ENNOH's FIRST DRAFT

COST-BENEFIT ANALYSIS (CBA) SINGLE-SECTOR METHODOLOGY

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1 INTRODUCTION

This methodology for the Cost Benefit Analysis of grid development projects was prepared by the European Network of Network Operators for Hydrogen (ENNOH) in compliance with the requirements of the EU Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure (TEN-E Regulation) as well as EU Regulation (EU) 2024/1789. It is the 1st Cost Benefit Analysis (CBA) methodology developed by ENNOH and focusses on the hydrogen infrastructure category, as defined in Annex II(3) of the TEN-E Regulation.

The developed indicators enable a harmonized, system-wide cost–benefit analysis (CBA) of projects. They support a consistent methodology, ensuring that all projects — regardless of whether they are proposed by a TSO or a third party — are evaluated and treated uniformly. The requirements of the TEN-E Regulation concerning market integration, competition, security of supply (SoS) and sustainability were shaping the design of the indicators.

The TEN-E Regulation foresees four decision-making processes for which project-specific CBAs consistent with this hydrogen CBA methodology could be used as input:

- Selection process of candidate projects to grant the status Project of Common Interest (PCI) or Project of Mutual Interest (PMI)[1];
- Cross-border cost allocation (CBCA) decisions for PCIs and PMIs[2];
- Decision to grant regulatory incentives for PCIs[3];
- Eligibility check of PCIs and PMIs for Union financial assistance in form of grants for works[4].

1 See Annex III.2.(1)(d) of the TEN-E Regulation. In line with Article 3 and Annex III.1. of the TEN-E Regulation, the selection decision is taken by the decision-making body of the Regional Groups (i.e., Member States and the European Commission) and can be objected by the European Parliament or the Council in accordance with Article 20(6) of the TEN-E Regulation.

2 See Article 16(4)(a) and Article 16(12) of the TEN-E Regulation. The decision on the cost allocation is taken by the relevant national regulatory authorities in accordance with Article 16(5) of the TEN-E Regulation, whereas ACER has to take the decision in accordance with Article 16(7) of the TEN-E Regulation if the relevant national regulatory authorities cannot reach an agreement.

3 See Article 16(4)(a) and Article 16(12) of the TEN-E Regulation. The decision on the cost allocation is taken by the relevant national regulatory authorities in accordance with Article 16(5) of the TEN-E Regulation, whereas ACER has to take the decision in accordance with Article 16(7) of the TEN-E Regulation if the relevant national regulatory authorities cannot reach an agreement.

4 See Article 18(2) and 18(5) of the TEN-E Regulation.

1.1 SCOPE OF THE DOCUMENT

The TYNDP process is composed of four key stages: scenario development, project collection, hydrogen infrastructure gaps identification, and the cost-benefit analysis (CBA). This structure aligns with the TEN-E Regulation, which mandates that projects must be evaluated under various planning scenarios – each reflecting a potential future state of the energy system. While individual project costs remain consistent across scenarios, the expected benefits of each project vary significantly depending on scenario-specific assumptions. Consequently, scenarios are used to explore the potential future value of transmission projects. The hydrogen infrastructure gaps identification aims at identifying regional infrastructure gaps within the assessed sets of hydrogen infrastructure assumed to be in place in a given year.

The purpose of this document is to offer guidance on carrying out the final step: a system-wide energy CBA. General information on the other steps is included only where necessary to support understanding of the CBA methodology.

The CBA methodology will be complemented by the following documents, jointly providing comprehensive guidance on the application of project-specific CBAs for the TYNDP process:

- The Project Submission Handbook for practical guidance for project promoters.
- Guidelines for Project Inclusion, specific for each TYNDP.
- CBA implementation guidelines: Dedicated input data specifications for each TYNDP cycle to outline the rules defined in this CBA methodology.
- The Scenario Report and accompanying documents for necessary underlying assumptions.

On this joint basis, the projects that are submitted to ENTSO-E, ENTSOG[5] and ENNOH during the TYNDP process determine the outputs.

1.2 OVERVIEW OF THE DOCUMENT

This document is structured into seven main chapters, supported by a number of Annexes to provide further details.

- **Chapter 1** introduces the CBA guideline and provides the context of the overall CBA methodology.
- **Chapter 2** discusses the general approach. This includes scenarios, modelling principles and infrastructure levels.
- A detailed description of the overall assessment, including the project grouping and project assessment, is given in **Chapter 3**. The concept of curtailed vs disrupted hydrogen demand is outlined in **Section 3.3**.
- **Chapter 4** provides the explanation of all indicators. It describes the methodology to be used and defines the principles and the requirements to properly assess the relevant indicator.
- Planned sensitivity analysis are outlined in **Chapter 5**.
- **Chapter 6** describes how economic parameters are taken into account for the CBA process.
- **Chapter 7** outlines how the energy efficiency first principle is implemented.

5 Inputs to ENTSO-E's TYNDP and ENTSOG's TYNDP are relevant since the assessments detailed in this CBA methodology contain analyses that may be based on ENTSO-E's and/or ENTSOG's TYNDP reference grid.

1.3 GUIDELINES FOR PROJECT INCLUSION

ENNOH will adopt, implement and publish the results of its first system wide CBA in the framework of TYNDP 2028. Therefore, the Guidelines for Project Inclusion will be updated in due time.

Project submissions are specified in the Guidelines for Project Inclusion and its Project Submission Handbook for each TYNDP. The Guidelines for Project Inclusion provide guidance to project promoters on the procedural steps as well as administrative and technical requirements that the project promoters need to comply with to have their projects included in the TYNDP.

Given that ENNOH Guidelines for Project inclusions will only be developed in 2026, the updated Guidelines for Project Inclusion adopted and published by ENTSOG in the framework of TYNDP 2026 are used as a reference of the current state of art. ENNOH´s Guideline for Project inclusion may extent and partially built-upon the ENTSOG guidelines, but ENNOH will be tasked with presenting alternative and novel approaches that are aligned to its own system assessment process and Single Sector Draft Methodology.

In accordance with Annex III.2(5) of the TEN-E Regulation, draft Guidelines for Project Inclusion are required to be consulted with ACER and the European Commission, and their recommendations are required to be considered before the publication of the final Guidelines for Project Inclusion. The Guidelines for Project Inclusion aim at implementing the requirement of subparagraph 1 of Annex III.2(5) of the TEN-E Regulation to ensure equal treatment and transparency of the TYNDP project inclusion process.

Table 1: Complementary information to be provided by TYNDP-specific Guidelines for Project Inclusion and its Project Submission Handbook

Brief explanation of the TYNDP process	Including current status of deadlines applying to following TYNDP steps and interlinkages with the PCI/PMI process.
Project categories	Aggregation of certain network elements (e.g., transmission and storage) of the relevant topologies (e.g., natural gas and hydrogen) into categories and possibly sub-categories.
Project promoter categories	Potentially considering each project category individually, project promoters' categorisation can factor in certifications, licenses, exemptions, unbundling, and ENNOH affiliation status (e.g., membership, observer status, associated partnership).
Administrative criteria	The criteria consider: _ Administrative criteria to be fulfilled by project promoters: these criteria are defined to ensure project promoters' credibility in terms of financial capability and technical expertise, and to ensure equal and fair treatment of all TYNDP project promoters. _ Administrative criteria for projects to be included in the TYNDP: these criteria are defined to ensure the acceptability and TYNDP relevance of submitted projects, and to ensure equal and fair treatment of all TYNDP projects. These criteria may be grouped in different categories and applied accordingly, depending on the type of infrastructure the respective project would implement. The final decision on the inclusion of a project in the TYNDP project list belongs to ENNOH*.
Technical criteria for projects to be included in TYNDP	Technical criteria are defined per infrastructure category or sub-category. These criteria ensure that the minimum set of information required to assess all projects is provided (e.g., costs, technical assumptions considered, capacity increments, commissioning year). This includes supply and demand allocations with the required granularity if not provided by the scenarios.
Plausibility check for commissioning year of projects	Definition of a validation check to verify project schedules. The project promoter is solely responsible for the correctness of the submitted information.

* To prove the eligibility of projects for the PCI/PMI process, further eligibility checks are required that are outside of ENNOH's mandate.

Plausibility check for project costs	Definition of a validation check to verify project costs. The project promoter is solely responsible for the correctness of the submitted information.
Project data requirements	Definition of the mandatory data submissions by projects promoters. This includes supply and demand allocations with the required granularity if not provided by scenarios.
Definition of hydrogen projects' maturity status	For the allocation of hydrogen projects to hydrogen infrastructure level(s).
Definitions and criteria used to define cross-border and internal infrastructures	Complementary information to definitions in this CBA methodology but not needed for this CBA methodology.
Simplified inclusion process into TYNDP for PCIs and PMIs on the Union list**	Description of the simplifications for PCIs and PMIs. Re-submission of PCIs and PMIs by project promoters is required for their inclusion in the TYNDP.
Consistency check phase of submitted information by ENNOH and correction of input data by project promoters	Description of the procedure to receive missing information and to correct data and the respective roles of ENNOH and project promoters. This may include an internal review phase between ENNOH and ENNOH's members to ensure the natural gas infrastructure representation is accurate and up to date. After the implementation of the findings of the check phase, it is not possible for project promoters to further amend the submitted project data (except if it is deemed that the changes would not influence any analysis). The relevant data submission deadline is displayed in the TYNDP.
Project promoters' access to assessment results	Description of the approach of sharing of assessment results by ENNOH including bi-lateral data sharing and/or meetings with project promoters as well as public workshops.
Project promoters' right to review their project assessment	Description of the approach of handling requests of project promoters to review their project assessment. The approach could include consultations with ACER and/or the European Commission.
Consistency of ENNOH, ENTSO-E and ENTSOG data collections	Consistency check of data with focus on collected electrolyser projects.

** Sentence 2 of subparagraph 1 of Annex III.2(5) of the TEN-E Regulation states that the Guidelines for Project Inclusion establish a simplified process of inclusion in the TYNDP for all projects on the Union list in force at the time. This simplification takes into account the documentation and data already submitted during the previous TYNDP process, provided that the documentation and data already submitted remains valid. The Union list is the joint list of PCIs and PMIs (see Recital (20) and Art. 3(5) of the TEN-E Regulation).

1.4 CBA IMPLEMENTATION GUIDELINES

The CBA methodology is a guidance document for the assessment of projects that is expected to be valid for more than one cycle of assessment (e. g., for several TYNDPs or PCI/PMI processes) and it is therefore not required to include exhaustive implementation details of the methodologies, which may vary for each cycle of assessment. Therefore, the CBA methodology requires supplementary CBA implementation guidelines for each assessment cycle.

The CBA implementation guidelines will be extensively consulted with relevant stakeholders before their application in the TYNDP. When planning the stakeholder consultation on the CBA implementation guidelines, ENNOH will provide sufficient time to ensure that the feedback received can be adequately considered. On some occasions, the CBA implementation guidelines can also be prepared in several steps with individual consultations.

Given that ENNOH CBA implementation guidelines will only be developed in 2026, the updated CBA Implementation Guidelines adopted and published by ENTSOG in the framework of TYNDP 2026 are used as a reference of the current state of art. ENNOH's Guideline for Project inclusion may extent and partially built-upon the ENTSOG guidelines, but ENNOH will be tasked with presenting alternative and novel approaches that are aligned to its own system assessment process and Single Sector Draft Methodology.

The following table outlines a summary of the typical information included in in the CBA implementation guidelines. ENNOH will adapt the information within the process of developing its first TYNDP in the framework of TYNDP 2028.

Table 2: Complementary information to be provided by TYNDP-specific CBA implementation guidelines

Additional rules for grouping of projects	If required, additional grouping guidelines applied to the CBAs, including complementary rules for the identification and treatment of competing projects.
Cost of Disrupted Hydrogen (CODH)	The approach and values of the CODH for the calculation of the relevant indicators.
Non-CO_2 emission types and emission factors	A list of non-CO_2 (greenhouse gas and non-greenhouse gas) emission types and related emission factors. Non-CO_2 GHG emissions are used for the calculation of the GHG emissions variations indicator (B1) and non-GHG emissions are used for the calculation of the non-GHG emissions variations indicator (B2).
Emission costs	Definition of the cost of CO_2e for the monetisation of GHG emissions within the GHG emissions variations indicator (B1) and the damage costs of non-GHG emissions for the monetisation of the non-GHG emissions variations indicator (B2).
Seasonality of demand and supply	If required, description of the approach to transform _ annual demand and supply data from the scenarios into seasonal values; _ generally it is assumed that hourly data is used in the modelling process
Usage of unit investment costs	Description of the unit investment costs used for CBAs, if relevant. These may be ACER's unit investment costs established as required by Art. 11(9) of the TEN-E Regulation.
Sensitivities	Selection of sensitivities and details required to calculate them.
Details on calculation of benefit indicators	If required, any other details for the calculation of benefit indicators that are not clarified in this CBA methodology.

In case ENNOH would propose to include in the CBA implementation guidelines for public consultation a set of elements which are not listed in Table 2, ENNOH shall consult ACER and the European Commission and take due account of their recommendations before taking a final decision.

1.5 FIRST APPLICATION OF THE CBA METHODOLOGY TO THE TYNDP PROCESS

This CBA methodology aims to be used for ENNOH's first TYNDP, TYNDP 2028. However, this CBA methodology may already be used for the TYNDP 2026 process. In this case, it would require additional alignments and coordination with ENTSOG, which would have to be further detailed in joint ENNOH/ENTSOG CBA implementation guidelines and other complementary documents to this CBA methodology.

2 GENERAL APPROACH

2.1 SCENARIOS

ENNOH will adopt and publish its first TYNDP in the framework of TYNDP 2028. Therefore, the basis of the TYNDP 2028 is the TYNDP 2028 scenarios. As these scenarios are not developed yet, you can hereinafter find the information about the scenarios published by ENTSOG in the framework of TYNDP 2026.

The Scenarios for the TYNDPs are established in line with Article 12 of the TEN-E Regulation. Article 12(2) of the TEN-E Regulation reads: "The ENTSO for Electricity and ENTSO for Gas shall follow ACER's framework guidelines when developing the joint scenarios to be used for the Union-wide ten-year network development plans. The joint scenarios shall also include a long-term perspective until 2050 and include intermediary steps as appropriate."

Article 12(1) of the TEN-E Regulation stipulates that ACER's "guidelines shall establish criteria for a transparent, non-discriminatory and robust development of scenarios taking into account best practices in the field of infrastructures assessment and network development planning.

The guidelines shall also aim to ensure that the underlying ENTSO-E and ENTSOG scenarios are fully in line with the energy efficiency first principle and with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective and shall take into account the latest available Commission scenarios, as well as, when relevant, the national energy and climate plans."

Each joint Scenario Report of ENTSO-E and ENTSOG has been specific to each distinct TYNDP cycle, and the report and its accompanying documents define the relevant information. From the scenarios, the following information is needed for the application of this CBA methodology for a certain TYNDP cycle:

Table 3: Consideration of scenario data in the CBAs based on this CBA methodology

Time horizon	Years for which data are prepared.
Scenarios	The CBAs are required to be based on the corresponding scenarios developed, according to Article 12 of the TEN-E Regulation.
Demand	Including peak demand cases and (seasonal) profiles. The scenarios are constructed so that they are in line with the energy efficiency targets as defined in the Energy Efficiency Directive (EU) 2018/2002 (EED) and its subsequent revisions. This ensures that subsequent steps of the TYNDP process are also in line with the energy efficiency first principle.
Supply	Potentials, flexibilities, and profiles of sources of electricity (e.g., power plant fleet), hydrogen (e.g., supply potentials, unabated hydrogen production facilities, low-carbon hydrogen production facilities, electrolyser capacities), and natural gas (e.g., national production, biomethane production, supply potentials).
Fuel prices, CO_2 prices, emission factors	Providing the required inputs for developing scenarios, as well as calculating benefit indicators, and monetising results as part of the CBA.
Market assumptions	Assumptions on the functioning of energy markets that are made when developing scenarios.
Sensitivities	Selection of sensitivities and details required to calculate them.
Details on calculation of benefit indicators	If required, any other details for the calculation of benefit indicators that are not clarified in this CBA methodology.

All scenario storylines should be used for the CBAs. If a required element was not provided by the scenario process, another high quality and publicly available data source is used and referenced, after having been consulted through the CBA implementation guidelines process.

2.2 MODELLING PRINCIPLES

The scenarios developed for as part of the TYNDP process demonstrate how future demand predictions are met given the currently available information on domestic and non-EU supply. As such, the core element of the scenario development process are quantitative models that allow for coherent supply/demand scenarios that are aligned to the European energy and climate goals across the entire time horizon studied by the corresponding TYNDP. In the following, the key elements of such models are characterised, and the basic principles of a corresponding modelling methodology are outlined. The CBA methodology is aligned to the results of energy system models that adhere to these principles.

2.2.1 KEY ELEMENTS

2.2.1.1 MARKET MODELS

In general, energy markets can be organised by exchanges. These entities collect buy and sell orders from market participants for a certain commodity. The orders are stacked in the form of demand and supply curves. Under uniform price auction schemes (see Figure 1), the markets are cleared by matching demand and supply curves to obtain market clearing prices for the corresponding commodities.

Market models used for the CBA methodology determine, given the model's assumptions, the system optimal market outcome. The supply needed to meet the demand is met in such way that the overall cost of the system is minimised. Market participants do not aim to maximise their own profit, instead, they bid their marginal costs. This is equivalent to the maximisation of the socio-economic welfare if the socio-economic welfare contains all system costs.

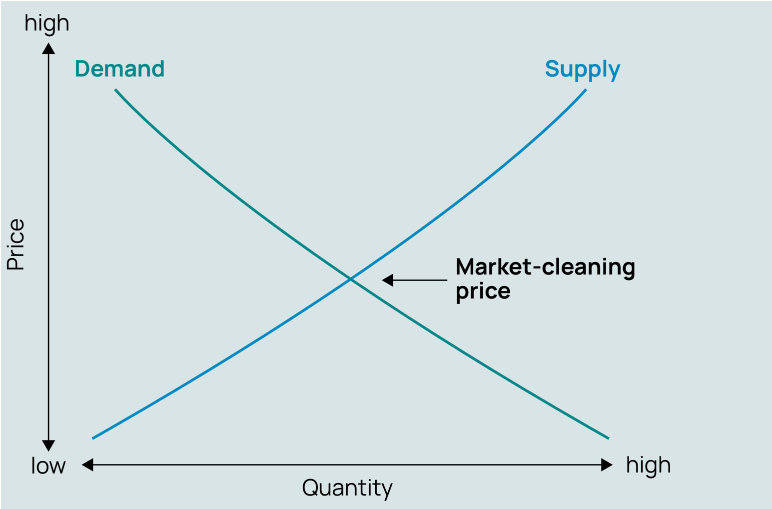


Figure 1: Price auction scheme

2.2.1.2 MULTI-ENERGY SYSTEM (MES) MODELS

Interlinked (sector) models or integrated multi-energy system (MES) models are market models that capture energy market transactions and interactions across various energy carriers and sectors. MES models determine the optimal market outcome across multiple energy carriers simultaneously. The optimal market outcome reflects the least cost to meet all energy demand across various carriers, hence reflecting potential trade-offs between energy carriers to minimise total energy system cost. MES models can cover markets for energy carriers such as electricity, hydrogen, natural gas, heat, biomass, coal, etc.

