Study on the allocation of costs and benefits for offshore infrastructure in EU sea basins

Final report

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Directorate C — Green Transition and Energy System Integration
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List of Acronyms

ACER	European Union Agency for the Cooperation of Energy Regulators
BCR	Benefit-cost ratio
BZ	Bidding zone
CAPEX	Capital expenditure
CEF	Connecting Europe Facility
CfD	Contract-for-difference
EE1st	Energy efficiency first principle
EED	Energy Efficiency Directive
EGC	Energy generation costs
ENNOH	European Network of Network Operators for Hydrogen
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
GHG	Greenhouse gas
HM	Home market
IoSN	Identification of System Needs
LCOE	Levelised cost of energy
MS	Member State
NPV	Net present value
NRA	National regulatory authority
NTC	Net transfer capacity
OBZ	Offshore bidding zone
ONDP	Offshore network development plan
OPEX	Operational expenditure
PCI	Project of Common Interest
PECD	Pan-European Climatic Database
PINT	Put-in-one-at-a-time
PMI	Project of Mutual Interest
PPA	Power purchase agreement
PS-CBA	Project-specific cost-benefit analysis
PS-CBCA	Project-specific cross-border cost allocation
RAB	Regulated asset base
RED	Renewable Energy Directive
REFM	Renewable energy financing mechanism
RES	Renewable energy source
SB-CBA	Sea basin cost-benefit analysis
SB-CBCS	Sea basing cross-border cost sharing
SB-ONDP	Sea basin offshore network development plan
SEW	Socio-economic welfare
TEN-E	Trans-European Networks for Energy
TOOT	Take-out-one-at-a-time
TSO	Transmission system operator
TYNDP	Ten-year network development plan
URDP	Union Renewable Development Platform
XB RES project	Cross-border renewable energy project

Abstract

European Union (EU) Member States have in January 2023 agreed on ambitious long-term goals for the deployment of renewable energy in five European sea basins. The goals represent an overall ambition of approximately 111 GW of offshore wind energy capacity by 2030, which would rise to around 317 GW by 2050. Since January 2023 these commitments have been complemented with ambitions for the whole North Sea, including non-EU countries, where at least 300 GW of offshore wind energy would be installed by 2050.

This study supports more coordinated approaches and processes for the planning, cost-benefit analysis and cost sharing/allocation of offshore electricity generation and transmission investments at the sea-basin and project levels, particularly involving hybrid transmission projects. Enhanced cooperation and coordination should facilitate achieving national ambitions in a more cost-efficient manner while also improving the electricity markets' functioning.

The main outputs of this study consist of recommendations: 1) for sea basin cost-benefit and cost-sharing options; and 2) for coordinated cost-benefit analyses and cost allocations of specific offshore electricity transmission and generation investments. These recommendations are directed primarily at national ministries, regulatory authorities and electricity transmission system operators (including EU and sea basin-level organisations where they are active), but also other EU and national stakeholders.

Résumé

En janvier 2023, les États membres de l'Union européenne (UE)ont convenu d'objectifs ambitieux en matière de déploiement d'énergie renouvelable en mer dans cinq bassins maritimes européens. Ces objectifs se traduisent par une ambition d'environ 111 GW de capacité éolienne en mer d'ici 2030, qui passerait à environ 317 GW d'ici 2050. Depuis janvier 2023, ces engagements ont été complétés par des ambitions pour l'ensemble de la Mer du Nord, y compris les pays non-membres de l'UE: au moins 300 GW d'énergie éolienne en mer sont prévus d'ici 2050.

La présente étude soutient la mise en place d'approches et processus mieux coordonnés pour la planification, l'analyse coûts-bénéfices et le partage/la répartition des coûts d'investissement, production et transport d'électricité en mer au niveau des bassins maritimes d'une part, et de projets individuels d'autre part, en particulier en ce qui concerne les projets de transport hybrides. Une meilleure coopération et coordination devrait faciliter l'atteinte des ambitions nationales d'une manière plus efficace tout en contribuant au meilleur fonctionnement des marchés de l'électricité.

Les principaux résultats de cette étude consistent en deux recommandations : 1) la première concerne les options de partage des coûts et des bénéfices dans les bassins maritimes ; et 2) la seconde s'attarde sur les analyses coûts-bénéfices coordonnées et la répartition des coûts d'investissement des actifs spécifiques de transport et de production d'électricité en mer. Ces recommandations s'adressent principalement aux ministères nationaux, aux autorités de régulation et aux gestionnaires de réseaux de transport d'électricité (y compris les organisations au niveau de l'UE et des bassins maritimes où ils sont actifs), mais aussi à d'autres parties prenantes au niveau national et européen.

EXECUTIVE SUMMARY

In November 2020, the European Commission published the EU strategy on offshore renewable energy, which sets high ambitions for deployment of offshore renewable energy in EU basins: at least 300 GW of offshore wind and 40 GW of ocean energies by 2050. Moreover, the revised TEN-E Regulation containing new provisions on offshore grids entered into force on 23 June 2022, driving the joint planning of offshore wind energy parks and related grid infrastructure per sea basin.

EU Member States have in January 2023 agreed on ambitious long-term goals for the deployment of offshore wind energy up to 2050 in five sea basins, with intermediate objectives to be achieved by 2030 and 2040. The announced figures represent an overall ambition of approximately 111 GW of offshore wind energy capacity by 2030, which would rise to around 317 GW by 2050. Since January 2023 these commitments have been complemented with ambitions for the whole North Sea, including non-EU countries, where at least 300 GW of offshore wind energy would be installed by 2050.

To prepare for such high volumes of offshore renewable energy, the Commission has launched a series of studies, including the present one which focuses on the following objectives:

1. Develop **recommendations for sea basin cost-benefit and cost-sharing options** applicable to integrated offshore network development plans and considering the necessary interlinks with the related offshore renewable energy generation projects;

2. Develop **recommendations for coordinated cost-benefit analyses and cost allocations of specific offshore electricity transmission and generation assets** that can be used to agree on financing, market and political arrangements on offshore electricity generation projects.

The study should **support a more coordinated process for the planning, cost-benefit analysis and cost sharing/allocation of offshore electricity generation and transmission at the sea-basin and project levels, particularly when involving hybrid transmission projects.** Moreover, this study should in particular support the Commission in developing the methodology referred to in article 15(1) of the revised TEN-E Regulation.

While the deployment of offshore hydrogen infrastructure may in some cases become an relevant complement to transport large energy volumes from sea basins to industrial sites, **this study focuses on electricity infrastructure projects**. Nonetheless, the potential extension of the processes proposed in this study to hydrogen infrastructure is also briefly discussed.

Stakeholder consultation

Comprehensive stakeholder engagement activities were conducted during the project, including a survey, workshops as well as bilateral interviews (further summarised in chapter 2). Through this process **the following topics have been identified as the stakeholders' main priorities and concerns** regarding future development of offshore transmission infrastructure:

- The non-binding nature of the sea-basin guidance;
- Interaction between sea-basin level and individual project cost-benefit analysis and cross-border cost-sharing/allocation;
- Impact on onshore reinforcements needs;
- Participation of countries not directly involved in project development/land-locked countries in the cost sharing at the sea-basin level;
- Include non-monetisable benefits in the assessment;
- Cost-sharing options between MSs;
- Sector coupling or assessing options across sectors;
- The definition of integrated project (with hybrid transmission) and how to assess these;
- Ownership in relation to cost allocation and captured benefits.

Recommendations for sea-basin CBA of integrated offshore network development plans and the associated sea-basin CBCS

Chapter 3 presents recommendations for sea basin cost-benefit (SB-CBA) and cost-sharing (SB-CBCS) options applicable to integrated offshore network development plans and considering the necessary interlinks with the related offshore renewable energy generation projects. It should support the Commission in developing the non-binding methodology specified in article 15(1) of the revised TEN-E Regulation and the associated integrated offshore network development plan (ONDP) process.

The objective of the SB-CBA recommendations is to provide insights to Member States on the methodology to quantify **costs and benefits of coordinated offshore networks needed to connect RES production capacities proposed by Member States** in their political agreements. This assessment, by feeding into the SB-CBCS and catalysing discussions on the funding of offshore energy infrastructure, is expected to facilitate the deployment of offshore energy generation projects and related networks, and in particular of offshore wind energy projects connected through hybrid networks. The recommendations on the sea-basin cost-benefit analysis covers the following aspects:

- Structure of the SB-CBA guidance;
- Scenarios and time horizons;
- Counterfactual;
- Reference grid;
- Modelling approach;
- Multicriteria analysis;
- Sensitivities;
- Potential extensions of the process to consider hydrogen infrastructure.

The objective of the SB-CBCS is to **provide a methodology to quantitatively estimate the costs that would be borne by each Member State**. The SB-CBCS, which is a **non-binding** exercise, can therefore be an essential tool to foster dialogue between Member States, allowing them to kickstart discussions and enter into agreements for cost sharing in advance of the development of specific projects. The recommendations on the sea-basin cross-border cost sharing covers the following aspects:

- Structure of the SB-CBCS guidance;
- Challenges for the SB-CBCS:
    - Uncertainty and lack of trust in the CBAs and their ability to capture all benefits;
    - Variability of the distribution of benefits depending on the scenarios;
    - Countries to be involved in the cost sharing process;
- Cost sharing options;
- Costs to be shared;
- Cost sharing key for the CB-CBCS;
- Extension to hydrogen infrastructure.

Recommendations on coordinated CBA and CBCA between offshore electricity transmission and generation

Chapter 4 presents recommendations on the **process for coordinating project-specific cost-benefit analyses (PS-CBA) and cross-border cost allocations (PS-CBCA)** for offshore electricity transmission and generation projects. Furthermore, the chapter also discusses more **high-level aspects which could enhance cross-border cooperation** and cost-efficient achievement of EU and national offshore energy targets.

The recommendations should improve the overall process for planning, assessing and agreeing on the cost allocation for both offshore electricity generation and transmission projects, while avoiding issues such as double-counting of costs or benefits. The **project-specific CBA and CBCA recommendations address the following elements**:

- Overall CBA and CBCA process for cross-border offshore projects;
- Coordination of offshore generation and infrastructure CBAs;
    - Definition of scenarios;
    - Bidding zone configuration;
    - Counterfactual definition;
    - Key performance indicators;
- Coordination of offshore generation and infrastructure CBCAs;
    - Scope of costs to be considered;
    - Inclusion of non-hosting countries;
    - Agreements on deviations of costs and benefits;
    - Further issues to be considered
        - Timing of offshore energy tenders and CBCAs;
        - Agreement on the allocation of congestion incomes;
        - Addressing the asymmetrical distribution of socio-economic welfare components.

Furthermore, this chapter presents **recommendations regarding specific governance and regulatory aspects** that can be considered to contribute to cost-efficiently reaching the offshore wind energy targets and to enhance efficient cooperation and coordination:

- The governance structure to enable agreements on the ambitions and timelines per sea basin for development of offshore wind energy;
- Reaching agreements on CBA and CBCA principles before CBA studies and CBCA agreements are concluded;
- The implementation of cooperation mechanisms amongst Member States on offshore renewable energy projects;
- Reaching agreements on the bidding zone configuration for each sea basin;
- The method for charging grid connection costs to offshore wind energy developers;
- The grid access tariffication principles applicable to offshore wind energy generators;
- Promoting PPAs between offshore wind energy operators and retailers or large users.

RÉSUMÉ EXÉCUTIF

En novembre 2020, la Commission européenne a publié sa stratégie sur les énergies renouvelables en mer, qui fixe des ambitions élevées pour le déploiement des énergies renouvelables en mer dans les bassins de l'UE : au moins 300 GW d'énergie éolienne en mer et 40 GW d'énergies marines d'ici 2050. En outre, la révision du règlement pour les infrastructures énergétiques transeuropéennes (*TEN-E*), contenant de nouvelles dispositions sur les réseaux en mer, est entré en vigueur le 23 juin 2022, impulsant la planification conjointe des parcs éoliens en mer et des infrastructures dans chaque bassin maritime.

Les États membres de l'UE se sont mis d'accord, en janvier 2023, sur des objectifs ambitieux à long terme pour le déploiement de l'éolien en mer, et ce jusqu'en 2050 dans cinq bassins maritimes, avec des objectifs intermédiaires à l'horizon 2030 et 2040. Les chiffres annoncés représentent une ambition globale d'environ 111 GW de capacité éolienne en mer d'ici 2030, qui passerait à environ 317 GW d'ici 2050. En janvier 2023, ces engagements ont été complétés par des ambitions pour l'ensemble de la Mer du Nord, y compris les pays non-membres de l'UE, où au moins 300 GW d'énergie éolienne en mer devraient être installés d'ici à 2050.

Pour se préparer à de tels volumes d'énergie renouvelable en mer, la Commission a lancé une série d'études, dont la présente, qui se concentre sur les objectifs suivants :

1. Élaborer des **recommandations pour la mise en œuvre d'options de partage des coûts et des bénéfices dans les bassins maritimes,** applicables aux plans de développement de réseaux offshore intégrés et tenant compte des liens nécessaires avec les projets de production d'énergie renouvelable en mer ;

2. Élaborer des **recommandations détaillées pour des analyses coûts-bénéfices coordonnées et la répartition des coûts de certains actifs de transport et de production d'électricité en mer**, qui peuvent être utilisées pour convenir de dispositions financières, commerciales et politiques concernant les projets de production d'électricité en mer.

L'étude vise à **favoriser un processus mieux coordonné pour la planification, l'analyse coûts-bénéfices et le partage/la répartition des coûts de la production et du transport d'électricité en mer au niveau des bassins maritimes et des projets, en particulier lorsqu'il s'agit de projets de transport hybrides.** Cette étude vise notamment aider la Commission à élaborer la méthodologie mentionnée dans l'article 15, paragraphe 1, du règlement TEN-E révisé.

Bien que le déploiement d'une infrastructure hydrogène offshore puisse, dans certains cas, représenter un complément pertinent pour transporter de grands volumes d'énergie des bassins maritimes vers les sites industriels, **cette étude se concentre essentiellement sur les projets d'infrastructure électriques**. Néanmoins, l'extension potentielle des processus proposés dans cette étude à l'infrastructure hydrogène est également brièvement discutée.

Consultation des parties prenantes

Des activités d'engagement des parties prenantes ont été menées au cours du projet, notamment une enquête, des ateliers et des entretiens bilatéraux (résumés au chapitre 2). Ce processus a permis d'**identifier les sujets suivants comme étant les principales priorités et préoccupations des parties prenantes** en ce qui concerne le développement futur de l'infrastructure de transport d'électricité en mer :

- La nature non contraignante des orientations relatives aux bassins maritimes ;
- Les interactions entre les analyses coûts-bénéfices et le partage/répartition transfrontalière des coûts au niveau des bassins maritimes et des projets individuels ;
- L'impact sur les besoins de renforcement des réseaux à terre ;
- La participation des pays qui ne sont pas directement impliqués dans le développement du projet et/ou de pays enclavés au partage des coûts au niveau des bassins maritimes ;
- La considération d'avantages non monétisables dans l'évaluation des projets ;
- Les options de partage des coûts entre États membres ;

- Le couplage sectoriel ou l'évaluation des options entre les secteurs ;
- La définition d'un projet intégré (avec transmission hybride) et la manière de l'évaluer ;
- La propriété des actifs, en relation avec la répartition des coûts et les avantages obtenus.

Recommandations portant sur l'analyse coûts-bénéfices par bassin maritime des plans de développement de réseaux intégrés en mer et du partage des coûts au niveau des bassins maritimes

Le chapitre 3 présente recommandations pour la mise en œuvre par bassin maritime des options d'analyse des coûts et des bénéfices (SB-CBA) et de partage des coûts (SB-CBCS) applicables aux plans intégrés de développement du réseau en mer, tenant compte des liens nécessaires avec les projets de production d'énergie renouvelable en mer. Il vise à aider la Commission à élaborer la méthodologie non contraignante prévue à l'article 15, paragraphe 1, de la révision du règlement TEN-E dans le cadre du processus d'élaboration et d'analyse des plans intégrés de développement du réseau en mer (ONDP).

L'objectif des recommandations SB-CBA est de fournir aux États membres des indications sur la méthode de quantification des **coûts et des bénéfices des réseaux coordonnés en mer nécessaires pour connecter les capacités de production d'énergies renouvelables proposées par les États membres** dans leurs accords politiques. Cette évaluation, en alimentant le SB-CBCS et en catalysant les discussions sur le financement des infrastructures énergétiques en mer, vise à faciliter le déploiement de projets de production d'énergie en mer et de réseaux connexes, et en particulier de projets d'énergie éolienne en mer reliés par des réseaux hybrides. Les recommandations relatives à analyse coûts-bénéfices par bassin maritime couvrent les aspects suivants :

- Structure des orientations du SB-CBA ;
- Scénarios et horizons temporels ;
- Contrefactuel ;
- Grille de référence ;
- Approche de modélisation ;
- Analyse multicritère ;
- Analyses de sensibilités ;
- Extension potentielle du processus pour prendre en compte l'infrastructure hydrogène.

L'objectif du SB-CBCS est de **fournir une méthodologie permettant d'estimer quantitativement les coûts qui pourraient être supportés par chaque État membre**. Le SB-CBCS, qui est un exercice **non contraignant**, peut donc être un outil essentiel pour favoriser le dialogue entre les États membres, en leur permettant d'entamer des discussions et de conclure des accords de partage des coûts avant le développement de projets spécifiques. Les orientations sur le partage des coûts transfrontaliers par bassin maritime couvrent les aspects suivants :

- Structure du guide SB-CBCS ;
- Défis pour le SB-CBCS ;
    - Incertitudes liées aux analyses coûts-bénéfices et leur capacité à saisir tous les bénéfices ;
    - Variabilité de la répartition des bénéfices en fonction des scénarios ;
    - Pays à impliquer dans le processus de partage des coûts ;
- Options de partage des coûts ;
- Identification des coûts à partager ;
- Clé de répartition des coûts pour le SB-CBCS ;
- Extension à l'infrastructure hydrogène.

Recommandations portant sur l'analyse coûts-bénéfices de projets spécifiques et sur la coordination entre les analyses des projets de transport et de production d'électricité en mer

Le chapitre 4 présente recommandations portant sur le **processus de coordination des analyses coûts-bénéfices de projets spécifiques (PS-CBA) et des répartitions transfrontalières des coûts (PS-CBCA)** pour les projets de transport et de production d'électricité en mer. En outre, ce chapitre aborde des **aspects plus généraux susceptibles de renforcer la coopération transfrontalière** et la réalisation des objectifs européens et nationaux en matière de déploiement de la production d'énergie en mer.

Ces recommandations visent à améliorer le processus global de planification, d'évaluation et d'accord sur la répartition des coûts pour les projets de production et de transport d'électricité en mer, tout en évitant des problèmes tels que le double comptage des coûts ou des bénéfices. Les **recommandations relatives à l'analyse coûts-bénéfices et à la répartition transfrontalière des coûts de projets spécifiques portent sur les éléments suivants** :

- Processus global d'analyse coûts-bénéfices et d'analyse coûts-bénéfices pour les projets offshore transfrontaliers ;
- Coordination des analyses coûts-bénéfices de la production et de l'infrastructure offshore :
    - Définition des scénarios ;
    - Configuration des bidding zones ;
    - Définition du contrefactuel ;
    - Indicateurs clés de performance ;
- Coordination des répartitions transfrontalières des coûts de production et d'infrastructure en mer :
    - Étendue des coûts à prendre en considération ;
    - Inclusion des pays non hôtes ;
    - Accords sur les écarts de coûts et de bénéfices ;
    - Autres questions à examiner
        - Calendrier des appels d'offres et des CBCAs ;
        - Accord sur la répartition des recettes tirées de la rente de congestion ;
        - Répartition asymétrique des composantes du surplus collectif.

Enfin, ce chapitre présente des **recommandations concernant des aspects spécifiques de gouvernance et de réglementation** qui peuvent être pris en compte pour contribuer à atteindre de manière efficace les objectifs en matière d'énergie éolienne en mer et pour améliorer l'efficacité de la coopération et de la coordination :

- La structure de gouvernance pour permettre des accords sur les ambitions et les calendriers par bassin maritime pour le développement de l'énergie éolienne en mer ;
- Conclure des accords sur les principes de CBA et de l'CBCA, avant que les études de CBA et les accords de CBCA ne soient conclus ;
- La mise en œuvre de mécanismes de coopération entre les États membres pour les projets d'énergie renouvelable en mer ;
- Conclure des accords sur la configuration des zones de marché (bidding zones) pour chaque bassin maritime ;
- La méthode d'allocation des coûts de connexion au réseau aux développeurs d'énergie éolienne en mer ;
- Les principes de tarification de l'accès au réseau applicables aux producteurs d'énergie éolienne en mer ;
- Promouvoir les accords d'achat d'électricité entre les exploitants d'énergie éolienne en mer et les détaillants ou les grands utilisateurs.

1. Introduction

Achieving the EU's energy and climate objectives, requires stepping up investments in offshore wind energy with the aim of reaching at least 300 GW of installed capacity in 2050, in line with the Commission's strategy for offshore renewable energy published in November 2020.[1] Next to using radial links to connect new offshore wind energy capacities, integrated projects involving hybrid transmission infrastructure should be developed. Coordinated long-term planning and development of offshore and onshore electricity grids should also be addressed. Offshore infrastructure planning should not be based anymore on a project-by-project approach but rather on a coordinated comprehensive approach ensuring the sustainable development of integrated offshore grids in line with the offshore wind energy plans in each sea basin, taking into account environmental impacts and other uses of the sea. The approach should be based on voluntary cooperation between EU Member States (and non-EU partners where relevant), which remain responsible for approving the projects in their respective territories.

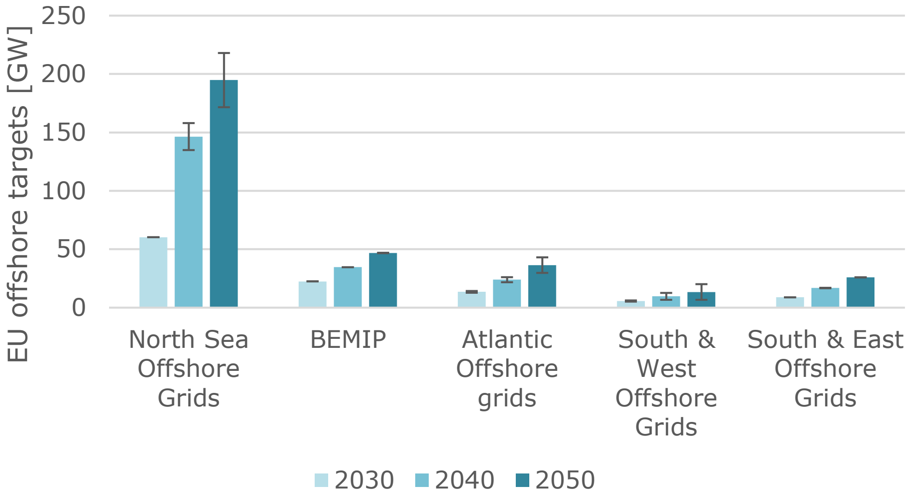
The revised TEN-E Regulation EU 2022/869 drives the joint planning of offshore wind energy parks per sea basin, that national Governments and TSOs have to plan for on the basis of non-binding offshore wind energy objectives for 2030, 2040 and 2050 in line with their commitment to net zero GHG emissions by 2050. In this context, the EU Member States have in January 2023 agreed on ambitious long-term goals for the deployment of offshore wind energy up to 2050 in each of the EU's five sea basins (detailed in Table 1-1), with intermediate objectives to be achieved by 2030 and 2040. The announced figures represent an overall ambition of approximately 111 GW of offshore wind energy capacity by 2030, which would rise to around 317 GW by 2050 as shown in Figure 1-1, reaching the goal proposed in the above-mentioned Strategy Communication.

Table 1-1 Sea basins as per the revised TEN-E Regulation

Sea basin	MS concerned	Waters
North Sea Offshore Grid	BE, DK, FR, DE, IE, LU, NL, SE	North Sea, Irish Sea, Celtic Sea, English Channel and neighbouring waters
BEMIP	DK, EE, FI, DE, LT, LV, PL, SE	Baltic Sea
Atlantic Offshore grid	FR, IE, PT, ES	North Atlantic Ocean
South & West Offshore Grid	FR, GR, IT, MT, PT, ES	Mediterranean Sea (including Cadiz Gulf) and neighbouring waters
South & East Offshore Grid	BG, HR, GR, IT, CY, RO, SI	Mediterranean Sea, Black Sea and neighbouring waters

[1] EU Offshore Renewable Energy Strategy

Figure 1-1 Non-binding EU offshore wind energy targets per sea basin.



These non-binding agreements represent the first deliverable of the regulatory set-up enshrined in the revised TEN-E Regulation and build amongst others on agreements in 2022 and 2023 during Summits and ministerial meetings of the North Sea and Baltic Sea.[2,3] Furthermore, since January 2023 these commitments have been further complemented by new announcements, which should lead to a combined installed capacity in 2050 across the European sea basins higher than the 317 GW indicated in January 2023 for the EU:

- North Sea: 120 GW by 2030 (compared to 19.8 GW installed by end 2020) and at least 300 GW by 2050 (Ostend Declaration on the North Seas as a Green Power Plant of Europe), including non-EU countries[4]
- Baltic Sea: 19.6 GW by 2030 (compared to 2.2 GW installed by end 2020) considering an overall potential of 93 GW (Marienborg Declaration of 30 August 2022)[5]

Moreover, for the remaining basins no further goals have been announced, but studies have been conducted or are ongoing:

- Atlantic Ocean: study concluded in 2023 identified an economic potential of up to 97 GW by 2050 (installed capacity by end 2020 was 32 MW)[6]
- Mediterranean Sea: study concluded in 2020 identified an economic potential of over 76 GW by 2050[7]
- Black Sea: studies are being undertaken to assess the potential and Black Sea Renewable Energy Coalition formed[8]

[2] Member States agree new ambition for expanding offshore renewable energy (europa.eu)
[3] Ostend Declaration on the North Seas as Europe's Green Power Plant
[4] Ostend Declaration on the North Seas as Europe's Green Power Plant
[5] The Marienborg Declaration - Regeringen.dk
[6] France Marine Energies et al. (2023) Study on the offshore energy potential in the Atlantic Ocean
[7] Guidehouse et al. (2020) Study on the offshore grid potential in the Mediterranean region
[8] https://www.enpg.ro/towards-a-black-sea-renewable-energy-coalition-strategic-partnership-for-energy-and-climate-security/

1.1. Objectives and structure of the study

To prepare for such high volumes of offshore renewable energy, the Commission has launched a series of studies, including the present one which focuses on the following objectives:

1. Develop **recommendations on options for sea basin cost-benefit and cost-sharing** applicable to integrated offshore network development plans and considering the necessary interlinks with the related offshore renewable energy generation projects;

2. Develop **recommendations on coordinated cost-benefit analyses and cost allocations of specific offshore transmission and generation assets** that can be used to underpin bi- or multilateral financing, market and political arrangements for offshore electricity generation and transmission projects.

The study should **support a more coordinated process for the planning, cost-benefit analysis and cost sharing/allocation of offshore generation and transmission at the sea-basin and project levels, particularly when involving hybrid transmission projects**[9]**.** Moreover, the study should support the Commission in developing the methodology specified in article 15(1) of the revised TEN-E Regulation.[10]

This report is structured as follows:

- **Chapter 2** provides a summary of the stakeholder consultation activities (survey, workshops and interviews), including key discussion items raised by stakeholders;
- **Chapter 3** presents the proposed recommendations for the cost-benefit analysis and cross-border cost sharing at sea basin level;
- **Chapter 4** presents recommendations on the process for coordinating project-specific CBAs and CBCA agreements for offshore electricity transmission and generation projects.

While the deployment of offshore hydrogen infrastructure may in some cases become an interesting alternative to transport large energy volumes from sea basins to industrial sites, **this study focuses on electricity infrastructure projects**. However, the potential extension of the processes proposed in this study to hydrogen infrastructure is also briefly discussed.

[9] In line with Article 14 of the revised TEN-E Regulation, we use the term hybrid project to refer to offshore transmission infrastructure with the dual purpose of connecting offshore renewable generation and interconnecting the electricity systems of two or more countries.

[10] The article states that by 24 June 2024, the Commission shall, together with the Member States and relevant TSOs, ACER and NRAs, develop guidance for a specific cost-benefit and cost-sharing methodology for the deployment of the sea-basin integrated offshore network development as defined in Article 14(2) in accordance with the non-binding agreement referred to in Article 14(1). This guidance shall be compatible with Article 16(1) of the Regulation.

2. STAKEHOLDER CONSULTATION

Understanding the perspectives of key stakeholders is essential to the creation of holistic recommendations. As such, the stakeholder engagement process and consultation were a central part of the project. It aimed to engage in proactive communication with key actors to assimilate their perspectives and address their concerns at an early stage, rather than having reactive communication. Engaging with the interested parties enabled a more comprehensive perspective on the challenges the project aims to overcome, provided with first-hand experience information and allowed participants to assimilate the recommendations as they are being designed.

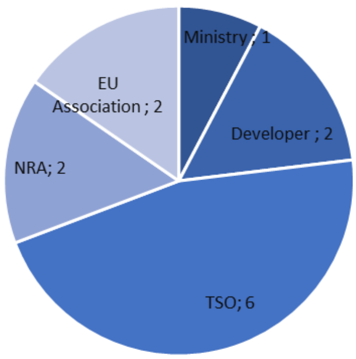
To fulfil this objective, a comprehensive survey was created and disseminated by the project partners. The survey collected information and views on three main areas: 1. Cost-Benefit Analysis (CBA), 2. Sea-Basin Cross-Border Cost Sharing (SB-CBCS) and 3. the Coordination of offshore wind energy generation and transmission infrastructure CBA and Cross-Border Cost Allocation (CBCA).

The survey was complemented with a bilateral interview process, for which the survey responses for each stakeholder were assessed to do a deeper dive into those replies that were of highest interest and relevance for the project and provided most value to the exercise. This resulted in distinct interviews, tailored to each stakeholder, allowing to foster and obtain first-hand information on the key actor's concerns, priorities and experience.

In addition, targeted stakeholder workshops were held. An initial workshop was conducted to present the project objectives and scope to stakeholders and obtain preliminary feedback. Targeted meetings were also held with ACER and member NRAs, ENTSO-E and member TSOs and parties active in the North Seas Energy Cooperation.

A total of 13 key stakeholders replied to the survey, shown in Figure 2-1; 6 TSOs, 2 NRAs, 2 European level associations, 2 developers and 1 ministry. From these stakeholders, 9 accepted follow up interviews to obtain further insight. These stakeholders represented Member States or had projects in the following sea basins: North (7 of them), Baltic (6), Atlantic (4), Adriatic (1), Celtic (1) and the Western Mediterranean (1); several respondents are developing projects in more than one sea basin.

Figure 2-1 Stakeholder groups participating in the stakeholder engagement



Most respondents considered the development of hybrid or joint projects in several locations such as the North Sea (e.g. North Sea Wind Power Hub between Denmark and the Netherlands) or the Baltic Sea (e.g. Bornholm Energy Island).

There were a number of **recurring overarching topics that through the survey and interview process** have been identified as the stakeholders' main priorities and concerns regarding future development of offshore transmission infrastructure. These items are **described below**, indicating where they are discussed in this report. Then, Annex I describes the stakeholder engagement findings in more detail, explaining the main points of agreement, as well as some views of individual respondents when presenting a differentiated perspective, a concern or when offering a critical view that the project considers useful to address. These key discussion items were:

- The **non-binding** nature of the sea-basin guidance. It is expected to be fundamental in supporting and securing agreements between MSs, by providing an indication of how costs could be divided to use as a basis for the discussion. The non-binding element allows space for the negotiations to dive into project-specific detail, while still facilitating the discussions and motivating the TSOs to take concrete actions. It also ensures that projects in sea basins that are already in development can continue as planned. Further detail on the objective and scope of the guidance can be found in subsection 3.4.1.

- Interaction between **sea-basin level and individual project CBAs and CBCAs**. In this report, sea basin-level CBAs/CBCAs are addressed in chapter 3, whereas chapter 4 focuses on project-specific mechanisms. The interaction between the two is addressed in section 4.6.

- **Impact on onshore reinforcements needs**. To facilitate the coordination, it is suggested by stakeholders for the guidance to specify what costs to include. Some stakeholders interviewed pointed that these **costs should include the onshore investments needed to connect the offshore capacity**. However, there is also acknowledgement that there would need to be clear boundaries and methods to determine exactly what costs for onshore reinforcements and connections could be included. This could be a challenge as determining the particular purpose of what is built onshore can be complex. The issue is addressed in sections 4.4.4 and 4.5.1.

- **Participation of countries not directly involved in project development, such as land-locked countries, in the cost sharing in SB-CBCS**. When asked about the criteria to define which MS benefits should be included in the CBCS, the views were mixed regarding whether there should be a minimum threshold that conditions which MSs are to be included. Several stakeholders considered that there should be no threshold as it has the risk of being arbitrary and small countries would perceptually benefit even at low shares of the overall (high) benefit. Others did consider that there should be a minimum threshold (e.g. like 10 % for CBCA) to avoid too detailed investigations of lesser cost-benefit values and ensure minor landlocked beneficiaries do not stall hybrid projects. If needed, smart thresholds were also mentioned as a possibility; for instance, having different criteria for countries directly involved (landing points) and others. Other criteria were also proposed to assess the benefits more broadly, such as using the imported flow share, sustainability indicators, socio-economic welfare, technological asymmetry or security of supply indicators already quantified in existing CBA methodologies. This is addressed in section 3.4.

- **Include non-monetisable benefits in the assessment**. In addition to monetizable costs and benefits, it was indicated that these parameters needed to be accompanied by **non-monetised indicators** that account for the costs and benefits that are not as easily monetised (e.g. adequacy, flexibility, social and environmental impacts). Costs and benefits of demand and renewables should not be underestimated, and efficiency benefits could be accounted for. Furthermore, the fact that more hydrogen means a higher need of renewable energy electricity and less efficiency is stressed. This is addressed in sections 3.3.7, 4.3 and 4.4.4.

- **Cost-sharing options between MSs**. Regarding the allocation-of-cost methodologies proposed, several survey respondents suggest having MSs directly involved in developing individual projects to **negotiate** their cost sharing options. Having **flexibility** to select alternative cost distributions is considered key to ensure continued development of favourable solutions, both inside and outside the framework of the SB-CBCA. MSs will benefit from being able to use the SB-CBCS guidance principles.

