably higher investment incentives. The resulting risk of overinvestment in infrastructure, also referred to as 'gold plating', is an acknowledged economic principle (Averch und Johnson 1962) and has been confirmed empirically for regulated network industries (Mathios and Rogers 1989). Given the early stage of the hydrogen market and the objective to realise a timely development of cross-border hydrogen infrastructure, 'gold plating' might be considered a small concern for the purpose of this impact assessment; However, this will have to be re-assessed for the long-term regulation of hydrogen infrastructure, where investment incentives should reflect the market needs (demand and supply dynamics) for infrastructure.
    - At the same time with cost-plus regulation profits are limited to a specific rate of return, which will strongly drive the investment incentives and thus risks of over- or under-investments under cost-plus compared to the case of no regulation.[32] Thus, the allowed rate of the return (and the underlying methodology) have a strong influence on the impact of cost-plus regulation on investment incentives. A higher allowed return also increases the adverse effects of a cost-plus regulation, which is why we assume a moderate rate of return in the assessment, similar to the gas market or possibly slightly higher.
- **Revenue regulation** sets out efficiency-increasing incentives as it allows network operators to realise higher margins from implementing measures that reduce costs until the revenue cap is adjusted for the next regulatory period. Evidence from previous network regulation shows that revenue regulation remedies part of the weaknesses of the lack of incentives in cost-plus regulation. For example, Ai and Sappington (2002) compared the correlation between cost-plus or incentive regulation and several performance measures in the US telecoms sector and found a greater network

[31] See (Frontier Economics 2020), page 28. See also https://ec.europa.eu/energy/sites/default/files/documents/exemption_decisions2018.pdf for an overview of exemption decisions for new energy infrastructure taken by the European Commission.

[32] Investment incentives naturally increase with the rate of return.

modernisation under incentive regulation. This is beneficial in a matured infrastructure sector to decrease costs and make TSOs more efficient. For a network expansion, however, revenue regulation could still be an obstacle as investors can only make profits in the short term while the above-mentioned asymmetric investment risks remain. Revenue regulation is more suited to an advanced market with a well-developed network, as efficiency gains are then rewarded.

3.2.4.5. Repurposing: Regulation of tariffs limits possible profits which could decrease incentives

Investments in new infrastructure and repurposing follow similar incentive mechanisms: Repurposing a gas pipeline to transport hydrogen becomes attractive if the profit from transporting hydrogen is higher than the opportunity cost; in this case, the profit from continuing gas transmission. Economic theory suggests that with **no regulation of hydrogen network tariffs**, firms will determine tariffs to maximise their profit. Larger margins would be possible in the hydrogen market than in the gas market, which incentivises repurposing. In addition, market-based incentives without regulation promote efficient investments. Firms would probably first repurpose pipelines whose conversion to hydrogen is most profitable.

Stricter regulation that limits high profits is expected to reduce repurposing incentives. **Cost-plus regulation** allows companies to set tariffs to cover their costs and make a certain profit. However, the permitted profits are limited in the case of cost-plus regulation. Unless this upper profit limit is very high (at a level of profit without regulation), repurposing incentives tend to decrease as margins decrease. This investment security might even create adverse investment incentives, e.g. firms could transfer pipelines into the hydrogen network for which there is no social profit at all. The consequence would be an inefficient repurposing of pipelines to the detriment of both hydrogen and gas networks. It is expected that cost-plus regulation makes repurposing attractive by creating higher investment security versus under revenue regulation (see below), but does not necessarily incentivise efficient investment decisions to transfer gas pipelines to the hydrogen network.CO

Revenue regulation counteracts inefficiency by rewarding companies with low costs. As the regulation uses the concept of dynamic efficiency, profits are possible only temporarily until regulated tariffs are adjusted downwards. This mechanism is effective at regulating prices in mature networks, but potentially an obstacle to repurposing. Compared to the options of cost-plus and no tariff regulation, revenue regulation does not allow automatic profits over a longer period of time, which weakens business cases and hampers a quick expansion of the hydrogen network via repurposing.

3.2.4.6. Summary on tariff regulation

Table 3-4 summarises the preceding discussions on how an impact assessment might evaluate the effects of different manifestations of tariff regulation in a hydrogen regulation.

Table 3-4 Summary of assessment of tariff regulation options

NB: choice of tariff regulation only possible for packages including horizontal unbundling

Regulation	Impact on… Hydrogen market structure (with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers (for new infrastructure)		Repurposing (existing infrastructure)	
No revenue or tariff regulation	Free choice of tariffs could increase hydrogen prices, leading to welfare losses as operators charge monopoly rents. No cost reflectivity, potential discrimination of price-insensitive network users No price transparency	– –	Lack of regulation of profits could lead to varying degrees of network expansion in EU nations Differing tariffs across EU nations hinder cross-border integration	–	Low administrative burden Cost allocation not transparent	+	Increased flexibility for network operators to adjust tariffs High incentives as profit-maximising tariffs are possible Investment uncertainty due to the risk of future regulation (unless ruled out in regulatory holidays)	+ +	High incentives to transfer a pipeline into the hydrogen network to escape gas regulation	+ +
Cost-plus regulation	Removes potential for monopoly pricing No incentives for network operators to increase efficiency: could lead to higher hydrogen prices	0	Regulation creates transparency and uniform rules across borders No additional clear impact on integration	0	Costs for regulatory oversight and reporting	–	Provides security (lower risk through allowed rate of return) for investors (and allows depreciation over longer period Dependence on definition of allowed return: Can result in inefficient (over-)investments, however potentially smaller concern for emerging market	0	Use of pipeline for hydrogen instead of gas removes risks Guaranteed profits but no possibility for high profits	0
Revenue regulation	TSOs operating under a revenue-cap regime have an incentive to reduce tariffs to increase allowed revenues and profits. Increased competition for demand at network points (probably not applicable in hydrogen ramp-up phase)	+	Predictability of investments on EU level enables better integration	+	Costs for regulatory oversight expected to be high, including reporting, benchmarking, and disputing settlement Hard to benchmark costs in a new market with few participants	– –	Asymmetric revenue risk for investors with deterrent effect on investments in new infrastructure Right mix of incentives vs. investment security for a matured network Might not give right incentives for emerging market	–	No secure profits, dynamic efficiency criterion prevents quick expansion of hydrogen network via repurposing Gas and hydrogen regulation are not fully harmonised, this could lead to arbitrage A more generous hydrogen regulation compared to gas could create incentives for repurposing	–

Legend									
- -	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	+ +	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

3.3. Applying assessment to EC's draft policy packages

This section outlines the transfer of the results of the assessment of single regulation measures for hydrogen infrastructure from the preceding chapter to draft policy packages.

The EC developed a spectrum of draft policy packages that entail possible regulatory frameworks for EU hydrogen infrastructure.[33] These draft policy packages constitute the point of departure for the impact assessment. Specifically, the EC's draft policy packages are:

- **BAU (business-as-usual) scenario**: No additional regulatory measures are introduced on an EU level compared to today's market frameworks.
- **Option 1 – Competition for the market**: This option implies that rights for hydrogen network investments or operations are tendered to market participants. There would be competition for the market (i.e. players bid for the market and are then granted a monopoly position) instead of in the market (i.e. anyone can enter the market and compete within it) and it would follow the winner takes it all principles for each lot tendered (e.g. on national level or local networks within MSs).
- **Option 2 – Main regulatory principles** including:
    - **Option 2a – Light regulation**: The main regulatory measures are introduced in their lighter versions such as vertical accounts unbundling and negotiated TPA, and high level principles with regards to capacity allocation and balancing are determined in secondary legislation (equivalent to Network Codes in electricity and natural gas markets). There is no dedicated tariff regulation (and so no equivalent to the Commission Regulation on transmission tariff structures for gas (2017)) that would provide principles for network tariff setting.
    - **Option 2b – Intermediate regulation**: More stringent manifestations of vertical unbundling and rTPA are introduced, tariffs (or revenues) are regulated.
- **Option 3 – Detailed rules at the EU level** implementing key regulatory principles to cater for cross-border market development/liquidity, including:
    - **Option 3a – National Independent Systems Operator (ISO)/Ownership Unbundling model**: Stringent rules for vertical unbundling and rTPA are introduced, national ISOs are put in place, and revenue regulation is introduced.
    - **Option 3b – EU TSO (ISO model):** In addition to the measures above, an EU hydrogen TSO is created tasked with operating and developing an EU hydrogen network (while the ownership of pipelines remains with the (national) gas TSOs.

In all packages with explicit tariff or revenue regulation (i.e. Options 2b, 3a, and 3b), the default manifestation of horizontal unbundling is horizontal accounts unbundling, implying a separate RAB for hydrogen networks. For Options 2b and 3a we also consider an alternative manifestation where hydrogen and natural gas network assets can be operated under a joint RAB, i.e. no horizontal unbundling condition.

This spectrum of policy packages is based on a set of regulatory measures. These include conventional regulatory measures such as **vertical unbundling, TPA, and revenue regulation,** as well as measures specific to the hydrogen sector (horizontal unbundling). Beyond that, we include the possibility to **tender rights for pipeline buildout and operation** in the assessment framework, as Option 1 of the EC draft policy packages suggests.

3.3.1. Assessment framework for EF's draft regulatory packages

This section outlines the approach on how to map our indicative assessment of main regulatory measures to the EC's draft policy packages. We base the overall evaluation of these draft policy packages on an aggregation of the individual assessment frameworks as developed in the preceding chapter. The first step therefore is to link the packages to the individual regulatory measures. Table 3-5 maps the EC's draft policy packages to regulatory measures as a basis for an impact assessment:

[33] As communicated to Guidehouse and Frontier by DG Ener on 14 December 2020.

Table 3-5 Mapping of the EC's draft policy packages to regulatory measures

Regulatory measures	BAU No additional measures	Option 1 Competition for the market	Option 2 Main regulatory principles		Option 3 Detailed rules at EU level	
			2a: Light regulation	2b: Intermediate regulation	3a: ISO model	3b: EU hydrogen TSO
Tendering	-	Tendering of concessions to own and operate hydrogen networks at national level	-	-	-	-
TPA	No TPA	No TPA	nTPA	rTPA for repurposed assets	rTPA	rTPA
Vertical unbundling	No vertical unbundling	No vertical unbundling	Accounts unbundling	Legal and functional unbundling	ISO/Ownership Unbundling	EU TSO (ISO model)
Tariff regulation	No tariff regulation	No tariff regulation	Cost-reflective tariffs	Cost regulation for repurposed assets	Revenue regulation	Revenue regulation
Horizontal unbundling – Default	No horizontal unbundling	No horizontal unbundling	No horizontal unbundling	Separate RAB (accounts unbundling)	Separate RAB (accounts unbundling)	Separate RAB (accounts unbundling)
Horizontal unbundling – Alternative	- *[Joint RAB not possible]*	- *[Joint RAB not possible]*	- *[Joint RAB not possible]*	Joint RAB	Joint RAB	Joint RAB

Note: In Option 1 minimum requirements on vertical unbundling, horizontal unbundling, TPA and tariff structures could be imposed ex post (art. 102 TFEU).

3.3.2. *Indicative summary on framework for assessment of EC draft policy packages*

Section 3.2 assessed the individual regulatory measures on an all things equal basis, i.e. we did not analyse potential interactions between different regulatory measures. The following sections offer a high-level assessment of the EC's different regulatory packages, where we also consider how regulatory measures function as a package.

3.3.2.1. Business-as-usual regulation – No additional measures

Under the BAU option the ownership and operation of hydrogen networks remains unregulated. Companies can invest in hydrogen pipelines and operate these pipelines with a large degree of commercial freedom. This allows for a range of companies and partnerships to develop. For example, a large hydrogen producer may enter into long-term supply contracts with industrial hydrogen consumers (or groups of companies) and offer the whole service of hydrogen production, transport, and structuring/storage/balancing (no vertical unbundling rules). The partners could agree freely on commercial terms (no tariff regulation) and the vertically integrated company could act as the sole user of the pipeline (no TPA), where the company may decide to buy part of the hydrogen from decentral hydrogen producers if a network connection and purchase is commercially viable (make or buy decision). Additional consumers can be connected if that is commercially attractive. An alternative setting is an infrastructure company that decides to invest in hydrogen pipelines and enter into long-term contracts with producers and consumers to secure the investment. Or consumers and producers create a joint venture to secure investments in transport infrastructure to enable hydrogen supply to the consumers.

The key learnings from our qualitative assessment include:

- **Investment incentives (new and repurposing)**: The commercial freedom to enter into long-term agreements and secure investments at bilaterally agreed-upon terms may facilitate investments in an early phase of hydrogen market development, where there are no captured customers to socialise high initial costs (absence of a common RAB approach or other forms of direct investment support such as subsidies). This holds for investments in new pipelines and investments required to repurpose natural gas pipelines for hydrogen.
- **Market structure**: For a given hydrogen network, the BAU no-regulation approach bears the risk of monopolistic network tariffs, with negative implications for the hydrogen uptake and ultimately for decarbonisation targets. If vertically integrated companies emerge, market foreclosure of upstream and downstream markets can result in monopolistic prices along the entire hydrogen value chain. Consequently, once the hydrogen market becomes increasingly mature with many locally distributed producers and consumers, additional regulatory measures may be introduced to prevent the downsides of monopolistic patterns.
- **Cross-border integration**: Without regulation, pipeline networks will be developed in a bottom-up approach, which is likely to result in dispersed, uncoordinated network development across the EU. Unregulated private investors will build pipelines where this is most profitable, which may lead to socially undesirable outcomes with different speeds of cross-border hydrogen pipeline developments. Generally, we expect the BAU no-regulation approach to lead to less cross-border integration than the other regulatory packages that explicitly support cross-border hydrogen network planning and cross-national harmonisation of rules.

3.3.2.2. Option 1: Competition for the market

This option is similar to the BAU option in that it does not impose explicit regulation on hydrogen network owners and operators (i.e. no competition in the market), but it expects tendering the rights for hydrogen network investments and operation to market participants (competition for the market). The successful bidder would be granted a regional monopoly position, e.g. on national level or for a local network within MSs or possibly even for a specific pipeline, under which the bidder could build and operate a hydrogen pipeline and supply hydrogen customers. There are several forms of such a tendering approach to consider. For instance, it could be a light touch approach where the successful bidder gains the exclusive right to build hydrogen pipelines in a certain region and would be free as to how and to which level this is used. The opposite extreme is a tender approach, where the tender documents precisely specify rights and obligations of the monopolist network operator, for example, with regards to the hydrogen pipelines that are to be built and operated exactly where and the maximum tariffs that can be granted, among others.

Although the definition of a concrete tendering approach is not in the scope of this report, some high-level take-aways follow:

- **Investment incentives (new pipelines)**: The level of investment incentives under this tendering approach depend strongly on the details of the approach.
    - If only the exclusive right to build and operate hydrogen networks is tendered (without further obligations on actual provision of transport services), the investment incentives are largely similar to those in the BAU approach, where the commercial freedom to bilaterally agree on long-term contracts may facilitate investments in the early market development where large producers serve large (industrial) consumers. The rights to build and operate hydrogen pipelines under the tendering approach may hamper investments, as it excludes the option that other stakeholders build pipelines to supply consumers if the regional monopolist (i.e. the successful bidder in the tender process) is not willing to connect a consumer.[34]
    - When the tendered concessions come with a specified set of rights and obligations (for example, to build certain hydrogen pipelines and offer particular services), the level of investments is no longer a bottom-up market outcome but basically a politically driven decision where the tendering details have to ensure that there are interested parties that bid for the concessions and ultimately build and operate the pipelines accordingly. One element of this may be the option that bidders do not pay to get the concession, but—in case they expect that costs to comply with the hydrogen transport supply obligations exceed revenues—rather receive (subsidy) payments to cover the expected deficits. However, this approach would require central bodies to identify concrete hydrogen transport needs and determine corresponding obligations for the concession, compared to a bottom-up approach where market parties with own commercial interests unite and define hydrogen transport needs. This central planner approach poses a significant risk that resulting hydrogen networks deviate from actual needs with regards to level, location, or timing of hydrogen transport capacity development.
- **Repurposing**: Creating appropriate repurposing investments is challenging in a tendering approach. A sensible tendering scheme requires vivid competition of at least a couple of potential bidders. This requires that the regional natural gas TSO(s) and other stakeholders both can realistically bid for the hydrogen concession. Let’s assume a non-gas TSO acquires the hydrogen concession, and thus the exclusive right to own and operate hydrogen pipelines for a certain period of time (e.g. 20 years). Assume natural gas consumption declines and a natural gas pipelines rapidly idle and could be repurposed to hydrogen; the natural gas pipeline asset then needs to be transferred from the natural gas TSO to the hydrogen network operator. In the case of an exclusive hydrogen network operator, however, there is a situation with a single potential seller (the gas TSO) and a single potential buyer (the hydrogen network operator), which requires a strong regulatory approach to determine the conditions of this asset transfer.
- **Market structure**: Unless the concession is associated with other conditions regarding TPA, vertical unbundling, or tariffs, the impacts of this approach on market structure and

[34] A potential example where this could become relevant is if the concession to own and operate hydrogen pipelines is won by a party that is affiliated with a certain industrial consumer (either via a joint venture or in a vertically integrated company) with the purpose to supply this consumer with hydrogen, and a competitor of that consumer asks to be supplied with hydrogen, too. In that case Art. 102 TFEU may offer the option to impose minimum requirements for example on vertical unbundling, TPA or tariff structures ex-post, but bidders in the tendering process will aim to have clarity about future rules to build their business models on, so significant risks of substantial changes of the framework can be detrimental to the willingness (and the prices) to bid for the concessions in the first place, and thus should be avoided as much as possible.

hydrogen uptake (for a given hydrogen network) are similar to those of the BAU no-regulation approach. It bears the risk of monopolistic network tariffs with potential negative implications for the hydrogen uptake and ultimately for decarbonisation targets. In contrast to the BAU approach, the tendering approach provides the central body tendering concessions the opportunity to generate income. This would allow the central body to absorb monopolistic rents of the regional monopolistic hydrogen network operators and redistribute it to hydrogen consumers, which may prevent the negative allocative effects of monopolistic pricing (i.e. low hydrogen uptake) and compensate for distributional effects.

- **Cross-border integration**: The level of cross-border integration will largely depend on political decisions, rather than on bottom-up decisions by market players. Compared to the draft policy packages that build on explicit mechanisms for harmonised network planning and market rules (such as packages 2b, 3a, and 3b) we expect this tendering approach to lead to lower cross-border integration, but higher integration compared to the BAU approach.

3.3.2.3.Options 2 and 3: EU regulation (default options without common RAB)

EU draft policy packages 2 and 3 introduce stricter sets of regulatory measures such as various forms of vertical unbundling, TPA, and tariff regulation. Section 3.2 details of the impacts of these measures. The key tendencies of the packages with regards to the criteria we consider in this report follow:

- **Investment incentives (new)**: Generally, stricter regulation may impede incentives to invest in hydrogen pipelines.
  - This may appear counterintuitive, because tariff regulation is generally understood to reduce revenue risks and facilitate investments. However, a revenue risk-reducing effect of tariff regulation requires captive customers, i.e. a secure customer base that covers the occurring cost of investments (and operation) of the regulated infrastructure irrespective of tariff levels. This is observed in many regional electricity and natural gas networks, where consumers carry the cost of the networks, which are regional natural monopolies. They are “captive customers”, i.e. they cannot escape tariff increases, as they cannot switch to other network operators. Some electricity and gas customers may reduce their consumption or even switch energy carriers in case of increased network tariffs (e.g. followed by new investments in networks), but:

    i) This effect is likely to be small given that electricity and gas consumers are comparably price-insensitive

    ii) The residual costs can be reallocated to the remaining customers (by increasing tariffs)

    As a result, costs of new network investments can in any case be socialised to the aggregate of network users and ultimately consumers, and tariff regulated companies rarely face cost recovery risks.[35]
  - For new investments that cannot rely on captive customers, however, tariff regulation can have the opposite effect on investment incentives. If there is uncertainty about the size of the likely customer base for a new infrastructure asset, even a revenue regulation cannot guarantee cost recovery as it relies on customers carrying the cost via tariffs. In this case, tariff regulation imposes asymmetric risks for investors, which may render investments unattractive. Although investors face the downside risk of incomplete cost recovery if the infrastructure asset is not or hardly used, the upside chances of high returns are capped by the revenue (or tariff) cap regulation, that would restrict revenues to exceed cost recovery (plus a reasonable margin).

[35] Note that we are simplifying here and abstracting from issues regarding a decreasing customer base in the natural gas market, which also imposes challenges for future cost recovery. We also abstract from revenue recovery risks associated with efficiency benchmarking (in the case where incentive regulation schemes compare efficiency of different network operators and reduce allowed tariffs for those operators that are identified as not fully efficient).

- In the absence of strict regulatory conditions, investors can enter into long-term agreements with infrastructure users such as producers, consumers, or wholesale traders (or integrate that supply chain in one vertically integrated undertaking) with commercial freedom as to the duration of contracts, the form of capacity allocation (no TPA), and tariffs. This opportunity to secure the commercial risk of capital-intense infrastructure investments closes once strict regulation is applied.

The asymmetric risk of regulation compared to the commercial leeway in an unregulated setting is why many investors in new electric and gas infrastructure apply for regulatory exemptions (regulation holidays). This is an opportunity the EC introduced in the 2nd Energy Package in 2003. The option to apply for exemptions is restricted to investments in major new infrastructure without captive customers, namely LNG terminals and cross-border gas pipelines and electricity interconnectors. Applicants have to demonstrate that they meet a couple of conditions, of particular relevance here is the condition that "*the level of risk attached to the investment must be such that the investment would not take place unless an exemption was granted*" (Art. 36 no. 1b Gas Directive 2009/73/EC). An example is an investment in an LNG import terminal where there are not necessarily any captive customers, as there are both pipeline and other LNG terminal alternatives to source gas, and so customers are not relying on the new terminal alone. Accordingly, approximately 70% of the LNG import terminal capacity in North-West Europe operates under exemptions from regulation, with the remainder stemming mostly from the period before the option of exemptions was introduced in 2003.[36]

Transferring this logic to hydrogen implies that the risks of investments in new hydrogen pipelines may be too high to be pursued under a standard regulation scheme as long as the hydrogen market development is in an early phase with significant uncertainty about the future uptake. There is no substantial hydrogen customer base yet, and potential consumers can still choose between a number of options (such as decarbonising with other technologies and energy carriers). Thus, there are no captive customers where investment cost could be socialised to.

These potentially detrimental effects of regulation on investment incentives are particularly relevant for packages with tariff regulation (as this causes the asymmetric revenue risk), so Options 2b, 3a, and 3b, but less so an issue in Option 2a where only mild forms of regulation such as nTPA and vertical unbundling are introduced.

- **Repurposing**: Generally, the rationale of limited investment incentives under regulation without captive customers holds for repurposing investments (note, this is under the assumption of a separate RAB approach, a discussion of joint RAB follows). There are differences in that repurposing investments are lower than investments in new pipelines, and so a lower share of total costs is CAPEX sunk straight after the investment is made. In that sense, customers who have been connected to a natural gas pipeline can now be converted to hydrogen via a repurposed pipeline and are more likely to be captive in the sense that alternative decarbonisation options are relatively more expensive (than for greenfield hydrogen consumers where the connection require new pipeline investments).
- **Market structure**: The key objective of introducing infrastructure regulation is to mimic competition for the infrastructure operation (e.g. by efficiency benchmarks when setting the allowed revenues or tariffs) to set incentives to increase cost efficiency and reduce infrastructure costs, and to enable competition in the business activities upstream and downstream the infrastructure, reducing costs and prices for these activities as well. Assuming a given infrastructure capacity (i.e. abstracting from the question of investment incentives), stricter forms of regulation generally help achieve these regulatory objectives. In the case of hydrogen, a light-touch regulatory approach such as Option 2a with nTPA and vertical accounts unbundling (but no tariff regulation) has the potential to achieve

[36] See (Frontier Economics 2020), page 28. See also https://ec.europa.eu/energy/sites/default/files/documents/exemption_decisions2018.pdf for an overview of exemption decisions for new energy infrastructure taken by the European Commission.

some of the objectives to enable competition in merchant activities. Based on the experience in electricity and gas markets, however, we can expect stricter measures will be required to sustainably enforce functioning competition and liquid markets. Such measures include rTPA, stricter forms of vertical unbundling (such as at least legal unbundling as in the case of Option 2b or even SO or ownership unbundling as in Options 3a and 3b), and tariff regulation. Consequently, once hydrogen networks are built and their costs remunerated to the investors, they may need to be exposed to stricter regulation than the light-touch regulation as in Option 2a.

- **Cross-border integration**: The introduction of regulation generally facilitates cross-border integration. While unregulated private investments are likely to happen in a more uncoordinated bottom-up manner, regulation allows policymakers and NRAs to require certain forms of top-down cross-border coordination.
    - The introduction of rTPA (in Options 2b and above) ensures non-discriminatory access to cross-border infrastructure, which is essential to enable transport of hydrogen over long distances, for example, for transit-flows that seek to connect low cost hydrogen regions with high hydrogen demand regions.[37] If network access, capacity allocation and balancing rules are further harmonised across borders (for example fostered by European or regional transparent capacity booking platforms), this provides additional ground for cross-border integration.
    - Vertical unbundling tackles the challenge that vertically integrated undertakings have incentives to protect their home markets by limiting cross-border capacity to not threaten profits in upstream and downstream markets of the hydrogen supply chain. Evidence in the natural gas market has shown that fully unbundled TSOs reinvest a higher share of their congestion revenue in new capacity.
    - The introduction of revenue regulation in Option 3a (possibly including an NC TAR equivalent to harmonise tariff principles across borders) may further increase cross-border integration.

  The strongest cross-border integration can be expected with the introduction of an EU-wide ISO (Option 3b) that internalises cross-border coordination within the EU.

3.3.2.4.Options 2b and 3a: EU regulation with alternative of common RAB

For draft policy package Options 2b and 3a, the EC suggests assessing an alternative without horizontal accounts unbundling. That is, providing the opportunity for TSOs to own and operate natural gas and hydrogen network assets under a joint RAB, enabling cross-subsidising hydrogen network costs by tariffs for natural gas network users (or the other way around). Section 3.2.3 details this (and Section 4.2.2 applies a semi-quantitative assessment). We summarise some key findings here:

- **Investment incentives**: The opportunity for a joint RAB model allows gas TSOs to cross-subsidise hydrogen network costs by natural gas consumers, which facilitates investments in hydrogen networks in an early development period where hydrogen networks have low use and where fully cost-reflective tariffs for hydrogen network users result in high tariffs. This generally holds for investments in new pipelines and for repurposing costs (although these are comparably low and so the detriment of a separate RAB may not be as severe as for new investments). A challenge of a joint RAB approach is a potential incentive to over-deliver on repurposing, if TSOs are incentivised to repurpose a natural gas pipeline. However, from a system perspective repurposing is more costly than decommissioning (e.g. if hydrogen demand is expected to be low). To address this, any repurposing decisions would need to require NRA approval. Another challenge is a potential competition distortion of non TSOs that may hamper private hydrogen network investments.

- **Market structure/hydrogen uptake**: As described (and quantified in Section 4.2.2), a joint RAB approach is likely to result in lower network tariffs for hydrogen consumers than a

[37] Experience in the natural gas market has shown that a lack of (non-discriminatory) access to the infrastructure has constituted an important obstacle to cross-border trade and further market integration in the past, see Jones (2016, 70).

separate RAB approach (as long as we abstract from other forms of support for hydrogen networks in a separate RAB approach). This can help increase incentives for consumers to switch to hydrogen, particularly in an early market ramp-up period.

- **Distributional effect**: With a joint RAB hydrogen and natural gas network tariffs would no longer be cost-reflective, i.e. natural gas users could end up paying for the hydrogen network, and these consumer groups may deviate substantially (e.g. in case hydrogen is largely used by industrial consumers in an early phase, while natural gas consumers are to a large extent residential users). This distributional effect is not among the criteria we analyse as part of this assessment framework (however, we do subsume it under market structure to make it transparent).

3.3.2.5. Summary

Table 3-6 summarises our qualitative findings. The next section elaborates on the specific issues on the transition from one regulatory package to the other, followed by our proposal on how to translate the qualitative findings of this impact assessment into the parameters required for the quantitative model approach in Section 3.4. Such a model-based analysis might allow for a more quantitative evaluation and so could facilitate a trade-off of the various aspects on a quantitative basis.