2.2.1.3 MARKET-COUPLING ACROSS ENERGY CARRIERS AND REGIONS

Markets for different energy carriers are coupled to each other by energy system assets with interfaces to more than one energy carrier. Examples for such assets are:

- Natural gas fired power plants act as demand on natural gas markets and are a supply source on electricity markets.
- Electrolysers act as demand on electricity markets and a supply source on hydrogen markets. Fuel cells and hydrogen fired power plants act as demand on the hydrogen market and are supply sources on electricity markets.
- A hybrid heat pump used to meet domestic heating demand can either act as demand on the electricity, natural gas or hydrogen market.

Markets for the same energy carrier, but covering different geographies, are coupled to each other by energy system assets with interfaces to more than one geography. Examples for such assets are:

- Natural gas or hydrogen pipelines that can transport gas from one market to another.
- Power transmission lines that can transport electricity from one market to another.
- LNG tankers and terminals that allow to link domestic natural gas markets to global LNG trade. The same applies to shipped hydrogen and its derivatives.

Projects enhancing the interface between different energy carriers and or energy markets can undergo a multi-sector or multi-system CBA assessment.

2.2.1.4 GEOGRAPHICAL SCOPE

The geographical scope should cover at least the EU, the European Economic Area, the Energy Community, and any other third country in which the project is located. In order to study the cross-border impact of new infrastructure projects, markets must at least be modelled at a country level (NUTS-0). However, a higher granularity might be needed if the European wide impact on national internal infrastructure projects needs to be assessed, for example to remove bottlenecks in pan-European supply corridors or the evaluation of projects with a cross-border impact on a regional level.

2.2.2 BASIC METHODOLOGY OF MES MODELS

2.2.2.1 THE OBJECTIVE FUNCTION

Scenarios that reflect the system optimal outcome are modelled using optimisation models. At the core of an optimisation model is a single objective function that is either maximised or minimised. As shown exemplary in Figure 2, the objective function in MES models tend to sum all system related costs for meeting demand scenarios, minimising the total system costs.

The objective function consists of parameters and variables. Parameters are inputs to the model, such as weather or demand data. Variables are modified to determine an optimal solution. The most important variables in MES models are the resulting energy flows.

Objective Function

Objective Function
= sum for all supplies (unitary cost of supply × rekated supply quantity)
+ sum for all arcs (unitary residual cost × related flow)
+ unitary CO_2 cost × CO_2 emissions
+ sum for all countries (unitary curtailment cost × related curtailed quantity)
+ sum for all storage (unitary target penalty × related curtailed quantity

Additional to the objective function, the models are working with constraints that can be understood as conditions that must be met and penalizations the model faces in finding the optimal solution. These conditions are set to make the model adhere to physical reasoning. the flows between two countries can't be higher than the transport capacity between them) and to find a solution that truly is optimal (if the model is trying to minimise costs a penalization on unserved demand has to be placed, otherwise the model will avoid serving demand just to minimise the production costs in the system). There are two types of constraints:

- Hard constraints consist of parameters that the model must respect whatever the consequences (even if it leads to the absence of a solution). These constraints describe the technical characteristics of the energy system. Examples of hard constraints are pipeline capacities, working gas volumes of underground storages, and the maximum supply potentials.

- Soft constraints are based on parameters that the model incorporates to find the optimum solution but is not strictly obliged to respect. Not adhering on the restriction of a soft constraint is penalized. In optimisation models that minimise total costs, noncompliance to a soft constraint has a cost penalty. Penalties for unserved demand (€/MWh), emission pricing (€/tCO_2), but also fuel consumption and corresponding fuel costs (€/MWh) are examples for soft constraints.

The optimum solution to the objective function is the best possible solution that satisfies all constraints and, in case of total system costs, leads to the lowest total costs. The optimum solution is identified through the mathematical minimisation of the objective function subject to hard and soft constraints. Given the complexity of the resulting mathematical problem, there is no closed-form formula that gives the solution. Instead, "solvers" as a mathematical software using different algorithm to approach the optimal solution are used. The more complex the model, the longer and more difficult it is for the solver to obtain a solution. Often, there is no best solution, but one best solution, among many.

The models used in the TYNDP process are linear optimisation problems, which facilitates both the interpretability of results and the executability of the optimisation model.

2.2.2.2 CONCEPT OF ARC AND NODES

Hydrogen, electricity and natural gas systems are represented through a simplified topology, composed of nodes and arcs. Nodes and arcs are objects that are attributed with different characteristics using parameters and constraints. The outcome of the optimisation problem is how these objects are used (variables).

Node

The basic block of the topology is the node at which level demand and supply is balanced for a specific energy carrier. A node can be thought of as a circle representing a modelling area within a country. This area can be dedicated to either:

- A specific geographic part of the country (e.g., to represent bottlenecks within the country, differentiation between onshore and offshore infrastructure); or
- A specific functional part of the country (e.g., imports, aggregation of storages, aggregation of demand).

Arc

An arc represents a connection between two nodes. It allows for transfer of some energy between these two nodes. This transfer is thereby limited to the sum of the capacity of all interconnection points between these two nodes that the arc is representing after application of the lesser-of-rule. According to the lesser-of-rule, when two opposite operators provide a different capacity on the same point, the lower of the two is considered. In this process capacities are computed for the model. This can be either related to natural gas, or hydrogen, or electricity, depending on the grid considered (see Figure 2).

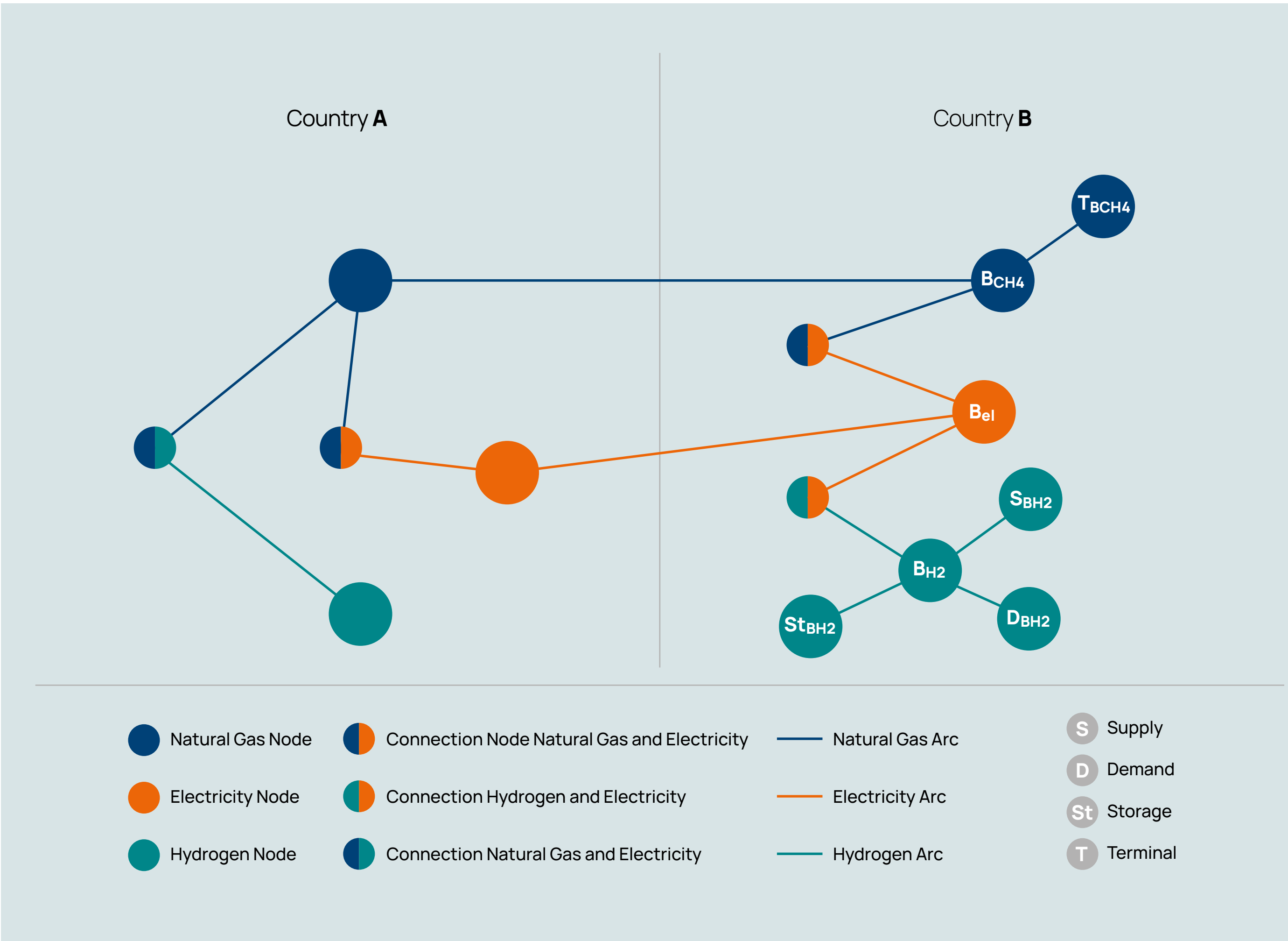


Figure 2: Example of an Arc Node Model

The supply and demand balance in a node depends on the incoming flow from other nodes or direct imports from a supply source. Hydrogen, natural gas, and electricity may also come from sources connected to the node itself (e.g., storages, import, or production facilities of the respective energy carrier). The sum of all these entering flows must match the demand of the node, plus the need for storage filling (e.g., injection into hydrogen storages or charging of batteries) and the exit flows to adjacent nodes. In case the balance is not possible, a disruption of demand is used as a last resort. In the model, as supply and demand must be balanced, unserved energy demand is penalized by the value that corresponds to the expected cost of insufficient energy supply. This approach enables an efficient analysis of the disrupted demand.

For the supply and the demand of the different sectors to interact, conversion assets are required. These enable a transfer of energy from one sector to another sector, subject to an efficiency factor. Conversion thereby acts as a demand in a node of the delivering sector and as a supply in a node of the receiving sector.

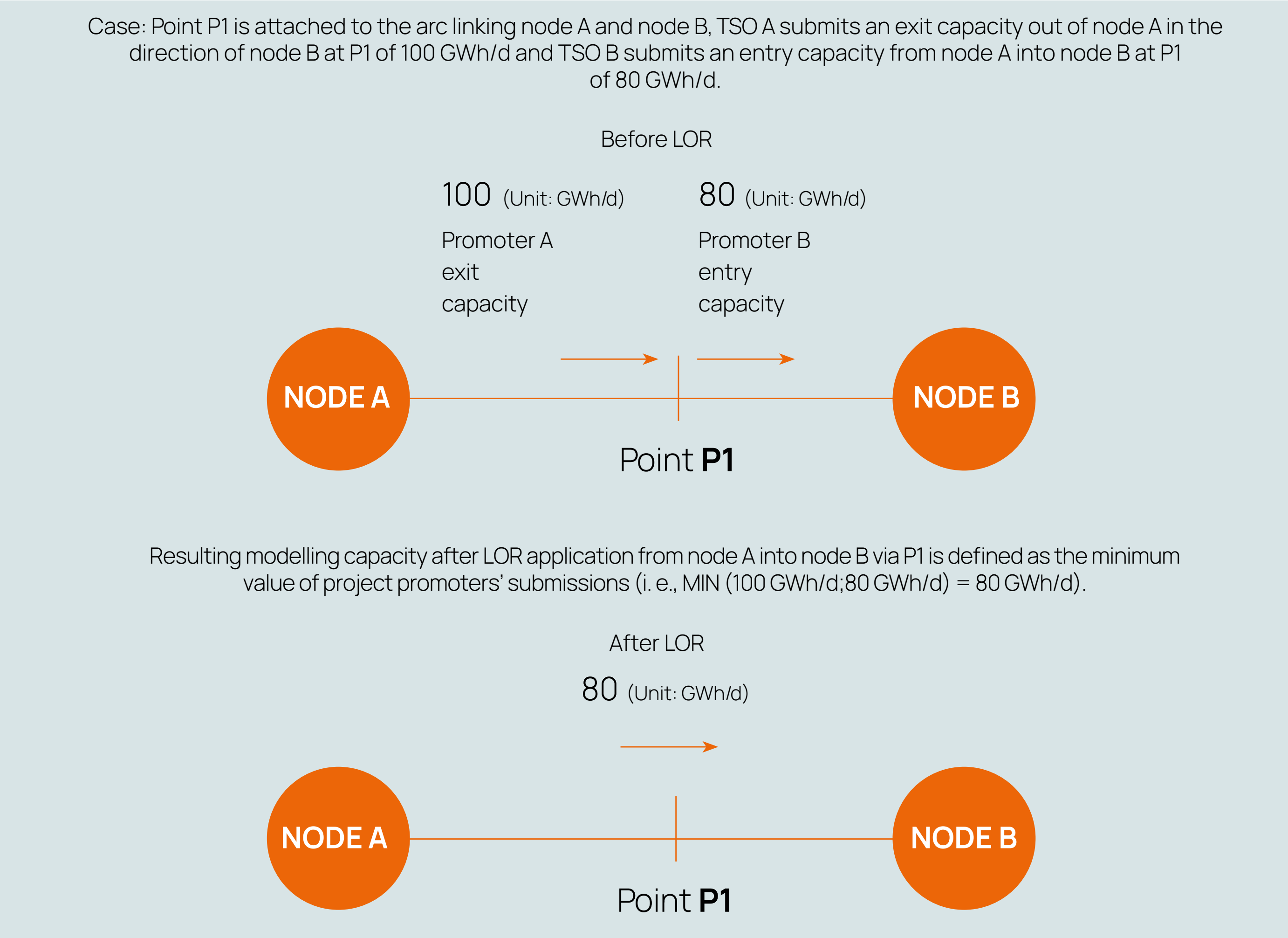


Figure 3: Example for the Lesser-of-Rule

2.2.2.3 DEMAND AND SUPPLY SOURCES

Modelling methodologies differ in how demand and supply are represented. In general[6] demand is a parameter (input) that is defined for each country or bidding zone node for each energy carrier. Depending on the specific modelling methodology in place, demand might be further disaggregated if a bidding zone is represented by various nodes that can represent, for example, different regions within a country or different types of demand.

In a similar manner, supply sources are allocated to each node. The main difference between demand and supply allocation is that the model may choose between different supply sources available at each individual node to meet the demand:

- Supply sources can be directly connected to a node, for example, representing different available hydrogen production technologies like electrolysers or steam methane reforming (SMR) installations.

- Supply can reach a node via arcs from other connected nodes. These arcs may, for example, represent interconnections to other bidding zones or import terminals to access non-EU hydrogen resources.

6 Energy system assets that either couple different energy carriers or energy storages may also result in additional energy demand at a specific node. Electrolysers, for example, can create a demand in the electricity grid that is not an input parameter but helps optimizing the overall costs.

2.2.2.4 ASSETS COUPLING ENERGY CARRIERS

One of the key features of the MES models is that different energy systems are coupled with each other by different energy system assets. These assets have in common that they transform one energy carrier into another. Hence, the demand for one energy carrier translates into a supply for another. Some examples for such assets are listed in section 2.2.1.3.

In MES models, such sector-coupling assets, are represented as objects that are placed at the interface between different energy carriers, being connected by arcs to the nodes that represent the corresponding supply energy carrier and demand energy carrier. For example, an electrolyser is a sector-coupling asset, if it is consuming electricity from an electricity node to supply hydrogen to a hydrogen node. Hence, the sector-coupling assets are a demand source for one node and at the same time a supply source for another node.

2.2.3 NETWORK MODELS

Network models can be used to simulate the physical flow of hydrogen through pipelines, taking into account factors like pressure, flow rate, and pipe characteristics. These models can be crucial for identifying grid bottlenecks linked to the hydrogen flows resulting from market activity. The outcomes could also serve as the basis for calculating indicators.

2.3 INFRASTRUCTURES LEVELS

2.3.1 CONCEPT OF INFRASTRUCTURE LEVELS

Infrastructure levels are defined as the potential stages of development of European hydrogen, electricity, or natural gas networks. Each infrastructure level represents the complete set of infrastructure components assumed to be in place over the relevant analysis time horizon. These levels significantly influence the outcomes of cost-benefit analyses, as projects are evaluated in relation to them. Consequently, the definition of infrastructure levels is of critical importance and must be approached with particular diligence and precision.

The following rules are considered when defining the infrastructure levels:

- When building the infrastructure levels, the lesser-of-rule should be consistently applied to all submitted projects (i.e., a project only effectively creates capacity at an interconnection point if there is also sufficient capacity at the other side of the interconnection point);
- When projects are found to be competing when establishing the infrastructure levels, the infrastructure levels will reflect this situation by including only one of the (group of) competing projects' capacities (e.g., by only including the capacity of the (group of) competing project(s) with the highest capacities);
- If an enabling project is not part of an infrastructure level, the project it enables cannot be part of this infrastructure level of the same energy sector.

The infrastructure level(s) for the CBAs are defined for each TYNDP cycle through the CBA implementation guidelines.

2.3.2 HYDROGEN INFRASTRUCTURE LEVELS

For the purpose of conducting Cost-Benefit Analyses (CBAs) in the hydrogen sector, multiple infrastructure levels can be differentiated, as illustrated in Figure 4. These levels reflect progressively inclusive configurations of the hydrogen infrastructure landscape:

- **Infrastructure Level 1** comprises only the existing, operational network assets.
- **Infrastructure Level 2** builds upon Level 1 by including all projects that have reached Final Investment Decision (FID).
- **Infrastructure Level 3** further expands the scope to encompass Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI), in addition to the elements included in Levels 1 and 2.
- **Infrastructure Level 4** includes all components of the preceding levels and is further extended to incorporate projects that are at an advanced stage of development.