  Other stakeholders consider that, despite potential complexity, the fairest approach is to have costs **prorated according to energy usage or distributed according to the benefits received.** It is proposed to have, as a minimum, an assessment of captured Socio-Economic Welfare for involved MSs and, if any imbalances are confirmed by the assessment, compensate between themselves to avoid arbitrary options that may create low cost-benefit for one party, and high cost-benefit for another.

  In addition, the application of an **ex-post financial correction** for part of the project costs is suggested to ensure that the cost-sharing does not only rely on sensitive scenario-based calculations, as for instance, as a small change in fuel costs could result in the activation of one generation over another, potentially changing the CBA result. An option suggested is to reflect deviations of realised investments in subsequent new infrastructure investments. These issues are covered in section 3.4.

- **Sector coupling or assessing options across sectors** was also a reoccurring theme. It is agreed that decisions taken for other sectors such as H_2 will have an impact on the electrical infrastructure needs. Nonetheless, the TSOs are not to be responsible for H_2 demand or commercial activities. While the deployment of offshore hydrogen infrastructure may in some cases become an interesting alternative to transport large energy volumes from sea basins to industrial sites, **this study focuses on electricity infrastructure projects** and thus hydrogen is only briefly discussed in sections 3.3.9 and 3.4.7 for the SB-CBA and SB-CBCS respectively.

- **The definition of integrated project (with hybrid transmission) and how to assess these**. How to assess **integrated projects** is the one of the main topics of discussion. Developers disagree on how to assess the benefits of such projects: a) whether to plan generation and transmission infrastructure together, as when deciding the capacity of an interconnector, the wind capacity has to be considered; b) or separately, to not combine regulated interconnector assets with market generation assets. Stakeholders agree on the need to have clear definitions and mechanisms to **avoid double-counting** and considering the regulatory framework to **ensure unbundling**. This central question involved multiple elements of cost-benefit analysis and cross-border cost sharing/allocation, and is addressed in various sections of chapters 3 and 4.

- **Asset ownership** in relation to cost allocation and captured benefits is one of the main concerns. There is agreement on the need for a clear determination of **what assets are part of the grid user's connection (in this case the offshore wind energy generator) and which part of the TSO infrastructure**. For instance, storage may be considered as TSO infrastructure by some parties, if under compliance with EU legislation, while others argue that its main business case is market-based (arbitrage or ancillary service provision) and hence it should in principle not be owned/operated by network operators. While we do not provide specific recommendations on this issue, it is briefly discussed in section 4.2.

3. Recommendations for sea-basin CBA of integrated offshore network development plans and the associated sea-basin CBCS

3.1. Objectives

This chapter presents the recommendations to the Commission for the elaboration of its guidance on the methodology to be used by ENTSO-E when undertaking SB-CBA and SB-CBCS analyses of ONDPs.

This chapter is structured into three sections: the first section presents the context for the development of a coordinated offshore network planning; the second section focuses on the recommendations for developing the guidance on the SB-CBA; and the third section contains recommendations for developing the guidance on SB-CBCS analyses.

3.2. Context

In the framework of Article 14(1) of the revised TEN-E Regulation, Member States should "*conclude a non-binding agreement to cooperate on goals for offshore renewable generation to be deployed within each sea basin by 2050, with intermediate steps in 2030 and 2040, in line with their national energy and climate plans, and the offshore renewable potential of each sea basin*", with support by the European Commission.

As indicated in chapter 1, five sea basins are identified in the revised TEN-E Regulation, in line with the priority offshore corridors; an overview is presented in Table 1-1. The first non-binding offshore wind energy generation targets per Member State and sea basin were published in January 2023; they range between 281 to 353 GW to be installed by 2050 in EU waters[11]. The currently planned offshore wind energy capacities are mainly to be deployed in the North Sea and Baltic Sea-basins, accounting for 75% of the total EU target, as shown in Figure 1-1.

According to Article 14(2) of the revised TEN-E Regulation, ENTSO-E is to develop "*high-level strategic integrated offshore network development plans for each sea-basin, in line with priority offshore grid corridors*" that consider the political ambition agreed upon by Member States. This analysis will be integrated to the TYNDP process, as a separate output, referred to in this report as Sea-Basin Offshore Network Development Plans (SB-ONDP). The TYNDP 2024 will be the first edition for which SB-ONDPs will be produced by ENTSO-E, according to the updated TEN-E priority corridors shown in Table 3-1.

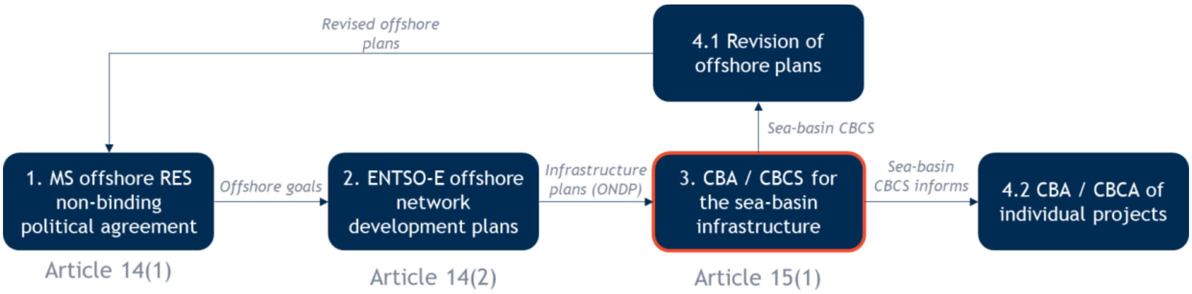
Given the shared environmental areas between Member States and the size of the projects identified in the SB-ONDP (e.g. connecting energy islands in the North Sea), an efficient cooperation between Member States at sea basin-level is key. Yet, these projects may see difficulties in being agreed upon, for instance due to cost sharing issues. The revised TEN-E Regulation brings in a significant improvement to the current process by introducing new tools that can act as "reality checks" to allow for Member States to (a) better understand the impact of their offshore RES ambitions on the costs that are likely to be borne by each Member State to build the required network infrastructure in a sea basin, (b) providing tangible information to kickstart discussions on the potential costs to be shared among MSs due to the development of the offshore network infrastructure, and (c) to potentially adapt their offshore RES ambitions (i.e. the goals referred to in Article 14(1) of the revised TEN-E Regulation).

The two new tools are the **sea-basin cost-benefit analysis** and the **sea-basin cross-border cost-sharing** analysis of the deployment of the sea-basin integrated offshore network development plans introduced in Article 14(2). These tools are referred to in this document as "SB-CBA" and "SB-CBCS" (with SB standing for sea-basin). These tools are introduced in Article 15 of the revised TEN-E Regulation, entrusting the European Commission to produce Guidance documents. The European Commission is expected to produce the SB-CBA and SB-CBCS Guidance documents by mid-2024. ENTSO-E will then carry out the SB-CBA and SB-CBCS following the Guidance documents. ENTSO-E shall present the results of the first edition of the SB-CBCS (assessing the ONDP 2024) by mid-2025[12].

[11] https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2023-01-19_en
[12] *Art. 15(2) TEN-E Regulation EU 2022/869 (link)*

The SB-CBA and SB-CBCS will ensure Member States can reach a common understanding of the expected costs and benefits related to offshore network costs, before project-specific cost-benefit analyses and cross-border cost allocation analyses of individual projects are carried out (referred to below as project-specific CBA and CBCA, i.e. "PS-CBA" and "PS-CBCA"). This is exemplified in Figure 3-1.

Figure 3-1 Main steps for the production and assessment of coordinated offshore electricity network development plans



3.3. SB-CBA Guidance

This section provides recommendations for the development of a Guidance for the SB-CBA study assessing the ONDPs that will be carried out by ENTSO-E. The recommendations take into account the feedback obtained from the stakeholders, in particular via interviews and several discussions with ENTSO-E, as well as past experience of project-specific CBAs and how this can be applied to the Sea-Basin context.

3.3.1. Objective and scope of the SB-CBA

The objective of SB-CBA is to provide quantitative insights to Member States on the **costs and benefits of the coordinated offshore network needed to connect the offshore RES capacities proposed by Member States** in their non-binding political agreements. This assessment, by feeding into the SB-CBCS and catalysing discussions on the financing of offshore infrastructure, is expected to facilitate the deployment of offshore generation, and of offshore wind parks connected through hybrid transmission infrastructure in particular.

As per the revised TEN-E, the SB-CBA aims to assess the benefits brought by the **offshore network infrastructure** identified by the ENTSO-E (i.e. the ONDPs). In other words, the SB-CBA will assess **only the network part of offshore priority corridors,** and not the combined value of offshore generation and offshore infrastructure.

Additionally, the scope of the SB-CBA, at least in its first edition (i.e. the one to be published as part of the TYNDP 2024 cycle), is limited to **electricity** infrastructure. Whilst it would be valuable to develop a SB-CBA that considers the interlinkages between electricity, methane and hydrogen, a prerequisite is that the ONDP itself considers both electricity and gaseous options to bring the energy generated by offshore assets to shore. As the first edition of the ONDP will not include any gas infrastructure, the core recommendations provided in this section assume that the ONDP consists of electricity infrastructure exclusively. Nevertheless, we provide some recommendations on the way to widen the scope of the SB-CBA should the ONDP become a multi-energy assessment of offshore infrastructure needs. The authors propose the European Commission to consider extending the scope of the ONDPs to gaseous energy vectors once the plans for electricity infrastructure are considered of sufficient quality, and to task the relevant TSO associations to collaborate towards developing integrated ONDPs.

The SB-CBA objective is not to propose a grid design, or to evaluate a particular project. The SB-CBA will assess a grid previously determined by ENTSO-E in the ONDPs. The ONDPs, which will be a part of the TYNDP process from the 2024 edition onwards, will be a high-level strategic plan to determine **offshore grid needs.** Thus, the SB-CBA will only evaluate the costs and benefits of the ONDPs, but it will not seek to determine alternative grid configurations.

3.3.2. Recommendations on the structure of the guidance related to SB-CBA

We propose the SB-CBA Guidance (to be produced by the European Commission) to provide the main principles that will allow ENTSO-E to perform the SB-CBA. Therefore, our recommendations address all the aspects required by a cost-benefit analysis methodology.

We recommend the European Commission to issue a guidance document structured as follows:

- **Introduction**
  - **Context**: Description of the process described in revised TEN-E, with focus on new provisions relating to SB-level processes. Addressed in Section 3.2;
  - **Objective and scope**: Precise definitions of objectives and scope, what is included and what is not included in the SB-CBA. Addressed in Section 3.3.1;
  - **Overview**: An executive summary of the SB-CBA methodology.
- **General approach**
  - **Scenarios and time horizons**: The scenarios of the TYNDP cycle which should be used, according to the SB-ONDP output time horizons. Addressed in Section 3.3.3;
  - **Counterfactual:** Provide main principles for counterfactuals, enumerate options and provide default and alternative (if needed) approaches. Addressed in Section 3.3.4;
  - **Reference grid:** Considerations of reference grid aspects, definition of 2050 reference grid. Addressed in Section 3.3.5;
  - **Modelling approach:** Type of simulations to be performed (market, redispatch, stability). Considerations of home market vs. offshore bidding zone. Addressed in Section 3.3.6;
  - **Multicriteria analysis:** List of KPIs to calculate, geographic granularity of reporting. Addressed in Section 3.3.7;
  - **Other assumptions:** NPV-related aspects, sensitivities, others. Addressed in Section 3.3.8 and 3.3.9.

In the next sections, we provide recommendations on all the points appearing in the "General approach" part of the above-mentioned recommended structure. Our recommendations are based on the understanding the authors have gained of the structure of the ONDPs that will be produced by ENTSO-E for each of the sea basins identified in the revised TEN-E Regulation.

We summarise our understanding of the structure of the ONDPs in the box below.

Our understanding of the ONDPs

An offshore network development plan (ONDP) is a new product to be published by ENTSO-E, which is to be included from the TYNDP 2024 cycle onwards. Most of the key aspects to be treated in the SB-CBA are dependent on the structure, modelling philosophy and outputs of the ONDP. The authors thank ENTSO-E for the discussions that have allowed to gain a better understanding of the ONDP process and outputs. The following paragraphs provide a summary of the authors' understanding of the ONDP.

The objective of the ONDP is to identify strategic offshore corridors to integrate the non-binding offshore RES generation objectives set out by Member States. This work is carried out by ENTSO-E for each of the sea basins defined by the revised TEN-E, which are listed in Table 1-1.

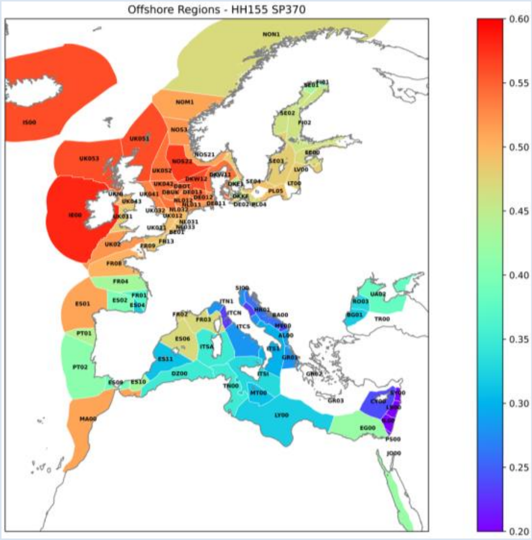
The key input into the ONDP process is the set of Member States' non-binding offshore objectives per time horizon (2030, 2040 and 2050) and per sea-basin. The collection process finished early 2023, with cumulative EU goals reaching 281-354 GW by 2050[13].

Offshore generation capacities are disaggregated by ENTSO-E (at least) at the offshore Pan-European Climate Database (PECD) zone level (see Figure 3-2 below), and they are integrated

[13] https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2023-01-19_en

into TYNDP scenarios: the National Trends scenario for 2030 and 2040, and the Distributed Energy scenario for 2050.

Figure 3-2 Offshore zones of the PECD 2021 and capacity factors for offshore wind[14]



ENTSO-E then proceeds to identify **offshore grid needs** to connect the offshore generation for each time horizon. The offshore generation is by default connected through radial connections to the **host country**[15], with can be complemented by **grid needs** to be built **in addition** to the radial connections. Additional grid needs can include hybrid interconnectors between two offshore generation areas in two different host countries[16], hybrid interconnectors from an offshore generation area to another country, reinforcements of radial connections, as well as direct interconnectors (i.e. not hybrids)[17].

The offshore grid needs are identified sequentially using an investment optimisation model:

- For the 2030 time horizon, no optimisation is carried out and only the projects to be commissioned by 2030 (as identified during the TYNPD cycle) are included in the ONDP;
- For the 2040 time horizon, offshore grid needs are identified in addition to projects that are expected to be commissioned by 2035 (i.e., the reference grid); and
- For the 2050 time horizon, offshore grid needs are identified in addition to the offshore grid needs from the 2040 horizon.

Results from the optimisation model are then subject to a review by ENTSO-E's experts, which can amend them based on expert judgement, for example correcting the sizing of interconnectors to real-world values.

The ONDP exercise is performed separately for each of the sea basins identified in Table 1-1.

The output of the ONDP will be the offshore grid needs (i.e. the number of interconnectors and capacities) between each (onshore and offshore) zone, as well as costs related to the investment needed for all offshore infrastructures (including radial connections, hybrids, and potentially direct

[14] Koivisto, Matti Juhani; Murcia Leon, Juan Pablo (2022): Pan-European wind and solar generation time series (PECD 2021 update). Technical University of Denmark. Collection. https://doi.org/10.11583/DTU.c.5939581.v3
[15] We define the **hosting country** as the country in which offshore generation is located, either in its territorial waters or the EEZ.
[16] We consider here a **hybrid interconnector**, the interconnector section connecting two offshore generation hubs, or one country with an offshore hub located in the EEZ in another country. A hybrid could also connect two bidding zones of the same country. However, bidding zone definition is out of scope of the ONDP, using a granularity at the country level.
[17] For an example of what could be the output of an ONDP, please see the North Seas Countries' Offshore Grid Initiative study, (2012): https://www.benelux.int/files/1414/0923/4478/North_Seas_Grid_Study.pdf

interconnectors). To our understanding, onshore grid reinforcements are not currently assessed in the first ONDPs.

It should be noted that for the first edition (ONDP 2024), the ONDP exercise will be performed before the Identification of System Needs (IoSN). The ONPD and IoSN are expected to be performed simultaneously from TYNDP 2026 onwards to ensure consistency between both exercises.

3.3.3. Scenarios and time horizons

The time horizons and scenarios to be used in the SB-CBA correspond to the time horizons and scenarios used in the ONDP process. For the first edition (ONDP 2024), this corresponds to using for 2030 and 2040 the National Trends scenario and for 2050 the Distributed Energy scenario.

No other scenario is going to be used for the development of ONDPs, at least in the 2024 edition, thus only one scenario for each time horizon should be used for the SB-CBA. However, it is recommended that in subsequent editions, ENTSO-E carries out the IoSN/ONDP exercise for additional relevant scenarios part of the TYNDP to obtain results that are robust against different future developments.

3.3.4. Counterfactual

The key challenge in the development of the SB-CBA methodology is the definition of the counterfactual situation. In the standard analysis of a specific infrastructure project (e.g. an interconnector), the CBA consists of comparing the value of a series of indicators between two situations:

- "With": A first situation with the project being assessed, the **factual**
- "Without": A second situation without the project being assessed, the **counterfactual**

This exercise can be relatively straightforward for the assessment of a single project, as detailed in current CBA guidelines through the TOOT or PINT approach (see for example the CBA 3.0[18] or CBA 4.1[19] by ENTSO-E).

However, at the sea basin level, a number of challenges emerge when defining the counterfactual situation. Indeed, at the sea basin level, the counterfactual aims to provide a realistic or plausible scenario of what would happen if no hybrid projects were developed at all in that sea basin. This requires the determination of the **network** and **generation** development alternative scenarios at the sea basin level.

In other words, the definition of the counterfactual will allow the SB-CBA to evaluate the impacts of a potentially large number of projects simultaneously (including all the hybrid projects that are part of the ONDP). This is due to the large geographical scope (the entire sea basin) and the long horizon (until 2050) being considered for the SB-CBA assessment. By removing a large number of infrastructure projects in the counterfactual, the situation described by the counterfactual could prove to be unplausible since, in the absence of hybrid infrastructure, alternative RES and grid projects would most probably be implemented (direct interconnections, radially connected offshore wind energy generation projects, etc.).

The counterfactual could also consider a modification of the **demand**. This is usually not considered in project-specific CBAs, as single-projects may have limited impact demand patterns or evolution. However, a large modification of the offshore generation and/or network infrastructure, as is the case in the SB-CBA counterfactual, could induce a change in demand (e.g. industrial hubs installing close to offshore wind farms). Authors, however, suggest **maintaining the same demand patterns/evolutions in the factual and the counterfactual**. Changing the demand in the counterfactual would represent a major change of the evaluation conditions and is not the primary objective of the SB-CBA, which is focused on the offshore network required to connect offshore generation). A modification of the demand in the counterfactual would also pose significant implementation challenges (e.g. How much should demand change? Where is it relocated?).

[18] 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, ENTSO-E, 2020
[19] 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, ENTSO-E, 2023

We describe below the approach we recommend in terms of defining the network and generation aspects of the counterfactual.

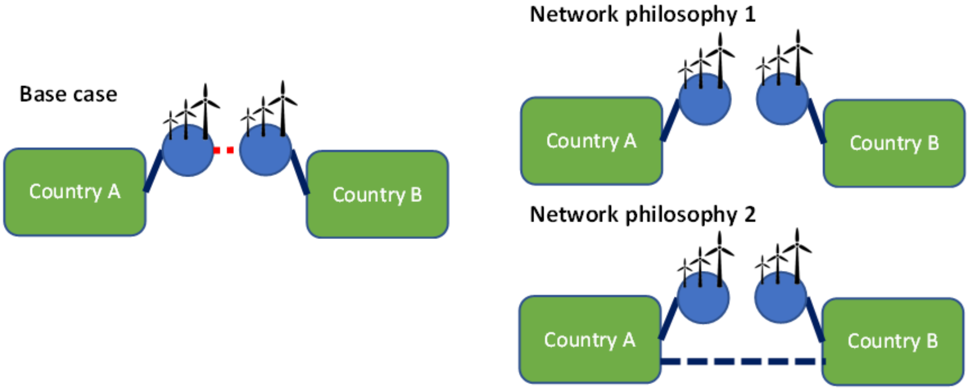
Network development

The development of hybrid projects allows increased interconnection capacity, thus reducing the need for direct interconnectors. In the counterfactual, i.e. in the absence of the development of hybrid projects, countries could develop direct interconnection capacities between them to increase cross-border capacity.

Therefore, two philosophies of counterfactuals can be identified, as shown in Figure 3-3:

- **Network philosophy 1:** Removing the hybrid interconnections, without adding alternative direct interconnectors in the counterfactual
- **Network philosophy 2:** Removing the hybrid interconnections and replacing them with direct interconnectors in the counterfactual (which could be offshore or onshore)[20].

Figure 3-3 Counterfactual philosophies regarding network development. Hybrid interconnection is shown in red in 'base case'



The two philosophies allow to assess the benefits of different aspects of the offshore network development plans:

- The first option would allow to assess the costs and benefits of increased interconnection provided by the project,
- The second would assess the cost and benefits of the coordination between the development of transmission infrastructure projects at the sea-basin level (i.e. developing hybrids instead of developing radials and direct interconnections).

We propose to follow network philosophy 1, removing the hybrid interconnectors of the ONDP without replacement. More details on the reasoning and implementation are given at the end of the section.

Generation development

When defining the counterfactual of the ONDP, which is expected to include hybrid projects, one might consider removing (part of) the offshore generation capacity, as its completion might be conditional on the development of the network infrastructure. In other words, it might prove unplausible to build a counterfactual that includes as much offshore wind as is considered in the ONDP.

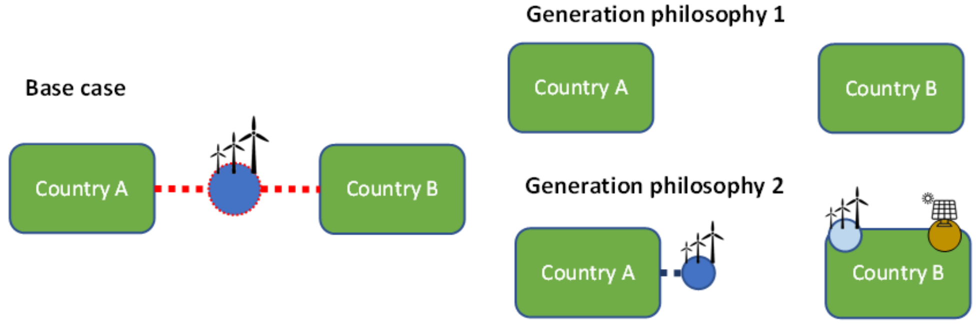
In case offshore RES capacities are removed in the counterfactual, meeting the demand and energy/climate targets (e.g. RES trajectories) could require adding alternative generation sources in some Member States.

[20] Onshore interconnectors can be an alternative to offshore interconnectors in cases where countries share an onshore border.

Analogous to the network development case, two generation philosophies for the counterfactual can be envisaged, in cases when offshore wind generation is present in the ONDP (Figure 3-4):

- **Generation philosophy 1:** Removing (part of) the offshore RES generation capacities connected by hybrids, without including alternative generation capacities.
- **Generation philosophy 2:** Removing (part of) the offshore RES generation capacities connected by hybrids, replacing them with alternative generation capacities.

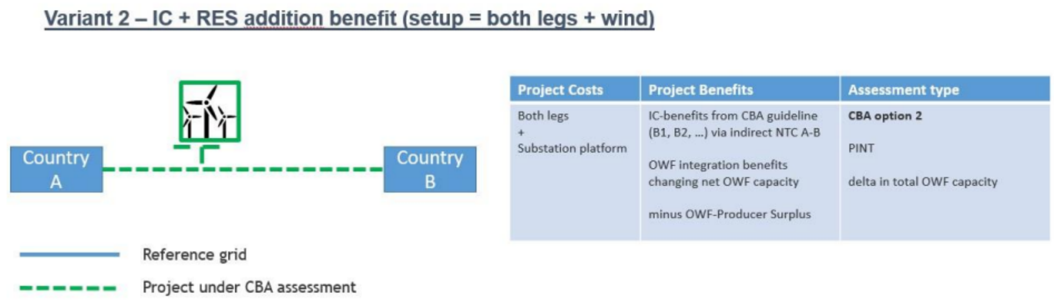
Figure 3-4 Counterfactual philosophies for generation development. The generation sources shown in the generation philosophy 2 are only illustrative



The first option (Generation philosophy 1) allows to assess the benefits of the entire hybrid projects, coming from both generation and network development. However, such a counterfactual can prove to be unplausible as gaps in terms of generation capacity might arise (potentially leading to adequacy issues). More importantly, this goes against the objective of the SB-CBA, which is the assessment of the ONDP (network part) only.

It should be noted that ENTSO-E follows Generation philosophy 1 when evaluating project-specific hybrids with a development of additional generation capacity[21]. In this case, ENTSO-E removes the network and generation in the counterfactual and corrects the total social economic welfare (SEW) by removing the producer surplus of the offshore RES asset (see Figure 3-5) in order to evaluate the benefits of the network part only. To our understanding, this approach is only valid in cases where the amount of generation to remove in the counterfactual is of limited size, i.e. it only has limited impacts on electricity prices. At the sea basin level, where potentially tens of GW of offshore generation will be connected, we believe this approach will not lead to satisfactory results as the removal of such a quantity of offshore RES is not a marginal modification of the scenario.

Figure 3-5 ENTSO-E's current practice for CBA assessment of hybrid project considering additional generation capacity. Source: ENTSO-E[22]



Maintaining equivalent generation in the counterfactual (Generation philosophy 2) allows to assess only the benefits of the network part of the hybrid project, but only if the same offshore RES development is considered. Allowing to modify the technology or location of the RES generation in the counterfactual can reflect the adaptation of countries' energy mixes to a different network

[21] ENTSO-E, 2020, TYNDP 2022 Implementation Guidelines.
[22] ENTSO-E, 2020, TYNDP 2022 Implementation Guidelines.

development strategy. In this case, the SB-CBA will evaluate the benefits of the network and of a coordinated generation development planning.

During the stakeholder consultation process, several stakeholders have signalled the importance of maintaining the decarbonisation objectives in the counterfactual. By replacing the removed offshore generation capacity by equivalent RES sources (which can include offshore generation as well as onshore RES), the same decarbonisation objectives can be met in the counterfactual.

However, there is a limited potential for "reshoring" RES, in particular onshore wind, as TYNDP scenarios already make extensive use of these resources. Replacing offshore capacity by onshore may not be plausible or even possible in a context with high (onshore) RES development. A middle point between Generation Philosophy 1 and 2, where part of the removed offshore generation capacity is not replaced can reflect the need of offshore generation (and of hybrid networks) to achieve the EU decarbonisation targets.

Recommendation on counterfactual philosophies

As the SB-CBA is a new process, a simpler approach for the first edition (SB-CBA 2024) is recommended below, upon which more complex (and plausible) counterfactuals or analysis can be built in the following editions (SB CBA 2026 and subsequent editions).

<u>Network counterfactual</u>

Given the objectives of the SB-CBA, which in part is to demonstrate the benefits associated with the development of hybrids, **we propose to adopt Network Philosophy 1**, not replacing the hybrid connections with direct interconnectors. Furthermore, the SB-ONDP can include point-to-point interconnectors, creating difficulties in the implementation of Network Philosophy 2.

<u>Generation counterfactual</u>

Regarding the generation counterfactual, we propose an incremental approach. For **SB-CBA 2024**, we propose that the offshore generation capacity is to be maintained in the counterfactual. This means that in this first edition the SB-CBA will compare a configuration with hybrids to a configuration with only radial connections. While this counterfactual might not always result in a realistic description of the development of RES at sea basin level, several studies have used it to perform cost-benefit analyses of offshore meshed grids, such as in the Baltic Sea[23] or in the German area[24].

It should be noted that the ONDP can include the reinforcement of the radial connections in addition to the hybrid section of the interconnector, to allow for increased transfer capacity through the hybrid link. In this case, all radial reinforcements should be removed in the counterfactual to leave only the radial interconnection needed for hosting the offshore RES generation via a radial connection.

In subsequent editions (**SB-CBA 2026 onwards**), more plausible generation counterfactuals should be defined, where the absence of hybrids can hinder offshore generation development. This would mean removing (part of) the offshore generation capacity and partly compensating it by a reshoring of offshore RES (when there is enough onshore wind and/or solar PV potential for reshoring). Part of the offshore wind energy generation might not be able to be replaced onshore (for example due to limits in land availability for onshore RES development), showing that cross-border offshore networks are needed for the EU to reach its decarbonisation targets[25].

An example of a virtual ONDP result and its counterfactual for SB-2024 is shown in Figure 3-6. The counterfactual does not include the hybrid interconnections, and radials are dimensioned as described above, i.e. the radial connected to C3 that is connecting to the meshed hybrids with C1 and C2 has an increased capacity of 3,000 MW, for only 2,000 MW of offshore generation capacity.

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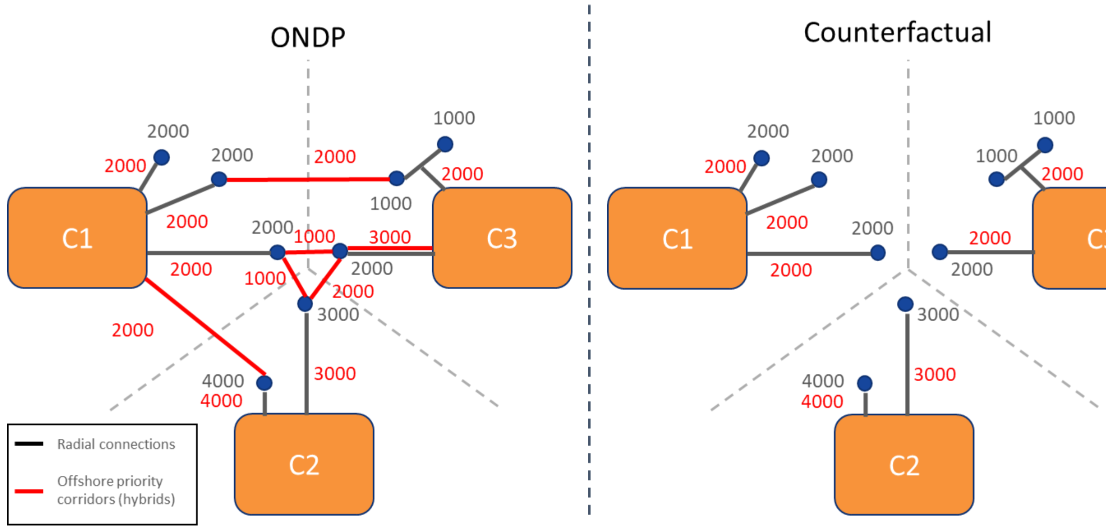
[23] Baltic InteGrid: towards a meshed offshore grid in the Baltic Sea, 2019 [Online]

[24] Ansätze eines Offshore-Stromnetzes in der Ausschließlichen Wirtschaftszone (AWZ), 2023 [Online]

[25] A dedicated indicator on decarbonisation policy compliance can be implemented in the SB-CBA, in addition to the CO2 emissions indicator (Indicator B2). For details on the multicriteria analysis, see Section 3.3.7

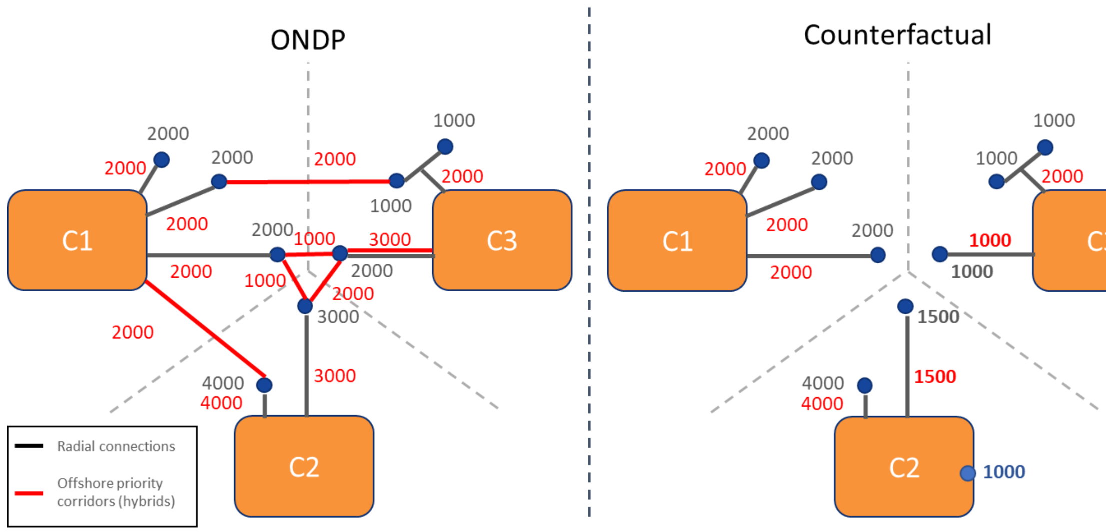
In the counterfactual, the capacity of the C3 radial has been reduced to the capacity of offshore generation only, i.e. 2,000 MW.

Figure 3-6 Example of a virtual ONDP and the proposed counterfactual for the SB-CBA 2024



A counterfactual for the SB-2026 onwards is shown in and Figure 3-7. Note in this case, there are 1,500 MW of offshore wind in C2 and 1,000 MW in C1 that are not developed in the counterfactual. C2 capacities are only partially compensated by 1,000 MW of onshore RES, while C1 capacities are not replaced at all, reflecting limits on the RES installable capacities.

Figure 3-7 Example of a virtual ONDP and the proposed counterfactual for the SB-CBA 2026 onwards



Implementation challenges of the counterfactual

For the SB-CBA 2024, no major challenges for the definition of the counterfactual have been identified as this is rather straightforward (hybrids vs. radials).

For subsequent editions, implementation challenges might arise. First, how to determine how much offshore generation should be "removed" or "reshored" in the counterfactual? The removed/reshored capacity is the share of offshore power generation which needs the development of the whole hybrid project to materialise. This capacity can be dependent on a number of factors, including the total offshore development in the country/sea basin (high concentration of offshore power generation may be more dependent on hybrids), or distance to shore of projects (projects further away from shore may be more susceptible to need hybrid connections to materialise).