Table 3-6 Summary of draft policy package assessment[38]

Draft policy package		Indicative impact on…									
		Hydrogen market structure (with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers (for new infrastructure)		Repurposing (existing infrastructure)	
BAU	No regulation across EU	Lack of competitive pressure entails risk of monopolistic prices No level playing field for all market participants	-	Lack of EU harmonisation with risk of lower cross-border integration	-	Low administrative burden for NRAs and TSOs	+	Commercial leeway for investors enables securing of investments	+	Commercial leeway for investors enables securing of repurposing investments (including pipeline purchase costs)	+
1	Rights for network investments/operation tendered	Lack of competitive pressure equivalent to BAU Tendering income can be used to redistribute back to consumers	0	Cross-border integration depends largely on policy stakeholders, general assessment infeasible	0	Low costs for actual regulation, but additional efforts for tendering process	0	Commercial leeway with positive effect, but exclusiveness may hamper investments	0	Generating appropriate repurposing incentives difficult in setting with only one seller and one buyer of pipeline	-
2a	Vertical accounts unbundling, nTPA, no tariff regulation	Light-touch regulation facilitates access to network to some extent with lower prices and higher hydrogen uptake, but this effect is limited	0	nTPA may allow for some level of cross-border coordination, but lack of rTPA keeps barriers to cross-border trade and limited forces to mandate cross-border network planning	0	Additional costs for NRAs and TSOs (compared to BAU), but limited in scope given light-touch approach (In addition, higher negotiation efforts for TSOs and network users)	-	Limitation of commercial leeway hampers hedging options for investors, but no systematic asymmetric risks as in packages with tariff regulation	0	Limitation of commercial leeway hampers hedging options for investors, but no systematic asymmetric risks as in packages with tariff regulation	0
2b	a) Legal + functional unbundling, rTPA for repurposed assets (nTPA for private networks), cost plus regulation for repurposed assets (no regulation for private), separate RAB	Stronger facilitation of network access plus tariff regulation may reduce prices and encourage hydrogen uptake But higher tariffs for hydrogen (compared to joint RAB) may hamper hydrogen uptake	0	rTPA allows to enforce cross-border network planning, plus legal basis for further harmonisation measures such as harmonised principles for capacity allocation or balancing	+	Additional costs for NRAs and TSOs (compared to 2a), while lower costs for network users through transparency and standardised rules (of rTPA)	-	Tariff regulation and limited commercial freedom in a situation without captive customers may result in hardly hedgeable asymmetric risks	-	Tariff regulation and limited commercial freedom in a situation without captive customers result in hardly hedgeable asymmetric risks But less detrimental than for new investments because repurposing investments are comparably low	0

[38] Please note that the assessment of the policy packages has been performed under the assumption that the respective regulatory measures are actually applied. The picture may change when taking the opportunity of exemptions from regulation into account, see row „Exemption regimes".

Draft policy package		Indicative impact on… Hydrogen market structure (with a given transport capacity)		Cross-border integration		Administrative costs		Investment incentives/barriers (for new infrastructure)		Repurposing (existing infrastructure)	
	b) Same as a) but with joint rather than separate RAB	Similar to 2b with separate RAB, but lower tariffs for hydrogen (through cross-subsidisation) may increase incentives for consumers to switch to hydrogen But: No level playing field between new market participants and gas TSOs And: No cost-reflectivity, burden at expense of gas consumers *[distributive effect]*	-	Similar to 2b with separate RAB	+	Similar to 2b (with separate RAB), with some synergies on the one hand, but also additional efforts to avoid "over-repurposing" (by regulatory oversight) on the other hand	-	Joint RAB allows gas TSOs to cross-subsidise high initial hydrogen investment costs by natural gas consumers Competition distortion for non TSOs may hamper private hydrogen network investments, though	0	Joint RAB leads to cross-subsidisation of repurposing investments by natural gas consumers Risk of over-repurposing (can mitigate through NRA approval) Competition distortion for non TSOs may hamper private hydrogen network investments, though	+
3a	a) Full vertical unbundling and TPA, national hydrogen ISOs are put in place, separate RAB	Similar to 2b (with separate RAB) plus network access further improved by full vertical unbundling/ISOs National ISOs can react agilely to local market development	+ +	Similar to 2b, plus improved possibility to harmonise tariff principles through revenue regulation	+	Additional costs for NRAs and TSOs (compared to 2b), while lower costs for network users through transparency and harmonised rules (of rTPA and revenue regulation)	-	Similar to 2b (with separate RAB)	-	Similar to 2b (with separate RAB)	0
	b) Joint RAB with revenue regulation	Similar to 2b (with joint RAB) plus network access further improved by full vertical unbundling/ISOs plus	0	Similar to 3a with separate RAB	+	Similar to 3a (with separate RAB), with some synergies on the one hand, but also additional efforts to avoid "over-repurposing" (by regulatory oversight) on the other hand	-	Similar to 2b (with joint RAB)	0	Similar to 2b (with joint RAB)	+
3b	a) Full vertical unbundling and TPA, EU TSO, separate RAB	Similar to 3a (with separate RAB), but EU TSO probably less agile in reacting to national / regional developments	+	Similar to 3a with additional cross-border integration through EU TSO	+ +	Similar to 3a (with separate RAB), with some additional costs for EU ISO but synergies for reduced direct TSO coordination	-	Similar to 2b (with separate RAB)	-	Similar to 2b and 3a (with separate RAB)	0
Exemption regime		The assessment above is undertaken on the assumption that the regulatory measures in each package are applied to all pipelines. In case certain pipelines (e.g. new pipeline investments) are granted exemptions from certain measures (e.g. TPA, vertical unbundling, tariff regulation) equivalent to regulatory exemptions for gas and electricity infrastructure, the assessment may differ. For example, the negative effects on investment incentives in draft policy packages 2 and 3 can be tackled with exemptions for new pipelines, while providing long-term certainty about the regulatory regime for a significant part of the asset lifetime (e.g. 20 years). Depending on the specifics of the exemption (e.g. duration), positive effects of regulation on market structure and cross-border integration can be largely maintained with an exemption regime.									

Legend									
	- -	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	+ +	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

3.3.3. Additional considerations regarding the transition phase

Hydrogen network development and regulatory priorities could shift optimal regulation schemes over time

The need for and type of regulation adequate for the hydrogen network depends on the regulator's priorities and the competitive situation in the market for hydrogen transport itself as well as in upstream (e.g. hydrogen production) and downstream (e.g. hydrogen supply) markets.[39] Parameters, which can provide an indication on the competitive situation within one of these markets, (apart from the sub-additive cost curve)[40] include the market concentration and number of suppliers or consumers of hydrogen, which constitute buyers of the hydrogen transport service. As the hydrogen market develops over time the competitive situation within these different stages of the value chain changes. Therefore, the optimal regulatory regime can change over time.

An optimal regulation also depends on the priorities a regulator wants to set. These priorities could shift for hydrogen network regulation, especially during the market ramp-up to 2040. In the short term, a fast market ramp-up could be prioritised, and so a regulation regime that fosters investments and makes entry into the market attractive. In the longer term, and especially when there is a mature network in place, the regulatory priorities could shift towards a focus on wholesale market competition and liquidity. As priorities change over time, a regulatory regime should also be constantly reviewed and revised if necessary.

An example for adjusting regulation over time could be the choice of the horizontal unbundling measure. A common RAB could serve the initial priority of a fast market-ramp up via cross-subsidisation between gas and hydrogen infrastructure and might facilitate repurposing. In the longer term, however, a separate RAB could be preferred to avoid distortions (e.g. with regards to market results or network development) between methane and hydrogen. Therefore, a joint RAB may not be a definitive solution but could be gradually phased out. Compared to the 2020s where only a small share of total investments to create hydrogen networks may be paid for by hydrogen consumers, there could be a requirement that hydrogen consumers pay 10% of total hydrogen infrastructure costs by 2030, gradually increasing that amount to 100% by 2040. Phasing out the common RAB regulation could make this approach more attractive politically.

Regardless of the regulation, planning security is a crucial factor for investment decisions

Investments are usually (re)financed over a longer timeframe, in particular investments in capital-intensive assets such as gas or hydrogen transport infrastructure. An investment decision depends on expected profits over a similar time horizon, which can be heavily influenced by the applicable regulatory framework. As a result, uncertainty about the future regulation and a resulting impact on expected profits can provide a major obstacle to investments, even if the short-term market situation constituted a strong business opportunity. Conversely, a clear expectation of the applicable (future) regulation creates investment security, which is likely to be beneficial for the development of a comprehensive hydrogen network. A regulator can provide such planning security by creating a reliable regulatory environment and by providing guidance on the design of future regulation as well as the points in time (or trigger points) when the regulation is likely to be amended. In other words, a regulatory regime should not remain unchanged over decades. Rather, regulatory authorities should communicate potential future measures over the next few decades as early as possible regarding when regulation will be revised and what changes could result from it.

Exemptions could be a suitable instrument to tailor the regulatory framework to accommodating investment incentives

Under specific circumstances, an unregulated network could promote strong investment incentives due to high potential investment returns (see Section 3.3.2). But this comes at the

[39] As outlined in Section 3.1.3, we assume that transmission and distribution will be a natural monopoly by 2030.

[40] See Trinomics et al (2020), Sections 2.2.2 to 2.2.4.

price of potential market failures in the form of monopolistic market outcomes (e.g. lower quantities, redistribution of rents towards monopolistic firm). A suitable trade-off between the two sides could be a regulation including exemptions and derogations for certain investments. An exemption of investment projects (for a certain period of time) can result in higher investment returns, making some investments profitable in the first place and accelerating the expansion of the hydrogen network. Such an exemption could either be decided case by case or set as a default for new assets. An example of the implementation of exemptions can be found in the current regulations of electricity and natural gas, where exemptions are granted for an infrastructure project if certain criteria (e.g. improvement of security of supply) are fulfilled (see Box 3-1 for a discussion of exemptions). An exemption from regulation could also be granted by default to hydrogen pipelines that existed before regulation was implemented via a grandfather clause.[41]

Regulation should consider national differences in ownership structure

Within the EU, some gas transmission networks are state owned whereas others are investor-owned. Regarding state-owned networks, national governments could decide to invest in creating a national hydrogen network, minimising risks for gas infrastructure companies. Privately owned networks may either require regulatory exemptions to reduce investor risks or may benefit from the absence of horizontal unbundling as this enables a broader distribution of investment risks.

Government financing could temporarily be employed to develop hydrogen infrastructure in nascent phase

While this assessment excludes explicit state subsidy schemes for the uptake of hydrogen or development of hydrogen infrastructure, it should be noted that a (temporary) government support in financing the initial investments into hydrogen infrastructure is considered in some jurisdictions, such as in the Netherlands.[42] Thereby the government does not necessarily need to be the developer, but could provide financial support to existing or future hydrogen TSOs. The underlying rationale is that the benefit of developing a hydrogen infrastructure that could potentially significantly support the decarbonisation process constitutes a societal benefit, which provides a basis for government funding. As the market matures, the government funding would be reduced, so that the financing reverts back to the TSOs and, in regulated system, the regulated asset base.

The need for amendments of the regulatory framework or specific regulatory interventions can be based on trigger points

Investors must have clear expectations on the applicable regulatory framework in the short-term and in the long-term. A secure environment for investment decisions can also be provided with a changing regulatory framework if changes are transparent and expectable. This implies that regulatory authorities should communicate potential future measures over the next few decades as early as possible regarding when regulation will be revised and what changes may result from it. Beyond that, regulatory authorities can make use of trigger points (criteria) which would result in a review or pre-defined change in the regulatory regime. By employing trigger points, regulatory authorities would not have to define specific points in time but can make use of criteria which are dependent on the market development or market maturity. Potential parameters that measure criteria such as market development (e.g. volumes traded or transported), market concentration (e.g. market share for specific regions), and operator activities (number of jurisdictions with hydrogen transport activities) can be used as trigger points, potentially in combination with each other.

While the definition of specific trigger points is outside the scope of this project, possible inspiration might be taken from approaches in other sectors, e.g. the approach of the regulation

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[41] A grandfather clause is a provision in which old rules continue to apply for existing assets while new rules apply for future assets.

[42] Ministerie van Economische Zaken en Klimaat (2020) Kamerbrief over voortgang beleidsagenda kabinetsvisie waterstof from 15/12/2020.

for digital platforms within the EU and the UK. The EC defines a list of criteria in its Digital Markets Act[43] for companies to be classified as "Gatekeepers", while the UK Competition and Markets Authority (CMA) defines criteria for a "Strategic Market Status."[44] The criteria suggested by the EC and the CMA include the following:

- Thresholds for revenues, market capitalisation and activities in number of EU markets
- Number of business and private customers
- Indicators for market power such as size or scale, important access points for consumers/businesses

3.4. Approaches for quantification

This section describes an approach to reflect the findings of a qualitative evaluation of EC packages (Section 3.3.2 illustrates this). We derive a set of parameters that would allow assessment of the effects of packages based on quantitative modelling results. Although it is difficult to directly translate regulatory measures into robust quantifiable parameters, the intention is to provide approaches that show indicative tendencies. The possible methods include the following:

- Within EC model frameworks quantifications, which could be implemented using energy system models, e.g. METIS.
- Standalone quantifications (i.e. quantifications that can be undertaken outside any larger model such as METIS)

These quantification approaches are mostly based on stylised facts and cannot be causally linked in their magnitude to the regulatory measures discussed in previous chapters. Similarly, the quantifications should be interpreted with caution. They rarely yield a precise value (e.g. change in social welfare) for a specific regulatory measure or stylised fact, but rather indicate directional effects and the relevance of individual measures relative to other measures.

The discussion shows the emergence of general tendencies along the policy packages and the assessment criteria. These tendencies can be approximated with various manifestations of quantifiable parameters, which can be described as stylised facts.

3.4.1. Hydrogen market structure analysed with focus on sectoral distribution effects (standalone assessment)

Section 3.3 shows that there will likely be different market outcomes depending on the regulatory framework that is applied:

- In a scenario with **no or little regulation** for hydrogen infrastructure (e.g. in BAU and Option 1 of the draft policy packages) it is likely that the market will tend towards **monopolistic outcomes**. A monopolistic outcome in the market for hydrogen networks is likely to be manifested through more difficult pipeline access requirements, higher tariffs for pipeline access, and a tariff design less favourable to small players with less bargaining power.
- A **strong regulatory framework** with requirements on TPA, unbundling, and tariff regulation (e.g. in Option 2 and 3 of the draft policy packages) likely intends to reach the outcome of a **competitive market**. There will be lower access requirements for pipelines access and the access prices will be lower than in the monopolistic scenario.

As a result of these market outcomes, we expect two economic effects, an allocative and a distributional effect. Neither is captured by linear optimisation models such as METIS:

- **Allocative effect**: In a monopolistic market outcome the traded volume of a good (hydrogen transport) is not at the socially optimal level. Higher prices for the

[43] See https://ec.europa.eu/info/strategy/priorities-2019-2024/europe-fit-digital-age/digital-markets-act-ensuring-fair-and-open-digital-markets_en

[44] See https://www.gov.uk/government/news/cma-advises-government-on-new-regulatory-regime-for-tech-giants

relevant good (hydrogen transport) result in a lower traded volume of the good than would be socially optimal.[45]

- **Distributional effect**: A monopolistic market outcome means that producers (operators of hydrogen infrastructure) possess market power and so set higher prices than socially optimal (i.e. higher than marginal costs in economic terms). As a result, these producers can realise a higher rent while consumers (e.g. hydrogen shippers) realise a lower rent than in the socially optimal outcome.

Price setting behaviour in the respective market must be captured to model allocative and distributional effects. Monopolistic market power would then be reflected within the prices that are determined in the model. Further, to model allocative effects, demand (for hydrogen transport) should also depend on the market price and would have to be endogenously determined.

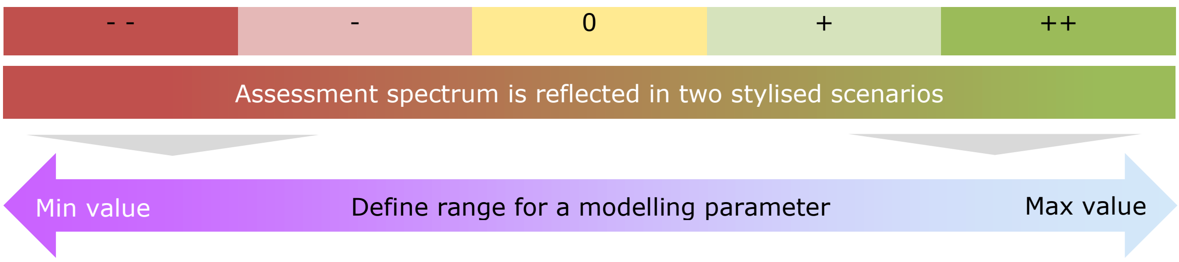
For this study, we have chosen to fix demand to the level in the PRIMES MIX55 H_2 scenario. We outline sectoral distribution effects with a focus on the hydrogen uptake across potential demand sectors in a standalone semi-quantitative analysis. In Section 4.2.1, we analyse differences between hydrogen end uses in terms of expected access to a potential future hydrogen grid and expected effects of regulation.

We do not change demand within or between sectors because we would then lose scenario integrity (sectors would use alternatives instead of hydrogen, which would not be captured in the model) and we would lose the link to the policies specified in PRIMES.

3.4.2. Cross-border integration parameterised through cross-border capacities (assessment within METIS model)

Figure 3-2 illustrates our approach to quantifying cross border capacities based on our qualitative assessment. We select a modelling parameter to represent an assessment criterion (e.g. cross-border capacity to reflect cross-border integration). We define a full spectrum of possible values for the parameter by setting a minimum and maximum value associated with the highest and lowest qualitative assessment of this criterion. We then assess the impact of this parameter in two scenarios, defined by the minimum and maximum values that represent a stylised outcome and so reflect the entire assessment spectrum.

Figure 3-2 Approach for quantification of assessment criteria



Stylised market outcomes can be reflected in a modelling framework through different assumptions on the development of cross-border transport capacity of hydrogen:

- In a scenario with **no or little regulation** for hydrogen infrastructure (e.g. in BAU or to some extent also in Option 1 and 2a) it is likely that there will be less coordination among TSOs, which makes it more likely that mostly private, somewhat isolated, and less interconnected networks across borders emerge. This can be reflected through a **lower cross-border interconnection capacity.** In this scenario we could expect that interconnection capacity will mostly stem from re-purposed pipelines as the TSOs have the benefit of gaining revenues from using

[45] Lower volumes of low-carbon hydrogen could also mean a slower decarbonisation of the EU economy, however this strongly depends on the development of alternative low-carbon energy carriers, which cannot be assessed as part of this analysis.

assets (for hydrogen transport), which would otherwise (when continued to use as gas infrastructure) lose in value with the risk of becoming stranded assets. This may differ in specific circumstances depending on the regional situation, for example through the availability of unused assets (which can be re-purposed with relatively little effort and at low opportunity costs for the gas network), the regional balance of demand and supply (both for gas and hydrogen) and the respective TSOs' financing options for hydrogen infrastructure.

- In contrast, it is likely that with a **strong regulatory framework** (e.g. in Option 2b, 3a or 3b) and a central role for NRAs (e.g. through revenue regulation and approval of investments/costs such as those required for cross-border infrastructure) there will be more cross-border coordination among the NRAs and TSOs. There are also better incentives to invest in cross-border capacity for vertically unbundled network operators compared to domestic vertically integrated champions that may try to protect upstream and downstream home markets (although this may be less relevant for nascent hydrogen markets compared to more mature gas or electricity markets when vertical unbundling has been introduced). Analogously, rTPA facilitates access to transport pipelines across borders.

  If potential negative impacts of stricter regulation on investment and repurposing incentives are addressed by the opportunity for temporary exemptions, such a regulated and coordinated approach to European hydrogen infrastructure can be parameterised using a **higher cross-border interconnection capacity.** A regulated environment is likely to be reflected in a more optimal match between demand, supply and transport infrastructure and possibly invokes a higher level of coordination between infrastructure operators across countries which facilitates the development of cross-border infrastructure.

Section 4.1.2 discusses the modelling of this stylised fact.

3.4.3. Administrative costs (standalone assessment)

Section 3.3 showed that different regulatory packages are likely to result in varying administrative costs. These costs are defined as the costs incurred by companies and regulators to meet legal obligations and provide information as required by the regulators or companies.

- An approach that does **not introduce additional regulation** (BAU) or fewer elements (such as Option 1 or Option 2a, which does not include a tariff regulation) is likely to require **fewer resources** from the regulator or from the infrastructure operator.
- A regulatory framework that implies a **strong regulatory approach** (such as Options 2b, 3a or 3b) with elements such as revenue regulation and functional unbundling is likely to require more resources for **oversight and regulating** (from the regulators perspective) and for internal **monitoring and reporting** (from the infrastructure operators perspective).

Such administrative costs can be observed empirically within the regulated areas of gas and electricity infrastructure. To our knowledge, a study of the costs on the infrastructure operators and regulators does not exist and would be part of a follow-up exercise. Such a study should follow the EC guideline "The Standard Cost Model for estimating administrative costs."[46]

Section 4.2.3 includes our high level quantification of the order of magnitude of administrative costs and differences between regulatory packages.

[46] https://ec.europa.eu/info/sites/info/files/file_import/better-regulation-toolbox-60_en_0.pdf

3.4.4. Investment incentives for new infrastructure (assessment within METIS)[47]

The incentives for investments into new infrastructure are influenced by the respective regulatory framework (such as expectations for future hydrogen demand). While the regulation of business activities can provide some security for the investment (e.g. with guaranteed returns), it can also undermine investments. For example, the regulation can put constraints on the ability to integrate vertically (to realise economies of scope) or on the ability to structure contracts or pipeline access tariffs with customers (e.g. hydrogen shippers or suppliers) in line with the profile of incurred costs.[48]

Section 3.3 discussed the main implications for the investment incentives:

- In a scenario with **no or little regulation** for hydrogen infrastructure (e.g. in BAU, but also to some extent in Option 1, 2a and with a joint RAB, which allows cross-subsidisation) investment incentives for new infrastructure are likely to be higher (keeping all else equal). Limited regulatory measures (e.g. no TPA, negotiated TPA, no tariff regulation) allow the company to maximise rents through vertical integration (pursuing business activities in the transport infrastructure and upstream or downstream sectors) or by structuring contracts with upstream or downstream customers in line with the investment needs (e.g. long-term contracts). But it is worth noting that investment incentives are also reinforced because, with little regulation, network operators can exploit their natural monopoly of the hydrogen network to maximise their own profits, which also includes potentially lower quantities (at a given capacity) and a redistribution of rents from consumers to network operators and vertically integrated companies.
- In contrast, a **strong regulatory framework** (e.g. Option 2b, 3a and 3b, in particular with separate RAB) is likely to be associated with lower investment incentives (keeping all else equal), since returns and business opportunities might be constrained and to some extent predefined by the regulation. The relevant regulatory agency needs to approve investment decisions and costs and determines the allowed return and potential cost saving targets and so constrains the business activities of a hydrogen infrastructure operator.

It is likely that stronger investment incentives encourage more players to engage in the development of new hydrogen transport infrastructure, which will also trigger additional market players in upstream and downstream markets (e.g. through a larger interconnected network area). As a result, more hydrogen transport capacity in the form of new pipelines and more supply (upstream) and demand sources (downstream) are likely to be part of the interconnected hydrogen network.

Our suggested approach to quantify investment incentives follows the same principle as for cross-border integration, shown in Figure 3-2. In a stylised modelling approach using METIS, we would reflect high investment incentives in a more extensive hydrogen network. More investments in new infrastructure are equivalent to higher overall pipeline capacity, and potentially to the integration of additional hydrogen supply and demand sources. A large share of the hydrogen network will run within countries, so an increased and accelerated expansion of new infrastructure will mainly be visible at the domestic level. In a modelling approach, the impact of the investment incentives criterion is predominantly reflected in **domestic transport capacities**. Since investment incentives and cross-border integration are assessed as two separate criteria, in the stylised model approach we differentiate between *domestic* and *cross-border* capacities. The latter are used to quantify cross-border integration and are excluded from the quantification of investment incentives to separate the two criteria.

For the quantification of investment incentives, through an assessment of domestic transport capacity, we similarly suggest defining two marker scenarios, which we differentiate as follows:

[47] An extension of the model to NUTS1 level is necessary for the approach.

[48] The criteria of investment incentives and repurposing are correlated with one another and, when combined, reflect infrastructure expansion. In general, repurposing, where possible, could always be preferred to new investments due to lower cost. In some cases, higher repurposing incentives could also lead to lower investments in new infrastructure. We therefore base our analysis on the assumption of "ceterus paribus" (as explained in Section 3.2.

- **High investment incentives** are parameterised through **high domestic hydrogen capacities in new pipelines** and potentially additional hydrogen demand points and supply sources connected to the hydrogen network.[49]
- This is compared with a scenario, where **lower investment incentives** are parameterised through **lower domestic hydrogen capacity in new pipelines**, which is assumed to reflect low investment incentives for hydrogen infrastructure.

The benefits of high investment incentives (and high domestic transport capacities) could then be assessed through the difference in METIS key performance indicators (KPIs) between the two marker scenarios, with all other parameters kept equal.

This quantitative assessment of varying degrees of domestic hydrogen pipeline capacities requires further development and a more granular version of the METIS model. Today, METIS follows a high-level approach by representing each country by a single node. For the analysis here, METIS would have to be extended to reflect domestic pipeline capacities (through at least two nodes per country), which differ between the scenarios.

The METIS model is already being extended to show network capacities at NUTS1 level. This could be used to assess the marker scenarios proposed here in a future study.

3.4.5. The impact on repurposing existing infrastructure parameterised through cost for hydrogen transport (assessment within METIS)

As Section 3.3 discusses, incentives for repurposing existing gas infrastructure into hydrogen infrastructure strongly depend on the regulatory framework, for example, on the horizontal unbundling requirements which determine whether gas network operators are allowed to operate hydrogen networks. They also depend on the commercial attractiveness as determined by the regulatory measures in comparison with the gas network regulation (e.g. how TPA requirements or tariff regulation compare with the gas regulation).

To assess the relevance of repurposing (domestic networks) for the development of hydrogen infrastructure we suggest the following modelling within a market model that reflects transport constraints in three sensitivities:

- A regulatory framework with few incentives for repurposing existing gas to hydrogen infrastructure (in particular Option 1) is reflected by a **low share of repurposed domestic gas pipeline capacity** for a hydrogen network. This means that achieving a pipeline capacity that supports the EC's hydrogen objectives comparatively more infrastructure will have to be newly built. This can be reflected as higher capital expenditures for hydrogen infrastructure (parameterised by **higher costs for hydrogen transport**) in a model assessment (Scenario 'Costs-CAPEX+' in Table 4-11).
- This is compared with a scenario where **a high share of domestic gas pipeline capacity** is repurposed, which reflects stronger incentives for repurposing (e.g. in BAU, Option 2b and 3a with joint RAB). This means that a large share of the pipeline capacity that supports the EC's hydrogen objectives will be from repurposed gas pipelines. This can be reflected as lower CAPEX for hydrogen infrastructure (parameterised by **lower costs for hydrogen transport**) in a model assessment (Scenario 'Costs-CAPEX-' in Table 4-11).
- As there are several other uncertainties that specifically affect hydrogen transport costs for repurposed pipelines (see Section 4.1.1.5), a third sensitivity analysis is performed to identify how sensitive model outcomes are to higher costs for repurposing pipelines (Scenario Costs-Repurposed CAPEX+ in Table 4-11). As the specific design of the RAB and all related factors determine how the actual costs are represented in tariffs, this sensitivity is also useful to explore the impacts related to changes in the way tariffs are regulated.

[49] High investment incentives accelerate infrastructure expansion and therefore also increase demand (more potential consumers connected). One possibility to reflect this would be to increase demand more rapidly in the scenario with high investment incentives.

4. Quantitative impacts

Quantifying the impacts of hydrogen market regulation is challenging. However, it is valuable to quantify expected impacts to better understand them and their relative importance, even when merely indicative.

We make specific, condensed, quantitative assumptions for the modelling to reflect the directional impacts derived in the qualitative assessment in Chapter 3. When interpreting the results of the modelling, however, the nuances of the full qualitative assessment should be included.

Impacts are quantified in two ways. First, we use the existing energy system models that the EC works with in its other impact assessments. However, these models require quantitative inputs and so we define stylised facts and use these to model the impact. We also describe expected impacts of the regulatory packages in semi-quantitative terms. This does enable quantitative comparisons between some regulatory measures but does not necessarily allow for comparison on a single metric across regulatory packages.

