TYNDP 2026 ANNEX D1 - Implementation Guidelines for Project-Specific Cost-Benefit Analysis of Hydrogen Projects

2026

Contents

Abbreviations

ACER	**European Union Agency for the Cooperation of Energy Regulations**
ATR	**Autothermal Reforming**
B1	**GHG Emissions Variation Indicator**
B2	**Non-GHG Emissions Variation Indicator**
B3.1	**Integration of Renewable Electricity Generation Indicator**
B3.2	**Integration of Renewable and Low Carbon Hydrogen Indicator**
B4	**Increase of Market Rents Indicator**
B5	**Reduction in Exposure to Curtailed Hydrogen Demand Indicator**
CAPEX	**Capital Expenditure**
CBA	**Cost-Benefit Analysis**
CCS	**Carbon Capture and Storage**
CO_2	**Carbon Dioxide**
CO_2-eq	**CO_2 equivalent**
CODG	**Cost of Disrupted Natural Gas**
CODH	**Cost of Disrupted Hydrogen**
DC	**Demand Curtailment**
DGM	**Dual Gas Model, also Dual Hydrogen/Natural gas Model**
DHEM	**Dual Hydrogen/Electricity Model**
DRES	**Dedicated Renewable Energy Sources**
DSR	**Demand Side Response**

DSO	Distribution System Operator
EBCR	Economic Benefit-to-Cost Ratio
EC	European Commission
EE1st	Energy Efficiency First
EEA	European Environmental Agency
EEA27	European Economic Area
EHB	European Hydrogen Bank
EIB	European Investment Bank
ETS	Emission Trading Scheme
ENPV	Economic Net Present Value
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ENTSOs	ENTSO-E and ENTSOG
EU	European Union
FEED	Front-End Engineering Design
FID	Final Investment Decision
GCV	Gross Calorific Value, also Higher Heating Value
GHG	Greenhouse Gas
GJ	Gigajoule
GWh	Gigawatt Hour
GWh_{H2}	Gigawatt Hour in terms of thermal energy of hydrogen

HCR	**Hydrogen Curtailment Rate**
HDC	**Hydrogen Demand Curtailment**
IGI	**Infrastructure Gaps Identification**
IPCC	**Intergovernmental Panel on Climate Change**
LOR	**Lesser-of-Rule**
MCA	**Multi-Criteria Analysis**
MWh	**Megawatt Hour**
MWh_{H2}	**Megawatt Hour in terms of thermal energy of hydrogen**
NCV	**Net Calorific Value, also Lower Heating Value**
NECP	**National Energy and Climate Plan**
NH_3	**Ammonia**
Non-GHG	**Non-Greenhouse Gas**
NOx	**Nitrogen Oxide**
NMVOC	**Non-Methane Volatile Organic Compounds**
NT+	**National Trends+ Scenario**
OPEX	**Operational Expenditure**
PCI	**Project of Common Interest**
PINT	**Put One In at a Time**
PLEXOS	**PLEXOS Energy Modeling Software**
PM 10	**Particulate Matter with a Diameter of 10 Micrometers or less**
PM 2.5	**Particulate Matter with a Diameter of 2.5 Micrometers or less**

PMI	Project of Mutual Interest
PS-CBA	Project-Specific Cost-Benefit Analysis, also Project Assessment
P2G	Power-To-Gas
PV	Photovoltaic
RES	Renewable Energy Sources
SMR	Steam Methane Reformer(s)
SO_2	Sulphur Dioxides
SRES	Shared Renewable Energy Sources
t	Ton
TEN-E Regulation	Regulation (EU) 2022/869
TOOT	Take Out One at a Time
TSO	Transmission System Operator
TYNDP	Union-wide Ten-Year Network Development Plan
VoLL	Value of Lost Load of Electricity
VOLY	Value of a Life Year
VO&M	Variable Operations and Maintenance Cost
VSL	Value of Statistical Life
WTP	Willingness To Pay
y	Year
YOLL	Years of Life Lost

1. Introduction

The objective of the ENTSOG TYNDP 2026 Implementation Guidelines is to provide detailed guidance on the different elements of relevance for the project-specific cost-benefit analysis, or *PS-CBA*, as part of the 2026 TYNDP cycle.

As explained in the Cost-Benefit Analysis Methodology, Chapter 1.3. [1] This document outlines the updates and refinements proposed for the current assessment cycle and explains the rationale behind each change. As the Cost-Benefit Analysis (CBA) methodology serves as a long-term guidance framework—intended to remain valid across multiple TYNDP and PCI/PMI cycles—it deliberately refrains from prescribing detailed implementation procedures that may evolve from one cycle to the next. To ensure clarity, consistency, and applicability, each cycle is therefore supported by dedicated Implementation Guidelines, which undergo extensive consultation with stakeholders to integrate relevant feedback. In cases where suggestions cannot be fully incorporated, clear justification is provided. The modifications presented in the sections below reflect this structured process, offering transparency on how stakeholder input, methodological adjustments, and cycle-specific considerations have shaped the current set of Implementation Guidelines.

Namely, the elements of the multi-criteria cost-benefit analysis applied by ENTSOG to perform project-specific CBAs in the TYNDP 2026 process and referred to in this document are:

- Project grouping principles
- Project status
- Benefit indicators for PS-CBA
- Summary of the Monetisation elements used for benefit indicators
- Summary of the Economic performance indicators

Summary of TYNDP 2026 / PS-CBA process

As anticipated in the 2024 TYNDP cycle, the 2026 TYNDP timeline continues to prioritize deliverables related to hydrogen. The reason is that such projects are submitted in time to the PCI/PMI selection process, currently expected to commence in the third quarter of 2026. Natural gas-related projects will still be taken into account in the TYNDP system-level assessment, but will not be covered by individual cost-benefit analyses, as in the previous edition and according to the 2022 update of the TEN-E regulation.

[1] https://www.entsog.eu/sites/default/files/2025-10/entsog_CBA_methodology_report_250225.pdf

Apart from PS-CBA results, main hydrogen-related deliverables are foreseen to become available during 2026. Any additional simulations shall be published after extended stakeholder consultations are conducted and opinions from regulatory bodies are received.

The PS-CBA or *Project Assessment* phase is expected to start as soon as the system-level assessment is completed. This latter analysis will result in the identification of infrastructure gaps compared to European energy and climate goals[2]. In line with Art. 4[3] of the "TEN-E"[4] Regulation, for each project which promoters intend to submit for PCI/PMI status attribution, a PS-CBA will be conducted in order to determine the degree to which the project contribute(s) to the criteria of sustainability, market integration, security of supply, and competition and to assess whether these benefits outweigh the associated costs. Such requirement is also referred to in the Annex III[5] of the TEN-E Regulation.

For wider context, the system-wide assessment itself starts as soon as the 2026 Scenarios report is available. Scenarios start from the existing infrastructure and draw out possible future energy system evolutions for the following decades; these provide a quantitative basis for the assessment, to which projects from the TYNDP are added to perform the system-wide assessment. In the image below, the three main phases of the TYNDP cycle are framed in connection to the generic steps of the PCI/PMI selection process.

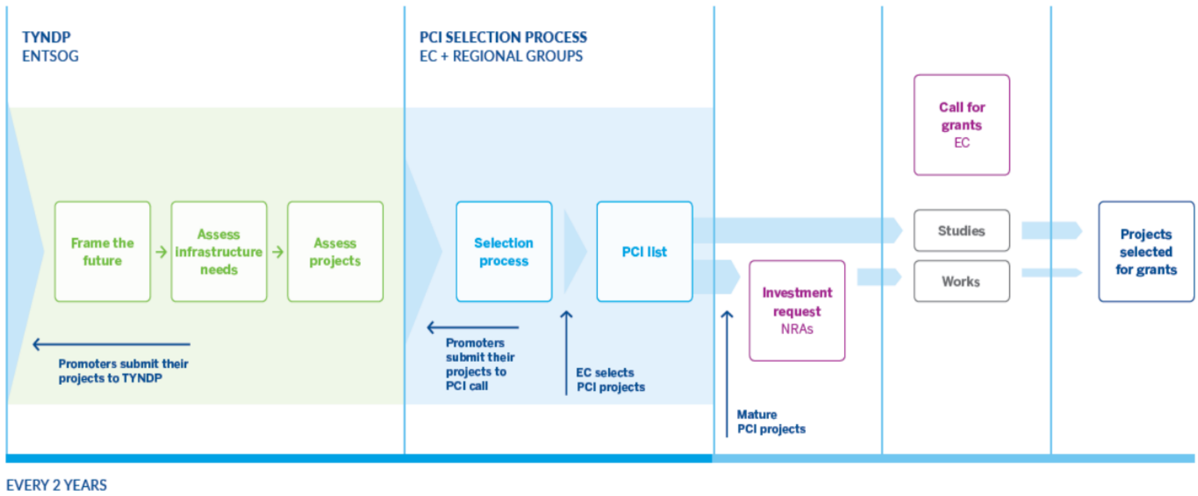


Figure 1 - TYNDP and PCI/PMI process overview

[2] 2030 targets for energy and climate and 2050 climate neutrality objective – see paragraph 1 of Art. 1 – Subject matter, objectives and scope

[3] Art. 4 – Criteria for the assessment of projects by the Group

[4] Reg. (EU) 2022/869, on guidelines for trans-European energy infrastructure, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32022R0869

[5] Section 2, point (1)(d) of Annex III

In line with the requirements of the TEN-E Regulation, public consultations are held to validate the methodological approach and results from the above-mentioned assessments, in line with Art. 11[6], 12[7], and 13[8] of the TEN-E Regulation. The schematic below illustrates the main steps of the outstanding TYNDP 2026 phases.

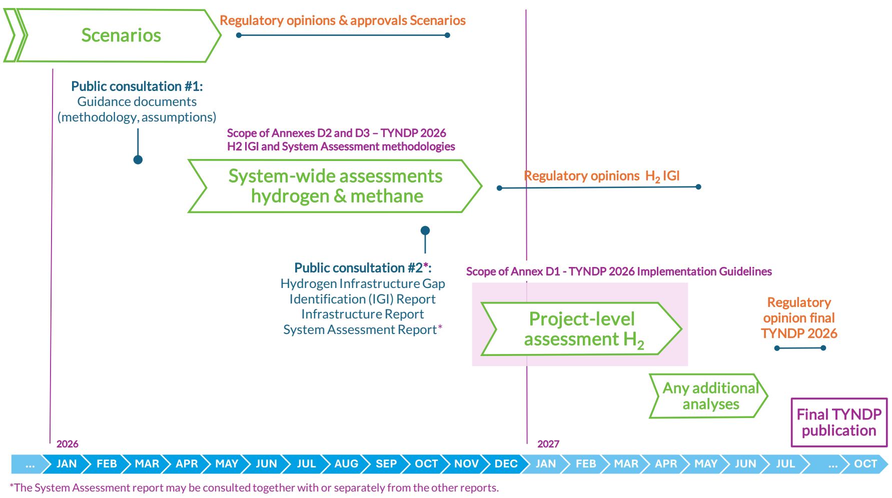


Figure 2 – Main outstanding TYNDP 2026 phases (updated February 2026)

Interaction between TYNDP 2026 and 8th PCI/PMI Selection process

The 8th PCI/PMI selection process, under the responsibility of the TEN-E Regional Groups led by the European Commission, is a separate process from the TYNDP 2026 project collection process[9]. As part of the 8th PCI/PMI project collection process, promoters will be asked to actively confirm their intention to apply to PCI/PMI status.

Following the TYNDP 2026 project collection and system-wide assessment ENTSOG will only run the project-specific assessment on hydrogen projects which:

(1) are eligible for the upcoming PCI/PMI selection process and

(2) for which promoters will have expressed their intention to participate to the PCI/PMI selection during the TYNDP 2026 project collection phase.

[6] Paragraph 2 of Art. 11 – Energy system wide cost-benefit analysis
[7] Paragraph 1 of Art. 12 – Scenarios for the ten-year network development plans
[8] Paragraph 1 of Art. 13 – Infrastructure Gaps Identification
[9] TYNDP 2026 Guidelines for Project Inclusion: https://www.entsog.eu/sites/default/files/2025-09/Guidelines%20for%20Project%20Inclusion_TYNDP2026.pdf

ENTSOG will provide PS-CBA results to promoters ahead of the publication of corresponding project fiches. Promoters will at this stage have the option to maintain or withdraw the project from the PCI/PMI selection process.

The process can be graphically summarized as follows:

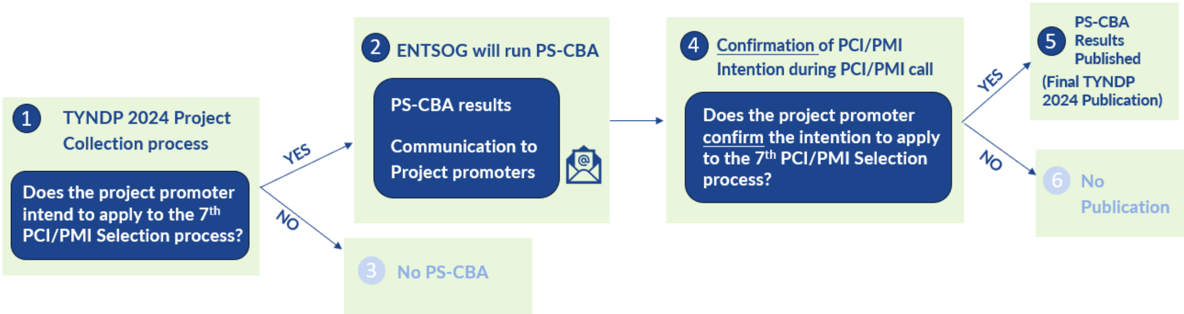


Figure 3: Interactions between TYNDP 2026 and 3rd PCI/PMI selection process under revised TEN-E

TYNDP 2026 Scenario Report

The ENTSOs have to use scenarios established in line with Art. 12 of the TEN-E Regulation as the basis for the TYNDPs and the calculation of the PS-CBAs used in PCI/PMI selection process. The draft scenario documents for the TYNDP 2026 are not yet publicly available.[10]

The following scenario inputs are used for the TYNDP 2026 PS-CBA:

- Selection of scenario: National Trends+ (NT+)[11]
- Timeframes: 2030, 2035, 2040, 2050
- Climatic Year: normal and stressful based on future weather years
- Sensitivities: prioritise "unlimited" simulations and then variants
  - Scenario variants for potential application in GI and SA, but not PS-CBA
    - Scenario variants are still under development; methodology is being finalised following the consultation.
    - High/Low economic cases prepared for 2035 and 2040.

    - Variations applied on the demand side, including:
      - Technology mix changes (+15% adjustment)
      - Activity level changes (+7.5% adjustment)
    - Variations applied on the supply side, including:
      - Adjustments to CO_2 prices

[10] https://2026.entsos-tyndp-scenarios.eu/

- Adjustments to commodity prices

2. Model description

This section of the TYNDP 2026 Implementation Guidelines provides a brief overview of the market and network modelling tools used for the TYNDP 2026PS-CBA. All details can be found in the Cost-Benefit Analyses Methodology, in Chapter 2.2. [12]

2.1 General description of the modelling approach for TYNDP 2026

Hydrogen infrastructure modelling requires integrated market and network analysis across hydrogen, natural gas, and electricity systems due to their increasing interdependencies.

Figure 4: Description of the interactions between Electricity, Hydrogen and Natural gas systems in TYNDP 2026 PS-CBA process.

Figure 4 illustrates these interactions and the two-step modelling approach applied in the PS-CBA:

- Dual Hydrogen-Electricity Model (DHEM):
  Captures the interactions between hydrogen and electricity through combined network and market modelling. DHEM supports the assessment of benefit indicators including GHG emissions (B1), non-GHG emissions (B2), renewable electricity integration (B3.1), renewable and low-carbon hydrogen integration (B3.2), market rents (B4), and reduced exposure to curtailed hydrogen demand (B5).

With minor adaptations described in Chapter 2.2 of the CBA Methodology, both models (DHEM and DGM) rely on essentially the same hydrogen network topology. The level of infrastructure detail balances modelling accuracy with the availability and complexity of underlying network data and includes both existing and planned assets.

[12] Methodolgy for Cost-Benefit Analysis of Hydrogen Infrastructure Projects

2.2 Hydrogen infrastructure level(s)

There are two default hydrogen infrastructure levels (see Figure 5):

> A **PCI/PMI hydrogen infrastructure level** containing existing hydrogen infrastructure, FID hydrogen projects, and hydrogen projects on the PCI/PMI list in force[13] at the time of the definition of infrastructure levels, modified by requests of the European Commission concerning import corridors.

> An **Advanced hydrogen infrastructure level** containing the existing hydrogen infrastructure, FID hydrogen projects, PCI/PMI hydrogen infrastructure level as well as advanced hydrogen projects, modified by requests of the European Commission concerning import corridors.

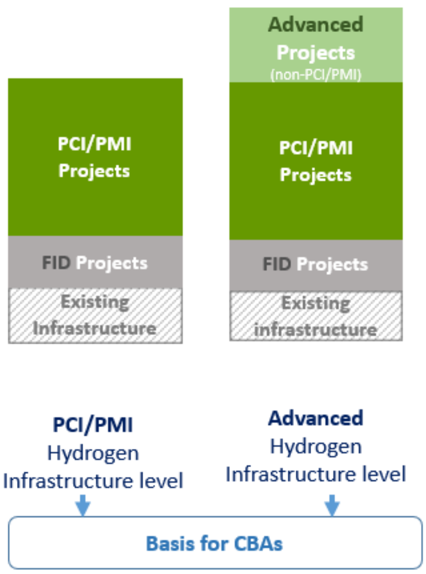


Figure 5: Hydrogen infrastructure levels as potential basis for TYNDP 2026 PS-CBA process, here without individual import corridor projects identified by the European Commission.