In the study from Koivisto et al (2020)[26], authors identify optimal renewable deployment in the North Sea region in the case of only radials and the case with hybrid interconnectors. They find that the offshore installed capacity is around 10% higher in the case with hybrids interconnectors. This value can provide a first estimate on the offshore capacity needing hybrids to materialise (i.e. to be removed in the counterfactual). However, to the best of our knowledge, this is the only study that has analysed this issue (albeit indirectly), and there have not been similar studies performed in other sea basins.

We recommend that ENTSO-E determines the share of offshore power generation capacity to be removed in the counterfactual, based on its expertise gained through the scenario development process, where potentials are being considered, or via further studies if needed. Operational experience from the first hybrid interconnector Kriegers Flak Combined Grid Solutions may also provide relevant information.

Second, when part of the offshore power generation capacity is removed in the counterfactual, the equivalent level of onshore RES needs to be defined. There are three identified possibilities:

- Same level of installed power generation capacity (GW)
- Same level of power generation (GWh)
- Same level of GHG emissions

To ensure implementability and aiming at maintaining the decarbonisation objectives as much as possible, it is recommended to replace offshore capacities by onshore ones with the same level of generation (GWh) in the onshore zone of same host country.

The additional onshore RES should respect total potentials for RES development in each country and reflect that more suitable places would probably be already developed. In some cases, this can lead to an impossibility of completely replacing offshore capacities by onshore ones, and thus a risk of higher GHG emissions. This result can provide evidence for the need of hybrid interconnectors to achieve EU decarbonisation objectives.

To determine the amount of additional onshore generation that can be installed in a country, *installable potentials* should be identified. This topic is already addressed in the literature, for example by exploiting land use and weather patterns datasets to derive renewable energy potentials (see for example, Klenschmitt et al, (2022)[27], Risch et al, (2022)[28] or the Long-term Scenarios III project[29]). If ENTSO-E does not have the necessary information to estimate the installable potentials, we recommend that it develops partnerships with the relevant (research) institutions to obtain this data with the appropriate granularity.

As explained above, (additional) installable potentials should exclude the renewable capacities that are in any case expected to be installed onshore regardless of the final offshore grid topology, since otherwise the renewable trajectories or targets of the Member State would not be met. Therefore, installable potentials that relate to onshore capacities to be located in renewable acceleration areas should always be excluded and the installable potentials should be limited to the marginal renewables capacity potentials that may or not be realised subject to the offshore topology. These additional (or marginal) onshore capacities might concern areas with lower "resource quality" (i.e., areas which are less suited for renewable installations, having, for example, lower capacity factors).

[26] Koivisto, M., Gea-Bermúdez, J., Kanellas, P., Das, K., and Sørensen, P.: North Sea region energy system towards 2050: integrated offshore grid and sector coupling drive offshore wind power installations, Wind Energy Science, 5, 1705–1712, https://doi.org/10.5194/wes-5-1705-2020, 2020.
[27] Kleinschmitt. C.; Fragoso Garcia. J.; Franke. K.; Teza. D.; Seidel. L.; Ebner. A.; Baier. M. (2022): Global potential of renewable energy sources. HYPAT Working Paper 03/2022. Karlsruhe: Fraunhofer ISI (ed.).
[28] Risch, S.; Maier, R.; Du, J.; Pflugradt, N.; Stenzel, P.; Kotzur, L.; Stolten, D. Potentials of Renewable Energy Sources in Germany and the Influence of Land Use Datasets. *Energies* **2022**, *15*, 5536. https://doi.org/10.3390/en15155536
[29] https://www.langfristszenarien.de/enertile-explorer-en/scenario-explorer/renewables.php

In this context, timeseries of renewable power generation with lower resource quality are already available within the PECD database (PECD 2021 update). This data can allow modelling the development of onshore capacities in less suitable locations for wind or PV generation when *onshoring* part of the offshore generation in the counterfactual.

3.3.5. Reference grid

The offshore network to be assessed via the SB-CBA will be the output of the ONDP process performed by ENTSO-E. The ONDP will be part of the TYNDP process, starting from the TYNDP 2024. In the context of the TYNDP process, ENTSO-E determines a so-called "Reference Grid" for a number of years (2030 and 2040 in the case of TYNDP 2022). This reference grid consists of NTCs linking bidding zones and is established by adding the current NTCs to the ones of a selection of projects. A number of projects proposed by project promoters, which can include hybrids, are evaluated by the ENTSO-E to be included in the reference grid. They can be included either at the 2030 or 2040 horizons[30].

The reference grid needs to be defined for each time horizon, for both onshore and offshore components. Three main categories of projects have been identified.

Onshore reference grid

The onshore reference grid used in the SB-CBA for each time horizon should be coherent with the reference grid used for the ONDP process. This means using the onshore grid of the reference scenarios (National Trends 2030 and 2040, Distributed Energy 2050).

Offshore grid – other sea basins

The SB-CBA will be performed for each sea basin separately. For each sea basin, the SB-CBA will require to perform computations at the pan-European level, thus including other sea basins in the geographical scope of the simulations (e.g., when performing the SB-CBA for the "North Sea" sea basin, the "Baltic" sea basin is to be included in the geographical scope of the modelling exercise).

We propose to include the ONDPs as part of the reference grid in the other sea basins. This means that when performing the SB-CBA for a given ONDP (e.g., North Sea SB), the other ONDPs (e.g., the offshore grid needs of the Baltic SB or Atlantic SB) will be included as the offshore reference grid. Therefore, the SB-CBA would follow a TOOT approach with respect to the entire ONDP, i.e. removing the entire ONDP and not removing each specific identified grid infrastructure need one at a time in the counterfactual.

Offshore grid of the concerned Sea Basin

In the SB that is being assessed, there can be projects that are part of the reference grid for the 2030 or 2040 horizons during the ONDP process (e.g., the Nautilus multipurpose interconnector BE-UK[31]). These projects are not considered as part of the ONDP's identified offshore grid needs. However, some of these projects might still be in a preliminary phase, without a final approval for development, and could therefore be considered as being uncertain.

It can be argued that offshore projects with a low maturity level will require a coordination of hosting MSs (and potentially others) to reach a final approval, potentially entering into a PS-CBCA and even potentially requesting PCI/PMI status and EU financing (e.g., CEF funding). Thus, these projects could be considered within the scope of the SB-CBCS, even if they are not assessed in the ONDP (as they are part of the reference grid, they are not subject to the ONDP optimisation).

With the aim of including all future costs of offshore grids which can be subject to negotiations among MSs, we propose projects with low level of maturity to be included within the scope of the SB-CBA, including hybrids and direct interconnectors. This means that:

[30] All projects included in 2030 are included in 2040.
[31] ENTSOE, "TR 121 - Nautilus: multi-purpose interconnector Belgium – UK" https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission/121

- Projects with a high maturity level (with final investment decision or, at least, where the PS-CBCA process has concluded or is very advanced) to be included in the offshore reference grid. These projects are included in both cases (ONDP and counterfactual);

- Projects with a low maturity level should not be included in the offshore reference grid. This means that they are included in the ONDP case and removed in the counterfactual, so that their costs and benefits will be factored in in the results of the SB-CBA.

3.3.6. Modelling approach

Once the two configurations are defined (the one including the ONDP and the counterfactual), a number of simulations need to be performed to compute a series of indicators evaluating the costs and benefits of the ONDP. We propose a workflow for the SB-CBA simulations hereunder:

First step: meeting adequacy criteria in both scenarios.

We refer to adequacy criteria as respecting certain minimum reliability standards. Reliability standards are usually defined based in terms of loss of load expectation (LOLE) or expected energy not served (EENS), which are required to be kept to a minimum acceptable level[32].

This step is similar to the approach followed by ENTSO-E to assess adequacy (indicator B6) in project-specific assessments for TOOT projects (see ENTSO-E CBA 4.1). This step is proposed to ensure that both scenarios (the ONDP and the counterfactual) respect minimum adequacy levels, avoiding a cost-benefit assessment based on an excessive reduction of energy not served (ENS) when computing the socio-economic welfare. Indeed, as in the counterfactual a large number of interconnectors could be removed, a potentially large number of loss-of-load hours (LOLH) and important energy-not-served volumes can occur (in addition to high curtailment). If this happens, the counterfactual will prove to be unrealistic, as countries would take measures to adapt the generation fleet and avoid such levels of LOLH. Therefore, we propose to adjust adequacy levels as a first step.

To ensure acceptable adequacy levels in the scenarios, we propose to adjust the **peaking capacities** of MSs in case of excessive LOLH or ENS, for each scenario (ONDP and the counterfactual) independently (i.e., increase the peaking capacity of the scenario if the adequacy criteria are not met). Peaking capacity technologies can include open cycle gas turbines (OCGTs), batteries, and hydrogen-based generation units for the long-term scenarios. The choice of technologies, as well as of adequacy criteria (number of LOLH, maximum level of ENS) should be defined by ENTSO-E, in line with the methodologies used in other TYNDP products such as the IoSN or the TYNDP scenarios.

To determine the additional peaking capacities for each scenario, several options exist. For example, a joint dispatch + investment optimisation model subjected to minimum adequacy criteria (translated in VoLL) can be used to identify the capacity (MW) and location (which nodes) where additional peaking capacities are needed. Alternatively, an iterative algorithm, similar to the one used in ENTSO-E's Mid-term Adequacy Forecast (MAF), can be used. This algorithm could work as follows: first, evaluate the adequacy level of each scenario. Second, assess if the adequacy criteria are met. If the adequacy criteria are not met, add peaking capacities in the node having the worst adequacy criteria violations. The process of assessing adequacy levels and adding peaking capacity is repeated till the adequacy criteria are met.

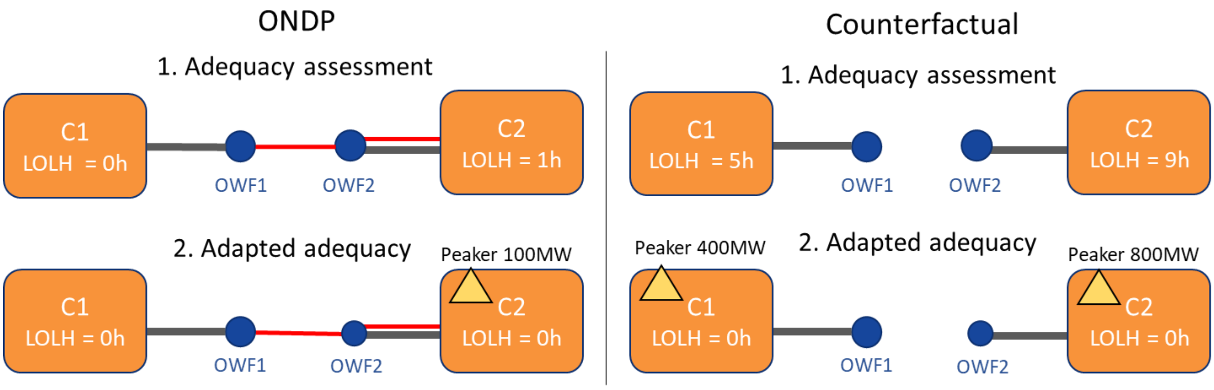
In this proposed workflow, peaking capacities are adjusted to ensure an adequacy criterion only in the assessed scenario (see 3.3.3) and representative climatic years in consideration. This is a simplified approach of the process followed by ENTSO-E in the MAF exercise, or in the CBA 4.1 to assess the "B6 – Security of Supply: Adequacy" indicator. In these ENTSO-E products, many Monte Carlo simulations of climatic years and outages are performed to obtain an accurate estimation of the expected loss of load hours or expected energy not served.

The outputs of this step are the scenarios (ONDP and the counterfactual) with adapted generation capacities that meet the adequacy criteria. Figure 3-8 shows a stylized example of the process to meet adequacy criteria in both scenarios. In this example, the adequacy criteria is 0 hours of loss of load. In a first step, the adequacy of both the ONDP and counterfactual are assessed, resulting in a

[32] See ENTSO-E Mid-term Adequacy Forecast Methodology for further details on adequacy assessment.

number of LOLH in each country. By adding peaking capacities (100 MW in C2 in the ONDP, and 1200 MW in the counterfactual), the LOLH can be reduced to meet the adequacy criteria (0h).

Figure 3-8 Stylized example of the process to meet adequacy criteria (a criterion of 0h of LOLH is considered)



Second step: performing dispatch (market) simulations for the ONDP and the counterfactual scenarios.

Simulations at the pan-European scope should be carried out. Relevant non-EU countries in the North Sea, North Africa, the Middle East or the Caucasus could be included if necessary for selected Sea Basins (for example other Mediterranean countries when assessing the South East and South West Sea Basins).

The geographical granularity of the simulations should be, at least, at the country level (i.e., one node per country)[33] for the onshore grids, in line with the Identification of System Needs exercise of the TYNDP. For the offshore grids, the dispatch simulations should include explicitly the nodes and offshore grid needs of the ONDP. This representation implicitly corresponds to assuming an offshore bidding zone configuration for hybrids' offshore generation, and is aligned with the current approach of ENTSO-E to assess hybrid projects (see CBA 4.1).

The simulations should be performed with, at least, an hourly resolution. This temporal resolution is in line with current practices in the TYNDP process, and with the temporal resolution of the PECD database.

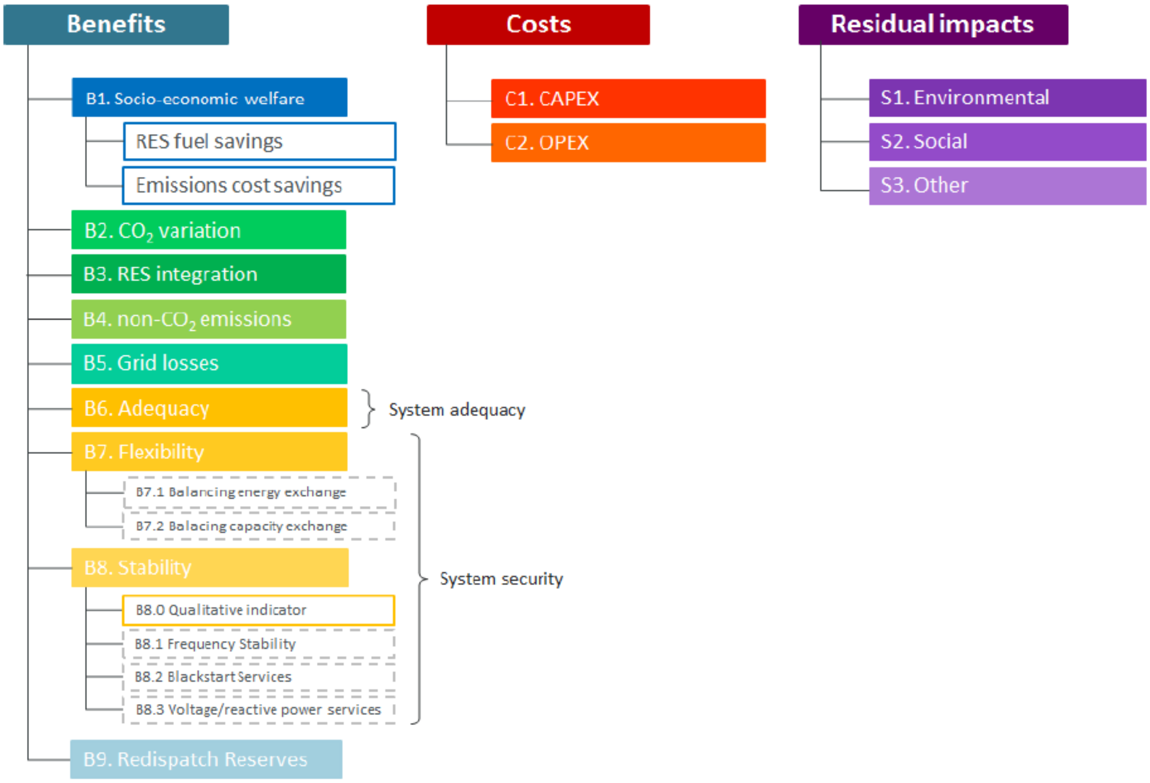
3.3.7. Multicriteria analysis

The results of the simulations allow for the computation of key performance indicators (KPIs) to determine the costs and benefits associated with the development of ONDPs.

In its CBA 4.1 methodology, ENTSO-E defines a list of indicators to be computed when carrying out project-specific cost benefit analyses, shown in Figure 3-9. The indicators include benefits, costs, and residual impacts.

[33] The ONDP and IoSN exercises do not perform simulations at the (current) bidding zone level, as the bidding zone definition is out of their scope. Additionally, current bidding zones may not be representative of market configurations in the medium-/long-term.

Figure 3-9 Categories of indicators for project-specific assessment, used by ENTSO-E[34]



Given the high-level nature of the SB-CBA, some indicators which require complex simulations or detailed data or grid models are not included in our recommendation. More precisely, we propose to consider the following subset of indicators:

Benefits:

- **B1. Socio-economic welfare:** this represents the benefits of increased wholesale energy market integration. It is computed based on the dispatch simulation results, as the sum of the surpluses of consumers, producers, and transmission owners.

- **B2. CO2 variation:** given by the different operation of fossil fuel-based generation technologies, in the assessed scenarios. It is computed based on the results of the dispatch simulations.

- **B3. RES integration:** It represents the ability of the power system to connect new RES generation, and make the better use of already connected RES by reducing curtailment. Curtailment is a result of the dispatch simulations, and it is expected that the counterfactual (i.e., without hybrid interconnectors) could have significantly higher levels of curtailment than the ONDP scenario.

- **B4. Non-CO2 emissions:** Similar to the CO2 emissions, fossil fuel-based generation emits other pollutants such as NOx, SOx or particulate matter (PM). The variation on non-CO2 emissions can be computed based on the results of the dispatch simulations.

  It should be noted that ENTSO-E's current methodology considers non-CO2 emissions as non-monetisable. This shall not limit, however, the computation of this indicator. The same emission factors as the one in CBA 4.1 should be used.

[34] ibid

- **B6. Adequacy:** This represents the ability of the system to meet demand over an extended period of time.

  In the proposed workflow, adequacy is ensured in both the ONDP and the counterfactual thanks to the Step 1 of the simulations (when adequacy criteria are met in both scenarios). This is achieved by adapting the peaking capacities in both of the scenarios. Thus, the B6 indicator can be computed as the cost difference for additional peaking capacities needed to ensure adequate supply in both scenarios, as identified in Step 1 of the simulations. The adequacy benefit can thus be computed as follows:

$$B6 = \sum_{p \in \mathrm{Peakers}_{\mathrm{Counterfactual}}} Costs_p - \sum_{q \in \mathrm{Peakers}_{\mathrm{ONDP}}} Costs_q$$

  Where $\mathrm{Peakers}_{\mathrm{Counterfactual}}$ and $\mathrm{Peakers}_{\mathrm{ONDP}}$ are the sets of additional peaker capacities for the counterfactual and ONDP (factual) respectively, identified in the adequacy step. $Costs$ represent the total costs over the lifetime of the peaker capacities (including CAPEX and OPEX).

  As it is expected that the ONDP will require lower levels of peaking capacities than the counterfactual to meet the adequacy criteria, the B6 indicator will show a positive benefit related to the lower need for peaking capacities (lower costs). Following the example of Figure 3-8, where 100MW of peaking capacities were needed in the ONDP, and 1200MW of peaking capacities in the counterfactual, the B6 indicator would be computed as follows:

$$B6 = Costs_{CF}(1200\mathrm{MW}) - Costs_{ONDP}(100\ MW)$$

  It should be noted that this indicator, in contrast to the methodology proposed by ENTSO-E in the CBA 4.1, may be computed without the need for a large number of Monte-Carlo simulations.

Costs:

- **C1. CAPEX:** The capital expenditure for the identified infrastructure investments.
- **C2. OPEX:** The operational expenditures of the identified infrastructure investments.

Indicators *B5. Grid losses*, *B7. Flexibility*, *B8. Stability* and *B9. Redispatch reserves* require complex methodologies or data models that are not (easily) available for the current exercise, considering the large scale and long-time horizon (up to 2050). In particular, the SB-CBA is a high-level exercise which identifies offshore grid needs, but not specific projects, which prevents assessments where detailed grid models are necessary (in particular to evaluate losses at the long-term horizon).

Similarly, residual impact indicators (S1. Environmental, S2. Social and S3. Other) aim to capture potential impacts that are not yet fully integrated or when the impacts may not be fully mitigated but cannot be objectively monetized. As per ENTSO-E's CBA 4.1, the residual impacts of network infrastructure relate mostly to environmental, social impacts of overhead lines or cables located in sensitive areas (such as environmentally protected areas or populated areas). As the ONDP will identify offshore grid needs, without defining routings for specific projects, it is not possible to assess the residual impact indicators. However, if the ONPD can provide routes for the hybrid grid infrastructure needs, residual indicators may be assessed in line with the methodology provided in the CBA 4.1.

The detailed methodologies for computing each indicator can be found in ENTSO-E's proposal for a CBA 4.1, which ensure avoiding double counting for some benefits.

Granularity of reporting

The SB-CBA will be the basis for the cross-border cost sharing exercise (SB-CBCS), which is described in the next section. Therefore, the results of costs and benefits should be reported with a spatial and temporal granularity that matches the needs of the SB-CBCS. This means that the indicators should be reported with a disaggregation at the country level, for each of the considered temporal horizons (2030, 2040 and 2050), including impacts on non-hosting countries.

It is also recommended that the indicators be presented aggregated at the sea basin level (i.e., aggregated for hosting countries). This can allow the direct comparison of costs and benefits of the ONDP for hosting countries, and the need of (economical) contribution of non-hosting countries to ensure net positive benefits for hosting countries.

3.3.8. Sensitivities

To increase the level of robustness of the cost-benefit analysis, it is recommended to perform sensitivity analyses on key modelling assumptions. ENTSO-E's CBA 4.1 provides a list of sensitivities which could be considered in project-specific CBAs (not all of them needing to be carried out for each project).

Given the scope of the ONDP, we recommend carrying out a limited number of sensitivities in the SB-CBA. Exploring a larger number of sensitivities for the SB-CBA can be labour-intensive and can create challenges for the subsequent SB-CBCS processes. Sensitivities should be focused on the key assumptions that impact the value of the ONDP, and could include:

- **Climatic years**: Using different climatic years can provide a more robust estimate of benefit indicators, in particular RES curtailment. This would be in line with current ENTSO-E practices for project specific assessments.

- **Fuel and CO2 prices:** While the EU power system is expected to be fully decarbonised by 2050, fuel and CO2 prices will still play a major role on the trajectory of the ONDP, and can have significant impacts on price formation (therefore, on the distribution of surpluses amongst actors and market zones).

- **Installed offshore capacities:** Offshore capacities are a main determinant in the ONDP configuration. Thus, a change in their volume or distribution can have significant impacts on the value of the ONDP. Slight deviations with respect to the MS non-binding targets (within +-5%) could be assessed to evaluate the robustness of the ONDP, in which case the different generation capacity configurations should be reflected in both the factual and counterfactual. Larger deviations would require recalculating a new (adapted) ONDP to make it plausible, which is out of scope of the SB-CBA.

Sensitivities around the development of large-scale regional projects, which can impact the value assessment of the ONDP (e.g., the significant development of new nuclear power in France or the development of large hydrogen demand clusters at the regional level) can be investigated. However, the authors believe this subject lies in the remit of project specific CBAs rather than in the one of the SB-CBA.

The main risks for the validity of the value assessment of the ONDP lie on the uncertainties of the evolution of the European energy system at a large scale. In the TYNDP process, this is accounted for by establishing different **scenarios** (National Trends, Distributed Energy and Global Ambition in the TYNDP 2022). Thus, we encourage ENTSO-E to perform the ONDP considering additional TYNDP scenarios in the ONDP process from the TYNDP 2026 onwards. Several options could be considered, for example the ONDP could feature a single network configuration that is compatible with all scenarios for the first 10 to 15 years, with potential deviations in the longer-term (i.e. the results for the short and medium term would be robust to potential changes in the way the transition is materialising).

3.3.9. Insights into potential extensions of the process to consider hydrogen infrastructure

The revised TEN-E Regulation states that the offshore network planning exercise carried out by ENTSO-E (the ONDP) should include the potential needs for hydrogen infrastructure (Article 14(2)).

*"The high-level strategic integrated offshore network development plans shall provide a high-level outlook on offshore generation capacities potential and resulting offshore grid needs, including the potential needs for interconnectors, hybrid projects, radial connections, reinforcements, and **hydrogen infrastructure**."*

The SB-CBA and SB-CBCS exercises can only assess the benefits of investing in hydrogen infrastructure if the ONDP has previously included it within its scope. As the first edition of the ONDP will not include hydrogen connections, the first step towards including hydrogen into the SB-CBA/SB-

CBCS scope is for ENTSO-E, in coordination with the relevant system operator associations, to develop a methodology to perform a multi-energy (i.e., cross-sectoral) ONDP to be able to jointly identify offshore electricity and hydrogen infrastructure needs.

Similar to the approach developed to identify electricity infrastructure, a cross-sectoral evolution of the ONDP could identify offshore conversion hubs, radial pipelines connecting the conversion hubs to the hosting MS shore, and hybrid pipelines enabling a cross-border trade of hydrogen.

As with the electricity SB-CBA, the multi-energy SB-CBA would need to define: a counterfactual, the simulations to be run, and the indicators to be computed. Overall, the principles defined in this report can be applied to a multi-energy system.

The definition of the counterfactual will depend on the objective of the multi-energy SB-CBA. A counterfactual can be defined to assess the cost and benefits of a coordinated offshore network development between countries (i.e., considering hybrids) versus a case without coordination (i.e., without hybrids), or to assess coordination among energy carriers (i.e., a multi-energy offshore grid with electricity and hydrogen infrastructure) versus a single-energy case (i.e., only electricity infrastructure).

The simulations to be run would also need to be adapted to a multi-energy approach. The two simulation steps would still need to be followed: first, ensuring adequacy for both hydrogen and electricity supply, and second, performing detailed dispatch simulations with (at least) an hourly time resolution. Simulations would require an explicit modelling of both electricity and hydrogen systems at the pan-European level.

The modelling of hydrogen systems will require specific studies and hypothesis, which present significant uncertainties at the current moment. This includes hydrogen demand volumes and localisation of demand clusters, hydrogen production technologies (electrolysers, fossil-gas based steam-methane reforming or autothermal reforming with/without carbon capture and storage), hydrogen storage, and international trade (import capacity, prices).

The indicators detailed in this report can be extended to cover the multi-energy scope (e.g., socioeconomic welfare, GHG emissions, etc), with careful consideration to cover all sectors' benefits and costs and avoiding double counting.

3.4. SB-CBCS Guidance

This section provides recommendations for the development of a Guidance for the SB-CBCS study that will be carried out by ENTSO-E, based on the SB-CBA. The recommendations are derived from feedback obtained from the stakeholder interviews, current practices and experience obtained from project-specific CBCAs, as well as on the objectives of the overall SB-CBA and SB-CBCS processes.

3.4.1. Objective and scope of the SB-CBCS

One of the challenges to be tackled for the development of a large-scale offshore network infrastructure to materialise is not only to ensure that its benefits outweigh its costs, but also that the financing of these assets is distributed in a fair way between Member States. Indeed, infrastructure projects can have profound impacts on the structure of energy flows, by enabling competition between different energy suppliers and flexibility providers to take place, and thereby on energy prices. Consequently, the distribution of benefits amongst Member States could be different from the distribution of the localisation of the offshore network investments.

Whilst this issue of potential misalignment between the distribution of benefits and costs for specific projects is usually addressed via the so-called cross-border cost allocation (CBCA) process, the revised TEN-E introduces a new tool, the sea-basin cross-border cost-sharing (SB-CBCS), to allow Member States to obtain a high-level view of the distribution of benefits and costs of the entire sea basin offshore network infrastructure.

More specifically, the objective of the SB-CBCS is to provide a quantitative estimate of the costs that would be borne by each Member State[35] if these costs were to be distributed in a way that is

[35] While only EU Member States are within the scope of the TEN-E regulation, other countries such as Norway or the UK will play a major role in the development of offshore networks, and could be part of the SB-CBCS process on a voluntary basis.

consistent with the distribution of benefits. The SB-CBCS can therefore be an essential tool to foster dialogue between Member States (including their national regulatory authorities), allowing them to kickstart discussions for cost sharing in advance of the development of specific projects, and e.g. enter into Memorandums of Understanding (MoUs) describing their intentions when it comes to the way the financing of offshore electricity infrastructure projects can be structured.

We propose that the SB-CBCS be a cost sharing exercise of the investment costs of the ONDP based on the results of the SB-CBA. Therefore, the costs and benefits identified for the scenario(s) and sensitivities of the SB-CBA are the key building blocks informing the SB-CBCS. This means that, at least for the 2024 edition, only the electricity network infrastructure is considered in the SB-CBCS, which is in line with the scope of the ONDP and of the SB-CBA described in previous sections. Hydrogen infrastructure can be included in future editions of the SB-CBCS calculations, provided it is included in the ONDP first and that an upgraded SB-CBA process is put in place (e.g. based on the recommendations we have provided in the dedicated section 3.3.9).

One essential point to recall is that the SB-CBCS exercise is **non-binding** on the Member States. This is in line with the objectives of the SB-CBCS, which is to provide a basis for Member States to start negotiations and agree on potential mechanisms to fund the network infrastructures to connect offshore generation. Binding cost allocation decisions will be carried out only in the context of specific projects via PS-CBCAs.

The SB-CBCS does not intend to determine modalities for cost allocation or required financing mechanisms. As a **non-binding** exercise, the SB-CBCS can inform Member States on the expected costs to be borne by each one, and kickstart and facilitate negotiations among them, and potentially prepare discussions on the way to implement PS-CBCAs.

3.4.2. Overview of the SB-CBCS Guidance

We propose the SB-CBCS Guidance (to be produced by the European Commission) to provide the main principles that will allow ENTSO-E to carry out the calculations required to produce the SB-CBCS.

We recommend the European Commission to issue a guidance document structured as follows:

- **Introduction**
    - **Context**: Description of the process described in revised TEN-E, with focus on new provisions relating to SB-level processes. Addressed in Section 3.2.
    - **Objective and scope**: Precise definitions of objectives and scope, what is included and what is not included in the SB-CBCS. Addressed in Section 3.4.1.
    - **Overview:** An executive summary of the SB-CBCS methodology
- **General approach**
    - **Costs to be shared**: Definition of the costs to be shared. Addressed in Section 3.4.5.
    - **Cost sharing key:** Definition of the cost sharing principles, including the scope of countries that need to participate in the cost sharing effort, and the preferred option for cost sharing. Addressed in Section 3.4.4 and 3.4.6.

In the next sections, after a discussion of the main challenges of cross-border cost allocation processes, we provide recommendations on all the points appearing in the “General approach” part of the above-mentioned recommended structure.

3.4.3. Challenges for the SB-CBCS

Cost allocation processes for specific projects (PS-CBCAs) are a tool that has been used for over 10 years in the EU for gas and electricity network infrastructure[36]. The experience in PS-CBCA can provide insights for the design and implementation of SB-CBCS, even if the non-binding nature of the SB-CBCS is a fundamental difference between both processes.

Three main challenges that materialise for PS-CBCAs can also be expected to be applicable for SB-CBCS:

1. Uncertainty and lack of trust in the CBAs and their ability to capture all benefits

PS-CBCAs are based on the results of benefits identified in a CBA. These benefits are dependent on the hypotheses considered in the scenarios and sensitivities. Certain parameters can make the total benefits of the projects vary significantly, such as fuel or CO2 prices, or the availability of certain technologies or grid assets. Countries impacted by a PS-CBCA can have different views on the hypotheses underlying the CBAs, leading to potential misalignments regarding the expected impacts of infrastructure projects.

This risk can be even greater for SB-CBAs due to the large geographical (an entire sea-basin) and temporal (up to 2050) scopes. The uncertainties regarding key assumptions, such as the installed offshore capacities up to 2050 or the evolution of the onshore generation mix, can be large and crucial for the evaluation of the investments (see discussion in Section 3.3.8). Therefore, the different countries involved in SB-level discussion could face challenges in aligning their views on the potential outcomes of SB-CBAs, and hence on the cost sharing that result from SB-CBAs.

To tackle this issue, and ensure the robustness of the results, CBAs consider several plausible scenarios and sensitivities. The SB-CBA in its first edition (2024) will be carried out only for one scenario since the ONDP will be developed for a single scenario of the evolution of the European energy system. However, we encourage that, for subsequent editions, the ONDP is carried out for additional TYNDP scenarios, with the consideration of key sensitivities to properly inform the SB-CBCS process, as mentioned in Section 3.3.3.

Additionally, promoting transparency all along the ONDP, SB-CBA and SB-CBCS processes, especially on models, datasets and key hypotheses, can make the results replicable by Member States and other stakeholders. This participates in creating an ambiance of trust among Member States, helping them converge on a shared understanding of the impacts of the ONDP by better understanding the drivers of value, thereby reducing the risks related to the low level of trust in CBA calculations.

Finally, authorities within Member States (e.g. ministries, NRAs, energy agencies, etc.) should also be reminded that the SB-CBCS is a **non-binding** exercise, and its results should be considered as informative. These results can be used for political discussions among Member States, paving the way for PS-CBCAs which will be themselves binding.

2. Variability of the distribution of benefits depending on the scenarios

The experience with PS-CBCAs has shown that an important variability of benefits can materialise depending on the scenarios. In particular, the distribution of these benefits among the involved countries can vary substantially when changing assumptions.

It should be noted that this result holds true for all cost-benefit analyses based on welfare maximisation at European level (or minimisation of total costs): while the overall results (e.g. total costs) are generally stable when marginally changing an assumption, it can happen that market zone results are impacted in a more important way. For example, if a moderate change in CO2 price impacts the merit order by inverting the order in which different technologies are called, the overall costs will only be moderately impacted but important swings can happen between countries (with thermal production moving from a set of countries to another set of countries). Therefore, without introducing additional constraints within CBAs (e.g. penalties on deviations from base-case

[36] ACER, 2020, Fourth Monitoring Report on Cross-Border Cost Allocation Decisions

dispatch), welfare impacts can, in some cases, be rather uncertain at Member State level whilst being robust at a pan-European level.

When considering different scenarios, the uncertainty on the results can be even greater. For instance, the CBA for the Celtic interconnector between Ireland and France considered eight cases (four main scenarios and a sensitivity applied to each scenario), with the distribution of benefits among the two hosting countries ranging between 56% to 81% to Ireland and 44% to 19% to France[37]. The wide range of the distribution of benefits can pose problems to define a way to allocate costs across countries.