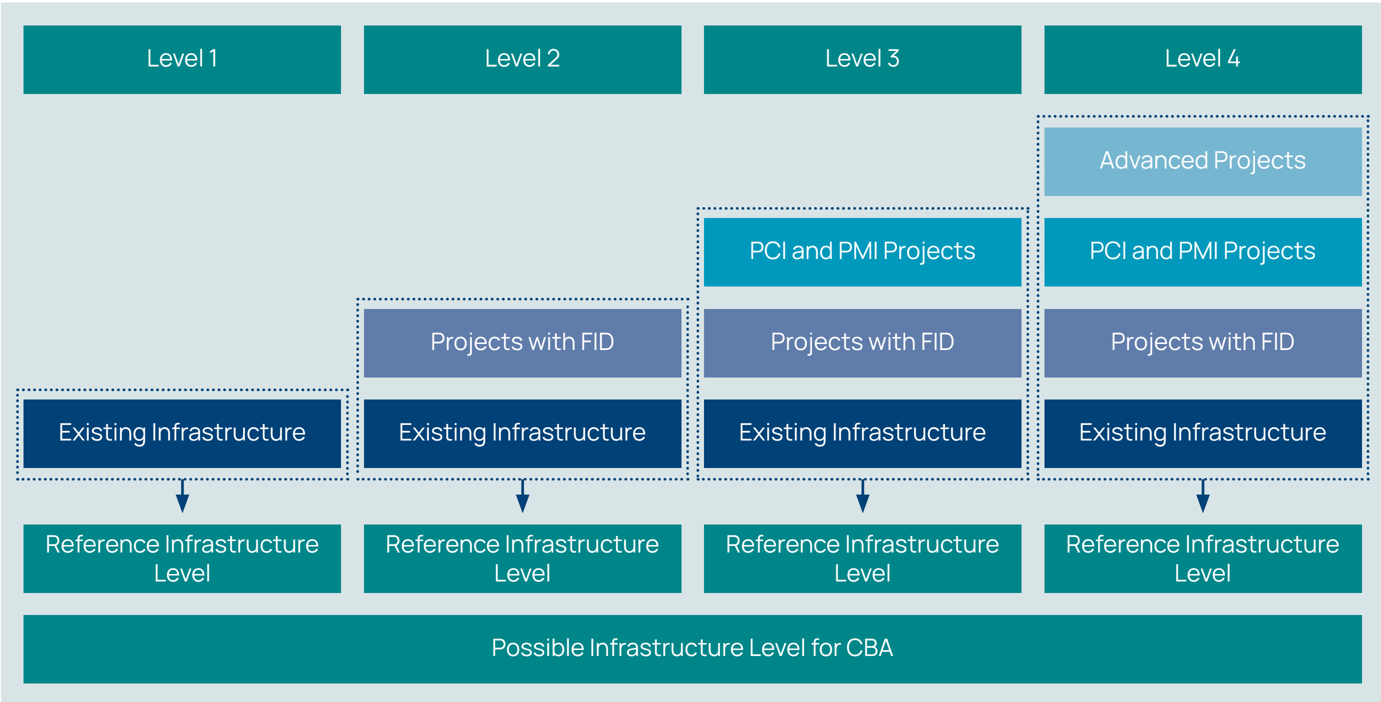


Figure 4: Possible Infrastructure Level for CBA

Whereas:

- **Existing, operational infrastructure** refers to hydrogen infrastructure that is existing at the time of the TYNDP 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 31 December of the nominal year of the TYNDP (e.g., 31.12.2026 for TYNDP 2026). The FID status was defined in Art. 2(3) of Regulation (EC) 256/2014 as follows: "final investment decision' means the decision taken at the level of an undertaking to definitively earmark funds for the investment phase of a project (…)".
- **Project with FID** refers to projects having taken the final investment decision ahead of the relevant TYNDP project data collection and the project is scheduled to be commissioned no later than 31 December of the year preceding the infrastructure levels' reference year.
- **PCI/PMI project** refers to hydrogen projects that are on the PCI/PMI Union list still in force at the moment of the creation of the hydrogen infrastructure levels.
- **Advanced project** refers to projects with an expected commissioning date no later than 31 December of the year preceding the infrastructure levels' reference year.

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.

3 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. The following criteria should be considered while grouping projects.

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.

Enabling projects and enabled projects

An enabling project (or enabler) is a project which is indispensable for the realisation of an enabled project, for the latter to start operation and to show any benefit. The enabling project 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 for an enabling project and an enabled project
Case: 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 for an enhancing project and an 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

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, if newly build, connecting pipeline to the hydrogen grid must be grouped together.
  - As a minimum, a hydrogen storage and its, if newly build, connecting pipeline to the hydrogen grid must be grouped together.
- Projects can only be grouped together if they are at maximum two advancement status apart from each other.
- Projects can only be grouped together if their commissioning dates are not more than ten years apart from each other.
- Projects that are enabled projects can only be grouped together with its enabling project.
- Projects that are enabling projects with project advancement status "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.
- Projects must be grouped and assessed jointly if it is foreseeable that the exclusion of interconnection projects would result in isolated sub-networks with insufficient access to the main transmission network.
- **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 to determinate 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**[7], 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 extra-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).

7 Multi-phase investments projects are composed of two or more sequential phases, where the first phase is required for the realisation 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 ASSESSMENT

3.2.1 QUANTIFICATION AND MONETISATION PRINCIPLES

This CBA methodology combines monetary elements pertaining to the CBA approach, as well as non-monetary and/or qualitative elements referring to the Multi-Criteria Analysis approach. Its scope is wider than the pure monetary assessment, as the reality of the energy markets and its effect for the European economy and society generally require that non-monetary effects are also considered. Quantitative indicators provide detailed, comprehensible, and comparable information independently from their potential monetary value.

For monetisation, it is important to identify all possible double counting of benefits in the assessment. Each indicator defined in this CBA methodology measures the contribution of the project to the specific criteria independently from the others and is considered as non-overlapping with the others. This is safeguarded by removing potentially overlapping parts of the different indicators as described per indicator.

Monetisation should only be performed when reliable monetisation is ensured, to avoid non-robust conclusions when comparing monetised benefits to project costs. Without it, (non-monetised) quantitative benefits should be maintained. Over time, specific investigations outside of the scope of this methodology may allow identification of meaningful and reliable ways to monetise an increased number of quantified benefits. Further monetisation should then be proposed and consulted as part of the TYNDP process.

3.2.2 THE INCREMENTAL APPROACH

Estimating benefits associated with projects require comparison of the two situations "with project" and "without project". This is the incremental approach. It is at the core of the analysis, and it is based on the differences in indicators and monetary values between the situation "with the project" and the situation "without the project".

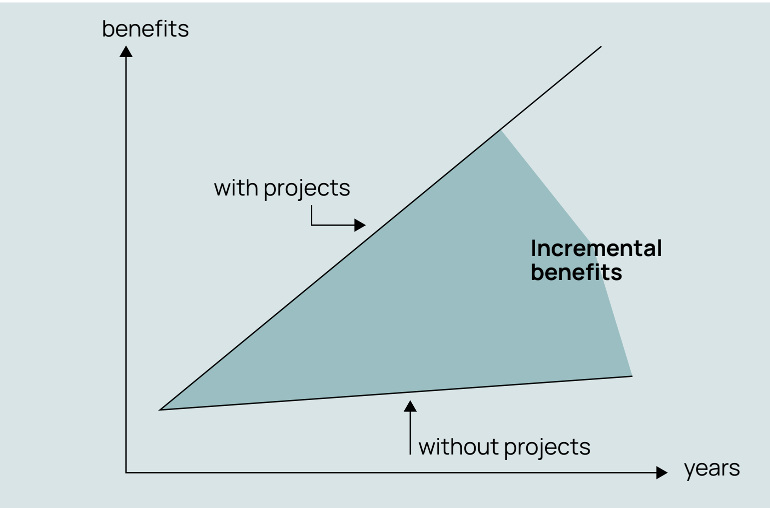


Figure 5: Incremental approach for benefits from the implementation of an assessed project

The literature makes available two methods for the application of the incremental approach:

- **Put in one at a time (PINT)** implies that the incremental benefit is calculated by adding the project(group) compared to the considered infrastructure level without the implementation of the project(group), to measure the impact of implementing the project(group). Following this approach, each project(group) is assessed as if it was the subsequent one to be commissioned (see Figure 6).

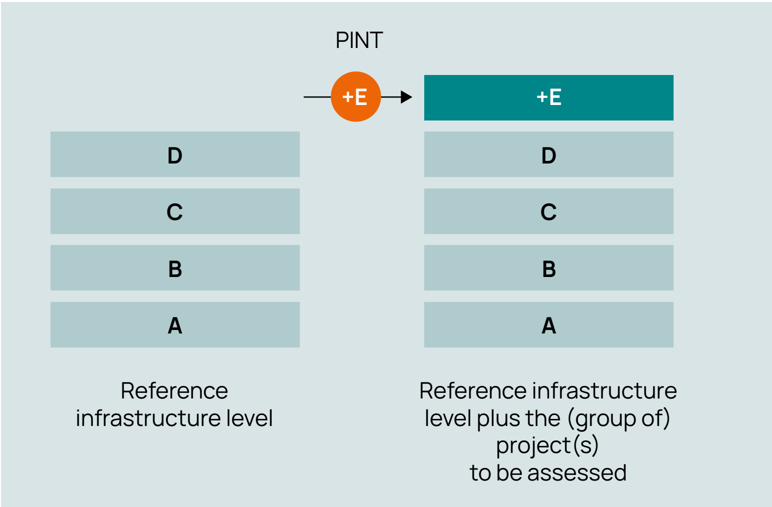


Figure 6: Assessment of Project(group) E using the PINT approach

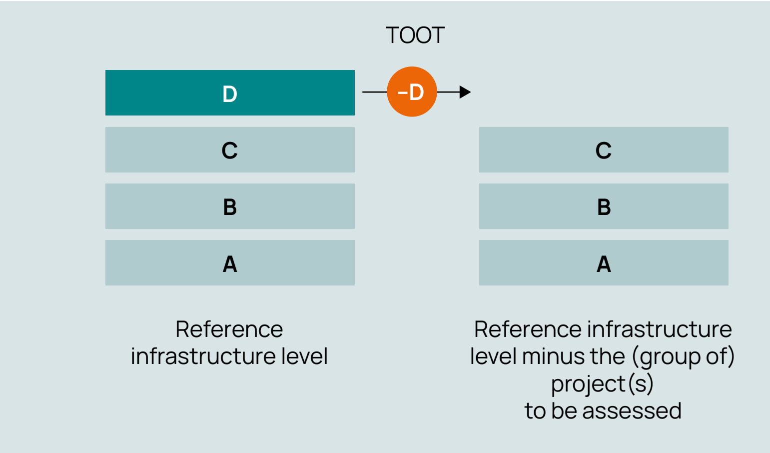


Figure 7: Assessment of Project(group) D using the TOOT approach

- **Take out one at a time (TOOT)** implies that the incremental benefit is calculated by removing the project(group) compared to the infrastructure level with the implementation of the project, to measure the impact of implementing the project(group). Following this approach, each project(group) is assessed as if it was the final one to be implemented (see Figure 7).

A (group of) project(s) will be assessed with the PINT approach if it was not part of the concerned infrastructure level, and it will be assessed with the TOOT approach if it was already part of the infrastructure level. If a group of projects contains (a) project(s) that is/are in the infrastructure level and (a) project(s) that is/are not, a mixed approach will be used. A mixed approach means that the incremental benefit is calculated by removing the projects that are part of the infrastructure level for the TOOT approach and then adding all projects of the group for PINT approach. In that way all the incremental benefit can be added up as shown in Figure 8.

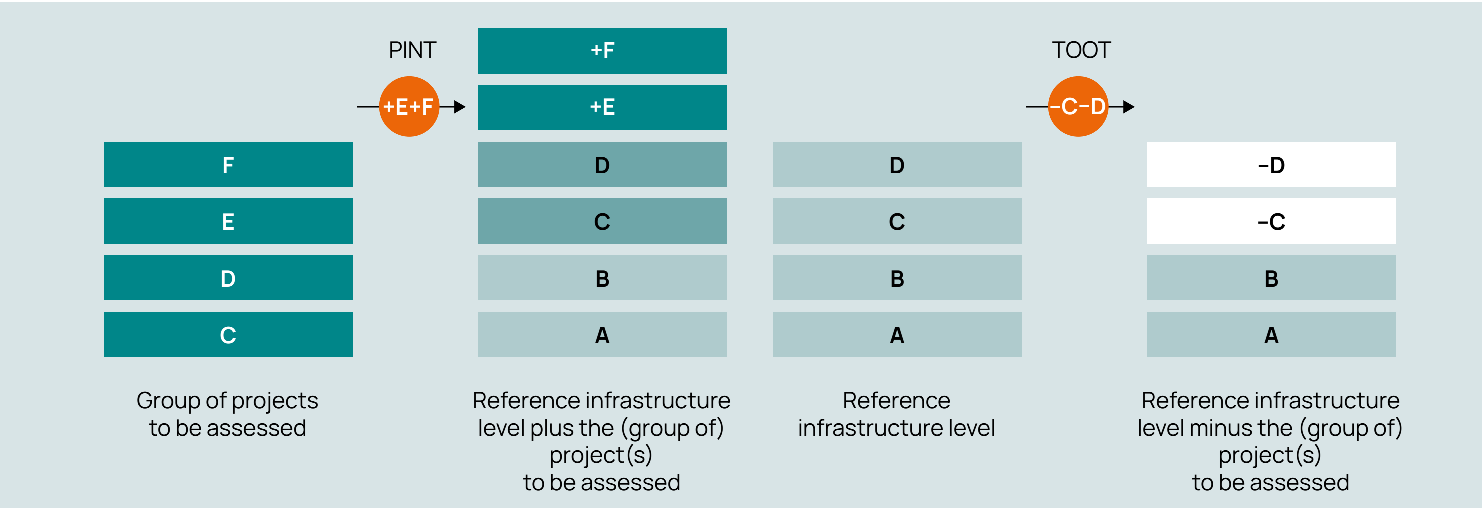


Figure 8: Assessment of a project group where (a) project(s) is/are part of the reference infrastructure level

3.3 CONCEPT OF CURTAILED VS DISRUPTED HYDROGEN DEMAND

The assessment of the benefits of the (group of) project(s) is conducted according to the benefit indicators methodology outlined in the following section 4. For this assessment, the concept of curtailed vs disrupted hydrogen demand is introduced. This concept describes, how hydrogen demand not served is taken into consideration for the project assessment.

Hydrogen demand not served in the context of the project assessment can be categorised as curtailed hydrogen demand, disrupted hydrogen demand or a combination of both.

Curtailed hydrogen demand is defined as unmet hydrogen demand which could be satisfied via a different energy source (e.g. natural gas, diesel, electricity). This different energy source is used to either produce the unserved hydrogen (e.g. a steam methane reformer on-site) or another energy carrier is used to replace hydrogen for the intended purpose (e.g. to produce heat). This could be relevant e.g. for applications in industry. Curtailed hydrogen demand would impact the demand for different energy carrier with implications on cost and CO_2 emissions. Curtailed hydrogen demand isn't relevant in the Security of Supply context as the intended purpose of the usage of hydrogen can be fulfilled by other means.

Disrupted hydrogen demand is defined as unmet hydrogen demand which cannot be substituted with a different energy source and thus remains unserved. The disruption of the hydrogen demand would then lead, e.g. in industry to a disruption of the production process relying on hydrogen. Disrupted hydrogen demand is relevant in the Security of Supply context as the intended purpose of the usage of hydrogen cannot be fulfilled by other means.

The categorisation of the unmet hydrogen demand is dependent on the demand scenarios and the year of the study. It will be detailed in the CBA implementation guidelines of each TYNDP.

This categorisation is necessary to assess CO_2 and non-CO_2 emissions as well as the cost to the unserved hydrogen demand in order to quantify the benefit provided by a (group of) project(s).

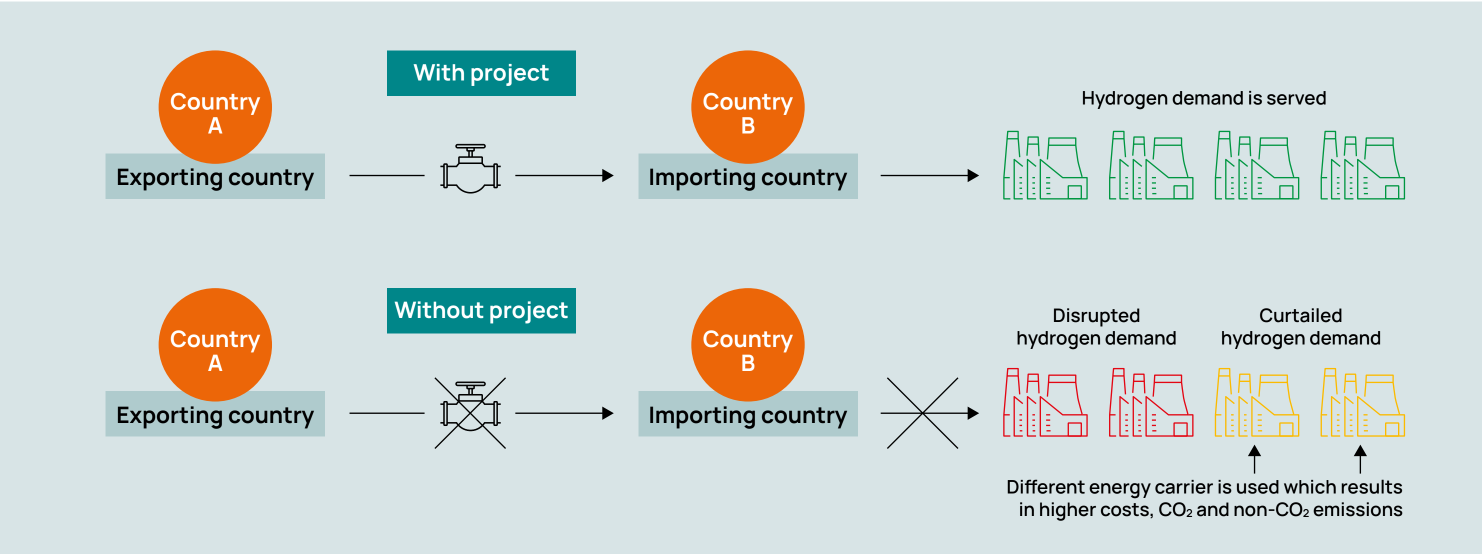


Figure 9: Concept of curtailed vs disrupted hydrogen demand

Two approaches can be applied depending on the underlying assumptions:

1) Curtailed hydrogen demand cost: In this case the unserved demand is monetised at the cost of the different energy source including the ETS cost for the CO_2 emissions, if the unserved hydrogen demand is monetised at this value an emission factor should be applied coherently for unserved hydrogen demand. The choice of the respective different energy carrier must be carried out in a coherent and consistent way and will be detailed in the CBA implementation guidelines.

2) Disrupted hydrogen demand leads to Cost of disrupted hydrogen (CODH): CODH represents the economic damage or loss of welfare experienced by the system due to the interruption or lack of hydrogen supply. When unserved hydrogen demand is monetised using CODH, no emission factor should be applied.

It is possible to apply one of those two quantifications of the cost of unserved demand or a combination of both for different sectors of the demand, the details can vary at each cycle depending on the demand scenarios and will be detailed in the CBA implementation guidelines of each TYNDP.

A robust, widely consulted, and accepted method to evaluate the extent and the scope of this concept is mandatory for its application in the TYNDP.

Considering the diversity of sectors and their specific characteristics, ENNOH will establish a default methodology and reference values through a targeted consultation with key industry stakeholders. Such a process would allow for agreement on a common approach (e.g., determining whether a disruption is foreseeable or unexpected) and the collection of sector-specific parameters (e.g., type and availability of alternative fuels, quantities, duration of use, and whether alternative fuels can be relied upon solely as an emergency measure or on a seasonal/year-round basis).

4 BENEFITS, COSTS AND RESIDUAL IMPACT

The assessment of projects is carried out using the benefit, cost, and residual impact indicators outlined in this Guideline. The benefits should be evaluated separately for each study scenario (e.g., the TYNDP scenarios).