Whereas:

> **Existing hydrogen infrastructure** refers to hydrogen infrastructure that is operational at the time of the TYNDP 2026 data collection as well as projects that acquired the final investment decision (FID) ahead of the relevant TYNDP project data collection and that are expected to be commissioned no later than 2026. The FID status was defined in Art. 2(3) of Regulation (EC) 256/2014 as follows: "*final investment decision' means the*

[13] As defined by in section B. (HI West, HI East and BEMIP Hydrogen) of the Annex VII to Regulation (EU) No 2022/869 https://energy.ec.europa.eu/system/files/2023-11/Annex%20PCI%20PMI%20list.pdf

decision taken at the level of an undertaking to definitively earmark funds for the investment phase of a project (…)".

- **FID hydrogen project** refers to projects having taken the final investment decision ahead of the TYNDP 2026 project data collection.
- **Advanced hydrogen project** refers to projects with an expected commissioning date no later than 31 December of 2032 and that fulfil at least one of the following criteria:
  - The project is included in the latest published national network development plan(s) of the respective country(ies) or in the national law(s).
  - The project was successfully consulted through a market test (including non-binding processes), which delivered positive results.
- **PCI/PMI hydrogen project** refers to hydrogen projects that are on the 8th PCI/PMI Union[14] list as detailed in section B of the Annex VII to the TEN-E Regulation.

The list of TYNDP 2026 projects conforming the proposed hydrogen infrastructure levels (i.e., PCI/PMI hydrogen infrastructure level and Advanced hydrogen infrastructure level) can be found in Annex I.

The hydrogen cross-border, import, and storage capacities at country/zone level can be found in Annex II.

2.3 Target Years

Based on the ACER Opinion No 13/2025 "ACER Opinion on ENTSOG's draft Ten-Year Network Development Plan (TYNDP) 2024" and the ENTSOG workshop on "TYNDP 2026 - Model Assumptions and Innovations for System-and Project-level assessments", ENTSOG proposed a change in the decision on selecting target years for IGI, SA, and PS-CBA considers several candidate milestones with distinct advantages. The target years for the TYNDP 2026 PS-CBA are foreseen to be the years 2035 and 2040.

By this approach ENTSOG envisaged the following advantages for their PS-CBA results:

- Adding 2035 offers proximity to the TYNDP 2026 publication date and establishes a 10-year reference horizon.
- Keeping 2040 reflects its status as the preferred target year by the European Commission in the 2024 cycle.

[14] https://energy.ec.europa.eu/document/download/3db5e3d1-9989-4d10-93e3-67f5b9ad9103_en?filename=Annex%20PCI%20PMI%20list.pdf

For project groups that are fully commissioned or that exhibit cost/ increments beyond the target years of 2035 and 2040, ENTSOG will incorporate the associated benefits and costs into the PS-CBA analysis.

2.4 Unlimited Simulations

Based on the ACER opinion for TYNDP 2024 publication of the IGI report (infrastructure gap identification report): "

ACER Opinion – point 3.

[...] Given the high level of uncertainty surrounding hydrogen market development and its impact on infrastructure development, ACER emphasizes the importance of ***incorporating scenario variants and sensitivity analyses*** *to better reflect a range of possible future infrastructure needs assessments.* the TYNDP 2026 will containing unlimited simulations as another measure for sensitivity analysis."

The TYNDP 2026 will contain additional sensitivity analysis in the National Trends+ scenario in the IGI report, the SA and the PS-CBA. "Unlimited" sensitivities will be prioritised for this approach, followed by the high economic variants and low economic variants of the NT+ scenarios.

2.5 Weather Scenarios

TYNDP 2026 enhances its weather modelling by combining historical datasets with future climate projections from the CMIP6 framework. This ensures that long-term energy system assessments account for climate-driven impacts on renewable generation and temperature-sensitive demand.

For each target year, two weather scenarios are used to capture uncertainty in future climate conditions:

- **Base case:** the least stressful scenario identified in the TYNDP 2026 Scenario Methodology.
- **Stressful case:** the most stressful scenario identified in the same methodology.

Weather years are selected from the PECD (Pan-European Climate Database) 4.2 dataset, using projections from the SSP2-4.5 pathway and three climate models (CMR5, ECE3, MEHR), providing 30 candidate years per target year for variables affecting wind, solar, hydro, and load.

A multi-stage statistical process narrows this pool to three representative weather years:

1. Calculation of regional averages and standard deviations for key variables
2. Normalization and PCA for dimensionality reduction
3. K-means clustering to identify distinct climate patterns

4. Selection of cluster medoids as representative years

These three years form the climatic basis for TYNDP 2026, ensuring scenarios that are robust, climate-adaptive, and reflective of a realistic range of future weather conditions.

Target Year	Weather Scenarios (Weighting Factor)	
	Base	Stressful
2035	WS059	WS037
2040	WS065	WS077

For each target year (2035, 2040), a 10-year window per climate model is used (e.g., TY2035: 2030–2039). With three models, this provides 30 candidate climate-year series per target year, from which three representative years are selected.

2.6 LTC Band[15]

For the analysis of the hydrogen infrastructure projects similar features will be used as for the methane infrastructure, especially regarding the structure of hydrogen flows based on long-term and short-term flexible contracts. The long-term contracts especially in early stages of the hydrogen infrastructure/hydrogen market development could play crucial role, as it is a proofed instrument for risk sharing management among hydrogen market players. Different levels of the long-term contracts (LTC) band from the TYNDP 2026 Scenario Report can be tested. The profile of the LTC Band remains flat while and at low/zero price the upper band can provide additional flexibility following electrolyzers production based on the RES on marginal pricing approach.

[15] No final decision on the inclusion is available yet. This section will be updated, once the test results are approved by the ENTSOG members.

2.7 Market assumptions in the DHEM[16]

Table 1: Summary of the market assumptions considered by DHEM for TYNDP 2026 PS-CBA process.

Market assumption		2030	2035[17]	2040	Description	Source
Assumed ETS price (unit: €/t $CO_{2\,eq}$)		97.5	197.5	297.5	Costs for covered GHG emissions under the ETS.	TYNDP 2026 draft Scenario Methodology Report
Fuel prices (unit: €/GJ)	Nuclear	**0.6**	0.6	**0.6**	EU-price per fuel	NT+ scenario (source: TYNDP 2026 draft Scenario Methodology Report).
	Natural gas	**9.2**	9.8	**10.4**		
	Blended gas	**9.6**	9.4	**11.8**		
	Light oil	**18.3**	19.5	**20.7**		
	Heavy oil	**15.0**	16.0	**17.0**		
	Hard coal	**4.1**	4.0	**3.9**		
	Lignite (G1[18])	**1.9**	1.9	**1.9**	Lignite price per region	
	Lignite (G2[19])	**2.4**	2.4	**2.4**		
	Lignite (G3[20])	**3.1**	3.2	**3.1**		
	Lignite (G4[21])	**4.1**	4.1	**4.1**		

[16] Due to ongoing processes, not all Scenario values for the market assumptions in the DHEM are available prior to the consultation. As soon as these values are finalized, they be made available in this document.

[17] For the target year 2035, all Scenario values are interpolated, once available in the final version.

[18] Lignite group 1: Bulgaria, North Macedonia, and Czech Republic.

[19] Lignite group 2: Slovakia, Germany, Serbia, Poland, Montenegro, UK, Ireland, and Bosnia and Herzegovina.

[20] Lignite group 3: Slovenia, Romania, and Hungary.

[21] Lignite group 4: Greece and Turkey.

Market assumption		2030	2035[17]	2040	Description	Source
Hydrogen import prices (unit: €/MWh$_{H2}$)[22]	Liquid imports				Assumed liquid imports in form of ammonia	
	North Africa				Estimated base price per import source	
	Ukraine					NT+ scenario (source: TYNDP 2026 draft Scenario Methodology Report)
Hydrogen production prices (unit: €/MWh$_{H2}$)[23]	Hydrogen production from natural gas with CCS				Hydrogen produced by SMR or ATR with CCS to capture and store 90% of the CO_2.	
	Hydrogen production from nuclear				Hydrogen produced by water electrolysis using electricity from nuclear energy. If the electricity price is higher in the relevant bidding zone, also the hydrogen production cost will be higher.	
	Hydrogen production from renewables					
Hydrogen Supply Potentials (unit: TWh/y (GCV))	Algeria	0.000	29.146	57.938	The maximum extra-EU hydrogen supply potentials to Europe in the NT+ scenario	NT+ scenario (source: TYNDP 2026 draft Scenario Methodology Report).
	Ukraine	25.134	25.134	38.350		
	Tunesia	61.832	69.974	78.116		
	Ammonia	76.110	137.588	243.906		
	Morocco	0.000	0.000	31.388		
	Total	163.08	261.84	449.70		

[22] To be based on the TYNDP 2026 SCN Methodology Report, once the final version is available in May 2026.

[22] To be based on the TYNDP 2026 SCN Methodology Report, once the final version is available in May 2026.

[23] To be based on the TYNDP 2026 SCN Methodology Report, once the final version is available in May 2026.

Market assumption	2030	2035[17]	2040	Description	Source
SMR and ATR capacities at country level		Technical parameters, economic parameters, capacities and their localisation.		The production capacities of SMR and ATR plants in each country and differentiation into those that are coupled with CCS and those that are not.	TYNDP 2026 Draft Scenario Methodology Report[24]
Electrolysers				Assets that use electricity to split water into hydrogen and oxygen.	TYNDP 2026 Draft Scenario Methodology Report
Water Prices				Used to assign a VO&M value to Electrolysis based on country specific water prices.	The International Benchmarking Network for Water and Sanitation Utilities (IBNET) database (see Annex III)
Thermal power plants				Power plants that generate electricity by converting heat energy, typically from fossil fuels.	TYNDP 2026 Draft Scenario Methodology Report
Demand-side response				Adjustments in electricity consumption by end-users in response to supply conditions or price signals.	TYNDP 2026 Draft Scenario Methodology Report
Hydro storages				Facilities that store energy in the form of water in reservoirs, used for hydroelectric power generation.	TYNDP 2026 Draft Scenario Methodology Report
Battery storages				Systems that store electrical energy in batteries for later use.	TYNDP 2026 Draft Scenario Methodology Report

Market assumption	2030	2035[17]	2040	Description	Source
RES plants				Renewable Energy Source plants that generate electricity from renewable resources like wind, solar, or hydro.	TYNDP 2026 Draft Scenario Methodology Report
Electricity generation profiles of RES		Per type (e.g., onshore wind, offshore wind, photovoltaic solar, concentrated solar power, other RES) and per country.		Patterns of electricity generation over time from renewable energy sources.	ENTSO-E Seasonal Outlooks website [25]
VoLL (unit: €/MWh$_{el}$)		3000		Value of Lost Load, representing the cost of unserved electricity to consumers.	TYNDP 2026 draft Scenario Methodology Report
$CODH_{H2}$ (unit: €/MWh$_{H2}$)	154	157		Estimated cost of hydrogen disruption for calculation of the market rents (B4) based on the estimated willingness to pay of hydrogen users.	ENTSOG based on European Hydrogen Bank auction information (see Annex III)
	tbd	tbd		Estimated cost of hydrogen disruption for monetization of B5.	ENTSOG
Hydrogen storages		Technical parameters: working gas volume as submitted, standardized injection and withdrawal curves, 1% of hydrogen consumption for hydrogen injection		Facilities to store hydrogen underground.	Based on submissions of project promoters during TYNDP 2026 project submission phase

Market assumption	2030	2035[17]	2040	Description	Source
		(simplified assumption, as the hydrogen storages' compressors are expected to run on electricity), localisation as submitted.			
Electricity demand		Elastic (i.e., this demand is price-sensitive) and inelastic (i.e., this demand is only interrupted if insufficient supply is available at costs below the VoLL) electricity demand.		The total amount of electricity required by all users at bidding-zone level.	TYNDP 2026 draft Scenario Methodology Report Climate stress case data requested from ENTSO-E
Hydrogen demand		Elastic (i.e., this demand is price-sensitive) and inelastic (i.e., this demand is only interrupted if insufficient supply is available at costs below the Cost of Disrupted Hydrogen) hydrogen demand.		The total amount of hydrogen required by all users at country level. In addition, total hydrogen demand at country level is assigned to the different hydrogen zones within the country (i.e., by default Zone 1 and Zone 2). For countries with two hydrogen zones the shares of demand are listed in Annex III. For countries with hydrogen topology composed by 3 or more zones, shares of hydrogen demand were considered as provided by project promoters.	TYNDP 2026 draft Scenario Methodology Report for hydrogen demand per country. ENTSOG based on project promoters for shares of hydrogen demand assigned per zone within a country.
Cooperation mode		Introduction of a hurdle cost for cross-border		A small hurdle cost is implemented for cross-border flows to limit the cooperation between countries.	ENTSOG

Market assumption	2030	2035[17]	2040	Description	Source
		flows and a WTP differentiation to formalize the intended limitations of the cooperation mode.		This way, a country with a hydrogen supply surplus will only supply an amount of hydrogen with its neighboring countries that does not result in curtailment of its own hydrogen demand. First, it would help to satisfy the hydrogen demand of its direct neighbors. By being a small hurdle cost, this hurdle cost will not distort the benefits indicators. If a country with a hydrogen supply surplus has several direct neighbors and it cannot help to mitigate all hydrogen demand curtailment in all of them, they will be helped equally in terms of the resulting hydrogen curtailment rates. This can be achieved by defining the WTP_{H2} value being slightly increasing with the curtailment rate in a country, with the value stated above in the center. This differentiation must be smaller than the hurdle cost to not distort the limitation of the cooperation. This extra rule is needed as otherwise the allocation of hydrogen supply to neighboring countries could be a random output of the model.	

3. Project Assessment

3.1 Project Grouping

A project can be assessed individually or in a group, in the case where a set of functionally-related projects need to be implemented together for their benefits to materialise.

Introduction and definitions:

> *Project advancement status*

The **project advancement status** describes the current phase of a project's implementation. The options for this status are:

i) under consideration;
ii) planned;
iii) permitting;
iv) under construction.

The project advancement status is derived from the information provided by the project promoter during the TYNDP 2026 project submission process.

> *Enabling projects and enabled projects*

An enabling project (or enabler) is a project which is indispensable for the realisation of an enabled project, in order for the latter to start operation and to show any benefit. The enabler itself might not bring any direct capacity increment.

If an enabling project's advancement status is "under consideration", the enabled project's advancement status is also considered as "under consideration".

Example : enabling project - enabled project

> Description: Project A connects a supply source with Point 1. Project B connects Point 1 with demand. Without Project A, Project B would have no connected supply source. Also, it relies on Project A's pressure provision to create its own transport capacity. Thus, Project A is indispensable for the realisation of Project B. Project A is enabler of Project B.

> *Enhancing projects and enhanced projects*

An enhancing project (or enhancer) is a complementary project that would allow another project (i.e., the enhanced project) to get improved. This could mean that synergies are created compared to the enhanced project operating on its own basis, increasing the benefits arising from the realisation of the enhanced project. An enhancer, unlike an enabler, is not strictly required for the realisation of the enhanced project.

Example: enhancing project - enhanced project

Case: Project A connects a supply source with Point 1. Project B connects Point 1 with demand. While Project B creates sufficient capacity to satisfy the demand, the supply source connected by Project A is not sufficient. Project C connects another supply source with Point 1, increasing the benefits that can be provided with Project B. Project C is not strictly required for the realisation of Project B but increases its benefits. Project C is enhancer of Project B.

Grouping principles

To avoid over clustering of investments when grouping them together, it is important to analyse projects' interlinkages (i.e., enabler/enabled relationships, enhancer/enhanced relationship) and take into consideration other factors such as their maturity status and/or project advancement. Therefore, the following **grouping principles** are applied:

- Projects should be grouped together when there is a functional relationship between them:
  - As a minimum, the transmission projects on both sides of a boarder that jointly form an interconnector must be grouped together.
  - As a minimum, a hydrogen reception terminal and its connecting pipeline to the hydrogen grid must be grouped together.
  - As a minimum, a hydrogen storage and its connecting pipeline to the hydrogen grid must be grouped together.
- Projects can only be grouped together if they are at maximum one project advancement status apart from each other.
- Projects can only be grouped together if their commissioning dates are not more than five years apart from each other.
- Projects that are enabled projects can only be grouped together with their enabling project.