4.1. Quantification of impacts using METIS based on stylised facts

The existing models the EC uses for its impact assessment can be leveraged to analyse different hydrogen market configurations:

- **PRIMES** is an EU energy system model that models the investments and total hydrogen supply and demand per sector (including transformation sectors such as the production of synthetic fuels) per MS in 5-year steps. PRIMES scenarios are driven by current and announced policies from which the model derives trajectories for investments and usage. It is a useful starting point. PRIMES models final hydrogen demand for energy and non-energy usage, green hydrogen production, and power-to-gas or liquids. Although hydrogen from steam methane reforming and use within chemical complexes is not explicitly modelled at the process level, it is possible to determine the grey hydrogen demand (most notably its use as an industrial feedstock) for ammonia production and for use in refineries from PRIMES. As a consequence, the model does not represent blue hydrogen production explicitly but applies carbon capture and storage (CCS) in the industry sector and so may implicitly include some brownfield blue hydrogen production. PRIMES does not model all energy markets on an hourly basis.
- **METIS** is a model for electricity, gas, and hydrogen for a given year. The model can make investments on a cost-optimisation basis. Cross-border transport of hydrogen is modelled on a high level. METIS can optimise hydrogen supply on a least-cost basis while also accounting for interlinkages with natural gas and electricity markets.

By combining these models, we leverage the demand modelling from PRIMES and energy system optimisation from METIS. This enables consistency with the EC's ongoing impact assessment work and other quantitative modelling (since it implies the same set of policy incentives as in PRIMES). It also enables accounting for more complex energy system interactions (e.g. determining electrolyser full-load hours based on hourly power system modelling) in a single model. As a result, internal scenario consistency is more readily achieved than if using standalone models.

To facilitate the analysis, we screened the METIS model inputs versus PRIMES model outputs. In some cases, we required additional input data or assumptions, as Section 4.1.1 describes. We define stylised facts that quantify how we expect METIS model inputs to differ when using various regulatory packages. Section 4.1.2 presents these stylised facts.

4.1.1. METIS inputs/assumptions/approaches

4.1.1.1.Electrolyser modelling

Although the supply volumes of green hydrogen are fixed (i.e. no supply elasticity) for the METIS model runs (based on PRIMES output), both production cost and delivered cost of green hydrogen will be key performance indicators (KPIs) to compare scenarios. The cross-border capacities (relevant in Scenarios A and B) will allow for delivered cost optimisation. Transport from MSs with lower production cost to MSs with higher production cost will be feasible if delivery costs do not exceed the difference between low and high production costs.

To the extent possible, it is instructive to model a realistic production pattern for green hydrogen and the associated costs. First, we present four options to do so (Table 4-1), alongside their pros and cons. Second, we make our recommendation for the approach to take in the impact assessment (including variants 4a and 4b). Third, we substantiate the reasons for recommending the selected options over the others. Finally, we provide a set of modelling specifications for the selected options.

We recommend using Option 4 (including variants 4a and 4b) as a default modelling approach, with Option 3 as a sensitivity. The reasons for this recommendation and further modelling specifications follow.

Option 4 has the best possibility to optimise full load hours (FLH) and production cost while investigating the effects on the renewability of the generated hydrogen. The EC has not used this approach before in a comprehensive modelling study so it might provide additional insights compared to standard modelling approaches (which are close to Option 1). Importantly, the differences between MSs in terms of their ability to produce green hydrogen cost-efficiently will be accentuated by this option. The model will capture the differences in FLH and associated LCOE of renewables as well as expected developments in overall electricity generation. Renewable electricity shares in total generation and wholesale electricity price divergence will both factor into the final results.[50] It may facilitate more cross-border hydrogen trade, which is complementary to the construction of the assessment scenarios A and B.

Option 3 is used as a sensitivity to Option 4. Option 3 has the advantage of being easier to grasp conceptually—the input electricity price and electrolyser FLH are based on the LCOE and FLH of the RES-E used (except for minimum load). For hybrid (wind/solar) sourcing, a blended rate is used. Option 3 will result in hydrogen production with more renewable energy content than Option 4; this is measured via KPIs (see further below). The more restrictive electrolyser operation under Option 3 will likely lead to higher production costs than Option 4. This may help illustrate the impacts of electrolyser operation on the cross-border trade in scenarios A and B.

[50] For Variant 4a, the electrolyser can only source in the hours when the day-ahead forecast for the RES-E share on total electricity generation exceeds the 2-year national average RES-E share on total generation.

Table 4-1 Overview of options for electrolyser production modelling

Option	Pros	Cons
(1) Production optimisation solely via wholesale electricity prices (hourly) • The share of green hydrogen produced is determined **ex post** as a percentage of RES-E share in the system in each hour. • Electrolysers produce in hours where the wholesale electricity price allows them to stay below the pre-determined (competitive) production cost ceiling (determined ex ante).	• A simple and common approach to model. • Likely green hydrogen production model (together with use of Guarantees of Origin, GOs) in the absence of RED II or other (national) regulations. • Approach is responsive to market signals.	• The approach is based on electricity market and price forecasts for 2030 that carries higher uncertainty than LCOE and FLH forecasts for renewables (Options 3 and 4). • This approach is closest to the currently used modelling approach which tends to create significant volumes of non-renewable hydrogen.
(2) Production optimisation via grid emission intensity and wholesale electricity prices (hourly) • Electrolysers are allowed to produce in hours in which the average **national grid emission intensity does not exceed the threshold of 60 $gCO2_{eq}$/kWh** (based on Taxonomy threshold for renewable hydrogen production of 3 $tCO2_{eq}/tH_2$ at assumed 67% electrolyser efficiency, LHV). In addition, the electrolysers only produce in hours where the wholesale electricity price allows them to stay below the pre-determined (**competitive**) production cost ceiling (determined ex ante).	• A feasible green hydrogen production model (aligned with Taxonomy) • Can deliver strong optimisation for the renewable share of the hydrogen produced while at the same time being partly responsive to market signals.	• The approach is based on electricity market and price forecasts for 2030 that carries higher uncertainty than LCOE and FLH forecasts for renewables (Options 3 and 4). • The produced hydrogen is not fully green (renewable). It is only as renewable as is the grid mix in each given hour of production.
(3) Production optimisation via dedicated renewables (hourly) • This power purchase agreement (PPA) option determines the FLH of the electrolysers **based on the production profiles of renewables:** solar PV, wind (onshore and offshore) and hybrid solar PV/wind. Partial FLH optimisation is possible via partial over-(under-)sizing (see below). ▪ Similarly, the input electricity price is based on the LCOE of renewables from the PPA or blended rate (in case of hybrid solutions). ▪ Partial over-(under-) sizing is allowed: the RES-E capacity will be restricted to between 75%–125% of the electrolyser nominal capacity. Both the RES-E and the electrolyser capacities are connected to the grid to avoid additional curtailment and to provide minimum load for electrolysers. Sale of electricity from the PPA to the grid is allowed but restricted against a hydrogen loss of load criterion. ▪ Electrolysers do not draw from the grid if their minimum load is met.	▪ A very likely green hydrogen production model. ▪ Produced hydrogen is fully renewable (excluding minimum load requirements) ▪ More reliable than forecasting wholesale electricity market and can help accentuate differences between MS in terms of renewable electricity production (and thus potentially green hydrogen production).	▪ Approach is not fully responsive to market signals and thus possibly sub-optimal from production cost perspective. ▪ The approach does not investigate further possibilities of optimising production cost via FLH increase (e.g. further oversizing the RES-E source regarding the electrolyser, PPA swaps, etc).

Option	Pros	Cons
(4) Production optimisation via hybrid wholesale electricity market and dedicated renewables sourcing (hourly) • This option combines the **Options (1, 2, and 3)** illustrated above. Two Variants (4a and 4b) are modelled. **Variant 4a combines Options 2 and 3.** **Variant 4b combines Options 1 and 3.** • **Electrolyser production is optimised** via PPA, wholesale market sourcing, and possible sale of part of the PPA electricity to the wholesale market. • **Variant 4a:** o Electrolysers primarily draw electricity from their attached PPA. In addition, they can source from the wholesale market freely, subject to the national grid emission intensity not exceeding the threshold of 60 $gCO2_{eq}$/kWh (in each given hour of production). • **Variant 4b:** o Electrolysers primarily draw electricity from their attached PPA. In addition, they can source from the wholesale market freely, subject to a maximum electricity price.	▪ The most comprehensive and cost-optimal approach for green hydrogen production.	▪ Partly dependent on wholesale market forecast compared to Option (3) ▪ Part of the hydrogen produced in not in fact fully renewable (similar to Options 1 and 2) ▪ It is unclear how the electrolysers will behave in different MSs; this needs to be tested.

Further modelling specifications

Variants 4a and 4b

We propose modelling Option 4 in two variants, 4a and 4b. This is to further investigate the impact of wholesale market sourcing on the total system costs (e.g. more or less electrolyser capacity needed) and several KPIs (renewability, greenhouse gas [GHG] impact, electricity sourcing patterns) that are described further below.

- **Variant 4a:** Combines Options 2 and 3. Wholesale sourcing is only allowed in hours when the grid emission intensity is below the threshold. This will likely lead to an increase of electrolyser capacity necessary compared to Variant 4b to meet the required load. Because it is expected to lead to higher renewable content of the resulting hydrogen, we chose this as our default option.
- **Variant 4b:** Wholesale sourcing is allowed without restriction[51] (some hours will be eliminated by carbon price). This will likely lead to a decrease of required electrolyser capacity compared to Variant 4a to meet the required load.

In both variants, the model will meet the necessary electrolytic hydrogen demand (except for loss of load, see below), but the generation will not necessarily be all green (i.e. not based exclusively on RES-E). To capture this dimension, we propose a set of KPIs in Table 4-2.

KPIs and varying degrees of green hydrogen

The different modelling options and variants of thereof (4a and 4b) will all produce electrolytic hydrogen with varying degrees of renewable energy content. Specifically:

- Option 3 will likely produce hydrogen with the most RES-E content, since only at hours when minimum load (see below) must be met the electrolyser is given the option to source from the grid.
- Variant 4a will likely produce hydrogen with less RES-E content than Option 3. In many MS, the sourced grid electricity can have relatively high GHG intensity (even average, not just marginal) despite the grid emission factor constraint.
- Variant 4b will likely produce hydrogen with the least RES-E content of all the options and variants modelled. The grid sourcing optimises only via wholesale electricity price.

Since this produced hydrogen will still be used to meet the demand required by the PRIMES model output, a set of KPIs is necessary to estimate the impacts of these different hydrogen production regimes.

We propose that the following KPIs are delivered for each METIS model run (in addition to the overall system KPIs defined elsewhere).

[51] But still optimising to minimise hydrogen production cost.

Table 4-2 KPIs to assess outcome of electrolyser modelling

KPI name	Explanation
EU/MS average cost of hydrogen delivered	The main impact metric of the modelled scenarios. The total cost of hydrogen production, storage, and transport is divided by the total volume of hydrogen delivered. Only hydrogen transported via transmission grids, both EU average and MS average.
Weighted average share of RES-E for hydrogen generation.	This KPI shows how much (%) of the total power usage for electrolysis was coming from RES-E. Different electrolyser operation options might yield more, or less renewable hydrogen. This is important to compare average cost of hydrogen delivered and total energy system cost.
Weighted average grid emission factor (hourly) for the electricity used for hydrogen generation.	This KPI allows to back calculate the average emission intensity of the hydrogen produced in each model run. Especially for Option 4b which does restrict the origin of wholesale market electricity, we need to understand the emission intensity of the electricity used for hydrogen production.
Weighted GHG emission intensity of the hydrogen produced per MS.	This is a complementary metric to the two metrics above.
Ratio of electricity sold/bought by the electrolysers versus total electricity sourced.	This KPI allows understanding of the behaviour of the electrolysers under different options and variants and enables fine tuning of the electrolyser modelling approaches, if necessary. In particular for 4b, we need to understand whether the model does not sell most of its PPA electricity to the grid at high prices and then buy electricity from the grid at low prices (unlikely, due to expected convergence between high RES-E production and low electricity prices).
Volumes of hydrogen loss of load per MS.	This KPI allows additional check for undesirable behaviour of the electrolysers. More on loss of load below.
Hydrogen interconnection capacity and utilisation by MS.	The model can optimise interconnection capacity in several scenario.
Total electrolyser capacity by MS.	The model can optimise electrolyser capacity within a defined corridor of values.
Total hydrogen production by MS.	The demand per MS will be given by the PRIMES inputs but can be optimised by the model within a defined corridor of values.

Minimum load

The electrolysers must always meet their minimum load requirements; **set here to 10% of their nominal capacity**. This means that the electrolyser might also produce (partially) grey electrolytic hydrogen in some hours. This effect is captured in the KPIs above.

Loss of load

Situations might arise when the expected load for hydrogen exceeds the permissible generation. We expect this to happen when:

- No additional RES-E capacity is available
- The electrolyser is not allowed to source from the grid due to price or renewability constraints
- Storage is empty
- No interconnector capacity is available

In this situation loss of load is permissible, i.e. the hydrogen demand-met in the METIS modelling would be less than the demand modelled in the PRIMES MIX55 H_2 hydrogen variant. The METIS model output will indicate the volume (if any) for loss of load for each of its runs. This volume is then combined with a (high) price which adds to overall system cost. We agreed to set the price **for the loss of load at 5 times the maximum electricity price for sourcing from the wholesale electricity market (variants 4b and 4a).**

RES-E and electrolyser capacities

RES-E and electrolyser capacities are co-optimised in the modelling. The corridors in each MS for installed RES-E capacities are determined by the RES-E installed capacities from the PRIMES

MIX55 H_2 variant in years 2030 (min) and 2035 (max). This is done to confirm the final modelling results are all coherent with the RES capacity plans in the MS' National Energy and Climate Plans.

To realistically optimise the electrolyser production profile for the RES-E capacity (and thus PPA), partial over-(under-)sizing is allowed. The RES-E capacity will be restricted between 75%–125% of the electrolyser nominal capacities. Further oversizing of the RES-E capacity to increase FLH of the electrolyser will not be allowed as the impacts on the PPA prices (for preferential dispatch to electrolysers) are unknown. Both the RES-E asset and the electrolyser are connected to the grid to avoid additional curtailment and to provide minimum load for electrolysers.

Hourly decision logic

Options 3 and 4 allow for several optimisation decisions. This needs to be based on hourly modelling. Table 4-3 summarises the hourly decision logic for the modelled options and variants.

Table 4-3 Hourly decision logic in electrolyser modelling

	Option 3	Variant 4a	Variant 4b
Selling to **the wholesale market**	**Allowed with no economic constraints.** The model can optimise the RES-E capacity via PPA between 75%-125% of the nominal capacity of the electrolyser. Loss of load is priced very high (300 EUR/MWh) to prevent situations in which selling to wholesale market is preferential to green hydrogen production at the expense of not meeting hydrogen demand.	**Allowed with no economic constraints**. The model can optimise the RES-E capacity via PPA between 75%-125% of the nominal capacity of the electrolyser. The electrolyser can sell more electricity to the grid than in Option 3 as it can compensate for that by additional sourcing from the wholesale market. The RES-E sold to the grid does not compensate for the sourced wholesale electricity in terms of GHG content/ renewability. The use-it-or-lose-it rule applies. Loss of load is priced very high (300 EUR/MWh) to prevent situations in which selling to wholesale market is preferential to green hydrogen production at the expense of not meeting hydrogen demand.	
Sourcing from **the wholesale market**	**Not allowed**, except for meeting minimum load in hours when PPA does not provide enough electricity to meet electrolyser minimum must-run capacity.	**Allowed, at a maximum price** of 60 EUR/MWh.[52] The RES-E share in a given hour must be above national 2-year average. Meeting minimum load is exempted from the requirements above.	**Allowed, at a maximum price** of 60 EUR/MWh.[53] Meeting minimum load is exempted from the maximum price constraint.

The electrolyser is constrained by the contracted volumes in the PPA on a yearly basis, i.e. it must source all the contracted power and either use it for own production or sell it to the wholesale market. As such, the electrolyser will behave as a rational market actor while still needing to meet certain yearly production volumes (driven by demand modelled in PRIMES), except for loss of load.

[52] This is equivalent to a maximum abatement cost of ~250 EUR/tH_2 compared to benchmark process (unabated SMR production) in 2030. SMR production cost 1 EUR/kg, 9.8 tCO_2/tH_2. Electrolyser, CAPEX: 400 EUR/kW$_{el}$, OPEX + REPEX: 3% of starting CAPEX/year, system efficiency 70% (LHV), discount rate 5%, depreciation period 20 years.

[53] Ibid.

4.1.1.2.Electrolyser capacity

Existing plans of MSs add up to 27.5 GW_{el}–28.5 GW_{el} of electrolyser capacity. These plans are based on national plans where imports are not always fully considered. It is not possible to calculate the precise amount of electrolyser capacity resulting from execution of the MS plans.

If electrolyser capacity is fixed, the model cannot optimise, and we cannot measure the value from cross-border connections. METIS will use 80% of the existing MS plans as a minimum for electrolyser capacity and allow for the model to increase electrolyser capacity per MS to meet demand in the most cost-effective way.

A separate analysis will be done with 60% instead of the 80% to test how sensitive the outcomes are to this arbitrary modelling choice.

Table 4-4 Planned electrolyser capacity 2030 by MS

Member state	Planned electrolyser installed capacity by 2030
Germany	5 GW_{el}
Netherlands	3 GW_{el}–4 GW_{el}
Portugal	2 GW_{el}
Spain	4 GW_{el}
France	6.5 GW_{el}
Poland	2 GW_{el}
Italy	5 GW_{el}
Total	27.5 GW_{el}–28.5 GW_{el}

4.1.1.3.Blue hydrogen production

The PRIMES data used as an input for the METIS model includes production of blue hydrogen, but only as an application of CCS to existing installations that produce grey hydrogen. This hydrogen is not expected to be traded (as it is required to meet local hydrogen demand), and not included in METIS modelling of hydrogen flows.

PRIMES does not include any new plants that produce hydrogen from natural gas combined with CCS to meet new hydrogen demand. Although the development of greenfield blue hydrogen production has been proposed in several project announcements, we do not include this in the METIS model to be consistent with the PRIMES scenarios. If such greenfield blue hydrogen installations would be included, this would likely outcompete green hydrogen production in the absence of subsidies (even including transport to demand regions) and result in lower volumes of produced green hydrogen and lower total hydrogen production costs.

The MIX55 H_2 scenario does not include the production of any blue hydrogen. The total brownfield blue hydrogen production (where CCS is applied to existing installations) is retrieved from PRIMES.

Although blue hydrogen volumes do not affect the hydrogen flows in METIS, blue hydrogen should be considered as part of total low carbon hydrogen production. Therefore, we propose calculating blue hydrogen production separately. This is done based on the current production of grey hydrogen in the EU. No official statistics exist for grey hydrogen, but the Fuel Cells and Hydrogen Joint Undertaking is collecting this data for all MSs and by several categories.

The current grey hydrogen production is projected to 2030 proportional to relevant proxies. For refineries, hydrogen production is assumed to be proportional to crude oil input to refineries. The PRIMES outputs show a relatively stable crude input to refineries between now and 2030 so we can assume the needs to be about the same as today. Although refinery hydrogen demand per tonne of crude input can change based on the type of crude, that is not taken into account here. Hydrogen production in the ammonia sector is proportional to ammonia production. We assume the needs for ammonia to be roughly the same in 2030 as today. Ammonia and refineries cover over 90% of grey hydrogen demand and so we can assume that total grey hydrogen demand in 2030 is the same as today (IEA 2019).

However, some of this grey hydrogen will be replaced by green hydrogen. Therefore, the green hydrogen used in these sectors (from the PRIMES model) is subtracted from grey hydrogen demand to get residual grey hydrogen demand. This is provided by different grey hydrogen production technologies. Of these processes, auto thermal reforming (ATR) and SMR are most cost-effective for blue hydrogen production. We consider the ATR/SMR grey hydrogen production as addressable for blue hydrogen. This excludes COG (Coke Oven Gas), CS (Chloro Alkali), ethylene, POX (partial oxydation), styrene, and refinery off-gas.

We finally assume a certain share of the addressable grey hydrogen volume will be converted to blue hydrogen. We propose to assume that in MSs where CCS is possible (i.e. those that allow for CCS, have incentives for CCS, and have technical possibility for CCS), 80% of addressable grey hydrogen production is switched to blue by 2030. We propose a separate analysis with 70% instead of the 80% to test how sensitive the outcomes are to this arbitrary modelling choice.

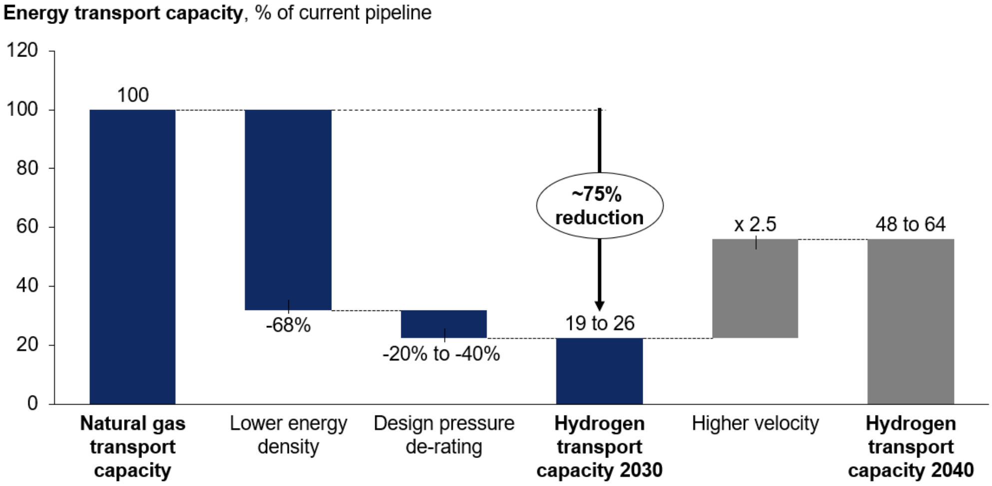
4.1.1.4.Hydrogen transport capacity in repurposed natural gas pipelines

When repurposing existing natural gas pipelines for hydrogen transport, several factors affect transport capacity. The most important factors are the energy density, the de-rating of design pressure, and the flow rate (Froeling 2019):

- **Energy density**: Hydrogen has a lower calorific value than natural gas (~12.7 MJ/Nm^3 versus ~40 MJ/Nm^3 for natural gas) and so at same pressure and velocity, the energy transport capacity is ~68% lower (Haeseldonckx 2009).
- **Design pressure de-rating**: Hydrogen can embrittle the steel of the pipeline, especially at higher pressures. To mitigate risks associated with hydrogen embrittlement, the maximum (design) pressure is reduced by around 25%–45% (depending on steel grade and pipeline dimensions) in technical standards (ASME 2014).
- **Velocity:** Natural gas transport velocity cannot exceed 15 m/s–20 m/s due to vibration and erosion issues at higher velocity. Hydrogen has a lower density and so higher velocities (up to 2.5 times that of natural gas) are possible within the safety parameters (Froeling 2019). Although technically higher velocity is possible and could increase the transport capacity, there are substantial cost implications associated with the additional costs for compression.

Combined, these factors allow energy transport capacity for hydrogen of around 55% of the current natural gas transport capacity. However, such high velocity and pressure requires substantial additional compressor capacity, and this is only justified with high throughput. Pipeline experts expect that lower pressure levels and flow rates will be used for the early stages of development of the hydrogen market (where throughput is still limited) (Froeling 2019). We estimate hydrogen transport capacity of a repurposed pipeline in 2030 to be closer to 25% of the original natural gas transport capacity (see Figure 4-1). This is roughly in line with what is mentioned in the pre-feasibility study for the Danish-German cross-border pipeline (Gasunie & Energinet 2021).

Figure 4-1 Change of energy transport capacity when repurposing natural gas pipelines for hydrogen transport.



4.1.1.5.Hydrogen transport system costs

The hydrogen transport system costs include costs associated with transportation and storage of hydrogen. They combine the effects of incentives for repurposing or new construction and of a lack of competition in markets. Table 4-5 shows the key drivers and uncertainties for the main CAPEX and OPEX cost components.

Table 4-5 Hydrogen transport system costs

Cost component	Description
CAPEX for pipelines	Includes costs for designing and constructing pipelines, including materials. For repurposed pipelines this includes inspection costs and minor required physical changes. Pipeline CAPEX are higher for new pipelines compared to repurposed pipelines (Guidehouse 2020). Repurposing costs uncertain due to very limited empirical data.
CAPEX for compressors	Includes costs for compressors and compressor stations. Existing compressors need replacement and additional compressors are needed to enable higher capacity (Gasunie & Energinet 2021). For small volumes and distances no compression is required (Gasunie & Energinet 2021). New hydrogen compressor types need to be developed by manufacturers, so costs are not yet known (Siemens Energy 2020). It is not fully clear yet when and how costs increase with volumes and distances.
CAPEX for other equipment	Includes costs for new equipment that can handle H_2 such as valves and meters. Equipment needs replacement when repurposing as current seals and membranes are often not suitable. This is a relatively small cost component compared to other CAPEX.
CAPEX for storage	Includes development of the working gas storage capacity and cushion gas storage capacity for salt caverns (new assets). Excludes costs associated with filling the storage with cushion gas (sunk costs). Costs highly uncertain due to very limited empirical data.
OPEX for compression power	Includes energy costs for powering compressors. Although most significant for transport, compression can also be required for storage. Since hydrogen is more expensive than natural gas, it is likely that the compressors will not be powered by hydrogen (current compressors are often powered by the natural gas), but by grid-supplied power. Similar to the compressor CAPEX, lower compression power is required initially considering the smaller volumes and distances.
Other OPEX	Includes other costs associated with operation and maintenance of the transport and storage system. Typically estimated as a percentage of CAPEX.

Given the large uncertainty in many of the cost factors, we are unable to conduct a detailed assessment of transport costs on the individual component level. This will become possible once empirical data and better understanding of the trade-offs and future operation of the system become available.

For the definition of transport costs in our modelling setup, one can derive hydrogen transport costs from current natural gas transport costs. These natural gas transport costs already reflect the various cost components and specifics of the existing pipeline (such as the length and transport capacity). Also, these costs are already available and collected for the METIS model. To account for the lower energy transport capacity for hydrogen compared to natural gas in the same pipeline (see Section 4.1.1.4), the natural gas transport costs should be multiplied by a factor 4. However, this is only possible for existing pipelines and not for new pipelines.

To enable a like-for-like comparison, we instead rely on cost estimates from gas TSOs for new pipelines as well as repurposed pipelines (Guidehouse 2021a). Cost figures differ depending on pipeline diameter, and we use the costs for 48-inch pipelines since we are only including cross-border pipelines and we assume these have higher capacity. The distance of the cross-border pipelines between two countries is assumed to be 200km for land-based, or 1000km for underwater pipelines.

Given the uncertainties in the resulting values, we run three sensitivities:

1. **Lowering pipeline CAPEX** by 50% for both new and repurposed pipelines. This is equivalent to the low-cost scenario (for repurposed pipelines) by EHB (Guidehouse 2020). This sensitivity can be used to explore implications of regulatory options that lower pipeline transport tariffs (e.g. cross-subsidisation in a joint RAB).
2. **Increasing pipeline CAPEX** by 400% for both new and repurposed pipelines. This is an extreme scenario that therefore covers the full range of uncertainties, including transit pipelines which cross multiple borders. This sensitivity can be used to explore implications of a lack of adequate regulation and monopolistic behaviour as well as technical setbacks that increase costs.
3. **Reducing the cost savings of repurposed** pipelines versus new by 50% by increasing CAPEX for repurposed pipelines. Note that this CAPEX value exceeds the high value reported by EHB (Guidehouse 2020). This sensitivity can be used to explore implications of regulatory options that make repurposing less attractive.

The CAPEX numbers are summarised in Table 4-6.

Table 4-6 CAPEX cost assumptions for new and repurposed pipelines in METIS

Scenario	New pipeline CAPEX, **M€/km**	Repurposed pipeline CAPEX**, M€/km**
Default	2.8	0.5
Sensitivity 1	1.4	0.25
Sensitivity 2	14	2.5
Sensitivity 3	2.8	1.65

4.1.1.6.Hydrogen storage

Another important aspect of hydrogen availability is the access to large-scale storage.[54] This is valid for long-term hydrogen storage and short-term hydrogen storage. Long-term storage must accommodate the seasonal variability of RES-E supply and so also affects variability of green hydrogen production and security of supply. Short-term storage has to accommodate green

[54] Note that due to the limitations (volume stored, efficiency, safety, cost) of above ground compressed, liquefied, chemical or other hydrogen storage, the storage places will most likely be located underground (in salt caverns, possibly depleted natural gas fields, aquifers, rock caverns or crystalline formations).