Due to the large scale of the investments assessed in the SB-CBCS, a large number of countries can see their socio-economic welfare being impacted by the infrastructure of the ONDP, including both hosting and non-hosting countries. Therefore, there is a risk that the captured benefits for each country can vary significantly depending on the hypothesis underlying the scenarios or sensitivities. Benefits can also vary for each time horizon analysed in the SB-CBA (2030, 2040, 2050) creating further complexity for this process.

Whilst there is no way of guaranteeing that all involved parties will come to an agreement on the expectations related to the distribution of benefits, an inclusive and transparent process can help achieve this desired outcome. Workshops aiming at presenting the results of the SB-CBA for each of the European sea basins, involving ministries and regulators, can help increasing the level of understanding of the different scenarios and/or sensitivity analyses and of the associated outcomes. High-level discussion amongst Member States relevant to each of the sea basins could be organised on that basis to try and identify a TYNDP scenario/sensitivity analysis that will be subsequently treated as the central scenario during the cost allocation discussions. Feedback from national authorities should be sought by ENTSO-E to inform the choice of sensitivity analyses for the subsequent editions of the ONDP and associated SB-CBAs.

3. Countries to be involved in the cost sharing process

CBCAs are complex and time-consuming processes, as they may require complex negotiations among two or more countries to decide on how to share the costs of an infrastructure project. As network infrastructure projects can impact a potentially large number of countries besides only hosting countries, it can be argued that costs should be allocated to all countries that benefit from it (i.e., that in the CBA they have a net positive benefit). However, including many parties to a negotiation can be impractical and can create high administrative and negotiation costs. Thus, for pragmatic reasons the number of countries involved in a CBCA process is often limited via the introduction of significance thresholds.

ACER recommendation on project-specific CBCA decision[38] limit the cases when CBCAs should be open to negotiations and the countries that should be involved in the process. The Guideline states that a **compensation** should be given only to hosting countries that have a net negative benefit (i.e., they are cost bearers). In principle, all countries (hosting countries or not) with a net positive benefit should provide compensation (i.e., be allocated part of the costs), but for practical reasons, a **significance threshold** of 10% of captured benefits is used to determine which countries are included in the cost allocation[39]. Countries below this significance threshold are not required to be included in the CBCA process.

ENTSO-E shares the need for a pragmatic approach for CBCAs, limiting the cases when a negotiation is needed and the number of countries involved, and goes further. In their recommendations for CBCA implementations[40], they state that the CBCA should be limited to hosting countries if the net impacts in the hosting countries perimeter is positive. This way, the process does not involve non-hosting countries unless needed.

The Lithuania-Poland electricity interconnector (LitPol) CBCA decision is an example of the pragmatic approach recommended by ACER. For the LitPol project, the CBA showed that Lithuania obtained

[37] https://www.cre.fr/Documents/Deliberations/Decision/Repartition-transfrontaliere-des-couts-du-projet-Celtic
[38] ACER, 2015, On good practices for the treatment of the investment request, including cross border cost allocation request, for electricity and gas projects of common interest
[39] The significance threshold can be lowered to ensure that the net positive benefits of included countries can covered the required compensation.
[40] ENTSO-E, 2016, ENTSO-E Recommendations to ACER and NRAs on the CBCA implementation

net positive benefits from the project but wanted for other countries (Norway, Sweden, Germany) to share the costs, as they benefited significantly as well (i.e., they captured benefits above the significance threshold). ACER ruled that since Lithuania was beneficiary, there was no need for a different cost sharing, thus allocating all the costs to Lithuania[41].

The issue of which countries should be involved in the SB-CBCS discussions is of major importance for the SB-CBCS process. Due to the large scale of network infrastructure investments needed for offshore networks, and its importance for achieving the decarbonisation objectives of the EU, the impacts of the development of the ONDP can be significant for a potentially large number of countries, even some countries that can be fairly distant from the considered sea basin. Non-hosting countries can be impacted via a significant share of overall benefits/losses, thus creating the need to include both hosting and non-hosting countries in the process.

The utilisation of a threshold to limit the number of involved countries in the SB-CBCS also poses problems. The determination of this threshold remains an arbitrary decision and thus can be challenged. Also, as a large number of countries will be directly involved (8 hosting countries in NSOG and Baltic, 7 in South & East, 6 in South & West and 4 in Atlantic), with significant impacts to an even higher number of countries, the use of the 10% as stated in ACER recommendation on CBCA decisions might not be appropriate, requiring defining a different (equally arbitrary) significant threshold. Finally, the use of a threshold (on the share of captured net positive benefits) favours small countries. Small countries may capture a small share of the total positive benefits (thus leaving them out of the cost sharing) but these positive impacts can be greater with respect to their size (or per capita) than for larger countries.

3.4.4. Cost sharing options

To allocate the costs of an infrastructure project between the relevant Member States, several options exist. A list of identified options used for project-specific cost allocations are presented below, as well as options that could be developed specifically for hybrid projects:

- **50/50 sharing (or equal split in case of more than 2 countries)**

  The allocation of costs is shared equally between all countries involved in the project. For most projects, only 2 countries are involved and share the investment costs at a 50/50 rate. This is the option that is most often used for cost allocation of **offshore infrastructure projects**[42].

- **Territorial principle**

  If this option is implemented, costs are allocated according to the jurisdictions over which the project – in this case, the sea-basin integrated offshore network development plan - physically extends. The larger the share of the project the country hosts, the more it will have to contribute to its financing. In the case of offshore projects, such a principle would depend on the Exclusive Economic Zones (EEZs) hosting the network development plan. This is the option that is most often used for cost allocation of **onshore infrastructure projects**[43].

- **CBA-based cost sharing**

  This sharing option is based on the results of a cost-benefit analysis, in this case coming from the SB-CBAs. The costs of the project and the benefits of the countries involved are analysed, and the distribution of the costs is made in proportion to the estimated benefits for each country (a threshold may be introduced to avoid involving too many Member States with marginal contributions). At first sight, this option seems to be the most sophisticated and fair one, as it quantifies the benefits for each country, creating an objective key of cost allocation. However, it has rarely been used in recent PS-CBCA agreements. The main reason for this infrequent use of CBA-based arrangements seems to be related to the lack of

[41] ACER, 2015, Decision on the allocation of costs for the Lithuanian part of the Electricity interconnection between Lithuania and Poland
[42] ACER, 2020, Fourth Monitoring Report on Cross-Border Cost Allocation Decisions
[43] Ibid.

confidence of NRAs in the results of the PS-CBAs that have been conducted and the difficulty to agree on key assumptions.

- **Compensation mechanism**

  Infrastructure projects may benefit a set of countries and losses to another set of countries, even if they provide overall societal benefits. In this case, a compensation mechanism can be put in place, in which the advantaged countries would pay a compensation to the disadvantaged countries. The difference between this option and the previous one (CBA-based allocation) is that this option would be used only when there is a hosting country with net-negative benefits, else the cost allocation would remain the default option (such as a 50/50).

  This option is followed by ACER recommendation on CBCA decisions. It should be noted, though, that the PS-CBCAs of recent years have been mostly set up for projects that benefit all the countries that are hosting the project, thus not requiring to set up a compensation mechanism. Some exceptions exist, like the CBCA decision on the Celtic Interconnector[44].

- **Other options, specific to hybrid projects**

  The options described above were not originally designed with hybrid projects in mind. One challenge of the SB-CBCS is to be able to engage non-hosting countries in the financing of ONDP infrastructure, requiring alternative cost sharing options to be envisaged. From the stakeholder survey, two main options have been identified. It should be noted that this study does not aim to provide detailed regulatory or economic assessment of these options, but to provide recommendations related to the process.

  First, the participation of non-hosting countries in asset financing and/or ownership. This option can provide incentives for non-hosting countries to bear part of the infrastructure costs, in return to ownership of the assets and, potentially, capturing congestion rents. However, this option can present governance and regulatory barriers which would need to be addressed.

  Second, the creation of specific funds for offshore infrastructure to be financed by non-hosting countries, potentially using the Renewable Energy Financing Mechanism as a vehicle (see also Section 4.2.3 for more insights on the possible role of REFM). This financing mechanism could then cover part of the costs of specific projects identified as part of the coordinated planning offshore infrastructure, similar to the Connecting Europe Facility-Energy (CEF-E) for Projects of Common Interests (PCI) (see also Section 4.2.3 for more information of CEF-E) [45]. This option can reduce the complexity of PS-CBCAs, as the direct involvement of non-hosting countries would not be needed, reducing negotiation burden. However, this option can have associated negotiation costs to create the dedicated financing mechanism instrument.

- **Combination of the previous options**

  As long as a common agreement amongst NRAs is found, combining the options mentioned above could be considered. For example, different types of costs can be shared with their own allocation key. This was the case of the Celtic Interconnector, where investment costs were shared with in a 60/40 ratio between Ireland and France, but operation and maintenance costs and congestion incomes were shared evenly.

[44] CRE, 2019, Deliberation by the French Energy Regulatory Commission of 10 October 2019 adopting the decision reviewing the joint decision on cross-border cost allocation for the Celtic Interconnector project

[45] CEF funding has been granted to 107 energy network infrastructure projects that have obtained the Project of Common Interest status (PCI). CEF has provided funding for actions at different levels, from feasibility studies to implementation. In particular, CEF has funded projects that present positive socio-economic benefits for the EU, but for which high risks or high non-monetisable benefits can make them hard to materialise, Projects that have received CEF funding for their implementation include the Celtic Interconnector between France and Ireland, the Biscay Gulf interconnector between France and Spain, and the EuroAsia interconnector between Greece and Cyprus.

3.4.5. Cost to be shared

ACER recommendation on CBCA decisions states that efficiently incurred **investment costs** shall be subject to cost allocation. Thus, other costs such as operation expenditures (OPEX) or losses are not considered for cost allocation but are used to compute the net impacts for each country. In addition, as mentioned in previous sections, only the costs related to the electricity network infrastructure are to be allocated, excluding any investment costs related to generation infrastructure.

For the SB-CBCS, the costs to be shared correspond to the **network infrastructure investment costs of the entire ONDP.** However, if the SB-CBCS is to be based on the SB-CBA, the costs to be shared can only correspond to the incremental costs with respect to the SB-CBA counterfactual. This means that only assets that are not present in the SB-CBA counterfactual can be included in the cost sharing when using a CBA-informed cost sharing approach, therefore leaving out radial connections needed to connect offshore generation of the costs to be shared (i.e., costs of radial connections would need to be borne by hosting countries). On the other hand, costs related to radial connection reinforcements (going beyond the capacity that would be needed for connecting offshore generation only) shall be included in the costs to be shared.

This is exemplified in Figure 3-10, which shows the factual (i.e., the ONDP) and its counterfactual. The costs to be shared would be the investment costs of all infrastructure assets removed in the counterfactual (shown in red). This includes the hybrid section connection the two offshore hubs, and the radial reinforcement in C2.

The SB-CBA counterfactual can consider a different offshore generation distribution, as proposed in Section 3.3.4 for the counterfactual from 2026 (onshoring of generation) and shown in the counterfactual of Figure 3-10 (note that part of OWF2 is *onshored* in the counterfactual). In this case a difference in the need of radial links needed to connect offshore generation capacity can appear (Radial R2 is 2,000 MW in the factual and 1,000 MW in the counterfactual of Figure 3-10). We recommend that these costs shall be borne by the hosting country and shall not be included in the costs to be allocated, as these costs are not directly related to the cross-border infrastructure needs identified in the ONDP. However, these costs should be reflected in the net impact calculation for the respective country.

A summary of the costs considered in the SB-CBCS with respect to Figure 3-10 is shown in Table 3-1.

Figure 3-10 Example of a virtual ONDP and the proposed counterfactual for the SB-CBA 2026 onwards

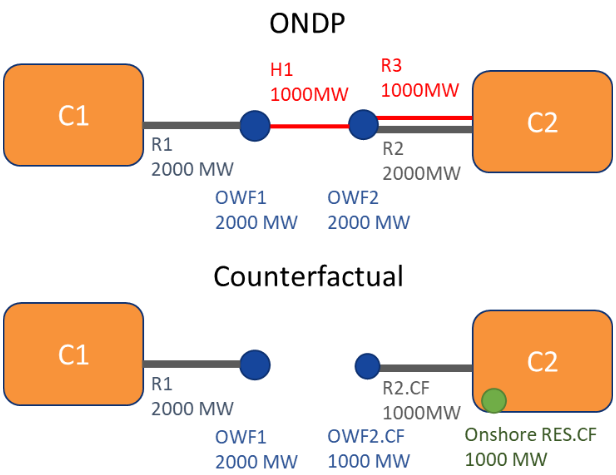


Table 3-1 Costs subject to cost sharing in a CBA-informed SB-CBCS

Costs	Assets in Figure 3-10	Subject to cost sharing	Used for net impact calculation
CAPEX Hybrids	+H1	Yes	Yes
CAPEX Radial reinforcements	+R3	Yes	Yes
CAPEX Radials for offshore connection	+R2 - R2.CF	No	Yes
CAPEX Generation infrastructure	+OWF2 – OWF2.CF - Onshore RES.CF	No	Yes
OPEX Network	$\Delta OPEX_{network}$	No	Yes
OPEX Generation	$\Delta OPEX_{generation}$	No	Yes

In line with ACER recommendation on project-specific CBCA decisions (see Section 4.4.1), we recommend that other costs or financial flows, such as financing costs, national transfers or grants shall not be considered in the SB-CBCS.

3.4.6. Cost sharing key for the SB-CBCS

As the SB-CBCS objectives is to kickstart discussions among Member States on financing options for the ONDP, and not to determine a binding cost sharing agreement, we recommend performing an *ideal* cost sharing exercise. This exercise would share all costs among the Member States with net positive impacts, without considering a minimum threshold. This means that non-hosting countries could bear part of the costs to be shared if they capture net-positive impacts, even if the share of benefits they capture is small.

In the SB-CBCS, **costs shall be shared proportional to the captured net-positive impacts (benefits)** of each Member State, as shown in the Equation (1) for a Member State *i*. Member States that have net-negative impacts do not have to contribute to the cost sharing effort, but shall not receive a compensation[46].

$$CostSharing_i = \frac{\max\,(NetImpact_i, 0)}{\sum_j \max\,(NetImpact_j\,, 0)} \qquad (1)$$

The proposed sharing key aims to encourage the consideration of all Member States benefiting from the development of coordinated offshore network infrastructure, by highlighting the benefits that they are expected to capture from it. By this, those MSs, hosting or not, that benefit from coordinated network development, will firstly become aware of such benefits they will perceive thanks to offshore grids. Secondly, the relevant MSs are able to initiate project-specific cost sharing discussions for future projects, including the principles by which the PS-CBA and PS-CBCA should be assessed. The relevant MSs may thereby incorporate non-hosting MSs, considering that without their participation in the discussions, the eventual project may not be economic and the non-hosting Member State will not perceive the benefits.

Moreover, the proposed sharing key also allows to account for the participation of both small and large Member States, as no minimum threshold is used to determine which Member States need to contribute.

The proposed sharing key also aims to be fair and simple to understand for all Member States. This, again, with the aim of fostering discussions among Member States to help them reach financing guidelines for coordinated offshore network development.

[46] We do not expect that hosting countries have net negative impacts from the SB-CBA without considering the investment costs of the ONDP.

Step-wise development of the ONDP

As described in the section discussing the SB-CBA, the ONDP will be developed in several steps, and the SB-CBA will assess three time horizons: 2030, 2040 and 2050. The benefits may be different both in magnitude and geographical distribution at each of the time steps. As a consequence, a key question that has to be addressed is the sharing of the investment costs when the distribution of benefits evolves over time.

A first option is to compute the total costs and total net impacts for each Member State over the entire assessment period of the ONDP. The total costs of the ONDP are then shared according to the expected total benefits perceived by each Member State. This option needs to have the costs and benefits actualised to a defined *present value* to make comparable costs and benefits accruing at different time horizons. This option considers the ONDP as a whole as one infrastructure project.

A second option is to share the costs incurred at each time step with respect to the benefits generated in the same time step. This option treats each part of the ONDP (2030, 2040 and 2050) as separate infrastructure projects.

We recommend following the first option (total costs and benefits over the entire time horizon). In our view, the ONDP shall not be considered as separate infrastructure projects for each time horizon, but of a consistent portfolio of coordinated infrastructure projects. Indeed, benefits of early developments cannot be separated from the benefits obtained from subsequent ones (e.g., the benefits created in 2040 come from both the hybrid infrastructure built in 2030 and 2040).

A second factor that points in favour of using an entire-time horizon option is the consideration of situations where a Member State obtains net positive impacts in a time horizon and negative in another. This is exemplified in Table 3-2 and Table 3-3, which shows a simplified CBCS for two timesteps and three countries (no discount rate is used for simplification).

In this example, the non-hosting country C3 has a net positive impact in the Step 1 but negative in Step 2, accounting for a total impact over the horizon of 0 M€. With the first option, considering the total impact over the entire time horizon, C3 does not need to contribute, as the different step-wise developments of the ONDP have different impacts which cancel each other. On the other hand, if the cost sharing is carried out following a step-wise approach (second option), C3 would need to contribute for the timestep in which it captures a net positive benefit, even though it does not capture a total benefit from the ONDP as a whole.

However, the use of a total costs and benefits over the time horizon option presents challenges, in particular with the uncertainty of future network developments. Indeed, the growing uncertainty of network developments occurring at later points in time may need to be considered, since it could affect the relevance of temporal distinctions of cost sharing. For example, if the two C1-C2 projects (i.e. in Step 1 and Step 2) are close to each other in time, an aggregation of the net positive and net negative C3 benefits may be effective and facilitate discussions between C1 and C2; but if too far away in time, a discussion with C3 may still be relevant.

As the SB-CBCS will consider a 30-year time span, there is significant uncertainty in the effective development of the long-term offshore network. Measures to take into account this effect should be considered when using the results of the SB-CBCS for negotiations among MSs.

Table 3-2 Costs and net impacts of a simplified ONDP, with three countries and two time steps

Costs and impacts	Step 1	Step 2	Total Step 1 & 2
Investments	Hybrid C1-C2 #1	Hybrid C1-C2 #2	
Costs [CAPEX]	500 M€	500 M€	**1000 M€**
Net impact C1	400 M€	600 M€	**1000 M€**
Net impact C2	400 M€	600 M€	**1000 M€**
Net impact C3	200 M€	-200 M€	**0 M€**
Total impact	**1000 M€**	**1000 M€**	**2000 M€**

Table 3-3 Cost sharing of the simplified ONDP under two cost sharing options

Cost sharing	Based on total impact over the whole horizon	Based on each time step		
		Step 1	Step 2	Total
Costs to be shared	1000 M€	500 M€	500 M€	1000 M€
Share C1	500 M€	200 M€	250 M€	450 M€
Share C2	500 M€	200 M€	250 M€	450 M€
Share C3	0 M€	100 M€	0 M€	100 M€

Other implementation aspects

ACER recommendation on CBCA decisions provides information on the implementation of project specific CBCAs[47], which can be applied for the SB-CBCS.

To make costs and benefits across time periods comparable, they need to be computed in *present value*, using the standardised social discount rate recommended by ACER recommendation on CBCA decisions (4% real).

The costs and benefits need to be computed for the whole lifetime of investments, so as residual value of investments is 0 at the end of the period. To evaluate costs and benefits for the entire lifetime, ACER recommendation on CBCA decisions state (in the CBCA Guidance, Annex I.2):

a) *"For years from the year of commissioning (start of benefits) to the mid-term year (if any), extend mid-term benefits backwards.*

a) *For years between the mid-term year and the long-term year, linearly interpolate benefits between the mid-term and long-term values.*

b) *For years beyond long-term horizon (if any), maintain benefits at long-term value"*

[47] ACER, 2015, On good practices for the treatment of the investment request, including cross-border cost allocation request, for electricity and gas projects of common interest, Annex I

Considering that the SB-CBCS will have cost and benefits values for 2030, 2040 and 2050, this translates for the SB-CBCS:

a) For years before 2030 (if any), extend 2030 values backwards.

b) For years between 2030 and 2040, and between 2040 and 2050, linearly interpolate with respective values.

c) For years beyond 2050 (if any) maintain benefits at 2050 values.

The SB-CBCS is mandatory for EU Member States per the revised TEN-E regulation, thus they are to be included in SB-CBCS. Neighbouring countries, such as the UK and Norway, are not subjected to the TEN-E regulation, and thus are not necessarily included in the SB-CBCS process. However, these countries may play a major role in the development of offshore wind, and of the associated network infrastructure. We encourage including these countries all along the SB planning and cost sharing process as much as possible.

This would require discussion from early stages, to obtain offshore generation targets needed for the ONDP. We understand this step is already put in place by ENTSO-E for the first (ONDP 2024) edition. Their inclusion in the Cost Sharing phase would be dependent on the countries' and EU's (voluntary) agreement, and in that case they should be treated as the EU Member States to determine their share of costs. If they do not take part of the cost sharing phase, we recommend that these countries shall bear, in the SB-CBCS exercise, the costs of any priority offshore corridors connecting it to the EU, using a 50/50 sharing key (e.g., if the ONDP identifies a hybrid connection between the UK to the EU, the UK shall bear 50% of that hybrid corridor's costs).

3.4.7. Extension to hydrogen infrastructure

As mentioned in the Section 3.3.9 related to the treatment of hydrogen in the SB-CBA, the extension of the SB-CBCS process to hydrogen infrastructure is dependent on the inclusion of hydrogen from the beginning of the ONDP process.

Regarding the Cost Sharing of electricity and hydrogen infrastructure, we recommend taking a holistic approach to the multi-energy planned infrastructure. A multi-energy SB-CBCS would allocate costs and benefits of the total costs of the multi-energy ONDP infrastructure based on the total net benefits of each Member State, and not perform a sector-specific allocation of costs. This means that a multi-energy ONDP would not define a share of electricity (or hydrogen) costs to the electricity (or hydrogen) TSO of a Member State, but instead provide total cost sharing. A distribution of cost shares between different TSOs or energy sectors (electricity, hydrogen) within one country is left to the country's policy and regulatory framework.

4. Recommendations on coordinated CBA and CBCA between offshore electricity transmission and generation

4.1. Objectives

This chapter aims to present recommendations on the **process for coordinating** project-specific CBAs and CBCA agreements for offshore electricity transmission and generation projects. Furthermore, the chapter also discusses more **high-level aspects which could enhance cross-border cooperation** and the achievement of EU and national offshore energy targets.

The aim of this chapter is not to conduct a critical assessment of existing methodologies and guidelines for CBAs and CBCA agreements for offshore renewable energy and transmission projects, such as the ENTSO-E CBA 3.0 methodology[48] and implementation guidelines[49], as well as the proposed 4.0 methodology[50], ACER's recommendation on cross-border cost allocation decisions[51] or the Commission guidance on methodologies for cross-border renewable energy projects.[52] There are other ongoing activities at the EU level in this regard, such as (at the time of writing) the update of ACER's recommendation in the 1st semester of 2023 following the TEN-E Regulation requirements, or the recent recommendations of the European Scientific Advisory Board on Climate Change on an energy system-wide cost-benefit analysis.[53]

Nonetheless, such methodologies and guidance are considered when relevant, and the present analysis might contribute to their improvement in the future. The chapter also does not aim to provide direct input to upcoming methodologies to be developed by the Commission for a harmonised energy system-wide cost-benefit analysis at Union level for various TEN-E project categories (electrolysers; smart gas grids; smart electricity grids; carbon dioxide; energy storages; hydrogen).

The chapter is structured as follows:

- Section 4.2 provides an **overview of the current procedures** for developing offshore electricity network infrastructure and generation projects, providing a basis for the recommendations presented in the rest of the chapter;
- Section 4.3 presents the **overall process for coordinating a CBA and CBCA** for a specific project, clarifying the relationships between the CBA and CBCA;
- Section 4.4 provides **recommendations on selected aspects for the coordination of CBAs** for offshore renewable energy generation and/or transmission infrastructure, and covers the following specific aspects:
    - Definition of scenarios
    - Bidding zone configuration
    - Counterfactual definition
    - Key performance indicators
- Section 4.5 provides **recommendations on selected aspects for the coordination of CBCAs** for offshore renewable energy generation and/or transmission infrastructure, and covers the following specific aspects:
    - Scope of costs to be considered
    - Inclusion of non-hosting countries
    - Agreements on deviations of costs and benefits

[48] ENTSO-E (2022) 3rd ENTSO-E guideline for cost benefit analysis of grid development projects
[49] ENTSO-E (2023) Implementation Guidelines for TYNDP 2022 based on 3rd ENTSO-E guideline for cost benefit analysis of grid development projects
[50] ENTSO-E (2023) 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects - Version 4.1 for ACER/EC/MS opinion
[51] ACER Recommendation 05/2015
[52] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF
[53] https://climate-advisory-board.europa.eu/reports-and-publications/towards-a-decarbonised-and-climate-resilient-eu-energy-infrastructure-recommendations-on-an-energy-system-wide-cost-benefit-analysis

  - Further issues to be considered in the CBA/CBCA process
- Section 4.6 discusses **potential improvements to relevant policies, strategies and methodologies** in order to achieve the EU and national offshore energy targets and enhance cross-border cooperation

4.2. Context: Offshore electricity network infrastructure and generation procedures

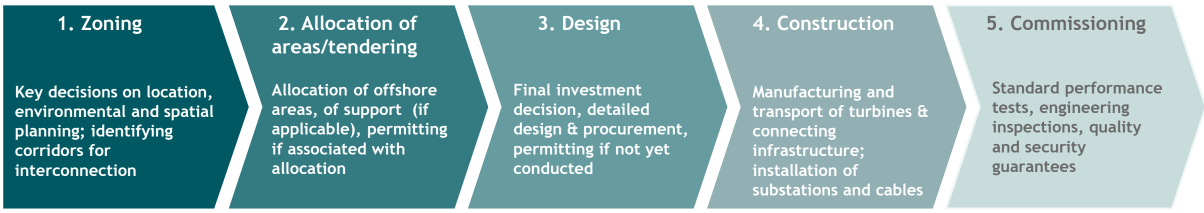
4.2.1. Overview of processes for developing specific offshore renewable electricity generation and transmission projects

To better understand the specific aspects of (hybrid) offshore electricity transmission infrastructure development, the different stages of developing offshore wind energy and electricity transmission projects are introduced shortly in this section. These stages will need to be accounted for to have coordinated CBAs and CBCAs between electricity generation and transmission.

The below figure gives an overview of the main phases in the development of offshore energy and transmission projects – including hybrid transmission projects. This is based on among others WindEurope[54] and the UK offshore wind programme board.[55] The development phases are detailed next. Given the lack of established procedures for ocean energy, the discussion here is focused on offshore wind energy – but the same issues should arise for ocean energy.

Compared to offshore renewable energy generation projects, transmission projects do not have a zoning or tendering phase. The timelines of different development stages vary as well, also between projects, depending on the challenges encountered and the engineering concept. Usually, in the early phases of any cross-border project, there are one or more countries organising tender(s) with multiple competing potential developers, which then results in a few selected developers driving the offshore generation project realisation at later stages, in combination with TSOs developing the offshore transmission.

Figure 4-1 Offshore energy wind generation and transmission development stages



Zoning

For offshore electricity generation, in the zoning phase, the physical high-level areas (maritime zones) for wind energy farms are chosen and targeted for project development. In this phase, spatial and environmental requirements have to be determined to make sure the wind energy farms minimise pressure on e.g. marine life, to consider other sea uses as defined in Maritime Spatial Plans, and ensure the future viability and profitability of the project. This can take into account also the impacts of the transmission projects required to connect the wind farms. This process typically takes 2 years. Usually, government authorities are responsible for conducting the necessary studies and defining the offshore wind energy zones (for example in the Netherlands, Belgium, Germany,[56] and Spain[57]) as well as defining the connection model and obtain the necessary environmental permits. However, this process can also be conducted by the project developers, who afterwards apply for authorisations to further develop the projects in the suitable zones (see the next step), such as in Ireland – where the Maritime Area Regulatory Authority (MARA) may still conduct auctions to allocate the authorisations in certain cases.[58] Similarly, during open-door procedures in

[54] WindEurope (2019) Our Energy Our Future. WindEurope-Our-Energy-Our-Future.pdf
[55] Overview of the offshore transmission cable installation process in the UK. DRAFT (catapult.org.uk)
[56] Global Wind Energy Council (2022) Global Offshore Wind Report 2022
[57] MITERD (2022) Hoja de Ruta para el desarrollo de la Eólica Marina y de las Energías del Mar
[58] Maritime Area Planning Act 2021

Denmark[59], developers who want to build an OWF apply for a license to carry out preliminary investigations themselves in the chosen area.

For interconnectors, the equivalent zoning process would be the high-level consideration and identification by TSOs of corridors to interconnect different systems and which could present positive net benefits. Any necessary environmental permits can also be obtained in this phase already.

The development of hybrid transmission projects requires the zoning of both the offshore wind farms and, if applicable, energy islands to be deployed, as well as the consideration of the hybrid transmission projects connecting the renewable energy projects and onshore systems. Given the transnational nature of the projects, agreements are established between the countries to be connected, such as in the case of the Danish energy islands, where political agreements were concluded with Germany, the Netherlands and Belgium. Agreements between the TSOs also take place, given their role in developing the transmission projects – in the same example, the Danish TSO has signed agreements with Dutch[60], German[61] and Belgian[62] TSOs.

Allocation of areas/tendering

Once zones for offshore renewable energy are defined, auctions are usually carried out by the country in which the physical asset (wind farm) is located in order to allocate the offshore areas and eventual associated economic support to the projects. It is also possible to employ an 'open-door' approach to allocating offshore areas, such as in Ireland. In this case, economic support, if any, can be tendered separately from the allocation of zones for development of offshore wind energy.

For **regulated transmission projects** there is no allocation of the project either through administrative or competitive procedures. The responsible TSOs will instead usually require authorisation from their respective NRAs for the investments.

However, if the asset is connected through cross-border hybrid project(s), multiple countries may have interest and may be involved in the allocation/tendering.[63] Currently, there is no common approach for such offshore energy generation and transmission projects. This has been identified as a barrier during the development phase[64] of multiple such projects (but is out of scope of this study project).

The Danish Energy Agency has scheduled to tender the shared ownership and operation of its two planned energy islands, as well as later on that of the offshore wind farms.[65] During the planning process of the Bornholm energy island/OWF, a market dialogue is facilitated between the Danish Energy Agency (DEA), Energinet (Danish TSO) and potential bidders. For this project, a one-stage tender for the partnership and the construction is proposed. The winning operator will become responsible for the construction, and the Danish State will own at least 50.1% of the island when finished. For Bornholm, the parties agreed that the winning operator will be responsible for the design phase too.[66]

Design

For offshore renewable energy generation, in the design phase multiple key decisions take place: suppliers are selected for the engineering, materials, equipment and construction for the relevant elements such as the turbines, foundation structures, and inter-array cables. Offshore platforms and substations may also be responsibility of the developer depending on where the connection point is set (see section 4.2.2 below). PPAs may be concluded to provide a guaranteed off-take to the electricity (still subject to curtailment due to network congestion). This is the phase where the final investment decision and the financial close also take place, taking into account

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[59] https://ens.dk/en/our-responsibilities/wind-power/offshore-procedures-permits
[60] https://www.nsenergybusiness.com/news/newsenerginet-german-and-dutch-tennet-sign-agreement-to-develop-north-sea-wind-power-hub-5772171/
[61] https://en.energinet.dk/About-our-reports/Reports/Business-case-for-Energy-Island-Bornholms-electrical-infrastructure/
[62] https://en.energinet.dk/About-our-news/News/2021/02/12/Elia-PR/?listId=3187dd0d-12d9-4de8-9f78-ea5c9d11227c
[63] Roland Berger (2018): Hybrid projects: How to reduce costs and space of offshore developments North Seas Offshore Energy Clusters study
[64] Examples the report refers to: IJmuiden Ver to UK (Chapter 4.4.3), CGS IJmuiden Ver to Norfolk (Chapter 4.5.3), NSWPH (Chapter 4.7.3), COBRA Cable (Chapter 4.8.3) and DE OWF to NL (Chapter 4.10.3).
[65] Danish Energy Agency (2022) Denmark's Energy Islands. https://ens.dk/en/our-responsibilities/wind-power/energy-islands/denmarks-energy-islands
[66] Energy Island Bornholm | Energistyrelsen (ens.dk)

support schemes that the project can take advantage of. This phase usually takes 2 years. Environmental permitting is often conducted already by authorities in the previous phases of zoning and allocation of the areas as mentioned, but can be conducted otherwise by project promotors in this phase.

For offshore electricity transmission, the design stage starts with identifying and quantifying the need for additional transmission capacity between two (or more) systems, for which an exact route for expansion has to be planned. Development rights have to be obtained, feasibility studies and ground investigation works (both on and offshore) need to be conducted to know if the engineering concept and overall project is feasible. Consultations also have to be conducted to collect stakeholders' feedback. After these preparatory works, the procurement stage of the project starts. Design can take up to 3 years, and need to cover all elements such as export cables, landing points and also offshore platforms and substations if (partially or fully) under the responsibility of the TSO. After the investment decision is taken, funds are released for detailed route engineering studies.[67]

Construction

Construction and installation are the last stage of a windfarm development. Components of the turbines and connecting infrastructure need to be manufactured, then pre-assembled and transported to the site, where the assets are constructed and connected to the grid preceding commissioning. This can take 3 years or more.

Installation and construction of interconnectors can begin once the planning, permitting and procurement of cable installation works are all complete. Construction consists of laying and burying the already constructed cables underground and underseas. Substations have to be installed onshore as well, and overall construction can take 1.5 years or more.

In the case of generation projects connected through hybrid projects, the construction phase will not necessarily take longer than conventional offshore energy or interconnector projects. However, besides onshore substations also offshore structures will need to be placed. Moreover, if an energy island needs to be constructed, this can take multiple years.

Commissioning

Commissioning of offshore wind energy farms generally covers all activities after construction and installation, and often involves standard tests of the electrical infrastructure and the turbines, accompanied by routine civil engineering inspections.[68] The results should guarantee that the wind farm meets TSO technical standards for grid connection (related to voltage levels, power quality, frequency control, etc.) and that it will operate safely and provide quality of service.