- Projects that are enabling projects under consideration can only be grouped with enabled projects of the same project advancement status.
- An enabled project can only be grouped with an enabling project if the enabling project's commissioning year is equal to or before the commission year of the enabled project.
- **Competing projects** need to be assessed separately and as many groups as projects in competition should be established, with only the competing project amended while the rest of the group stays unchanged. There are several possible sources of information about the competing nature of certain projects:
  - Competition identified by the involved project promoters.
  - Competition between projects connecting an outside-EU supply source with a specific Member State. It is derived by comparing the NT+ scenario's supply potential for this outside-EU supply source with the import capacities into this Member State provided by projects. There is competition if a reduced set of projects would provide sufficient capacity to import the supply source's full supply potential (e.g., if a supply source has a supply potential of 50 and there are two projects submitted to connect this supply source to the same country with a capacity of 60 and 70 respectively).
- **Enhancing project(s)** need to be grouped with and without the enhanced project. The benefit indicators and economic performance indicators that can be calculated for the groups with and without the enhancing project(s) allow the determination if the benefits related to the enhancement are justifying the additional investments related to the enhancing project(s).
- In case of a project consisting of **multiple phases**[26], each phase should be assessed separately in order to evaluate the incremental impact of all phases (e.g., in case of a project composed of two different phases, one group considers only phase 1 while a second group considers phase 1 and phase 2).
- Projects that are connecting outside-EU supply sources with demand along a hydrogen corridor should be grouped together. Pipelines connecting extra-EU hydrogen supplies (i.e., extra-EU hydrogen supply corridor) should be grouped with the directly or indirectly connected EU-countries or European demand centre(s).

[26] Multi-phase investments projects are composed of two or more sequential phases, where the first phase is required for the realization of the following phases (e.g., extension and capacity increase of reception terminal, capacity increase of import route, extension and capacity increase of an hydrogen storage, etc.).

3.2 Project-Specific Cost-Benefit Analysis (PS-CBA)

3.2.1 Quantification and monetisation principles

The TYNDP 2026 PS-CBA combines monetary CBA elements with non-monetary and qualitative aspects through a Multi-Criteria Analysis (MCA). Its broader scope reflects the need to account for non-monetary impacts in energy markets, while quantitative indicators ensure clear and comparable information regardless of monetisation.

Monetisation requires careful avoidance of double-counting. Each benefit indicator independently measures a project's contribution to one criterion, with any overlapping components removed as specified. Monetisation should only be used when sufficiently reliable; otherwise, non-monetised quantitative benefits should be retained to avoid non-robust benefit-cost comparisons. More information on the quantification and monetisation principles can be found in the Methodology for Cost-Benefit Analyses of Hydrogen Infrastructure Projects[27].

3.2.2 Introduction and overview of benefit indicators

The TEN-E Regulation has identified four main criteria for the assessment of hydrogen projects: sustainability, security of supply and flexibility, competition, and market integration. In line with those criteria, hydrogen infrastructure projects' potential benefits will be measured in the PS-CBA process through the variation of the following benefit indicators:

- B1: Societal benefit due to GHG emissions variations
- B2: Societal benefit due to non-GHG emissions variations
- B3.1: Integration of renewable electricity generation
- B3.2: Integration of renewable and low-carbon hydrogen
- B4: Increase of market rents
- B5: Reduction in exposure to curtailed hydrogen demand

This is summarised in the Figure below.

[27] Methodolgy for Cost-Benefit Analysis of Hydrogen Infrastructure Projects

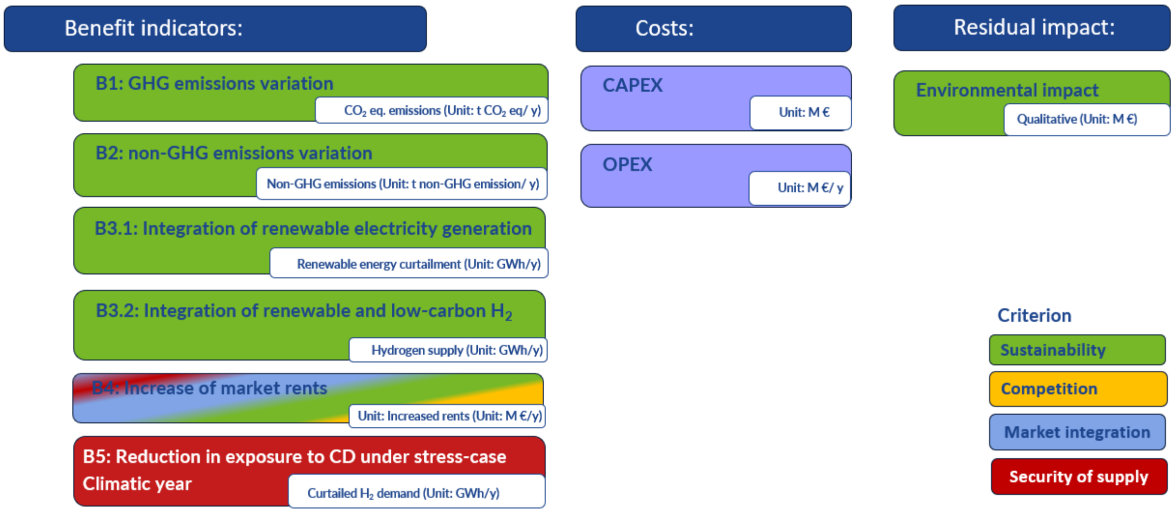


Figure 6: Proposed benefit indicators under TYNDP 2026 PS-CBA process

All benefit indicators are calculated through the incremental approach (as described in CBA Methodology, Chapter 3.2.3[28])) in order to evaluate the EU-related contribution of a (group of) project(s).

For all categories of hydrogen projects falling under Annex II(3) of the TEN-E Regulation, all benefit indicators will be calculated.

The benefit indicators GHG emissions variations (B1), non-GHG emissions variations (B2), integration of renewable electricity generation (B3.1), integration of renewable and low-carbon hydrogen (B3.2) and increase of market rents (B4) are based on the same DHEM base-case simulation, while different simulation output parameters are used for their calculations.
The reduction in exposure to curtailed hydrogen demand indicator (B5) uses a dedicated DHEM simulation based on a more stressful climate year than the reference case used for other indicators. This is followed by a DGM simulation that also accounts for natural gas system constraints, testing whether sufficient natural gas is available to support the required hydrogen production.

[28] Methodolgy for Cost-Benefit Analysis of Hydrogen Infrastructure Projects

3.2.3 B1: GHG emissions variation

DEFINITION	This benefit indicator (B1) measures the variations in GHG emissions as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B1) > Considers the change of GHG emissions as a result of changing the generation mix of the electricity sector and the supply sources used to meet hydrogen demand; > Calculates the GHG emissions by multiplying the usage of electricity generation type (e.g., coal-fired power plant), hydrogen production type (e.g., unabated SMR) with respective CO_2 equivalent emission factors capturing direct emissions; > Includes savings in GHG emissions through the reduction of demand curtailment in hydrogen and electricity sectors by the replacement or reduction of alternative fuels (natural gas / light oil or coal) > Is first expressed in quantitative terms in tons of CO_2 equivalent emissions savings per year (tCO_2-eq/y); > Can be expressed in monetary terms (€/y) by multiplying the CO_2 equivalent emissions savings (tCO_2-eq/y) by the societal cost of carbon (€/tCO_2-eq) of the corresponding simulated year, additionally considering double-counting with the increase of market rents indicator (B4).
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B1) is interlinked with the integration of renewable electricity generation indicator (B3.1), the integration of renewable and low carbon hydrogen indicator (B3.2), and the increase of market rents indicator (B4). Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach for both, hydrogen and electricity sector, the following formula is applied. The simulation outputs thereby cover all elements of the formula except the GHG emission factors.

$$
\begin{aligned}
&\Delta GHG\ emissions\ enabled\ by\ (group\ of)project(s) \\
&\quad = \Big(\sum_i^n (power\ generation_{i,with\ (group\ of)project(s)} * CO_{2-eq} emission\ factor_i) \\
&\quad + \sum_j^m (hydrogen\ production_{j,with\ (group\ of)project(s)} \\
&\quad * CO_{2-eq} emission\ factor_j) \\
&\quad + \sum_l^r (hydrogen\ import\ from\ supply\ potential_{l,with\ (group\ of)project(s)} \\
&\quad * CO_{2-eq} emission\ factor_l) \\
&\quad + \sum_i^s (Curtailed\ energy_{i,with\ (group\ of)project(s)} * CO_{2-eq} emission\ factor_i)\Big) \\
&- \Big(\sum_i^n (power\ generation_{i,without\ (group\ of)project(s)} * CO_{2-eq} emission\ factor_i) \\
&\quad + \sum_j^m (hydrogen\ production_{j,without\ (group\ of)project(s)} \\
&\quad * CO_{2-eq} emission\ factor_j) \\
&\quad + \sum_l^r (hydrogen\ import\ from\ supply\ potential_{l,without\ (group\ of)project(s)} \\
&\quad * CO_{2-eq} emission\ factor_l) \\
&\quad + \sum_i^s (Curtailed\ energy_{i,without\ (group\ of)project(s)} * CO_{2-eq} emission\ factor_i)\Big)
\end{aligned}
$$

On the basis of:

> n: number of different types of electricity generation.

> m: number of different types of hydrogen production.

> r: number of different supply sources that are considered with the supply potential approach.

> All CO_2 equivalent emission factors proposed for the TYNDP 2026 PS-CBA process capture direct GHG emissions as detailed in Annex III-V.

> Power generation$_i$: Amount of electricity produced by power generation of type 'i' (e.g., coal-fired power plant, etc.). Variations with and without the (group of) project(s) are resulting from changing the generation mix and total generation of the electricity sector.

> CO_2-eq emission factor$_i$: GHG emission factor expressed in CO_2 equivalence of power generation of type 'i' per unit of energy generated in form of electricity.

> Hydrogen production$_j$: Amount of hydrogen produced by hydrogen production from natural gas of type 'j' (e.g., unabated hydrogen production from natural gas with SMR,

low-carbon hydrogen production from natural gas with SMR and CCS, etc.). Variations with and without the (group of) project(s) are resulting from changing the usage of supply sources and the total production and imports of hydrogen if the country is not considered with the supply potential approach. Electrolytic hydrogen production is already addressed by the power generation term of the formula as the electrolyser usage itself is not causing additional GHG emissions.

> CO_2-eq emission factor$_j$: GHG emission factor expressed in CO_2 equivalence of hydrogen production of type 'j' per unit of energy produced in form of hydrogen.

> Hydrogen import from supply potential$_l$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'l'. It is used to capture the changes of imports from supply sources that are considered with the supply potential approach.

> CO_2-eq emission factor$_l$: GHG emission factor expressed in CO_2 equivalence of hydrogen source that is considered with the supply potential approach of type 'l' per unit of energy used.

> s: number of sectors in the DHEM (i.e. hydrogen and electricity).

> Curtailed energy$_i$: Amount of unsatisfied energy demand from electricity and hydrogen sectors.

> CO_2-eq emission factor$_i$: Assumed GHG emission factor expressed in CO_2 equivalence per unit of unsatisfied energy demand from hydrogen and electricity systems.

The resulting amount of variation of GHG emissions in tons of CO_2-eq shall be valued in monetary terms. The unit is €/y.

There are different approaches to monetise GHG emissions:

> To simulate an expected market behaviour, it is prudent to include those costs of GHG emissions that must be paid by market participants, as those will influence their decision making. These costs are related to the Emission Trading Scheme (ETS). They are internalised into the increase of market rents indicator (B4) through the producer rent, as the marginal costs of each production asset is defined as the sum of the fuel cost, variable operation and maintenance costs, as well as the ETS price (as forecasted in the scenarios). Therefore, the increase of market rents indicator (B4) already considers a certain monetisation of GHG emissions.

- However, also a societal cost of carbon can be established based on two concepts that typically consider higher cost of carbon than the ETS[29]:
  - The social cost (or social cost of carbon) that represents the total net damage of an extra metric ton of CO_2 emissions due to the associated climate change; and
  - The shadow price (or shadow cost of carbon) that is determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint.
- This benefit indicator (B1) aims to monetise the GHG emissions variations resulting from the implementation of a (group of) project(s) with societal cost of carbon. These costs do not influence the market behaviour as it is not paid by a market participant as a direct consequence of its actions. Therefore, the assessment of this benefit indicator (B1) is based on the same market behaviour as the increase of market rents indicator (B4). Since latter benefit indicator (B4) already captures the ETS-related costs, they are removed from this benefit indicator (B1) to avoid a double-counting of benefits.

The societal cost of carbon used for this benefit indicator (B1) should be based on reputable scientific investigations and international studies. In line with the EC technical guidance on the climate proofing of infrastructure in 2021–2027[30] and EC Economic Appraisal Vademecum 2021-2027 General Principles and Sector Applications[31], the reference values for the monetisation of the B1 indicator are societal cost of carbon that are based on the shadow cost of carbon as detailed in Table 2 below.

Table 2: Proposed societal cost of carbon for TYNDP 2026 PS-CBA process for simulated years (source: EIB[32]).

Monetization factor (B1)[33]	2035	2040
Proposed societal cost of carbon (published 2024 by EIB) (unit: € /t CO_2-eq)	387.5	525

[29] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2.[30] Commission Notice Technical guidance on the climate proofing of infrastructure in the period 2021-2027 (link).

[30] Commission Notice Technical guidance on the climate proofing of infrastructure in the period 2021-2027 (link).

[31] Economic Appraisal Vademecum 2021-2027 General Principles and Sector Applications (link).

[32] EIB Group Climate Bank Roadmap 2021-2025 (https://www.eib.org/en/publications/the-eib-group-climate-bank-roadmap) and EIB Climate Bank Roadmap Progress Report 2022 (https://www.eib.org/en/publications/20230002-climate-bank-roadmap-progress-report-2022).

[33] Monetization factor of B1 indicator for non-simulated years will be based on linear interpolation[34] The numbers for SCC published by the EIB in 2024 were factored by 1,9% EU-wide annual inflation, based on: https://ec.europa.eu/eurostat/web/products-euro-indicators/w/2-19012026-ap#:~:text=to%202025=100.-,Overview,and%20energy%20(%2D0.18%20pp).

Proposed societal cost of carbon (factored by Eurostat inflation index 2025)[34] (unit: € /t CO_2-eq)	394.86	534.98

In order to ensure consistency throughout the time horizon, the already incurred costs (investment) shall be considered as constant prices for the year of occurrence.

This benefit indicator (B1) is monetised as follows:

$$B1_{monetised} = (Societal\ Cost\ of\ Carbon * GHG\ emissions\ variations\ enabled\ by\ (group\ of)project(s)) - \ total\ GHG\ emission\ costs\ monetised\ in\ B4$$

On the basis of:

> Societal Cost of Carbon: Cost of Carbon for the specific year.

> GHG emissions variations enabled by (group of) project(s): As defined in the formula above.

> Total GHG emission costs monetised in B4: Variation of GHG emission costs enabled by the (group of) project(s) as considered in the increase of market rents indicator (B4) on the basis of the forecasted ETS price.

Example for a hypothetical hydrogen storage project

> Case: The hydrogen storage project allows increased usage of renewable hydrogen which replaces unabated hydrogen production from natural gas.

> Assumed ETS price in the assessed year: 113.4 €/tCO2

> Assumed societal cost of carbon in the assessed year: 324 €/tCO2

> Results:

- Reduction of CO2 equivalent emissions covered by the ETS and this benefit indicator (B1): 0.5 MtCO2/y
- Additional reduction of CO2 equivalent derived from energy curtailment reduction (B1): 0.2 MtCO2/y

[34] The numbers for SCC published by the EIB in 2024 were factored by 1,9% EU-wide annual inflation, based on: https://ec.europa.eu/eurostat/web/products-euro-indicators/w/2-19012026-ap#:~:text=to%202025=100.-,Overview,and%20energy%20(%2D0.18%20pp).

- Reduction of CO_2 equivalent emissions covered by the ETS and the increase of market rents indicator (B4): 0.5 $MtCO_2/y$
- Reduction of total CO_2 equivalent emissions covered by this benefit indicator (B1): 0.7 $MtCO_2/y$
- CO_2 equivalent emissions variations monetised in the increase of market rents indicator (B4): 0.5*113.4 M€/y = 56.7 M€/y

> CO_2 equivalent emissions variations monetised in this benefit indicator (B1): 0.7*324 M€/y – 56.7 M€/y = 170.1 M€/y

This benefit indicator (B1) is interlinked with

- The integration of renewable electricity generation indicator (B3.1) as using more renewable electricity generation reduces GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The integration of renewable and low carbon hydrogen indicator (B3.2) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher CO_2 equivalent emission factors, which reduces GHG emissions;
- The increase of market rents indicator (B4) which also includes a monetisation of the part of the GHG emissions as described above. Therefore, the GHG emissions costs that are monetised in the increase of market rents indicator (B4) are removed from this benefit indicator (B1) to avoid double-counting.

Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

This benefit indicator (B1) requires careful consideration if the assessed (group of) project(s) reduces curtailed hydrogen demand in the reference weather year: As curtailed hydrogen demand is not creating emissions in the DHEM, even electrolytic or low carbon hydrogen that satisfies hydrogen demand can increase emissions in comparison to hydrogen demand curtailment. Therefore, this benefit indicator (B1) underestimates the reduction of emissions enabled by a (group of) project(s) that reduces hydrogen demand curtailment under normal conditions. Therefore, the change of hydrogen demand curtailment under normal conditions is displayed as extra information under the increase of market rents indicator (B4).