Benefit indicators

- B1: GHG emmisions
- B2: Non-GHG emmisions
- B3: Share of renewable EU H_2 production
- B4: Renewable & low carbon H_2 production & imports
- B5: Socio-economic welfare
- B6: H_2 system adequacy
- B7: H_2 system resilience
- B8: H_2 system flexibility

Sustainability | Market integration and competition | Security of Supply and flexibility

Costs

- CAPEX
- OPEX

Residual impact

- Enviromental impact

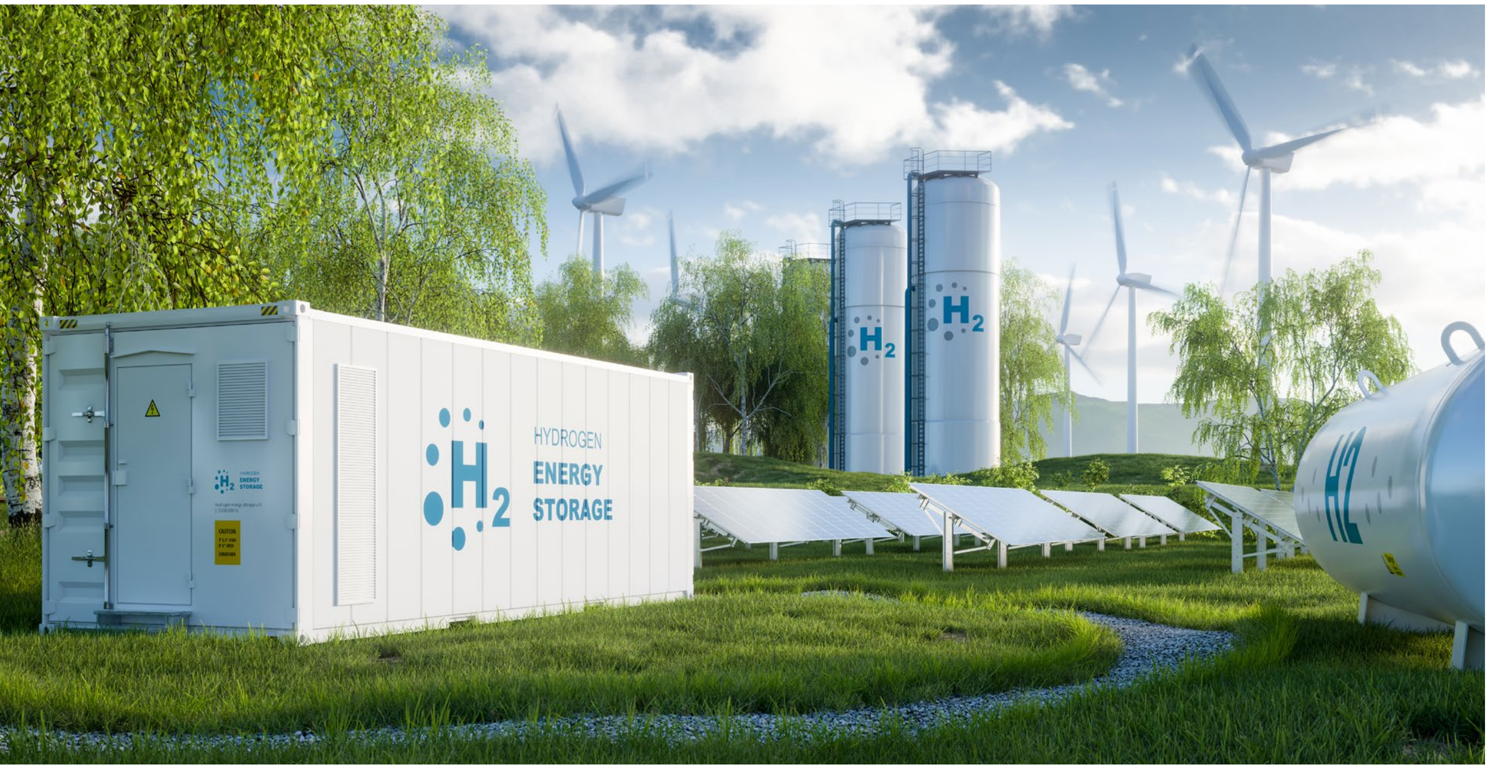
Figure 10: Overview of Benefit Indicators, Costs and Residual Impact

These indicators have been selected to facilitate the assessment of benefits and costs regarding trans-European energy infrastructure development. They address the EU key objectives regarding grid development:

- Contribution to EU climate policy and sustainability objectives (i.e. GHG reduction)
- Safeguarding Security of Supply
- Increasing market integration and competition to strive towards a unified internal energy market (i.e. increasing the Social Economic Welfare (SEW)

All benefit indicators are calculated through the incremental approach 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 description of the benefit indicators is the following:

B1: GHG emissions

This indicator measures the societal benefit due to GHG emissions variations. It reflects the change in carbon emissions from the power system and the supply sources used to meet hydrogen demand resulting from the project. It is referring to the EU's climate policy goals, i.e. of reducing greenhouse gas emissions by at least 55 % by 2030 relative to 1990 levels and to achieve net-zero in 2050.

The change of GHG emissions arises from adjustments in the usage of electricity generation type, hydrogen production type, and hydrogen import options with respective CO_2 equivalent emission factors capturing direct emissions. If the absence of the (group of) projects results in curtailed and/or disrupted energy demand, the estimated impact must be considered according to Section 3.3.

This indicator can be expressed in both non-monetised terms and in monetised terms.

B2: Non-GHG emissions

This indicator measures the societal benefit due to non-GHG emissions variation. It reflects the change in air pollutants from the power system and the supply sources used to meet hydrogen demand resulting from the project. This is linked to the EU ambitions to reduce non-GHG emissions, in particular for five different air pollutants: nitrogen oxides (NO_X), sulphur dioxides (SO_2), fine particulate matter, non-methane volatile organic compounds, and ammonia (NH_3).

The change of non-GHG emissions arises from adjustments in the usage of electricity generation type, hydrogen production type, and hydrogen import options with respective CO_2 equivalent emission factors capturing direct emissions. If the absence of the (group of) projects results in curtailed and/or disrupted energy demand, the estimated impact must be considered according to section 3.3.

This indicator can be expressed in both non-monetised terms and in monetised terms.

B3: Share of renewable EU hydrogen production

A higher share of domestic renewable hydrogen production supplied by RES (electrolytic or using biomass and derivatives) can reduce the GHG emissions and non-GHG emissions, as captured (and monetised) by the indicators B1 and B2.

This Indicator (B3) captures the additional impact of a higher share of domestic renewable hydrogen production, namely the reduction of the EU's reliance on energy imports, thereby enhancing security of supply. It can be calculated by assessing the variation of the share of renewable hydrogen production within the EU as a result of implementing a (group of) project(s).

This indicator can be expressed in non-monetised terms.

B4: Renewable and low-carbon hydrogen production and imports

Renewable hydrogen production in Europe is one important pillar of the hydrogen supply. This pillar can be complemented by low carbon production in Europe as well as import of renewable and low-carbon hydrogen. All these sources can be used to meet the future hydrogen demand. This indicator primarily measures the ability of a project to ensure that future hydrogen demand is met using all available sources that are compliant with climate neutrality targets. It can be calculated by assessing the variation of renewable and low-carbon hydrogen production and imports as a result of implementing a (group of) project(s).

This indicator can be expressed in non-monetised terms.

B5: Socio economic welfare

This benefit indicator captures the improvement in socio-economic welfare, quantified as the reduction in total system supply costs resulting from the implementation of a (group of) project(s). It reflects the surplus generated in the system as a result of having access to cheaper energy supply by calculating net change in total supply costs, considering both the costs of imports and national production. This includes changes in the costs for the hydrogen supplied to meet demand for final consumers and changes in the costs for the supply of other energy carriers that are affected by the hydrogen sector through interlinked infrastructures. If the absence of the (group of) projects results in curtailed and/or disrupted energy demand, the estimated impact must be considered according to section 3.3.

This indicator can be directly expressed in monetised terms.

B6: Hydrogen system adequacy

This indicator (B6) measures the ability of a project to ensure that hydrogen demand is met under an extreme climate year. It compares the variance of hydrogen disruption without (a group) of project for the reference weather year and a stressful weather year. Given that a project is installed and has enabled hydrogen demand, the indicator shows to what extent (a group of) project ensures supply security in extreme weather scenarios.

It must be noted, though, that indicator B6 (and also B7) addresses a different aspect of security of supply than indicator B3. Indicator B3 approaches the security of supply aspect from an import dependency while B6 and B7 approach security of supply more from the demand perspective, measuring how much demand must be curtailed in stressful situations.

B7: Hydrogen system resilience

This indicator (B7) measures the ability of a project to ability of a project to ensure that hydrogen demand is met under an extreme event scenario, in particular disruption of supply route/infrastructure. It compares the variance of hydrogen demand disruption without (a group) of project for the reference case and a disruption case. Given that a project is installed and has enabled hydrogen demand, the indicator shows to what extent (a group of) project ensures supply security in extreme event scenarios.

B8: Hydrogen system flexibility

This indicator measures the correlation between renewable electricity generation and renewable hydrogen output. The higher the value, the more the hydrogen systems can enhance energy system flexibility by aligning hydrogen production with volatile renewable electricity.

This indicator is non-advanced as the proposed methodology is in its early stage.

4.1 B1: GHG EMISSIONS VARIATIONS

4.1.1 DEFINITION

This benefit indicator (B1) measures the variations in GHG emissions as a result of implementing a (group of) project(s). This change arises from adjustments in the usage of electricity generation type, hydrogen production type, and hydrogen import options with respective CO_2 equivalent emission factors capturing direct emissions. If the absence of the (group of) projects results in curtailed and/or disrupted energy demand, the estimated impact of this must be considered according to section 3.3. It is dependent on the model, specified in the CBA implementation guidelines.

This indicator can be expressed in both non-monetised terms and in monetised terms. In non-monetised terms, the indicator is expressed as tons of CO_2 equivalent emissions variations per year (tCO_2e/y). It can be monetised (€/y) by multiplying the CO_2 equivalent emissions variations (tCO_2e/y) by the societal cost of carbon (€/tCO_2e) of the corresponding simulated year.

4.1.2 METHODOLOGY

The GHG emissions are calculated by multiplying the usage of electricity generation type (e.g., coal-fired power plant), hydrogen production type (e.g., unabated SMR), and hydrogen import options (e.g., low-carbon hydrogen from Norway) with respective CO_2 equivalent emission factors capturing direct emissions.

As a minimum, besides CO_2, the following primary non-CO_2 GHG emissions should be considered: Nitrous oxide (N_2O) and methane (CH_4).

Based on the modelling methodology specified in the CBA implementation guidelines, the calculation of GHG emissions variations needs to account for the emission intensity of unserved renewable and low-emission energy demand. This need is best illustrated using an example. Given that without a (group of) project that enables hydrogen flows between country A (net hydrogen exporter) and country B (net hydrogen importer) it is infeasible to meet the excepted hydrogen demand in country B. Based on the modelling methodology specified, this can lead to two very different outcomes:

Case 1: The model can't address the implication of curtailed hydrogen demand

There is no alternative for the model to ensure that all hydrogen demand is met. Hence, the results indicate curtailed and/or disrupted hydrogen demand. Since demand scenarios are based on expected energy consumption for the investigated year, for example 2040, curtailed hydrogen demand means that one part of the expected energy consumption is not correctly accounted for on the supply side with its corresponding emission intensity. When interpreting such model results, it should be assumed that instead of curtailing their energy demand, some part of the final consumers could use other, often more emission intensive energy sources, instead. For example, an industrial consumer will not invest in new high-temperature processes to move from natural gas to hydrogen if the hydrogen supply is not ensured. Hence, the emission intensity of curtailed hydrogen demand must be accounted for ex-post.

- The CBA implementation guidelines must introduce a methodology to account for the resulting emission intensity of curtailing hydrogen demand to correctly calculate the B1 indicator for a specific (group of) project(s).

Case 2: The model can address the implication of curtailed hydrogen demand

There is an alternative for the model to ensure that the total energy demand is met, even though not all hydrogen demand is met. In this case, demand scenarios would have to be designed in such way that the model has fallback options available for most hydrogen demand sectors. This entails not only that gas-to-power generators can run on methane or that expected synfuel production is replaced with conventional fuels, such as kerosene, but also that fallback options are available for at least most industrial hydrogen demand.

- The CBA implementation guidelines specify sufficient alternative supply routes to ensure that all energy demand is met under consideration of curtailed hydrogen demand. The resulting emissions when not implementing (a group of) projects can be used to calculate indicator B1 without further consideration of the curtailed hydrogen demand.

The following formula is used to calculate the GHG emission variations:

$$GHG\ emissions\ variation\ enabled\ by\ (group\ of)\ \ project(s)$$

$$= (\sum_{i}^{n}\ (power\ generation_{i,\ with\ (group\ of) project(s)}\ x\ CO_2 e\ emission\ factor_i)$$

$$+\sum_{j}^{m}\ (hydrogen\ production_{j,\ with\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_j)$$

$$+\sum_{k}^{r}\ (hydrogen\ import\ from\ supply\ potential_{k,\ with\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_k)$$

$$+\sum_{l}^{o}\ (hydrogen\ substitutes_{l,\ with\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_l))$$

$$-(\sum_{i}^{n}\ (power\ generation_{i,\ without\ (group\ of) project(s)}\ x\ CO_2 e\ emission\ factor_i)$$

$$+\sum_{j}^{m}\ (hydrogen\ production_{j,\ without\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_j)$$

$$+\sum_{k}^{r}\ (hydrogen\ import\ from\ supply\ potential_{k,\ with\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_k)$$

$$+\sum_{l}^{o}\ (hydrogen\ substitutes_{l,\ with\ (group\ of)\ project(s)}\ x\ CO_2 e\ emission\ factor_l))$$

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.
- o: number of different types of hydrogen substitutes
- All CO_2 equivalent emission factors capture direct GHG emissions.
- 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_2e 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_2e emission factor$_i$: 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$_k$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'k'. It is used to capture the changes of imports from supply sources that are considered with the supply potential approach.
- CO_2e emission factor$_k$: GHG emission factor expressed in CO_2 equivalence of hydrogen source that is considered with the supply potential approach of type 'k' per unit of energy used.
- Hydrogen substitutes$_l$: Amount of curtailed hydrogen substituted by energy carriers or feedstock of type 'l' (e.g., natural gas, coal, etc.). Variations with and without the (group of) project(s) are resulting from changing the mix of substitutes and total consumption.
- CO_2e emission factor$_l$: GHG emission factor expressed in CO_2 equivalence of substitute of type 'l' that is considered for the curtailed hydrogen per unit of energy used.

4.1.3 MONETISATION

The resulting amount of variation of GHG emissions in tonnes of CO_2e shall be valued in monetary terms reflecting the non-monetised societal cost of carbon. The unit is €/y.

The societal cost of carbon can refer to two different concepts for the economical evaluation of the effects and damages caused by GHG emissions:

- 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.

The societal cost of carbon used for this benefit indicator (B1) should be based on reputable scientific investigations and international studies. Because of the expected spread of values that typically arise from different sources, the costs that are used can be given as a range, e.g., by defining minimum, medium and maximum values. They should ideally be agreed between the main stakeholders and reflect the most recent values as given by the European Commission. The values used for the monetisation of this indicator are required to be provided within the CBA implementation guidelines, together with a link to the scientific and agreed study. As default reference source, the shadow cost of carbon of the European Investment Bank (EIB) should be used for the monetisation of GHG emissions through this indicator (B1). When available, the cost of carbon should include more granular inputs with respect to its development over time (e.g., yearly inputs).

The societal cost of carbon will already be reflected partially in the model results, given that the MES models used will incorporate the EU ETS as carbon pricing mechanism for those emitters covered by the carbon market under the current legislation. Market results are subject to EU ETS prices, and the EU ETS carbon price is internalized in the market outcome. Hence, EU ETS carbon pricing is monetised in the scenarios and should be considered jointly with other market-based system costs in indicator B4 to avoid double-counting of benefits.

The monetisation of the societal costs of carbon for benefit indicator (B1) should therefore reflect those costs that have not been monetised as part of the market-based system costs in indicator B5. The societal cost of carbon typically considers a higher cost of carbon than the ETS.[8] Hence, it represents the share of the societal cost of carbon that has not been paid for via the EU ETS. The monetisation of benefit indicator (B1) therefore aims to reflect the variation of those societal emission costs that have not been monetised by the EU ETS for the implementation of a (group of) project(s).

The following formula is used to calculate the non-monetised societal cost of carbon emission variations:

$$B1_{monetised} \\ = Societal\ \ Cost\ of\ Carbon\ x\ GHG\ emissions\ variations\ enabled\ by\ (group\ of)\ project(s) \\ - total\ GHGemission\ costs\ monetised\ in\ B5$$

On the basis of:

- Societal Cost of Carbon: Cost of Carbon for the specific year as published by the EIB[9].
- GHG emissions variations enabled by (group of) project(s): As defined in the formula above.
- Total GHG emission costs monetised in B5: Variation of GHG emission costs enabled by the (group of) project(s) as considered in the increase of socio-economic welfare indicator (B5) on the basis of the forecasted ETS price.

8 IPCC Special report on the impacts of global warming of 1.5 °C (2018) – Chapter 2

9 EIB Group Climate Bank Roadmap 2021–2025 (November 2020)

4.1.4 INTERLINKAGES WITH OTHER INDICATORS

- The increase of socio-economic welfare indicator (B5) which also includes a monetisation of the part of the GHG emissions as described above. Therefore, the GHG emissions costs that are monetised in socio economic welfare indicator (B5) are removed from this benefit indicator (B1) to avoid double-counting.
- The integration of renewable electricity generation indicator (B3) 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 (B4) 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;

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

4.2 B2: NON-GHG EMISSIONS

4.2.1 DEFINITION

The societal benefit due to non-GHG emissions variations reflects the change in carbon emissions from the power system and the supply sources used to meet hydrogen demand resulting from the project. This is linked to the EU ambitions to reduce non-GHG emissions, in particular for five different air pollutants: nitrogen oxides (NO_X), sulphur dioxides (SO_2), fine particulate matter, non-methane volatile organic compounds, and ammonia (NH_3).

The change of non-GHG emissions arises from adjustments in the usage of electricity generation type, hydrogen production type, and hydrogen import options with respective CO_2 equivalent emission factors capturing direct emissions. If the absence of the (group of) projects results in curtailed and/or disrupted energy demand, the estimated impact of this must be considered according to section 3.3.

This indicator can be expressed in both non-monetised terms and in monetised terms. In non-monetised terms, the indicator is expressed as variations of tonnes of pollutant emitted per year (e.g., tNO_X/y, tSO_2/y, tPM/y, etc.). It can be 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.

4.2.2 METHODOLOGY

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. The detailed consideration of the emission factor will be outlined in the CBA implementation guidelines.

The following formula is used to calculate the non-GHG emission variations:

$$Non - GHG\ emissions\ variation\ enabled\ by\ (group\ of)\ project\ (s)_y$$
$$= (\sum_i^n (power\ generation_{i,\ with\ (group\ of) project(s)}\ x\ Non - GHG\ emission\ factor_{i,y})$$
$$+\sum_j^m (hydrogen\ production_{j,\ with\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{j,y})$$
$$+\sum_k^r (hydrogen\ import\ from\ supply\ potential_{k,\ with\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{k,y})$$
$$+\sum_l^o (hydrogen\ substitutes_{l,\ with\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{l,y}))$$
$$-(\sum_i^n (power\ generation_{i,\ without\ (group\ of) project(s)}\ x\ Non - GHG\ mission\ factor_{i,y})$$
$$+\sum_j^m (hydrogen\ production_{j,\ without\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{j,y})$$
$$+\sum_k^r (hydrogen\ import\ from\ supply\ potential_{k,\ with\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{k,y})$$
$$+\sum_l^o (hydrogen\ substitutes_{l,\ with\ (group\ of)\ project(s)}\ x\ Non - GHG\ \ emission\ factor_{l,y}))$$

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.
- o: number of different types of hydrogen substitutes
- All non-GHG emission factors capture direct emissions.
- 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$_k$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'l'.

- Non-GHG emission factor$_{k,y}$: Non-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.

- Hydrogen substitutes$_l$: Amount of curtailed hydrogen substituted by energy carriers or feedstock of type 'l' (e.g., natural gas, coal, etc.). Variations with and without the (group of) project(s) are resulting from changing the mix of substitutes and total consumption.

- Non-GHG emission factor$_{l,y}$: Non-GHG emission factor for pollutant 'y' of the substitute of type 'l' that is considered for the curtailed hydrogen per unit of energy used.

The formula is applied to each assessed non-GHG pollutant 'y' individually. The set of the resulting quantitative non-GHG emission reductions is the non-monetised B2 indicator.

4.2.3 MONETISATION

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

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

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 costy: Cost of the emission of pollutant 'y' (€/t[Pollutant]).