As for interconnectors, after installation of the cables, onshore stations and any other assets, electrical tests need to be performed in order to demonstrate the reliable and safe operation of the cable system and make sure there are no damages, and power frequency tests are undertaken on the cables. To reach the operational stage, commissioning dates are important to pay attention to and need to be cross-checked the National Development Plans and NRAs' latest updates valid at the date of submission of the project. Operation can begin once the project is commissioned.

4.2.2. Analysis of relevant characteristics

This section presents relevant characteristics of offshore renewable energy and transmission projects (including hybrids) which have an influence on their coordination, and which thus have to be taken into account when developing the guidance for coordinated offshore CBAs and CBCAs for generation and cross-border transmission projects, including hybrids.

Timing of projects

The timeline of the installation of RES generation and transmission assets can differ significantly as detailed in section 4.2.1. Thus, it is important to coordinate these as much as possible in the early development stages, in order to avoid any negative technical or economic impact from inconsistencies in the timing of the different sub-projects. If for example a windfarm is connected

[67] Offshore Wind Programme Board (2015) Overview of the offshore transmission cable installation process in the UK
[68] Wind Farm Design: Planning, Research and Commissioning (renewableenergyworld.com)

late to an interconnector because of a delay in the tendering process, this can negatively eventually lead to revenue losses for both parties.

Aligning the timelines is especially relevant in projects with a significant difference in the development start or commissioning date of assets. This can be the case especially for projects including hybrid interconnectors, where the renewable energy generation and the interconnection assets may be developed and commissioned in different phases. For example, in the case of the Kriegers Flak combined grid solution, the wind farms were developed and connected radially to Denmark and Germany prior to their interconnection. Harmonising timelines thus supports the development of hybrid projects[69]. It can also bring other benefits such as ensuring consistency and streamlining of the respective permitting procedures.

Available funding programs

A large variety of EU funding programmes are available to finance energy projects. Those relevant for offshore RES generation (both wind and ocean energy) are listed below. Often, funding from these sources can be combined with additional national, regional or other EU funding and financing, while respecting State aid rules and always avoiding double-funding.[70,71]

Most of these instruments support the development of offshore renewable energy, from projects with a low maturity to those with a high maturity (and commercially viable or not). Some instruments also support investments for the radial connection of wind energy farms, while other instruments specifically focus on interconnectors and projects with cross-border relevance, particularly in the case of PCIs which can benefit from CEF funding.

Therefore, while offshore renewable energy and transmission projects may benefit from funding at EU and national levels, different instruments may support both the generation and (hybrid) transmission assets of a same project, requiring sufficient attention to avoid double remuneration of projects costs. The following list has been compiled based on the EC's overview of funding programmes relevant to offshore renewable energy financing:[72]

Table 4-1 EU funding programmes for offshore energy generation and/or transmission

Instrument	Coverage
Horizon Europe (Cluster 5)	G, T
EU Innovation Council	G
LIFE – Clean Energy Transition sub-programme	G
European Maritime Fisheries and Aquaculture Fund (EMFAF) and BlueInvest	G, T[73]
Innovation Fund	G
Cohesion policy (ERDF, Interreg, CF, JTF)	G, T
Connecting Europe Facility (CEF)	G, T
InvestEU	G, T
Modernisation Fund	G, T
Recovery and Resilience Fund	G, T

Legend: Generation (G) or Transmission (T)

[69] https://www.rolandberger.com/en/Insights/Publications/Hybrid-projects-How-to-reduce-the-cost-and-space-of-offshore-wind-projects.html
[70] Overview_table_funding_instruments_offshore_final.pdf (europa.eu)
[71] https://energy.ec.europa.eu/topics/renewable-energy/financing/eu-funding-offshore-renewables_en
[72] https://energy.ec.europa.eu/topics/renewable-energy/financing/eu-funding-offshore-renewables_en
[73] As part of Blueinvest initiative only https://webgate.ec.europa.eu/maritimeforum/en/system/files/market_opportunity_snapshot-blue_renewable_energy.pdf

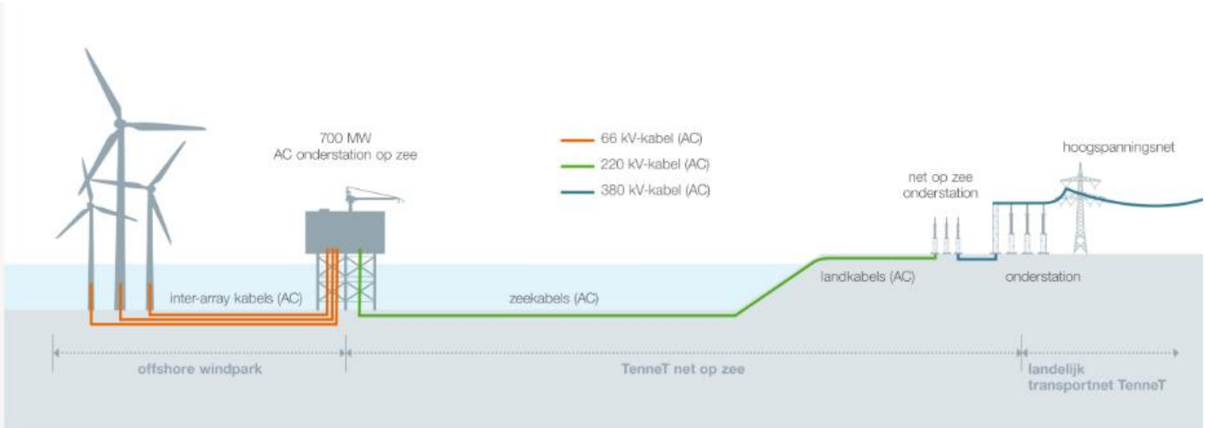
Asset types and connection point

A number of assets make up offshore renewable energy generation (including connection to shore) and interconnector projects, including:

- Turbines and blades (G)
- Support structures (bottom-founded or floating, G)
- Inter-array and export cables (G)
- Offshore platform (G/T)
- Substations (offshore, G/T)
- Subsea cable lines (T)
- Cable connections/interconnectors (T)
- Substations (onshore, T)
- Compensation reactors (T)
- Artificial islands (G/T)

Several assets can be part of the offshore electricity generation or transmission project. It is thus necessary to clearly specify where the offshore generation project finishes and the transmission project starts: the connection point between offshore electricity generation and transmission, or some other agreed threshold for allocation of asset costs. This connection point may even be located in an offshore platform, with thus shared ownership of some assets in the platform as long as unbundling rules are preserved. A typical connection of a wind farm to shore using an AC cable is illustrated in Figure 4-2[74], with the boundary between the offshore wind and the transmission system shown.

Figure 4-2 Offshore generation and transmission[75]



Coordination of the engineering works that precede the installation of some assets, such as the landing of cables or construction of dyke crossings, could benefit from cross-border cooperation and best practice exchange to optimise the timelines and efficiency of construction, as well as to minimise environmental damage associated claims. Cable-laying or jack-up vessels, or any other crucial marine equipment, could also be shared between parties in case of cross-border or joint projects.

Priority dispatch and compensation for curtailment

Article 12 of the Electricity Regulation[76] indicates that priority dispatch should be guaranteed to all small-scale RES and demonstration projects, while dispatch for all other installations, regardless of the technology used, should be non-discriminatory, transparent and (with exceptions) market-based. Priority dispatch thus does not apply to offshore wind farms.

[74] Offshore projects Netherlands (tennet.eu)
[75] Offshore projects Netherlands (tennet.eu)
[76] Internal electricity market regulation under the Clean Energy for all Europeans Package

However, under extraordinary circumstances, Member States may request a derogation from the European Commission to have specific projects exempted and thus not count in the requirement for TSOs to make available to the market at least 70% of the cross-zonal capacity of each border, as long as they can be classified as small systems (as foreseen in article 64 of the Electricity Regulation 2019/943), ensuring that the interconnector capacity can be used first for transporting the offshore renewable energy. This was the case particularly of the Kriegers Flak Combined Grid Solution (CGS).[77] However, the Kriegers Flak CGS is exceptional in this regard, as its development predates the adoption of the new EU electricity market design in 2019, and future offshore projects will likely not be considered small systems. Moreover, Member States can establish offshore bidding zones, where the export by the offshore wind farm would directly account towards the compliance of the 70% rule.

Downward curtailment of power output refers to limiting the maximum possible output of an electricity generator, in specific cases. Such limitations can be imposed by grid operators in case of grid congestion or for grid security reasons, necessary controls of the voltage level and to limit excess generation during off-peak demand periods.[78]

The Electricity Regulation foresees that market-based redispatching should be used when possible. As an imposed reduction of the grid injection affects the profitability of RES generators, any curtailment of renewable electricity generation through non-market-based redispatching should be the last resort measure in system management, and should be accompanied by a financial compensation to the curtailed generator.

Differences in support schemes

There are various renewable energy support schemes used across Europe that incentivise investments in RES generation and aim to provide long-term revenue security to producers, typically based on the cost of each generation technology versus the market price. The type of support impacts the behaviour of developers and operators in all phases of development and operation, thus a predictable and suitable framework is essential for cost-optimal outcomes:

- **FiTs**: Feed-In-Tariffs provide a fixed remuneration per kWh produced (or injected) to the generator. A certain price level is guaranteed for a specific time period, which makes the plant's revenues independent of electricity market developments. As such fixed remuneration scheme can lead to inefficient production dispatching (local storage in case of low or negative prices is not incentivized), it is not recommended anymore and gradually being replaced by more market-based support schemes.
- **CfDs:** Contracts for Difference guarantee a fixed remuneration level, determined via an auction, to electricity generators. Depending on the difference between the strike price and the reference market price, as well as on the actual design of the CfD (e.g. single- or double-sided, and how the reference price is defined, such as every 15 minutes or averaged monthly), the generator receives an additional revenue from the counterparty, or has to pay some money back.[79]
- **FiPs**: Feed-in premiums support electricity generators for a specific period of time with a set premium on top of the market price. Similarly to CfDs, FiPs are often allocated through auctions which are favourable from a public planning perspective, but risks prevail that the offered premium will not allow to recover the full investment costs in case of downward fluctuations of market prices[80] or that the premium will still incentivise the operators to generate even in the case of negative prices, depending on the mechanism design. If properly designed and implemented, both CfDs and FiPs can avoid inefficient dispatching.
- **Green certificates**: Green certification schemes involve the issuing of certificates for each unit of power produced from RES (typically 1 MWh) to testify minimum volumes of RES in suppliers' or consumers' energy portfolio. They are separately tradeable from the generated power, allowing for virtual transfers of RES between parties (although in some cases support schemes may foresee that supported operators do not have right to any green certificates).

[77] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32020D2123&rid=3
[78] https://www.rolandberger.com/en/Insights/Publications/Hybrid-projects-How-to-reduce-the-cost-and-space-of-offshore-wind-projects.htm
[79] http://aures2project.eu/glossary-terms/fip-fixed-or-sliding/
[80] http://aures2project.eu/glossary-terms/fip-fixed-or-sliding/

In general, a specific support scheme is offered to offshore energy projects by the authorities of the country in whose territorial sea the project is located. Exceptions are possible and some countries have included them in national law, e.g. in the Netherlands, where subsidies can be granted to wind farms in other Member States.[81] The recast Renewable Energy Directive (EU) 2018/2001 defines cross-border cooperation mechanisms in the form of joint support schemes, joint projects and statistical transfers. These are further detailed in section 4.2.3.

The business case and financial security for offshore wind energy generators can be guaranteed without having to involve governments e.g. by concluding Power Purchase Agreements (PPAs) with large electricity consumers or suppliers/retailers. PPAs are a suitable instrument to secure RES development and reduce electricity price risks for both parties, in the form of bilaterally agreed contracts over a longer period of time. Such contracts provide predictability for both parties as well as a guaranteed offtake of the produced electricity, albeit the RES production may still be curtailed in case of network congestion.

System access tariffs (G-charges)

So-called G-charges are network fees for the access to and utilisation of the grid by electricity generators. These tariffs generally exist in the form of energy-based charges and/or power-based charges. Energy-based tariffs set a per-kWh rate that recovers costs per kWh injected and transported via the grid. Power-based[82] charges tariffs according to a grid user's subscribed capacity and/or network's usage during the system peak (coincident peak load) or during a prespecified time period (non-coincident peak load). G-charges must be structured to reflect the costs the generator actually causes to the system and the benefits it provides to the system. In practice, designing fully cost-reflective tariffs is difficult, but cost reflectiveness must be pursued as it is legally enshrined in the Electricity Regulation[83].

Different G-charge structures exist across the countries, also due to the range of charges and exemptions permitted by Regulation (EU) 838/2010[84] 'on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging'.[85] G-charges are generally low across the coastal EU Member States (representing less than 5% of total network operator charges), with the exception of Finland (18.6%), Ireland (25%), Norway (24%), Portugal (9.3%) and Sweden (37%).[86] This illustrates also the wide range of G-charges across the EU.

Connection regimes

Connection costs for offshore wind energy farms are at present allocated differently in the concerned Member States; these differences may have to be accounted for in CBCAs. For an onshore renewable energy project, grid-related costs directly related to a project are typically recovered via grid connection charges, while wider grid reinforcement costs (upstream investments) are recovered via the general system operator network tariffs (so called 'shallow approach'). The latter cover investments and operating expenses of the wider network. Connection costs are set out in the regulated tariff methodologies of each Member State for a given regulatory period. This typically also includes tariff projections.[87]

However, for offshore wind energy projects, even the direct connection costs are in some cases recovered by the network operator through the general network tariffs (i.e. these costs are socialised). This is the case for example in France, where the regime was changed recently,[88] but also Denmark[89], Germany and the Netherlands.[90]

[81] Including for offshore wind farms, as the SDE++ decree §5a of the applies to all renewable electricity, gas, and/or heat generators.
[82] Or often called "capacity-based"
[83] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943
[84] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF
[85] https://www.rolandberger.com/en/Insights/Publications/Hybrid-projects-How-to-reduce-the-cost-and-space-of-offshore-wind-projects.html
[86] https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/l_entso-e_TTO-Report_2020_03.pdf
[87] CBA Guideline for C-B RES Projects (europa.eu)
[88] https://www.cliffordchance.com/content/dam/cliffordchance/briefings/2022/05/favourable-winds-for-french-offshore-wind-farms.pdf
[89] In the regulated model, as Denmark also has an open-door procedure
[90] https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf

Congestion income and allocation of revenues between TSOs/RES producers

Congestion income is the revenue collected by TSOs from the allocation of cross-zonal transmission capacity over different market timeframes.[91] It should be employed primarily to further develop the transmission network in order to resolve structural congestions.

Integrated hybrid offshore systems with separate offshore bidding zones (OBZs) will in general reduce the average price level in the connected zones and thus also reduce the revenues perceived by offshore wind energy generators, when compared to a traditional integration into an existing onshore bidding zone ('home market' configuration). Compared to the latter, solutions with hybrid interconnectors may "shift" part of the value from the generator to consumers and to TSOs in the form of congestion incomes.[92] This is in fact an appropriate outcome of an efficiently designed market that accounts for the offshore network constraints during dispatching, lowering the need for redispatching and counter-trading actions close to real time. Thereby, OBZs increase system security and decrease costs for consumers. Moreover, in the long term, they provide price signals to incentivise the development of electrolysers for hydrogen production, storage or other offshore demand and, where relevant, to develop new grid projects.[93]

Laur et al. (2022) recommends that if revenue losses from transmission capacity reduction are caused by the operational derating of offshore transmission by TSOs, this should lead to eventual compensation to offshore wind energy generators by TSOs (as well as in the case of a change of bidding zone configuration for an already existing offshore project), and propose a 'Transmission Access Guarantee' (TAG) instrument to define this compensation and tackle the associated risk. The TAG would establish an objective to ensure that the actual export capabilities of the offshore generator in the market are consistently equal to or greater than the capability of the offshore wind farm to generate considering the wind availability and other factors.

Next to a transfer of congestion income from TSOs to power generators, reallocation of revenues between TSOs can be considered, as already implemented according to the inter-TSO compensation mechanism (ITC) defined in Commission Regulation 838/2010.[94] The ITC mechanism aims to compensate TSOs for costs caused by transit flows (due both to electricity grid losses and the need to make the infrastructure available).

While the assessment of this issue is not part of the scope of the current study project, any revenue reallocation between TSOs and RES generators may have to be taken into account into the project-specific CBCAs.

4.2.3. Overview of the relevant legislation and associated procedures

This section presents the prevailing EU-level processes, legislation and funding schemes for offshore renewable energy and transmission projects.

EU cooperation mechanisms for renewable energy

Three types of cooperation mechanisms[95] are foreseen under the RED II to facilitate joint RES projects: joint projects (between EU Member States or EU-non-EU countries), joint support schemes (between EU Member States or between EU and non-EU countries), and statistical transfers (between EU Member States).

- **Joint projects** allow two or more EU Member States to cooperate in offshore wind energy projects, and **share the produced renewable electricity** for the purpose of meeting their targets. These projects can, but do not have to, involve the physical transfer of energy from one country to another. EU countries may also enter into joint projects with non-EU countries, which could be considered for instance in the North Sea (e.g. with the UK or Norway). The resultant energy will count towards national targets if the project involves electricity generation or the physical flow of energy into the EU.

[91] Laur et al. (2022) Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market. Congestion offshore BZ.ENGIE Impact.FinalReport_topublish.pdf (europa.eu)
[92] Laur et al. (2022) Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market. Congestion offshore BZ.ENGIE Impact.FinalReport_topublish.pdf (europa.eu)
[93] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020SC0273
[94] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF
[95] https://energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/cooperation-mechanisms_en

- Two or more EU Member States can **co-fund a joint support scheme** to spur offshore wind energy production in one or both of their territories. This form of cooperation can involve measures such as a common auction and resulting support scheme (e.g. two-way CfD). Joint support schemes may become particularly interesting for enabling large and innovative offshore cross-border projects or aggregation of projects.

- Finally, **statistical transfers** allow to allocate a certain amount of offshore wind energy produced in the territory of country A to the national target of country B, based on a bilateral agreement. Luxembourg has for instance concluded such an agreement with Lithuania[96] and in February 2023 also with Denmark.[97] In December 2021, the Commission launched the **Union Renewables Development Platform** to facilitate statistical transfers. It provides national EU administrations with relevant information and offers a tool to help countries find potential partners and agree on the conditions of a statistical transfer.[98] Guidance to conclude statistical transfers including a template agreement are also made available for interested countries.[99]

The TYDNP and TEN-E processes

The 10-year network development plan for electricity (TYNDP) is elaborated by ENTSO-E and published every two years. Based on scenarios jointly developed with ENTSOG and on market and network modelling, it lists and assesses the costs and benefits of relevant transmission and storage projects, detailing the power grid pathways in the next 10-30 years under various scenarios so that it can effectively contribute to achieving the EU energy and climate goals.

Projects included in the TYNDP are assessed using the standard, pan-European CBA methodology.[100] The generation cost approach of the implementation guidelines for the CBA 3.0 compares generation costs with and without the specific projects for the chosen bidding areas.[101] The TYNDP CBA 3.0 methodology and related implementation guidelines (as well as the proposed TYNDP CBA 4.0 methodology[102]) also help assessing the costs and benefits of two or more transmission or storage projects that could potentially compete with each other but serve the same purpose. The CBA process thus serves to assess whether the socio-economic viability of specific investments is reduced or enhanced by other investments in the TYNDP list, and what the overall net benefit is of (not) realising both projects.[103]

The resulting CBA/CBCA agreement enables TYDNP projects to apply for PCI status, for which the selection is guided by the TEN-E Regulation and its guidelines. These processes are necessary to be completed for offshore projects before applying for CEF funding. ACER gave its recommendations on CBCA decisions, adopted in September 2015[104], providing guidance to project promoters on the submission of an investment request and guidance for the TYNDP process on how to calculate net impacts per country. Furthermore, the chapters:

- Advise on how to consult the relevant TSOs;
- Make suggestions on which NRAs the investment request should be addressed to, and inform about reporting requirements to them and TSOs;
- Guide the adjustment of CBCA decisions, cross-border payments, the inclusion of costs in tariffs and the evaluation of impacts on network tariffs.

[96] Luxembourg and Lithuania to continue cooperating in the field of renewable energy | Ministry of Energy of the Republic of Lithuania (lrv.lt)
[97] Luxembourg and Denmark have concluded a cooperation agreement to accelerate the energy transition - Claude TURMES // The Luxembourg Government (gouvernement.lu)
[98] About the platform | Union Renewable Development Platform (europa.eu)
[99] Guidance_for_member_states_to_conclude_statistical_transfers_final.pdf (europa.eu)
[100] https://tyndp.entsoe.eu/about-the-tyndp
[101] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2022/IG/220304_TYNDP2022-Implementation-Guidelines.pdf
[102] ENTSO-E (2023) 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects - Version 4.1 for ACER/EC/MS opinion
[103] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/CBA/210322_3rd_ENTSO-E_CBA_Guidelines.pdf
[104] https://documents.acer.europa.eu/en/Gas/Infrastructure_development/CBCA-decisions

The Connecting Europe Facility funds for PCIs, PMIs and cross-border RES

The Connecting Europe Facility (CEF) is a key funding instrument for targeted cross-border investments at the EU level focusing on transport, energy and digital infrastructure as well as renewable energy generation. Concerning energy infrastructure, eleven priority corridors and three priority thematic areas have been identified for intervention in the revised TEN-E framework. CEF for Energy (CEF-E) is an important instrument that supports the establishment of trans-European energy networks by financially contributing to certain PCIs and PMIs that fulfil specific criteria.

Under the revised CEF Regulation, the mechanism also lists and supports **cross-border renewable energy projects,** aiming to enable Member States to reach their RES targets and ensure the cost-effective deployment of renewables in the Union, using the cooperation mechanisms mentioned above.[105] The cross-border projects are assessed following the Commission's 2021 methodology for conducting CBAs[106] before they can apply for CEF funding. At present, one offshore wind energy project (ELWIND – Estonian-Latvian joint offshore wind project) was included in the list of selected cross-border projects in the field of renewable energy in 2022[107] and another one (SLOWP – Saare-Liivi Offshore Wind Park) in 2023.[108]

The Union Renewable Energy Financing Mechanism (REFM)

Stemming from article 33 of the Governance Regulation (EU) 2018/1999,[109] the REFM has been in force since September 2020. It links countries that voluntarily pay into the mechanism (called **contributing countries**) with countries that agree to have new projects built on their territory (**hosting countries**).

Via this mechanism, contributing countries can finance renewable energy projects elsewhere that are potentially more cost effective than building them on their own territory. For example, for landlocked Member States, offshore wind energy farms can represent an opportunity to cost-efficiently reach their RES targets.[110]

State aid rules do not apply to either of the participating parties in the mechanism, and there is no direct link or negotiation between contributing and hosting countries.

4.3. Overall CBA and CBCA process for cross-border offshore projects

This section provides recommendations on how to conduct the overall CBA and CBCA process for specific cross-border offshore energy projects. It thus indicates how the project-specific CBA and CBCA are linked, as well as to what are the responsibilities of each national party. The following sections then provide recommendations on the specific elements relevant to project-specific CBAs (section 4.4) and CBCAs (section 4.5).

Overview of relevant legislation and procedures

For electricity transmission PCIs, including offshore, the process and responsibilities for conducting CBAs and agreeing on CBCA decisions are defined in article 16 of the revised TEN-E Regulation. For cross-border projects in the field of renewable energy, the requirements for conducting CBAs as well as the process for applying for CEF funding are specific in the revised CEF Regulation as well as the associated Commission Delegated Regulation (EU) 2022/342.[111]

Furthermore, existing legislation and procedures regarding the allocation rule are relevant for this section. ACER recommendation 05/2015 is the main document in this regard, covering the allocation of the costs of electricity and gas PCI categories of the original TEN-E Regulation:

- ACER recommends that the allocation of costs should be such that it compensates the net negative impacts in the relevant Member States;

[105] EUR-Lex - 32022R0342 - EN - EUR-Lex (europa.eu)
[106] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF
[107] EUR-Lex - 32022R2202 - EN - EUR-Lex (europa.eu)
[108] https://cinea.ec.europa.eu/news-events/news/cef-energy-two-new-projects-obtain-status-join-cb-res-list-2023-09-19_en
[109] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2018.328.01.0001.01.ENG
[110] https://energy.ec.europa.eu/topics/renewable-energy/financing/eu-renewable-energy-financing-mechanism_en
[111] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32022R0342&qid=1686302962376

- Further reallocation going beyond the compensation of net negative impacts may be done in order to account for the uncertainties or due to significant differences in the net impacts between the relevant Member States;
- ACER indicates 100% of the efficiently-incurred costs should be allocated.

Why does the issue matter?

The calculation and allocation of costs and benefits is naturally the focus of the CBA/CBCA process, with the ultimate objective of allocating costs to hosting and when relevant non-hosting Member States in such a manner as to enable the development of an offshore renewable energy and/or transmission project which would otherwise not take place. Main reasons for a project not taking placing otherwise are the existence of one or more hosting Member States experiencing a net negative impact in the absence of a cost allocation agreement, or perceiving the net benefits distribution to be unfair in some way.

Furthermore, in the case of statistical transfers of renewable energy between Member States, the agreement for the benefitting Member State to pay the hosting Member State amounts to an allocation of (part of) the costs of the project. The overall allocation of costs for projects which include renewable energy generation is thus intrinsically linked to any statistical transfer.

Also, joint offshore wind with hybrid transmission and other projects requiring cross-border cooperation between Member States impact distribution of specific socio-economic welfare components in a number of ways:

- Member States with a low electricity supply capacity margin compared to their actual and future demand levels or an expensive electricity supply structure may perceive a higher share of the consumer surplus arising from the cross-border cooperation. Thus, consumers from some of the hosting Member States may perceive a lower surplus compared to a counterfactual scenario where wind energy would be connected via radial cables;
- The cross-border cooperation will also have an impact on the producer surpluses – both that of the new offshore energy producers as well as of existing producers;
- Also, depending on the dimensioning of the offshore (and onshore) transmission system, congestion may more frequently occur in certain assets and thus a higher congestion income would be allocated to certain TSOs or group of TSOs. The cross-border projects may also affect the congestion income perceived by already-existing assets and their operators;
- Member States should take cost allocation decisions based on the total SEW per country, regardless of whether this is due to changes in consumer surplus, producer surplus or congestion incomes, although each of these components may have different uncertainties associated to them (for example congestion incomes will vary depending on the market conditions and the offshore transmission system configuration).

Hence, an agreement on the cross-border allocation of network costs (and if appropriate congestion incomes) will often be necessary for offshore projects, especially for hybrid transmission due to their complex configuration and dual purpose of the offshore infrastructure.

Recommendations on the issue

The present recommendations are mainly targeted to cross-border infrastructure projects where several TSOs and Member States are involved. The allocation guidance should:

- Define clearly and agree bilaterally, early in the discussions, which assets are considered as part of the cross-border project and, if relevant, which are excluded from it and considered instead national assets (e.g. assets included in the RAB that a MS decides to explicitly exclude from the cross-border project);
- Cover all relevant costs and benefits components that can be allocated so that the cost allocation agreement covers 100% of the relevant costs as well as the relevant congestion income;
- Present the possible allocation rules to be used and in which cases they are appropriate;
- Account for the stages of development of the offshore generation and transmission projects;
- Indicate the role of the different stakeholders in the process.

The CBA and CBCA process described below are based on a clear separation of roles between the main stakeholders (national governments, TSOs and ENTSO-E, NRAs, ACER and offshore energy project developers). Overall, we recommend that NRAs, who have a decisive role in agreeing on the conditions for specific infrastructure projects, and are in charge of negotiations thereof, are involved in approving project-wide (both generation and transmission) CBA assumptions as well as provide inputs to its results. National governments (ministries or other designated authorities) should be responsible for the overall maritime spatial planning, defining (cross-border) offshore renewable energy targets and conducting the necessary processes to enable the offshore renewable energy projects, such as tenders and permitting procedures, as well as eventual statistical transfers. TSOs should be responsible for conducting CBAs in accordance with the indications from NRAs and developing the offshore transmission infrastructure. Regulatory authorities should advise ministries, ENTSO-E and national TSOs.

We recommend allocating costs proportionally to the net positive impacts in case all hosting Member States experience net positive impacts, and to compensate any net negative impacts otherwise. That is, an allocation of costs proportional to benefits is preferred to e.g. a 50/50 rule (or to a division based on the physical location of the infrastructure) in case of net positive benefits. Member States and their competent authorities would still be free to opt for a 50/50 or other allocation rule if they chose to.

The recommended governance and costs/benefits allocation process is described next:

Cost-benefit analysis process

1. Ministries of the hosting Member States agree on the scope of cooperation through a memorandum of understanding defining:
    - Renewable energy areas to develop (offshore but also onshore if the Member States so agree), including indicative capacity and location;
    - Preferred form of development of offshore renewable energy projects and cross-border cooperation (national initiative, joint project, joint support mechanism, statistical transfer);
    - In case of cooperation in renewable energy (joint project, joint support mechanism, or statistical transfer), the high-level terms for sharing costs - that is, the cost allocation rule(s) to be considered - and the allocation of the renewable energy shares.
2. Hosting TSOs (under the mandate of the national governments) establish an MoU, submitting those to their respective NRAs for comment or approval.
3. NRAs of the hosting Member States jointly agree on/approve the assumptions to be considered jointly by TSOs such as the set of scenarios to be considered including the joint scenarios established for the Union-wide TYNDP and, only when deemed necessary, a limited number of additional scenarios consistent with the Union renewable targets and climate objective, with the same level of consultation and scrutiny, and assessed by ACER in accordance with article 16 of the TEN-E Regulation. A lack of agreement between NRAs on assumptions, sensitivities or an unlimited number of scenarios, especially if unilaterally proposed, may risk making following negotiations much more complicated.
4. TSOs provide a joint cost-benefit analysis for the overall project (generation + transmission). TSOs should consider the parameters defined in the inter-governmental MoU, particularly offshore wind energy capacity, different transmission configurations and differentiating the generation and transmission benefits following the CBA recommendations described in section 4.4.3. The transmission part should be consistent with the ENTSO-E CBA methodology pursuant to article 11 of the TEN-E Regulation. NRAs should be responsible for approving the inputs and assumptions to the CBA, as well as the CBA results.

Cross-border cost allocation process - generation

5. Ministries allocate any public support costs for joint projects or joint support mechanisms between Member States, proportionally to the changes in SEW ascribed to the generation assets (ΔG). The process for calculating ΔG is presented in section 4.4.3. Renewable energy

shares are allocated through statistical transfers according to the allocation of public support costs, unless otherwise agreed by Member States.

6. Further statistical transfers of renewable energy shares may be negotiated besides this original allocation. This should not be considered in the allocation of the transmission costs and congestion incomes.

7. Ministries (or their designated authorities) conduct the tenders or other processes for awarding the development of the offshore energy areas.

Cross-border cost allocation process - transmission

8. NRAs allocate the transmission costs (and if needed congestion incomes, see below) between TSOs proportionally to the changes in SEW ascribed to the transmission assets (ΔT). The process for calculating ΔT is presented in section 4.4.3. That is, NRAs should allocate costs proportionally to the benefits that are assigned to transmission infrastructure.

9. The ΔT should complement the ΔG allocated by Ministries within their cross-border cooperation on renewable energy in step 4. $\Delta G + \Delta T$ should be equal to the SEW change ΔP of the entire project as detailed in section 4.4.

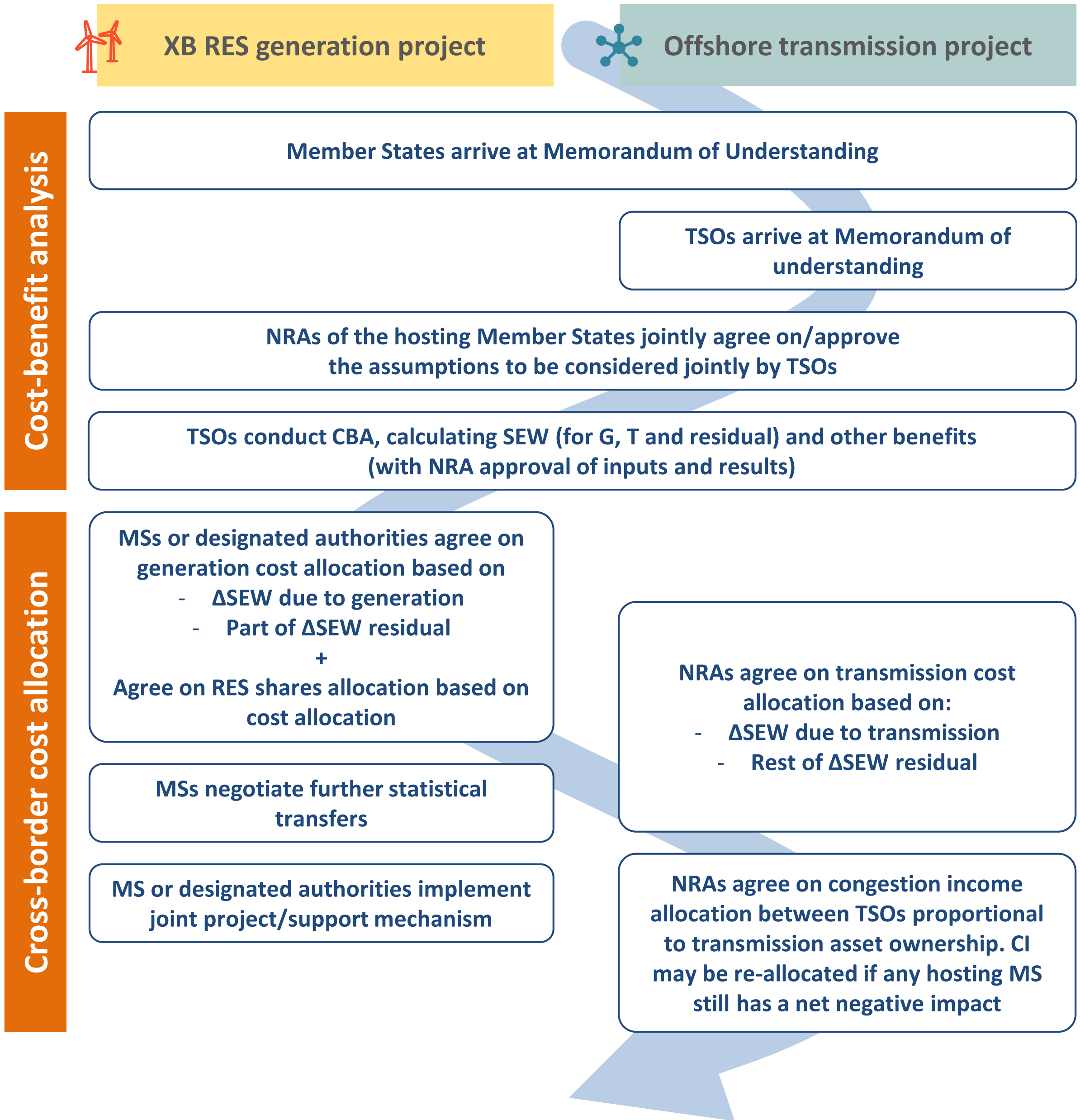
Note that the process for cross-border cost allocation of generation on one hand (steps 5-7) and transmission on the other (steps 8-9) can largely be conducted in parallel. The generation CBCA process is illustrated as starting first in the picture because we propose to first allocate the socio-economic welfare of the overall project first to the generation assets, and then the remainder to transmission assets (as detailed in section 4.4.3).