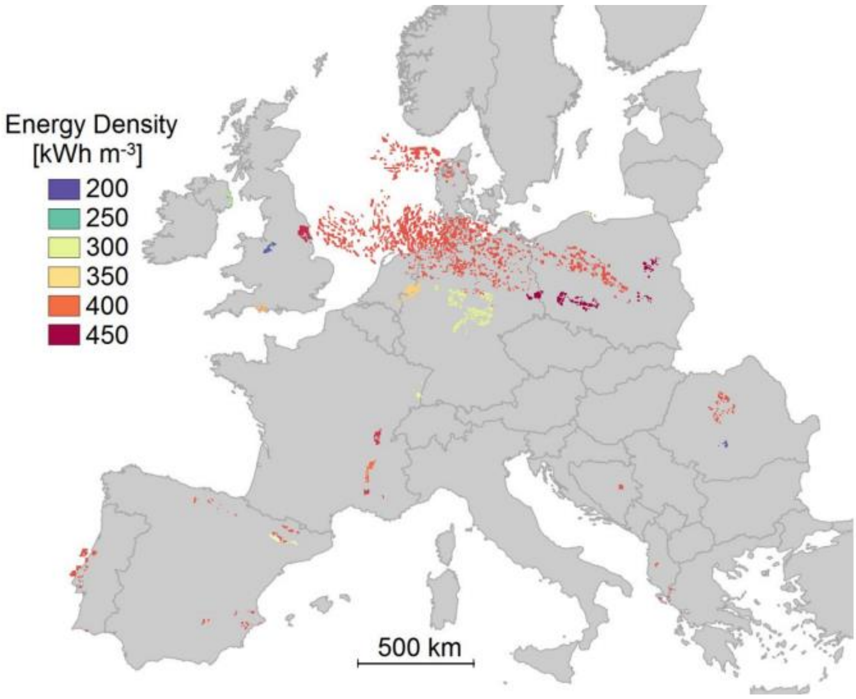
hydrogen production that (partly) follows intermittent RES-E generation but is faced with an uninterruptible demand (e.g. industrial applications).[55] Such short-term balancing with hydrogen pipelines (linepack) is likely limited as the lower density and pressure (compared to natural gas) reduce the ability to create linepack. Access to storage will be fundamental to green hydrogen uptake in the majority of the demand applications by 2030, as modelled by PRIMES.

Currently, the only proven method of large-scale hydrogen storage is in salt caverns. Storage in depleted natural gas fields and aquifers[56] has not been proven beyond feasibility concepts and it is unlikely that it will be available by 2030. Salt caverns currently used for natural gas storage could potentially be repurposed for hydrogen. However, such assessments must be done on individual asset level, considering the specific conditions and requirements for security of supply.

We recommend that METIS is given the option to only invest into new salt cavern storage for hydrogen. This approach severely restricts availability of hydrogen storage in the EU (see Figure 4-2). However, it seems prudent to not rely on low technology readiness level (TRL) options (such as the storage in depleted fields) for 2030 modelling. The effects of the storage types on hydrogen properties such as purity is out of scope for this study.[57] If this approach proves too restrictive (storage only in salt caverns and no linepacking ability), we might allow other types of large-scale underground storage, however, these other types are currently at very low TRL.

Figure 4-2 Distribution of potential salt cavern sites across Europe with their corresponding energy densities

Energy density is cavern storage potential divided by the volume



Salt caverns, the only proven large-scale hydrogen storage option, will be a critical piece in the development of Europe's hydrogen transmission infrastructure. However, such geological

[55] Note that large scale blue hydrogen production based on SMR, ATR is also rather inflexible and likely will not be able to compensate for fluctuations in green hydrogen production.

[56] Or other types such as rock caverns or crystalline formations.

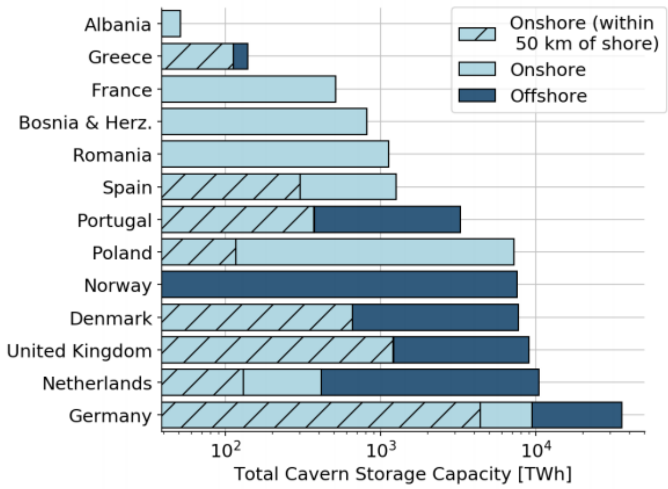
[57] Studies that investigated (non-engineering) pure hydrogen storage in depleted gas field include (Amid, Mignard and Wilkinson 2016), (Tarkowski 2019) or (Visser 2020). There seems to be a consensus on the feasibility of the concept, e.g. "There appears to be no insurmountable technical barrier to the storage of hydrogen in a depleted gas reservoir" (Amid, Mignard and Wilkinson 2016). The key issues seem to be contamination of hydrogen by other gases (e.g. methane) and bacterial conversion of hydrogen into methane leading to hydrogen losses and potential storage integrity issues (Smart Delta Resources 2020), (Visser 2020).

formations are not available in all MSs. (Caglayan, et al. 2020) investigated the technical potential for hydrogen storage in salt caverns, see Figure 4-2.

Only a limited number of MSs have the technical potential for salt cavern storage and many of the potential locations are located offshore, mainly in the North Sea. Figure 4-3 summarises the estimated technical potential per MS (and several additional European countries). Accordingly, only 9 MSs have any significant salt cavern storage potential (Germany, the Netherlands, Denmark, Poland, Portugal, Spain, Romania, France, and Greece), complemented by several non-EU countries (UK, Norway, Bosnia & Herzegovina, Albania). The total technical potential estimated at ~85 PWh of hydrogen (~23 PWh of hydrogen onshore) far exceeds the expected the need for hydrogen storage in Europe. The geographical availability of the locations may bring difficulties to balancing the hydrogen infrastructure networks with salt cavern storage.

Figure 4-3 Total cavern storage potential in European countries by class

Source: (Caglayan, et al. 2020)



As input for the METIS modelling, we use the estimated technical potential for hydrogen storage in salt caverns in the EU, per MS. This is defined as storage potential up to 50 km from the shore (for comparison, all current natural gas storage in salt caverns is onshore in the EU). As this estimation included utilisation of existing, operational salt cavern storage sites for natural gas, we subtract these volumes to arrive at estimated hydrogen storage potential in salt caverns (TWh), which should be used in METIS modelling.

The ratio between potential energy storage in salt caverns in the form of hydrogen and natural gas is estimated at 23% (hydrogen/natural gas energy density per m^3). This assumes the only difference are

- in working gas (cushion gas assumptions are kept constant),
- compression to 137 bar and
- temperature 38˚C.

In sum, the existing, operational salt cavern storage for natural gas is multiplied by the derating factor (23% of the original working gas capacity) and subtracted from the hydrogen storage potential in salt caverns to arrive at the estimated hydrogen storage potential in salt caverns. Table 4-7 summarises the data.

Table 4-7 Estimated hydrogen storage potential in salt caverns

Member state	Hydrogen storage potential in salt caverns within 50km from shore (TWh)[58]	Existing, operational salt cavern storage for natural gas (TWh)[59]	Estimated hydrogen storage potential in salt caverns (TWh)
Germany	9,450	152	**9,415**
Netherlands	400	3.9	**299**
France	510	16.3	**506**
Spain	1,260	None	**1,260**
Poland	7,240	17.2	**7,236**
Greece	100	None	**100**
Romania	1,100	None	**1,100**
Denmark	700	Unknown	**700**
Portugal	350	3.6	**349**

We propose to use the following values for the investment cost for developing hydrogen salt cavern storage,:

- **CAPEX:** 334 EUR/MWh of hydrogen stored (this assumes 1,160 tH_2 (38.7 GWh) of working gas capacity). Total CAPEX thus should be **445 EUR/MWh of hydrogen stored** (including investment for cushion gas capacity).[60]
- **OPEX:** 4% of initial total CAPEX/year.
- **Cushion gas requirements:** One-third of the total storage capacity.
  In the METIS modelling, this interferes with the total demand volume inflexibility. We suggest treating this is as a sunk cost, rather than physical hydrogen that is lost from the total production volume in the model. The cushion gas requirement will become a cost added to the storage cost, calculated based on the weighted average hydrogen production cost in each run : cushion gas cost = one-third of the total storage capacity * weighted average hydrogen production cost.

4.1.2. *Stylised facts on cross-border capacity*

We translate the qualitative findings from Section 3.4 into stylised facts or sensitivities that can be used in METIS. For the impact of cross-border integration we define the stylised fact *cross-border capacity* to model in METIS. This is based on the premise, as explained in Section 3.3, that regulatory packages differ in how they enable or stimulate cross-border pipeline transport of hydrogen and therefore can be expected to enable different amounts of cross-border pipeline capacity.

Differences in cross-border transport capacity between MSs can be modelled in METIS to assess the extent to which this additional room for optimisation benefits Europe. In consideration of the expected effects of the regulatory packages, we define four possible scenarios regarding cross-border capacities:

- **The BAU scenario assumes no cross-border transport** of hydrogen via pipeline (except for existing commercial pipelines). Although there are already projects in the planning phase, these began under the expectation that European regulations would enter into force before the actual repurposing takes place. In the absence of European regulation, we assume these projects will not be executed for this scenario. This implies that all hydrogen in each MS is supplied domestically. We do

[58] (Caglayan, et al. 2020).
[59] (Gas Infrastructure Europe 2021).
[60] (ASSET 2020).

not consider existing commercial cross-border pipelines because they will likely not be in scope for EU regulation.

- **Scenario "A constrained" assumes low, fixed cross-border capacity** based on the updated 2021 European Hydrogen Backbone (EHB) 2030 vision for dedicated hydrogen infrastructure in 19+2 MSs.[61] It consists of several fragmented national and regional grids with limited interconnection. The transport capacities are fixed and not subject to optimisation in METIS. We consider this the lower end of the spectrum in a world that has sufficient regulation to allow for cross-border connections, but to a minimal extent. For context, PRIMES MIX55 H_2 scenario operates with green hydrogen demand of 150 TWh in 2030 (covering EU27). The EHB projects green and blue hydrogen demand of 310 TWh (covering EU27).[62]
- **Scenario "A optimised" assumes low, fixed cross-border capacity and additional cross-border capacity where needed.** The fixed cross-border capacity from scenario "A constrained" is used as a minimum, and METIS is allowed to increase the cross-border capacity to minimise total system costs. We consider this the higher end of the spectrum in a regulated world that allows for cross-border connections, where the network development is coordinated on a European level and cross-border connections are adequately incentivised.
- **Scenario "B optimised" assumes a high, fixed cross-border capacity and additional cross-border capacity where needed.** This scenario is a variation of the scenario "A optimised" where the minimum cross-border capacity is not based on the 2030 EHB vision, but on the 2035 EHB hydrogen infrastructure vision. This vision predicts a substantial increase in cross-border capacity from 2030 to 2035. As in "A optimised," METIS can add new or repurpose more pipelines to minimise system costs. We consider this an extreme scenario that explores the effects of a more aggressive rollout of infrastructure to accommodate a more rapid hydrogen uptake. We expect that this scenario will have over-dimensioned cross-border transport infrastructure. The EHB does not project hydrogen demand for 2035 directly. The midpoint between 2030 and 2040 (linear) EHB forecasted demand for green and blue hydrogen is 755 TWh, that is more than two times higher than the 310 TWh demand in 2030.

Table 4-8 summarises the scenarios.

Table 4-8 Scenario variations for cross-border capacity stylised fact

Scenario	Minimum cross-border capacity	Maximum cross-border capacity	Optimisation of cross-border capacity
BAU	None	0	No
A constrained	EHB 2030	None	No
A optimised	EHB 2030	None	Yes
B optimised	EHB 2035	None	Yes

These four scenarios offer a useful basis for analysis as they cover the spectrum of plausible futures. The scenarios span the most pessimistic (BAU) and optimistic (Scenario A optimised) ends of the spectrum and scenarios that cover plausible outcomes at the low (Scenario A constrained) and high (Scenario B optimised) end.

From the EHB analysis, we retrieve which pipelines will as a minimum be repurposed in each scenario (or maximum in the scenario "A constrained"). The capacities of the specific pipelines (in million Nm^3/d) are taken from the ENTSOG map[63] and, where needed, complemented with

[61] The updated 2021 EHB study covers Austria, Belgium, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Poland, Slovakia, Slovenia, Spain, Sweden, the United Kingdom and Switzerland. This study will be published in Q2 2021.

[62] Note that while the vision for the hydrogen infrastructure covers only the aforementioned 21 countries, the demand projection here is for EU27.

[63] (ENTSOG 2021)

data from the IGG[64] dataset, or in some cases from specific projects. The data is converted to GW capacity (assuming 0.46 GW per million Nm^3/d). Table 4-9 shows the resulting interconnection capacities between MSs. Section 7.2 describes the other assumptions and sources for these interconnections.

These cross-border capacities per scenario are used in the METIS model to quantify impacts. They enter METIS as fixed minimum capacities, which means that the model can increase pipeline repurposing if this reduces overall system costs (except for the BAU scenario, where no cross-border pipeline capacity is available). This will be relevant for countries that do not have any cross-border connections in the scenarios, but where domestic production is costly. Note that the hydrogen demand will be retrieved from PRIMES.

Box 4-1 displays more information about the EHB initiative.

Box 4-1 About the European Hydrogen Backbone initiative

The European Hydrogen Backbone (EHB) initiative consists of a growing group of now 23 European gas infrastructure companies, working together to plan a pan-European dedicated hydrogen transport infrastructure. Participating companies are Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys, Gas Connect Austria, Gasgrid Finland, Gasunie, GAZ-SYSTEM, Gas Networks Ireland, GRTgaz, National Grid, NET4GAS, OGE, ONTRAS, Plinovodi, TAG, Teréga, Snam, and Swedegas.

The hydrogen transport network envisioned by the EHB is largely based on repurposed existing gas infrastructure. By 2030, the EHB would consist of an initial 11,600 km pipeline network, connecting emerging hydrogen valleys. The hydrogen infrastructure could then grow to become a pan-European network, with a length of 39,700 km by 2040, with further possible developments after 2040.

The group is currently discussing the European Hydrogen Backbone plan with key stakeholders in the value chain, and with gas infrastructure companies from other European countries. On 15 June 2021 it published its latest assessment report which includes supply and demand scenarios in addition to the network requirements.

For more information see https://gasforclimate2050.eu/ehb/.

Table 4-9 shows the EHB cross-border pipeline capacities in 2030 and 2035. For the new pipelines, the capacity is given in hydrogen terms (5 GW for pipelines built before 2030, 10 GW for pipelines built after 2030), whereas for the repurposed pipelines the capacity is given in natural gas terms.

Table 4-9 Minimum hydrogen interconnector capacities in Scenarios A and B

Inter-connec-tion	New/ repurposed	Pipelines	Scenario A	Scenario B	Unit
AT-IT	New build	New_1	0	10	GW hydrogen capacity
AT-SI	New build	New_2	0	10	GW hydrogen capacity
AT-HU	Repurposed	BRUA_Extra_24	0	6.38	GW natural gas capacity
AT-SK	Repurposed	Baumgarten 1	0	10.3	GW natural gas capacity
BE-FR	Repurposed	Blarégnies L (BE) / Taisnières B (FR)	7	7	GW natural gas capacity
	Repurposed	Pitgam_Maldegem	10	10	GW natural gas capacity
BE-NL	Repurposed	Gravenvoeren_Bemelen	14.2	14.2	GW natural gas capacity

[64] IGG is a merged database containing the **I**NET (InternetDaten), **G**IE (Gas Infrastructure Europe) and **G**SE (Gas Storage Europe) datasets.

Inter-connec-tion	New/ repurposed	Pipelines	Scenario A	Scenario B	Unit
	Repurposed	Westerschelde Oost_Zelzate1	17	17	GW natural gas capacity
	Repurposed	Zandvliet H-gas	2	2	GW natural gas capacity
	New build	New_3	5	5	GW hydrogen capacity
CZ-SK	Repurposed	Lanžhot 2	0	16.7	GW natural gas capacity
CZ-DE	Repurposed	Brandov STEGAL (CZ) / Stegal (DE)	0	12	GW natural gas capacity
	Repurposed	Transgas_10	0	17.9	GW natural gas capacity
DE-FR	Repurposed	Obergailbach (FR) / Medelsheim (DE)	0	20	GW natural gas capacity
	Repurposed	MosaHYc	0.06	0.06	GW natural gas capacity
DE-NL	Repurposed	Jemgum (DE) (astora) / Oude Statenzijl (NL)	8	8	GW natural gas capacity
	Repurposed	Winterswijk	7.5	7.5	GW natural gas capacity
	Repurposed	Zevenaar	13.7	13.7	GW natural gas capacity
	Repurposed	Vlieghuis	3	3	GW natural gas capacity
	Repurposed	Epe	1.8	1.8	GW natural gas capacity
DE-DK	Repurposed	Deudan 1	0	4	GW natural gas capacity
	New build	New_4	0	10	GW hydrogen capacity
DE-PL	New build	New_5	0	10	GW hydrogen capacity
DK-SE	New build	New_6	0	10	GW hydrogen capacity
EE-FI	New build	New_7	0	10	GW hydrogen capacity
EE-DE	New build	New_8	0	10	GW hydrogen capacity
ES-MO	Repurposed	Tarifa	0	18.5	GW natural gas capacity
ES-FR	Repurposed	VIP PIRINEOS	0	9.4	GW natural gas capacity
FR-LU	Repurposed	MosaHYc	0.06	0.06	GW natural gas capacity
FI-SE	New build	New_9	5	5	GW hydrogen capacity
	New build	New_10	0	10	GW hydrogen capacity
FI-DE	New build	New_11	0	10	GW hydrogen capacity
HU-SI	New build	New_12	0	10	GW hydrogen capacity
HR-SI	Repurposed	Lucko_Rogatec	0	2.2	GW natural gas capacity
HR-HU	Repurposed	Varosfoeld_Slobodnica_ 11	0	3.26	GW natural gas capacity
HU-RS	Repurposed	Szoreg_Banatski Dvor	0	5.92	GW natural gas capacity
HU-RO	Repurposed	Arad_Szeged	0	2.2	GW natural gas capacity
HU-UA	Repurposed	Beregdaróc 1400 (HU) - Beregovo (UA) (UA>HU)	21.5	21.5	GW natural gas capacity
HU-SK	Repurposed	Balassagyarmat (HU) / Velké Zlievce (SK)	0	5.3	GW natural gas capacity
IT-SI	New build	New_13	0	10	GW hydrogen capacity
IT-TN	Repurposed	Mazara del Vallo	48	48	GW natural gas capacity
SK-UA	Repurposed	Uzhgorod (UA) - Velké Kapušany (SK)	0	21.13	GW natural gas capacity

4.1.3. *Modelling scenarios and sensitivity analyses*

The considerations above lead us to define which scenarios to assess using the METIS system model. The main scenario definition derives from the cross-border capacity scenarios which will be paired with default model inputs aligned with the PRIMES model where possible.

In addition to these scenarios, we want to test sensitivity of the following model inputs:

- **Electrolyser operation**: Run the default scenario with Option 3 instead of Option 4 (see Section 4.1.1.1) to see how removing the link between electrolysers and wholesale electricity markets will affect hydrogen market design (increasing or decreasing the impact of presence of cross-border capacity).
- **Electrolyser capacity**: Decrease the share of fixed electrolyser capacity from 80% (default) to 60% to test how the additional flexibility in the model affects the results.
- **Transport costs**: Decrease pipeline CAPEX (new and repurposed) by 50%, increase pipeline CAPEX (new and repurposed) by 400%, and increase CAPEX for repurposed pipelines to halve the cost difference between new and repurposed pipelines.

Table 4-10 summarises the main variables and their sensitivities.

Table 4-10 Modelling variables and their sensitivities

Variable	Default	Sensitivity #1	Sensitivity #2	Sensitivity #3
PRIMES scenario	MIX55 H_2 variant	_	_	
Cross-border scenario	BAU Scenario A constrained Scenario A optimised	Scenario B	_	
Electrolyser operation	Option 4a	Option 4b. *Compared to 4a, part of the electrolyser capacity is optimised purely on electricity price.*	Option 3. *Producing most renewable hydrogen of the three options.*	
Electrolyser capacity (MS-level)	80% fixed	60% fixed. *Possible additional relocation of electrolysers to decrease production cost.*	_	
Pipeline CAPEX (new and repurposed)	Normal	-50%. *Impacts on cross-border trade with less costly transport of hydrogen.*	+400%. *Impacts on cross-border trade with much more costly transport of hydrogen.*	Increase repurposed CAPEX by 50% of the cost difference between new and repurposed. *Cross-border trade less affected by existing infrastructure.*

The combination of these variables and sensitivities results in 14 proposed METIS model runs: Three main scenarios, spanning the three cross-border options, and 11 sensitivities. Table 4-11 summarises these scenario definitions while Table 4-12 shows a description per scenario.

Table 4-11 Overview of model runs

Bolding highlights the values of the sensitivity parameters in comparison to the default scenario values

Name	PRIMES scenario	Cross-border scenario	Electrolyser operation	Electrolyser capacity	Pipeline CAPEX (new)	Pipeline CAPEX (repurposed)
H2-BAU	MIX55 H_2 var	BAU	Option #4a	80% fixed	Default	Default
H2-A constrained	MIX55 H_2 var	A (without optimisation)	Option #4a	80% fixed	Default	Default
H2-A optimised	MIX55 H_2 var	A (with optimisation)	Option #4a	80% fixed	Default	Default
H2-BAU-4b	MIX55 H_2 var	BAU	**Option #4b**	80% fixed	Default	Default
H2-A constrained -4b	MIX55 H_2 var	A (without optimisation)	**Option #4b**	80% fixed	Default	Default
H2-A optimised-4b	MIX55 H_2 var	A (with optimisation)	**Option #4b**	80% fixed	Default	Default
H2-B optimised	MIX55 H_2 var	**B (with optimisation)**	Option #4a	80% fixed	Default	Default
H2-B optimised-4b	MIX55 H_2 var	**B (with optimisation)**	**Option #4b**	80% fixed	Default	Default
Electrolyser -PPA	MIX55 H_2 var	A (with optimisation)	**Option #3**	80% fixed	Default	Default
Electrolyser -60%	MIX55 H_2 var	A (with optimisation)	Option #4a	**60% fixed**	Default	Default
Electrolyser -60%-4b	MIX55 H_2 var	A (with optimisation)	**Option #4b**	**60% fixed**	Default	Default
Costs-CAPEX-	MIX55 H_2 var	A (with optimisation)	Option #4a	80% fixed	**-50%**	**-50%**
Costs-CAPEX+	MIX55 H_2 var	A (with optimisation)	Option #4a	80% fixed	**+400%**	**+400%**
Costs-Repurposed CAPEX+	MIX55 H_2 var	A (with optimisation)	Option #4a	80% fixed	Default	**+230%**

Table 4-12 Scenario descriptions of the 14 METIS model runs

Name	Description
H2-BAU	Default scenario with BAU cross-border capacity (i.e. no cross-border capacity)
H2-A constrained	Default scenario with low cross-border capacity without additional capacity build options ("Scenario A constrained")
H2-A optimised	Default scenario with low cross-border capacity with additional capacity build options ("Scenario A optimised")
H2-BAU-4b	As above, but electrolysers can source electricity freely from the market without constraint on the RES-share
H2-A constrained-4b	Ditto
H2-A optimised-4b	Ditto
H2-B optimised	Scenario with high cross-border capacity with additional build options ("Scenario B optimised")
H2-B optimised-4b	As above, but electrolysers can source electricity freely from the market without constraint on the RES-share
Electrolyser-PPA	Electrolysers follow Option 3, i.e. are only sourcing from PPA NOT from the market (unless minimum load not met)
Electrolyser-60%	Minimum electrolyser capacity is set to 60% of MS planned electrolyser capacity
Electrolyser-60%-4b	As above, but electrolysers can source electricity freely from the market without constraint on the RES-share
Costs-CAPEX-	Lower transport costs to assess uncertainty in this parameter and regulatory measures that lower transport costs
Costs-CAPEX+	Higher transport costs to assess uncertainty in this parameter
Costs-Repurposed CAPEX+	Higher transport costs for repurposed pipelines to reflect low incentives for repurposing

4.1.4. *Impact metrics*

We propose a number of impact metrics to be measured across the model runs, as Table 4-13 shows. These consist primarily of the specific electrolyser modelling KPIs Table 4-2 details, complemented by a total energy system cost indicator.

Table 4-13 Definition of impact metrics

Impact metric	Unit	Reasoning
Overall system KPIs		
Total energy system cost	EUR	Besides impact on hydrogen cost, the different scenarios can impact total energy system costs non-linearly.
Previously defined KPIs to assess electrolyser modelling outcomes		
EU/MS average cost of hydrogen delivered	EUR/MWh H_2 (LHV)	[see Table 4-2]
Weighted average share of RES-E for hydrogen generation per MS and at EU level	%renewable/%total electricity demand for hydrogen	[see Table 4-2]
Weighted average grid GHG emission factor (hourly) for the electricity used for hydrogen generation per MS and at EU level	gCO_{2eq}/kWh	[see Table 4-2]
Weighted GHG emission intensity of the hydrogen produced per MS and at EU level	gCO_{2eq}/kWh H_2 (LHV)	[see Table 4-2]
Ratio of electricity sold/bought by the electrolysers versus total electricity sourced per MS	% sold/over total electricity demand for hydrogen %bought/over total electricity demand for hydrogen	[see Table 4-2]
Volume of hydrogen loss of load per MS	GWh H_2 (LHV)	[see Table 4-2]
Hydrogen interconnection capacity by MS	GW	[see Table 4-2]
Hydrogen interconnection utilisation by MS	FLH	[see Table 4-2]
Total electrolyser capacity by MS	GW_{el}	[see Table 4-2]
Total hydrogen production by MS	GWh H_2 (LHV)	[see Table 4-2]

METIS does include other metrics that might be valuable (e.g. social welfare), but it remains to be seen whether any differentiation can be observed between the assessed scenarios (see Annex 7.3 for a full list of METIS KPIs).

4.2. Semi-quantitative assessment

4.2.1. *Sectoral distribution effects*

The modelling assesses the impacts of cross-border transport, an area where EU regulation may be of added value. However, EU regulation can also drive the development of networks within member states.

The benefit of a domestic network with a wide coverage is its ability to connect hydrogen supply with those demand sectors where it provides most value. Conversely, in a scenario without such an extensive hydrogen grid, hydrogen would be expected to primarily flow through:

- Dedicated private networks/hydrogen cluster networks (existing and potentially new networks, most likely supplying the larger industrial customers)
- Repurposed gas pipelines (likely primarily serving industrial customers to achieve economies of scale)

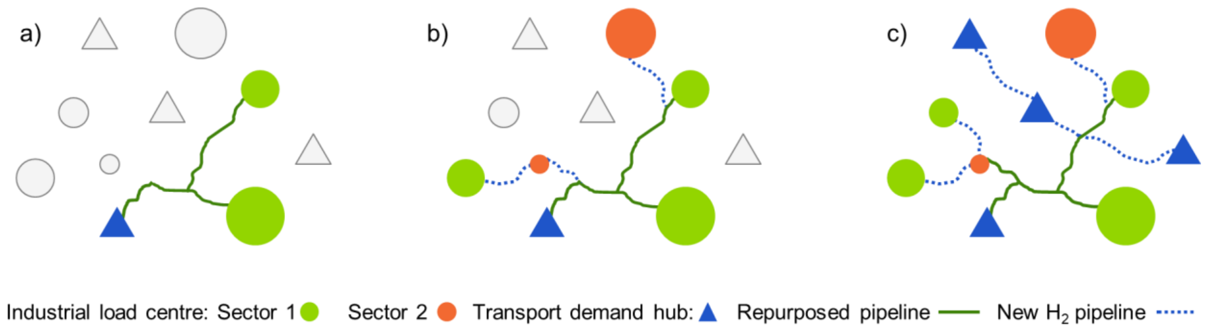
Within the industrial customer segment, there will be differences between subsectors and geographies in terms of access to the existing gas grid or a potential future private/cluster hydrogen grid.

We presume the relationship Figure 4-4 shows at a high level:

a) No additional build-out would likely reach the largest industrial users currently connected to the gas network and some conveniently located transport demand hubs
b) Limited build-out or private networks would likely reach other industrial customers first, but may reach different geographies and sectors differently depending, for example, on available infrastructure that can be repurposed.
c) A full build-out of the network could reach transport demand hubs in additional to industrial demand centres.