Transparent and preferably publicly available sources of information (such as the European Environment Agency[10]) regarding the damage costs of pollutants are preferred. In addition, the sources of the used emission factors and the damage costs must be referenced and should be consulted in the CBA 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 €/tCO_2
- Assumed damage cost of pollutant x in the assessed year: 200 €/tCO_2
- Non-monetised results of this benefit indicator (B2):
- Reduction of emissions of pollutant y: 0.1 Mt/y
- Reduction of emissions of pollutant x: 0.05 Mt/y
- Non-GHG emissions variations monetised in this benefit indicator (B2): 100 × 0.1 M€/y + 200 × 0.05 M€/y = 20 M€/y

4.2.4 INTERLINKAGES WITH OTHER INDICATORS

This benefit indicator (B2) is interlinked with

- The integration of renewable hydrogen indicator (B3) 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 (B4) 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.

10 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.

4.3 B3: SHARE OF RENEWABLE EU HYDROGEN PRODUCTION

4.3.1 DEFINITION

This benefit indicator (B3) considers the share of hydrogen that is supplied by RES (electrolytic or using biomass and derivatives) inside the EU (also labelled domestic hydrogen). It calculates the variation of the share of renewable hydrogen production within the EU supply as a result of implementing a (group of) project(s). The benefits are expressed in quantitative terms in variations of energy per year (%/y). No monetisation step is applied, since it is already monetised as part of other benefit indicators.

In MES models only renewable hydrogen would be produced in Europe that can also be consumed. It is economically more beneficial to curtail RES rather than to produce renewable hydrogen and then curtail it.

4.3.2 METHODOLOGY

To calculate the indicator, the following formula is applied.

$$B3 = \sum_{i}^{n} \frac{domestic\ renewable\ hydrogen\ generation_{i,\,with\ (group\ of)\ project(s)}}{entire\ H2\ supply_{\,with\ (group\ of)\ project(s)}} - \sum_{i}^{n} \frac{domestic\ renewable\ hydrogen\ generation_{i,\,without\ (group\ of)\ project(s)}}{entire\ H2\ supply_{\,without\ (group\ of)\ project(s)}}$$

On the basis of:

- n: number of types of renewable generation routes.
- Domestic renewable hydrogen generation: amount of hydrogen produced by renewable hydrogen of type 'i' (MWh/y).
- Entire H_2 Supply: The whole H_2 supplied in the model, including the entire hydrogen production and all imports of hydrogen (MWh/y).

4.3.3 MONETISATION

This benefit indicator is not monetised, since it is already monetised as part of other benefit indicators.

4.3.4 INTERLINKAGES WITH OTHER INDICATORS

This benefit indicator (B3) is interlinked with

- The GHG emissions variations indicator (B1) as using more renewable electricity generation producing hydrogen reduces GHG emissions, replacing more emitting alternatives that would otherwise be used.
- The non-GHG emissions variations indicator (B2) as using more renewable electricity generation producing hydrogen reduces non-GHG emissions, replacing more emitting alternatives that would otherwise be used.
- The integration of renewable and low-carbon hydrogen (indicator B4) through increased domestic renewable hydrogen generation. The production of electrolytic hydrogen can replace more expensive, non-renewable hydrogen sources.
- The increase of socio-economic welfare indicator (B5) through higher renewable electricity generation/import which can then replace more expensive electricity generation and enable higher electrolytic hydrogen generation in lieu of costlier fossil-fuel hydrogen.

- Indicator B6, which measures exposure to disrupted hydrogen demand, can improve if renewable hydrogen production increases.

- Jointly with the B6 and B7 indicators, the indicator B3 can be used to measure security of supply. While the B5 indicator considers all available hydrogen supply and its ability to meet the demand the B3 indicator can be used to measure the domestic energy security for hydrogen supply since an increase in the indicator means that more domestic hydrogen production is available.

4.4 B4: INTEGRATION OF RENEWABLE AND LOW CARBON HYDROGEN

4.4.1 DEFINITION

This benefit indicator (B4) considers the production of electrolytic and low carbon hydrogen as well as the import of renewable and low carbon hydrogen. It calculates the variation of variance in the availability of renewable and low-carbon hydrogen supply as a result of implementing a (group of) project(s). The benefits are expressed in quantitative terms in variations of energy per year (MWh/y). No monetisation step is applied, since it is already monetised as part of other benefit indicators.

In MES models only renewable hydrogen would be produced in Europe that can also be consumed. It is economically more beneficial to curtail RES rather than to produce renewable hydrogen and then curtail it.

4.4.2 METHODOLOGY

The following formula is applied:

$$
\begin{aligned}
B4 = \Big(&Electrolytc\ hydrogen\ production_{with\ (group\ of)\ project(s)} \\
&+ Low\ carbon\ hydrogen\ production_{with\ (group\ of)\ project(s)} \\
&+ renewable\ hydrogen\ imports_{with\ (group\ of)\ project(s)} \\
&+ low\ carbon\ hydrogen\ imports_{with\ (group\ of)\ project(s)}\Big) \\
&- \Big(Electrolytc\ hydrogen\ production_{without\ (group\ of)\ project(s)} \\
&+ Low\ carbon\ hydrogen\ production_{without\ (group\ of)\ project(s)} \\
&+ renewable\ hydrogen\ imports_{without\ (group\ of)\ project(s)} \\
&+ low\ carbon\ hydrogen\ imports_{without\ (group\ of)\ project(s)}\Big)
\end{aligned}
$$

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 scenarios (MWh/y).

- Low carbon hydrogen imports: Hydrogen imported from supply sources that are considered to supply low carbon hydrogen in the scenarios (MWh/y).

Example for a hypothetical hydrogen transmission project

Case: Country A's domestic hydrogen market is fully satisfied. Country A' s hydrogen market is currently not connected to other countries. This is limiting the 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 with a capacity of 10 TWh/y. 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 (B4): Variation of relevant hydrogen production: +10 TWh/y

4.4.3 MONETISATION

This benefit indicator is not monetised, since it is already monetised as part of other benefit indicators.

4.4.4 INTERLINKAGES WITH OTHER INDICATORS

This benefit indicator (B4) 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 hydrogen generation indicator (B3) 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 socio economic welfare 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 socio economic welfare 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.

4.5 B5: SOCIO-ECONOMIC WELFARE

4.5.1 DEFINITION

This benefit indicator captures the improvement in socio-economic welfare, quantified as the reduction in total system supply costs resulting from the implementation of a (group of) project(s). It reflects the surplus generated in the system as a result of having access to cheaper energy supply.

4.5.2 METHODOLOGY

The socio-economic benefit is defined as the sum of economic surpluses of consumers, producers and transmission infrastructure owners. A reduction in total system supply costs resulting from the realisation of a (group of) project(s) leads to economic gains that manifest either as lower prices for final consumers and/or increased profits for producers and transmission operators. While in theory it is possible to identify the distinct surpluses for consumers, producers, and transmission owners, doing so requires additional assumptions and consideration about price formation, market behavior and policies in place. This level of granularity is beyond the scope of this cost-benefit analysis. Therefore, the analysis focuses on a system-wide approach. Under the assumption of inelastic demand (which is a standard assumption for energy markets), calculating the difference in the total system supply costs with and without the project delivers the same result of the sum of the economic surplus for consumer, producers and transmission infrastructures owners, while ensuring transparency and methodological simplicity.

Example for a hypothetical hydrogen transmission project

Case: The implementation of a hydrogen project enables access to cheaper hydrogen, changing a country's hydrogen supply curve from the blue line in Figure 11 to the orange line. The price of hydrogen is determined by the crossing of the supply and demand lines.

In this example the price of hydrogen is decreasing from P1 to P2 as a result of the realisation of the project. In Figure 11 we can observe the change in the surplus for the economic agents:

- Consumers will gain a surplus determined by the change of price multiplied by the hydrogen consumed
- Producers will receive a loss determined by the reduction of price as they're no longer able to sell some of the hydrogen above its marginal cost. They will experience a loss equal to the area striped in red on the graph.

The net socio-economic benefit to the system is the difference between the gain in consumer surplus and the loss in producer surplus. This net benefit reflects the overall improvement in economic efficiency due to the project. Figure 11 shows the total system supply cost approach: the economic surplus is calculated considering the reduction in costs of the hydrogen supplied (green area on the graph on the right). As it is showed to the graph, under standard assumptions, the same result is reached using the two methods.

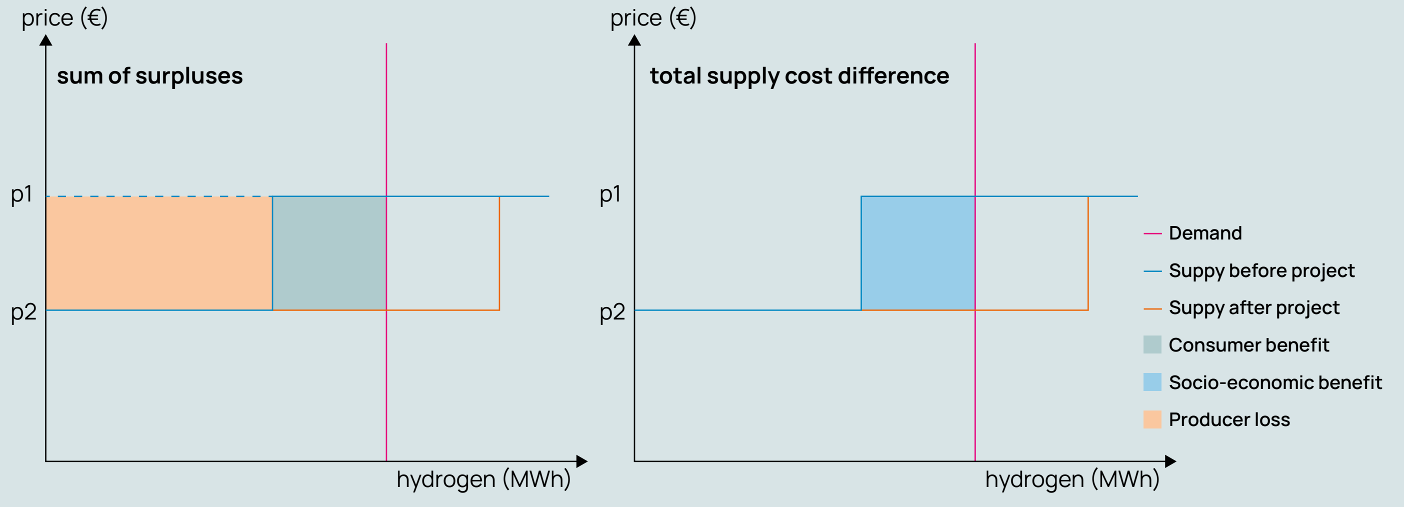


Figure 11: Socio-economic benefit as sum of surpluses and as total supply cost difference

In the context of sector coupling, the calculation of total supply costs must extend beyond the hydrogen supplied to meet final demand. It should also account for the interlinkages between hydrogen and other energy carriers, whose supply costs may be affected by the implementation of the project.

For example:

- If hydrogen is used as an input for electricity generation, a project that enables the supply of lower-cost hydrogen can also reduce the cost of electricity production. This occurs because electricity generators now have access to a cheaper fuel source, thus lowering their overall supply costs.
- Conversely, if hydrogen is produced from natural gas, a project that facilitates access to lower-cost green hydrogen can lead to reduced demand for natural gas in the hydrogen production process. This shift may, in turn, lead to a decline in natural gas prices, benefiting other sectors that rely on this fuel.

These interconnected effects represent real economic surpluses generated as a consequence of the (group of) project(s). As such, they must be included in the calculation of socio-economic benefits under a total system supply cost framework. The sector included in the calculation of the benefit will be detailed in the CBA implementation guidelines and will depend on the modelling tools available for the TYNDP.

4.5.3 MONETISATION

This benefit indicator is directly expressed in monetised terms (€/y). The following formula is used for the calculation of the socio-economic benefit:

Total Supply Cost (TSC): $\sum_j (c_j + dd_j + cd_j)$

Where:

- c refers to the total generation costs of the supply
- j refers to the energy sector considered (hydrogen, electricity, natural gas)
- dd refers to the disrupted demand monetise at cost of disrupted supplyj (CODSj)
- cd refers to the cost of the different energy carrier used to meet the curtailed demand

Socio-economic benefit (B5):
$TSC_{\text{without the project}} - TSC_{\text{with the project}}$

4.5.4 INTERLINKAGES WITH OTHER INDICATORS

This benefit indicator (B5) is interlinked with the GHG emissions variations indicator (B1), the integration of renewable electricity generation indicator (B3), and the integration of renewable and low carbon hydrogen indicator (B4). Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double counting is avoided.

4.6 B6: HYDROGEN SYSTEM ADEQUACY

4.6.1 DEFINITION

This benefit indicator (B6) measures the variance of disrupted hydrogen demand in a given area due to the implementation of the (group of) project(s) for a stressful weather year compared to the reference weather year.

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 (B6) 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.

Other than for the calculation of indicator B1 and B2, the indicator B6 departs from the premise that the infrastructure is already installed, and hydrogen demand needs to be met. Though, curtailed hydrogen demand for indicator B1 and B2 in the reference weather year might be calculated the same way as the disrupted hydrogen demand in the reference weather year for indicator B6, their role in evaluating the a (group of) project(s) is different.

4.6.2 METHODOLOGY

While the weather year used for the calculation of the other benefit indicators is supposed to be a representative one, this benefit indicator (B6) 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 disruption introduced by the (group of) project(s) for the stressful weather year compared to the reference weather year. In a first step, the variance Hydrogen Demand Disruption (HDD) is calculated for the whole assessed duration in energetic terms (MWh) for the reference weather year. The HDD is calculated for the stressful weather year as well as for the reference weather year. For each of the two weather years, the variance HDD is calculated with and without the (group of) project(s).

$$\begin{aligned}\Delta HDD_{reference\ weather\ year} &= HDD_{reference\ weather\ year\ with\ a\ (group\ of)\ project(s)} \\ &- HDD_{reference\ weather\ year\ without\ a\ (group\ of)\ project(s)}\end{aligned}$$

$$\begin{aligned}\Delta HDD_{stressful\ weather\ year} &= HDD_{stressful\ weather\ year\ with\ a\ (group\ of)\ project(s)} \\ &- HDD_{stressful\ weather\ year\ without\ a\ (group\ of)\ project(s)}\end{aligned}$$

HDD variations for the reference weather year were already considered in the other benefit indicators in form of curtailed hydrogen demand. This indicator only considers additional disrupted hydrogen demand for the stressful weather year by subtracting the following HDD variance that is enabled for the reference weather year from the HDD variation in the stressful weather year. The non-monetised benefit indicator is therefore defined as follows:

$$HDD_{B6} = \Delta HDD_{stressful\ weather\ year} - \Delta HDD_{reference\ weather\ year}$$

4.6.3 MONETISATION

This benefit indicator can then be monetised as follows:

$$B6_{monetised} = \Delta HDD_{B6}\ x\ Probability\ of\ occurence\ x\ CODH$$

On the basis of:

- CODH: Cost of Disrupted Hydrogen (€/MWh). An approximation of the he cost faced by consumers from a temporary interruption in the supply of hydrogen. If with the definition of an EU hydrogen and low carbon gases security of supply policy[11], a definition of a Cost of Disrupted Hydrogen (CODH) would be recommended, this CODH value could be introduced as harmonised reference value of the monetisation factor at EU level unless differently defined in the CBA implementation guidelines.
- Probability of occurrence: Probability of the occurrence of a stressful weather year (e.g., 10 %), to be defined in the CBA implementation guidelines.

4.6.4 INTERLINKAGES WITH OTHER INDICATORS

Other than for the calculation of indicator B1 and B2, the indicator B6 departs from the premise that the infrastructure is already installed, and hydrogen demand needs to be met. Though, curtailed hydrogen demand for indicator B1 and B2 in the reference weather year might be calculated the same way as the disrupted hydrogen demand in the reference weather year for indicator B6, their role in evaluating the a (group of) project(s) is different.

No interlinkage, as other benefit indicators are calculated based on the reference weather year and the HDD of the reference weather year is removed from this benefit indicator (B6). No interlinkage with benefit indicator B7 as they are calculated under different assumptions (stressful weather year vs infrastructure disruption).

4.7 B7: H2 SYSTEM RESILIENCE

4.7.1 DEFINITION

This benefit indicator (B7) considers the unavailability of supply sources due to infrastructure disruption. The assessment allows to consider risk factors on the infrastructure of technical, geopolitical or environmental nature, including the impact of extreme weather events on the infrastructure as requested by the TEN-E regulation[12]. While benefit indicator B6 considers stress factors mainly on the production side due to the reduced availability of renewable electricity for hydrogen production, this indicator (B7) considers stress factors on the infrastructure side or on imports. Hence, the two indicators are complementary. This indicator is calculated based on a reduced reference infrastructure grid due to:

- Disturbances on some of the infrastructures caused by extreme weather events or other physical damages
- Unavailability of import supply sources caused by geopolitical factors or other disturbances described above

Further characterisation of the disruption, such as duration and probability, should be detailed in the CBA implementation guidelines.

The supply stress tests the system resilience through the availability of alternatives routes of import, interconnection capacities, storage capacities or local production.

This benefit indicator captures the mitigation of additional hydrogen demand disruption introduced by the (group of) project(s) for the period assessed in presence of disruption on one or more infrastructures included in the reference infrastructure grid compared to the reference simulation with the whole infrastructure grid.

11 Report from the European Commission to the Council and the European Parliament reviewing the application of Regulation (EU) 2017/1938, October 2023.

12 Annex IV, 3 (c)

4.7.2 METHODOLOGY

In a first step, the Hydrogen Demand Disruption (HDD) is calculated for the whole assessed duration in energetic terms (MWh). The variance of the HDD is calculated for the case of an infrastructure disruption as well as for the one without infrastructure disruption. For each of the two cases, the HDD is calculated with and without the (group of) project(s). From this, the change in the HDD due to the implementation of the (group of) project(s) can be calculated for the case of the largest single infrastructure disruption.

$$\Delta HDD_{without\ infrastructure\ disruption} = HDD_{without\ infrastructure\ disruption\ with\ a\ (group\ of)\ project(s)} - HDD_{without\ infrastructure\ disruption\ without\ a\ (group\ of)\ project(s)}$$

$$\Delta HDD_{with\ infrastructure\ disruption} = HDD_{with\ infrastructure\ disruption\ with\ a\ (group\ of)\ project(s)} - HDD_{with\ infrastructure\ disruption\ without\ a\ (group\ of)\ project(s)}$$

The non-monetised benefit indicator is therefore defined as follows:

$$HDD_{B5.2} = \Delta HDD_{with\ infrastructure\ disruption} - \Delta HDD_{without\ infrastructure\ disruption}$$

A double counting of HDD reductions that were already considered in the other benefit indicators should be avoided by considering only the additional HDD arising from the disruption period. This can be achieved by removing the following HDC reduction that is enabled for the reference simulation.

4.7.3 MONETISATION

This benefit indicator can then be monetised as follows:

$$B5.2_{monetised} = \Delta HDD_{B5.2}\ x\ Probability\ of\ Occurence\ x\ CODH$$

On the basis of:

- CODH: Cost of Disrupted Hydrogen (€/MWh). An approximation of the he cost faced by consumers from a temporary interruption in the supply of hydrogen. If with the definition of an EU hydrogen and low carbon gases security of supply policy[13], a definition of a Cost of Disrupted Hydrogen (CODH) would be recommended, this CODH value could be introduced as harmonised reference value of the monetisation factor at EU level unless differently defined in the CBA implementation guidelines.
- Probability of occurrence: Probability of the occurrence of a stressful weather year (e.g., 10 %), to be defined in the CBA implementation guidelines.