Inclusion of hydrogen infrastructure in the CBA and CBCA

As indicated in chapter 1, this study focuses on electricity infrastructure projects, and thus does not address in detail hydrogen infrastructure nor its potential inclusion in the cost-benefit analysis or cost sharing/allocation at sea-basin and project levels.

Nonetheless, Member States and their parties could opt for the inclusion of hydrogen infrastructure in the cost-benefit analysis of specific projects, as well as agree on the allocation of costs for nay offshore hydrogen infrastructure. While in this case further analysis would be needed to define the overall CBA and CBCA process, the principles presented above would remain valid: a joint CBA for the entire offshore project (including offshore renewable energy generation as well as electricity and hydrogen infrastructure) could be concluded, including the disaggregation of the join impact on socio-economic welfare between offshore energy generation and infrastructure assets. Afterwards, Member States or designated authorities could agree first on the allocation of costs and benefits of offshore generation, and then on the allocation for offshore infrastructure (electricity and hydrogen, either separately or jointly).

Figure 4-3 Overall process CBA and CBCA process for cross-border offshore energy projects



4.4. Coordination of offshore generation and infrastructure CBAs

4.4.1. Definition of scenarios

Although the societal and financial impacts of an energy generation or transmission project will always carry uncertainty, scenarios help depicting potential supply and demand forecasts and energy exchange patterns, and ensure that main uncertainties in future energy (and economic) developments are addressed and accounted for, as well as ensuring that projects are evaluated against adequate assumptions (as opposed to overly optimistic or pessimistic ones) that are aligned with energy and climate policy targets.[112] The chosen set of scenarios thus all need to be considered in the investment decision and CBCA agreement, as they all describe a plausible framework within which future project developments are possible to occur, and thus can have an impact on the actual costs and benefits of the project. These scenarios may be complemented by sensitivity analyses to understand the influence of deviations from the inputs and assumptions of the scenarios.

[112] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF

Overview of relevant legislation and procedures

Electricity generation CBA	Transmission infrastructure CBA
The Commission XB RES Guidance[113] recommends the EU Reference Scenario which is prepared by the Commission, as the benchmark for use in generation CBAs. The Reference Scenario shows the fundamental socio-economic and technological developments and current policies in the EU. This should guarantee reflecting the existing policy framework in the EU. This reference scenario needs to respect two boundary conditions: the 1) time horizon, and the 2) discount rate. **Time horizon**: The minimum time horizon to be considered by project promoters is 15 years, starting with the first year of operation of the project. **Discounting**: A social discount rate of 4% is used as per the CEF regulation.	Joint scenarios are published by ENTSO-E together with ENTSOG every 2 years after Commission approval[114]. Concerning electricity transmission projects, the scenarios are employed for the CBA within the TYNDP as well as for electricity transmission PCIs and PMIs. As per the TYNDP CBA guideline 3.0[115] and proposed 4.0 revision[116], these scenarios apply to the EU level (they can be adapted to regional level) and must reflect both EU and national legislation, including NECPs and energy efficiency targets as set out in the EED. Different time horizons distinguish the different scenarios: 1) the mid-term horizon is 5-10 years, 2) the long-term horizon is typically 10-20 years, and the 3) very long-term scenarios cover 30-40 years.

Why does the issue matter?

In today's changing energy landscape, to cope with multiple possible visions for the future energy system, scenarios used in CBA exercises need to be diverse:

- Scenarios should reflect different supply and demand values depending on the latest political agreements within and between countries (e.g. in ONDPs) and available projections on energy system development in different time horizons, impacted by the maturity of projects or planned later extensions of capacities;
- Scenarios thus represent the main uncertainties surrounding future energy system developments;
- The choice of scenarios ultimately impact space requirements, price, and benefits associated with generation or transmission projects.

At the same time, the use of a different set of scenarios significantly compromises the comparability of CBA results. In case of projects with hybrid transmission, given non-harmonisation of generation and transmission CBAs, various aspects can directly impact results:

- **Time horizons**: for example TYNDP runs 3 different time horizons, the longest to 2050, while the CBA of CEF XB RES projects should be of at least 15 years;
- It is important to reflect the appropriate technological lifetimes of energy assets to ensure that the long-term net societal benefits are correctly estimated;
- **Social discount rates** can differ between generation and transmission CBAs. A standard (real) rate of 4% should be applied for the CBAs according to the ENTSO-E CBA guidance 4.0 and the Commission XB RES project guidance. The social discount rate assigns a present value on the future costs and benefits of policies and projects with intended societal benefit, with indicating the degree to which the future is 'discounted' in comparison to present action.

Recommendation on how to harmonise

A number of aspects related to the CBA scenarios could be harmonised, namely:

[113] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF p13
[114] https://2022.entsos-tyndp-scenarios.eu/
[115] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/CBA/221019-3rd%20CBA_Guidelines%20.pdf
[116] ENTSO-E (2023) 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects - Version 4.1 for ACER/EC/MS opinion

- The **same set of scenarios** should be used. It is recommended to utilise only the TYNDP joint scenarios, which have been reviewed by regulatory authorities and the Commission, and limiting the negotiations to a reduced set of cases confirmed to be consistent with EU renewable and climate policy. Increasing substantially the number of scenarios may make the negotiations harder. While diverging is not advisable, if for any reason it was necessary, at least minimum aspects on the sets of scenarios employed should be harmonised, for example regarding RES deployment, other supply and demand development and expected cross-border power exchanges. The TYNDP could provide a good basis, particularly taking into account ACER's recommendations.[117]
- In addition to supply and demand, other assumptions and non-scenario parameters which affect the economic results of CBAs could be adopted[118], including:
    - Valuation of the cost of carbon;
    - Valuation of non-GHG emissions (e.g. nitrogen oxides, sulphur oxides, particulate matter);
    - Value of lost load.
- Scenarios may include sensitivities for development of offshore grid (e.g. further new interconnectors) as well as include modelling projections for future climate patterns.[119]
- Use **same final and intermediate time horizons** for estimating project benefits and costs, with clear-cut benchmarks (e.g. every decennium). They should encompass minimum 15 years and cover the 2030, 2035 and 2040 horizons[120], but beyond which the horizon should reflect on the technological and economic lifetime of assets.
- Continuously update assumptions on the **reference grid[121]** and EU as well as MS climate and energy targets that will directly impact the supply and demand scenarios, reflecting NECPs, offshore renewable energy ambitions and others.

4.4.2. Bidding zone configuration

Overview of relevant legislation and procedures

The question of bidding zone configuration, particularly the choice between the home market (HM) versus offshore bidding zone (OBZ), has already been introduced in chapter 3 as well as in section 4.2. The Commission as well as ENTSO-E recommend the use of OBZs for hybrid transmission projects in the actual market design as well as the CBA.

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[117] See for example ACER's opinion on the Draft TYNDP 2022 Scenario Report

[118] ACER's (2022) position paper on greater consistency of CBA methodologies https://www.acer.europa.eu/Position%20Papers/ACER_Consistency%20of%20CBA%20methodologies.pdf

[119] EEA (2021) Advice on an EU energy system-wide CBA https://www.eea.europa.eu/about-us/climate-advisory-board/advice-on-a-harmonised-eu/view

[120] As developments in 2050 are inherently subject to great uncertainty, we do not recommend using the very-long trajectories as they are of limited usability for the purpose of network planning and project assessment.

[121] The reference grid represents the future electricity grid (including offshore networks), including the most probable projects at the time of calculation compared to the current grid setup

Table 4-2 Overview of relevant legislation and procedures for the bidding zone configuration

Electricity generation CBA	Transmission infrastructure CBA
The Commission guidance on electricity market arrangements[122] recommends the use of OBZs due to its higher overall efficiency compared to a HM configuration and compatibility with the existing electricity market design, particularly the 70% rule. ACER and CEER reflection on the EU Strategy on Offshore Renewable Strategy[123] supports the Commission's proposal to integrate offshore renewable energy through OBZs. They note, however, that under the current market design offshore generators in OBZs are at a disadvantage vis-à-vis onshore generators or those offshore but located in a HM zone. This is due to the fact that the intraday cross-border gate closure time (GCT) is 1 hour before delivery, while the GCT for intra-zonal trades is frequently closer to delivery.[124] This allows offshore generators to adjust their imbalances closer to real time in the ID market, while generators in OBZ have to rely on balancing markets after the cross-zonal GCT. It should be noted that since the ACER-CEER reflection, this aspect would be addressed if the Commission's proposal for an Electricity Market Design revision is agreed by co-legislators.	ENTSO-E guideline for CBA guidance and Implementation Guidelines recommend the use of an offshore bidding zone configuration for the assessment of all hybrid transmission projects within the TYNDP process. There should be no "internal bottlenecks" within each individual OBZ. Radial wind farms which evolve into a hybrid transmission project should also employ an OBZ in the assessment.

Why does the issue matter?

The choice of BZ configuration is crucial for a number of aspects related to conducting the CBA of offshore projects as well as agreeing on the allocation of costs and benefits. More specifically:

- **The choice of bidding zone configuration affects the allocation of benefits:** As indicated in chapter 3, the use of a HM or OBZ will not lead to significant differences in the total socio-economic welfare, except in the case of curtailment of offshore wind generation due to congestion. However, the bidding zone configuration influences the distribution of benefits between countries and the SEW components (consumer and producer surpluses, congestion income). Differences in the distribution of SEW between countries particularly can affect the CBCA decisions (as Member States or regulators should consider the total SEW changes to their countries in order to allocate costs – and not the changes to individual SEW components such as consumer surplus).
- **The bidding zone configuration at the time of commissioning the project may differ from the one employed in the CBA:** Member States or their designated competent authorities may decide to employ a HM or OBZ configuration for offshore wind farms located in their EEZ. The CBA of the generation and transmission assets may or may not employ the same bidding zone configuration that will be actually used. That is, OBZs could be used for conducting the CBA while the Member State(s) may nonetheless decide to employ a HM configuration at the time of commissioning the project.
- **Defining counterfactuals also involves a choice of BZ configuration:** Some guidance is also necessary for the definition of bidding zones in the counterfactual. Stakeholders have different opinions on whether offshore bidding zones should be employed in the counterfactual or not. Stakeholders have also proposed to separate a hybrid offshore network into multiple BZs in case of internal congestion.

[122] Commission SWD/2020/273 final. Guidance on electricity market arrangements: A future-proof market design for offshore renewable hybrid projects.
[123] ACER and CEER (2022) Reflection on the EU Strategy to Harness the Potential of Offshore Renewable Energy for a Climate Neutral Future
[124] See section 8 of https://www.epexspot.com/sites/default/files/2021-05/SIDC_Information%20Package_April%202021-99076f6ed5001c4d47442ae5cccebf30.pdf

- **As the offshore energy systems becomes more meshed, the bidding zone configuration may change:** The BZ configuration may change, for example, if an existing radially-connected wind farm is then also connected through a 2nd transmission asset to another country. Onshore developments may also warrant a reconfiguration of bidding zones. Hence, the uncertainty regarding the BZ configuration should be accounted for as much as possible in the configuration used for the CBA.

Recommendations on the issue the bidding zone configuration

A suitable choice of bidding zone configuration for the CBA of generation and transmission assets should:

- Provide comparable results for both generation and transmission CBAs, that is, no matter the choice of the BZ configuration in both CBAs, the results regarding the distribution of the SEW per country and component (consumer and producer surpluses, congestion incomes) should be meaningful. In practice this will be difficult to achieve with different BZ configurations for the generation and transmission CBAs, leading to the recommendations below.
- Reflect the expected actual distribution of costs and benefits between countries as far as possible, while avoiding high complexity. As discussed above, there may exist uncertainties regarding which BZ configuration may actually be used in practice (even if OBZ are clearly recommended), and the configuration may change as the offshore system develops.

Therefore, based on this a number of recommendations can be made on the choice of the bidding zone configuration for conducting the CBA of offshore generation and transmission assets:

- **Future projects with hybrid transmission should preferentially employ an offshore bidding zone configuration,** both for the CBA as well as in reality, in line with the Commission and ENTSO-E recommendations. The resolution of any remaining barriers for the use of OBZs are out of scope of this section.
- **The same bidding zone configuration for the offshore system should be used for both the generation and transmission CBAs.** If a wind farm is assessed under a HM configuration for allocating the costs of the generation assets, the transmission CBA should employ the same configuration. Otherwise, results would not be comparable and thus rendered meaningless for arriving at an agreement on how to allocate the costs and benefits. For recommendations on how to define the counterfactual so that results are not only comparable but do not overlap (i.e. so there is no double-counting), see section 4.4.3;
- **The actual expected bidding zone configuration should be used for the CBA as far as possible**. That is, if it is known a certain wind farm will be included in a home market BZ (although as mentioned above this is not the recommended approach), the CBA should reflect this. If the configuration is not known or could not be agreed between involved parties at the moment of conducting the CBA, an OBZ should be used as default. It is nevertheless advisable to strive at making a firm decision on the bidding zone arrangement for a concrete project before initiating CBA and CBCA discussions. Moreover, to increase resilience in the process and minimise uncertainty to developers, radial projects that ONDPs indicate are likely to become part of a meshed network may benefit from establishing the BZ configuration as an OBZ directly from its start.
- **ENTSO-E's reduced NTC methodology is adequate to represent congestions** on the home market leg of the interconnector, in case a wind farm is assessed under the home market configuration.

4.4.3. Counterfactual definition

Overview of relevant legislation and procedures

As indicated in the analysis of chapter 3, indicators in a cost-benefit analysis are calculated by comparing the situation with the project to be assessed (the factual) against the situation where the project would not be developed (the counterfactual). Hence, a counterfactual needs to be defined when conducting CBAs in order to estimate the contribution of the (cross-border) project to socio-economic welfare as well as other indicators. As such, existing CBA methodologies relevant for the present guideline already provide guidance on the definition of counterfactuals.

The most important guidance documents and their approach to defining counterfactuals are introduced below.

Table 4-3 Overview of relevant legislation and procedures for the definition of counterfactuals

Electricity generation CBA	Transmission infrastructure CBA
The Commission's XB RES CBA Guidelines introduces standardised and case-specific counterfactuals: for the standardised case, the project is compared with a scenario where the same project (regarding its size and technological features) is built in the contributing Member State, compared to the host Member State. The standard counterfactual may not always serve/suit the concept of a specific project (e.g. if the cooperation is based on a joint support scheme), and thus may not allow for a good comparison. In these cases, the project developers can apply a case-specific counterfactual that is sufficiently justified. This counterfactual could be another project that contributes to RES target achievements, subject to the condition that it has to include RES deployment, therefore a counterfactual with a fossil fuel technology is not acceptable.[125] The counterfactual project may deploy a different technology or may have different project set-up of cross-border cooperation. In case of a joint support scheme, the counterfactual can be that the project does not happen at all.	ENTSO-E's guideline for CBA analysis 3.0 and 4.0 and CBA Implementation Guidelines set out how to calculate socio-economic welfare benefits in TYNDPs of hybrid transmission projects where both the offshore wind and transmission assets are developed simultaneously. The counterfactual proposed by ENTSO-E for the assessment of the costs and benefits of the transmission project is the hybrid project not happening at all. This means the delta in socio-economic welfare of the factual and counterfactual represents the entire net benefits of the hybrid project.[126] For this reason, the Implementation Guidelines indicate the producer surplus of the offshore wind farm should be subtracted from the SEW delta calculated, as a proxy for the costs of the offshore wind farm.

Why does the issue matter?

The definition of an appropriate counterfactual requires balancing a number of needs. The counterfactual should be realistic and illustrate a credible pathway for development of the system in case the project under assessment would not be developed. At the same time, the methodology to define a counterfactual should not be too complex and allow the assessment of the contributions of the factual.

A number of aspects of existing CBA guidelines/methodologies for the assessment of TYNDP/PCI candidates and cross-border RES projects could make the CBA of projects with hybrid transmission more difficult:

- **The existing guidelines/methodologies use different counterfactuals for renewable energy generation and for offshore transmission** (as shown above), with the CBA of XB RES projects including standard or case-specific generation projects as counterfactuals, while TYNDP project-specific CBAs do not include any electricity generation as counterfactual (when the generation assets are new and developed as part of the hybrid project in the so-called CBA option 2 of the CBA 3.0 Implementation Guidelines). This is driven among others because the XB RES methodology aims to assess the benefits of cross-border cooperation, while the TYNDP CBA methodology aims to assess the overall societal benefits of a project – regardless of whether it is a hybrid transmission project or not.
- **The TYNDP project-specific CBA methodology may include benefits which could be allocated to the generation assets**. In the CBA 3.0 Implementation Guidelines, the producer surplus of the offshore wind farm is removed from the EU-wide socio-economic welfare, "as a proxy to warrant the required RES investment".[127] However, the connection of offshore generation through a hybrid transmission project also leads to consumer surpluses, which are thus in this methodology fully allocated to the transmission project, while they could be partly allocated to the generation asset. In a few specific cases, this

[125] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF
[126] ENTSO-E (2022) 3rd ENTSO-E guideline for cost benefit analysis of grid development projects
[127] ENTSO-E (2023) Guidelines for TYNDP 2022 based on 3rd ENTSO-E guideline for cost benefit analysis of grid development projects - July 2022

could also overestimate the contributions of the offshore wind project and underestimate that of the transmission assets.

- **Conversely, the XB RES CBA methodology could include costs and benefits which pertain to the transmission assets.** The CBA for XB RES projects should follow the Commission methodologies specified in SWD(2021) 429, and thus include an indicator on system integration costs, which comprises profile, balancing and grid-related costs. Therefore, the costs for the transmission assets of a hybrid transmission project could be incorrectly considered in the XB RES CBA (although not any benefits from such assets, apart from reduced system integration costs for the offshore wind energy generation).
- **The XB RES CBA methodology does not require the calculation of changes (delta) in socio-economic welfare**. Instead, it calculates the societal NPV of the project and its counterfactual based on the LCOE as well as other components, namely system integration costs, GHG emissions, security of energy supply, and air and local pollution. Costs of support and innovation are also assessed but not included in the NPV calculations. However, the changes in socio-economic welfare of the European energy system do not need to be calculated (and hence energy systems modelling is not actually required to develop the CBA).
- **Another reason for why the methods are not fully comparable is because there are differences in reference grid assumptions.** The reference network in TYNDPs comprises of the existing grid plus the projects that *are expected* to be implemented. The latter is defined by looking at the proof of maturity[128] of projects. The Commission XB RES Guidelines do not provide guidance on the reference grid assumptions.

Thus, the current lack of harmonisation impacts benefits, and using current CBA guidance would likely not be sufficient for properly evaluating offshore renewable projects connected via hybrid transmission, where the interconnection of markets plays a fundamental role. The resulting benefits in terms of socio-economic welfare (SEW) would have overlaps if the SEW was calculated for XB RES projects (which it is not, as only the net present value (NPV) is calculated) and not be directly comparable due to differences in assumptions such as the reference grid. **There exists a risk for lack of coordinated counterfactuals** which reduce comparability and increase the overlapping of CBA results.

This does not mean that the existing methodologies and guidelines are unsuited for the purposes they were originally created, but reflects the fact that their original purposes were to assess the costs and benefits of only transmission assets (in the case of the ENTSO-E CBA methodology and Implementation Guidelines) and the benefits of cross-border cooperation for XB RES projects (in the case of the Commission XB CBA Guidelines).

In any case, regulators and project promoters have flexibility in which inputs and methods they use for allocating the costs and benefits of the generation projects. The methodologies established in the Commission XB CBA Guidelines and ENTSO-E guideline for CBA analysis 3.0 and 4.0 Guidelines should be followed in the respective processes (consideration for XB RES status for generation projects and inclusion in the TYNDP/consideration for PCI/PMI status for transmission projects) but do not restrict the cost allocation agreement. The TEN-E Regulation indicates this explicitly in its article 16(5): "In allocating costs across borders, the relevant national regulatory authorities, after consulting the TSOs concerned, shall seek a mutual agreement based on, **but not limited to**, the information specified in paragraphs 4, first subparagraph, points (a) and (b), of this Article" (our emphasis).

Recommendations on the issue the counterfactual definition of offshore wind energy generation and transmission assets

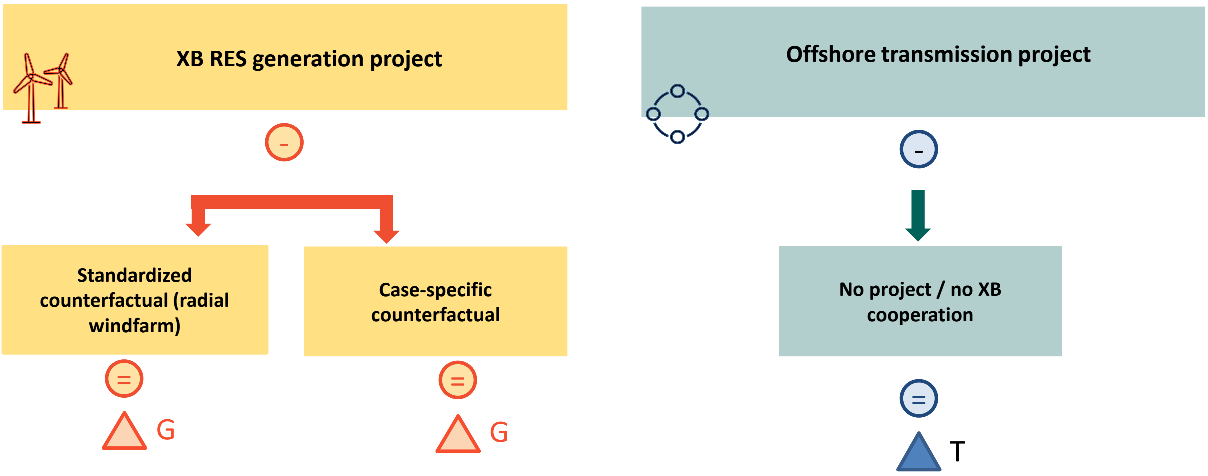
Based on the above we conclude that when allocating the costs of offshore generation and (hybrid) transmission projects, Member States and national regulatory authorities could employ additional information than that available from the application of the CBA methodologies/guidelines for XB RES and TYNDP/PCI projects in order to improve the allocation of costs and benefits of offshore renewable energy generation and transmission.

[128] A project can be included in the reference network when its capacity is available in the year that the simulation is applied for, thus its development status needs to be solid and commissioning date has to be certain - ENTSO-E CBA 3.0 Guidelines

When defining the counterfactual for the generation and transmission assets of such projects, a number of philosophies could be considered:

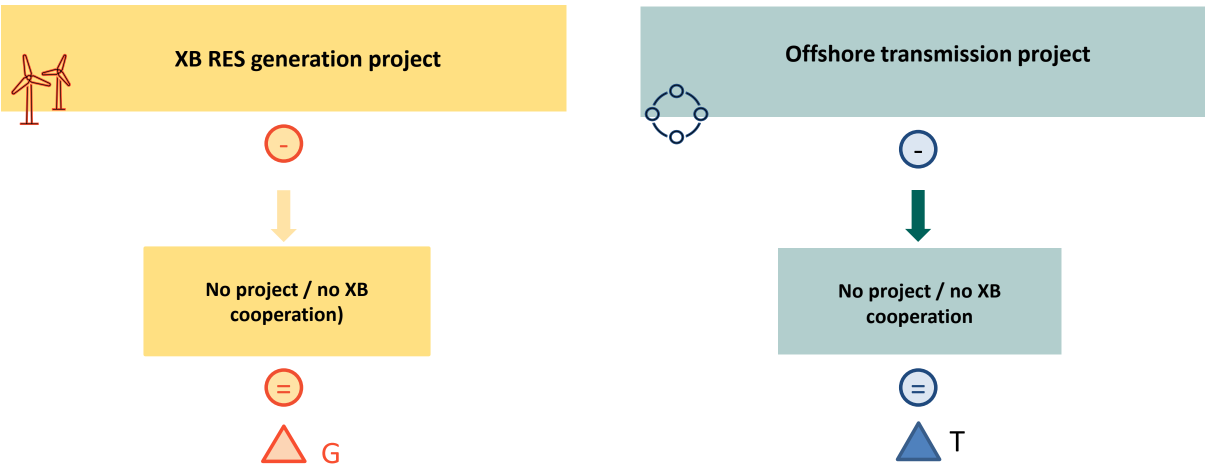
- **Philosophy 1: Keep the original counterfactuals for the generation and transmission assets**, e.g. in the case of a XB RES project analysis, the counterfactual would be a radial wind farm (if the standardised counterfactual were used), and for the transmission assets the counterfactual would be no project. But this would lead to overlapping and incomparable CBA results as discussed, and would be difficult to harmonise even with ex-post adjustments.

Figure 4-4 Philosophy 1 - Current XB RES (CEF) and transmission (TYNDP) counterfactuals



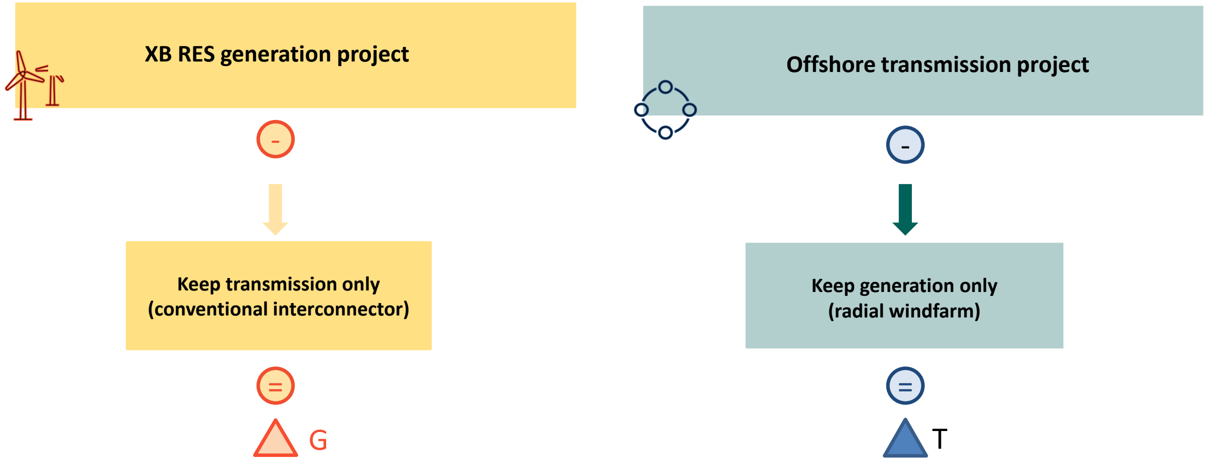
- **Philosophy 2: Use no project at all as the counterfactual for both the offshore generation and transmission CBAs.** This would lead to directly comparable CBA results (assuming that other assumptions such as the reference grid are the same). However, this would lead to significant overlapping of benefits. In the extreme case the net benefits for the generation and transmission CBA would be the same and equal to the benefits of the integrated project itself. Or, if some ex-post treatment took place (as in the current ENTSO-E CBA 3.0 implementation guidelines), misallocation between the benefits originating from the generation or transmission parts of the project would occur.

Figure 4-5 Philosophy 2 - No project as counterfactual (TYNDP)



- **Philosophy 3: Remove from the factual the relevant assets to be assessed.** That is, 1) the counterfactual for the offshore generation CBA would be a conventional interconnector, and 2) the counterfactual for the offshore transmission CBA would be a radial windfarm. This approach has the advantage that it would represent the 'pure' benefits of the generation and transmission assets respectively. However, the sum of the SEW deltas for the two CBAs would be different from the SEW benefits from the complete integrated project.

Figure 4-6 Philosophy 3 - Complementary counterfactuals



Thus, none of the methods above is fully suitable for allocating the costs and benefits of integrated projects between the generation and transmission parts without leading to double counting, under-estimation or misallocation of the total net benefits. A suitable CBA guideline should allow for:

- Cost allocation of transmission assets between TSOs (investment and if appropriate other costs), including effective utilization of all available cooperation and cost-sharing instruments;
- Allocation of subsidy costs for wind energy parks between Member States (if subsidies are needed), allowing for greater societal benefits;
- Allocation of RES output to national targets per MS (independently of physical flows), while avoiding double counting, to minimize the costs of reaching targets.

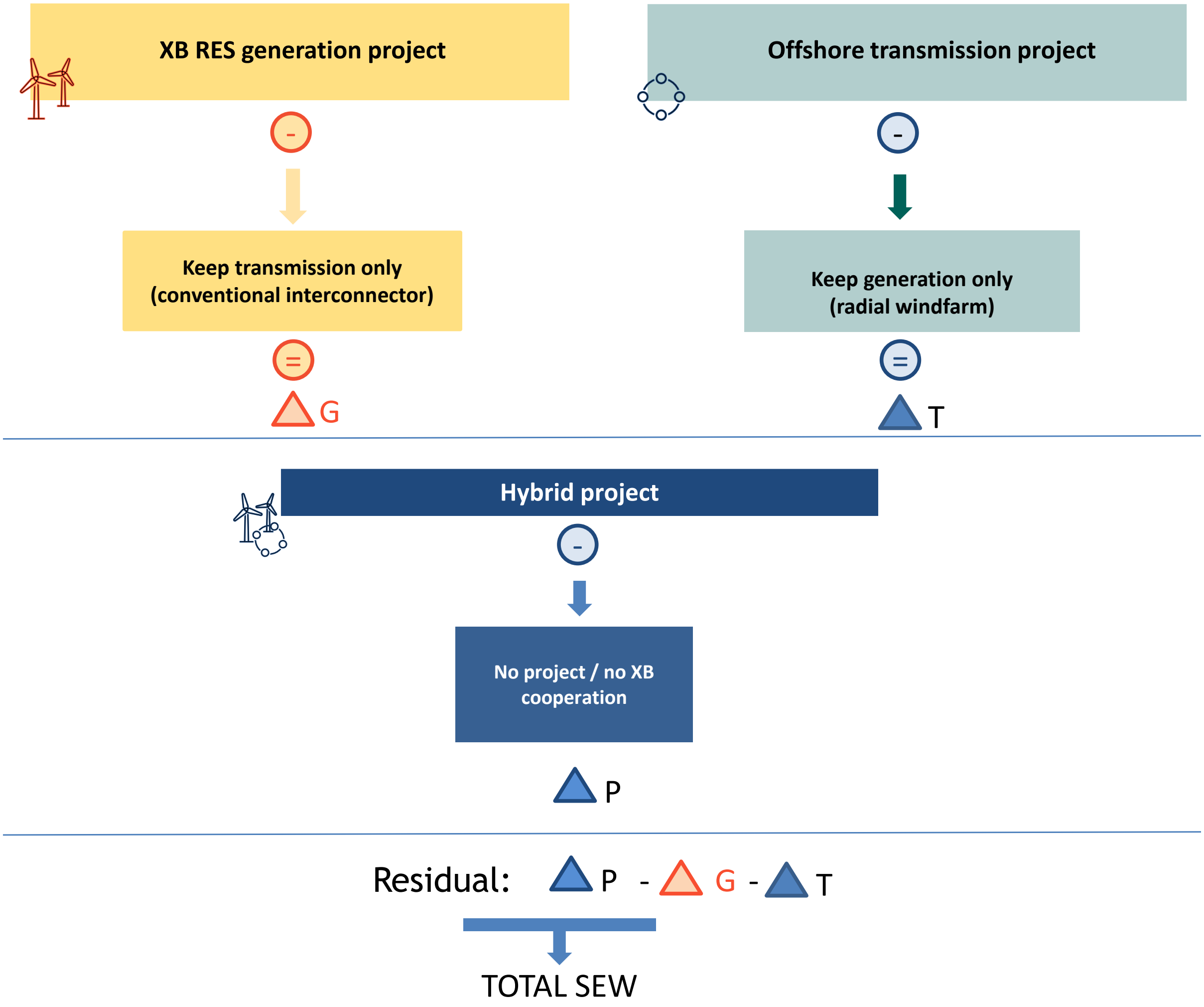
We therefore propose a **step-wise approach combining philosophies 3 and 2 above**, going beyond the mandatory (incomparable) CBA methodologies, by applying complementary counterfactuals and then allocating the residual benefits in order to match the net benefits of the whole integrated project. In other words:

a) Calculate separate 'pure' SEW changes due to the generation (ΔG) and transmission (ΔT) assets by defining counterfactuals as per philosophy 3 above;

b) Calculate the total SEW changes of the overall project against a counterfactual of no project (ΔP), as per philosophy 2 above. This SEW change should be higher than the sum ΔG + ΔT of the separate SEW changes calculated in a);

c) Allocate the residual difference ΔP - ΔG – ΔT between the generation and transmission assets, arriving at final adjusted ΔG and ΔT values. If Member States and regulatory authorities cannot arrive at a different allocation of the residual SEW changes, it can be fully allocated to the transmission assets.

Figure 4-7 Final (combined) approach



The approach described above is illustrated for a simple 'tie-in' hybrid with associated generation. Nonetheless, for more complex configurations, the same philosophy can be applied: individual CBAs for generation and transmission can be conducted with the counterfactual removing the assets to be assessed. This can then be complemented by a CBA of the whole integrated project and finally the residual SEW changes allocated.