3.2.4 B2: Non-GHG emissions variation

DEFINITION	This benefit indicator (B2) measures the reduction in non-GHG emissions as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B2) > Considers the change of non-GHG emissions as a result of changing the generation mix of the electricity sector and the supply source used to meet hydrogen demand; > Calculates the non-GHG emissions for each assessed pollutant by multiplying the usage of electricity generation type (e.g., coal-fired power plant), hydrogen production type (e.g., unabated SMR), with respective emission factors reflecting direct emissions; > Includes savings in non-GHG emissions through the reduction of demand curtailment in hydrogen and electricity sectors by the replacement or replacement of alternative fuels (natural gas / light oil or coal).Is first expressed in quantitative terms in variations of tons of pollutant emitted per year (e.g., tNOx/y, tSO2/y, tPM/y, etc.); > Can be further expressed in monetary terms (€/y) by multiplying the non-GHG emission variations (t[Pollutant]/y) by the damage cost of air pollutants (€/t[Pollutant]) of the simulated year.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B2) is interlinked with the integration of renewable electricity generation indicator (B3.1) and the integration of renewable and low carbon hydrogen indicator (B3.2). Since the interlinked benefit indicators are not monetised, double-counting is avoided.

In the EU, the Directive (EU) 2016/2284 sets national emissions reduction commitments for five different air pollutants: nitrogen oxides (NO_x), sulphur dioxides (SO_2), coarse and fine particulate matter (i.e., PM 10 and PM 2.5), non-methane volatile organic compounds (i.e., NMVOC), and ammonia (NH_3). Also, the European Commission has set in the European Green Deal the zero-pollution ambition for a toxic-free environment[35], in addition to 2030 targets for the reduction of air pollution set in the zero-pollution Action Plan[36].

[35] EC Communication: Pathway to a Healthy Planet for All (https://eur-lex.europa.eu/resource.html?uri=cellar:a1c34a56-b314-11eb-8aca-01aa75ed71a1.0001.02/DOC_1&format=PDF).
[36] EU Action Plan: '(Towards Zero Pollution for Air, Water and Soil' (https://eur-lex.europa.eu/resource.html?uri=cellar:a1c34a56-b314-11eb-8aca-01aa75ed71a1.0001.02/ DOC_1&format=PDF).[37] European Environment Agency: Estimating the external costs of industrial air pollution: Trends 2012-2021, Technical note on the methodology and additional results from the EEA briefing 24/2023, Table 3.1.[38] 'Surplus' and 'rent' are used interchangeably.

These pollutants contribute to poor air quality, leading to significant negative impacts on human health and the environment. Energy use in transport, industry and in power sectors, as well as in heat generation, are major sources of emissions especially for NO_x and SO_2.
In this context, hydrogen infrastructure could significantly contribute to the fulfilment of the above-mentioned targets, as hydrogen causes almost no air pollution when used.
The emissions factors greatly differ depending on the use of the fuel, and in particular depending on the combustion techniques and abatement techniques. Ideally, each fuel user in the model would have a different emission factor for each air pollutant considered in the assessment. To simplify the calculation of the indicator, it is recommended to consider one emission factor per pollutant and technology type.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied. The simulation outputs thereby cover all elements of the formula except the GHG emission factors.

$$\Delta Non - GHG\ emissions\ enabled\ by\ (group\ of)project(s)_y$$
$$= \Big(\sum_i^n (power\ generation_{i,with\ (group\ of)project(s)} \cdot Non$$
$$- GHG\ emission\ factor_{i,y})$$
$$+ \sum_j^m (hydrogen\ production_{j,with\ (group\ of)project(s)}$$
$$\cdot Non - GHG\ emission\ factor_{j,y})$$
$$+ \sum_l^r (hydrogen\ import\ from\ supply\ potential_{l,with\ (group\ of)project(s)} \cdot Non$$
$$- GHG\ emission\ factor_{l,y})$$
$$+ \sum_i^s (Curtailed\ energy_{i,with\ (group\ of)project(s)} * Non$$
$$- GHG\ emission\ factor_{i,y})\Big)$$
$$- \Big(\sum_i^n (power\ generation_{i,without\ (group\ of)project(s)} \cdot Non$$
$$- GHG\ emission\ factor_{i,y})$$
$$+ \sum_j^m (hydrogen\ production_{j,without\ (group\ of)project(s)}$$
$$\cdot Non - GHG\ emission\ factor_{j,y})$$
$$+ \sum_l^r (hydrogen\ import\ from\ supply\ potential_{l,without\ (group\ of)project(s)}$$
$$\cdot Non - GHG\ emission\ factor_{l,y})$$
$$+ \sum_i^s (Curtailed\ energy_{i,without\ (group\ of)project(s)} * Non$$
$$- GHG\ emission\ factor_{i,y})\Big)$$

On the basis of:

- n: number of different types of electricity generation.
- m: number of different types of hydrogen production.
- r: number of different supply sources that are considered with the supply potential approach.
- All non-GHG emissions factors capture direct non-GHG emissions variation from nitrogen oxides (NO_x), sulphur dioxide (S_2O) and particulate matter (fine particles and coarse particles) from stationary fuel combustion (as described in Annex V).
- Power generation$_i$: Amount of electricity produced by power generation of type ‘i’. Variations with and without the (group of) project(s) are resulting from changing the generation mix and total generation of the electricity sector.
- Non-GHG emission factor$_{i,y}$: non-GHG emission factor for pollutant ‘y’ of power generation of type ‘i’ per unit of energy generated in form of electricity.

> Hydrogen production$_j$: Amount of hydrogen produced from natural gas by hydrogen production of type 'j' (e.g., unabated hydrogen production from natural gas with SMR, low-carbon hydrogen production from natural gas with SMR and CCS, etc.). Variations with and without the (group of) project(s) are resulting from changing the usage of supply sources and the total production and imports of hydrogen if the country is not considered with the supply potential approach. Electrolytic hydrogen production is already addressed by the power generation term of the formula as the electrolyser usage itself is not causing additional non-GHG emissions.
> Non-GHG emission factor$_{i,y}$: non-GHG emission factor for pollutant 'y' of hydrogen production of type 'i' per unit of energy produced in the form of hydrogen. Variations with and without the (group of) project(s) are resulting from changing the supply sources used to meet the hydrogen demand (e.g., unabated hydrogen production from natural gas, low carbon, or electrolytic hydrogen) and the total production and imports of hydrogen.
> Hydrogen import from supply potential$_l$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'l'.
> Non-GHG emission factor$_{l,y}$: GHG emission factor for pollutant 'y' of hydrogen source that is considered with the supply potential approach of type 'l' per unit of energy used.

> s: number of sectors in the DHEM (i.e. hydrogen and electricity).

> Curtailed energy$_i$: Amount of unsatisfied energy demand from electricity and hydrogen sectors.

> Non-GHG emission factor$_i$: Non-GHG emission factor for pollutant 'y' expressed in tonne of pollutant per year per unit of unsatisfied energy demand from hydrogen and electricity systems.

The formula is applied to each assessed non-GHG pollutant individually. The set of the resulting quantitative non-GHG emission reductions is the non-monetised non-GHG emissions variation indicator (B2).

The monetisation of the variations of emissions from the considered air pollutants is described as follows:

$$B2_{monetised} = \sum_{y} (Non - GHG\ emissions\ variation\ by\ (group\ of)\ project(s)_y * Damage\ cost_y)$$

On the basis of:

> Non-GHG emission variation by (group of) project(s)$_y$: Result for non-GHG emissions variation for pollutant 'y' (t[Pollutant]/y).
> Damage cost$_y$: Cost of the emission of pollutant 'y' (€/t[Pollutant]).

Table 3: Average EU damage cost per tonne of pollutant (source: European Environment Agency[37]).

Pollutant	Average EU damage cost (unit: € (2021)/t pollutant)	
	VOLY	VSL
NO_x	15.353	42.953
SO_2	16.212	38.345
PM 10	51.482	141.145
PM 2.5	86.490	237.123
NH_3	18.991	52.268
NMVOC	1.844	4.480

Damage costs per ton of each pollutant were quantified as EU average by the European Environment Agency (EEA). A sensitivity analysis has been performed using two commonly applied methods for valuing mortality, i.e., the value of statistical life (VSL) and the value of a life year (VOLY). The former is based on the number of deaths associated with air pollution, while the latter is based upon the loss of life expectancy (expressed as years of life lost, or YOLLs). The ranges of external costs (low – high) included in the Table 3 correspond to the values estimated by EEA[27] using these two methods.

For the monetisation of this benefit indicator (B2) in the TYNDP 2026 PS-CBA process, ENTSOG proposes to consider the average (EU) damage costs based on the value of a life year (VOLY) or value of statistical life (VSL) (see Table 3), to be decided according to the outcome of the Public Consultation of the TYNDP 2026 Implementation Guidelines.

Example for a hypothetical hydrogen import terminal project

- Case: The hydrogen import terminal project allows increased usage of renewable hydrogen which replaces unabated hydrogen production from natural gas. Pollutant y and pollutant x are assessed.
- Assumed damage cost of pollutant y in the assessed year: 100 €/t pollutant y

[37] European Environment Agency: Estimating the external costs of industrial air pollution: Trends 2012-2021, Technical note on the methodology and additional results from the EEA briefing 24/2023, Table 3.1.[38] 'Surplus' and 'rent' are used interchangeably.

> Assumed damage cost of pollutant x in the assessed year: 200 €/t pollutant x
>
> Non-monetised results of this benefit indicator (B2):
>
> - Reduction of emissions of pollutant y: 0.1 Mt pollutant y/y
> - Reduction of emissions of pollutant x: 0.05 Mt pollutant x/y
>
> Non-GHG emissions variations monetised in this benefit indicator (B2):
> 100*0.1M€/y + 200*0.05M€/y = 20 M€/y

This benefit indicator (B2) is interlinked with

- The integration of renewable electricity generation indicator (B3.1) as using more renewable electricity generation reduces non-GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The integration of renewable and low carbon hydrogen indicator (B3.2) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher emission factors, which reduces non-GHG emissions;

Since the interlinked benefit indicators are not monetised, double-counting is avoided.

This benefit indicator (B2) requires careful consideration if the assessed (group of) project(s) reduces curtailed hydrogen demand in the reference weather year: As curtailed hydrogen demand is not creating emissions in the DHEM, even electrolytic or low carbon hydrogen that satisfies hydrogen demand can increase emissions in comparison to hydrogen demand curtailment. Therefore, this benefit indicator (B2) underestimates the reduction of emissions enabled by a (group of) project(s) that reduces hydrogen demand curtailment under normal conditions. Therefore, the change of hydrogen demand curtailment under normal conditions is displayed as extra information under the increase of market rents indicator (B4).

This benefit indicator (B2) alone should not justify the societal viability of a project. Therefore, economic performance indicators (see section 4) will be prepared with and without consideration of this benefit indicator (B2).

3.2.5 B3.1: Integration of renewable electricity generation

DEFINITION	This benefit indicator (B3.1) measures the reduction of renewable electricity generation curtailment as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B3.1) > Considers the amount of electricity that is provided by RES; > Calculates the sum of all non-curtailed renewable electricity production within the EU; > Is expressed quantitatively in terms of energy (MWh/y); > Is not monetised, since it is already monetised as part of other benefit indicators.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B3.1) is interlinked with the GHG emissions variations indicator (B1), the non-GHG emissions variations indicator (B2), the integration of renewable electricity indicator (B3.2), the increase of market rents indicator (B4), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since this benefit indicator (B3.1) is not monetised, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM, the following formula is applied.

$$B3.1 = \sum_{i}^{n}\left(uncurtailed\ renewable\ electricity\ generation_{i,with\ (group\ of)\ project(s)}\right) - \sum_{i}^{n}\left(uncurtailed\ renewable\ electricity\ generation_{i,without\ (group\ of)\ project(s)}\right)$$

On the basis of:

- n: number of types of renewable generation.
- Uncurtailed renewable electricity generation: amount of uncurtailed electricity produced by RES of type i (MWh/y).

Example for a hypothetical hydrogen storage project

> - Case: The hydrogen storage project allows increased usage of renewable electricity production by providing a storage option for renewable energy in the form of hydrogen.
> - Non-monetised results of this benefit indicator (B3.1):
>   - Variation of renewable electricity generation: +1 TWh/y

This benefit indicator (B3.1) is interlinked with

- The GHG emissions variations indicator (B1) as using more renewable electricity generation reduces GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The non-GHG emissions variations indicator (B2) as using more renewable electricity generation reduces non-GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The integration of renewable and low carbon hydrogen indicator (B3.2) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources that are not renewable or low carbon;
- The increase of market rents indicator (B4) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors;
- The reduction in exposure to curtailed hydrogen demand indicator (B5) in case the integration of renewable electricity is also improved for the more stressful weather year used for the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5) and the additional renewable electricity can be used to produce electrolytic hydrogen that reduces hydrogen demand curtailment.

Therefore, this benefit indicator (B3.1) is not monetised to avoid double-counting.

3.2.6 B3.2: Integration of renewable and low carbon hydrogen

DEFINITION	This benefit indicator (B3.2) measures the increase of the production of electrolytic and low carbon hydrogen as well as the increase in the import of renewable and low carbon hydrogen as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B3.2) > Considers the production of electrolytic and low carbon hydrogen as well as the increase in the import of renewable and low carbon hydrogen; > Is expressed quantitatively in terms of energy (MWh/y); > Is not monetised, since it is already monetised as part of other benefit indicators.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B3.2) is interlinked with the GHG emissions variations indicator (B1), the non-GHG emissions variations indicator (B2), the integration of renewable electricity generation indicator (B3.1), the increase of market rents indicator (B4), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since this benefit indicator (B3.2) is not monetised, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied.

$$B3.2 = \begin{pmatrix} Electrolytic\ hydrogen\ production_{with\ (group\ of)\ project(s)} \\ +Low\ carbon\ hydrogen\ production_{with\ (group\ of)\ project(s)} \\ +\ Renewable\ hydrogen\ imports_{with\ (group\ of)\ project(s)} \\ +\ Low\ carbon\ hydrogen\ imports_{with\ (group\ of)\ project(s)} \end{pmatrix}$$
$$\begin{aligned} &-\big(Electrolytic\ hydrogen\ production_{without\ (group\ of)\ project(s)} \\ &+\ Low\ carbon\ hydrogen\ production_{without\ (group\ of)\ project(s)} \\ &+\ Renewable\ hydrogen\ imports_{without\ (group\ of)\ project(s)} \\ &+\ Low\ carbon\ hydrogen\ imports_{without\ (group\ of)\ project(s)}\big) \end{aligned}$$

On the basis of:

> Electrolytic hydrogen production: Hydrogen produced by electrolysers (MWh/y).

> Low carbon hydrogen production: Hydrogen produced from natural gas in combination with CCS (MWh/y).

- Renewable hydrogen imports: Hydrogen imported from supply sources that are considered to supply renewable hydrogen in the NT+ scenario (MWh/y), i.e., North Afrika, Ukraine, and imports by ship.
- Low carbon hydrogen imports: Hydrogen imported from supply sources that are considered to supply low carbon hydrogen in the NT+ scenario (MWh/y), i.e., Norway.

Example for a hypothetical hydrogen transmission project

- Case: Country A's domestic hydrogen market is already is fully satisfied. As it is not connected to other countries, this is limiting further usage of electrolytic hydrogen production. Country B's hydrogen demand is satisfied with unabated hydrogen production from natural gas. The hydrogen transmission project allows for exports from country A to country B. Thereby, it allows for increased usage of electrolytic hydrogen production in country A. In the importing country B, this reduces the usage of unabated hydrogen production from natural gas.
- Non-monetised results of this benefit indicator (B3.2):
    - Variation of relevant hydrogen production: +10 TWh/y

This benefit indicator (B3.2) is interlinked with

- The GHG emissions variations indicator (B1) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher CO_2 equivalent emission factors, which reduces GHG emissions;
- The non-GHG emissions variations indicator (B2) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher emission factors, which reduces non-GHG emissions;
- The integration of renewable electricity generation indicator (B3.1) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources that are not renewable or low carbon;
- The increase of market rents indicator (B4) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors;
- The reduction in exposure to curtailed hydrogen demand indicator (B5) in case the integration of renewable and low-carbon hydrogen is also improved for the more stressful weather year used for the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5) and can be used to reduce hydrogen demand curtailment.

Therefore, this benefit indicator (B3.2) is not monetised to avoid double-counting.

3.2.7 B4: Increase of market rents

DEFINITION	This benefit indicator captures the change in market rents as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator is defined as the sum of the short-run economic surpluses[38] of consumers, producers, transmission owners (congestion rent beneficiaries (transmission system operators for electricity, while other parties like producers, consumers, or shippers could benefit for hydrogen depending on the hydrogen market rules and commercial contracts),) and cross- sectoral rents beneficiaries (electrolysers). It considers both the electricity and the hydrogen sector. > This indicator is directly expressed in monetized terms (€/y).
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B4) is interlinked with the GHG emissions variations indicator (B1), the integration of renewable electricity generation indicator (B3.1), the integration of renewable and low carbon hydrogen indicator (B3.2), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since the interlinked benefit indicators are either not monetized or the potentially mutual benefits are removed, double-counting is avoided.

In the DEHM, the sum of the market rents is defined with the total surplus approach that is further detailed in Annex VI. Investments in production capacities, transmission capacities, import capacities, and storage solutions typically increase the sum of these surpluses as they enable to match the demand with cheaper supply sources.

The sum of all market rents along the sectors S є {electricity, hydrogen} is calculated as follows based on the outputs of the objective function of the DHEM:

$$Market\ rents_{global} = \sum_{j\epsilon S} R^{j}_{consumer} + \sum_{j\epsilon S} R^{j}_{producer} + \sum_{j\epsilon S} R^{j}_{storage} + \sum_{j\epsilon S} R^{j}_{congestion} + R^{electricity\leftrightarrow hydrogen}_{cross-sector}$$

[38] ‘Surplus’ and ‘rent’ are used interchangeably.