4.7.4 INTERLIKANGES WITH OTHER INDICATORS

No interlinkage, as other benefit indicators are calculated based on the reference weather year and the HDD of the reference weather year is removed from this benefit indicator (B7). No interlinkage with B6 as they are calculated under different assumptions (stressful weather year vs infrastructure disruption).

13 Report from the European Commission to the Council and the European Parliament reviewing the application of Regulation (EU) 2017/1938, October 2023.

4.8 B8: HYDROGEN SYSTEM FLEXIBILITY

4.8.1 DEFINITION

In energy systems that increasingly rely on volatile renewable electricity generation, more flexibility is needed. Flexibility can be defined as the ability of the integrated energy system to swiftly react to demand and supply shifts (see CERRE report[14]). The hydrogen system can play a key role in responding to the additional flexibility needs on the electricity system.

4.8.2 METHODOLOGY

Hydrogen systems are not expected to cause major additional flexibility needs in an integrated energy system. Increased flexibility needs in the integrated energy system are primarily driven by additional volatile renewable electricity generation. Hence, this indicator aims at determining the additional flexibility the hydrogen system can offer for dealing with the volatility of renewable electricity generation when implementing a (group of) project(s). The indicator is defined as the change in the correlation coefficient (r) between uncurtailed renewable electricity generation and the renewable hydrogen generation when implementing a (group of) projects).

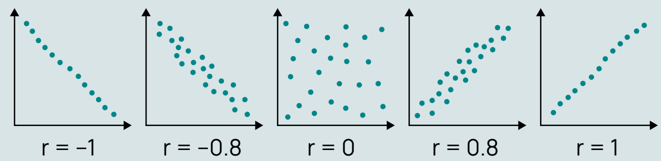
$$r = \frac{\sum_{i=1}^{n}(x_i-\bar{x})(y_i-\bar{y})}{\sqrt{\sum_{i=1}^{n}(x_i-\bar{x})^2 \sum_{i=1}^{n}(y_i-\bar{y})^2}}$$

With x_i as the uncurtailed renewable electricity generation (x) for each hour (i) of the year (n=8760h) and y_i as renewable hydrogen generation (y) for each hour (i) of the year (n).

The terms $\bar{x},\bar{y}$ denote the mean annual value for uncurtailed electricity generation ($\bar{x}$) and renewable hydrogen generation ($\bar{y}$).

An r value of 1 means that renewable electricity generation and renewable hydrogen generation are perfectly correlated. As such, the hydrogen system perfectly responds to the flexibility needs caused by volatile renewable electricity generation.

Hence, an increase in the r value for implementing a (group of) projects is representative of the additional ability of the hydrogen system to provide energy system flexibility when needed due to uncurtailed volatile renewable electricity generation.



Note that this indicator benefits hydrogen storage since an increased operation of electrolysers to produce renewable hydrogen is only feasible when sufficient hydrogen storage capacity is available.

The indicator does account for the ability of hydrogen system to not produce hydrogen when no or little volatile renewable electricity is available. However, the indicator does not acknowledge that the hydrogen system is able to additionally respond to the flexibility needs of the electricity system by operating hydrogen CCGTs when no or little volatile renewable is available.

4.8.3 MONETISATION

This indicator is only expressed in non-monetised terms.

4.8.4 INTERLINKAGES WITH OTHER INDICATORS

There are no interlinkages with other indicators.

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4.9 ENVIRONMENTAL IMPACT

Similarly to other energy infrastructure categories, each hydrogen infrastructure has an impact on its surroundings. This impact is of particular relevance when crossing some environmentally sensitive areas, such as Natura 2000[15], namely on biodiversity. Mitigation measures are taken by the promoters to reduce or even fully mitigate this impact and comply with the EU EIA Directive[16] and European Commission Biodiversity Strategy.

In order to give a comparable measure of project effects, the fields described in the table are to be filled in by the promoter as an obligatory requirement.

Table 4: Minimum set of information to be included in the PS-CBA assessment phase regarding the environmental impact of a hydrogen project

Project	Type of infrastructure	Surface of impact	Environmentally sensitive area	Potential impact	Mitigation measures	Related costs included in project CAPEX and OPEX per year	Justification of costs
Section 1							
Section 2							

Where:

- The section of the project may be used to geographically identify the concerned part of the project (e.g., section point A to point B of the project routing).
- Type of infrastructure identifies the nature of the section (e.g., compressor station, hydrogen transmission pipeline, etc.)

15 https://ec.europa.eu/environment/nature/natura2000/index_en.htm

16 EIA Directive (Council Directive 2011/92/CE)

- Surface of impact is the area covered by the section in linear meters and nominal diameter for pipe, as well as in square meters. This last value should not be used for comparison as it may depend on the national framework
- Environmentally sensitive area(s) in which the project is built, such as Natura 2000, as described in the relevant legislations (including where possible the quantification of the concerned surface)
- Potential impact, as the potential consequence on the environmentally sensitive area arising from the realisation of the concerned project
- Mitigation measures, that are the actions undertaken by the promoter to compensate or reduce the impact of the section (e.g., as referred to in the Environmental Impact Assessment prepared by the promoter or National Competent Authority)
- Related costs: Expected related CAPEX and OPEX per year which must be part of the CAPEX and OPEX used for the calculation of the economic performance indicators. Promoters are required to also provide adequate justification of these costs (see Table 4).
- Residual costs: Qualitative or quantitative description, in case the submitted project CAPEX and OPEX do not include the cost of mitigation measures required for the project implementation.
- Qualitative or quantitative information about any other environmental impact not listed above.

4.10 CLIMATE ADAPTATION MEASURES

Hydrogen infrastructure is usually long-lasting and may be exposed for many years to a changing climate with increasingly adverse and frequent extreme weather and climate impacts. For this reason, this CBA methodology recommends project promoters to assess climate vulnerability and identify the related climate risks as part of the project assessment.

In line with the EC 'Technical Guidance on the climate proofing of infrastructure in the period 2021–2027', this CBA methodology recommends integrating the assessment of climate vulnerability and related risk assessment from the beginning of the project development process.

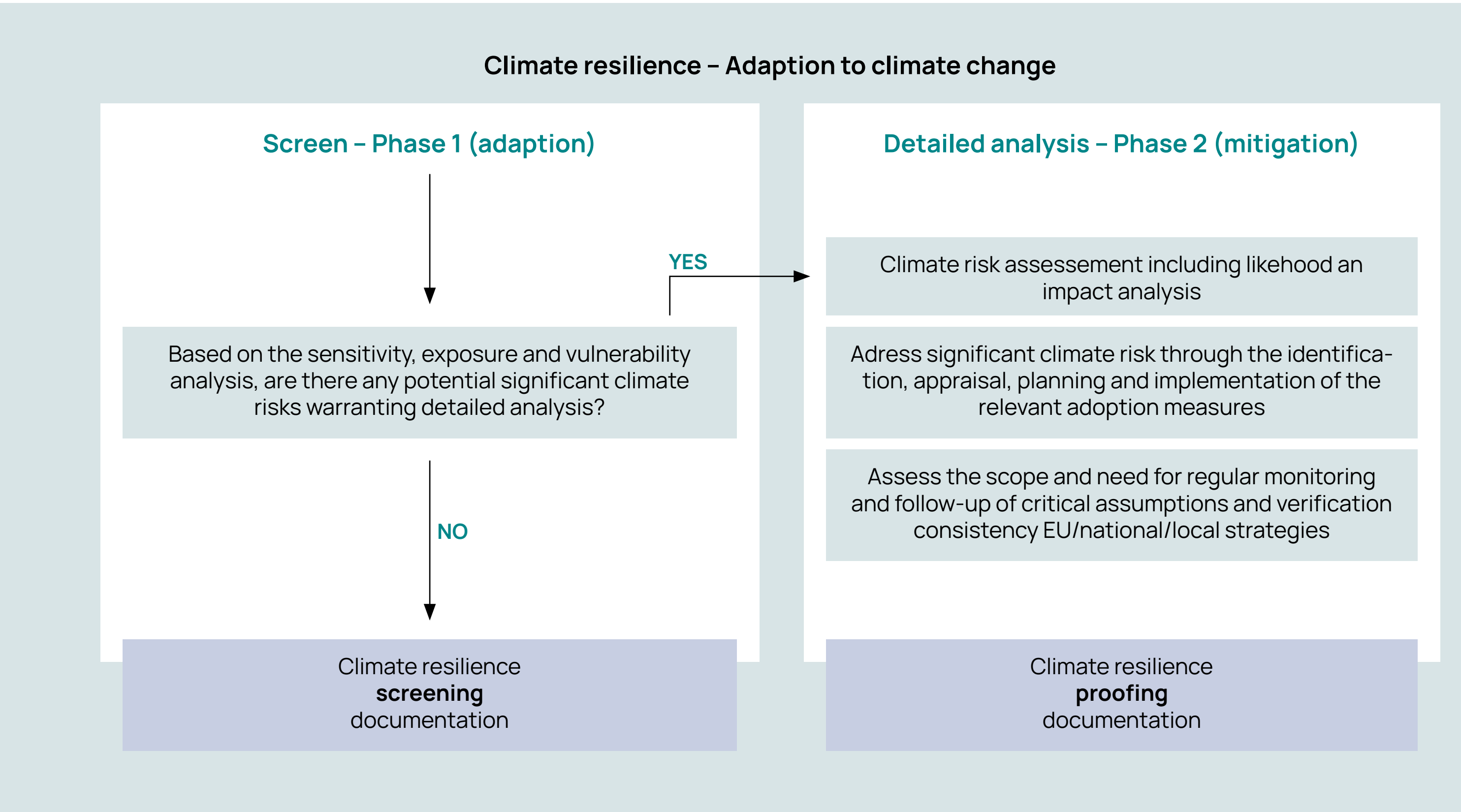


Figure 12: Overview of the climate adaptation-related process (Source: Technical guidance on the climate proofing of infrastructure in the period 2021–2027, European Commission

As described in the figure above, project promoters are asked to identify potential climate risks may impact the project and evaluate the related risks based on the sensitivity, exposure and vulnerability analysis. If promoters identified significant climate risk, they should provide a climate risk assessment and impact analysis, including the identification of climate adaptation measures that will be included in the project cycle. Climate adaptation measures are defined as "a process that ensures that resilience to the potential adverse impacts of climate change of energy infrastructure is achieved through a climate vulnerability and risk assessment, including through relevant adaptation measures" in the TEN-E Regulation[17]. Climate adaptation measures include all adaptations to an investment to cope with possible (predicted) future extreme weather events due to climate change. This could include e.g. flooding, extreme heat or extreme cold, hurricanes, thunderstorms, etc.

4.11 PROJECTS COSTS

Costs represent an inherent element of a 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[18] by:

- Capital expenditure (CAPEX)
  - 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 incurring after the commissioning of an asset and which are not of an investment nature, such as direct operation and maintenance

- Enhanced costs, administrative and general expenditures, etc.

Where a part of the OPEX is calculated by the model, e.g., energy costs[19], it is already included in the calculated benefits. When calculating the economic performance indicators, to avoid double-counting of these costs, either i) the respective part of the OPEX included in the model must be removed from the benefits, or ii) the respective part of the OPEX as submitted directly by the project promoter must be excluded from the costs.

All cost data should be considered at constant (real) prices. As part of the TYNDP, it is recommended that constant prices refer to the year of the TYNDP project collection.

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.

17 TEN-E Regulation Article 2 (19)

18 This classification is in line with the EC Guide to Cost-Benefit Analysis of Investment Projects

19 Example: 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.

5 SENSITIVITY ANALYSES

Given the uncertainties when defining possible future scenarios, for each CBA, sensitivity analyses should be conducted to increase the validity of the CBA results.

Sensitivity analyses can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the model results. This provides a deeper understanding of the system's behaviour with respect to the chosen parameter or interlinked parameters. It should be noted that interdependencies between the below listed sensitivities can occur. However, as a robust investigation on these interdependencies can become very complex, this goes beyond the single treatment of sensitivities as addition to the CBA.

In general, a sensitivity analysis must be performed on a uniform level, i.e., the sensitivity needs to be applied to all projects under assessment in the respective study. However, in some cases the added value of the sensitivity might be given only for specific projects (e.g., a sensitivity using 40 years of economic lifetime instead of 25 years does not influence the assessment of projects that have a technical lifetime of 25 years, as the economic lifetime cannot be longer than the technical lifetime). In such cases it is, together with a sufficient argumentation within the CBA implementation guidelines, reasonable to apply the respective sensitivity only to the relevant projects. In principle, each individual model parameter can be used for a sensitivity analysis. Furthermore, different parameters can have a different impact on the results depending on the scenario. For this purpose, detailed information about the selection of the parameters must be given within the CBA implementation guidelines.

The parameters listed below can be used to perform sensitivities. This list is not exhaustive and provides some examples of useful sensitivities together with a short overview of the expected actions necessary to perform the respective sensitivity analysis.

- **Fuel and ETS prices**: A global set of values for fuel prices is defined as part of the scenario development process. A degree of uncertainty regarding these values and prices is unavoidable. Fuel and ETS prices determine the specific costs of various assets and, therefore, the merit order. On that basis, varying fuel and ETS prices impact the merit order, which in turn has an impact on the related benefit indicators required to be reported on, as part of this CBA methodology.
    - New simulations are required to be run to properly evaluate this sensitivity, since the prices influence the merit order. This can influence all benefit indicators and the economic performance indicators.

- **Cost of carbon:** A sensitivity study could be performed in which the cost of carbon is varied.
  - For this sensitivity, no new simulations are required. Instead, the GHG emissions variations indicator (B1) can be calculated with the alternative cost of carbon. This can also influence the economic performance indicators.
- **Weather year:** Using historical climate data from different years might influence the benefits of a project. For example, the integration of renewable hydrogen generation indicator (B3) depends on the infeed of RES and weather conditions. For this reason, performing an analysis with different weather years would lead to a better understanding of how market results depend on weather conditions. This can be used to understand how the indicators are impacted by climatic conditions.
  - For each weather year, new simulations have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- **Installed energy storage, power generation, and hydrogen production capacity:** The amount of these capacities is defined within the scenarios. For this sensitivity, it is crucial to not excessively change the capacities. More fundamental changes would instead lead to the definition of new scenarios.
  - New simulations using the changed capacities have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- **Flexibility of energy demand, power generation, hydrogen production, and supply potentials:** This sensitivity could include the change in the behaviour of demand side response or how electrolysers are modelled.
  - New simulations using the changed parameters have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- **Other relevant parameters:** Sensitivities on project-specific data should be reflected in the CBA. This relates to
  - CAPEX and OPEX: As long as dispatch models are used no new simulations are required. Such sensitivity will not influence the benefit indicators, but the economic performance indicators can be influenced.
  - Economic lifetime: A sensitivity with 40 years instead of 25 years (see section 5.2.3): No new simulations are required. Such sensitivity would extend the benefit indicators as well as the project costs in time. This can influence the economic performance indicators.
  - The commissioning date of various projects: The projects to be assessed and the commissioning date related to these are information provided by project promoters during the project data collection phase. However, the timely commissioning of projects might be delayed due to several reasons (e.g., longer permitting phase, unexpected incidents while construction, etc.). This CBA methodology recommends such sensitivity for the CBA of multi-phase projects and groups of projects (see section 5.2.5).

6 ECONOMIC PERFORMANCE INDICATORS

6.1 INTRODUCTION AND GENERAL RULES

Economic performance indicators are based on project costs as well as the part of the benefits that are monetised. Economic performance indicators are sensitive to the assessment period, residual value, and the retained socio-economic discount rate and therefore to the distribution of benefits and costs over the assessment period. In order to ensure consistent and comparable results, it is important to use consistent economic parameters for each CBA.

This CBA methodology describes two different economic performance indicators: The Economic Net Present Value (ENPV) and the Economic Benefit-to-Cost Ratio (EBCR).

The CBA methodology builds on Multi-Criteria Analysis, on the basis that not all benefits of projects can be monetised. For this reason, the economic performance indicators only represent a part of the balance between project costs and benefits.

For the calculation of economic performance indicators, costs and benefits for each investment are to be represented annually.

The year of commissioning is the year that the investment is expected to come into first operation. The benefits are accounted for from the first full operational year after commissioning.

To evaluate projects on a common basis, benefits should be aggregated across the years as detailed in section 6.2.5. Since not every year is modelled, benefits and costs must thereby be interpolated. Concerning the interpolation of benefits, the interpolation should be performed on the basis of the quantified benefits that are not yet monetised. When monetising the interpolated quantified benefits, year-specific monetisation values should be used (e.g., for the societal cost of carbon).

To assess a project that is comprised of multi-phase investments[20], the annualised benefits and OPEX for the project are accounted for from the commissioning of the first investment.

For any group of projects, also if consisting of different infrastructure categories, the economic performance indicators should be jointly calculated with the full cost and monetised benefits of the whole group. This means that the monetised benefits calculated for the group will be coupled with the sum of costs of all grouped projects. The resulting economic performance indicator is then valid for the whole group of projects.

6.2 ECONOMIC PARAMETERS

6.2.1 CONSTANT (REAL) PRICES

In order to ensure transparency and comparability, the analysis of socio-economic benefits and costs will be carried out at constant (real) prices, i.e., considering fixed prices at a base year[21]. By doing so, one neutralises the effect of inflation for all projects. For the TYNDP, it is recommended that constant prices refer to the year of the TYNDP project collection.

6.2.2 SOCIAL DISCOUNT RATE

The social discount rate constitutes the parameter that ensures comparability of benefits and costs accruing at different points in time. It is applied to both CAPEX and OPEX, thereby enabling the consideration of the time value of money in cost-benefit analyses.

The social discount rate reflects the minimum level of economic return that a project must achieve in order to generate net economic benefits. In this context, it expresses the weight that society assigns to future benefits in relation to present ones, acknowledging that benefits realised in the future are valued less than those realised in the present.

For the purpose of ensuring a consistent and transparent basis for project appraisal, a flexible social discount rate (x) shall be applied. The definitive value of this rate shall be established in accordance with the Cost-Benefit Analysis (CBA) Implementation Guidelines.

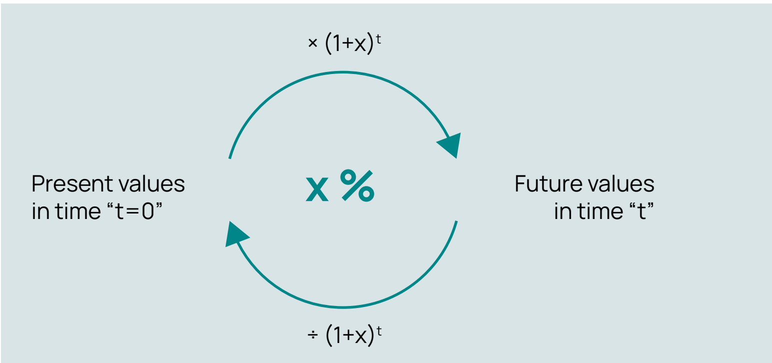


Figure 13: Social discount rate

6.2.3 ASSESSMENT PERIOD

It is important to consider when estimating the reference period for hydrogen projects, that these projects are expected to produce benefits in the long term, as hydrogen infrastructure is currently at early stages of implementation.

The project's economic life is defined as the expected time during which the project remains useful (i.e., capable of providing goods/services) to the promoter, and it could be different than the physical or technical life of the project.