The following calculation illustrates how one could arrive to the changes in SEW (based on hypothetical generation and transmission values) according to the above steps:

a) Original ΔG: 300 M€ (SEW change in price due to generation assets)

   Original ΔT: 500 M€ (SEW change in price due to transmission assets)

b) ΔP: Total SEW change in price of the project compared to no project (counterfactual) = 1000 M€

c) Residual SEW change to allocate = ΔP - ΔG - ΔT = 1000 M€ - 300 M€ - 500 M€ = 200 M€

An abstract representation of the recommended approach can be seen below:

Figure 4-8 Combined approach, step 1

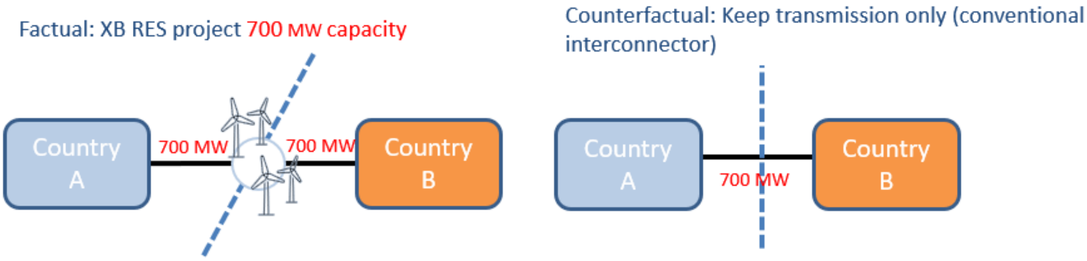


Figure 4-9 Combined approach, step 2

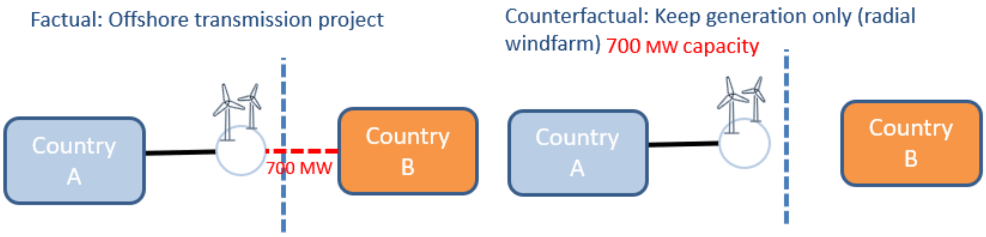
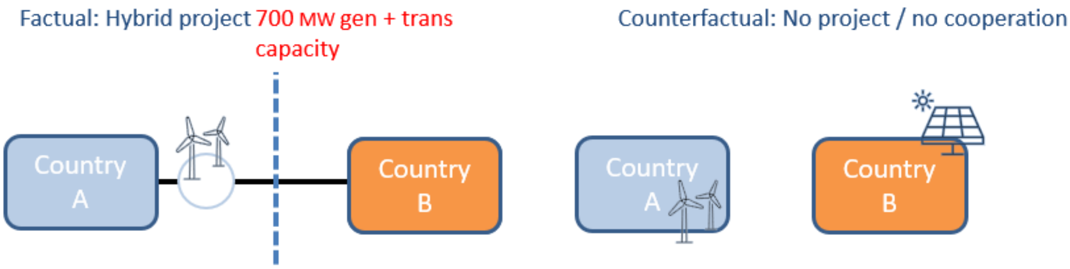


Figure 4-10 Combined approach, step 3



While reasonably simple, **the proposed approach** requires Member States, NRAs and TSOs to conduct additional CBA calculations to that required for the TYNDP or applying for PCI or XB RES project status. One must note nonetheless that usually additional analyses and scenarios which consider the specific project context are employed for arriving at cross-border cost allocation decisions anyway, and following this structured approach **can greatly reduce misunderstandings on the interpretation of socio-economic welfare impacts of the project**. Moreover, the results of the CBAs conducted for the TYNDP or XB RES status application can and should be used as complementary information.

Textbox 4-1 Simplified approach compatible with ENTSO-E's CBA methodology for calculating SEW changes

It is possible to **adapt the above approach to not require additional calculations beyond the current ENTSO-E CBA methodology and implementation guidelines**, if resource limitations exist. In this case, it suffices to set the SEW changes ΔG allocated to the offshore project as the offshore producer surplus calculated according to the ENTSO-E's instructions for offshore hybrid projects (option 2),[129] and allocate the remainder of the SEW changes to the offshore transmission assets as ΔT. For the reasons stated above this carries a risk of misestimating the SEW changes due to the offshore renewable energy generation assets, but is compatible with existing CBA processes.

Furthermore, we recommend harmonising other assumptions, such as the reference grid as discussed in section 4.4.1 in order to render comparable results: one reference transmission

[129] According to the CBA methodology 4.0 section 6.2.3.2, "the producer surplus can be calculated as the dispatched RES feed-in volume for all hours of the considered year, multiplied by the price the OWF gets, which is determined by the bidding zone in which it is

network should be used for both the XB RES and transmission projects assessments, as well as the counterfactual project assessment. This can follow the TYNDP method and can include proof of maturity (project only included if certain conditions are met) and cover the offshore as well as the onshore reference grid.

Our proposed approach thus keeps the generation and transmission CBAs as separate analyses, but with an additional step tries to arrive at an adequate total SEW for the overall project which is equal to the sum of the SEW allocated to the generation and transmission assets of the project. In the future, we recommend harmonising these approaches even more to arrive at the real societal benefits of integrated projects.

4.4.4. Key performance indicators (KPIs)

Overview of relevant legislation and procedures

Any CBA reports on certain indicators or key performance indicators (KPIs) to operationalise costs and benefits. The indicators used in the most important guidance documents for generation (XB CBCA) and infrastructure (ENTSO-E) CBAs are shown in Table 4-4.

Table 4-4 Indicators used in leading generation (XB RES) and infrastructure (ENTSO-E) guidance documents

Indicator (benefits and costs)	Generation CBA	Transmission infrastructure CBA
Social Economic Welfare (SEW)	**Not used**	**Used** – including priced emission savings
CO_2 emissions	**Used** - in tonnes/year and €/year	**Used** – in tonnes/year and €/year
RES integration	**Not used**	**Used** – in MW or MWh/year
Non-CO_2 emissions	**Used** - air pollutants in tonnes/year + €/year	**Used** - air pollutants in tonnes/year
Grid losses	**Not used**	**Used** - energy efficiency indicator in MWh/year
Adequacy	**Not used**	**Used** – ability to meet demand in MWh/year
Security of supply	**Used** – value of imported energy in €/year	**Used** – exists as flexibility + stability (non-mature, i.e. not quantified)
Redispatch reserves	**Not used**	**Used** – in €/year
Energy generation costs (EGC)	**Used** – using energy output + LCOE, €/year	**Not used**
CAPEX	**Used** – to calculate EGC in €/year	**Used** – in €/year
OPEX	**Used** – to calculate EGC in €/year	**Used** – in €/year
Grid related system integration costs	**Used** – in €/year	**Not used** specifically but covered under CAPEX and OPEX.
Support costs	**Used** – not quantified	**Not used**
LCOE	**Used**	**Not used**
Residual impacts	**Used** – Innovation, but not quantified	**Used** – residual environmental, social and other impacts, not quantified

The **Commission XB CBA guidelines** for generation projects include various indicators, some of which are used to calculate the project's net present value (NPV) compared to a counterfactual, other (qualitative) indicators are not used for the NPV calculation. The following indicators are taken

considered. This calculation can be done ex-post and, in the event the RES is connected to 2 or more bidding zones onshore in a separate bidding zone setup, then it will get the lowest price of all bidding zones to which it is linked."

into account for the NPV calculation: energy generation cost, grid related system integration costs, greenhouse gas emissions, security of supply, and air and local pollution:

- The **energy generation costs** are calculated using the annual expected electricity output (MWh) and the LCOE (constructed by the NPV of total costs and benefits).
- The **system integration costs** are the grid related costs, calculated using the grid related CAPEX (decommissioning, cable materials, cable construction, substation, wind park, grid extensions, and shunt reactors) and OPEX, profile costs, and balancing costs.
- The avoided **greenhouse gas** (GHG) **emissions** are calculated based on the RES production and a country specific emission factor. GHG emissions are monetised using the European Commission's values from the *Commission guidance on climate proofing of infrastructure.*
- The **security of supply** indicator is calculated using the energy imports reduction and the value of energy imports.

The indicators that are not used in the NPV calculation are innovation (as residual impact) and the cost of support. Innovation is not quantified.

The **ENTSO-E guideline for CBA 3.0 and CBA Implementation Guidelines**[130] for infrastructure uses a longer list of indicators, as shown in Table 4-4. In comparison with the CBA, we observe:

- In contrast to the XB CBA guidelines, ENTSO-E proposes a specific indicator for socio-economic welfare.
- Like the XB CBA guidelines, ENTSO-E also covers indicators for GHG emissions, non-CO_2 emissions (air pollutants), security of supply, project costs (CAPEX and OPEX) and residual impacts. However, for most indicators, the underlying parameters, methodology and/or units differ.
- For GHG emissions, ENTSO-E does not specify the values for monetisation. Moreover, the ENTSO-E guidelines only cover CO_2 emissions, rather than GHG emissions.
- For non-CO_2 emissions, ENTSO-E recommends reporting in tons/year (thus not monetising).
- For security of supply, ENTSO-E recommends different parameters and a qualitative reporting method.
- For project costs, there are many similarities. However, the project costs as per the ENTSO-E guidelines may overlap with the system integration costs from XB CBA
- For residual impacts, ENTSO-E considers a different set of indicators.

In addition to the Commission XB CBA guidelines and ENTSO-E guideline for CBA 3.0 and CBA Implementation Guidelines, the study on 'offshore electricity grid approaches in the Exclusive Economic Zone (EEZ)' for the German ministry of economic affairs and climate action provides relevant input on indicators to consider.[131] In their study, the researchers model the costs and benefits for different offshore grid configurations for connecting offshore wind turbines. They consider various KPIs, including: CO_2 emissions and the contribution to the energy transition, cost differences, (safe) operations of the offshore grid, cost savings in the offshore grid, spatial impacts, sustainability, security of supply, and coordination effort and feasibility.

Why does the issue matter?

The existing CBA guidelines/methodologies are not fully compatible for the assessment of projects combining offshore generation with hybrid transmission, while such projects can result in significant energy system costs savings. As shown above, the leading guidance documents for generation CBAs on the one hand and infrastructure CBAs on the other hand use different indicators in many cases. Moreover, in those cases in which the guidelines propose similar indicators, the methods for assessing indicators may differ. This is problematic as it may lead to incomparable CBAs, or even to double counting of costs or benefits.

[130] These observations also apply to ENTSO-E's guideline for CBA draft version 4.0
[131] https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/ansaetze-eines-offshore-stromnetzes-in-der-ausschliesslichen-wirtschaftszone-awz.pdf?__blob=publicationFile&v=10

Recommendations on the issue

A suitable CBA guideline should:

- Provide minimum requirements on indicators to allow for a simple and consistent framework to identify the potential benefits and complementarities of cross-border projects.
- Assure that any major impact is considered.

By nature, there are many differences between generation and infrastructure projects as well as between the objectives of the legislation supporting them, leading to similarities and differences between the leading guidance documents for both generation and infrastructure CBAs.

Against this background, the guidance on the indicators can be separated between non-quantified, quantified and monetised indicators:

- For those **indicators** that are **not quantified**, differences between indicators across projects are acceptable (as Member States have the option to consider them for the cost allocation in whatever manner they prefer).
- For those **indicators** that are **quantified**, but not monetised, we recommend harmonisation as these indicators can then be considered for cost allocation purposes. However, this is not strictly necessary.
- For those **indicators** that are **quantified** and **monetised**, harmonization is strongly recommended. In this case, a high degree of similarity in methods is important.

Hence, while differences between the generation and transmission assessment are not necessarily an issue for qualitative and even quantitative (but not monetised) indicators, it is an issue for monetised indicators as these constitute the first basis which parties use to take cost allocation decisions. **Therefore, we recommend that social welfare should be a mandatory indicator in any CBA, thus also for generation CBAs.**

Moreover, cross-border offshore projects, particularly with hybrid transmission, can bring a number of benefits compared to conventional projects. A typical example is the offshore and onshore transmission investment savings and reduced number of cable and landing points of a hybrid project. However, this may come at the cost of higher congestion in the offshore transmission system (depending on the sizing of the assets), and thus renewable curtailment.

Hence, in order to correctly assess the costs and benefits of cross-border projects and facilitate their deployment, some benefits and costs need to be considered in one way or another and be comparable and non-overlapping in the assessment of the generation and transmission assets. Thus, costs and benefits which should be considered comprise:

- Socio-economic welfare
- The transmission CAPEX (offshore, and if agreed some onshore assets which can be clearly assigned to the project being assessed)
- RES integration / reduced curtailment

Furthermore, once adequate methodologies are developed to quantify certain system costs, these should be included in the minimum set of KPIs to be considered when conducting the CBAs for offshore generation and transmission assets. The system costs KPIs comprise balancing/flexibility and profile/adequacy costs (in the terminology of the Commission XB CBA guidelines / ENTSO-E CBA methodology, respectively).

4.5. Coordination of offshore generation and infrastructure CBCAs

4.5.1. Scope of costs to be considered

Overview of relevant legislation and procedures

ACER's recommendation on good practices for the treatment of the investment requests, including cross-border cost allocation requests, for electricity and gas Projects of Common Interest (no 5/2015) provides relevant input for the CBCA decision procedures for offshore transmission hybrid projects. Even though ACER's recommendation no 5/2015 is solely focussed on grid related infrastructure projects, it still comprises several relevant observations on the scope of costs to be included which could be applicable in the future offshore CBCA procedures for not only transmission but also generation assets. A central point when considering costs remains avoiding double counting. Moreover, regarding to the **scope of costs** to be considered according to the recommendation:

- Costs to be included in the calculation of net impacts:
  - CAPEX: development and project management costs, material and assembly costs (including installation and commissioning costs), other construction costs and consenting costs, replacement costs.
  - OPEX: maintenance costs.
  - End of life: decommissioning costs.
- Costs / financial flows to be excluded from the calculation of net impacts:
  - Financing and tax related costs (if the regulation of any country requires the TSO to be remunerated for the financing costs, they may do so. However, other participating countries in the joint project should not cover these costs).
  - National monetary transfers (as these are offset within countries).
  - Potential grants should not be considered (i.e. should be excluded from the costs considered in the CBCA), but information should be shared with the concerned NRAs.

Although ACER thus recommends a number of different costs to be included in the calculation of net impacts, it further recommends that only investment costs are considered for cost allocation (the CAPEX costs mentioned above, but excluding replacement costs).

In addition to ACER's recommendation, the study on 'offshore electricity grid approaches in the Exclusive Economic Zone (EEZ)' provides relevant input on the scope of costs to be considered.[132] They consider electricity generation costs, onshore and offshore network costs, congestion management, and hydrogen infrastructure and production costs.

Why does the issue matter?

Concerning the scope of costs to be considered, the first and foremost reason to clearly define the scope of costs and benefits is to prevent double counting by clarifying which costs pertain to the offshore generation project and which costs to the offshore transmission project. In addition, offshore projects are often realised in sea basins that are shared between countries, which warrants their inclusion in CBCA processes in more cases than for onshore projects. Lastly, defining the boundaries of the costs to be considered is relevant to streamline the process for CBCAs of offshore generation and transmission, and to improve comparability between different future CBCA decisions.

Recommendations on the issue

A suitable CBCA guideline should:

- Leave no room for double-counting of costs between the offshore generation and transmission CBCA decisions, nor due to the receipt of grants;
- Provide minimum requirements on costs that should be considered in any CBCA to assure that major costs are covered; and
- Assure that there is an agreement on a how to deal with uncertainties upfront, at least for a minimum set of cost components.

Our starting principle is that **only non-privately recovered costs should be considered in the CBCA process**. This implies that only support mechanism-related costs (State aid to generation and if applicable transmission) and regulated costs (transmission costs) should be considered. As the CAPEX and OPEX for generation projects are private costs, we recommend excluding them from the CBCA process (although State aid of course is meant to support CAPEX and/or OPEX). CAPEX and OPEX should nonetheless be considered in the CBA as usual.

The next recommendation is that all major non-privately recovered costs should be included. As regulated transmission investment costs are a major cost component of offshore projects, we

[132] https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/ansaetze-eines-offshore-stromnetzes-in-der-ausschliesslichen-wirtschaftszone-awz.pdf?__blob=publicationFile&v=10

recommend that **regulated transmission investment costs should be considered in all CBCA decisions**. Within these investment costs, all major components should be considered, while excluding replacement costs (as recommended by ACER). As operational costs for transmission project are substantial as well, we also recommend **considering transmission operational costs in all CBCA decisions**.

In the case of **merchant interconnectors,** where the merchant party owns the whole interconnector, these generally should not be subject to a CBCA agreement, as costs are privately incurred, and the perceived congestion income should remunerate the investments. However, public support in the form of e.g., a cap-and-floor mechanism might be given in order to de-risk the investment. For example, in 2014 Ofgem and CREG have agreed on a cap-and-floor mechanism for the NEMO interconnector.[133] In the case of NEMO, Ofgem and CREG agreed to split any payments and adjustments (for non-controllable cost deviations) for revenues below the floor as well as any revenues above the cap paid back on a 50/50 basis.[134] No other CBCA decision has been agreed between the regulators as far as we are aware, with no such decision listed in ACER's latest overview.[135]

For **system costs**, we recommend **excluding the balancing and profile costs** as these are private costs, both for generation and for transmission projects. Grid reinforcement costs, especially of the onshore network, are socialised and may be substantial. As such, these costs meet the requirements to be included in the CBCA process. However, given the complexity, the **NRAs can best decide whether to consider grid reinforcement costs in the CBCA process**.

The table below provides a summary of which cost components should be considered in the CBCA process.

Table 4-5 Recommendation on consideration of cost components for cost allocation

Cost component	Generation	Transmission
CAPEX	No	Yes
OPEX	No	Up to MSs/NRAs to decide
System costs: balancing and profile	No	No
System costs: grid reinforcements	N/A	Up to MSs/NRAs to decide
State aid	Yes	No
EU-level grants	No	No

4.5.2. Inclusion of non-hosting countries

Overview of relevant legislation and procedures

Article 16(1) of the revised TEN-E Regulation (EU) 2022/869 indicates "the efficiently incurred investment costs, which exclude maintenance costs, related to a project of common interest [...] shall be borne by the relevant TSO or the project promoters of the transmission infrastructure **of the Member States to which the project provides a net positive impact** ". Moreover, Article 16(4) requires PCI project promoters to submit an investment request including "where the project promoters agree, a substantiated proposal for a cross-border cost allocation" to the concerned NRAs. This means that the contribution of non-hosting Member States with a significant positive net impact is mandatory according to the TEN-E Regulation. Contributions from non-EU Member States is not mandatory as they are not subject to the Regulation, including at the moment of writing any of the

[133] https://www.creg.be/nl/publicaties/beslissing-b658e/66
https://www.ofgem.gov.uk/publications/decision-cap-and-floor-regime-gb-belgium-interconnector-project-nemo
[134] https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/final_cap_and_floor_regime_design_for_nemo_master_-_for_publication_1.pdf
[135] ACER (2021) Overview of Cross-Border Cost Allocation Decisions.
https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Documents/2021116-Overview%20of%20CBCA%20decisions.pdfhttps://acer.europa.eu/Official_documents/Acts_of_the_Agency/Documents/2021116-Overview%20of%20CBCA%20decisions.pdf

EEA countries, unless part of a Project of Mutual Interest, for which the provisions apply mutatis mutandis.

ACER Recommendation 05/2015 provides further guidance on involving non-hosting countries. Non-hosting countries with a significant positive net impact should contribute to the project costs, with a significance threshold (10% of the expected net benefits) proposed by ACER in order to involve only countries with a significant positive net impact in the cost allocation. The threshold of 10% may be lowered gradually in case the net positive impacts are not sufficient to cover all costs, until a minimum of 5%.

In its recommendation on CBCA implementation to ACER and NRAs[136], ENTSO-E recommends keeping to a minimum the number of parties participating on a CBCA agreement, and indicates that if non-hosting parties are to be included, they should be included early on and willingly in the governance of the project.

There have been no electricity PCI CBCA decisions allocating costs to non-hosting countries. There have been four gas PCI CBCA decisions (9% of the decisions surveyed by ACER in its fourth CBCA monitoring report) amounting to 130 M€ allocated costs to non-hosting countries. The main such decision is that for the Twinning of Southwest Scotland Onshore System between Cluden and Brighouse Bay project, located in the UK but fully allocated to the Republic of Ireland as agreed between Ofgem (GB), the Utility Regulator (NI) and CRE (IE) after negotiations.[137] It must be noted that this project is particular in that while located in Scotland, it mostly benefited Ireland, thus justifying the allocation of costs to a non-hosting country – but constituting a scenario that is unlikely to occur for offshore renewable energy as it can be expected that hosting countries will significantly benefit from their deployment, at least to the point where their electricity mixes are fully decarbonised, even if non-hosting countries could also see important benefits.

It must be noted that there are no similar requirements for the contribution of non-hosting Member States to costs of cross-border renewable energy projects. Nonetheless, the non-binding offshore renewable generation agreement between Member States, the associated ONDP developed by ENTSO-E as required by article 14 of the revised TEN-E Regulation as well as the application of the cross-border cost sharing methodology defined in article 15 should provide guidance to Member States on the allocation of costs at sea basin level as discussed in chapter 3, which in turn should support CBCA decisions for specific projects, including with the participation of non-hosting countries.

Why does the issue matter?

The question of whether and how to include non-hosting countries and their parties is relevant for a number of reasons:

- Given the significant forecast deployment of offshore renewable energy, particularly wind, it will have significant impacts on the European electricity system, and not remain confined to the hosting countries or even basin countries.
- Projects with hybrid transmission will already be more complex than conventional cross-border generation or transmission projects, both due to the integrated nature of the projects as well as the potential to involve more than two hosting countries.
- Projects should increase European socio-economic welfare, but the distribution between countries will be asymmetrical – with non-hosting countries potentially seeing important SEW changes.
- Non-hosting Member States with significant net positive impacts may be asked or, in the case of PCIs and PMIs, required to contribute to the costs of a project.

Recommendations on the issue

A guidance on whether and how to include non-host countries in the CBCA decisions of cross-border projects should:

- Avoid unnecessary complexity in the CBCA decision process;

[136] https://www.entsoe.eu/2016/06/23/entso-e-recommendations-cbca-implementation/
[137] ACER (2020) Fourth Monitoring Report on Cross-Border Cost Allocation Decisions

- Strive for the compensation of any net negative impacts for hosting countries, to enable the realization of the project;
- Promote cooperation on cross-border energy projects at the project and basin levels.

In our view, the existing requirements and guidance for the inclusion of non-hosting countries are adequate. **The participation in and contribution to the costs of offshore renewable energy projects (including through agreements on statistical transfers) is strictly voluntary**. Non-hosting countries will typically benefit from such projects through access to lower-costs renewable electricity (compared to the counterfactual) for which the national market players will pay for and, if also agreed, part of the renewable energy shares can be transferred for meeting its RES target. Hence, privately-incurred costs of the offshore renewable energy projects should not require a contribution from non-hosting countries, as that would amount to a double contribution from those countries.

Non-hosting countries could potentially contribute to the costs associated with support schemes for the projects. However, using modern tender designs such as double-sided contracts for difference means that public subsidies would be required only in case of low market prices – and would lead to public revenues in the opposite case. Hence non-hosting countries should not contribute to such costs of public support unless they are involved early on in the governance of the projects and design of the support mechanisms, as well as benefitting from any upsides. This would amount to the countries participating in the joint project or joint support mechanism forms of cooperation defined in the revised Renewable Energy Directive. Therefore, no contribution of countries which do not participate in the cross-border renewable energy generation cooperation should be required.

The current high-level process for transmission is also adequate, even if specific changes might be implemented regarding e.g. the significance threshold following ACER's revision of its recommendation on CBCA decisions. The contribution to the costs of offshore electricity infrastructure PCIs and PMIs by non-hosting countries with a significant positive impact is already mandatory, as discussed above.

Non-hosting countries should be required to contribute only to transmission-related costs **when they are significantly and positively impacted**, while contribution to energy generation costs should be strictly voluntary. **Governments and project promoters could consider further including non-hosting parties in the governance and ownership** of offshore transmission infrastructure to which they contribute.

As detailed in section 4.3, we recommend the CBCA decision for transmission projects/assets be taken after the CBCA decision for offshore renewable energy assets, and that the benefits to be allocated in the former already exclude any benefits assigned to the generation project/assets. Therefore, this requirement is also met with the proposed process.

4.5.3. Agreements on deviations of costs and benefits

Overview of relevant legislation and procedures

This section covers the issue of handling deviations in either the costs and/or benefits of the projects compared to the estimations of the CBA underlying the CBCA agreement between parties. ACER recommendation 05/2015 indicates that regarding the aspect of deviations of costs and benefits in CBCA agreements, uncertainty ranges should be identified (downward and upward variation), as well as factors affecting costs (and benefits). Moreover, ACER provides specific guidance on how to deal with differences between expected and realised costs, with different approaches for countries with net negative and positive impacts:

- Countries with net negative impacts: If actual costs are lower than expected costs, compensation should be decreased proportionally. If actual costs are higher than expected costs, no changes to the contributions of the country (except if the NRAs agree otherwise);
- Countries with net positive impacts: If actual costs are lower than expected costs, the sum of compensations should be decreased using same principles as in CBCA procedure. If actual costs are higher than expected costs, no changes (except if the NRAs agree otherwise).

Why does the issue matter?

Uncertainty regarding the deviations from calculated CBA results can significantly hinder arriving at a CBCA agreement. Moreover, the level of uncertainty on offshore system development is relatively high. Thus, to reach an CBCA agreement and to prevent unnecessary disputes among parties, dealing with uncertainty regarding the actual costs and benefits of the projects is crucial. As realised costs and benefits will certainly deviate from the expected values to some extent, especially in case of projects with long time horizons, like projects with hybrid transmission, it may be beneficial to address this uncertainty upfront, especially given the high investment volumes involved and the higher risk for cost overruns of such projects compared to onshore or even conventional offshore projects with radial connections, for which there is a much longer track record.

Recommendations on the issue

With respect to uncertainty, we recommend that all mechanisms to deal with uncertainty should be agreed in the CBCA decision – although post-construction adjustments in the costs and benefits allocation should be possible, as long as it is based on clear rules agreed beforehand in the CBCA decision. CBCA decisions should focus on the project at hand and be forward-looking by preference, i.e. not aiming to compensate any net benefit deviations of past projects.

Moreover, the CBA should provide a basis for agreement between the national parties, but they should still have the necessary flexibility to arrive at a different cost allocation than what would be suggested by the CBA results, should that facilitate an agreement. This is compounded by the fact that increasing complexity of the offshore system will lead to higher uncertainty and thus lower robustness of CBCA results, as was highlighted in a study for the North Sea Wind Power Hub.[138]

The recommendations can be further separated per CBA component. For deviations in the project costs, the approach will depend on whether this refers to transmission or generation costs. For deviations in the transmission infrastructure costs, the CBCA decision should foresee the rule for allocation of costs overruns (or savings) according to the uncertainty ranges calculated in the CBA – indicating that for example a certain percentage of costs overruns will be borne by Member State A, and the remainder by the other Member State. Generation cost overruns (or savings) should in principle to be borne by private project developers and thus not be allocated to Member States, although the parties may agree otherwise (e.g. in case cost overruns are to a certain extent covered in a de-risking mechanism foreseen in a joint support mechanism). The latter agreements could gain importance in the future when a greater number of offshore energy projects will be profitable and thus dispense economic support, but still require some sort of de-risking mechanism.

It must be noted also that for support mechanisms designs currently in use, such as contracts for difference, the actual volumes of subsidies are known only during the duration of the public support mechanism (which may coincide or not with the technical lifetime of the generation assets). This should preferably not lead to a reallocation of costs. Instead, Member States should agree on the terms for allocating the costs (or benefits) of any under- (or over-estimation respectively) of the support needed within the joint project or joint support mechanism framework. Statistical transfers on the other hand may not require such agreements on the allocation of the RES shares in case of over/underproduction, as the energy production of the projects over several years is much more certain than market conditions and also should not be significantly impacted by the market conditions (except for example in the case of significant occurrence of negative prices).

Concerning the uncertainty of benefits and potential deviations of the socio-economic welfare components compared to the estimations of the CBA, the approach can be differentiated per component. For congestion income, an agreement on its split is always explicit for any transmission CBCA decision (with the proposed default split being according to transmission asset ownership, as indicated in section 4.3). Thus, there is no need for an agreement on how to distribute deviations in the congestion income, as any congestion income should simply be split according to the CBCA decision. The uncertainty regarding the overall socio-economic welfare and its remaining components (consumer and producer surpluses) should be accounted for through the CBA scenarios considered in the CBCA decision (see the scenarios recommendations of section 4.4.1. The CBCA may include scenario sensitivities, for example considering the development of new interconnectors.

[138] North Sea Wind Power Hub (2023) CBCA methodology paper – ACER CBCA targeted stakeholder workshop

4.5.4. Further issues to be considered in the CBA/CBCA process

Timing of offshore energy tenders and CBCAs

As indicated in section 4.5.1, State aid costs to generation should be considered in the CBCA process. Moreover, the proposed definition of counterfactuals and definition of socio-economic welfare changes between generation and transmission (detailed in section 4.4.3) indicates that the SEW should be allocated to generation first and then to transmission. We also foresee in section 4.3 that the processes for generation and transmission CBCA can largely run in parallel should the authorities desire. Hence, NRAs may want to reach a CBCA agreement for the offshore transmission infrastructure before the actual public support costs for generation are known (e.g. when the tender for the offshore energy areas described in step 5 has not taken place yet). In this case the transmission CBCA agreement of step 6 should indicate that the final cost allocation will consider the tender results as per the process and rules above.

Agreement on allocation of congestion incomes between countries

We note that not only costs can be allocated, but also congestion incomes as they accrue to (in the current context regulated) TSOs. Socio-economic welfare gains, including congestion incomes, have a higher uncertainty than costs, as SEW will depend on actual market conditions as well as other offshore and onshore developments such as other new interconnectors or offshore (or onshore) generation projects whose deployment can be highly uncertain. Projects are subject to cost overruns, which are also uncertain but such risks can be more easily managed.

Therefore, we recommend that the allocation of costs and benefits should be done primarily through allocation of costs, on the basis of the net benefits (SEW) for each hosting and if applicable non-hosting country. Congestion incomes should be allocated between Member States proportionally to the ownership of the transmission assets by TSOs, and in case the allocation of costs alone is insufficient to compensate any net negative impacts of hosting Member States (after any contributions from non-hosting Member States with positive net impacts above the significance threshold are considered), allocation of congestion incomes can be agreed between NRAs to compensate the net negative impacts.

Addressing the asymmetrical distribution of socio-economic welfare components

Another issue that decision-makers may face when agreeing on a CBCA is whether there should be further allocation in cases of projects with significant asymmetrical distribution of benefits, e.g. in case one country perceives most of the consumer/producer surplus, and another the remaining components – such as the congestion income or the producer/consumer surplus (even if each country overall has a similar benefit-cost ratio). Also, whether there should be allocation to address the distribution of benefits between entities (TSOs and governments) in the same country.

Article 19(2) of the Electricity Regulation states that congestion incomes of EU TSOs should be used as a priority for: "a) guaranteeing the actual availability of the allocated capacity including firmness compensation; or (b) maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors by means of coordinated remedial actions, where applicable, or covering costs resulting from network investments that are relevant to reduce interconnector congestion". If those objectives have been fulfilled, NRAs may use the income to reduce network tariffs.

At the investment decision stage, in case it is expected that an offshore transmission project (hybrid or conventional interconnector) would exhibit structural congestion, increasing the transmission capacity of the project should be the considered as the default option. However, this may not be the preferred option in all cases, since there is always a socio-economic welfare balance between lowering congestions, which allows to further increase consumer/producer surplus, and increasing project costs, which might mean that increasing the capacity further to fully eliminate all expected congestions is not optimal.

Therefore, in specific cases a strongly asymmetrical distribution of benefits might occur. It must be noted that the distribution of benefits among countries will always be asymmetrical to some extent. In theory, countries should not have a preference towards certain components of socio-economic welfare. That is, they should not prefer to receive congestion income instead of benefitting from consumer or producer surpluses, or vice-versa. However, in practice countries might have a preference to perceive a particular SEW component, e.g. congestion income (which can be used to increase interconnection capacities and availability, or reduce network tariffs) or consumer surplus (which would reflect a decrease in energy prices).

All three SEW components have similar levels of (high) uncertainty, and benefit the country that perceives them. But while congestion income needs to be allocated, consumer and producer surplus are usually not. Consumer and producer surpluses could in theory be reallocated through e.g. lump-sum payments between NRAs through an inter-governmental cross-border cost allocation agreement, which could be reflected in network tariffs in each country. We are however not aware of such practices today, which could nonetheless become relevant for future joint projects or other sorts of cooperation mechanisms. Adjustment of the network tariffs at interconnection points could also impact the distribution of surpluses between the countries, but this would increase the complexity of the tariffs and likely reduce cost-reflectiveness.

Hence, Member States do not and should not attempt to reallocate consumer and producer surpluses, which would normally be a market distortion (although they should be of course considered when agreeing on the CBCA for costs and congestion income). Congestion income in contrast can be allocated and used to not only guarantee the availability of the interconnector but also increasing interconnection capacity – or reduce network tariffs in case the previous objectives have been fulfilled. Moreover, congestion income is perceived by the TSOs, while producer and consumer surpluses are perceived by market players.

Countries may nonetheless have a preference to, in addition to agreeing at an overall distribution of costs, SEW and other benefits, achieving a more balanced distribution of the individual SEW components as mentioned above. Such distribution could be achieved only by re-allocating costs or congestion income. If necessary, options such as finding a way of re-balancing nationally the consumer/producer surpluses with that of the transmission owner could be explored within the country aiming to make rebalances of SEW components, while such exercise would always need to comply with EU competition law and State aid rules.[139] See an example below on how this could take place. Attempting cross-border rebalances of both the SEW and its individual components would likely increase enormously the complexity of the negotiations between countries and thereby increase the risk of failure of such negotiations.

As mentioned, producer and consumer surpluses cannot be easily re-allocated, only compensated ex-ante through transfers (ex-post compensation for surpluses perceived could be possible but would be impractical). Therefore, allocation of costs or congestion income to compensate for an asymmetrical distribution of the SEW components would likely lead to a change in the distribution of total costs and benefits.

For these reasons, **we do not recommend that countries attempt to achieve a more symmetric distribution of individual SEW components** – consumer surplus, producer surplus and congestion income – when negotiating cross-border cost allocation agreements, but **instead focus on total socio-economic welfare** created by the project. However, the matter should be left to national governments and NRAs, which should be free to achieve such agreement in case the asymmetry is perceived to be a barrier for the project, due to political considerations or otherwise.