Figure 4-4 Schematic of expected demand reach for different network build-out scenarios

a) No additional build-out, b) Limited build-out/private networks, c) full build-out



We assess this effect on a conceptual level and quantify where possible. To this end we:

- Prioritise hydrogen end uses from a societal perspective
- Assess the expected impact of regulatory measures on this hierarchy

4.2.1.1. Prioritisation of hydrogen end uses

This section assesses which hydrogen end uses should be prioritised from a societal perspective. We first consider different end uses of hydrogen and establish a hierarchy based on various criteria. Then we consider which of these end uses would most likely be supplied in the different regulatory packages.

Four categories of end uses are considered: Feedstock applications, power generation applications, transport applications, and heat applications. Within these categories the main end uses are covered. Some niche applications (e.g. vegetable oil processing, forklifts, aerospace) are not covered here, as volumes are smaller and so the impact of these end uses on infrastructure and policy decisions is expected to be small. Hydrogen demand for innovation projects are excluded for the same reason.

We consider the following criteria to determine the hierarchy:

- **Breakeven hydrogen cost in 2030:** This is the maximum cost at which end users are willing to buy hydrogen. A higher breakeven cost means that less demand side support (e.g. subsidies) is required. In most cases the breakeven cost is determined

compared to current fossil fuel technologies and not to alternative decarbonisation options. As a result, these alternatives are considered in parallel.
- **Decarbonisation impact value:** Although hydrogen can deliver societal value in different ways, we consider the decarbonisation impact as a proxy for the total societal value because decarbonisation is the main reason for developing clean hydrogen. We consider the direct GHG emission reductions from using the hydrogen and the indirect GHG emission effects.
- **Hydrogen transport costs:** Some end uses have inherently higher hydrogen transport costs (e.g. due to the pressure at which it is used or due to more distributed demand). This increases total system costs.
- **Alternative decarbonisation options:** For some end uses, there are alternative technologies available for decarbonisation. In many cases, these offer lower costs or other benefits compared to hydrogen. The alternative options are not always available yet, but we do filter out immature technologies that will likely not be available in 2030.
- **Other considerations:** We capture any other relevant characteristics of the end use that differentiates it from the others with regards to the hierarchy.

Feedstock applications

When using hydrogen as a chemical feedstock, the low carbon hydrogen is not competing with alternative technologies, but with grey hydrogen. Although theoretically other processes can be developed that avoid the use of hydrogen (for example direct electrolysis of iron ore instead of direct reduction with hydrogen), no other processes are available at a technological maturity level that enables commercial application in 2030. The direct GHG impact is the same for all chemical applications where hydrogen is currently already used as a feedstock. However, in the steel sector, hydrogen can replace coal, which results in higher GHG emission reductions per tonne of hydrogen. Industrial plants are often located in areas where natural gas was historically available in large volumes at low costs. It is likely that many of them can be connected to repurposed natural gas pipelines to supply hydrogen.

Ammonia production

The ammonia sector uses grey hydrogen at a current cost of 0.7 USD/kg–1.6 USD/kg (IEA 2020) or around 1.4 USD/kg in 2030 (Hydrogen Council 2021). Low-carbon hydrogen replaces hydrogen produced with steam methane reforming. This amounts to GHG savings of around 9 tCO_2/tH_2 (IEAGHG 2017). There are no alternative ammonia production technologies that do not need hydrogen. Ammonia can be transported more easily than hydrogen, and so ammonia plants might relocate to regions where renewable hydrogen can be produced at lower cost.

Fossil fuel refining

In fossil fuel refining, renewable hydrogen competes with SMR hydrogen at a cost of 0.7 USD/kg–1.6 USD /kg today (IEA 2020) or around 1.4 USD/kg in 2030 (Hydrogen Council 2021). When using renewable hydrogen instead of SMR hydrogen in fossil fuel refining, GHG savings of around 9 tCO_2/tH_2 can be achieved (IEAGHG 2017). There are no alternative technologies that refine fuels without hydrogen (although the type of feedstock determines the hydrogen demand).

Biofuel refining

Similar to fossil fuel refining, for biofuel refining, renewable hydrogen competes with SMR hydrogen and has the same direct GHG reductions per kilogramme of grey hydrogen replaced. However, when using hydrogen in biofuel refining, the hydrogen enables the use of the biofuels, which in turn avoid fossil carbon emissions. These avoided emissions are much larger than the direct emission reductions from replacing the grey hydrogen. Therefore, using clean hydrogen in biofuel refineries can be considered more valuable from a societal GHG reductions perspective. Biofuels require significantly more hydrogen per litre of fuel than conventional fossil fuels. Because hydrogen costs are a relatively small part of the production costs for biofuels (compared to ammonia, for example), it is less likely that biofuel refineries will relocate to get access to lower cost hydrogen.

Bio naphtha hydrogenation

Fossil naphtha used to produce high value chemicals (such as ethylene, propylene, benzene, toluene, and xylenes) can be replaced with alternative feedstocks. Such alternatives include bio-naphtha and pyrolysis oil from chemical recycling. These alternative feedstocks need to be hydrogenated before meeting cracker feedstock specifications. When using fossil feedstocks, the hydrogen produced by the cracker is sufficient to hydrogenate the feedstock, but with bio-naphtha and pyrolysis oil more hydrogen is needed than is produced by the cracker. Like biofuel refining, the majority of the GHG impact is not in the hydrogen itself, but rather in the end-of-life phase of the products (e.g. GHG emissions from incinerating plastic waste at the end of life). As this is a new technology, the costs are still unclear, but when comparing against using grey hydrogen, the breakeven cost would be around 1.4 USD/kg in 2030 (Hydrogen Council 2021). Hydrogenation of the feedstock does not necessarily need to happen at the cracker site. Hydrogenation may also take place at the location where the bio-naphtha is produced (e.g. at a biofuel refinery) or where pyrolysis oil is produced. In that case, hydrogen transport might be more expensive as new pipelines or road or train transport may be required if this location is not near existing natural gas transport infrastructure that can be repurposed.

Steel – Direct Reduction Iron (DRI)

The DRI-EAF (direct reduction iron and electric arc furnace) steel production route is more efficient than traditional BF-BOF route (blast furnace and basic oxygen furnace) and currently uses natural gas instead of coal. When running on hydrogen rather than methane, emissions are even further reduced. A tonne of steel produced with BF-BOF emits around 1.9 tCO_2/t. The hydrogen DRI-EAF route reduces this to 0.1 tCO_2/t. This amounts to GHG savings of around 30 tCO_2/tH_2 with an estimated 0.06 tonne hydrogen demand per tonne steel.[65] Hydrogen DRI plants require hydrogen production costs around 0.6 USD/kg in 2030 to breakeven without carbon credits, and around 4.6 USD/kg with carbon price of 100 USD/tCO_2 (Hydrogen Council 2021).

Steel – Hydrogen injection

Pulverised coal is injected into the blast furnace to optimise performance and reduce costs in the BF-BOF route. Hydrogen can replace pulverised coal as an additional reducing agent in a blast furnace and so reduces GHG emissions. German steel producer Thyssenkrupp is testing this technology at a large industrial scale (Thyssenkrupp 2021). As the technology is still young and requires an additional feedstock stream, the breakeven costs for renewable hydrogen need to be low to make this technology competitive by 2030. Based on interviews with experts, GHG savings of around 0.2 tCO_2e/t crude steel is expected, with 40 kg hydrogen consumed per tonne of hot metal. This amounts to GHG savings of around 5.6 tCO_2/tH_2. This process has the potential to decrease CO_2, but it does not fully eliminate them, thus not offering a fully carbon-neutral steel production (McKinsey 2020).

Carbon capture and utilisation (fuels)

Synfuels can be produced from captured carbon dioxide (CO_2) and hydrogen or from captured carbon monoxide (CO) and hydrogen. CO_2 can be captured from flue gases or from the atmosphere. Certain industrial waste streams can capture CO; in the steel sector, CO streams from blast furnaces are typically combusted to generate electricity, emitting CO_2 to the atmosphere (SPIRE 2021). Other waste streams emit CO to the atmosphere where it oxidises and produces CO_2 (SPIRE 2021). CO needs less renewable hydrogen to produce hydrocarbons compared to CO_2-based processes because it has a higher energetic value than CO_2.

Capturing CO_2 from flue gases is more cost-effective than from the atmosphere due to the higher concentration. However, capturing CO or CO_2 from flue gasses creates a lock-in into (typically fossil-based) combustion processes, and still leads to fossil carbon emissions when the produced fuels are used. When synfuels are produced with renewable hydrogen and biogenic carbon or carbon from CO_2 captured directly from the atmosphere, the full well-to-wheel emissions of the fuel are avoided.

[65] Derived from (Material Economics 2019) by assuming 3.5 MWh electricity based on the 3-4 range stated in the report and assuming 70% electrolyser efficiency

Synfuels produced from carbon captured from the air can replace fossil kerosene for aviation at a breakeven cost of ~0.6 USD/kg hydrogen in 2030 in the absence of a carbon price, and 1.0 USD/kg–1.6 USD/kg with a carbon price of 100 USD/tCO_2e according to a report by the Hydrogen Council (Hydrogen Council 2021). However, the same report mentions this technology is unlikely to be used in 2030. Synfuels produced from CO are likely more cost-effective than those from CO_2 (although this depends also on the policy framework).

For many fuel applications there are low carbon alternatives that are more cost-effective. For example, battery electric vehicles are a more cost-effective solution for lightweight passenger transport. The produced synfuels are only the most attractive options for certain sectors where such alternatives are not (yet) available, such as long-distance shipping or aviation.

Carbon capture and utilisation (materials)

In addition to fuels, industrial CO and CO_2 can also be used to produce materials. The key difference is in the use phase and end of life phase of the products. With fuels, the captured carbon is always entering the atmosphere as CO_2 when it is used. However, with materials this is only the case at the end of life, and only if the materials are incinerated and the emissions released without capture. If materials are recycled, the carbon does not enter the atmosphere. This makes the use of CO for production of materials more attractive from a societal perspective than using the CO to produce fuels. However, the availability of CO could reduce drastically once steel plants convert from BF-BOF to DRI-EAF route on a large scale.

If the carbon is from biogenic or atmospheric origin, the end-of-life emissions are offset at the time when the carbon was captured from the atmosphere and the net impact is zero. This effectively avoids the full life cycle emissions from fossil-based plastics, from production well to end-of-life.

Hydrogen costs need to decrease significantly for this technology to become competitive as fossil feedstock for materials is very cheap, and producers of fossil-based materials are not directly incentivised to reduce end-of-life emissions. The renewable hydrogen-based process has ~5 times the energy demand (DECHEMA 2017). Additional energy is required for carbon capture. For the direct air capture case, the location is likely to be determined by the availability of low-cost hydrogen.

Power generation applications

Electrolytic hydrogen can generate electricity in a turbine similar to natural gas-fired turbines. Hydrogen does not have some of the limitations of other forms of energy storage, such as storage degradation and capacity limitations of batteries and geographic limitations of hydro storage. Hydrogen (and hydrogen-based molecules) is a highly scalable solution to deliver dispatchable electricity generation. As a result, hydrogen may be able to facilitate higher penetration of variable renewable electricity generation technologies in the energy system.

In this case, hydrogen competes with natural gas in power generation at a breakeven cost of 0.8 USD/kg in 2030 (Hydrogen Council 2021). This breakeven hydrogen cost assumes an average of combined cycle and single cycle turbine application. When natural gas is combusted, it emits around 56.1 kgCO_2/GJ, while hydrogen combustion has zero CO_2 emissions (IPCC 2014). With an energy density of hydrogen of around 120 GJ/t, this amounts to GHG savings of 6.7 tCO_2/tH_2.

Existing power plants can be repurposed to run on hydrogen. Power plants are typically located near natural gas production facilities or pipelines. It is likely that these plants can be connected to a repurposed natural gas pipeline to supply hydrogen at a low transport cost.

There are alternatives to using hydrogen in power generation for the purpose of load balancing, such as biogas-fired turbines, battery storage, hydropower storage, and some types of nuclear power generation. Another alternative is load shifting, which avoids the need for dispatchable power. Although these technologies might not be as scalable as hydrogen-fired power generation, they are likely able to provide the vast majority of dispatchable power in the 2030 energy system.

Transport applications

Hydrogen competes with transport fuels such as diesel for road transport. Breakeven hydrogen costs depend on the vehicle in question. According to the Hydrogen Council, the breakeven cost of hydrogen in 2030 ranges from 2.3 USD/kg for mid-sized vehicles to 5.7 USD/kg for busses, with breakeven costs for trains, trucks, and SUVs being in between with 5.1 USD/kg, 2.8 USD/kg–4.1 USD/kg, and 4.4 USD/kg, respectively (Hydrogen Council 2021).

GHG savings compared to the current fuels are relatively high. Replacing diesel with renewable hydrogen in the power train of trucks amounts to GHG savings of around 17.4 tCO_2/tH_2 (JRC 2020) (European Comission 2021).[66] However, for most transport modes there are battery electric alternatives available that offer lower costs and higher end-to-end efficiency.

Hydrogen refuelling stations for road transport require liquid and high purity hydrogen. Liquid hydrogen for refuelling stations is distributed by trucking, resulting in significantly higher transportation costs than using repurposed natural gas pipelines (~2 USD/kg H_2 vs <0.1 USD/kg H_2) (Hydrogen Council 2021). When the location allows it, refuelling stations may connect to the hydrogen pipeline network, but this will require more pipeline transport infrastructure with a smaller capacity, which results in higher transport costs.

Heat applications

High temperature heat

Hydrogen can replace other fuels currently used to produce high temperature heat (over 250°C) in industry. Hydrogen competes with natural gas in high temperature heat production at a breakeven cost of 0.3 USD/kg in 2030 (Hydrogen Council 2021). Assuming that natural gas is replaced, GHG savings are the same as in power generation: 6.7 tCO_2/H_2. For high temperature heating, there are only limited alternatives available. For example, electric arc furnaces have been used in the steel sector for decades to deliver high temperature heat. However, other sectors still need to further develop these high temperature processes (e.g. electric crackers). A recent study found that 78% of industrial energy demand for heating can be electrified with commercially available technologies, and 99% can be achieved with technologies that are under development (Madeddu, et al. 2020). In some processes, the flame currently reacts with the material. When switching to hydrogen or electricity that might affect the quality of the material (SPIRE 2021).

Industrial plants are typically located near natural gas production facilities or pipeline. It is likely that these plants can be connected to a repurposed natural gas pipelines to supply renewable hydrogen at a low cost.

Low temperature heat

Hydrogen can replace other fuels that are currently used to produce low temperature heat (under 250°C) in industrial processes or in buildings (space and water heating). Hydrogen competes with natural gas in low temperature heat production for building heating at a breakeven cost of 0.5 USD/kg in 2030 (Hydrogen Council 2021). The cost values assume boilers with the existing network.

Assuming that natural gas is replaced, GHG savings are 6.7 tCO_2/H_2. For this application, hydrogen is competing mainly with insulation and with heat pumps. Heat pumps are more efficient than hydrogen boilers and they can be used for cooling as well. At very low temperatures heat pumps are not able to provide sufficient heat without costly underground reservoirs. Bioenergy can be a competing technology in cold climates.

Industrial plants are typically located near natural gas production facilities or pipelines. It is likely that these plants can be connected to a repurposed natural gas pipeline to supply renewable hydrogen at a low transport cost. However, buildings are more dispersed and so will require more transport infrastructure with a smaller transport capacity, which results in higher transport costs.

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[66] This is calculated following the avoided emissions methodology as prescribed for applications for the Innovation Fund

Table 4-14 High level assessment of different hydrogen end uses

End use	Breakeven H_2 cost in 2030[1]	Decarbonisation impact	H_2 transport costs	Key alternative	Other considerations
Feedstock applications					
Ammonia	Low ~1.4 USD/kg	Medium	Low	None	Might relocate to low hydrogen cost regions
Fossil fuel refining	Low ~1.4 USD/kg	Medium	Low	None	GHG savings associated with the hydrogen production
Biofuel refining	Low ~1.4 USD/kg	High (due to GHG impact of products)	Low	None	
Bio naphtha production	Low	High (due to GHG impact of products)	Low	Limited	GHG savings include the impact from the bio feedstock
Steel – DRI	Low ~0.6 USD/kg	High	Low	None	Might relocate to low hydrogen cost regions
Steel – H2 injection	Low	Low	Low	DRI steel production	Does not offer a fully carbon-neutral steel production
Carbon capture and utilisation (fuels)	Low ~0.6 USD/kg †[67]	Medium (with DAC)	Low	None for some fuel applications	Full carbon impact only with renewable carbon source
Carbon capture and utilisation (materials)	Low	Medium (with DAC)	Low	Biobased materials	Full carbon impact only with renewable carbon source
Power generation applications					
Hydrogen as fuel – power generation	Low ~0.8 USD/kg	Low	Low	Biogas, hydro, battery power, load shifting	More important for deeper decarboni-sation post-2030
Transport applications					
Busses	High ~5.7 USD/kg	High	High	Battery electric, overhead lines	
Trains	High ~5.1 USD/kg	High	High	Battery electric, overhead lines	
SUVs	Medium ~4.4 USD/kg	High	High	Battery electric	
Trucks	Medium ~2.8 USD-4.1 USD/kg	High	High	Battery electric, overhead lines	
Mid-sized vehicles	High ~2.3 USD/kg	High	High	Battery electric	
Heat applications					
High-temperature heat	Low: ~0.3 USD/kg	Low	Low	Various electric technologies	
Low-temperature heat	Low: ~0.5 USD/kg	Low	High[68]	Heat pumps	

Green shaded cells indicate the key aspects that prioritise the end use.

[67] Hydrogen cost required to break even with fossil fuel technology; based on (Hydrogen Council 2021)

[68] Applies to dedicated hydrogen transport and distribution which is the focus of this study. Costs of blending hydrogen in the natural gas grid (likely the key transportation mode for hydrogen in heating in 2030) are expected to be low.

Prioritisation from a societal perspective

Multiple aspects should be considered in determining which hydrogen end uses should be prioritised from a societal perspective. Here we consider a few key elements; a more in-depth assessment would cover others in more detail (e.g. impact on European GDP from total value chains considered, decarbonisation impact on a full value chain level, or potential limitations of alternative decarbonisation measures on a system level). A holistic assessment is required to avoid potential undesired lock-ins due to infrastructure (such as sub-optimal location of hydrogen-intensive industries). However, we can already draw several high-level conclusions based on this assessment:

1. For many ends uses, there are competing technology options that might enable meeting the European climate targets at lower costs. Prioritising **end uses where no alternatives for hydrogen exist** avoids sub-optimal policy and infrastructure decisions. These are the existing processes where hydrogen is used as a feedstock (ammonia, refining) as long as they have a long-term perspective, but also emerging low carbon processes that require hydrogen (DRI steelmaking, biofuel refining, bio naphtha production).
2. For several other end uses, it is **relatively certain that hydrogen is the best solution for 2050, but not for 2030**. Some long-distance transport modes do not have alternative technologies available, and for these synfuels could be the best solution. However, even if synfuel technologies would develop rapidly, then costs would likely still be too high for large-scale deployment in 2030. Hydrogen could provide a near-term low carbon solution to balancing systems with high shares of variable renewable generation by providing zero-carbon dispatchable power at scale. However, providing dispatch power in times of low renewable generation is unlikely to be required by 2030, because there are still other sources of dispatchable electricity.
3. The last group of end uses is those where **alternative technologies may offer higher energy efficiency and better economics.** For transport end uses, the breakeven hydrogen costs are higher compared to fossil fuels. However, when compared to electric vehicles this is not the case. In heat applications electric technologies can be more cost-effective, although this depends on the specific application and there may be limitations to a system-wide electrification of heat applications due to the significant seasonality of heat demand that does create challenges to electricity infrastructure and production.

Similar hierarchies are proposed by other studies (Energy Transitions Commission 2021) (Fraunhofer IEE 2020) (Ueckerdt, et al. 2021).

4.2.1.2.Expected impacts of regulatory packages

As Section 3.4.1 outlines, hydrogen regulation may have an allocative effect and a distributional effect. Although we cannot quantify the extent of these effects (the change in traded volume and the shift of surpluses from hydrogen users to hydrogen transporters), we can consider the implications of increased hydrogen transportation prices. For the end uses where alternative low carbon technologies are available at similar cost, this means that they will use these alternative technologies instead. No major impacts are expected, although total energy infrastructure costs may increase due to increased electricity demand (Navigant 2019). This group of end uses is also the group that is the least interesting for hydrogen transport providers because of the small transport capacity needs.

The new end uses where hydrogen technologies are not yet critical in 2030 will be impacted more by increased hydrogen transportation prices. In the synfuels application the higher price can hamper the development of a European synfuel sector, and so limits the decarbonisation impact of the synfuels. However, as synfuel installations do not exist today they can also be located near hydrogen supply, which would avoid transport costs altogether. The same effect can be expected to some extent for power generation applications. New hydrogen power plants could be built near hydrogen production/storage sites to avoid hydrogen transport. The impact for the power sector will be small, as this application is expected to be small in 2030.

For the end uses where no alternatives exist, a higher price for hydrogen transport can delay the switch to low carbon hydrogen. Companies would wait for EU Emissions Trading System (ETS) prices to increase further and make the business case feasible. However, this depends on how the policy incentives are set, because the hydrogen transport costs could be covered by subsidies under some models.

Overall, the impacts of sectoral distribution effects depend on how demand side subsidy schemes are set up. If transport costs are covered by subsidies, an unregulated hydrogen network is expected to increase required subsidies, and if these are not increased this leads to lower hydrogen uptake and an increased use of alternatives. As these alternatives are mostly electric, this will result in more electrification and likely higher total energy system costs compared to a regulated hydrogen network. If transport costs are not covered by subsidies, an unregulated network is expected to delay hydrogen uptake (and related decarbonisation effects), and result in more electrification and likely higher total energy system costs compared to a regulated hydrogen network.

4.2.2. Indicative impacts of RAB models on natural gas and hydrogen tariff structures

In 2012, the EU started a regulatory debate on the reference price methodologies (RPMs). Differing approaches to determining NG transmission tariffs (tariffs) were observed between MSs. The EU concluded that these varying approaches impact transportation prices and potentially hinder cross-border trade (ACER 2020). The intended role of the Commission Regulation (EU) 2017/460 of 16 March 2017 (European Commission 2017), establishing a network code on harmonised transmission tariff structures for gas (NC TAR), was to create a level playing field amongst domestic and cross-border network users, reduce cross-subsidisation between these users, and increase tariff transparency. The ultimate goal of the regulation is facilitating cross-border trade (ACER 2020). Yet even under the NC TAR, the NRAs and TSOs have a lot of freedom in proposing a suitable RPMs, allowing them to take account of the national characteristics of the network and of policy and regulatory objectives.

Differences between MSs with respect to determining tariffs still exist. Section 3.2.4 explores the different tariff regulation methodologies and their likely impact. In this section, we provide a stylised quantified insight for asset valuation and transfer between RABs and insight on the effect of joint RAB and a separate RAB on the natural gas and hydrogen tariffs. For this assessment we omit the differences between cost-plus, revenue-cap, or hybrid approaches on the final tariffs. Rather, we focus on the level of horizontal unbundling (i.e. determining joint or separate RAB) and cost-allocation methodologies on determining tariffs for natural gas and hydrogen. As such, we assume that gas TSOs would in principle be allowed to operate both natural gas and hydrogen networks without full (ownership) horizontal unbundling.

4.2.2.1. Key parameters in creating tariffs

The economic principles of creating tariffs can be explained with a reference to three key parameters: CAPEX, OPEX, and (allowed) return.

CAPEX is spread over a depreciation period to determine annual eligible expenses—the depreciation allowance. In principle, three broad categories for RAB valuation exist (Economic Consulting Associates 2018):

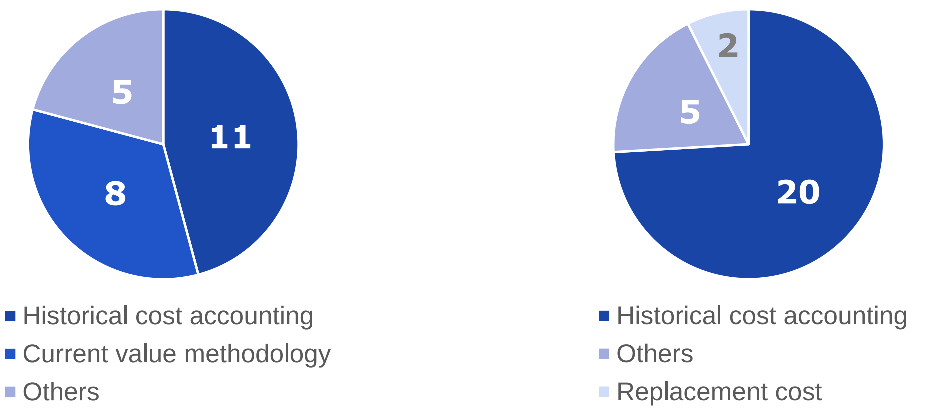
- Historical cost accounting methods based on the actual cost of acquiring and renewing assets in the past less the cumulative depreciation on those assets, such as net book value (NBV), or depreciated historical costs (DHC).
- Replacement cost methods based on the cost that would be involved in replacing the service capability of the existing assets, taking account of the cost of replacing their service capability were it to be replaced now and adjusting for depreciation to reflect the remaining useful lives of the assets.
- Current (economic) value method based on the *value in use*, which reflects the present value of future net cash flows that can be expected from the operation of and services provided by those assets.

Disallowances of CAPEX depreciation on unused assets (e.g. empty pipeline) are typically not possible ex post with historical cost account methods. Once an asset (and its cost) can be accounted for in the RAB during a past regulatory period, the asset remains in the RAB until it has been fully depreciated. This persists even if it transpires later that this original investment was inefficient and the asset is now underused. This stands in contrast with the replacement cost and current value methods that exclude any unused or underused assets beyond the specified planning horizon (Oxera 2011).

In the past, NRAs had to establish an opening asset value when the current regulatory frameworks were established. According to ACER, historical cost-accounting methods were most common (11 countries), eight countries used current value methodology and five NRAs used other approaches. NRAs also perform periodic revaluations of the RAB. ACER specifies that historical cost is the prevailing method (20 countries); five countries use other methods and two countries use replacement cost methods (Economic Consulting Associates 2018).

Figure 4-5 Valuation standards used across MS over time

Source: (Economic Consulting Associates 2018).



Most prevalent methods at original asset valuation

Most prevalent method during most recent periodic revaluations

Both the original asset valuation and the periodic revaluation methods are relevant for hydrogen. The choice of valuation methodology is particularly important if a separate RAB between natural gas and hydrogen is pursued as a regulatory model because the asset transfer of a natural gas asset to hydrogen needs to follow one of the valuation methodologies. In turn, the various methodologies can (and will) have an impact on the final tariffs for both natural gas and hydrogen.

OPEX represents the eligible day-to-day expenses related to TSO operations.

Finally, (allowed) **return** is the third key RAB component as the TSOs also incur the costs of financing the asset base (i.e. paying an appropriate return to the debt and equity holders). The **annual allowed revenues** are the sum of the three key parameters (CAPEX, OPEX, return) for a particular year and are used to determine the natural gas transmission tariffs.

There are differences in fixed versus flexible adjustment of the RAB. Either the RAB is fixed for a given regulatory period (e.g. 10 years), or adjustments to the RAB are in principle possible yearly via adjustment mechanisms (Z factors) that are put in place to manage the differences between the value estimated ex ante and the values actually observed.

4.2.2.2.Asset valuation for transfer between RABs

In sum, when considering the effects of different RAB regulatory regimes on the prospective natural gas and hydrogen tariffs, the following elements are important:

- **Asset valuation for transfer between RABs**
- **Fixed versus adjustable RAB regulatory periods** (especially relevant for separate RAB)

The prevailing method for appreciation of RAB among MSs is based on historical cost. However, depending on whether the regulator applies NBV or DHC standards, different asset life, inflation adjustments, and return expectations are used. This can result in very different asset (RAB) appreciation.

Table 4-15[69] illustrates the effect on different historical valuation methods on the initial natural gas RAB appreciation for Gasunie.