On the basis of:
- $R^{j}_{consumer}$ is the consumer rent of sector j ϵ S.
- $R^{j}_{producer}$ is the producer rent of sector j ϵ S.
- $R^{j}_{storage}$ is the storage rent of sector j ϵ S.
- $R^{j}_{congestion}$ is the congestion rent of sector j ϵ S.
- $R^{electricity\leftrightarrow hydrogen}_{cross-sector}$ is the cross-sector rent stemming from the interlinkage between electricity and hydrogen sector.

Any component c ϵ C of the energy system that introduces a coupling between the electricity and the hydrogen sector (i.e., electrolysers and hydrogen-based power plants) belongs to a certain electricity bidding zone with a timestep-specific market clearing price for electricity and to a certain hydrogen market area with a timestep-specific market clearing price for hydrogen. The cross-sector rent is dependent on the price difference and is summed up over all timesteps t ϵ T (e.g., each hour of a year) by applying the following formula:

$$R^{electricity\leftrightarrow hydrogen}_{cross-sector} = \sum_{t\epsilon T}\sum_{c\epsilon C}\left|mcp^{c,t}_{hydrogen} * p^{c,t}_{cross-sector,hydrogen} - mcp^{c,t}_{electrictiy} * p^{c,t}_{cross-sector,electricity}\right|$$

On the basis of:
- $mcp^{c,t}_{hydrogen}$ is the market clearing price of hydrogen in the hydrogen market area of component c at timestep t.
- $mcp^{c,t}_{electricity}$ is the market clearing price of electricity in the electricity bidding zone of component c at timestep t.
- $p^{c,t}_{cross-sector,hydrogen}$ and $p^{c,t}_{cross-sector,electricity}$ denote the component’s output or input power reference to the hydrogen and electricity side, respectively. These powers are different as they are coupled with the component’s efficiency for the conversion from one energy carrier into another.

The producer rent for sector j ϵ S is composed of the contributions of the production components c ϵ P (e.g., coal fired-power plants generating electricity, or SMR producing hydrogen) and is described by the following formula:

$$R^{j}_{producer} = \sum_{t\epsilon T}\sum_{c\epsilon G}\left(mcp^{c,t}_{j} - marginalCost^{c}\right) * p^{c,t}_{generation,j}$$

On the basis of:

- $marginalCost^{c}$ is the marginal cost of the production asset type associated with component c ϵ P. The marginal cost includes the ETS-related costs of associated direct GHG emissions based on the ETS price forecast used in the NT+ scenario.
- $mcp_{j}^{c,t}$ is the market clearing price at time step t ϵ T at the corresponding market area of sector j ϵ S.
- $p_{production,j}^{c,t}$ is the energy output of component c ϵ G of sector j ϵ S at timestep t ϵ T.

The storage rent for sector j ϵ S is composed of the contributions from the storage components c ϵ ST (e.g., batteries storing electricity, or hydrogen underground storages storing hydrogen) that contains the benefits of arbitrage and is described by the following formula:

$$R_{storage}^{j} = \sum_{t \epsilon T} \sum_{c \epsilon ST} (mcp_{j}^{c,t} * p_{from\ storage,j}^{c,t} - mcp_{j}^{c,t} * p_{into\ storage,j}^{c,t})$$

On the basis of:

- $p_{into\ storage,j}^{c,t}$ is the energy flow that is sent into the storage component c ϵ ST of sector j ϵ S at timestep t ϵ T. Its sum over all timesteps T is typically bigger than the sum of $p_{from\ storage,j}^{c,t}$ over all timesteps T, as the storage component c ϵ ST is coupled with the efficiency of its storage asset type.

The consumer rent is determined by the following formula:

$$R_{consumer}^{j} = \sum_{t \epsilon T} \sum_{c \epsilon L} (elasticity^{c} - mcp_{j}^{c,t}) * p_{consumption,j}^{c,t}$$

On the basis of:

- $elasticity^{c}$ is the strike price level for which a consumer or a demand side response (DSR) component c ϵ L is willing to buy energy from the markets.

The congestion rent for sector j ϵ S is summed up over i) all components c ϵ TR that provide capacity between two market areas of the same sector and ii) all timesteps t ϵ T by the following formula:

$$R_{congestion}^{j} = \sum_{t \epsilon T} \sum_{c \epsilon TR} \left| (mcp_{j}^{side\ 1,t} - mcp_{j}^{side\ 2,t}) * p_{exchange,j}^{c,t} \right|$$

On the basis of:

- $mcp_{j}^{side\ 1,t} - mcp_{j}^{side\ 2,t}$ is the difference between the market clearing prices of the two market areas of sector j ϵ S linked my component c ϵ TR at timestep t ϵ T.

> $p^{c,t}_{exchange,j}$ is the energy flow between the two market areas of sector j ϵ S linked by component c ϵ TR at timestep t ϵ T.

The market rents are derived from the results of the objective function of the DHEM. The market rents approach allows for a decomposition in order to consider the cross-sectoral links between the electricity and hydrogen systems and to be able to, in principle, allocate benefits to individual countries or to a group of countries.

$$DMarket\ rents_{global} = Market\ rents_{global,with\ (group\ of)project(s)} - Market\ rents_{global,without\ (group\ of)project(s)}$$

By default, this benefit indicator (B4) only considers the rents of the hydrogen sector as well as the cross-sector rents between the electricity sector and the hydrogen sector.

This benefit indicator (B4) is interlinked with:

> The GHG emissions variations indicator (B1) which also includes a monetisation of the GHG emissions (see section 3.2.3Error! Reference source not found.). Therefore, the GHG emissions costs that are monetised in this benefit indicator (B4) are removed from the GHG emissions variations indicator (B1) to avoid double-counting;

> The integration of renewable electricity generation indicator (B3.1) and the integration of renewable and low carbon hydrogen indicator (B3.2) as reduced curtailment of renewable electricity generation is acting on all three indicators. This is because reduced curtailment of renewable electricity generation can replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors.

Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

Under this benefit indicator (B4), additional information can be provided:

> Reduction of hydrogen demand curtailment (HDC) enabled by a (group of) project(s) without stress cases to indicate its contribution to security of hydrogen supply under normal conditions and to judge if the GHG emissions variation indicator (B1) and the non-GHG emissions variation indicator (B2) are underestimating the respective benefits of the (group of) project(s);

> The change of the market rents of the electricity sector as an externality of the implementation of the (group of) project(s).

3.2.8 B5: Reduction in exposure to curtailed hydrogen demand

DEFINITION	This benefit indicator (B5) measures the reduction of curtailed hydrogen demand in a given area due to the implementation of the (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B5) > Is calculated under consideration of a more stressful weather year than the reference weather year used for the other benefit indicators; > In a first step, the DHEM is used to calculate the hydrogen demand curtailment (HDC) in energetic terms (MWh) for the stressful weather year; > In a second step, the DHEM is used to calculate the HDC in energetic terms (MWh) for the reference weather year; > In a third step, the HDC value provided by the third step is removed from the higher HDC value as provided by the first two steps to remove double-counting with other benefit indicators that use the reference weather year; > Can also be expressed in monetised terms (€/y), by applying assumptions on the CODH, and an assumed frequency of the occurrence of such stressful weather years.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	No interlinkage, as other benefit indicators are calculated based on the reference weather year and the HDC of the reference weather year is removed from this benefit indicator (B5).

In contrast to the natural gas sector, currently no dedicated EU law exists for the security of hydrogen supply which would set infrastructure standards or prescribe solidarity mechanisms between Member States. This benefit indicator (B5) is therefore less strict than the security of supply assessments that are performed for natural gas and that consider the prolonged unavailability of major supply sources or infrastructures.

While the climate year used for the calculation of the other benefit indicators is supposed to be a representative one, this benefit indicator (B5) is calculated on the basis of another weather year which is more stressful due to

> Lower renewable electricity production (limiting the possibility to produce electrolytic hydrogen) including
  - Onshore and offshore wind profiles,
  - PV profiles,
  - Water-based profiles; or

- Higher electricity consumption (limiting the availability of electricity for electrolytic hydrogen production), e.g. for heat pumps or air conditioning; or
- A combination of cases described above.

Thereby, the supply and demand stress tests the availability of alternatives like SMR capacities, hydrogen storage capacities, hydrogen import capacities through terminals and pipelines, and inner-EU hydrogen interconnection capacities.

This benefit indicator captures the mitigation of additional hydrogen demand curtailment introduced by the (group of) project(s) for the stressful weather year compared to the reference weather year.

In a first step, the **Hydrogen Demand Curtailment (HDC)** is calculated for the whole assessed duration in energetic terms (MWh) with the DHEM. It can be displayed on node level, country level, EU level, or European level. It can also be displayed in relative terms (%) as **Hydrogen Curtailment Rate (HCR)** for the mentioned levels, representing the share of total demand that is curtailed. The HDC is calculated for the stressful weather year as well as for the reference weather year. For each of the two weather years, the HDC is calculated with and without the (group of) project(s). From this, a reduction of HDC due to the implementation of the (group of) project(s) can be calculated.

$$\begin{aligned} DHDC_{DHEM,stress\ year} &= HDC_{DHEM,European\ Union,stress\ year,with\ (group\ of)\ project(s)} \\ &- HDC_{DHEM,European\ Union,stress\ year,without\ (group\ of)\ project(s)} \end{aligned}$$

The DHEM is using hourly timesteps compared to the monthly timesteps of the DGM. Therefore, peaks of production and consumption show more effect in the DHEM.

Furthermore, a double-counting of HDC reductions that were already considered in the other benefit indicators should be avoided by considering only the additional HDC arising from the stressful weather year. This can be achieved by removing the following HDC reduction that is enabled for the reference weather year.

$$DHDC_{DHEM,reference\ year} = (HDC_{DHEM,European\ Union,reference\ year,with\ (group\ of)\ project(s)} - HDC_{DHEM,European\ Union,reference\ year,without\ (group\ of)\ project(s)})$$

The none-monetised benefit indicator is therefore defined as follows:

$$DHDC_{B5} = MAX\left(DHDC_{DHEM,stress\ year}\right) - DHDC_{DHEM,reference\ year}$$

This benefit indicator can then be monetised as follows:

$$B5_{monetised} = CODH * DHDC_{B5} * Probability\ of\ occurence$$

On the basis of:

> CODH: Cost of Disrupted Hydrogen (€/MWh).

> Probability of occurrence: Probability of the occurrence of a stressful weather year.

Cost of Disrupted Hydrogen (CODH)

As requested by ACER opinion No 13/2025, and ACER Opinion No 08/2023 it should analyse industrial demand.
ACER opinion No 13/2025: “*ACER notes that ENTSOG took into account the comments received in the consultation for defining the Cost of Disrupted Hydrogen (CoDH) value. Still, ACER notes that the value used, which is based on the maximum value of daily average wholesale electricity prices from 2022 and 2023, seems high (i.e. 598.1 €/MWh). Hence, also considering that only one stakeholder provided feedback on this topic during the consultation, ACER recommends ENTSOG to conduct a study to define a methodology for quantifying hydrogen disruption costs.”*

The CODH should reflect the potential economic impacts of disruptions in hydrogen supply across Europe. In contrast to the Willingness to Pay (CBA Methodology Chapter 3, Subchapter XXX of the Annex D1) which should leave room for an actual producer surplus, the CODH is the price that users would pay to prevent damage to their appliances and/or the price that a user would pay in exceptional situations.

For the TYNDP 2026 PS-CBA process, ENTSOG proposes to assume CODH value as an approximation equal to the electricity prices in a context of tight energy supply and demand balance. CODH will be defined as the maximum value of daily average wholesale electricity prices from 2022 (i.e. 598,1 (€/MWh), for more details see Annex III). The final value is to be decided according to the outcome of the Public Consultation of the TYNDP 2026 Implementation Guidelines.

Stressful weather year and probability of occurrence

For the TYNDP 2026 PS-CBA process, ENTSOG proposes to consider two weather scenarios for each target year, namely one weather scenario base case and a more stressful weather scenario. Climate data and probabilities of occurrence will be delivered timely.

3.3 Environmental impact

Hydrogen infrastructure has an impact on its surroundings, particularly when crossing environmentally sensitive areas such as Natura 2000, with relevance for biodiversity. Promoters take mitigation measures to reduce or fully mitigate this impact and to comply with the EU EIA Directive and the European Commission Biodiversity Strategy. All inputs on the environmental impact are shown in the CBA Methodology, in Chapter 3.2 .

3.4 Climate Adaption Measures

Hydrogen infrastructure is long-lasting and may be exposed for many years to a changing climate with increasingly adverse and frequent extreme weather and climate impacts. In the TYNDP 2026 PS-CBA process, ENTSOG recommends that project promoters assess climate vulnerability and identify related climate risks as part of the project assessment. In line with the European Commission Technical Guidance on the climate proofing of infrastructure in the period 2021–2027, ENTSOG recommends integrating the assessment of climate vulnerability and related risk assessment from the beginning of the project development process. All details for this process can be assessed in our CBA Methodology in Chapter 3.2.

As lined out in the CBA Methodology Chapter 3.2, project promoters are asked to identify potential climate risks that may impact the project and to evaluate the related risks based on sensitivity, exposure and vulnerability analysis. If significant climate risk is identified, promoters should provide a climate risk assessment and impact analysis, including the identification of climate adaptation measures that will be included in the project cycle. The exact definition of climate adaption measures is available in the TEN-E Regulation.

3.5 Project costs

Costs represent an inherent element of a PS-CBA analysis. According to Annex V (8) of the TEN-E Regulation, the CBA "*shall, at least, take into account the following costs: capital expenditure, operational and maintenance expenditure costs, as well as the costs induced for the related system over the technical lifecycle of the project as a whole, such as decommissioning and waste management costs, including external costs*".

Investment costs are therefore classified[39] by:

> Capital expenditure (CAPEX)

[39] This classification is in line with the EC Guide to Cost-Benefit Analysis of Investment Projects (https://jaspers.eib.org/LibraryNP/EC%20Reports/Economic%20Appraisal%20Vademecum%202021-2027%20-%20General%20Principles%20and%20Sector%20Applications.pdf).

- **Initial investment cost**, that corresponds to the cost effectively incurred by the promoter to build and start operation of the concerned infrastructure. CAPEX should consider the costs related to obtaining permits, feasibility studies, obtaining rights-of-way, groundwork, preparatory work, designing, equipment purchase, equipment installation and decommissioning.
- Costs already incurred at the time of running the project cost-benefit analysis should be generally considered in the assessment, while in case of expansion projects only the costs related to the expansion should be taken into account since the costs incurred before already allowed the project to be functional.

> **Operational and maintenance expenditure** (OPEX) corresponds to costs that are incurred after the commissioning of an asset and which are not of an investment nature, such as direct operating and maintenance costs, administrative and general expenditures, etc.

Where a part of the OPEX is calculated by the model, e.g., energy costs[40], it is already included in the calculated benefits. When calculating the economic performance indicators, to avoid double-counting of these costs, the respective part of the OPEX as submitted directly by the project promoter is removed from the costs.

All cost data should be considered at constant (real) prices. As part of the TYNDP 2026, constant (real) prices shall refer to 2025, based on the project collection being completed in 2025. This is based on the Methodology for Cost-Benefit-Analyses, published in 2025.

Unit investment costs for hydrogen infrastructure may be used for comparison. ACER is required to establish such unit investment costs based on Article 11(9) of the TEN-E Regulation.

[40] Example: In the DHEM, the injection into hydrogen storages is associated with a consumption of energy. For the consumed energy, the actual market clearing price is assumed in the model. Thereby, these energy costs are already included in the benefit indicators.[41] https://www.entsog.eu/sites/default/files/2025-10/entsog_CBA_methodology_report_250225.pdf

4. Economic performance indicators

Economic performance indicators assess project costs alongside monetised benefits and depend on parameters such as the assessment period, residual value, discount rate, and the timing of costs and benefits. Consistent economic parameters are required across all PS-CBA assessments.

For TYNDP 2026, ENTSOG uses two indicators: **Economic Net Present Value (ENPV)** and **Economic Benefit-to-Cost Ratio (EBCR)**. Because the PS-CBA applies a multi-criteria approach and not all benefits can be monetised, these indicators reflect only part of the overall cost–benefit balance.

For multi-phase projects, annual benefits and OPEX are counted from the commissioning of the first phase. For project groups—regardless of infrastructure type—economic indicators are calculated jointly, combining the full costs and total monetised benefits for the entire group. All details can be found in the CBA Methodology in Chapter 5.[41]

5. Sensitivity Analysis

Sensitivity analyses assess how changes in individual parameters—or sets of linked parameters—affect PS-CBA results, helping to understand how the system responds to these variations. All details can be found in the CBA methodology, Chapter 4.

For TYNDP 2026, sensitivities are performed on:

- **Societal cost of carbon:** Varies the carbon cost and re-monetises the GHG emissions indicator (B1), affecting economic indicators. No new simulations are needed.