This CBA methodology prescribes **an assessment period of 25 years** as a default case, and that this same reference assessment period should be retained for all projects assessed to ensure comparability in the analysis of the results. In addition, in the case that the technical lifetime of the asset is shorter than the assessment period, the economic analysis will be performed based on the technical lifetime of the asset.

20 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.).

21 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.

6.2.4 RESIDUAL VALUE

Projects should be assessed without residual value if the assessment period is covering 25 years of operation.

6.2.5 CASH FLOW INTERPOLATION

For the Economic Performance Indicators and based on project-specific benefit indicator results for simulated years, the economic cash flow for each year will be calculated in the following way:

- From the first full year of operation until the next simulated year the monetised benefits are considered equal to the monetised benefits of the simulated year.
- The monetised results as coming from the simulations and used to build the economic performance indicators will be linearly interpolated between two simulated years (e.g., n+10 and n+20).
- The monetised benefits will be kept constant until the 24th year of life of the project after the last simulated year.
- The assessment of all the projects should take place at the same year of analysis (n) and take into consideration an economic lifetime of 25 years. For example, projects may be commissioned in 2029 or 2033, their benefits and costs will be considered for the following 25 years but all discounted in the same year (e.g., 2024) as follows:

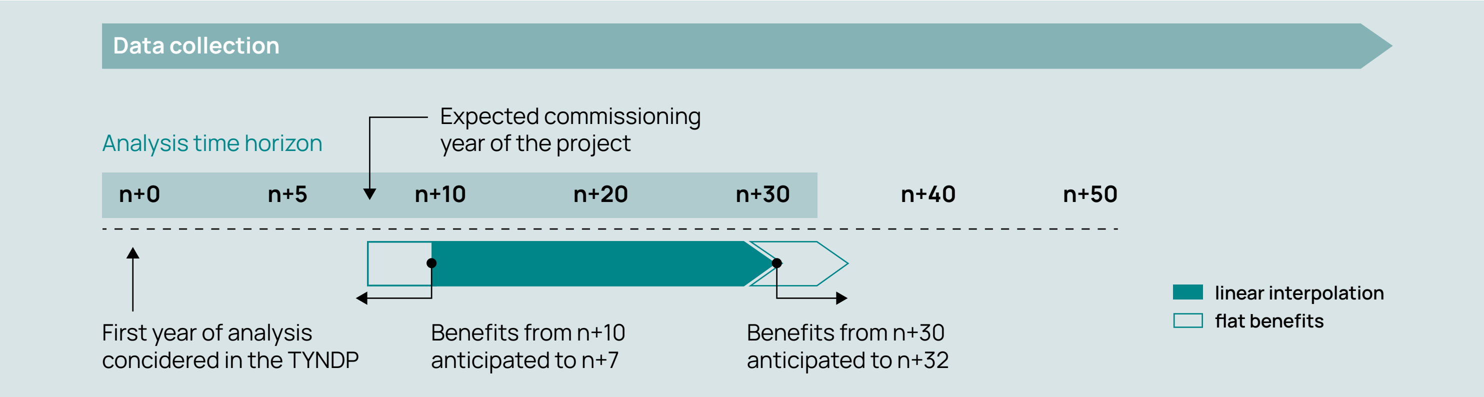
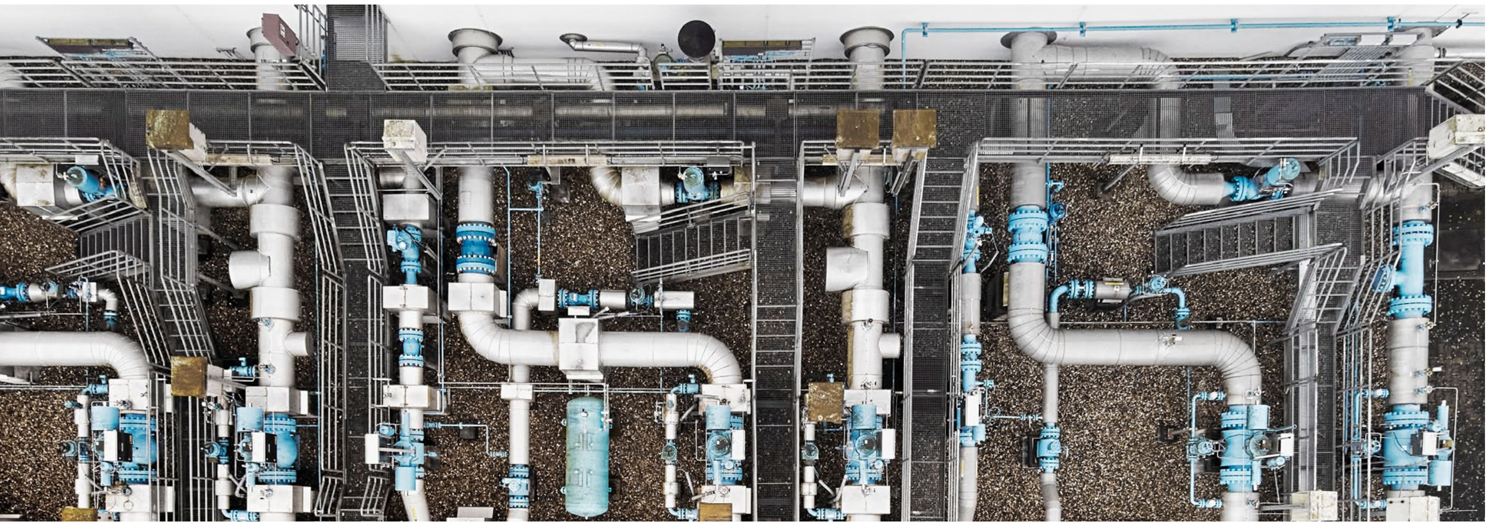


Figure 14: Representation of economic cash flow assessment in case of projects to be commissioned between two assessed years (here: reference case of 25 years economic lifetime)

For multi-phase projects or a group of projects the benefits will be counted according to the year of the first phase (of the first project) to be commissioned. This allows consideration of projects or a group of projects where the implementation of the first phase (of the first project) already brings benefits and contributes as enhancer to the other phases/projects of the group.



6.3 ECONOMIC PERFORMANCE INDICATOR 1: ECONOMIC NET PRESENT VALUE (ENPV)

The Economic Net Present Value (ENPV) is the difference between the discounted monetised benefits and the discounted costs expressed in constant (real) terms for the basis year of the analysis (discounted economic cashflow of the project). The ENPV reflects the performance of a project in absolute values. If the ENPV is positive the project generates a net monetary benefit, and it is favourable from a socio-economic perspective.

$$ENVP = \sum_{t=f}^{c+24} \frac{B_t - C_t}{(1+r)^{t-n}}$$

Whereas:

- t: Overall appraisal period.
- f: First year where costs are incurred.
- c: First full year of operation.
- B_t: Sum of all monetised benefits induced by the (group of) project(s) on year t.
- C_t: Sum of CAPEX and OPEX on the year t.
- n: Year of analysis (common for all projects).
- r: Social Discount Rate.

6.4 ECONOMIC PERFORMANCE INDICATOR 2: ECONOMIC BENEFIT-TO-COST RATIO (EBCR)

The Economic Benefit/Cost Ratio (EBCR) represents the ratio between the discounted monetised benefits and the discounted costs. It is the present value of project benefits divided by the present value of project costs.

$$EBCR = \frac{\sum_{t=f}^{c+24} \frac{B_t}{(1+r)^{t-n}}}{\sum_{t=f}^{c+24} \frac{C_t}{(1+r)^{t-n}}}$$

Whereas:

- t: Overall appraisal period
- f: First year where costs are incurred.
- c: First full year of operation.
- B_t: Sum of all monetised benefits induced by the (group of) project(s) on year t.
- C_t: Sum of CAPEX and OPEX on the year t.
- n: Year of analysis (common to all projects).
- r: Social Discount Rate.

If the EBCR exceeds 1, the project is considered as economically efficient as the monetised benefits outweigh the costs on the economic life. This indicator has the advantage of not being influenced by the size of projects, not disadvantaging small ones. This performance indicator should therefore be seen as complementary to the ENPV and as a way to compare projects of different sizes (different level of costs and benefits).

This performance indicator allows comparison of projects even in case of an EBCR lower than 1. It is not appropriate for mutually exclusive projects. Being a ratio, the indicator does not consider the total amount of net benefits and therefore a comparison of (groups of) project(s) can reward more (groups of) project(s) that contribute less to the overall increase in public welfare as described in the example below.

Example coparison of the EBCR for two project groups

- Project group A (higher ENVP)
  - Total discounted benefits: 9.863 (M€)
  - Total discounted costs: −6.865 (M€)
  - EBCR: 1,44
- Project group B (lower ENVP)
  - Total discounted benefits: 1.146 (M€)
  - Total discounted costs: −796 (M€)
  - EBCR: 1,44

7 IMPLEMENTATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE

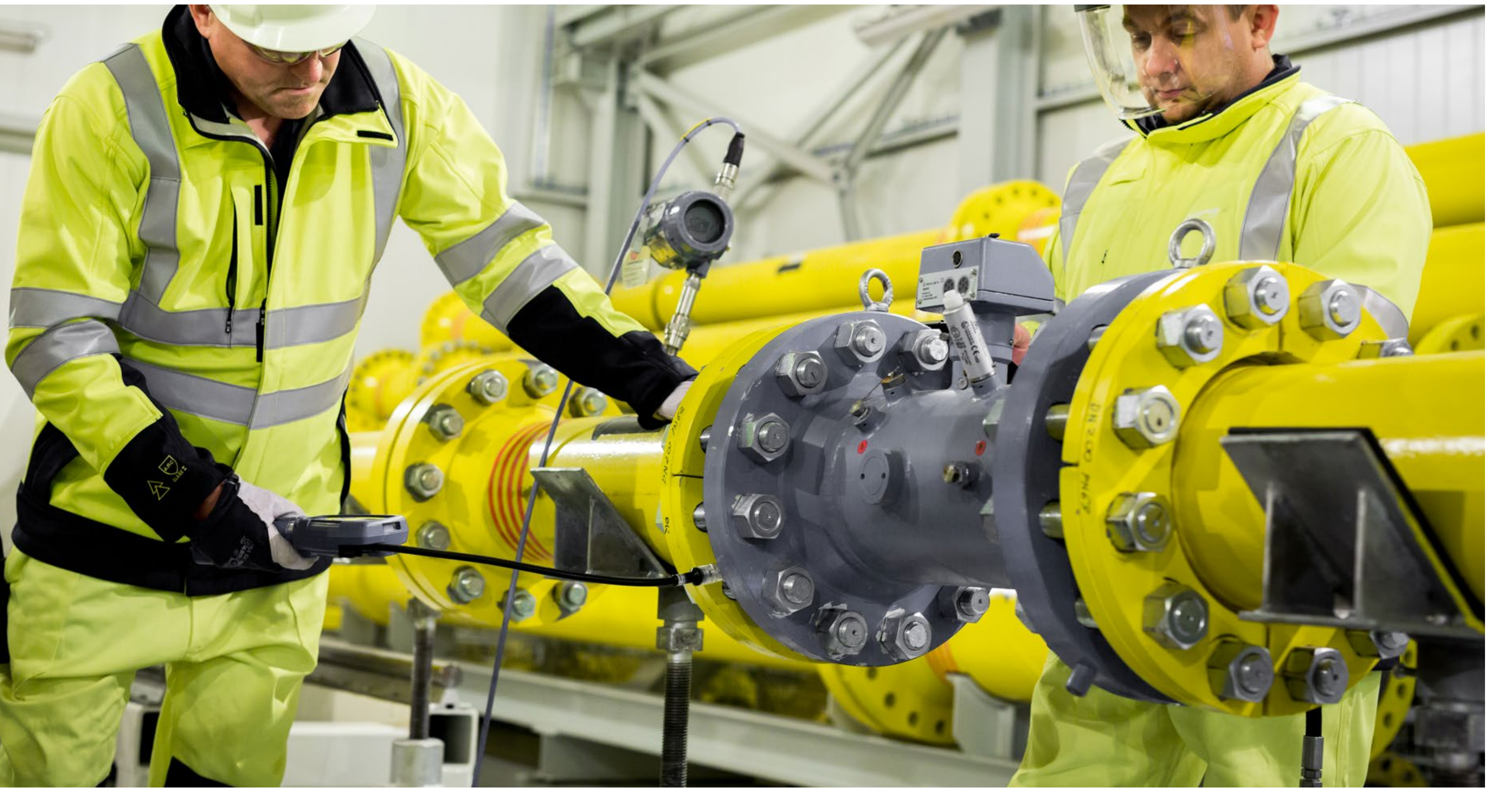
In the energy efficiency first principle guidelines that are annexed to the European Commission Recommendation (EU) 2021/1749 of 28 September 2021, the principle's application in this CBA methodology is detailed as follows:

"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.

The mentioned concepts are thereby partially overlapping and are required to be interpreted in the context of this CBA methodology:

- The support study of the quoted European Commission Recommendation states that demand side management includes two parts: energy efficiency and demand response. Energy efficiency is understood to contain renovation of buildings.



- Market arrangement solutions and market mechanisms are understood as the respective energy market design which is captured in the market behaviour and assumptions of the model. It includes demand side response (based on demand side resources) which is understood as the option that demand can be optimised on the
  - end user level: e.g., hybrid heat pumps shifting demand between sectors based on temperature-related efficiencies and prices, or demand of certain end users being shifted into more favourable time steps, or the demand of certain end users being subject of demand side response due to a trigger like a certain energy price;
  - conversion level: e.g., electrolyser usage based on prices, conversion efficiencies, energy availabilities in the sectors.
- Digital solutions are understood both as technologies enabling the optimised behaviour of end users as well as technologies that enable better utilisation of existing infrastructure by operational mechanisms.

7.1 CONSIDERATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE IN THE SCENARIO DEVELOPMENT

As the scenario development is governed by Article 12 of the TEN-E Regulation, the descriptions in this section are not intended to prejudge future scenario developments and innovations, especially in relation to the further application of the energy efficiency first principle.

- **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 sectors like hydrogen and electricity allows an optimisation of the utilisation of the existing infrastructure's capacities in the model, through flexibility provisions across energy sectors.

- **Inclusion of options to include more energy-efficient technologies:** The scenarios are developed on an NECP-based scenario storyline as well as deviating storylines. Within the scenario development, energy-efficient technologies are either i) set at ambitious levels (due to NECPs, EU energy and climate targets, or infrastructure operator inputs in combination with stakeholder consultations); or ii) provided with an option to further expand their deployment based on economic decisions. 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 (e.g., electrolysers) or through cross-sectoral demand shifts (e.g., hybrid heat pumps);
  - assets allowing flexibility like time-shifting of demand (e.g., time flexibility of heating) or storage (e.g., electric vehicles charging in a supportive manner and providing supply if needed);
  - 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 (e.g., 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., crosschecking with the EU's legal energy and climate targets, 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. Since such investigations (especially concerning the future developments) are associated with uncertainties, different scenario storylines and/or variants are established.

7.2 CONSIDERATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE IN THE INFRASTRUCTURE GAPS IDENTIFICATION

As the infrastructure gaps identification is governed by Article 13 of the TEN-E Regulation, the descriptions in this section are not intended to prejudge future infrastructure gaps identification developments and innovations, especially in relation to the further application of the energy efficiency first principle.

- **Inclusion of options for better utilisation of existing infrastructure:** The existing infrastructure considered in the TYNDP topology is updated for each TYNDP cycle with information that is provided by the infrastructure operators. This provides the option to update the underlying energy infrastructure capacities which are the main parameter capturing the ability of better utilisation through operational improvements, including by digital solutions. Also, the consideration of infrastructure of multiple energy sectors like hydrogen, electricity, and natural gas allows an optimisation of the utilisation of the existing infrastructure's capacities in the model through flexibility provisions across energy sectors.
- **Inclusion of options to include more energy-efficient technologies:** The infrastructure gaps identification is performed on the basis of the scenarios that include energy efficiency measures as described in the previous section. Thereby, a decisive share of the measures (e.g., renovations of buildings) have been set at the highest level that can be considered as feasible and realistic under current targets, policies, and expected technological advancements. Thereby, 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. By already being part of the scenario, the selected energy efficiency measures are not associated with additional investments in the infrastructure gaps identification exercise and their usage is always an option alongside the assessment of hydrogen infrastructure investments. Since such investigations, especially concerning the future developments, are associated with uncertainties, different scenario storylines and/or variants should be used for the infrastructure gaps identification.
- **Inclusion of options to make better use of the market mechanisms:** By considering perfect competition only limited by infrastructure constraints between nodes, 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 therefore considered. The pattern of the total demand is not simply transferred from the scenarios to the TYNDP, but the underlying assets are considered to be used within their specifications to allow their optimised utilisation.

  The model considers sources of flexibility like assets coupling, assets allowing time-shifting of demand or storage and demand shedding. Finding the optimal solution the model will consider all relevant alternatives to new infrastructure.
- **Aiming at balancing security of supply, quality of energy supplied, and cost-efficiency:** The wider benefits of investments are addressed from a system efficiency and societal perspective. Concerning the assessment performed using the model, this relates to
  - Monetising unserved energy demand (e.g., VoLL and CODH)
  - Penalising energy losses and emissions
  - Assessing indicators covering different energy sectors

7.3 CONSIDERATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE IN THE CBAS

The description of the previous section applies mutatis mutandis.

8 ANNEX

ANNEX I: LEGAL BACKGROUND

ENNOH prepared this CBA methodology based on Article 11 of the TEN-E Regulation. Article 11(1) states that ENNOH's CBA methodology covers energy infrastructure set out in Annex II (3).

ANNEX II(3) OF THE TEN-E REGULATION CONCERNS FOLLOWING HYDROGEN INFRASTRUCTURE CATEGORIES

(a) pipelines for the transport, mainly at high pressure, of hydrogen, including repurposed natural gas infrastructure, giving access to multiple network users on a transparent and non-discriminatory basis;

(b) storage facilities connected to the high-pressure hydrogen pipelines referred to in point (a);

(c) reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances with the objective of injecting the hydrogen, where applicable, into the grid;

(d) any equipment or installation essential for the hydrogen system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations;

(e) any equipment or installation allowing for hydrogen or hydrogen-derived fuels use in the transport sector within the TEN-T core network identified in accordance with Chapter III of Regulation (EU) No 1315/2013 of the European Parliament and of the Council.

Any of the assets listed in points (a) to (d) may be newly constructed or repurposed from natural gas to hydrogen, or a combination of the two.

Art. 11 (1) of the TEN-E Regulation furthermore states that ENNOH's CBA methodology shall be drawn up in line with the principles laid down in Annex V, be based on common assumptions allowing for project comparison, and be consistent with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective, as well as with the rules and indicators set out in Annex IV.