Table 4-15 Valuation standards used in Gasunie RAB appreciation

Source: (Oxera 2011)

	Net book value	DHC (nominal)	DHC (real)
Application	Applied until 2004	Promoted by the DTe between 2001 and 2004 (not applied)	Prescribed by the DTe in 2005 (decision annulled)
Asset lives	Pipelines: 20 years Installations: 10 years	Pipelines: 55 years Installations: 30 years	Pipelines: 55 years Installations: 30 years
Inflation adjustment	None	None	CPI
Value as at December 2005 (€ billion)	**0.95**	**2.59**	**4.74**

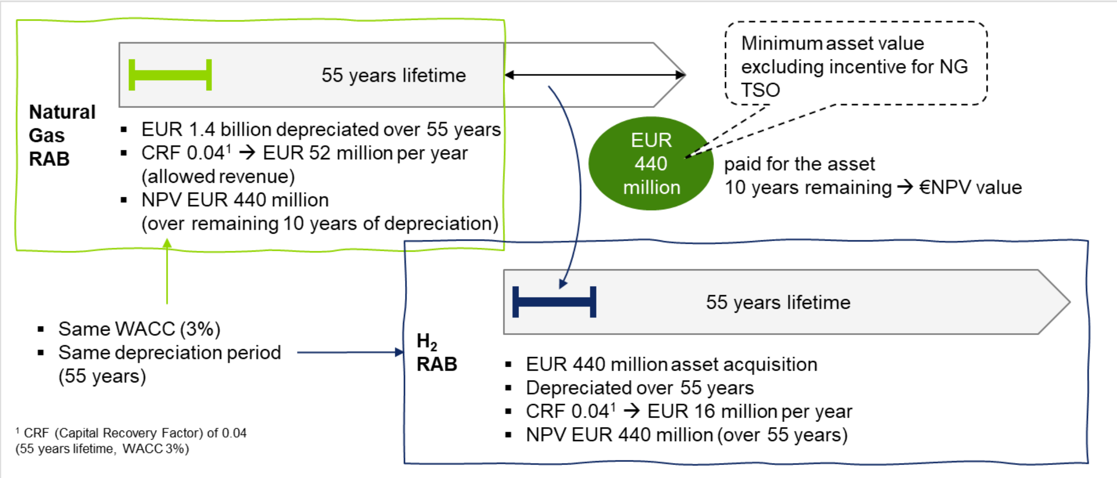
Similarly, if assets (e.g. pipelines) were transferred from one RAB into another (repurposing), the transfer value might differ significantly under various appreciation standards. Figure 4-6 depicts one possible example of asset valuation when transferring between natural gas and hydrogen RAB. In the example, we analyse a natural gas pipeline asset that has been operating for 45 years, with 10 years remaining until the calculated asset lifetime of 55 years is reached. The net present value (NPV) of the remaining 10 years of allowed revenues is considered the minimum asset transfer value (below this value the natural gas TSO is theoretically not incentivised to transfer the asset).[70] In the example below, EUR 440 million is the asset transfer value. The purchased asset is now part of the hydrogen RAB. The asset then depreciates again over 55 years at the same weighted average cost of capital (WACC).[71] The resulting annual allowed revenues for the hydrogen RAB are EUR 16 million/year. That results into the new NPV matching the original NPV value. This is a highly stylised example and, as outlined above, the asset valuation might differ under different accounting rules. The following section describes how this could translate into a tariff structure under the separate hydrogen RAB.

[69] CPI (Consumer Price Index) examines the weighted average of prices of a basket of goods and services. CPI is used to account for the effects of inflation during the depreciation period.

[70] Minus, for instance, maintenance costs associated with the asset in question.

[71] Note that the depreciation period and WACC might of course be different between the NG and hydrogen RAB. Higher WACC, for instance, could represent a higher risk to the investors or a nTPA regime. In our example, we keep the values constant for consistency of the comparisons.

Figure 4-6 Stylised valuation for asset transfers between natural gas and hydrogen RAB



It is important to realise that with such an approach, end users might be paying more (compared to the original asset valuation) for the same assets. In the previous example, the same asset depreciates over a much longer than the original depreciation period (55 years versus 100 years (45 + 55)). It could be argued that the hydrogen RAB is only allowed to depreciate the 10 years of the remaining original asset lifetime. However, that would likely lead to much higher annual allowed revenues in the hydrogen RAB and therefore higher tariffs.

Alternatively, the argument can be made that especially for unused natural gas assets, the natural gas TSO should not be allowed to use the WACC in the calculation of the asset transfer valuation since the transferred asset would no longer be physically in the natural gas RAB. This would likely disincentivise the natural gas TSO from transferring these assets to the hydrogen RAB as they would earn lower revenues than if they kept the unused asset under the natural gas RAB. Nevertheless, there might be other criteria that come into play, such as regulatory regimes that reward operational efficiency (e.g. efficiency benchmarking in a revenue cap regulation regime) of the RAB or outright prohibition for unused assets to stay in the RAB.

Additionally, it is unclear what would happen with the revenues accrued by the natural gas RAB from the hydrogen RAB (purchase value). These might either be recognised as dividends to investors, used to adjust the current RAB (Z factor adjustment), or only used to adjust RAB in the next regulatory period (fixed RAB).

In sum, we provide a highly stylised example of how asset valuation for transfer between RABs could be implemented, but a more in-depth evaluation of this issue should be performed. The asset transfer value from Figure 4-6 is used in the calculation of the hydrogen tariffs in the stylised scenario with separate RAB (Figure 4-7).

Importantly, when repurposing assets for hydrogen, the TSOs would still have to comply with security of supply (SoS) regulation, i.e. the TSOs would have ensure that the overall network still complies with SoS requirements. In our scenario, we assume that 20% of natural gas capacity is repurposed for hydrogen. On an annual basis this would increase utilisation of the natural gas network from 40% to 50% which should be possible. However, hourly gas flow modelling is required to ascertain whether the network will still be able to meet demand peaks . Additionally, natural gas pipeline infrastructure could use other tools to manage SoS. These include, where possible, expanded utilisation of (underground) natural gas storage, use of LNG terminals, or LNG/CNG trucking to (temporarily) undersupplied demand centres.

4.2.2.3. The effects of joint and separate RAB on the final network tariffs for hydrogen and natural gas

The effects of joint and separate RAB on the final network tariffs for hydrogen and natural gas, when repurposing natural gas assets, cannot yet be predicted accurately due to the multitude of variables involved (e.g. appreciation method, regulatory periods, market developments) and their variation between MSs. We constructed a highly stylised scenario to illustrate the effects of the joint versus separate RAB, based on several assumptions and considerations:

- For the joint and separate RAB we used the DHC method (nominal), with 3% WACC and asset lifetime of 55 years. This is more akin to a rTPA regime, whereas under a nTPA regime the depreciation period would likely be shorter and the WACC higher.
- When transferred from natural gas to hydrogen RAB (separate RAB), the assets are valued based on their specific value in the RAB at the time of transfer, as recommended by ACER (and using the historical cost method described in the previous section).[72]
- Flexible adjustment of the RAB and cost-plus regime are assumed (i.e. no incentive regulation with efficiency benchmarking). Note that if fixed regulatory period was used, the only major difference to our current conclusions would be the timing of the RAB adjustments. Under a fixed regulatory period, the RAB adjustments presented in the following analysis as "instant" would only take effect in the next regulatory period.
- The CAPEX and network capacity figures roughly correspond to the Dutch TSO network operated by Gasunie Transport Services as of 2020.[73]
- A capacity utilisation of 40%, which corresponds roughly to the aggregate bookings of transportation capacity at selected capacity allocation mechanism (CAM) points between 2015–2019.[74]
- Resulting natural gas and hydrogen tariffs are calculated without allowed revenues from OPEX and return margin.
- The capacity of assets repurposed from NG to hydrogen decreases to 25% of their original capacity.[75]
- Finally, we assume that
    - Under a joint RAB approach, the hydrogen tariff is cross-subsidised to achieve parity (on a EUR/MWh basis) with the natural gas tariff
    - Under a separate RAB, the hydrogen tariff is fully cost-reflective (hence not cross-subsidised)

The stylised scenario (Figure 4-7) depicts a situation in which the network operator has unused assets in the RAB, the capacity utilisation is relatively low (40%) and the DHC value of these assets is recognised in the RAB.

- **Under the joint RAB assumption**, the overall network capacity decreases as repurposed assets have lower maximum (hydrogen) capacity than with natural gas. However, despite the decreased capacity the natural gas network can still deliver the same volumes of energy as before repurposing by increasing utilisation from 40% to 50%. The hydrogen network utilisation is assumed to be 40%. The hydrogen tariff is cross-subsidised and both tariffs show uniform value. There is a slight decrease in the natural gas tariffs due to increased total energy flows across the natural gas and hydrogen networks. The resulting tariffs are EUR 1.51/MWh before repurposing and EUR 1.49/MWh after repurposing (both natural gas and hydrogen).
- **Under the separate RAB assumption**, the main difference is in the resulting natural gas and hydrogen tariffs. The natural gas tariff decreases compared to the initial situation as the value of the natural gas RAB decreases and the network still delivers the same volumes of energy as before repurposing. The natural gas tariff is also significantly lower than under the joint RAB assumption because there is no cross-subsidisation of hydrogen costs by natural gas users. The hydrogen tariff is fully cost-reflective and so significantly higher than under joint RAB. The resulting tariffs are EUR

[72] (ACER and CEER 2021).

[73] (Gasunie 2021) and (ENTSOG 2021).

[74] Based on (ACER 2021).

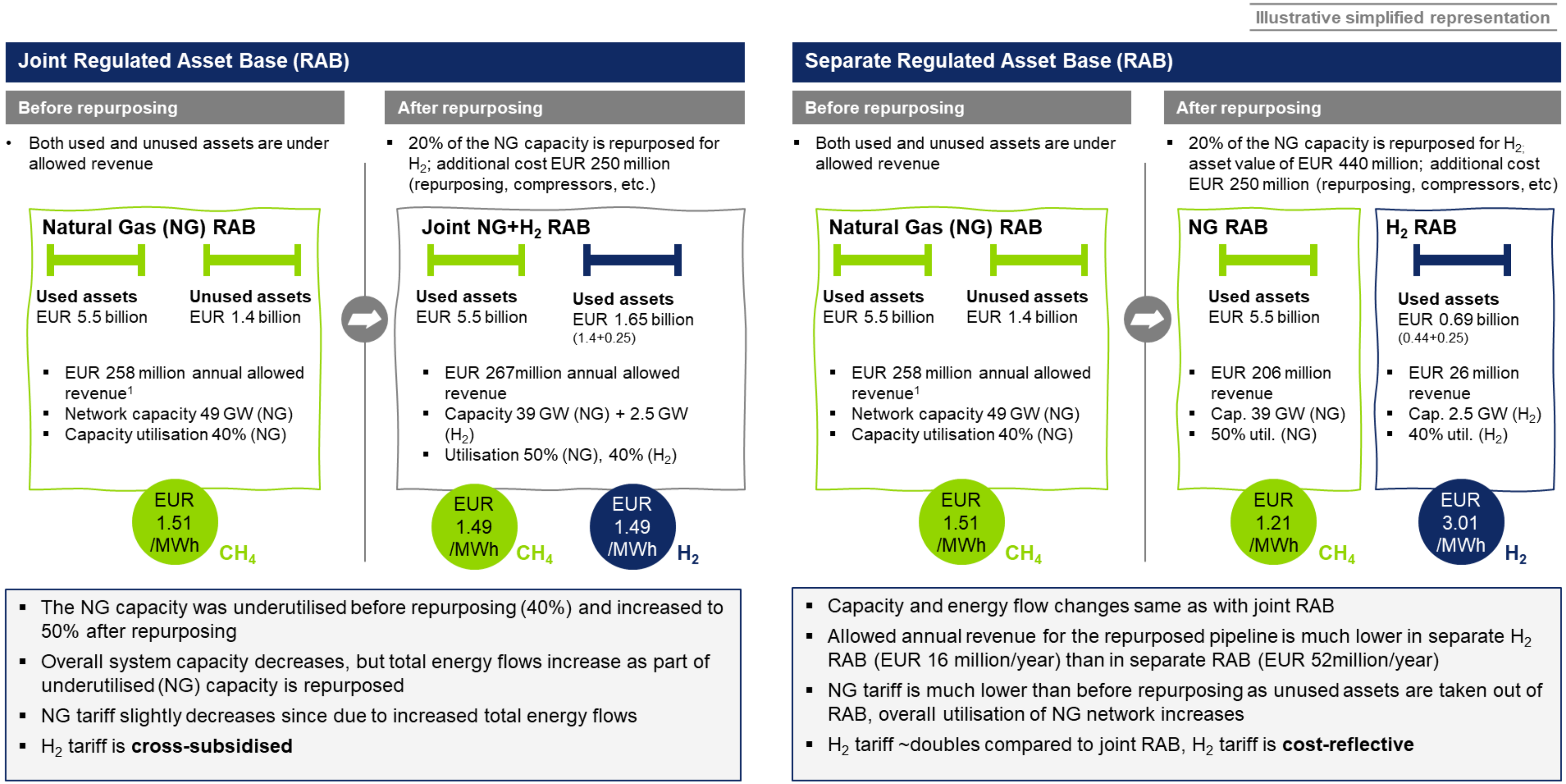
[75] Note we assume the same capacity utilisation for hydrogen as for natural gas (base case).

1.51/MWh before repurposing and EUR 1.21/MWh for natural gas and EUR 3.01/MWh for hydrogen after repurposing.

- **Sensitivity**. In all the examples, 3,504 FLH (40% utilisation) for the pipeline capacity (natural gas and hydrogen) as a base case (before repurposing) is assumed for consistency.[76] If the actual hydrogen flows were lower in the initial period of the development of the network infrastructure, the tariff would be higher. Assuming average utilisation of 20% for hydrogen (1,752 FLH), the joint RAB would yield a tariff of EUR 1.52/MWh (compared to EUR 1.51/MWh; both natural gas and hydrogen) and EUR 6.03/MWh for separate RAB (compared to EUR 3.01 EUR/MWh; hydrogen only).

[76] Note that after repurposing the capacity utilisation of the natural gas network increases to 50% in both examples (joint and separate RAB).

Figure 4-7 Stylised Scenario: Joint and separate RAB



[1] All annual allowed revenue calculations are done with CRF of 0.04 (55 years lifetime, WACC 3%)

4.2.2.4. Sensitivities

The results presented in the analysis above are calculated for a set of assumptions, as noted earlier. The assumptions are based on the most common regulatory regimes across MSs for natural gas. Below, we list the major sensitivities in these assumptions and their anticipated impact:

- **Pipeline utilisation**. As noted above, assumptions in pipeline utilisation change the results for both natural gas and hydrogen tariffs. The effects are more pronounced for hydrogen tariffs under separate RAB.
- **Fixed vs flexible regulatory period**. Under a fixed regulatory period, the RAB adjustments presented in the analysis as "instant" would only take effect in the next regulatory period.
- **RAB regulatory models**. We assume a cost-plus model. Under revenue-cap, or hybrid approaches, including efficiency benchmarking, underutilised assets (e.g. pipelines) would likely not be favoured. This could render unused assets in the scenario unlikely. Note that there could still be unused assets in the ownership of the TSOs, however these could not be recognised as part of the RAB and allowed revenues.
- **RAB valuation methods**. We assume historical cost accounting methods. Replacement cost methods or current (economic) value methods would affect the asset valuation in the transfer between RABs. Valuation with replacement cost methods would mean zero transfer value in the stylised scenario. Similar effects would be expected using current (economic) value methods.
- **Different historical cost accounting methods** would also affect the WACC and (economic) lifetime. We assume DHC method (nominal). If DHC (real), or net book value were used instead the resulting valuation of the assets (as well as the whole RAB) would change. The effects are illustrated in Table 4-15. Different accounting methods could significantly affect the results in either (upward or downward) direction. Generally, shorter (economic) lifetimes and accounting in real terms (thus correcting for inflation) will increase the overall RAB valuation and thus affect the tariffs as well as asset valuation in absolute terms.

4.2.2.5. Summary

This section illustrates how asset valuation for transfer between RABs and tariff impacts of joint versus separate RAB, might develop under a strict set of assumptions. Several findings can be summarised here:

- Joint RAB typically leads to higher NG and lower hydrogen tariffs (compared to separate RAB). This outcome might be desirable to facilitate hydrogen network ramp-up (unless other options to support hydrogen infrastructure are pursued, such as explicit subsidies); however, it leads to a (distributional) disadvantage of natural gas users cross-subsidising hydrogen end users.
- Separate RAB typically leads to only smaller changes in natural gas RAB (only in case of unused assets that are part of RAB), but to much higher hydrogen tariffs under the separate hydrogen RAB (compared to joint RAB). This effect would likely be even more pronounced in case of lower utilisation of the hydrogen assets in the nascent period of the network development.
- Although the tariffs calculated in this section are highly stylised, they should be compared to the expected other costs in the hydrogen value chain (especially production). The production cost alone (especially for renewable hydrogen) will likely be between EUR 2/kg–EUR 4/kg (EUR 60/MWh–EUR 120/MWh) up to 2030. Even the

highest calculated hydrogen tariff (sensitivity of separate RAB) only results in EUR 6.01/MWh.[77]

However, this picture presents just one possible interpretation of these effects and large uncertainties exist. The many regulatory and accounting details that set the RAB methodologies in different MSs drive these uncertainties. A full evaluation of these effects for a given combination of regulatory principles and methodologies would have to be performed across MS. Alternatively, the EC could consider setting out a general regulatory framework for the hydrogen market (e.g. requiring either joint or separate RAB, standardised CBA methodology, and possibly an asset valuation methodology), but leave the specific decision for either joint or separate RAB to the regulatory bodies at the MS level. To a certain extent, this approach would be similar to the implementation of the NC TAR, where the general principles were set out on EU level. However, given the many national specifics and considerations, some implementation decisions were left with the MSs.

4.2.3. Administrative costs

For this impact assessment, we define administrative costs as the costs incurred by companies and regulators to meet legal obligations and provide information as required by the regulators or companies. This section identifies differences in administrative costs between regulatory measures and between the different regulatory packages. For this purpose, a high-level indicative assessment is sufficient. A more detailed estimation would require a more detailed definition of how measures are implemented and how they work together (as synergies can likely be achieved in practice when combining regulatory options efficiently). At this stage that is not feasible.

The EU Standard Cost Model is used as much as possible to quantify the impacts (EC 2017). The assessment focusses on the most material impacts and does not aim for an exhaustive assessment of administrative costs. The unit costs provided for person-years in this assessment (EUR 100,000 for companies and national authorities and EUR 150,000 for European agencies)[78] can be interpreted as covering the full costs of employment and additional costs attributable to this employee. The assessment focusses on 2030, but also considers the one-off costs that will likely take place before 2030 to enable a more balanced comparison of options. The assessment assumes 27 NRAs and 30 hydrogen TSOs, based on the current natural gas market. Note that the costs for a pan-European coordinating body (analogous to ACER) are not included in this assessment, but such costs can be added in an impact assessment based on actual costs of ACER.

We now discuss each of the main regulatory measures with regards to their impact on administrative costs. The BAU serves as a benchmark, meaning we assess the impact on administrative costs relative to the costs occurred in the BAU. For a more detailed qualitative discussion of the impact of specific regulatory measures on administrative costs, as well as other costs associated with policy measures, see Section 3.2.

Regulated TPA requires TSOs to provide access to third parties and to show to the NRA they do this. That takes up more resources than in the BAU scenario, where TSOs are not required to provide such access. The NRA regularly checks that companies are abiding by the requirements. We estimate this requires one person-year for each TSO and each NRA. A regulated TPA requires regulators to know more about the (local) conditions, operators' costs, and the market structure to define access conditions, but costs associated with building up and maintaining this knowledge are not considered administrative costs following the Standard Cost Model. There are also costs associated with settlement of disputes. We assume here that this requires 2 person years from the NRA, and we double this to account for the administrative costs to the businesses that filed the complaints.

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[77] Note that this omits OPEX and return share of the RAB calculation and assume a utilisation of hydrogen pipelines of at least 60%.

[78] These numbers are based on the administrative cost estimation of the revised EU ETS (p.186) (EC 2015)

Negotiated TPA requires similar information transfer and verification as for a regulated TPA. Under negotiated TPA, time and resources are needed to ensure and show that negotiations take place in line with the regulatory requirements. Since individual contracts can differ from user to user, more time is required for reporting and verification than with the regulated TPA. Time and expenses for negotiation (both for TSOs and users) are expected to be considerable, but they are not administrative costs and so are not included here. Substantially fewer disputes are expected here, and these are captured in the oversight, and not quantified separately like with the rTPA.

Table 4-16 depicts the assumptions and resulting costs.

Table 4-16 Assumptions and resulting administrative costs for TPA

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
Negotiated TPA	Ensuring compliance	TSO	30	2	100,000	6,000,000	Annual
	Oversight	NRA	27	2	100,000	5,400,000	Annual
Regulated TPA	Ensuring compliance	TSO	30	1	100,000	3,000,000	Annual
	Oversight	NRA	27	1	100,000	2,700,000	Annual
	Disputes settlement	NRA/Users	27	4	100,000	10,800,000	Annual

Accounts, legal, or functional unbundling (horizontal or vertical) requires continuous monitoring of the companies by the NRA. Companies need to report on compliance, which has some associated administration costs. **Ownership unbundling** results in less administrative costs because activities are separated more clearly (we assume 10% of the costs here). For horizontal and vertical unbundling, similar costs are expected because of the separation of activities, reporting, and oversight is similar irrespective of what activities are separated from what others. When horizontal and vertical unbundling are implemented, administrative costs are not expected to be the sum of the costs for vertical and for horizontal unbundling options. Instead, the highest costs (either horizontal or vertical) are taken for the total administrative costs.

Table 4-17 Assumptions and resulting administrative costs for unbundling

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
Accounts/ legal/ functional unbundling	Oversight	NRA	27	1	100,000	2,700,000	Annual
	Reporting	TSO	30	1	100,000	3,000,000	Annual
Ownership unbundling	Oversight	NRA	27	0.1	100,000	270,000	Annual
	Reporting	TSO	30	0.1	100,000	300,000	Annual

Revenue regulation requires a substantial one-off cost benchmarking exercise (although it is uncertain whether this can already be done for the nascent hydrogen network). The NRA is required to collect (sometimes detailed) cost figures, possibly conduct a benchmarking exercise, report the results, and determine the tariffs. TSOs are required to collect and share cost information. There will also likely be some costs associated with settlement of disputes. Reporting costs for companies are included in this assessment, although they are expected to be offset by lower costs associated with defining tariffs (which essentially the regulator is now taking over). The benchmarking is assumed to happen every 5 years.

Table 4-18 Assumptions and resulting administrative costs for revenue regulation

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
Revenue regulation	Cost benchmarking	NRA	27	10	100,000	27,000,000	Every 5 years
	Cost benchmarking	TSO	30	1	100,000	3,000,000	Every 5 years
	Reporting	NRA	27	1	100,000	2,700,000	Annual
	Disputes settlement	NRA	27	3	100,000	8,100,000	Annual
	Reporting	TSO	30	2	100,000	6,000,000	Annual

For **cost-plus regulation** the administrative costs are only recurring and related to the reporting on costs to the regulator by companies, and verification of compliance by the NRA.

Table 4-19 Assumptions and resulting administrative costs for cost plus regulation

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
Cost plus regulation	Oversight	NRA	27	1	100,000	2,700,000	Annual
	Reporting	TSO	30	2	100,000	6,000,000	Annual

Administrative costs for an **EU TSO** are uncertain as the responsibilities and activities for this option are not well-defined. However, such an organisation would likely be relatively small (we estimate 50 full-time equivalents, i.e. 50 person-years). Assuming that (national) TSOs remain needed for operational tasks, we expect that substantial exchange of information is required. Some of the EU TSO activities would replace activities within TSOs, leading to cost savings. These are not taken into consideration here.

Table 4-20 Assumptions and resulting administrative costs for an EU TSO

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
EU TSO	Management and planning	European TSO	1	50	150,000	7,500,000	Annual
	Coordination	TSO	30	2	100,000	3,000,000	Annual

The **tendering of rights** is an alternative option. Scoping and details of this option are not well defined, but some assumptions are made to derive some indicative insights. We assume that each regulator needs 20 person-years per 10-year period to prepare the tender. Each TSO applies for three tenders and 5 person-years on each tender application. We assume that such a tender process would happen every 10 years.

Table 4-21 Assumptions and resulting administrative costs for tendering

Option	Component	Actor	Number of actors	Person years	Unit cost	Total cost	Freq.
Tendering of rights	Tender application	TSO	30	15	100,000	45,000,000	Every 10 years
	Tender process	NRA	27	20	100,000	54,000,000	Every 10 years

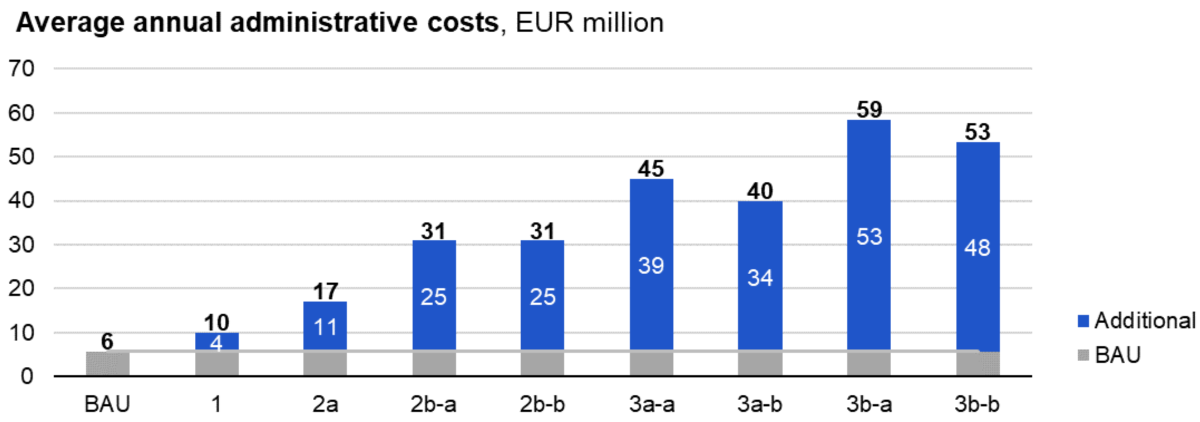
The different options are mapped to the draft policy packages as Table 4-22 depicts.

Table 4-22 Mapping of regulatory assessed elements to draft policy packages

Aspect	BAU	1	2a	2b-a	2b-b	3a-a	3a-b	3b-a	3b-b
TPA	*none*	*none*	nTPA	rTPA	rTPA	rTPA			
Vertical unbundling	*none*	*none*	Accts, legal, or funct.			Ownership			
Horizontal unbundling	Accts, legal, or funct.	*none*	Accts, legal, or funct.	Accts, legal, or funct.	*none*	Accts, legal, or funct.	*none*	Accts, legal, or funct.	*none*
Tariff regulation	*none*	*none*	*none*	Cost plus	Cost plus	Revenue			
Other	*none*	Tendering of rights	*none*	*none*	*none*	*none*	*none*	EU TSO	EU TSO

Averaging out the one-off administrative costs over the years based on the estimated frequencies delivers the results in Figure 4-8. It shows that the annual costs of all options are higher than in the BAU scenario, ranging from an increase of EUR 4 million to an increase of EUR 53 million. The high one-off costs for tendering in Option 1 deliver the lowest average annual increase in administrative costs, but the estimation for this option is particularly uncertain. Overall an increase in administrative costs is observed with increased regulation, with light Option 2a having lower costs than other options with more regulation. However, the estimated administrative costs of Options 2b through 3b-b are of a similar order of magnitude.

Figure 4-8 Results of administrative cost assessment by draft policy package



Compared to the expected societal benefits from regulation (to be derived from the METIS modelling) the additional administrative costs are likely relatively small.

Note that these high-level cost estimates are sensitive to the various assumptions made and so are only useful to draw directional conclusions.

5. Synthesis

The framework presented in this report assesses the possible impacts of proposed hydrogen network regulations.

Proposed regulatory options could have a range of benefits; however, drawbacks must be considered and potentially mitigated against. We also assessed the impacts of a lack of regulation.