  The B1 indicator is defined as followed:

[41] https://www.entsog.eu/sites/default/files/2025-10/entsog_CBA_methodology_report_250225.pdf

$$
\begin{aligned}
&\Delta GHG\ emissions\ enabled\ by\ (group\ of)project(s) \\
&\quad = \Big(\sum_i^n \big(power\ generation_{i,with\ (group\ of)project(s)} * CO_{2-eq}emission\ factor_i\big) \\
&\quad + \sum_j^m \big(hydrogen\ production_{j,with\ (group\ of)project(s)} \\
&\quad * CO_{2-eq}emission\ factor_j\big) \\
&\quad + \sum_l^r \big(hydrogen\ import\ from\ supply\ potential_{l,with\ (group\ of)project(s)} \\
&\quad * CO_{2-eq}emission\ factor_l\big) \\
&\quad + \sum_i^s \big(Curtailed\ energy_{i,with\ (group\ of)project(s)} * CO_{2-eq}emission\ factor_i\big)\Big) \\
&- \Big(\sum_i^n \big(power\ generation_{i,without\ (group\ of)project(s)} * CO_{2-eq}emission\ factor_i\big) \\
&\quad + \sum_j^m \big(hydrogen\ production_{j,without\ (group\ of)project(s)} \\
&\quad * CO_{2-eq}emission\ factor_j\big) \\
&\quad + \sum_l^r \big(hydrogen\ import\ from\ supply\ potential_{l,without\ (group\ of)project(s)} \\
&\quad * CO_{2-eq}emission\ factor_l\big) \\
&\quad + \sum_i^s \big(Curtailed\ energy_{i,without\ (group\ of)project(s)} * CO_{2-eq}emission\ factor_i\big)\Big)
\end{aligned}
$$

- **Damage cost of non-GHG emissions:** Varies between VSL and VOLY approaches, re-monetising indicator (B2) and influencing economic indicators. No new simulations required.
- **Cost of Disrupted Hydrogen (CODH):** Varies assumed CODH values, re-monetising indicator (B5) and potentially affecting economic indicators. The final values will be assessed in the stakeholder consultation phase.
- **Project-specific data:**
    - *CAPEX/OPEX ranges:* Uses high/low cost ranges from promoters; influences only economic indicators.
    - *Assessment period (40 vs. 25 years):* Extends costs and benefits over time; influences economic indicators.
    - *Cash-flow interpolation beyond modelled years (2035/2040):* Either continues the trend after 2040 or freezes benefits at the 2040 value; affects non-modelled-year benefits and thus economic indicators.

- *Projects with Commissioning Year beyond the analysed target year 2040:* For projects where the default case results in a value of zero due to a commissioning year past 2040, we anticipate shifting the commissioning year of the project increment to 2040 in order to demonstrate a flat benefit[42] for the second target year of the PS-CBA.

Across all cases, sensitivities rely on re-processing existing results rather than running new simulations.

[42] "Flat benefit" refers to a projected benefit profile that does not change over time—i.e., it remains constant across the analysis horizon. By moving the commercial year to 2040, the model effectively displays a steady, non-increasing and non-decreasing benefit, rather than showing a zero outcome in earlier years.

6. Energy Efficiency First Principle

In the energy efficiency first principle guidelines that are annexed to the European Commission Recommendation (EU) 2021/1749 of 28 September 2021[43], the principle's application in the TYNDP is detailed as follows:

> *"The TEN-E [Regulation] includes the EE1st principle in all the stages of the European ten-Year Network Development Plans development, more specifically in the scenario development, infrastructure gaps identification and projects assessment. […] The practical implication of the EE1st principle in the planning means that the infrastructure development must include within the decisional process options to better utilise the existing infrastructure (by operational mechanisms), implement more energy-efficient technologies, and make better use of the market mechanisms such as, but not exclusive to, demand-side response. […] When implementing the EE1st principle, one must strive to reach the balance between secure and reliable energy supply, quality of energy supplied and overall associated costs […]."*

Annex III.2(12) of the TEN-E Regulation thereby lists four priority solutions for the application of the energy efficiency first principle that should be considered instead of the construction of new supply side infrastructure, if considered more cost-efficient from a system wide perspective: i) Demand-side management; ii) market arrangement solutions; iii) implementation of digital solutions; iv) renovation of buildings. All points can be found int the CBA methodology, Chapter 6.[44]

6.1 Consideration of the energy efficiency first principle in the NT+ scenario development for PS-CBA

In the NT+ scenario, the energy efficiency first principle was considered in the following ways:

- Inclusion of options for better utilisation of existing infrastructure
    - The existing infrastructure considered in the scenario topology is updated for each scenario cycle with information that is provided by the infrastructure operators and/or publicly consulted. This provides the option to update the underlying energy infrastructure capacities. The capacities are the main parameter capturing the ability of better utilisation through operational improvements, including by digital solutions. Additionally, the consideration of infrastructure of multiple energy carriers, such as hydrogen and electricity allows an optimisation of the utilisation of the existing infrastructure's capacities in the model, through flexibility provisions across energy sectors.

[43] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32021H1749[44]
https://www.entsog.eu/sites/default/files/2025-10/entsog_CBA_methodology_report_250225.pdf
[44] https://www.entsog.eu/sites/default/files/2025-10/entsog_CBA_methodology_report_250225.pdf

- Inclusion of options to include more energy-efficient technologies
    - The NT+ scenario is developed on an NECP-based scenario storyline. Within the NT+ scenario development, energy-efficient technologies are set at ambitious levels based on the NECPs, EU energy and climate targets, or infrastructure operator inputs in combination with stakeholder consultations. The renovation of buildings is also included in the set of assumptions at a highly ambitious level.
- Inclusion of options to make better use of the market mechanisms
    - By considering perfect competition only limited by infrastructure constraints between zones being represented as nodes (e.g., hydrogen zone 1 of a country, hydrogen zone 2 of a country, or individual electricity bidding zones) as well as by allowing demand side response to be acting without infrastructure or market restrictions (e.g., if the demand side response is located at DSO level) within a whole zone, the market behaviour is optimistic regarding the effects of demand side management. Several demand side responses are thereby considered like optimised utilisation of :
        - assets coupling the sectors through conversion (i.e., electrolysers and hydrogen-fired power plants);
        - demand shedding (e.g., reduction of industrial demand for a limited time that is triggered by a certain market clearing price).
- Aiming at balancing security of supply, quality of energy supplied, and cost-efficiency
    - The wider benefits of investments including energy efficiency measures and infrastructure developments are addressed from a system efficiency perspective within the scenario modelling by
        - monetising unserved energy demand (i.e., VoLL and CODH);
        - including adequacy loops;
        - penalising energy losses contributing negatively to life cycle efficiencies (e.g., reflection in marginal costs of fuels, conversion losses of electrolysers, conversion losses of power plants, efficiencies of energy storages);
        - penalising of emissions (e.g., cross-checking with the EU's legal energy and climate targets and reflection in marginal costs of fuels).
    - In line with the energy efficiency first principle, the most energy efficient solution does not have to prevail but should be considered within the decision making process and be preferred if being similarly cost-efficient, and beneficial for security of supply.

> ANNEX I: List of projects conforming hydrogen and infrastructure levels[45]

List of hydrogen projects included in the PCI/PMI hydrogen infrastructure level:

Code		*Project Name*	*Country*	*Promoter*	*Maturity Status*	*Project Commissioning Year First*	*Project Commissioning Year Last*
H2T-N-1239	PCI	**Nordic-Baltic Hydrogen Corridor - LT section**	Lithuania	AB Amber Grid	Less-Advanced	2033	2033
H2T-A-991	PCI	**AquaDuctus**	Germany	AquaDuctus Pipeline GmbH	Advanced	2030	2040
H2T-F-642	PCI	**HyPipe Bavaria – The Hydrogen Hub**	Germany	bayernets GmbH	FID	2029	2030
H2T-N-788	PCI	**H2 transmission system in Bulgaria**	Bulgaria	Bulgartransgaz EAD	Less-Advanced	2032	2032
H2T-N-1280	PCI	**Nordic-Baltic Hydrogen Corridor - LV section**	Latvia	Conexus Baltic Grid, JSC	Less-Advanced	2033	2033
H2T-F-987	PCI	**mosaHYc (Mosel Saar Hydrogen Conversion) - Germany**	Germany	Creos Deutschland Wasserstoff GmbH	FID	2029	2029
H2T-N-1294	PCI	**HY4Link**	Luxemburg	Creos Luxembourg Hydrogen S.A.	Less-Advanced	2032	2035
H2T-N-706	PCI	**Komnina-Florovouni H2 Pipeline**	Greece	DESFA S.A.	Less-Advanced	2035	2036
H2T-N-970	PCI	**Internal hydrogen infrastructure in Greece towards the Bulgarian border**	Greece	DESFA S.A.	Less-Advanced	2032	2040
H2T-N-1122	PCI	**Nordic-Baltic Hydrogen Corridor - EE section**	Estonia	Elering AS	Less-Advanced	2033	2033
H2S-A-508	PCI	**H2 storage North-1**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2034

[45] As the Annex A for TYNDP 2026 is not yet finalized the fully corrected overview of the projects will be added at a later point in time.

H2T-A-1149	PCI	**Spanish Hydrogen Backbone 2030**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2032
H2S-A-1152	PCI	**H2 storage North-2**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2040
H2T-N-1324	PCI	**H2Med-CelZa (Enagás)**	Spain	Enagás Infraestructuras de Hidrógeno	Less-Advanced	2032	2032
H2T-N-1151	PCI	**H2Med-BarMar**	Spain	Enagás Infraestructuras de Hidrógeno/Terega/Natran/Open Grid Europe	Less-Advanced	2032	2032
H2T-A-1236	PCI	**DK Hydrogen Pipeline, West DK Hydrogen System**	Denmark	Energinet	Advanced	2029	2035
H2S-N-1238	PCI	**DK Hydrogen Storage**	Denmark	Energinet	Less-Advanced	2033	2033
H2S-A-1279	PCI	**Hystock Opslag H2**	Netherlands	EnergyStock B.V, an affiliate of N.V.Nederlandse Gasunie	Advanced	2030	2033
H2T-N-835	PCI	**SK-HU H2 corridor**	Slovakia	eustream, a.s.	Less-Advanced	2032	2032
H2T-N-1264	PCI	**Slovak Hydrogen Backbone**	Slovakia	eustream,a.s.	Less-Advanced	2032	2032
H2S-A-749	PCI	**CHC Hydrogen Storage Expansion Huntorf**	Germany	EWE GASSPEICHER	Advanced	2029	2029
H2S-A-761	PCI	**CHC Hydrogen Storage Jemgum**	Germany	EWE GASSPEICHER	Advanced	2029	2032
H2S-N-574	PCI	**EWE Hydrogen Storage Ruedersdorf**	Germany	EWE GASSPEICHER	Less-Advanced	2032	2032
H2T-A-1206	PCI	**HU/SK hydrogen corridor**	Hungary	FGSZ Ltd.	Advanced	2032	2032
H2T-N-1286	PCI	**Alpine H2 Corridor**	Switzerland	Fluxswiss sagl	Less-Advanced	2035	2045
H2T-F-725	PCI	**Belgian Hydrogen Backbone - Interconnection BE-NL (Zandvliet & Zelzate)**	Belgium	Fluxys Hydrogen NV/SA	FID	2030	2032
H2T-A-708	PCI	**Belgian Hydrogen Backbone - Interconnection BE-DE**	Belgium	Fluxys Hydrogen NV/SA	Advanced	2029	2029
H2T-A-1399	PCI	**Belgian Hydrogen Backbone - Tie-in Antwerp NH3 Terminals**	Belgium	Fluxys Hydrogen NV/SA	Advanced	2029	2033

H2T-N-709	PCI	**Belgian Hydrogen Backbone - Interconnection BE-UK**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2045
H2T-N-710	PCI	**Belgian Hydrogen Backbone - Interconnection BE-FR (Blaregnies)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-711	PCI	**Belgian Hydrogen Backbone - Interconnection BE-FR (Alveringem)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-726	PCI	**Belgian Hydrogen Backbone - Interconnection BE-NL (Gravenvoeren)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-1372	PCI	**Belgian Hydrogen Backbone - Interconnection BE-LUX**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2035
H2T-N-1373	PCI	**Belgian Hydrogen Backbone - Zeebrugge import**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2035
H2L-N-820	PCI	**Dunkerque New Molecules development**	France	Fluxys NV/SA	Less-Advanced	2035	2035
H2L-N-1325	PCI	**Zeebrugge New Molecules development**	Belgium	Fluxys NV/SA	Less-Advanced	2035	2035
H2L-N-664	PCI	**Antwerp NH3 Import Terminal**	Belgium	Fluxys NV/SA and Advario	Less-Advanced	2032	2032
H2T-N-740	PCI	**Alpine HyWay**	Germany	Fluxys TENP GmbH and Open Grid Europe GmbH	Less-Advanced	2035	2045
H2T-A-757	PCI	**H2 Backbone WAG + Penta West**	Austria	GAS CONNECT AUSTRIA GmbH	Advanced	2031	2031
H2T-A-796	PCI	**Flow - Making Hydrogen Happen (East)**	Germany	GASCADE Gastransport GmbH	Advanced	2026	2037
H2T-N-1315	PCI	**H2 interconnection DE-PL**	Germany	GASCADE Gastransport GmbH	Less-Advanced	2034	2034
H2T-A-1136	PCI	**Nordic Hydrogen Route – Bothnian Bay – FI section**	Finland	Gasgrid vetyverkot Oy	Advanced	2029	2029
H2T-N-443	PCI	**Nordic-Baltic Hydrogen Corridor - FI section**	Finland	Gasgrid vetyverkot Oy	Less-Advanced	2032	2033
H2T-N-1355	PCI	**The Baltic Sea Hydrogen Collector (BHC) – Section A**	Finland	Gasgrid vetyverkot Oy, Copenhagen Energy Islands ApS, GASCADE Gastransport	Less-Advanced	2032	2032

H2T-N-1389	PCI	**The Baltic Sea Hydrogen Collector (BHC) - Section B**	Finland	Gasgrid vetyverkot Oy, Nordion Energi H2, Copenhagen Energy Islands ApS	Less-Advanced	2034	2034
H2T-F-1000	PCI	**Hyperlink**	Germany	Gasunie Deutschland Transport Services GmbH	FID	2029	2033
H2T-A-1001	PCI	**Danish-German Hydrogen Network; German Part - HyPerLink Phase III**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2029	2035
H2T-A-933	PCI	**Hyperlink 4**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2029	2032
H2S-N-671	PCI	**Gasunie SpHyGER Etzel (GSE)**	Germany	Gasunie Energy Solutions 1 GmbH	Less-Advanced	2032	2032
H2T-N-779	PCI	**Pomeranian Green Hydrogen Cluster**	Poland	GAZ-SYSTEM S.A.	Less-Advanced	2034	2034
H2T-N-1144	PCI	**Nordic-Baltic Hydrogen Corridor - PL section**	Poland	GAZ-SYSTEM S.A.	Less-Advanced	2033	2033
H2S-N-565	PCI	**GeoH2**	France	Géométhane	Less-Advanced	2032	2032
H2T-F-1366	PCI	**Dutch Hydrogen Network - DRC**	Netherlands	Hynetwork Services B.V.	FID	2028	2039
H2T-A-1365	PCI	**Dutch Hydrogen Network - North West**	Netherlands	Hynetwork Services B.V.	Advanced	2030	2042
H2T-A-693	PCI	**Dutch Hydrogen Network - North East**	Netherlands	Hynetwork services B.V.	Advanced	2026	2037
H2T-A-694	PCI	**Dutch Hydrogen Network - South West**	Netherlands	Hynetwork services B.V.	Advanced	2030	2032
H2T-N-1137	PCI	**Central European Hydrogen Corridor (UKR part)**	Ukraine	LLC Gas TSO of Ukraine	Less-Advanced	2032	2032
H2T-N-573	PCI	**UK-BE H2 Interconnector**	Belgium	National Gas & Fluxys NV/SA	Less-Advanced	2035	2045
H2T-N-572	PCI	**PU East to H2 Interconnector**	United Kingdom	National Gas Transmission	Less-Advanced	2035	2045
H2T-F-899	PCI	**mosaHYc - Mosel Saar Hydrogen Conversion**	France	NaTran	FID	2029	2029
H2T-A-969	PCI	**RHYN**	France	NaTran	Advanced	2030	2033

H2T-N-569	PCI	**HY-FEN – H2 Corridor Spain – France – Germany connection**	France	NaTran	Less-Advanced	2032	2032
H2T-N-667	PCI	**MidHY**	France	NaTran	Less-Advanced	2032	2032
H2T-N-909	PCI	**Connexion HY-FEN-GeoH2**	France	NaTran	Less-Advanced	2032	2032
H2T-N-1035	PCI	**Franco-Belgian H2 corridor**	France	NaTran	Less-Advanced	2034	2035
H2T-N-1187	PCI	**HY4Link (FR)**	France	NaTran	Less-Advanced	2032	2034
H2T-N-1017	PCI	**H2Poseidon Pipeline**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Less-Advanced	2034	2036
H2L-N-932	PCI	**Ionian Energy Terminal**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A.	Less-Advanced	2034	2034
H2T-N-1251	PCI	**Czech H2 Backbone NORTH**	Czechia	NET4GAS, s.r.o.	Less-Advanced	2032	2032
H2T-A-1034	PCI	**Czech H2 Backbone WEST**	Czechia	NET4GAS,s.r.o.	Advanced	2030	2030
H2T-A-926	PCI	**Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Sweden**	Sweden	Nordion Energi H2 AB	Advanced	2029	2029
H2T-A-1171	PCI	**Nordic Hydrogen Route – Bothnian Bay (SE)**	Sweden	Nordion Energi H2 AB	Advanced	2030	2030
H2S-N-861	PCI	**NWKG H2 Storage**	Germany	Nord-West Kavernengesellschaft mbH	Less-Advanced	2029	2036
H2T-N-1310	PCI	**Nordic-Baltic Hydrogen Corridor - DE section**	Germany	ONTRAS Gastransport GmbH	Less-Advanced	2033	2033
H2T-F-1038	PCI	**H2ercules Network West**	Germany	Open Grid Europe GmbH	FID	2028	2028
H2T-A-738	PCI	**Delta Rhine Corridor H2 Germany North**	Germany	Open Grid Europe GmbH	Advanced	2030	2030
H2T-A-1037	PCI	**H2ercules Network North**	Germany	Open Grid Europe GmbH	Advanced	2027	2036
H2T-A-1075	PCI	**H2ercules Network North-West**	Germany	Open Grid Europe GmbH	Advanced	2031	2031