ANNEX V OF THE TEN-E REGULATION SETS UP PRINCIPLES FOR THE ENERGY SYSTEM-WIDE CBAS

The methodologies for cost-benefit analyses developed by the ENTSO for Electricity and the ENTSO for Gas[22] shall be consistent with each other, taking into account sectorial specificities. The methodologies for a harmonised and transparent energy system-wide cost-benefit analysis for projects on the Union list shall be uniform for all infrastructure categories, unless specific divergences are justified. They shall address costs in the broader sense, including externalities, in view of the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective and shall comply with the following principles:

(1) the area for the analysis of an individual project shall cover all Member States and third countries, on whose territory the project is located, all directly neighbouring Member States and all other Member States in which the project has a significant impact. For this purpose, ENTSO for Electricity and ENTSO for Gas shall cooperate with all the relevant system operators in the relevant third countries. In the case of projects falling under the energy infrastructure category set out at point (3) of Annex II, the ENTSO for Electricity and the ENTSO for Gas shall cooperate with the project promoter, including where it is not a system operator;

(2) each cost-benefit analysis shall include sensitivity analyses concerning the input data set, including the cost of generation and greenhouse gases as well as the expected development of demand and supply, including with regard to renewable energy sources, and including the flexibility of both, and the availability of storage, the commissioning date of various projects in the same area of analysis, climate impacts and other relevant parameters;

(3) they shall establish the analysis to be carried out, based on the relevant multi-sectorial input data set by determining the impact with and without each project and shall include the relevant interdependencies with other projects;

(4) they shall give guidance for the development and use of energy network and market modelling necessary for the cost-benefit analysis. The modelling shall allow for a full assessment of economic benefits, including market integration, security of supply and competition, as well as lifting energy isolation, social and environmental and climate impacts, including the cross-sectorial impacts. The methodology shall be fully transparent including details on why, what and how each of the benefits and costs are calculated;

(5) they shall include an explanation on how the energy efficiency first principle is implemented in all the steps of the Union-wide ten-year network development plans;

(6) they shall explain that the development and deployment of renewable energy will not be hampered by the project;

(7) they shall ensure that the Member States on which the project has a net positive impact, the beneficiaries, the Member States on which the project has a net negative impact, and the cost bearers, which may be Member States other than those on which territory the infrastructure is constructed, are identified;

(8) they shall take into account, at least, the 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. The methodologies shall give guidance on discount rates, technical lifetime and residual value to be used for the cost-benefit calculations. They shall furthermore include a mandatory methodology to calculate benefit-to-cost ratio and the net present value, as well as a differentiation of benefits in accordance with the level of reliability of their estimation methods. Methods to calculate the climate and environmental impacts of the projects and the contribution to Union energy targets, such as renewable penetrations, energy efficiency and interconnection targets shall also be taken into account;

(9) they shall ensure that the climate adaptation measures taken for each project are assessed and reflect the cost of greenhouse gas emissions and that the assessment is robust and consistent with other Union policies in order to enable comparison with other solutions which do not require new infrastructures.

22 Art. 31 of the TEN-E Regulation in the version of 5 February 2025: In the Annexes to this Regulation, any reference to 'ENTSO for Gas' shall be understood to mean 'the ENTSO for Gas and the ENNOH' for the purpose of the transitional provisions pursuant to Article 61 of Regulation (EU) 2024/1789. From 1 January 2027, any reference to 'ENTSO for Gas' shall be understood to mean 'the ENNOH'.

ANNEX IV OF THE TEN-E REGULATION SETS UP RULES AND INDICATORS CONCERNING CRITERIA FOR PROJECTS

(1) A project of common interest with a significant cross-border impact shall be a project on the territory of a Member State and shall fulfil the following conditions: (...)

- (d) for hydrogen transmission, the project enables the transmission of hydrogen across the borders of the Member States concerned, or increases existing cross-border hydrogen transport capacity at a border between two Member States by at least 10 % compared to the situation prior to the commissioning of the project, and the project sufficiently demonstrates that it is an essential part of a planned cross-border hydrogen network and provides sufficient proof of existing plans and cooperation with neighbouring countries and network operators or, for projects decreasing energy isolation of non-interconnected systems in one or more Member States, the project aims to supply, directly or indirectly, at least two Member States; (e) for hydrogen storage or hydrogen reception facilities referred to in point (3) of Annex II, the project aims to supply, directly or indirectly, at least two Member States;

- (e) for hydrogen storage or hydrogen reception facilities referred to in point (3) of Annex II, the project aims to supply, directly or indirectly, at least two Member States;

(...)

(2)A project of mutual interest with significant cross-border impact shall be a project and shall fulfil the following conditions: (...)

- (b) for projects of mutual interest in the category set out in point (3) of Annex II, the hydrogen project enables the transmission of hydrogen across at the border of a Member State with one or more third countries and proves bringing significant benefits, either directly or indirectly (via interconnection with a third country) under the specific criteria listed in Article 4(3), at Union level. The calculation of the benefits for the Member States shall be performed and published by the ENTSO for Gas in the frame of Union-wide ten-year network development plan;

(...)

(5) Concerning hydrogen falling under the energy infrastructure category set out in point (3) of Annex II, the criteria listed in Article 4 shall be evaluated as follows:

- (a) sustainability, measured as the contribution of a project to greenhouse gas emission reductions in various end-use applications in hard-to-abate sectors, such as industry or transport; flexibility and seasonal storage options for renewable electricity generation; or the integration of renewable and low-carbon hydrogen with a view to consider market needs and promote renewable hydrogen;

- (b) market integration and interoperability, measured by calculating the additional value of the project to the integration of market areas and price convergence to the overall flexibility of the system;

- (c)security of supply and flexibility, measured by calculating the additional value of the project to the resilience, diversity and flexibility of hydrogen supply;

- (d) competition, measured by assessing the project's contribution to supply diversification, including the facilitation of access to indigenous sources of hydrogen supply.

(...)

ANNEX III SPECIFIES THE INCLUSION OF PCI AND PMI CANDIDATES IN THE TYNDP

(…)

2. Process for establishing regional lists

(…)

(4) From 1 January 2024, the proposed hydrogen projects of common interest falling under the energy infrastructure categories set out in point (3) of Annex II to this Regulation are part of the latest available Community-wide ten-year network development plan for gas, developed by the ENTSO for Gas pursuant to Article 8 of Regulation (EC) No 715/2009[23].

(5) By 30 June 2022 and subsequently for every Union-wide ten-year network development plan, the ENTSO for Electricity and the ENTSO for Gas shall issue updated guidelines for inclusion of projects in their respective Union-wide ten-year network development plan, as referred to in points (3) and (4), in order to ensure equal treatment and the transparency of the process. For all the projects on the Union list in force at the time, the guidelines shall establish a simplified process of inclusion in the Union-wide ten-year development plans taking into account the documentation and data already submitted during the previous Union-wide ten-year network development plan process, provided that the documentation and data already submitted remains valid.

The ENTSO for Electricity and the ENTSO for Gas shall consult the Commission and the Agency about their respective draft guidelines for inclusion of projects in the Union-wide ten-year network development plans and take due account of the Commission's and the Agency's recommendations before the publication of the final guidelines.

(…)

ARTICLE 4 SETS UP CRITERIA FOR THE ASSESSMENT OF PROJECTS BY THE REGIONAL GROUPS

1. A project of common interest shall meet the following general criteria:

- (a) the project is necessary for at least one of the energy infrastructure priority corridors and areas set out in Annex I;
- (b) the potential overall benefits of the project, assessed in accordance with the relevant specific criteria in paragraph 3, outweigh its costs, including in the longer term;
- (c) the project meets any of the following criteria:
  - (i) it involves at least two Member States by directly or indirectly, via interconnection with a third country, crossing the border of two or more Member States;
  - (ii) it is located on the territory of one Member State, either inland or offshore, including islands, and has a significant cross-border impact as set out in point (1) of Annex IV.

2. A project of mutual interest shall meet the following general criteria:

- (a) the project contributes significantly to the objectives referred to in Article 1(1), and those of the third country, in particular by not hindering the capacity of the third country to phase out fossil fuel generation assets for its domestic consumption, and to sustainability, including through the integration of renewable energy into the grid and the transmission and distribution of renewable generation to major consumption centres and storage sites;
- (b) the potential overall benefits of the project at Union level, assessed in accordance with the relevant specific criteria in paragraph 3, outweigh its costs within the Union, including in the longer term;
- (c) the project is located on the territory of at least one Member State and on the territory of at least one third country and has a significant cross-border impact as set out in point (2) of Annex IV;

23 See Article 26 of Regulation (EU) 2024/1789

- (d) for the part located on Member State territory, the project is in line with Directives 2009/73/EC[24] and (EU) 2019/944 where it falls within the infrastructure categories set out in points (1) and (3) of Annex II to this Regulation;

- (e) there is a high level of convergence of the policy framework of the third country or countries involved and legal enforcement mechanisms to support the policy objectives of the Union are demonstrated, in particular to ensure:

  - (i) a well-functioning internal energy market;
  - (ii) security of supply based, inter alia, on diverse sources, cooperation and solidarity;
  - (iii) an energy system, including production, transmission and distribution, moving towards the objective of climate neutrality, in line with the Paris Agreement and the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective, in particular, avoiding carbon leakage;

- (f) the third country or countries involved support the priority status of the project, as set out in Article 7, and commit to complying with a similar timeline for accelerated implementation and other policy and regulatory support measures as applies to projects of common interest in the Union.

(...)

3. The following specific criteria shall apply to projects of common interest falling within specific energy infrastructure categories:

(...)

- (d) for hydrogen projects falling under the energy infrastructure categories set out in point (3) of Annex II, the project contributes significantly to sustainability, including by reducing greenhouse gas emissions, by enhancing the deployment of renewable or low carbon hydrogen, with an emphasis on hydrogen from renewable sources in particular in end-use applications, such as hard-to-abate sectors, in which more energy efficient solutions are not feasible, and supporting variable renewable power generation by offering flexibility, storage solutions, or both, and the project contributes significantly to at least one of the following specific criteria:

  - (i) market integration, including by connecting existing or emerging hydrogen networks of Member States, or otherwise contributing to the emergence of an Union-wide network for the transport and storage of hydrogen, and ensuring interoperability of connected systems;
  - (ii) security of supply and flexibility, including through appropriate connections and facilitating secure and reliable system operation;
  - (iii) competition, including by allowing access to multiple supply sources and network users on a transparent and non-discriminatory basis;

(...)

4. For projects falling under the energy infrastructure categories set out in Annex II, the criteria set out in paragraph 3 of this Article shall be assessed in accordance with the indicators set out in points (3) to (8) of Annex IV.

(...)

24 Repealed by directive (EU) 2024/1788

LIST OF REGULATORY CRITERIA AND WHERE TO FIND THEM IN THE CBA METHODOLOGY

Table 5: Comparioson of TEN-E requirements and this CBA Methodology

TEN-E requirement	Coverage in CBA methodology
Art. 11 – Energy system wide cost-benefit analysis	
Art. 11(1) – ENTSOs for Gas and Electricity are tasked with drafting single-sector methodologies, for a harmonised energy system-wide cost-benefit analysis at Union level for projects on the Union list; – Such methodologies shall include energy network and market models and shall be consistent between themselves, as well as aligned with the Union's 2030 targets for energy and 2050 climate neutrality objectives; – For the above, an extensive consultation process must be carried out, of relevant stakeholders.	Energy network and market models are explained in section 2.2.1.1 and section 2.2.1.2 and will be updated in line with the deadline set by Art. 11(10). This CBA methodology covers all projects falling under the energy infrastructure category in Annex II (3), while ENTSO-E's CBA methodology covers projects falling under the energy infrastructure categories defined in Annex II(1)(a), (b), (d), and (f). As explained in the rows below, the CBA methodology is drawn up in line with the principles laid down in Annex V and the rules and indicators set out in Annex IV. As explained in the scenario section, it is also consistent with the EU's 2030 targets for energy and climate and its 2050 climate neutrality objective. For the creation of this CBA methodology, an extensive consultation process of relevant stakeholders is carried out.
Art. 11(6) – Calendar for the publication of methodologies for cost-benefit analysis after EC approval: two calendar weeks; – Obligation for the ENTSOs to publish input and output data relevant for such methodologies.	Input data requirements are addressed in sections 1.3, 1.4, 2.1 and by the documents referred to in these sections. Regarding output data, at least the following information shall be produced as part of the CBAs: – Infrastructure level(s) used, project grouping, benefit indicators, project group costs, monetised benefits, and economic performance indicators (see sections 5.3 and 5.4).
Art. 11(9) – ENTSOs may use reference unit investment costs published by ACER for comparable projects in PS-CBAs	Option to use ACER's unit investment costs covered by sections 1.4 and 4.10

TEN-E requirement	Coverage in CBA methodology
Annex V – Energy system wide cost-benefit analysis	
Annex V introduction _ The cost-benefit analysis methodologies developed by the ENTSOs for Gas and Electricity must be consistent between themselves; _ Such methodologies must be applied in a uniform way to all infrastructure categories; _ Costs, including externalities, shall be addressed in CBA methodologies.	Consistency with ENTSO-E methodology is ensured in the following ways: _ Definition of a common input data set through TYNDP scenarios and common market assumptions. _ Definition of a common TYNDP geographical perimeter. _ Definition of common duration of default assessment period and social discount rate for economic assessments. This is also aligned with the CBA methodologies of all other TEN-E energy infrastructure categories. _ Definition of common clustering rules for project grouping (see section 3.1). _ Alignment through the introduction of guidelines for project inclusion and TYNDP-specific CBA implementation guidelines (see sections 1.3 and 1.4). _ Alignment in the consideration of project costs (see section 4.11) that include besides capital expenditure, operational and maintenance expenditure costs, also the costs of the project as a whole, such as decommissioning and waste management costs, including external cost. _ Alignment in the methodology to calculate economic performance indicators of (groups of) project(s) (see section 6). _ Alignment through the inclusion of common indicators and interlinkages (see sections 2.2.1.3 and 4).
Annex V (1) _ The area of analysis for individual projects shall cover all territories where a project is located – Member State or third country – all neighbouring Member States and other Member States where the project has a significant impact in cooperation with involved promoters	Under the section about scenarios, ENTSOG's CBA methodology recommends considering the full range of scenarios in the project-specific CBAs. The country dataset of the TYNDP Scenario Report includes all EU-27 Member States, as well as all Energy Community countries. Consistent application of provisions of the Guidelines for Project Inclusion and of this CBA methodology safeguard equal treatment of project promoters that are not a system operator.
Annex V (2) Methodologies for cost-benefit analysis must incorporate sensitivity analyses for factors such as: the cost of energy generation, greenhouse gas emissions, expected changes in demand and supply (including related to renewable energy sources), flexibility of these sources, storage availability, commissioning dates for projects in the same area, climate impact, inter alia.	See section 5.

TEN-E requirement	Coverage in CBA methodology
Annex V (3) _ Methodologies for cost-benefit analyses shall be based on pertinent multi-sectoral input data, assessing the impact with and without each project; _ Interdependencies with other projects should also be considered.	Integrated into the incremental approach (see section 3.2.2), the consideration of input data and of models covering the multiple sectors (see section 2.2.2), description of indicators for the analysis (see section 4), and infrastructure levels and grouping principles that capture relevant interdependencies with other projects (see sections 2.3 and 3.1).
Annex V (4) _ Methodologies for cost-benefit analysis shall guide the development and use of energy networks and market models employed for cost-benefit analysis; _ Economic impact areas covered by such analyses should comprise: market integration, supply security, competition, energy isolation, social, environmental, and climate impacts, including cross-sector effects; _ Clarity should be provided on how each benefit and cost is calculated.	Details to be specified in complementary documents (see sections 1.3, 1.4, and 2.1). The development and use of the energy network and market modelling necessary for the CBAs is detailed in sections 2.2 and 3.2.
Annex V (5) _ Methodologies for cost-benefit analysis shall explicitly highlight how the energy efficiency first principle is implemented in all steps of the TYNDP process.	The energy efficiency first principle was taken into account as described in section 7
Annex V (6) _ Methodologies for cost-benefit analysis shall explain how renewable energy production is not hampered by each project assessed.	The integration of renewable EU hydrogen indicator (B3) evaluates how the integration of RES is affected or supported by the assessed projects (see section 4.3).
Annex V (7) _ Methodologies for cost-benefit analysis clearly identify: Member States in which projects have net positive and net negative impact, cost bears and beneficiaries, regardless of whether the project is located on their territory or not.	Fulfilled as the benefit indicators can be displayed at different granularities like Member State level or EU level.

TEN-E requirement	Coverage in CBA methodology
Annex V (8) _ Methodologies for cost-benefit analysis should account for the following variables: capital and operational and maintenance costs, including the project's entire technical lifecycle and external costs; _ They should define discount rates, technical lifetime, and residual value for cost-benefit analysis; _ Benefit-to-cost ratios and net present value, should also be defined; _ The degree of reliability of estimation methods of assessed benefits should be described; _ Methodologies should describe calculations of the climate/environmental impact of projects as well as their contributions to Union energy targets, for instance: the penetration of renewable energy, the degree of interconnection and energy efficiency.	Section 4.11 on costs, section 6.2.2 on the discount rate, section 6.2.3 on project lifetime, sections 6.2.4 on residual value, section 6.3 on Net Present Value, section 6.4 on Benefit-to-Cost Ratio, section 4.9 on the environmental impact, and section 4 in general regarding the contribution of projects to Union energy targets. The degrees of reliability of estimation methods of the different benefit indicators are in the following order: _ B3, B4, B5 indicators: The B5 indicator is directly based on the objective function of the underlying model and thereby equivalent to the starting point of all other benefit indicators with most inputs coming from the scenarios. The B3 and B4 indicators are directly derived from results of the objective function of the underlying model, thereby having a comparable level of certainty. _ B6 and B7 indicators: The monetisation step has uncertainties related to the cost of disruption and the assumed probabilities. _ B1 indicator: To mitigate uncertainty of the used cost of carbon, a sensitivity is introduced. _ B2 indicator: To mitigate the uncertainty of this indicator, the general approach as well as the considered pollutants are consulted with the CBA implementation guidelines to ensure its improvement in future cycles. Also, the indicator should only be counted for the economic performance indicator calculations if another sustainability benefit indicator is also positive.
Annex V (9) _ Methodologies for cost-benefit analysis should evaluate climate adaptation measures for each project, considering costs of greenhouse gas emissions; _ Methodologies should be in alignment with other Union policies, to facilitate comparisons with infrastructure-free solutions.	Relevant climate adaptation measures are collected from the project promoters (see section 4.10). The societal cost of carbon considered in the GHG emissions variations indicator (B1) uses as reference source the EIB. This is in alignment with the EC general principles for cost benefit analyses. The environmental impact indicator investigates environmental mitigation measures (see section 4.9).

9 ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CODH	Cost of Disrupted Hydrogen
DSO	Distribution System Operator
EBCR	Economic Benefit-to-Cost Ratio
EC	European Commission
EE1st	Energy Efficiency First Principle
EEA	European Environment Agency
EED	Energy Efficiency Directive (EU) 2018/2002
EIA	Environmental Impact Assessment
EIB	European Investment Bank
ENNOH	European Network of Network Operators for Hydrogen
ENPV	Economic Net Present Value
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emission Trading Scheme
EU	European Union
FID	Final Investment Decision
GHG	Greenhouse Gases
H_2	Hydrogen
HDC	Hydrogen Demand Curtailment
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquefied Natural Gas
MES	Multi-Energy System
Mt	Megatonnes
Mt/y	Megatonnes per Year

$MtCO_2/y$	Megatonnes of Carbon Dioxide per Year
MWh	Megawatt Hours
MWh/y	Megawatt Hours per Year
NDP	National Development Plan
NECP	National Energy and Climate Plan
NG	Natural Gas
NH_3	Ammonia
NO_x	Nitrogen Oxides
PCI	Project of Common Interest
PMI	Project of Mutual Interest
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SO_2	Sulphur Dioxides
SoS	Security of Supply
SoS Regulation	Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010
TEN-E Regulation	Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013. Being amended by Regulation (EU) 2024/1789.
TOOT	Take out One at a Time Principle
TSO	Transmission System Operator
TWh	Terawatt Hour
TWh/y	Terawatt Hours per Year
TYNDP	Ten-Year Network Development Plan
VoLL	Value of Lost Load

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ennoh.eu
info@ennoh.eu

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