5.1. Results and interpretation

We created and presented a holistic framework to assess the impacts of regulation on the creation of hydrogen infrastructure in the EU for 2030. Given the uncertainties inherent in this early stage market, our assessment differentiates between the following:

- A qualitative assessment framework of possible impacts of four key regulatory measures on the five key impact areas characterising the future EU hydrogen network
- The approach for an impact assessment of the draft EU policy packages and an initial directional discussion given the findings for the four individual regulatory measures
- A quantitative assessment framework for various aspects of these impacts, using the EC's METIS model, including definitions of all input parameters and modelling scenarios
- A semi-quantitative assessment of impacts that could not be quantified using METIS but where a high-level estimate was deemed useful and possible to achieve

5.1.1. Qualitative assessment of individual measures and overall packages

The indicative qualitative assessment of individual measures and overall packages exhibits the complex and multifaceted nature of considerations around potential regulatory regimes. We have followed a ceterus paribus approach to identify the most relevant impacts of regulation and, among many other elements, find that:

- All four regulatory measures are expected to have impacts on the five areas to varying degrees and that the direction of the impact varies by regulatory measure and by impact area.
- The absence of regulation may facilitate investments in an early phase of hydrogen market development, but at the risk of vertically integrated, monopolistic network operators and a dispersed and uncoordinated network development across the EU.
- With a tendering approach the market development and outcome may be defined to a large extent by political decisions and the design of the tendering approach and its parameters. Unless the tendered concession is associated with a regulatory framework it bears the risk of monopolistic market outcomes.
- A stricter regulatory approach may impede incentives to invest in hydrogen pipelines, however, it can help achieve the key objectives of the introduction of infrastructure regulation (e.g. increase cost efficiency and enable competition in business activities upstream and downstream the infrastructure) and potentially facilitates cross-border integration.
- An EU regulation with a common RAB might facilitate investments in hydrogen networks, particularly in early development periods. This approach can also result in lower network tariffs for hydrogen consumers which may help increase incentives for consumers to switch to hydrogen, however network tariffs would no longer be cost-reflective and could lead to cross-subsidisation between gas and hydrogen consumers.

5.1.2. Quantitative assessments with METIS

The EC will use the METIS model to assess a range of scenarios and sensitivities to assess the impact of varying degrees of cross-border integration on a range of quantitative KPIs. This report contains all the required input data and assumptions for these METIS modelling runs. Future iterations of the METIS model may also allow more detailed modelling.

5.1.3. Semi-quantitative assessments

We assessed three aspects of possible hydrogen legislation separately, as they could not be captured in the full quantitative modelling: sectoral distribution, the effect of joint versus separate RAB, and administrative costs.

For sectoral distribution effects we find that end-uses can be differentiated based on whether or not the hydrogen is essential (i.e. without alternatives) to the end-use, whether this is likely to persist in the medium-to-long term and what the alternatives are, if any.

We postulate that transport costs, in conjunction with subsidy structures, may have an influence over which of these end-uses will be served through the emerging hydrogen network.

For the effect of joint versus separate RAB we find that assessments are highly uncertain as they depend strongly on the applicable regulation and accounting details which may differ by MSs. In our simplified EU level example assessment, we find that

- Joint RAB typically leads to higher natural gas but lower hydrogen tariffs, implying cross-subsidisation
- Separate RAB leads to higher hydrogen tariffs while natural gas tariffs are mostly unaffected
- The impact of RAB on hydrogen tariffs is mostly negligible compared to total hydrogen costs up to 2030 as these are expected to be relatively high.

For administrative costs we find that the more highly regulated policy packages imply higher administrative costs, but that these are expected to be small compared with overall benefits of regulation. This needs to be confirmed in the METIS modelling following this work.

We suggest the overall structure in Table 5-1 for the representation of the assessment results in the full Impact Assessment. The results of the quantitative modelling are absent from this table as they will be finalised after the publication of this study. However, they have been added to the Executive Summary in the revised version of this report.

Table 5-1 Overview of results of complete impact assessment (quantitative modelling results from a separate study by Artelys)

	BAU	Option 1	Option 2		Option 3	
		1	2a	2b	3a	3b
Impacts qualitative assessment (without exemptions)[79]						
Market structure	-	0	0	0/-	++/0	+
Cross-border integration	-	0	0	+	+	++
Administrative costs	+	0	-	-	-	-
Investment incentives/barriers	+	0	0	-/0	-/0	-
Repurposing	+	-	0	0/+	0/+	0
Stylised fact used in modelling of impacts						
Cross-border transport capacity	BAU	"A constrained"				"A optimised"
Impacts – quantitative assessment (in comparison to BAU)						
Total energy system cost [EUR]	n/a					
Average cost of hydrogen (incl. transmission; EU weighted average, MS simple average [EUR/MWh $H_{2\ (LVH)}$]	n/a					
Average share of RES-E in electricity used for hydrogen generation (EU weighted average, MS simple average) [%]	n/a					
Weighted average grid emission factor (hourly) for electricity used for hydrogen generation (EU weighted average, MS weighted average) [gCO_2eq/kWh]	n/a					
Weighted GHG emission intensity of the hydrogen produced (EU weighted average, MS weighted average) [$kgCO_2eq/MWh\ H_{2\ (LHV)}$]	n/a					
Ratio of electricity sold and bought by the electrolysers versus total electricity sourced (by MS) [(%) total $Electricity_{sold+bought}$/ total $Electricity_{consumed}$]	n/a					
Volumes of hydrogen loss of load by MS [MWh $H_{2\ (LHV)}$]	n/a					
Hydrogen interconnection capacity by MS [GW]	n/a					
Hydrogen interconnection utilisation by MS [FLH]	n/a					
Total electrolyser capacity by MS [GW_{el}]	n/a					
Total hydrogen production by MS [MWh $H_{2\ (LHV)}$]	n/a					
Impacts – semi-quantitative assessment (in comparison to BAU)						
Impact of transport costs on sectoral distribution	n/a	Differ by sector and depend on subsidy scheme structure				
Impacts of joint versus separate RAB on tariffs	n/a	Impacts H_2 tariffs: likely small c.f. total H_2 costs. Impacts NG tariffs: small.				
Administrative costs [EUR million]	n/a	~5	~10–25		~30–50	

Legend	--	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	++	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

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[79] The qualitative assessment is undertaken on the assumption that the regulatory measures in each package are applied to all pipelines. In case certain pipelines (e.g. new pipeline investments) are granted exemptions from certain measures (e.g. TPA, vertical unbundling, tariff regulation) equivalent to regulatory exemptions for gas and electricity infrastructure, the assessment may differ. E.g., the negative effects on investment incentives in policy packages 2 and 3 can be tackled with exemptions for new pipelines, while providing long-term certainty about the regulatory regime for a significant part of the asset lifetime (e.g. 20 years). Depending on the specifics of the exemption (e.g. duration), positive effects of regulation on market structure and cross-border integration can be largely maintained with an exemption regime.

5.2. Additional considerations: Technical regulation

In the policy measures assessed here we have concentrated on measures that would affect market and ownership structure. There are additional, more technical regulations that are expected to be beneficial under any of these regimes, although we have not explicitly assessed their impacts in this report. These include primarily standards on interoperability, such as network codes and purity considerations, and safety. We discuss interoperability in this section and summarise the state of research on purity in Annex 7.1.

Network Codes (NCs) help organise access to the EU's gas market to lower entry barriers for market participants, promote market integration, and improve market efficiency (ACER 2021). As such, NCs are crucial for managing cross-border gas flows within and into the EU. This opens the question to which extent a set of NCs should be adopted or modified for the (dedicated) hydrogen infrastructure and market, especially for the facilitation of cross-border flows. This section summarises some of the most relevant considerations, focussing on whether EU intervention in this area from the onset is desirable or not, rather than an in-depth evaluation of the NCs.

There are currently four NC and a Guideline on congestion management (European Commission 2021):

- NCs on capacity allocation mechanisms in gas transmission systems (2017/459/EU): Require gas grid operators to use harmonised auctions when selling access to pipelines. These auctions sell the same product at the same time and according to the same rules across the EU.
- NCs on harmonised transmission tariffs structures for gas (2017/460/EU): For transparent and harmonised measures for the charging methodologies, revenue recovery, reserve, and payable price across the EU.
- NCs on gas balancing and transmission networks (2014/312/EU): Sets out gas balancing rules, including the responsibilities of TSOs and users.
- NC on interoperability and data exchange rules (2015/703/EU): Creates operational, technical, communication, and business rules for the proper operation and interoperability of gas transmission systems. This is especially important for cross-border flows within and into the EU.
- Guidance on best practices for congestion management procedures in natural gas transmission networks [SWD (2014) 250]: Aims to reduce congestion in gas pipelines. Companies are required to make use of their reserved capacity or risk losing it, while unused capacity should be placed back on the market.

All four NCs were designed and written for a mature gas market, which is significantly different from the current hydrogen market state (NCs were adopted post-2014, whereas cross-border flows have existed since the 1960s). As such, the interoperability NC is of primary interest here as it connects most directly to the facilitation of cross-border (hydrogen) flows. The other three NCs and the guidance are partly covered by the discussion in the other sections of this report[80] and their detailed evaluation is out of the scope of this work.

To ensure interoperability of MS gas networks, elements around gas quality standard, odorisation, communication, monitoring, forecasting, dispute management, and many others need to be considered by the regulatory bodies. For instance, natural gas might have a different Wobbe index[81] in different countries (e.g. high and low calorific gas), might be odorised or not, or might contain various impurities. Such differences might or might not present a significant problem when transporting and trading gas from one country to another. In any case, some rules for interoperability of the gas networks are always required.[82]

[80] See Section 3.2.1 for a discussion of access requirements (third-party access) and Section 3.2.4 for a discussion of tariff regulation.

[81] The Wobbe Index is an indicator of the interchangeability of fuel gases.

[82] For instance, the NG quality specifications are defined by the European Association for the Streamlining of Energy Exchange – gas (EASEE-gas). At an entry point, the TSO is obliged to accept NG within these set limits. At an exit point, the TSO guarantees that gas is delivered within these limits.

Before the implementation of the interoperability NC, many bilateral agreements existed between individual TSOs to ensure cross-border flows. Sometimes these bilateral agreements expanded into regional ones—e.g. in North-West Europe, where interoperability rules were more or less standardised.[83] In other regions, notably for some of the TSOs in Southern and Eastern Europe, additional costs were incurred due to the implementation of the interoperability NC. These were typically costs for personnel and information and communications technology rather than CAPEX-heavy investments.[84]

What could this mean for the hydrogen market? The underlying motivation is that as soon as there is cross-border trade of hydrogen, some interoperability rules must be established. This can be done on a bilateral basis or can be standardised across the EU. The expectation is that the EU should have a somewhat developed hydrogen cross-border trade by 2030, so implementation of the interoperability NC for hydrogen may be appropriate.[85] This is especially valid given that most of the expected costs associated with interoperability have already been incurred[86] and relevant systems have been implemented for natural gas. Many of these practicalities could be copied for hydrogen. An early implementation of (harmonised) interoperability rules might be easier than the development of rules at a later stage, once potentially different bilateral or multilateral arrangements have emerged. Given the EC's intention to facilitate cross-border flows and hydrogen trade, a set of basic interoperability rules could be considered. Gas quality is likely to be central for these interoperability rules, while other rules such as those around flow control, quantity matching, and allocation and dispute settlement rules might be of secondary interest in the initial phases of hydrogen market development.

However, the implications of applying interoperability rules to the hydrogen market are different if horizontal unbundling is required—in that case, the benefits of the already implemented interoperability NC might be lost for hydrogen. If the interoperability NC is transposed (with relevant modifications) to the hydrogen market, it must consider whether it is presenting an undue burden in the nascent phases of the market. If it is, certain derogations in the first years and a focus on the most central elements such as gas quality standards and odorisation might be necessary.

The possible interoperability of NC for hydrogen on the cross-border trade and its impacts are hard to estimate. It is safe to assume that cross-border trade would happen regardless of the implementation of the interoperability NC, based on bilateral or multilateral agreements. However, TSOs and regulatory groups (ACER, CEER, EC) could leverage the experience acquired and investments made in the implementation of the interoperability NC to define a common set of rules for the hydrogen market, which can facilitate the development of cross-border hydrogen trade and flows.

5.3. Additional considerations: Hydrogen market development 2030–2040

The Impact Assessment, and therefore also this assignment, focusses on the expected hydrogen development for 2030. However, development of the dedicated hydrogen and market regulation must also consider a longer-term perspective. Notably, when repurposing existing natural gas infrastructure for hydrogen, capacity might be over-dimensioned (i.e. larger than required) for the expected 2030 hydrogen domestic supply and demand as well as cross-border transportation. This is because of the ultimate goal of reaching net zero emissions across EU27 by 2050, where hydrogen is supposed to play a much bigger role than in 2030. Conversely, the infrastructure will likely be repurposed/built out with that goal mind.

In the modelling approach, we partly build the cross-border scenarios (Section 4.1.2) on the expected infrastructure developments presented in the European Hydrogen Backbone (EHB) vision. Both modelling scenarios A have the 2030 EHB infrastructure development as a starting

[83] Fluxys interview. Michel van den Brande, Tom de Winter, Karl Beelen, 24/3/2021.

[84] Ibid.

[85] E.g. the EU Hydrogen Strategy discusses transporting hydrogen from high RES regions to low RES regions (European Commission 2020) (European Commission 2020).

[86] Excluding investments into e.g. monitoring and safety hardware.

point. The sensitivity scenario B has the 2035 EHB infrastructure development a minimum. The 2030 EHB vision consists of mostly domestic hydrogen infrastructure with cross-border transport only in North-West Europe. The 2035 map interconnects many additional regions, but ultimately, only in 2040 the EHB becomes a truly pan-European hydrogen network.

It is important to view these infrastructure developments in the context of the expected demand. The EHB expects 310 TWh of green and blue hydrogen in 2030 and ~755 TWh in 2035 (covering EU27).[87] By 2040,1,200 TWh is forecasted, several times the demand in 2030.

This section puts the results modelled in the Impact Assessment into a broader context of the long-term expected developments. Infrastructure planning as well as market regulation should therefore take into account that while some of the results modelled in the Impact Assessment might be suboptimal from 2030 perspective, the 2040 (or even 2050) perspective needs to be taken into account as well. A clear example could be expected hydrogen cross-border tariffs that might be impacted by the (expectably) lower utilisation rates of some of the repurposed hydrogen pipelines (or even new ones if built with long term vision in mind). In 2030 the hydrogen tariffs might be therefore higher than from the in the long run when the pipeline utilisation rates would likely increase.[88]

5.4. Next steps

Following this study, Artelys and the EC will complete the quantitative assessment using the METIS model as laid out in Chapter 4.

The EC may also wish to deepen aspects of the qualitative assessment as Chapter 3 suggests. This could include a more focussed assessment of the favoured regulatory package, including interdependencies between the regulatory measures and manifestations and an assessment of the potential implications within the specific environments across the EU MSs, e.g. assessing the impact of the regulation against the backdrop of regional/national demand and supply dynamics, stock of national (gas) infrastructure which could be re-purposed, current national/regional development of the respective hydrogen market and in light of the existing national actors in the hydrogen sphere and the relevant national regulatory systems.

The quantitative, and potential additional qualitative, assessments from Artelys and the EC will then be merged with the assessments in this report. This will inform the overall impact assessment on hydrogen network regulation, which is to be published by the EC later in 2021. Other considerations for the overall impact assessment include the phasing of regulation on the way to 2030, required exemptions or derogations, and other flexible regulatory measures, stakeholder input, and more.

[87] EHB does not project hydrogen demand directly for the year 2035. The figure presented here is a midpoint between demand projected in 2030 and 2040 (linear).

[88] This is true both directly (as in separate RAB), or indirectly by inflating both NG and hydrogen tariffs (as in joint RAB).

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7. ANNEXES

7.1. Hydrogen purity

Different applications require different purity standards for hydrogen. This has implications for the development of hydrogen infrastructure, both in terms of purification facilities and transport lines to ensure hydrogen reaches the end user at the required purity level.

The Impact Assessment under discussion in the main body of this report is concerned with hydrogen standard for **cross-border transport of hydrogen**. In Section 5.2 we conclude that a hydrogen gas quality standard set uniformly across the EU is desirable for facilitating cross-border flows as part of interoperability rules.

A separate question, outside of this Impact Assessment, concerns the **domestic hydrogen standards** across the MS.

These can differ from country to country based on its

- supply and demand composition (i.e. different production technologies produce hydrogen of different levels of quality, different end-use technologies have various impurity tolerances) as well as
- specific domestic hydrogen infrastructure (e.g. different types of storage might result in different impurities).

At the request of the Commission, we explore three questions regarding domestic transport in this standalone Annex. The objective was to explore the following questions:

- What purification technologies can be used to purify hydrogen to the required quality for different end-uses?
- What are the costs of these technologies (investment and operational)?
- Where are these technologies best sited (at production, end-user site)?

7.1.1. Background and current hydrogen purity standards

This section is mostly based on the results of the work deliver as part of the programme HY4HEAT (WP2) HYDROGEN PURITY & COLOURANT for the UK Department for Business, Energy and Industrial Strategy (BEIS) (DNVGL 2019), and complemented with other sources where needed. Note that the current availability of relevant literature sources is very limited.

Hydrogen purity requirements are usually determined by the end-use application. The primary guidance document for hydrogen use as a fuel is the ISO 14687, see Table 7-1 and Table 7-2 below. However, for several key end-use applications, the specifications have been amended, or are missing:

- **Hydrogen for heating** (domestic and commercial) is specified in ISO/FDIS 14687 as Grade A hydrogen, however BEIS considered it "not fit for purpose" as it may have been originally based on polymer electrolyte membrane fuel cell applications and may not have considered all options for traditional combustion appliances. Also, it does not include input from appliance manufacturers (DNVGL 2019). Therefore, BEIS developed a draft recommendation for the UK hydrogen quality standard for hydrogen heat applications, see Table 7-3.
- **Hydrogen for road PEM fuel cell vehicles.** The Commission Delegated Regulation (EU) 2019/1745 for the 2014 Alternative Fuel Infrastructure Directive will replace ISO 14687-2 with EN 17124, shown in Table 7-4.
- **Hydrogen use as an industrial feedstock**. Currently, purification steps are integrated directly into industrial processes using hydrogen (e.g. ammonia production), unusual impurities might occur if hydrogen is transported via large scale pipelines/entering various types of large-scale, underground storage. This is further discussed in the following sections.

Importantly, the experts from gas distribution companies concluded that "distribution of hydrogen through a complex, multi-connected pipeline network is not conducive with ultra-high purity requirements" (DNVGL 2019). Thus, purity will be impacted by pipeline transport, however whether that is an issue or not depends on the specific impurities.[89]

Table 7-1 Classification grades of hydrogen (ISO 14687)[90]

Type	Grade	Category	Applications
I Gas	A	-	Gaseous hydrogen; Internal combustion engines for transportation; Residential/commercial combustion appliances (e.g. boilers, cookers and similar applications)
	B	-	Gaseous hydrogen; Industrial fuel for power generation and heat generation except PEM fuel cell applications
	C	-	Gaseous hydrogen; Aircraft and space-vehicle ground support systems expect PEM fuel cell applications
	D	-	Gaseous hydrogen; PEM fuel cells for road vehicles
	E	PEM fuel cells for stationary appliances	
		1	Hydrogen based fuel; High efficiency/low power applications
		2	Hydrogen based fuel; High power applications
		3	Gaseous hydrogen; High power/high efficiency applications
II Liquid	C	-	Aircraft and space-vehicle on-board propulsion and electric energy requirements; Off-road vehicles
	D	-	PEM fuel cells for road vehicles
III Slush	-	-	Aircraft and space-vehicle on-board propulsion

PEM: Proton Exchange Membrane

Note 1 – Grade D may be used for other fuel cell applications for transportation including forklifts and other industrial trucks if agreed upon between supplier and customer.

Note 2 – Grade D may be used for PEM fuel cell stationary appliances alternative to Grade E category 3.

Note 3 – It should be recognised that biological sources of hydrogen can contain additional constituents (e.g. siloxanes or mercury) that can affect the performance of the various applications, particularly PEM fuel cells, however these are not included in most of the following specifications due to insufficient information.

[89] The typical ones include odorant, oxygen, carbon monoxide and water dewpoint (hence water concentration).
[90] (DNVGL 2019)

Table 7-2 Fuel quality specification for applications other than PEM fuel cell road vehicle and stationary applications (ISO 14687)[91]

Constituents (assay)	**Type I**			**Type II**	**Type III**
	Grade A	**Grade B**	**Grade C**	**Grade C**	
Hydrogen fuel index (minimum mole fraction, %)	98.0 %	99.90 %	99.995 %	99.995 %	99.995 %
Para-hydrogen (minimum mole fraction, %)	NS	NS	NS	95.0 %	95.0 %
Impurities (maximum content)					
Total gases	20 000 µmol mol^{-1}	1 000 µmol mol^{-1}	50 µmol mol^{-1}	50 µmol mol^{-1}	
Water (H_2O) (mole fraction, %)	Non-condensing at all ambient conditions		c	c	
Total hydrocarbon	100 µmol mol^{-1}	Non-condensing at all ambient conditions	c	c	
Oxygen (O_2)	b	100 µmol mol^{-1}	d	d	
Argon (Ar)	b		d	d	
Nitrogen (N_2)	b	400 µmol mol^{-1}	c	c	
Helium (He)			39 µmol mol^{-1}	39 µmol mol^{-1}	
Carbon dioxide (CO_2)			e	e	
Carbon monoxide (CO)	1 µmol mol^{-1}		e	e	
Mercury (Hg)		0.004 µmol mol^{-1}			
Sulphur (S)	2.0 µmol mol^{-1}	10 µmol mol^{-1}			
Permanent particulates	g	f	f	f	
Density					f

[a] The hydrogen fuel index is determined by subtracting the "total non-hydrogen gases" expressed in mole percent, from 100 mole percent.
[b] Combined water, oxygen, nitrogen and argon; maximum mole fraction of 1.9 %.
[c] Combined nitrogen, water and hydrocarbon: max. 9 µmol mol^{-1}.
[d] Combined oxygen and argon: max. 1 µmol mol^{-1}.
[e] Total CO_2 and CO: max. 1 µmol mol^{-1}.
[f] To be agreed between supplier and customer.
[g] The hydrogen shall not contain dust, sand, dirt, gums, oils or other substances in an amount sufficient to damage the fuelling station equipment or the vehicle (engine) being fuelled.

91 (DNVGL 2019).

Table 7-3 Draft recommendation for a UK hydrogen quality standard for heat applications[92]

Content or characteristic	Value	Rationale
Hydrogen fuel index (minimum mole fraction)	98 % (cmol mol^{-1})	This value is a good compromise between hydrogen cost and effects on boiler.
Carbon Monoxide	20 ppm (μmol mol^{-1})	A practical engineering limit based on achievable production limits and to meet long term exposure limits HSE EH/40)
Hydrogen sulphide content	≤ 5 mg m^{-3} 3.5 ppm (μmol mol^{-1})	These values are taken from GSMR:1996 as any detrimental effects would be similar for hydrogen and natural gas, in a repurposed pipeline network.
Total sulphur content (including H_2S)	≤ 50 mg m^{-3} 35 ppm (μmol mol^{-1})	
Oxygen content	≤ 0.2 % (cmol mol^{-1})	
Hydrocarbon dewpoint	-2 °C	Complies with GSMR:1996 and EASEE-gas, and avoids liquid drop-out
Water dewpoint	-10 °C	
Sum of methane, carbon dioxide and total hydrocarbons	≤ 1 % (cmol mol^{-1})	No detrimental effects to boiler, this limit is to reduce carbon content of the exhaust
Sum of argon, nitrogen and helium	≤ 2 % (cmol mol^{-1})	To avoid transporting inert gases with no calorific value in the hydrogen gas (in agreement with ISO/FDIS 14687) and to limit the impact on Wobbe Number (see below)
Wobbe Number range	42 – 46 MJ m^{-3}	Range and percentage variation based on natural gas range in GSMR1996 Wobbe Number is calculated at UK metric standard conditions of 15 °C and 101.325 kPa
Other impurities	The gas shall not contain solid, liquid or gaseous material that might interfere with the integrity or operation of pipes or any gas appliance, within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998, that a consumer could reasonably be expected to operate	

[92] (DNVGL 2019).

Table 7-4 Fuel quality specifications for PEM fuel cell road vehicle applications (EN 17124)[93]

Constituent	Characteristics
Hydrogen fuel index (minimum mole fraction)	99.97%
Total non-hydrogen gases	300 µmol mol^{-1}
Maximum concentration of individual contaminants	
Water (H_2O)	5 µmol mol^{-1}
Total hydrocarbons (THC) (Excluding Methane)	2 µmol mol^{-1}
Methane (CH_4)	100 µmol mol^{-1}
Oxygen (O_2)	5 µmol mol^{-1}
Helium (He)	300 µmol mol^{-1}
Nitrogen (N_2)	300 µmol mol^{-1}
Argon (Ar)	300 µmol mol^{-1}
Carbon dioxide (CO_2)	2 µmol mol^{-1}
Carbon monoxide (CO)	0.2 µmol mol^{-1}
Total sulphur compounds (H_2S basis)	0.004 µmol mol^{-1}
Formaldehyde (HCHO)	0.2 µmol mol^{-1}
Formic acid (HCOOH)	0.2 µmol mol^{-1}
Ammonia (NH_3)	0.1 µmol mol^{-1}
Halogenated compounds (Halogenate ion basis)	0.05 µmol mol^{-1}
Maximum particulates concentration	1 mg kg^{-1}
For the constituents that are additive, such as total hydrocarbons and total sulphur compounds, the sum of the constituents shall be less than or equal to the acceptable limit.	
[a] The hydrogen fuel index is determined by subtracting the "total non-hydrogen gases" in this table, expressed in mole percent, from 100 mol percent. [b] Total hydrocarbons include oxygenated organic species. Total hydrocarbons shall be measured on a carbon basis (µmolC mol^{-1}). [c] Total of CO, HCHO, HCOOH shall not exceed 0.2 µmol mol^{-1}. [d] All halogenated compounds which could potentially be in the hydrogen gas (for example, hydrogen chloride (HCl), and organic halides (R-X)) should be determined according to the hydrogen quality assurance discussed in Clause 6 of EN 17124 and the sum shall be less than 0.05 µmol mol^{-1}.	

Aside from the standards described above, the Dutch gas TSO Gasunie has been working on three hydrogen quality specifications (see Table 7-5) (Gasunie 2020). Currently, they are obtaining feedback on these specifications of their suitability for all the potential end user they anticipated as part of the Dutch hydrogen backbone.

[93] (DNVGL 2019).

Table 7-5 Hydrogen purity specifications as defined by Gasunie

Constituents	Specification 1	Specification 2	Specification 3	Opm.
Hydrogen fuel index	≥98,0 mol%	≥99,0 mol%	≥99,5 mol%	1
Total hydrocarbons including methane	≤1000 µmol/mol	≤1000 µmol/mol	≤1000 µmol/mol	2
Oxygen (O_2)	0,1-0,2 mol%	0,1-0,2 mol%	0,1-0,2 mol%	3
Sum of Inerts	≤2 mol%	≤1,0 mol%	≤0,5 mol%	4
Carbon dioxide (CO_2)	≤20 µmol/mol	≤20 µmol/mol	≤1 µmol/mol	5
Carbon monoxide (CO)	≤20 µmol/mol	≤20 µmol/mol	≤1 µmol/mol	6
Total sulphur incl H_2S	≤5 µmol/mol	≤5 µmol/mol	≤1 µmol/mol	7
Formic acid	≤10 µmol/mol	≤10 µmol/mol	≤1 µmol/mol	8
Formaldehyde (HCOH)	≤10 µmol/mol	≤10 µmol/mol	≤1 µmol/mol	8
Ammonia (NH_3)	≤10 µmol/mol	≤10 µmol/mol	≤1 µmol/mol	8
Halogenated compounds	≤0,05 µmol/mol	≤0,05 µmol/mol	≤0,05 µmol/mol	9
Water dewpoint	-8 °C bij 70 bara	-8 °C bij 70 bara	-8 °C bij 70 bara	10
All other impurities	disclaimer	disclaimer	disclaimer	11
Temperature	5-30 °C	5-30 °C	5-30 °C	12

1. Purity hydrogen
2. Because there is no Wobbe limit a limit on hydrocarbons is necessary
3. For pipelines transporting hydrogen gas, degradation can set a limit on the fatigue loading in terms of pressure variations and/or number of cycles. The degradation can be mitigated by adding a small amount of oxygen gas to the hydrogen gas. This has the advantage that the fatigue loading does not have to be limited and monitored. (ref: VA 20.0214; minimum oxygen gas level to mitigate hydrogen-enhanced fatigue in pipelines)
4. Limitation on inerts also based on the purity of hydrogen. For fuel cells also limited.
5. CO_2 level as low as possible, aim is no CO_2 emission.
6. Because of personal safety reasons at end-users the CO level on the given value.
7. Total sulpher on low level because no sulpher is expected in the hydrogen.
8. Important for fuel cells and can be produced by electrolyser hydrogen production.
9. Adopted from ISO 14687
10. Adopted from the Ministerial Regulation Gas quality (MR gas quality) in the Netherlands
11. Disclaimer: Shall not contain solid, liquid or gaseous material that might interfere with the integrity or operation of pipes or any gas appliance.
12. Limitation on temperature because of the design temperature of the pipeline.