H2T-N-1052	PCI	**H2ercules Network South-West**	Germany	Open Grid Europe GmbH; NaTran Deutschland GmbH	Less-Advanced	2032	2032
H2T-N-1055	PCI	**H2ercules Network South-East**	Germany	Open Grid Europe GmbH; NaTran Deutschland GmbH	Less-Advanced	2032	2032
H2T-N-978	PCI	**Portuguese Hydrogen Backbone**	Portugal	REN - Gasodutos, S.A.	Less-Advanced	2032	2032
H2T-N-1156	PCI	**H2Med/CelZa**	Portugal	REN - Gasodutos, S.A.	Less-Advanced	2032	2032
H2S-A-767	PCI	**RWE H2 Storage expansion Gronau-Epe**	Germany	RWE Gas Storage West GmbH	Advanced	2030	2030
H2S-A-1287	PCI	**RWE H2 Storage Gronau-Epe - 2nd expansion**	Germany	RWE Gas Storage West GmbH	Advanced	2030	2030
H2T-A-735	PCI	**North Africa Hydrogen Corridor**	Tunisia	Sea Corridor S.r.l.	Advanced	2031	2034
H2T-N-1023	PCI	**Italian H2 Backbone (Poggio Renatico - P. Gries)**	Italy	Snam Rete Gas S.p.A	Less-Advanced	2034	2034
H2T-A-1205	PCI	**Italian H2 Backbone**	Italy	Snam Rete Gas S.p.A.	Advanced	2031	2034
H2S-A-1189	PCI	**Fiume Treste Livello F Underground Hydrogen Storage**	Italy	STOGIT	Advanced	2031	2033
H2S-N-907	PCI	**SaltHy Harsefeld II**	Germany	Storengy Deutschland GmbH	Less-Advanced	2034	2034
H2S-N-934	PCI	**SaltHy Harsefeld**	Germany	Storengy Deutschland GmbH	Less-Advanced	2033	2033
H2S-N-1321	PCI	**Extension AURA (HyPSTER_3)**	France	Storengy France	Less-Advanced	2033	2033
H2T-A-986	PCI	**H2 Readiness of the TAG pipeline system**	Austria	TAG GmbH	Advanced	2029	2031
H2T-N-444	PCI	**HySoW Atlantic to Mediterranean**	France	Teréga	Less-Advanced	2032	2034
H2S-N-1352	PCI	**HySoW storage**	France	Teréga	Less-Advanced	2032	2034
H2T-A-1096	PCI	**RHYn Interco**	Germany	terranets bw GmbH	Advanced	2030	2035

H2T-A-906	PCI	**Vlieghuis - Ochtrup**	Germany	Thyssengas GmbH	Advanced	2026	2029
H2S-N-1244	PCI	**UST Hydrogen Storage Krummhörn**	Germany	Uniper Energy Storage GmbH	Less-Advanced	2039	2039
H2S-N-1295	PCI	**UST Hydrogen Storage Epe**	Germany	Uniper Energy Storage GmbH	Less-Advanced	2039	2039
H2L-N-968	PCI	**Green Wilhelmshaven H2 Terminal incl. operational Storage and Cracker**	Germany	Uniper Hydrogen GmbH	Less-Advanced	2033	2033
H2L-A-822	PCI	**H2/NH3 import terminal Antwerp - Vopak Energy Park Antwerp**	Belgium	Vopak Energy Park Antwerp NV	Advanced	2029	2029
H2L-A-1127	PCI	**Amplifhy Rotterdam**	Netherlands	VTTI Terminal Support Services (“VTTI”)	Advanced	2029	2033
H2L-N-1100	PCI	**Amplifhy Antwerp**	Belgium	VTTI Terminal Support Services (“VTTI”)	Less-Advanced	2029	2033

List of hydrogen projects included in the ADVANCED hydrogen infrastructure level):

Code	*Project Name*	*Country*	*Promoter*	*Maturity Status*	*Project Commissioning Year First*	*Project Commissioning Year Last*
H2T-N-1239	**Nordic-Baltic Hydrogen Corridor - LT section**	Lithuania	AB Amber Grid	Less-Advanced	2033	2033
H2T-A-991	**AquaDuctus**	Germany	AquaDuctus Pipeline GmbH	Advanced	2030	2040
H2T-F-642	**HyPipe Bavaria – The Hydrogen Hub**	Germany	bayernets GmbH	FID	2029	2030
H2T-N-788	**H2 transmission system in Bulgaria**	Bulgaria	Bulgartransgaz EAD	Less-Advanced	2032	2032
H2T-N-1280	**Nordic-Baltic Hydrogen Corridor - LV section**	Latvia	Conexus Baltic Grid, JSC	Less-Advanced	2033	2033
H2T-F-987	**mosaHYc (Mosel Saar Hydrogen Conversion) - Germany**	Germany	Creos Deutschland Wasserstoff GmbH	FID	2029	2029
H2T-N-1294	**HY4Link**	Luxemburg	Creos Luxembourg Hydrogen S.A.	Less-Advanced	2032	2035
H2T-A-1091	**Connection of DESFA's transmission system with East Med pipeline**	Greece	DESFA S.A.	Advanced	2027	2036
H2T-N-706	**Komnina-Florovouni H2 Pipeline**	Greece	DESFA S.A.	Less-Advanced	2035	2036
H2T-N-970	**Internal hydrogen infrastructure in Greece towards the Bulgarian border**	Greece	DESFA S.A.	Less-Advanced	2032	2040
H2L-A-680	**Project Eos**	Netherlands	Ecolog Eos B.V.	Advanced	2030	2042

H2T-N-1122	**Nordic-Baltic Hydrogen Corridor - EE section**	Estonia	Elering AS	Less-Advanced	2033	2033
H2T-A-696	**Spanish Hydrogen Backbone: Coruña-Zamora**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2031
H2T-A-699	**Spanish Hydrogen Backbone: Castilla y León**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2031
H2T-A-1220	**Spanish Hydrogen Backbone: Huelva-Cadiz**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2039
H2T-A-1368	**Spanish Hydrogen Backbone: Castilla - La Mancha & Conexión Madrid**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2031
H2S-A-508	**H2 storage North-1**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2034
H2T-A-1149	**Spanish Hydrogen Backbone 2030**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2032
H2S-A-1152	**H2 storage North-2**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2031	2040
H2T-N-1324	**H2Med-CelZa (Enagás)**	Spain	Enagás Infraestructuras de Hidrógeno	Less-Advanced	2032	2032
H2T-N-1151	**H2Med-BarMar**	Spain	Enagás Infraestructuras de Hidrógeno/Terega/Natran/Open Grid Europe	Less-Advanced	2032	2032
H2T-A-1236	**DK Hydrogen Pipeline, West DK Hydrogen System**	Denmark	Energinet	Advanced	2029	2035
H2S-N-1238	**DK Hydrogen Storage**	Denmark	Energinet	Less-Advanced	2033	2033
H2S-A-1279	**Hystock Opslag H2**	Netherlands	EnergyStock B.V, an affiliate of N.V.Nederlandse Gasunie	Advanced	2030	2033
H2T-N-835	**SK-HU H2 corridor**	Slovakia	eustream, a.s.	Less-Advanced	2032	2032
H2T-N-1264	**Slovak Hydrogen Backbone**	Slovakia	eustream,a.s.	Less-Advanced	2032	2032
H2S-A-839	**EWE Hydrogen Storage Huntorf_IPCEI**	Germany	EWE GASSPEICHER	Advanced	2027	2027
H2S-A-749	**CHC Hydrogen Storage Expansion Huntorf**	Germany	EWE GASSPEICHER	Advanced	2029	2029
H2S-A-761	**CHC Hydrogen Storage Jemgum**	Germany	EWE GASSPEICHER	Advanced	2029	2032
H2S-N-574	**EWE Hydrogen Storage Ruedersdorf**	Germany	EWE GASSPEICHER	Less-Advanced	2032	2032
H2T-A-1206	**HU/SK hydrogen corridor**	Hungary	FGSZ Ltd.	Advanced	2029	2029
H2T-N-1286	**Alpine H2 Corridor**	Switzerland	Fluxswiss sagl	Less-Advanced	2035	2045
H2T-F-725	**Belgian Hydrogen Backbone - Interconnection BE-NL (Zandvliet & Zelzate)**	Belgium	Fluxys Hydrogen NV/SA	FID	2030	2032
H2T-A-708	**Belgian Hydrogen Backbone - Interconnection BE-DE**	Belgium	Fluxys Hydrogen NV/SA	Advanced	2029	2029

H2T-A-1399	**Belgian Hydrogen Backbone - Tie-in Antwerp NH3 Terminals**	Belgium	Fluxys Hydrogen NV/SA	Advanced	2029	2033
H2T-N-709	**Belgian Hydrogen Backbone - Interconnection BE-UK**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2045
H2T-N-710	**Belgian Hydrogen Backbone - Interconnection BE-FR (Blaregnies)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-711	**Belgian Hydrogen Backbone - Interconnection BE-FR (Alveringem)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-726	**Belgian Hydrogen Backbone - Interconnection BE-NL (Gravenvoeren)**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2034	2034
H2T-N-1372	**Belgian Hydrogen Backbone - Interconnection BE-LUX**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2035
H2T-N-1373	**Belgian Hydrogen Backbone - Zeebrugge import**	Belgium	Fluxys Hydrogen NV/SA	Less-Advanced	2035	2035
H2L-N-820	**Dunkerque New Molecules development**	France	Fluxys NV/SA	Less-Advanced	2035	2035
H2L-N-1325	**Zeebrugge New Molecules development**	Belgium	Fluxys NV/SA	Less-Advanced	2035	2035
H2L-N-664	**Antwerp NH3 Import Terminal**	Belgium	Fluxys NV/SA and Advario	Less-Advanced	2032	2032
H2T-N-740	**Alpine HyWay**	Germany	Fluxys TENP GmbH and Open Grid Europe GmbH	Less-Advanced	2035	2045
H2T-A-757	**H2 Backbone WAG + Penta West**	Austria	GAS CONNECT AUSTRIA GmbH	Advanced	2031	2031
H2T-A-851	**Southern Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS d.o.o. Sarajevo	Advanced	2028	2028
H2T-A-224	**Northern Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS Sarajevo	Advanced	2030	2030
H2T-A-910	**Western Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS Sarajevo	Advanced	2031	2031
H2T-A-849	**Flow - Making Hydrogen Happen (West)**	Germany	GASCADE Gastransport GmbH	Advanced	2029	2029
H2T-A-1178	**HYROW**	Germany	GASCADE Gastransport GmbH	Advanced	2028	2028
H2T-A-796	**Flow - Making Hydrogen Happen (East)**	Germany	GASCADE Gastransport GmbH	Advanced	2026	2037
H2T-N-1315	**H2 interconnection DE-PL**	Germany	GASCADE Gastransport GmbH	Less-Advanced	2034	2034
H2T-A-1136	**Nordic Hydrogen Route – Bothnian Bay – FI section**	Finland	Gasgrid vetyverkot Oy	Advanced	2029	2029
H2T-N-443	**Nordic-Baltic Hydrogen Corridor - FI section**	Finland	Gasgrid vetyverkot Oy	Less-Advanced	2032	2033
H2T-N-1355	**The Baltic Sea Hydrogen Collector (BHC) – Section A**	Finland	Gasgrid vetyverkot Oy, Copenhagen Energy Islands ApS, GASCADE Gastransport	Less-Advanced	2032	2032

H2T-N-1389	**The Baltic Sea Hydrogen Collector (BHC) - Section B**	Finland	Gasgrid vetyverkot Oy, Nordion Energi H2, Copenhagen Energy Islands ApS	Less-Advanced	2034	2034
H2T-F-1000	**Hyperlink**	Germany	Gasunie Deutschland Transport Services GmbH	FID	2029	2033
H2T-A-1001	**Danish-German Hydrogen Network; German Part - HyPerLink Phase III**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2029	2035
H2T-A-933	**Hyperlink 4**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2029	2032
H2S-N-671	**Gasunie SpHyGER Etzel (GSE)**	Germany	Gasunie Energy Solutions 1 GmbH	Less-Advanced	2032	2032
H2T-N-779	**Pomeranian Green Hydrogen Cluster**	Poland	GAZ-SYSTEM S.A.	Less-Advanced	2034	2034
H2T-N-1144	**Nordic-Baltic Hydrogen Corridor - PL section**	Poland	GAZ-SYSTEM S.A.	Less-Advanced	2033	2033
H2S-N-565	**GeoH2**	France	Géométhane	Less-Advanced	2032	2032
H2T-F-1366	**Dutch Hydrogen Network - DRC**	Netherlands	Hynetwork Services B.V.	FID	2028	2039
H2T-A-1365	**Dutch Hydrogen Network - North West**	Netherlands	Hynetwork Services B.V.	Advanced	2030	2042
H2T-A-693	**Dutch Hydrogen Network - North East**	Netherlands	Hynetwork services B.V.	Advanced	2026	2037
H2T-A-694	**Dutch Hydrogen Network - South West**	Netherlands	Hynetwork services B.V.	Advanced	2030	2032
H2T-N-1137	**Central European Hydrogen Corridor (UKR part)**	Ukraine	LLC Gas TSO of Ukraine	Less-Advanced	2032	2032
H2L-A-1395	**MB New Energy Gate Hamburg I**	Germany	MB Energy Holding GmbH & Co. KG (MBE)	Advanced	2030	2030
H2S-A-805	**Project Hydrogen Infrastructure Storage and Distribution (HENRI)**	Slovakia	NAFTA a.s. (joint stock company)	Advanced	2027	2027
H2T-N-573	**UK-BE H2 Interconnector**	Belgium	National Gas & Fluxys NV/SA	Less-Advanced	2035	2045
H2T-N-572	**PU East to H2 Interconnector**	United Kingdom	National Gas Transmission	Less-Advanced	2035	2045
H2T-A-1291	**Hynframed**	France	NaTran	Advanced	2030	2030
H2T-F-899	**mosaHYc - Mosel Saar Hydrogen Conversion**	France	NaTran	FID	2029	2029
H2T-A-969	**RHYN**	France	NaTran	Advanced	2030	2033
H2T-N-569	**HY-FEN – H2 Corridor Spain – France – Germany connection**	France	NaTran	Less-Advanced	2032	2032
H2T-N-667	**MidHY**	France	NaTran	Less-Advanced	2032	2032
H2T-N-909	**Connexion HY-FEN-GeoH2**	France	NaTran	Less-Advanced	2032	2032
H2T-N-1035	**Franco-Belgian H2 corridor**	France	NaTran	Less-Advanced	2034	2035
H2T-N-1187	**HY4Link (FR)**	France	NaTran	Less-Advanced	2032	2034