7.1.2. *Overview of purification technologies and their costs*

The need for purification depends on the whole route from hydrogen production to end use, hence on the production technology, means of transport and end use application. BEIS identifies six distinct hydrogen production and purification routes[94]:

<table>
<tr><th>Production and purification route</th><th>Description</th><th>Impurity levels</th><th>Cost data</th></tr>
<tr><td>SMR/ATR + WGS[95] + Amine wash</td><td>This method consists of production of hydrogen by a reformer, followed by water gas shift reactions and carbon capture from the syngas using an amine wash.</td><td>
<table>
<tr><th>Impurity</th><th>SMR (dry mol%)</th><th>Oxygen-Fed ATR (dry mol %)</th><th>Air-Fed ATR (dry mol %)</th></tr>
<tr><td>CO</td><td>0.1-4</td><td>0.3-2</td><td>0.6-0.7</td></tr>
<tr><td>CO_2</td><td>0.35-0.7</td><td>0.7-1.7</td><td>0.4</td></tr>
<tr><td>CH_4</td><td>3.5-8</td><td>0.3-3</td><td>0.08-0.4</td></tr>
<tr><td>N_2</td><td>0-0.3</td><td>0.7</td><td>23-46</td></tr>
<tr><td>Ar</td><td>0</td><td>0.6</td><td>0.5-0.6</td></tr>
<tr><td>H_2O</td><td><0.03 – 0.4</td><td><0.03 – 0.4</td><td><0.03-0.4</td></tr>
<tr><td>O_2</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>H_2S</td><td>< 50 x10^{-4}</td><td>< 50 x10^{-4}</td><td>< 50 x10^{-4}</td></tr>
</table>
</td><td>37.5 EUR/MWh (no carbon capture)
56.8 EUR/MWh (94% CO_2 capture rate)</td></tr>
<tr><td>SMR/ATR + WGS + Amine Wash + Methanation</td><td>This method of hydrogen production was commonly used, without the CO2 being compressed for capture, prior to the commercialisation of pressure swing adsorption. It is the same as case above with the addition of the methanation reaction to remove carbon monoxide.</td><td>
<table>
<tr><th>Impurity</th><th>SMR (dry mol%)</th><th>Oxygen-Fed ATR (dry mol %)</th><th>Air-Fed ATR (dry mol %)</th></tr>
<tr><td>CO</td><td>10 - 50 x 10^{-4}</td><td>10 - 50 x 10^{-4}</td><td>10 - 50 x 10^{-4}</td></tr>
<tr><td>CO_2</td><td>0.35-0.8</td><td>0.7-1.7</td><td>0.4</td></tr>
<tr><td>CH_4</td><td>3.6-14</td><td>0.6-3</td><td>0.7-1.1</td></tr>
<tr><td>N_2</td><td>0 – 0.3</td><td>0.7</td><td>23-47</td></tr>
<tr><td>Ar</td><td>0</td><td>0.6</td><td>0.5-0.6</td></tr>
<tr><td>H_2O</td><td><0.03 – 0.4</td><td><0.03 – 0.4</td><td><0.03 – 0.4</td></tr>
<tr><td>O_2</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>H_2S</td><td>< 50 x10^{-4}</td><td>< 50 x10^{-4}</td><td>< 50 x10^{-4}</td></tr>
</table>
</td><td>Not yet available.</td></tr>
</table>

[94] Purification using palladium membrane diffusion, cryogenic technologies and electrochemical purification were not evaluated further for their currently low Technology Readiness Level (TRL).

[95] Steam methane reforming (SMR), Autothermal reforming (ATR), Water Gas Shift (WGS). Note that blue hydrogen production (thus with CO_2 capture and storage) is assumed.

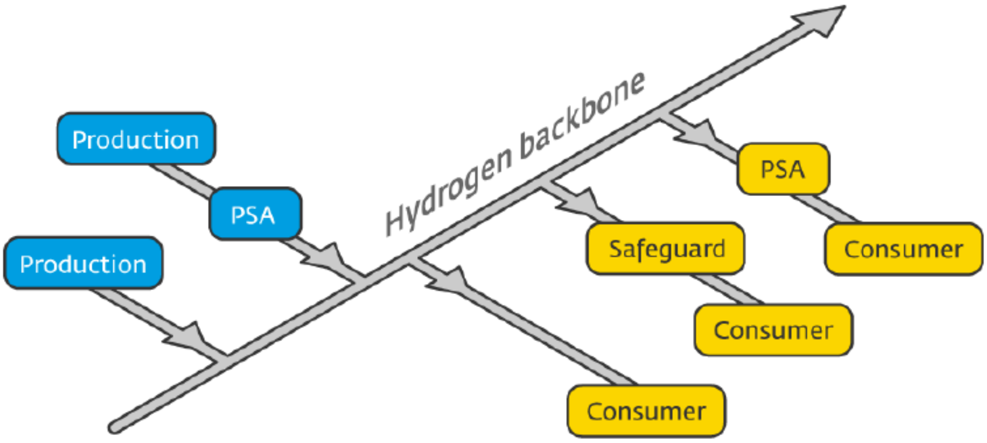
<table>
<tr><th>Production and purification route</th><th>Description</th><th>Impurity levels</th><th>Cost data</th></tr>
<tr><td>SMR/ATR + WGS + Amine Wash + PSA[96]</td><td>Pressure swing adsorption is the current industry standard for purifying hydrogen produced by a fossil fuel, but carbon capture is not yet widely practised. There are examples of carbon capture plants in Concon in Chile and the Shell Quest project in Alberto, Canada. Each of these examples use an amine wash for carbon capture before using PSA.</td><td>Hydrogen purified by PSA can meet even the most stringent purity limits for vehicle</td><td>Usually causes about ~10% hydrogen loss.</td></tr>
<tr><td>Reformer +WGS + Amine Wash + Polymer Membrane</td><td>Polymer-based membranes have been used commercially for the separation of hydrogen from various refinery, petrochemical and chemical process streams. However, due to various reasons, BEIS does not recommend polymer membranes as a suitable purification method for other than the abovementioned onsite applications.</td><td>Roughly 5-10% of the carbon monoxide would remain in the hydrogen stream, leaving carbon monoxide levels in the range of 50-4000 ppm. Some methane and inert gases would also be removed by the membrane.</td><td>CAPEX unclear but assumed to be low.
Operation will cause a ~2-15% hydrogen loss.
Membranes decrease hydrogen output pressure; recompression might be needed.</td></tr>
<tr><td>Electrolysis</td><td>Electrolysis is usually combined with a temperature swing adsorber (TSA) in order to remove water and oxygen from the hydrogen product. BEIS considers the output of electrolysis pure enough for heating applications. Both polymer electrolyte membrane and alkaline electrolysis can be used.</td><td>The impurities found in hydrogen produced by PEMWE without TSA in the table below. In ALK, oxygen can be reduced to 50 ppm and water levels of >100 ppm are expected. The water found in hydrogen produced by ALK is expected to contain either the K+ or Na+ ions found in the alkaline conducting solution.
<table><tr><th>Impurity</th><th>Impurity Level</th></tr><tr><td>H_2O</td><td>>100 ppm</td></tr><tr><td>O_2</td><td>18-500 ppm</td></tr><tr><td>CO_2</td><td>0.2-5.4 ppm</td></tr><tr><td>Inert gases</td><td>Within ISO 14687 Vehicle PEMFC limit</td></tr></table></td><td>No additional costs for purification.</td></tr>
<tr><td>Electrolysis + Temperature Swing Adsorption</td><td>TSA, including a catalytic de-oxygenation step, is the current standard practice for drying electrolysis produced hydrogen.</td><td>Hydrogen produced through this process can meet the ISO 14867 vehicle PEMWE standard.</td><td>CAPEX estimated at 5% of the electrolyser CAPEX.
Additional electricity use of 0.038 kWh/kWh H_2 (LHV) and about 3%-4% hydrogen loss.</td></tr>
</table>

[96] Pressure Swing Adsorption (PSA).

7.1.3. Possible location of the purification steps in the dedicated hydrogen infrastructure

As mentioned above, the necessity and/or placement of the purification steps depends on the hydrogen production methods, transport means and the end-use applications. In general, the various possible options are illustrated in Figure 7-1 developed by Gasunie (Gasunie 2020).

Figure 7-1 Possible requirements for hydrogen purity



Various delivery models can therefore be imagined:

1. Production with direct pipeline injection (e.g. from electrolysis).
2. Production with a purification step (illustrated as PSA above) prior to pipeline injection.
3. Consumption of the pipeline hydrogen "as is".
4. Consumption safeguards where compromised quality of pipeline hydrogen would for instance trigger a purification step or stop the process using hydrogen.
5. Consumption with dedicated purification step of pipeline hydrogen (illustrated as PSA above).

The specific need for purification and its placement will therefore be determined for each individual application. Notably, gas TSO such as Gasunie are considering adding small amount of oxygen to the hydrogen gas to limit pipeline degradation. This might present a problem for certain industrial applications, that might need to by definition employ hydrogen purifiers (e.g. membrane, PSA, or catalytic removal of oxygen all present possible options). Additional questions arise for potential hydrogen storage in depleted oil and gas fields as a possible future technology, where contaminations from methanogenesis (methane contamination), or bacterial sulphate reductions (sulphide contamination) might occur (Hemme and van Berk 2018).

In summary, all impurities can be removed from hydrogen. The specific need to do so depends on the production technologies, possible transport and storage contaminations and end use requirements. All of these aspects are not yet defined for the EU hydrogen market and will also be somewhat location specific. The specific cost of hydrogen purification will depend on the type of impurities and the flows (e.g. FLH of the purification unit). The potential hydrogen gas standard will have to be based on the input from all Member State TSOs and regulatory bodies."

7.2. Detailed approach for stylised facts on cross-border capacity

This section describes how we get to stylized facts for cross-border connections. We start out by taking the cross-border connections from the EHB maps. As the EHB study does not mention which pipelines exactly are repurposed, we assess the pipelines and select a pipeline for which we believe it is most likely to be repurposed. Then we retrieve the pipeline transport capacity from databases. For new pipelines we make assumptions for capacity.

7.2.1. Results taken forward into METIS modelling

The table below shows the cross-border pipeline capacities in 2030 and 2035. Note that for the new pipelines the capacity is given in hydrogen terms (5 GW for pipelines built before 2030, 10 GW for pipelines built after 2030), whereas for the repurposed pipelines the capacity is given in natural gas terms. This natural gas capacity needs to be converted to hydrogen capacity with the 25% assumption described in Section 4.1.1.4.

The next sections describe how we arrived at these numbers - note that the next sections include all the interconnectors currently in place between the regions connected in the EHB. The Results section here summarises the interconnector capacities selected as inputs for the METIS model runs.

Interconnection	New/repurposed	Pipelines	Unit	2030	2035
AT-IT	New build	New_1	GW hydrogen capacity	0	10
AT-SI	New build	New_2	GW hydrogen capacity	0	10
AT-HU	Repurposed	BRUA_Extra_24	GW natural gas capacity	0	6.38
AT-SK	Repurposed	Baumgarten 1	GW natural gas capacity	0	10.3
BE-FR	Repurposed	Blarégnies L (BE) / Taisnières B (FR)	GW natural gas capacity	7	7
	Repurposed	Pitgam_Maldegem	GW natural gas capacity	10	10
BE-NL	Repurposed	Gravenvoeren_Bemelen	GW natural gas capacity	14.2	14.2
	Repurposed	Westerschelde Oost_Zelzate1	GW natural gas capacity	17	17
	Repurposed	Zandvliet H-gas	GW natural gas capacity	2	2
	New build	New_3	GW hydrogen capacity	5	5
CZ-SK	Repurposed	Lanžhot 2	GW natural gas capacity	0	16.7
CZ-DE	Repurposed	Brandov STEGAL (CZ) / Stegal (DE)	GW natural gas capacity	0	12
	Repurposed	Transgas_10	GW natural gas capacity	0	17.9
DE-FR	Repurposed	Obergailbach (FR) / Medelsheim (DE)	GW natural gas capacity	0	20
	Repurposed	MosaHYc	GW natural gas capacity	0.06	0.06
DE-NL	Repurposed	Jemgum (DE) (astora) / Oude Statenzijl (NL)	GW natural gas capacity	8	8
	Repurposed	Winterswijk	GW natural gas capacity	7.5	7.5
	Repurposed	Zevenaar	GW natural gas capacity	13.7	13.7
	Repurposed	Vlieghuis	GW natural gas capacity	3	3
	Repurposed	Epe	GW natural gas capacity	1.8	1.8
DE-DK	Repurposed	Deudan 1	GW natural gas capacity	0	4
	New build	New_4	GW hydrogen capacity	0	10
DE-PL	New build	New_5	GW hydrogen capacity	0	10
DK-SE	New build	New_6	GW hydrogen capacity	0	10

Interconnection	New/repurposed	Pipelines	Unit	2030	2035
EE-FI	New build	New_7	GW hydrogen capacity	0	10
EE-DE	New build	New_8	GW hydrogen capacity	0	10
ES-MO	Repurposed	Tarifa	GW natural gas capacity	0	18.5
ES-FR	Repurposed	VIP PIRINEOS	GW natural gas capacity	0	9.4
FR-LU	Repurposed	MosaHYc	GW natural gas capacity	0.06	0.06
FI-SE	New build	New_9	GW hydrogen capacity	5	5
	New build	New_10	GW hydrogen capacity	0	10
FI-DE	New build	New_11	GW hydrogen capacity	0	10
HU-SI	New build	New_12	GW hydrogen capacity	0	10
HR-SI	Repurposed	Lucko_Rogatec	GW natural gas capacity	0	2.2
HR-HU	Repurposed	Varosfoeld_Slobodnica_11	GW natural gas capacity	0	3.26
HU-RS	Repurposed	Szoreg_Banatski Dvor	GW natural gas capacity	0	5.92
HU-RO	Repurposed	Arad_Szeged	GW natural gas capacity	0	2.2
HU-UA	Repurposed	Beregdaróc 1400 (HU) - Beregovo (UA) (UA>HU)	GW natural gas capacity	21.5	21.5
HU-SK	Repurposed	Balassagyarmat (HU) / Velké Zlievce (SK)	GW natural gas capacity	0	5.3
IT-SI	New build	New_13	GW hydrogen capacity	0	10
IT-TN	Repurposed	Mazara del Vallo	GW natural gas capacity	48	48
SK-UA	Repurposed	Uzhgorod (UA) - Velké Kapušany (SK)	GW natural gas capacity	0	21.13

7.2.2. Inputs from European Hydrogen Backbone 2030 map

The EHB expects 310 TWh of green and blue hydrogen in 2030 (covering EU27) (Guidehouse 2021b). The EHB map for 2030 looks as follows (Guidehouse 2021a):

The map shows that cross-border connections are foreseen mostly in north-west Europe:

1. Between BE and FR there are 2 connections
2. Between DE and FR there is 1 connection
3. Between FR and LU there is 1 connection
4. Between BE and NL there are 4 connections, of which **1 new**
5. Between DE and NL there are 5 connections
6. Between IT and TN there is 1 connection
7. Between FI and SE there is **1 new** connection
8. Between HU and UA there is 1 connection

When looking in the IGG database for existing natural gas pipelines, we find the following. Although MosaHYc is not currently an interconnector, we include it since it is included on the EHB map. For several connections the ENTSOG map is used because the IGG database did not include these pipelines.

Interconnection	Pipelines	Repurposed in 2030	Description	Capacity	Source
BE-FR	Blarégnies L (BE) / Taisnières B (FR)	Yes	Good fit	2x 3.5 GW	IGG
	Pitgam_Maldegem	Yes	Good fit	10 GW	IGG
DE-FR	Obergailbach (FR) / Medelsheim (DE)	No	Too far to the east	20 GW	IGG
	MosaHYc	Yes	Good fit and existing project	0.06 GW	GRT[97]
FR-LU	MosaHYc	Yes	Good fit and existing project	0.06 GW	GRT[1]
BE-NL	Gravenvoeren_Bemelen	Yes	Only connection on that side of the country	340.8 GWh/d = 14.2 GW	ENTSOG
	Westerschelde Oost_Zelzate1	Yes	Good fit	407 GWh/d = 17 GW	ENTSOG
	Hilvaarenbeek	No	Poor fit	642 GWh/d = 27 GW	ENTSOG
	Zandvliet H-gas	Yes	Only smaller pipeline crossing border near Geleen	47 GWh/d = 2 GW	ENTSOG
	New build	Yes	New build	5 GW	EHB
DE-NL	Bunde (DE) / Oude Statenzijl (H) (NL) (GASCADE)	No	Lots of pipelines at this interconnector, not perfect fit	-	ENTSOG
	Jemgum (DE) (astora) / Oude Statenzijl (NL)	Yes	Good fit	193.1 GWh/d = 8 GW	ENTSOG
	Belfeld_St Hubert	No	Too far south	20 GW	IGG
	Winterswijk	Yes	Good fit	178.6 GWh/d = 7.5 GW	ENTSOG
	Zevenaar	Yes	Good fit	327.6 GWh/d= 13.7 GW	ENTSOG
	Vlieghuis	Yes	Good fit	72 GWh/d = 3 GW	ENTSOG
	Epe	Yes	Many pipelines, picked smallest pipeline, good fit	43.3 GWh/d = 1.8 GW	ENTSOG
IT-TN	Mazara del Vallo	Yes	Good fit	1150.3 GWh/d = 48 GW	ENTSOG
FI-SE	New build	Yes	New build	5 GW	EHB
HU-UA	Beregdaróc 1400 (HU) - Beregovo (UA) (UA>HU)	Yes	Good fit	516.6 GWh/d = 21.5 GW	ENTSOG
	Beregdaróc 800 (HU) – Beregovo (UA) (HU>UA)	No	Only interruptible capacity	0	ENTSOG

[97] http://www.grtgaz.com/en/press/press-releases/news-details/article/hydrogene-lancement-du-projet-mosahyc.html

For the new pipelines built before 2030 we assume a capacity of 5 GW (hydrogen).

7.2.3. *Inputs from European Hydrogen Backbone 2035 map*

The EHB expects 755 TWh in 2035 (covering EU27) (Guidehouse 2021b).[98] The EHB map for 2035 looks as follows (Guidehouse 2021a):

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[98] EHB does not project hydrogen demand directly for the year 2035. The figure presented here is a midpoint between demand projected in 2030 and 2040 (linear).

The map shows a substantial increase in cross-border connections compared to 2030:

1. Between AT and IT there is 1 **new** connection that was not on the 2030 map
2. Between AT and SI there is 1 **new** connection that was not on the 2030 map
3. Between AT and HU there is 1 connection that was not on the 2030 map
4. Between AT and SK there is 1 connection that was not on the 2030 map
5. Between BE and FR there are 2 connections (of which 2 already on the 2030 map)
6. Between BE and NL there are 4 connections, of which 1 new (of which 4 already on the 2030 map)
7. Between CZ and SK there is 1 connection that was not on the 2030 map
8. Between CZ and DE there are 2 connections that were not on the 2030 map
9. Between DE and FR there are 2 connections (of which 1 already on the 2030 map)
10. Between DE and NL there are 5 connections (of which 5 already on the 2030 map)
11. Between DE and DK there are 2 connections, of which 1 **new** (none of which on the 2030 map)
12. Between DE and PL there is 1 **new** connection that was not on the 2030 map
13. Between DK and SE there is 1 **new** connection that was not on the 2030 map
14. Between EE and FI there is 1 **new** connection that was not on the 2030 map
15. Between EE and DE there is 1 **new** connection that was not on the 2030 map
16. Between ES and MO there is 1 connection that was not on the 2030 map
17. Between ES and FR there is 1 connection that was not on the 2030 map
18. Between FR and LU there is 1 connection (of which 1 already on the 2030 map)
19. Between FI and SE there are 2 **new** connections (of which 1 already on the 2030 map)
20. Between FI and DE there is 1 **new** connection that was not on the 2030 map
21. Between HU and SI there is 1 **new** connection that was not on the 2030 map
22. Between HR and SI there is 1 connection that was not on the 2030 map
23. Between HR and HU there is 1 connection that was not on the 2030 map
24. Between HU and RS there is 1 connection that was not on the 2030 map
25. Between HU and RO there is 1 connection that was not on the 2030 map
26. Between HU and UA there is 1 connection that was already on the 2030 map
27. Between HU and SK there is 1 connection that was not on the 2030 map
28. Between IT and SI there is 1 **new** connection that was not on the 2030 map
29. Between IT and TN there is 1 connection that was already on the 2030 map
30. Between SK and UA there is 1 connection that was not on the 2030 map

Interconnection	Pipelines	Repurposed in 2030	Description	Capacity	Source
AT-IT	New build	No	New build	10 GW	EHB
AT-SI	New build	No	New build	10 GW	EHB
AT-HU	BRUA_Extra_24	No	Good fit, only pipeline	153.1 GWh/d = 6.38 GW	ENTSOG
AT-SK	Baumgarten 1	No	Good fit	247.5 GWh/d = 10.3 GW	ENTSOG
	Baumgarten 2	No	Good fit	1570.4 GWh/d = 65.4 GW	ENTSOG
	Láb (SK) / Láb IV (AT)	No	Poor fit	138.3 GWh/d = 5.8 GW	ENTSOG
BE-FR	Blarégnies L (BE) / Taisnières B (FR)	Yes	Good fit	2x 3.5 GW	IGG
	Pitgam_Maldegem	Yes	Good fit	10 GW	IGG
BE-NL	Gravenvoeren_Bemelen	Yes	Only connection on that side of the country	340.8 GWh/d = 14.2 GW	ENTSOG
	Westerschelde Oost_Zelzate1	Yes	Good fit	407 GWh/d = 17 GW	ENTSOG
	Hilvaarenbeek	No	Poor fit	642 GWh/d = 27 GW	ENTSOG
	Zandvliet H-gas	Yes	Only smaller pipeline crossing border near Geleen	47 GWh/d = 2 GW	ENTSOG
	New build	Yes	New build	5 GW	EHB
CZ-SK	Lanžhot 1	No	Good fit	913.7 GWh/d = 38 GW	ENTSOG
	Lanžhot 2	No	Good fit	400.4 GWh/d = 16.7 GW	ENTSOG
	Dolni Bojanovice 1	No	Looks like storage	95.6 GWh/d = 4 GW	ENTSOG
	Dolni Bojanovice 2	No	Looks like storage	74.3 GWh/d = 3.1 GW	ENTSOG
CZ-DE	Brandov STEGAL (CZ) / Stegal (DE)	No	Good fit – north west (will repurpose to not only have 4 GW capacity)	287.7 GWh/d = 12 GW	ENTSOG
	Hora Svaté Kateřiny (CZ) / Deutschneudorf (Sayda) (DE)	No	Good fit north west	95 GWh/d = 4 GW	ENTSOG
	Brandov-OPAL (DE)	No	Good fit north west	951.9 GWh/d = 39.7 GW	ENTSOG
	Transgas_10	No	Good fit – south west	17.91 GW9	IGG
DE-FR	Obergailbach (FR) / Medelsheim (DE)	No	Good fit	20 GW	IGG

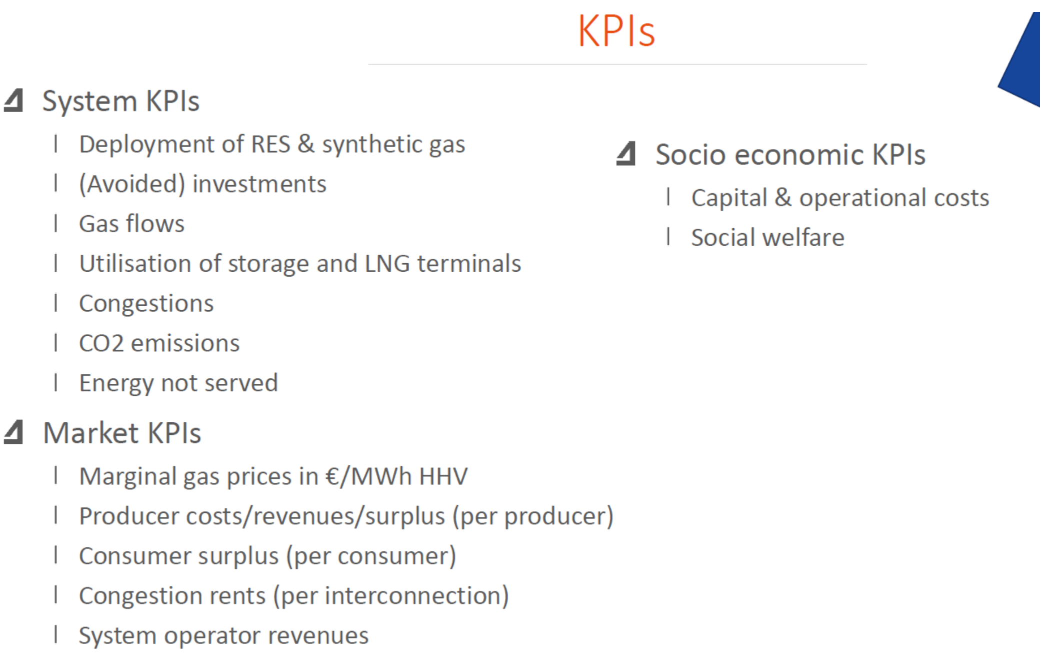
Interconnection	Pipelines	Repurposed in 2030	Description	Capacity	Source
	MosaHYc	Yes	Good fit and existing project	0.06 GW	GRT[99]
DE-NL	Bunde (DE) / Oude Statenzijl (H) (NL) (GASCADE)	No	Lots of pipelines at this interconnector, not perfect fit	-	ENTSOG
	Jemgum (DE) (astora) / Oude Statenzijl (NL)	Yes	Good fit	193.1 GWh/d = 8 GW	ENTSOG
	Belfeld_St Hubert	No	Too far south	20 GW	IGG
	Winterswijk	Yes	Good fit	178.6 GWh/d = 7.5 GW	ENTSOG
	Zevenaar	Yes	Good fit	327.6 GWh/d= 13.7 GW	ENTSOG
	Vlieghuis	Yes	Good fit	72 GWh/d = 3 GW	ENTSOG
	Epe	Yes	Many pipelines, picked smallest pipeline, good fit	43.3 GWh/d = 1.8 GW	ENTSOG
DE-DK	Deudan 1	No	Good fit	4 GW	IGG
	New build	No	New build	10 GW	EHB
DE-PL	New build	No	New build	10 GW	EHB
DK-SE	New build	No	New build	10 GW	EHB
EE-FI	New build	No	New build	10 GW	EHB
EE-DE	New build	No	New build	10 GW	EHB
ES-MO	Tarifa	No	Good fit	442.7 GWh/d =18.5 GW	ENTSOG
ES-FR	VIP PIRINEOS	No	Good fit	224.4 GWh/a = 9.4 GW	ENTSOG
	ArtereDeLAdour0	No	Too much West	19.8 GW	IGG
FR-LU	MosaHYc	Yes	Good fit and existing project	0.06 GW	GRT[1]
FI-SE	New build	Yes	New build	5 GW	EHB
	New build	No	New build	10 GW	EHB
FI-DE	New build	No	New build	10 GW	EHB
HU-SI	New build	No	New build	10 GW	EHB
HR-SI	Lucko_Rogatec	No	Good fit, only pipeline	53.7 GWh/d = 2.2 GW	ENTSOG
HR-HU	Varosfoeld_Slobodnica_11	No	Good fit, only pipeline	78.3 GWh/d = 3.26 GW	ENTSOG

[99] http://www.grtgaz.com/en/press/press-releases/news-details/article/hydrogene-lancement-du-projet-mosahyc.html

Interconnection	Pipelines	Repurposed in 2030	Description	Capacity	Source
HU-RS	Szoreg_Banatski Dvor	No	Good fit, only pipeline	142 GWh/d = 5.92 GW	ENTSOG
HU-RO	Arad_Szeged	No	Good fit, only pipeline	52.1 GWh/d = 2.2 GW	ENTSOG
HU-UA	Beregdaróc 1400 (HU) - Beregovo (UA) (UA>HU)	Yes	Good fit	516.6 GWh/d = 21.5 GW	ENTSOG
	Beregdaróc 800 (HU) – Beregovo (UA) (HU>UA)	No	Only interruptible capacity	0	ENTSOG
HU-SK	Balassagyarmat (HU) / Velké Zlievce (SK)	No	Good fit, only pipeline	127 GWh/d = 5.3 GW	ENTSOG
IT-SI	New build	No	New build	10 GW	EHB
IT-TN	Mazara del Vallo	Yes	Good fit	1150.3 GWh/d = 48 GW	ENTSOG
SK-UA	Uzhgorod (UA) - Velké Kapušany (SK)	No	Good fit, 4 pipelines, only cummulative capacity available so will do ¼ capacity repurpose	2028 GWh/d = 84.5 GW (21.13)	ENTSOG

For the new pipelines built after 2030 we assume a capacity of 10 GW (hydrogen).

7.3. Full METIS KPI table



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