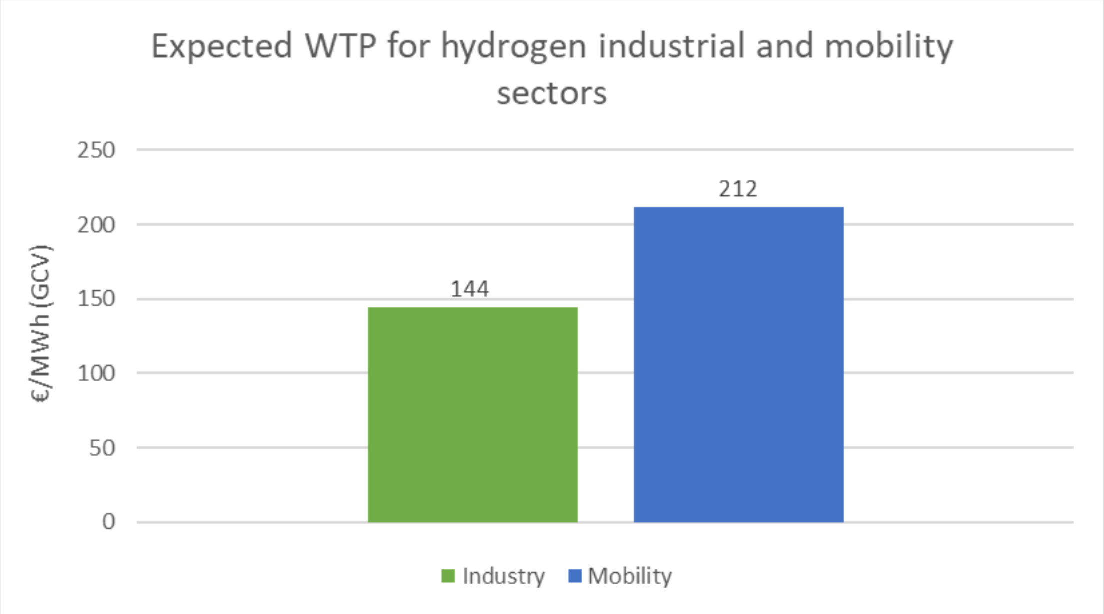
H2T-N-1017	**H2Poseidon Pipeline**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Less-Advanced	2034	2036
H2L-N-932	**Ionian Energy Terminal**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A.	Less-Advanced	2034	2034
H2T-N-1251	**Czech H2 Backbone NORTH**	Czechia	NET4GAS, s.r.o.	Less-Advanced	2032	2032
H2T-A-1034	**Czech H2 Backbone WEST**	Czechia	NET4GAS,s.r.o.	Advanced	2030	2030
H2T-A-926	**Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Sweden**	Sweden	Nordion Energi H2 AB	Advanced	2029	2029
H2T-A-1171	**Nordic Hydrogen Route – Bothnian Bay (SE)**	Sweden	Nordion Energi H2 AB	Advanced	2030	2030
H2S-N-861	**NWKG H2 Storage**	Germany	Nord-West Kavernengesellschaft mbH	Less-Advanced	2029	2036
H2T-N-1310	**Nordic-Baltic Hydrogen Corridor - DE section**	Germany	ONTRAS Gastransport GmbH	Less-Advanced	2033	2033
H2T-A-0	**H2ercules Network Central**	Germany	Open Grid Europe GmbH	Advanced	2026	2050
H2T-F-1038	**H2ercules Network West**	Germany	Open Grid Europe GmbH	FID	2028	2028
H2T-A-738	**Delta Rhine Corridor H2 Germany North**	Germany	Open Grid Europe GmbH	Advanced	2030	2030
H2T-A-1037	**H2ercules Network North**	Germany	Open Grid Europe GmbH	Advanced	2027	2036
H2T-A-1075	**H2ercules Network North-West**	Germany	Open Grid Europe GmbH	Advanced	2031	2031
H2T-N-1052	**H2ercules Network South-West**	Germany	Open Grid Europe GmbH; NaTran Deutschland GmbH	Less-Advanced	2032	2032
H2T-N-1055	**H2ercules Network South-East**	Germany	Open Grid Europe GmbH; NaTran Deutschland GmbH	Less-Advanced	2032	2032
H2T-A-66	**Interconnection Croatia-Bosnia and Herzegovina (Slobodnica-Bosanski Brod)**	Croatia	Plinacro Ltd	Advanced	2030	2030
H2T-A-68	**H2 Ionian Adriatic Pipeline**	Croatia	Plinacro Ltd	Advanced	2030	2030
H2T-A-70	**Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)**	Croatia	Plinacro Ltd	Advanced	2030	2032
H2T-A-302	**Interconnection Croatia-Bosnia and Herzegovina (South)**	Croatia	Plinacro Ltd	Advanced	2028	2028
H2T-A-303	**Interconnection Croatia-Bosnia and Herzegovina (west)**	Croatia	Plinacro Ltd	Advanced	2031	2031
H2T-A-868	**SLOH2 Backbone - AT-SI H2 Interconnection**	Slovenia	Plinovodi d.o.o.	Advanced	2030	2035
H2T-N-978	**Portuguese Hydrogen Backbone**	Portugal	REN - Gasodutos, S.A.	Less-Advanced	2032	2032
H2T-N-1156	**H2Med/CelZa**	Portugal	REN - Gasodutos, S.A.	Less-Advanced	2032	2032
H2S-A-802	**RWE H2 Storage Staßfurt**	Germany	RWE Gas Storage West GmbH	Advanced	2030	2030

H2S-A-767	**RWE H2 Storage expansion Gronau-Epe**	Germany	RWE Gas Storage West GmbH	Advanced	2030	2030
H2S-A-1287	**RWE H2 Storage Gronau-Epe - 2nd expansion**	Germany	RWE Gas Storage West GmbH	Advanced	2030	2030
H2T-A-735	**North Africa Hydrogen Corridor**	Tunisia	Sea Corridor S.r.l.	Advanced	2031	2034
H2L-A-776	**Hydrogen Mediterranean Gateway Hub Project at Port-La Nouvelle**	France	SEMOP PORT-LA NOUVELLE; HOËGH EVI: TEREGA SOLUTIONS	Advanced	2031	2039
H2T-N-1023	**Italian H2 Backbone (Poggio Renatico - P. Gries)**	Italy	Snam Rete Gas S.p.A	Less-Advanced	2034	2034
H2T-A-1205	**Italian H2 Backbone**	Italy	Snam Rete Gas S.p.A.	Advanced	2031	2034
H2T-A-418	**Connection Fiume Treste Livello F**	Italy	Snam Rete Gas Spa	Advanced	2031	2031
H2T-A-555	**Apulia H2 Backbone**	Italy	Snam S.p.A.	Advanced	2027	2027
H2S-A-1189	**Fiume Treste Livello F Underground Hydrogen Storage**	Italy	STOGIT	Advanced	2031	2033
H2S-N-907	**SaltHy Harsefeld II**	Germany	Storengy Deutschland GmbH	Less-Advanced	2034	2034
H2S-N-934	**SaltHy Harsefeld**	Germany	Storengy Deutschland GmbH	Less-Advanced	2033	2033
H2S-N-1321	**Extension AURA (HyPSTER_3)**	France	Storengy France	Less-Advanced	2033	2033
H2T-A-986	**H2 Readiness of the TAG pipeline system**	Austria	TAG GmbH	Advanced	2029	2031
H2T-A-892	**HySoW connection to Lannemezan**	France	Teréga	Advanced	2031	2031
H2T-A-1025	**HySoW connection to Port la Nouvelle Terminal**	France	Teréga	Advanced	2031	2031
H2T-N-444	**HySoW Atlantic to Mediterranean**	France	Teréga	Less-Advanced	2032	2034
H2S-N-1352	**HySoW storage**	France	Teréga	Less-Advanced	2032	2034
H2T-A-1096	**RHYn Interco**	Germany	terranets bw GmbH	Advanced	2030	2035
H2T-A-876	**IP Elten/Zevenaar - Cologne**	Germany	Thyssengas GmbH	Advanced	2029	2029
H2T-A-917	**Emsbüren - Leverkusen**	Germany	Thyssengas GmbH	Advanced	2030	2030
H2T-A-906	**Vlieghuis - Ochtrup**	Germany	Thyssengas GmbH	Advanced	2026	2029
H2S-A-579	**Aljarafe**	Spain	Trinity Energy Storage, S.L.	Advanced	2030	2030
H2S-N-1244	**UST Hydrogen Storage Krummhörn**	Germany	Uniper Energy Storage GmbH	Less-Advanced	2039	2039
H2S-N-1295	**UST Hydrogen Storage Epe**	Germany	Uniper Energy Storage GmbH	Less-Advanced	2039	2039
H2L-N-968	**Green Wilhelmshaven H2 Terminal incl. operational Storage and Cracker**	Germany	Uniper Hydrogen GmbH	Less-Advanced	2033	2033
H2L-A-822	**H2/NH3 import terminal Antwerp - Vopak Energy Park Antwerp**	Belgium	Vopak Energy Park Antwerp NV	Advanced	2029	2029

H2L-A-1127	**Amplifhy Rotterdam**	Netherlands	VTTI Terminal Support Services (“VTTI”)	Advanced	2029	2033
H2L-N-1100	**Amplifhy Antwerp**	Belgium	VTTI Terminal Support Services (“VTTI”)	Less-Advanced	2029	2033

Willingness to pay for hydrogen (WTP_{H2})

WTP values for hydrogen industrial and mobility sectors derived from the results of the Pilot Auction for Renewable Hydrogen[46] by the European Hydrogen Bank (EHB) are shown in **Error! Reference source not found.**, i.e. 144 €/MWh_{H2} for the industry sector and 212 €/MWh_{H2} for the mobility sector. The TYNDP 2026 PS-CBA estimates the WTP_{H2} based on an weighted average between both sectors. The weighting is based on the NT+ scenario with a transport demand sector share of the final energy demand for hydrogen of 14% in 2030 and of 19% in 2040. The WTP_{H2} for the calculation of the increase of market rents indicator (B4) is therefore 154 €/MWh_{H2} in 2030 and 157 €/MWh_{H2} in 2040.[47]



European tap water prices

Member State	Price tap water (€/m3)[48]
Norway	5.51
Germany	3.47
Denmark	4.37
Netherlands	3.82
Sweden	3.60
France	2.82
Belgium	3.49
Switzerland	2.80
Czechia	3.09

[46] https://climate.ec.europa.eu/eu-action/eu-funding-climate-action/innovation-fund/competitive-bidding_en
[47] The displayed values are the most recent ones published prior to the consultation. As the WTP will be updated based on the latest bidding phase, new figures may be made available in the final version.
[48] Water prices are taken from The International Benchmarking Network for Water and Sanitation Utilities (IBNET) database. The data compares tap water prices in the cities up to 15m³ per month. https://www.waternewseurope.com/water-prices-compared-in-36-eu-cities/

Austria	2.80
Finland	2.52
Spain	1.87
Italy	1.16
Ireland	1.85
Croatia	1.68
Portugal	1.66
Poland	1.42
Hungary	1.23
Greece	1.16

ANNEX III: GHG emissions factors

GHG emissions factors of Power Plants

The proposed GHG emissions factors consider direct GHG emissions (CO_2, N_2O, and CH_4) from the fuels' stationary combustion.

These emissions factors account for unoxidised carbon by consideration of default factors of: solid = 0.98, liquid = 0.99, and gas = 0.995 (Source: IPCC, 2006[49]).

Fuel	Type	Efficiency range NCV terms	Standard efficiency NCV terms	CO_2 eq EF (t/ net TJ)	CO2 eq EF (t/ gross MWh)	CO2 eq EF (t/ net MWh)
Nuclear	-	30% – 35%	33%	0,00	0,00	0,00
Hard coal	old 1	30% – 37%	35%	95,03	0,32	0,96
Hard coal	old 2	38% – 43%	40%	95,03	0,32	0,84
Hard coal	new	44% – 46%	46%	95,03	0,32	0,73
Hard coal	CCS	30% – 40%	38%	9,50	0,03	0,09
Lignite	old 1	30% – 37%	35%	101,43	0,34	1,02
Lignite	old 2	38% – 43%	40%	101,43	0,34	0,89
Lignite	new	44% - 46%	46%	101,43	0,34	0,78
Lignite	CCS	30% - 40%	38%	10,14	0,03	0,09
Natural Gas	conventional old 1	25% – 38%	36%	56,16	0,18	0,56
Natural Gas	conventional old 2	39% – 42%	41%	56,16	0,18	0,49
Natural Gas	CCGT old 1	33% – 44%	40%	56,16	0,18	0,50
Natural Gas	CCGT old 2	45% – 52%	48%	56,16	0,18	0,42
Natural Gas	CCGT present 1	53% – 60%	56%	56,16	0,18	0,36
Natural Gas	CCGT present 2	53% – 60%	58%	56,16	0,18	0,35
Natural Gas	CCGT new	53% – 60%	60%	56,16	0,18	0,34
Natural Gas	CCGT CCS	43% – 52%	51%	5,62	0,02	0,04
Natural Gas	OCGT old	35% – 38%	35%	56,16	0,18	0,57
Natural Gas	OCGT new	39% – 44%	42%	56,16	0,18	0,48
Light oil	-	32% – 38%	35%	74,34	0,25	0,76
Heavy oil	old 1	25% – 37%	35%	74,34	0,25	0,76
Heavy oil	old 2	38% – 43%	40%	74,34	0,25	0,66
Oil shale	old	28% – 33%	29%	101,43	0,34	1,23
Oil shale	new	34% – 39%	39%	101,43	0,34	0,92

[49] Source: IPCC Report, 2006 (https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html)

GHG emissions factors of fuels as considered for hydrogen supply

The proposed GHG emissions factors for hydrogen production and imports are based on the TYNDP 2026 draft Scenario Methodology Report which is mainly derived from a JRC report[50]:

Fuel	*Comments*	*CO_2 eq EF (t/ net MWh)*	*CO_2 eq EF (t/ gross MWh)*
Hydrogen produced from natural gas with CCS	National production in the following countries: Belgium, France, Italy, Lithuania, The Netherlands, Germany and UK.	0.0262	0.022
Renewable hydrogen imports	Imports from North Africa and Ukraine as well as ammonia imports.	0	0

Assumed GHG emissions factors of energy curtailment

Type	*Comments*	*CO_2 eq EF (t/ net TJ)*	*CO_2 eq EF (t/ net MWh)*
Curtailed hydrogen demand	Proposed EF for consultation	94 56.16	0.32
Curtailed electricity demand	Proposed EF for consultation	56.16	0.18

[50] Source : https://op.europa.eu/en/publication-detail/-/publication/278ae66b-809b-11e7-b5c6-01aa75ed71a1

ANNEX IV: non-GHG emissions factors

Non-GHG emissions factors of Power Plants (source: ENTSO-E[51])

Fuel	Type	NO_x EF (kg/gross GJ)	NH_3 EF (kg/gross GJ)	SO2 EF (kg/gross GJ)	PM2.5 and smaller EF (kg/gross GJ)	PM10 EF (kg/gross GJ)	NMVOC EF (kg/gross GJ)
Hard coal	old 1	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	old 2	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	new	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	CCS	0,068	0,0016	0,067	0,0024	0,005	0,0007
Lignite	old 1	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	old 2	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	new	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	CCS	0,080	0,0009	0,152	0,0040	0,005	0,0009
Gas	Conventional old 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	Conventional old 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT old 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT old 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT present 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT present 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT new	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT CCS	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	OCGT old	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	OCGT new	0,017	0,0054	0,001	0,0001	0,000	0,0019
Light oil	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil	old 1	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil	old 2	0,226	0,0000	0,150	0,0058	0,008	0,0022
Oil shale	old	0,228	0,0000	0,152	0,0059	0,008	0,0022
Oil shale	new	0,228	0,0000	0,152	0,0059	0,008	0,0022
Other non-RES	-	0,049	0,0114	0,036	0,0030	0,003	0,0037
Lignite biofuel	-	0,080	0,0009	0,152	0,0040	0,005	0,0009
Hard Coal biofuel	-	0,068	0,0016	0,067	0,0024	0,005	0,0007
Gas biofuel	-	0,018	0,0057	0,001	0,0002	0,000	0,0020

[51] Implementation Guidelines for TYNDP 2024 based on 4th ENTSOE Guideline for Cost-Benefit Analysis of grid development projects

Light oil biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Oil shale biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022

Non-GHG emissions factors of hydrogen production (source: E4tech[52])

Fuel	Source	NO_x EF (kg/gross GJ)	SO2 EF (kg/gross GJ)	PM2.5 and smaller EF (kg/gross GJ)	PM10 EF (kg/gross GJ)	NMVOC EF (kg/gross GJ)
Hydrogen produced from natural gas with CCS	Salkuyeh et al., 2017[53]	0,1219	0,0001	-	0,0134	0,0155
Hydrogen produced from natural gas without CCS	Salkuyeh et al., 2017	0,0832	0,0001	-	0,0113	0,0113
	Sun et al., 2019[54]	0,0063	0,0001	0,0020	0,0021	0,0017
	Nnabuife et al., 2023[55]	0,0118	0,0007	0,0031	0,0038	0,0000

Non-GHG emissions factors of curtailed energy

Type	**Comment**	**NO_x EF** (kg/gross GJ)	**NH_3 EF** (kg/gross GJ)	**SO2 EF** (kg/gross GJ)	**PM2.5 and smaller EF** (kg/gross GJ)	**PM10 EF** (kg/gross GJ)	**NMVOC EF** (kg/gross GJ)
Hydrogen	Proposed values for consultation	0,068	0,0016	0,067	0,0024	0,005	0,0007
		0,017	0,0054	0,001	0,0001	0,000	0,0019
Electricity	Proposed value for consultation	0,017	0,0054	0,001	0,0001	0,000	0,0019

[52] Source: https://assets.publishing.service.gov.uk/media/5cc6f1e640f0b676825093fb/H2_Emission_Potential_Report_BEIS_E4tech.pdf

[53] Yaser Khojasteh Salkuyeh, Bradley A. Saville, Heather L. MacLean, Techno-economic analysis and life cycle assessment of hydrogen production from natural gas using current and emerging technologies, International Journal of Hydrogen Energy,Volume 42, Issue 30,2017, Pages 18894-18909,ISSN 0360-3199

[54] Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities, Pingping Sun, Ben Young, Amgad Elgowainy, Zifeng Lu, Michael Wang, Ben Morelli, and Troy Hawkins, Environmental Science & Technology 2019 53 (12), 7103-7113, DOI: 10.1021/acs.est.8b06197

[55] Nnabuife, S.G.; Darko, C.K.; Obiako, P.C.; Kuang, B.; Sun, X.; Jenkins, K. A Comparative Analysis of Different Hydrogen Production Methods and Their Environmental Impact. Clean Technol. 2023, 5, 1344-1380. https://doi.org/10.3390/cleantechnol5040067

ANNEX V: Factors

Assumed GCV/NCV ratio per fuel type

Fuel	Ratio GCV/NCV
Hydrogen	1,176
Natural gas	1,108
Coal	1,053
Light oil	1,064