There is also the question of whether there should be allocation to address the distribution of benefits between entities (TSOs and governments) in the same country. Absent or limited congestion incomes for one of the hosting TSOs might in theory discourage the TSO from developing the offshore transmission project. However, we argue that TSOs have a guaranteed return on investments through the RAB remuneration model (and in case there are significant uncertainties regarding congestion incomes, a cap-and-floor or other mechanism could be used to de-risk investments) and thus would not be significantly disincentivized to invest in interconnection capacity. Moreover, such issues should be addressed by a proper oversight framework where the relevant NRA monitors and, if necessary, mandates the TSO to develop the project if beneficial from a societal perspective.

Regarding compensation between governments and the respective national TSOs, governments may provide subsidies for the TSOs to develop the offshore transmission project if they perceive it as necessary, respecting any applicable EU requirements. But as mentioned above, we do not see this as the best approach to address disincentives the TSO may face due to low congestion incomes.

[139] For example, offshore hybrid projects are covered under the Commission Guidelines on State aid for climate, environmental protection and energy ('CEEAG').

Moreover, transfers of congestion income from TSOs to governments are not allowed according to article 19 of the Electricity Regulation.

<u>Example: eventual de-risking and reallocation of individual SEW components to facilitate hybrid projects</u>

As described, dealing with asymmetries is challenging exercise that will be different per project. A concrete and complex example is hereby presented. Let us imagine a project defined by two countries where part of the hybrid interconnector asset is owned by a merchant party of one country while the other part is considered as a regulated transmission investment by the other country. In such case, the respective countries should assess the total SEW of the project as per the process proposed in this report (if the project also contained the connection of new offshore wind farms, then defining the total SEW of the project as well as the corresponding to the transmission and that corresponding to the generation, as described earlier in this report).

Then, after assessing the SEW created by the hybrid interconnector, the countries could for example conclude that, on the one hand, producer and consumer surpluses generated across borders thanks to the hybrid interconnector are substantial and benefit more one of the two countries, while on the other hand the congestion income generated by the hybrid could remain relatively limited for that same country, challenging the bankability of the project for the merchant owner for the respective part of the project. This could be the case if the estimation of generated congestion income was insufficient to make the hybrid profitable for the merchant actor. In such instance, as described above, a cap-and-floor regime could be sufficient to de-risk the merchant actor's investment, which could be appropriate for approval by the respective NRA considering that the total SEW of its country is positive. Such positive national total SEW can take place, for example, if the country perceives much larger consumer or producer surpluses than congestion income, or as a result of the negotiations between the two countries, which may lead to a cross-border cost allocation that makes positive the total SEW for the country in question. Thus, once the total socio-economic welfare of the country is positive, if the congestion income perceived is deemed insufficient by a country, its NRA can de-risk the asset by including it in a RAB or cap-and-floor regime.

It should be noted that maximising congestion income is never the objective of interconnector assets, but the total SEW instead. In fact, new cross-border assets are set in place to create new market trade opportunities not already existing or, where they do exist between two countries, to reduce congestions (and thus relative congestion income per exchanged energy volumes), with the markets becoming more coupled and enabling additional creation of consumer and producer surpluses.

Therefore, the total socio-economic welfare generated by the offshore project should still remain positive for the countries to desire to pursue the hybrid interconnector, and maximising congestion income should not become an objective.

If, even after balancing out the costs and benefits of the project through cross-border cost allocations (or even direct financial transfers) and putting in place any relevant de-risking options for the merchant line such as a cap-and-floor regime, further support to the merchant party was considered necessary, the country could still explore national mechanisms to further share the country's positive SEW from the project with the merchant party in its territory. If so, it would be up to such country to find a way to redistribute the relevant part of its positive socio-economic welfare to its merchant actor, in accordance with the relevant competition legislation and State aid rules.

This way, the project would remain interesting and fair to both countries first, maintaining a holistic view of the value of the project, and to all their parties, merchant or regulated, second. It is essential in this type of complex cases to maintain an overarching picture that accounts for the entirety of the SEW, and not limiting the discussions to the interests of a particular merchant actor. Otherwise, the discussion would be disregarding all the other benefits provided by the project, substantially risking reaching an agreement between the two countries. Moreover, not accounting for the economic, social and environmental costs and benefits of the project (which would be the case when only looking at congestion income) would not be in line with the provisions in the TEN-E Regulation.

4.6. Suggestions to consider in the governance approach related to offshore wind energy deployment

This section presents suggestions to consider in the governance approach related to offshore wind energy deployment that can contribute to cost-efficiently achieving the EU and national offshore energy targets and enhancing cross-border cooperation. As such, it addresses issues which are less specific than the aspects covered in sections 4.3 to 4.5, that should be implemented in the longer term, or that should be reinforced.

Governance structure and reaching agreements on the ambitions and timelines per sea basin for development of offshore wind energy

As discussed in this study, the revised TEN-E Regulation provides the framework for Member States to jointly agree in regional groups on offshore renewable energy deployment non-binding targets and for providing non-binding offshore network development plans. In addition, through the high-level groups[140] relevant work is facilitated, such as via the North Seas Energy Cooperation and the Baltic Energy Market Interconnection Plan, in which countries in the North and Baltic Seas have established platforms for conducting the necessary studies and collaborate on sea basin-level agreements.

Member States could consider increasing cooperation on offshore energy in the remaining sea basin regions by leveraging existing or new initiatives. By including working groups on aspects such as maritime spatial planning, financing, cost-benefit analysis and other topics, the initiatives can provide the analytical basis for the (increased) sea basin ambitions and cross-border cooperation agreements. The working groups could include not only ministries but also regulators and TSOs.

Member States could also clearly define responsibilities for the realisation of CBAs and CBCAs and cross-border cooperation initiatives (when not already done). Our proposed approach is presented in section 4.3, where we indicate the responsibilities of the main actors:

- National governments (ministries or other designated authorities) should be responsible for the overall maritime spatial planning, for defining offshore renewable energy targets (agreed on with other concerned national governments) and conducting the necessary processes to enable the offshore renewable energy projects, such as tenders and permitting procedures, as well as negotiating eventual statistical transfers. Policymakers should also define the mandates of TSOs in this regard, including the obligation to explore opportunities for cross-border offshore infrastructure projects.
- NRAs should have a decisive role in agreeing on the conditions for specific infrastructure projects, and be in charge of negotiations thereof, be involved in approving project-wide (both generation and transmission) CBA assumptions as well as assess its results.
- TSOs should be responsible for conducting CBAs and developing the offshore transmission infrastructure. NRAs should advise ministries, ENTSO-E and national TSOs.

Agreement on CBA and CBCA principles

An important step to ensure the timely development of cross-border projects is to agree on principles for cooperation on specific projects before CBA studies and CBCA agreements are conducted. While details of the CBA studies and CBCA agreements should be agreed by the TSOs and NRAs responsible during their elaboration, the ex-ante agreement on principles should ensure that the CBCA agreements are based on objective and transparent CBA methodologies and inputs as well as cost-allocation rules.

Collaboration principles could be agreed by Member States at the sea basin-level or in memorandums of understanding for specific projects. The High-Level Groups such as NSEC and BEMIP can provide an effective framework for such sea-basin discussions.

[140] https://energy.ec.europa.eu/topics/infrastructure/high-level-groups_en

A high-level sequence for cooperation is presented below. Note that a framework already exists for most of the steps in the process:

- The revised TEN-E Regulation defines the process and obligations for Member States arriving at an agreement on offshore renewable energy ambitions, as well as for ENTSO-E developing the ONDP.
- The TEN-E Regulation provides the framework for the development of project-specific CBAs for TYNDP candidates and PCIs/PMI candidates, as well as the framework for CBCAs for PCIs/PMIs.
- The revised CEF Regulation provides the framework for CBAs of projects applying for a cross-border renewable energy status.

Therefore, the current EU regulatory framework already addresses all steps in the sequence below, except for the third step, where policymakers, regulators and TSOs should agree, based on the results of the sea basin-level activities, on the principles for development of project-specific CBAs and CBCAs. While a specific framework in this regard is not necessary, policymakers in particular but also other stakeholders (regulators and TSOs) should strongly consider agreeing on these principles ahead of the CBA and CBCA agreement execution.

Figure 4-11 High-level sequence for cross-border cooperation at sea basin and project-specific levels

The principles agreed on this step could comprise, among others (the recommendations developed in chapters 3 and 4 of this report provide further details on the recommended approach for some of these principles):

- Definition of CBA inputs and methodologies, such as which scenarios, counterfactuals, reference grid and indicators to be used;
- Rules for involvement of non-hosting countries (including non-EU), based on discussions with these countries and in line with relevant EU-level requirements and guidance;
- Cost allocation rules for any CBCA agreements, defining either a single rule or a limited menu of options to be explored (the latter if necessary in order to not unduly restrict policymakers and regulators when negotiating the CBCA).

The sea-basin level exercise will support the definition of principles in various ways: the outputs and assumptions of the ONDP can for example provide a basis for defining the reference grid for the CBA of specific projects. It can also highlight non-hosting countries with significant net benefits from the overall sea-basin level development, and which can thus be considered for inclusion in the project-specific CBCA (if the PS-CBA confirms net positive benefits to the non-hosting country).

Agreement on implementation of cooperation mechanisms amongst Member States on offshore renewable energy projects

As indicated in section 4.2.3, both directly and indirectly involved Member States can work together in offshore wind energy parks and other forms of offshore energy via one of the three cooperation mechanisms set up under the Renewable Energy Directive 2018/2021/EU: joint projects, joint support schemes and statistical transfers (with the new Union Renewables Development Platform aiming to facilitate the later). Moreover, contributing and hosting Member States can make use of the Union Renewable Energy Financing Mechanism set up by the Governance Regulation 2018/199.

At the sea-basin level, further processes could be considered to support the identification of cooperation opportunities. For example, Member States could conduct studies in order to compare the marginal cost between countries for 2030/2040 to achieve national targets, and in that basis pursue cooperation opportunities through the mechanisms indicated above for developing projects in the countries with the lowest marginal cost.

Regarding the guidance, the recommendations on cost-benefit analysis and cost sharing/allocation at the sea basin and project levels developed in the present study can serve as basis to agree on cross-border cooperation through the different mechanisms available to Member States. The question remains how Member States can make use of the CBA results to agree on which cooperation mechanism to use, and on the actual allocation of costs and benefits for specific projects.

Moreover, as noted in section 4.5.3, the different costs and benefits of the projects have different levels of uncertainty. For the generation assets, the average renewable energy generation of the projects have comparatively low uncertainty over the project lifetime, while costs for both generation and transmission assets have higher uncertainty, including public or regulated costs such as transmission CAPEX and the required public support under contracts-for-differences schemes. The benefits from generation and transmission cross-border cooperation for specific projects also depend on many uncertain external factors, such as market conditions and other offshore infrastructure developments.

This means that the allocation of costs and benefits through statistical transfers have a low uncertainty, while for joint projects and joint support schemes any CBCA agreement will have a higher uncertainty regarding the actual allocation of both costs and benefits. As recommended in section 4.5.3, Member States should agree in the CBCA decision on the allocation of any costs and benefits deviations from the ones assumed in the underlying CBA. Such agreements should focus on public and regulated costs, as discussed in section 4.5.1, including any costs such as for example de-risking tools such as cap-and-floor mechanisms to merchant interconnectors but not including privately-incurred costs.

Agreement for each sea basin on the bidding zone configuration

To efficiently integrate offshore wind energy farms into the electricity market, the concerned Member States (preferably at the sea basin level) should agree on whether to set up a specific Offshore Bidding Zone as an alternative to the Home Market approach. In principle, using specific offshore wind energy bidding zones is the preferred approach to maximise European welfare and to enable massive deployment of offshore wind energy generation as discussed in section 4.4.2. Unlike the Offshore Bidding Zones approach, electricity pricing can be distorted under the Home Markets approach. This can lead to welfare losses as a result of inefficient dispatch and investment behaviour.[141] Furthermore, there are established processes for defining and revising bidding zone configurations which need to be followed by Member States.

Besides recommending the use of offshore bidding zones, the recommendations on section 4.4.2 highlights the importance to use the actual bidding zone configuration (if known) in the CBA as much as possible. But EU and national actors could further investigate ways to avoid distortion of competition between generators located in OBZs vs onshore / home market offshore generators under the current market design. While not a main focus of this study, further improving the internal electricity market design to eliminate such potential distortions would strengthen the use of offshore bidding zones. This could include an analysis of how to set tariffs in order to recover transmission costs in offshore bidding zones.

Agreement on the method for charging grid connection costs to offshore wind developers

Offshore grid connections are needed to transport the wind energy generated in the sea basins to end-consumers (or P2X such as electrolysers). These connections link up the offshore wind energy installations with onshore connection points, from where the electricity is transported via the onshore grid. Due to the distance of the offshore wind energy installations from the coast, the grid connection is a technical, financial and logistical challenge. There is thus a need for close coordination between the design of a wind farm and the related grid connection so that the work can be synchronised and the financial risks minimised.[142]

[141] Thema Consulting Group (2020), Market Arrangements for Offshore Hybrid Projects in the North Sea
[142] BMWK - Connecting offshore wind energy to the grid

To avoid competition distortion between offshore wind energy companies that operate in the same sea basin (and hence in the same regional electricity market), the concerned MSs should agree on using the same method to recover grid connection costs from the concerned operators.

A priori, applying the shallow methodology which consists of only charging the direct connection costs (and not the upstream investment cost to enable the connection) seems the most appropriate approach, as any other method may lead to different charges (and hence competition distortion) due to the different physical location and options taken by authorities and TSOs to transport the offshore wind energy to the shore.

The Swedish government has in February 2021 published a proposal to reduce electricity producers' cost of connecting offshore power plants to the national electricity grid, by extending the national electricity grid to maritime areas where it is possible to connect several facilities. The grid expansion would take place where it is judged to promote the fulfilment of the national target of 100% renewable electricity production. Meanwhile, the state-owned TSO Svenska Kraftnät has been tasked to build up to six grid connection points at sea with a combined capacity of up to 10 GW. Offshore wind developers will in the future not have to pay to link their projects to those grid connection points, while until now developers in Sweden had to build their own transmission lines. In the future they will only need to pay for the grid connections within their wind farms as well as the connection between the wind farm and the grid connection point provided by the TSO.[143]

The practices implemented in Sweden could serve as an example for other national authorities. Grid connection costs can represent a major cost component for offshore wind energy parks. In a British study, the effect of different attribution mechanisms of these costs on the overall cost-effectiveness from the consumers' perspective is analysed.[144] The major result of this investigation is that an attribution of grid connection costs to grid operators – as opposed to generators – leads to a smaller producer surplus and, hence, to lower transfer costs for electricity consumers.

In this context, it has to be stressed that reduced expenditures for one party (e.g. wind farm operators) lead to – not necessarily proportional – additional costs for the other party (e.g. grid operators). Eventually, both parties will pass over their costs to consumers. Hence, such configurations have to be found in the attribution of duties, which keep the costs for reaching a certain renewable energy policy target and thus the quantity of public transfers to a minimum. In the presence of public support, this requirement implies a political dimension. The postulate of maintaining cost-effectiveness in the support of RES-E presumes a normative motivation: the minimization of consumers' transfers is given priority over the maximization of the producers' surplus.

Agreement on the grid access tariffs charged to offshore wind energy generators

Recital (10) of Commission Regulation (EU) No 838/2010 stipulates that the variations of transmission charges faced by producers across the EU should not undermine the internal market and should be kept within a range which helps to ensure that the benefits of harmonisation are realised.

Annex B of this Regulation sets the legal ranges of the annual average transmission charges to be paid by producers, excluding charges paid for physical assets required for connection to the system or the upgrade of the connection, charges paid related to ancillary services and specific system loss charges, in each Member State. The value of the annual average transmission charges paid by producers shall in general be within a range of 0 to 0.5 EUR/MWh, except in Denmark, Sweden and Finland where the range is 0 to 1.2 EUR/MWh, and Ireland, Great Britain and Northern Ireland where the range is 0 to 2.5 EUR/MWh, and Romania where a range of 0 to 2.0 EUR/MWh applies. In addition, the Decision of the EEA joint Committee No 7/2011 sets a legal range of the annual average transmission charges paid by producers also in Norway.

Member States that are involved in wind energy projects in the same sea basin should agree on harmonized grid access principles and tariffs for the concerned operators in order to ensure a level

[143] Sweden: Making up lost ground on offshore wind | WindEurope
[144] Offshore wind power grid connection—The impact of shallow versus super-shallow charging on the cost-effectiveness of public support - ScienceDirect

playing field for all concerned operators that are operating and competing in the same supra-national market.

According to a British study,[145] there is no apparent value in locational tariff signals to offshore wind farm developers. The lead time for offshore wind farm development is indeed such that investment decisions and biddings are made without confidence in future transmission use of system charges. Differentiated transmission tariffs depending on the location within the sea basin should hence not be considered, also due to the fact as such an approach may undermine the certainty and predictability of the regulatory framework for project developers.

Promoting PPAs between offshore wind energy operators and retailers or large users

Increased use of long-term green PPAs for offshore wind energy parks, and a more liquid PPA market, could help project developers to hedge their electricity price risks. At present, demand for green electricity PPAs is lagging behind supply, due to limited availability of suitable PPA offerings, a shortage of concrete policies to electrify and decarbonize industry, which limits the interest of industrial consumers in such PPAs, and other factors.[146]

The two most common PPAs are physical and virtual (financial) PPAs. In a physical PPA, an effective transmission of electricity takes place via the grid, while a virtual PPA is not linked to physical electricity supply, but only serves to hedge price risks. From an investors' perspective, PPAs increase the stability and predictability of revenues from offshore wind electricity production, while for the off-taker, PPAs also reduce their price risks and allow them to use or supply green electricity. Depending on the creditworthiness of the off-taker (e.g. industrial user or supplier), PPAs decrease the risk for debt providers and equity providers, which can facilitate the access to external capital providers and decrease the cost of capital. Therefore, PPAs are an important instrument for mitigating increased exposure to market price risks when support schemes will be phased out. It should be noted indeed that the development of a mature PPA market is closely linked to the (dis)continuation of support schemes that hedge merchant price risks. At present there is in most EU countries no incentive to hedge market price risks through PPAs as this risk is sufficiently hedged through government support schemes, such as CfDs or fixed support. The electricity market design reform proposed by the Commission contains specific provisions targeted at facilitating private PPAs.[147] If support schemes are maintained, this could distort the market because they hamper the development of a mature PPA market.[148] As offshore wind parks can increasingly be developed without specific public support, PPAs could become an adequate alternative to reduce the risks for developers, while also reducing price volatility for retailers and end-users.

While PPAs based on onshore wind and solar energy parks have become mainstream, the first offshore wind energy deals have recently been agreed on. Denmark's Ørsted has signed three corporate PPAs for offshore wind energy farms in the U.K. and Germany, totalling 154 MW. Google is buying offshore wind power from an Engie project off Belgium. Experts consider offshore wind energy projects as an obvious solution for corporate PPAs, because of their scale, relatively predictable generation amounts and green energy.[149]

According to ACER (as per its response to the Commission's market reform consultation), the use of PPAs might reduce the liquidity of organized forward and futures markets. While the development of liquid and competitive forward markets (preferentially via organized platforms to increase transparency) is indeed important including through increasing cross-border hedging opportunities, PPAs for offshore wind energy projects would be an appropriate complementary instrument, with PPAs and organised forward markets exhibiting synergies. PPAs could to some extent be standardized and traded via organized platforms. The concerned national authorities could hence stimulate the use of this instrument, as would be their obligation as per the electricity market reform proposal[150].

[145] tnuos-offshore-wind-addendum---sept-2021.pdf (ssen-transmission.co.uk)
[146] S&P Global (2023) INTERVIEW: European PPA market could see record deals in 2023: Pexapark
[147] https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591
[148] pwc-invest-nl-financing-offshore-wind.pdf
[149] What Offshore Wind Can Bring to the Corporate PPA Party (edisonenergy.com)
[150] Article 19a of the Proposal for amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52023PC0148

5. Annex I – Stakeholder consultation

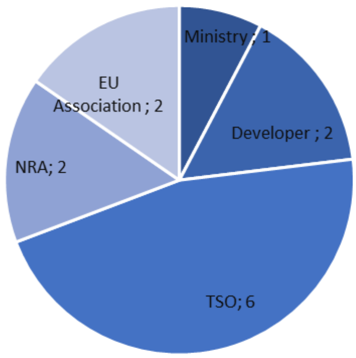
Understanding the perspectives of key stakeholders is essential to the creation of holistic guidelines. As such, the stakeholder engagement process and consultation were a central part of the project. It aimed to engage in proactive communication with key actors to assimilate their perspectives and address their concerns at an early stage, rather than having reactive communication. Engaging with the interested parties enables a more comprehensive perspective on the challenges the project aims to overcome, provides with first-hand experience information, and allows participants to assimilate the guidelines as they are being designed.

To fulfil this objective, a comprehensive survey was created and disseminated by the project partners, implementing the input from a first stakeholder workshop. The survey collected information and views on three main areas; 1. Cost-Benefit Analysis (CBA), 2. Sea-Basin Cross-Border Cost Sharing (SB-CBCS) and 3. the Coordination of offshore wind energy generation and transmission infrastructure CBA and Cross-Border Cost Allocation (CBCA).

The survey was complemented with a bilateral interview process, for which the survey responses for each stakeholder were assessed to do a deeper dive into those replies that were of highest interest and relevance for the project and provided most value to the exercise. This resulted in distinct interviews, tailored, and prepared for each stakeholder, allowing to foster and obtain first-hand information on the key actor's concerns, priorities and experience.

A total of 13 key stakeholders replied to the survey, shown in Figure 5-1; 6 TSOs, 2 NRAs, 2 European level associations, 2 developers and 1 Ministry. From these stakeholders, 9 accepted follow up interviews to obtain further insight. These stakeholders represented Member States or had projects in the following sea basins; North (7 of them), Baltic (6), Atlantic (4), Adriatic (1), Celtic (1) and the Western Mediterranean (1); several respondents developing projects in more than one sea-basin.

Figure 5-1 Stakeholder groups participating in the stakeholder engagement



Most respondents are considering the development of hybrid or joint projects in several locations such as the North Sea (North Sea Wind Power Hub between Denmark and the Netherlands) or the Baltic Sea (Bornholm Energy Island).

5.1. Sea-Basin Cost-Benefit Analysis (SB-CBA)

5.1.1. Main challenges when designing a Sea Basin CBA (SB-CBA)

Firstly, prior to the design of the SB-CBA and the implementation guidelines, the question of how it will interplay with the project-specific CBA, CBCA guidelines and inter-MS agreements subject to political negotiation is raised by one of the survey respondents. How this structure will facilitate the process, with guidelines being non-binding documents is perceived as unclear. This respondent recommends explaining how SB-CBAs would complement TYNDP CBAs and how the desired actions from MS will be prompted, encouraging consistency.

Furthermore, there are several challenges foreseen when designing a SB-CBA. Some of these will depend on what the main goal is, for instance, facilitating the development of wind, lowest costs, or lowest environmental impact. This should also be clarified to define the counterfactual and establish if the project aims to assess the benefits of 1. regional coordination vs MS developing projects without coordination, 2. hybrids vs radially connected wind farms or 3. transport to land as electricity vs. hydrogen.

When designing a SB-CBA, there is a significant number of influencing factors that need to be accounted for. Survey respondents highlight different regulation regimes and policies, future electricity demand, social cost of carbon (SCC), sizing of circuits, data collection issues or security of supply parameters.

In addition, the SB-CBA should incorporate a holistic assessment of the necessary infrastructure in the entire sea basin. It has to be developed in steps over several years; from radial to hybrids and meshed grid, making the reference grids for several scenario years, potentially 2030, 2040 and 2050. Accounting for the evolution of these factors throughout the different timeline stages is perceived as one of the main challenges, as expected lead times, coordination and planning delays need to be assessed. Furthermore, the benefits of upgrading the network will rise but perhaps not incrementally with the first few bidding zones added.

Finally, some stakeholders consider the SB-CBA should also distinguish between benefits due to buildout of generation/storage capacity and transmission infrastructure, and account for impacts on the onshore grid and need for reinforcements. How to consider integrated project including hybrid transmission is also perceived as a key challenge. It is suggested to have a single CBA for the entire integrated project, instead of treating it as two separate (generation and transmission) investments.

5.1.2. General Design of SB-CBA

The survey respondents considered that the main overarching topics to be addressed in the CBA guidance were:

- Having **unbiased, independent, traceable and transparent** permitting, planning and decision making based on a development target. Such an increased visibility increases attractiveness for investors.
- How to address the **changing benefits and costs with time**, due to stepwise buildout and ensuring up-to-date cost-benefit estimations. One survey respondent considers at least an assessment with firm cost-sharing (either through fixed numbers or clear rules) at Final Investment Decision (FID) a reasonable principle.
- How to address **the statistical contribution to MSs' RES targets** (and their willingness to pay a share of the costs).
- **Interaction between generation and transmission assets**.
- **Inclusion of landlocked countries.**
- Regulation/governance:
    - A reviewed transparent **regulatory model and governance system** consistent with current policies.
    - Access to **EU financial assistance** for eligible PCIs.
    - Governance issues and **distribution of roles and responsibilities** among Member States and relevant stakeholders e.g., generation and transmission developers and operators, maritime space users.
    - Planning, tendering, financing, permitting processes: which parts will be **coordinated at national and which at international level** e.g., cross-border tenders and support mechanisms or only national processes?

- Definition of **the counterfactual and reference grids** that deliver the **decarbonisation objectives** / include the SCC, integration of RES or CO2 avoidance measures. Long-term view to 2050 considering future electrification including locational aspects of directly and indirectly electrified demand.

- The indicators to be computed (SEW, Avoided CO2 emissions, RES integration (avoided spillage), CAPEX, OPEX) and how to compute them practically.

  - **Hybrid**/meshed grids; Getting the correct SEW and other indicators for hybrids. The SB-CBA should be the **tool to assess the hybrid infrastructure and networks of integrated projects in the sea basins.**

- Accounting for **full energy solution** that includes **sector coupling** with, for instance, heat, transport, industry and across energy carries like hydrogen or gas.

- **Uncertainty due to scale** compared with a project specific CBA closer in time to delivery.

- Other items: technology development (e.g., grid **optimisation technologies** to be considered along with grid expansion), Security of Supply (SoS) and stability.

5.1.3. ENTSO-E's CBA 3.0 draft proposal as a basis for the SB-CBA

ENTSO-E's CBA 3.0 as an adequate basis for the assessment of sea-basin infrastructure

Most survey respondents (10/13) **considered ENTSO-E CBA 3.0 draft as an adequate** basis for the assessment of the sea-basin infrastructure. It is key input for the PCI process and some of its indicators are relevant to compute.

However, stakeholders propose **to incorporate grid losses**, the **impact on onshore infrastructure** and analyse the **risk of overlapping and underestimating indicators** and their **suitability** when assessing AC vs HVDC grids. Furthermore, the potential danger that the **PINT and TOOT processes becomes too complex** for TSOs to consider is highlighted; as when looking at a whole sea-basin one can get thousands of viable alternatives, and it might not be realistic to run PINT and TOOT on all of them.

Regarding how to assess **hybrid projects**, TYNDP22 promoters can choose between two methodologies. One respondent suggests not to give options and base the SB-CBA on one methodology depending on whether the aim is to determine the optimal buildout or also how much capacity to be connected to each country. Another stakeholder considered that the two options proposed in the TYNDP can work for a limited number of projects only as a temporary solution addressing 1. wind farms already auctioned and radially connected as national assets and 2. farms auctioned and planned before the TYNDP integrating an offshore hybrid model in the CBA for individual projects (latest 2026), still to be radially connected as national assets but not for 3. wind farms and transmission assets auctioned jointly as integrated projects.

There was a respondent that **did not consider ENTSO-E's CBA 3.0 as appropriate** and believed that it would be more relevant to develop the methodology based on the one described in the Identification of the System Needs (IoSN) implementation guidelines, as its goals are more aligned with the SB-CBA. Another respondent believed that despite the incremental approach to project development being a safe and regulatory sound, it was insufficient to achieve the decarbonisation goals and considered that evaluating offshore grids based on a merit order was unreasonable when electricity will be mostly produced by RES, hence having a zero price most of the time in the future. Basing the CBA on demand scenarios that ensure that net zero GHG scenarios are met was suggested, as well as adding modifications to include sector coupling, flexibility, complementarity of solutions, scalability and modularity. Several stakeholders suggested that scenarios should be prescriptive rather than such that provide a forecast of the most likely path. It is also highlighted that dynamic performance of the proposed networks and the impact of enlarged DC networks in the stability of the European Synchronous systems could be assessed.

Indicators suggested by ENTSO-E CBA 3.0

Regarding the application of the indicators suggested by ENTSO-E CBA 3.0, survey respondents believed that the indicators suggested are **appropriate** but potentially insufficient. Stakeholders suggest to also consider:

- Costs and benefits **outside the spot price effects** (also considering closer to the real-time market time frames and non-market effects) and analyse how to monetise these.
- **System strength and stability**
- The addition of **hybrid and meshed offshore grid specificities**. For instance, indicators that assess adequacy or grid losses may be more suited for meshed AC infrastructure containing non-RES capacity and may **not be suited** for hybrid interconnectors. Therefore, benefit indicators **B5 - B9** should probably be omitted as a whole or at least adequately adjusted.
- **The impact on onshore infrastructure**
- Indicators that reflect the **Energy Efficiency First Principle** (EE1st).
- Adding a benefit indicator regarding **better utilisation of landing points**, as they are a scarce resource.
- How larger PtX units can be connected with a meshed offshore grid, reducing impacts elsewhere.

Residual impacts at sea-basin level

Respondents highlighted 4 types of residual impacts that could be studied: environmental, technical, social and political. Firstly, many **environmental impacts** to consider were suggested. These included heat emissions, visual impacts, noise, biodiversity, impact of crossing of protected nature reserves, land use (km of cable in environmentally sensitive zones or fishing areas), material use (life-cycle) and effects on the seabed/the formation of a sediment cover and pollution risk in, for instance, oil leaks from cable substations or other potential incidents.

Regarding **technical impacts**, respondents suggested to assess the operation of grids at lower voltage levels, e.g. by applying super-conducting AC and DC transmission technology, the number and size of circuits needed and their pathways to avoid stranded assets, ensuring robust technical feasibility and accounting for the effects on innovation, particularly the innovation benefits during the first buildout phase.

Among the **social impacts**, the externalities, social cost of carbon, benefits of innovation and job creation related to the development of energy intensive industries or storage facilities in coastal areas next to connection points that strengthen their position as energy hubs were proposed. It was also suggested to evaluate local acceptance and on what degree it can hinder the deployment of offshore infrastructure, as well as benefits of offshore interconnectors replacing onshore ones, reducing nuisances for homeowners.

Finally, regarding the **political environment**, it was highlighted that having the infrastructure allows to reach RES targets and accelerates achieving climate (additional installed GW of offshore RES), CO2 reduction and wind buildout goals. Regulatory limitations should also be considered.

5.1.4. Assessment of Costs and Benefits

Monetisable and non-monetisable costs and benefits – NPV, Benefit-to-Cost Ratio

Survey respondents **agreed** that **using NPV and BCR** as the primary parameters for analysing costs and benefits that can be monetized **is appropriate**, also for SB-CBAs, being attentive to the sensitivity to discount rates and use the correct time periods and parameters. The NPV is considered useful to compare competing investments if consistent assumptions are applied. Other economic parameters recommended to explore are lifetime, WACC, inflation, SEW, Avoided CO2 emissions, RES integration (avoided spillage), CAPEX, OPEX, with aligned assumptions and scenarios.

In addition, it was indicated that these parameters needed to be accompanied by **non-monetised indicators** that account for the costs and benefits that are not as easily monetised (e.g. losses, SoS or CO2 losses). Costs and benefits of demand and renewables should not be underestimated, and efficiency benefits could be accounted for. Furthermore, the fact that more hydrogen means a higher need of renewable energy electricity and less efficiency is stressed.

Distributional Effects

Some survey respondents **considered distributional effects of high importance** and consider that distributional effects for all impacted MSs, markets and stakeholders should be considered in as much detail as possible. One proposed to **disclose producer and consumer surplus effect of projects separately**. Another suggested to analyse the overall distributional effects **of developing an optimised sea basin-wide approach**, considering effects accrued to all impacted nations, or at least generation surplus and congestion income, aiming to reflect the true costs that include external and hidden costs (e.g. congestion) and the benefits to society. It was suggested to explore different alternatives; **facilitating a methodology to split electricity generation revenues between countries, develop storage hubs, or allow countries to decide** which models to choose.

Other respondents identified some issues regarding focusing on distributional effects, as it could lead to assessing national optimisation rather than the SB approach. One survey respondent considers that **decisions should be made based on net socio-economic welfare gain only**, **not considering distributional effects** between countries that could potentially block the optimal solutions at a European level. Nonetheless, another respondent highlights that identifying which country could **benefit/lose from an optimal portfolio can be time consuming and give unstable results**, that for a certain SB are influenced by what happens in the other SBs.

It is also reflected that a CBCA that relies on country-split of CBA results, as applied in the past, is **sensitive to changes in the CBA calculations**. Therefore, it is suggested that if a CBCA uses a different allocation methodology, there is no need for a CBA with country-level results. Examples of alternative allocation methodologies that were mentioned are:

- Climate impact: GDP per capita. The objective of this allocation method is that reaching the climate goals is a European task and Member States should contribute according to their capabilities.

- Local emission reduction: cost allocation based on CO2 and non-CO2 emission reduction per country.

The consortium notes that these methodologies still rely on country split of CBA results, except that they consider non-monetary KPIs. Stakeholders mentioned that as another alternative, CBCAs could determine cost allocation per individual sectors (power, hydrogen) per country. It is also proposed to **display distributional effects per country**, considering that **it should not impact the assessment.**

5.1.5. Reference Grid

The survey respondents offered recommendations regarding how to establish the reference grids at sea basin level. It was strongly stressed that all reference grids **should comply with the EU environmental goals** and be based on the expected offshore production according to EU-goals and optimisation tools, as well **national network development plans and the TYNDP approved by ACER**. In this context, similar to the proposed scenarios approach. Most respondents argued for the prescriptive approach as to which generation background the reference grid should cater for, rather than making a forecast of how the grid is likely to evolve under persisting policies.

Respondents highlighted that **separate reference grids would be needed for the different time horizons, namely 2030, 2040 and 2050**, to close the gap between what is already operational and future plans for a fully decarbonised Europe.

For the **2030** reference grid, it is expected to include **already decided projects at Member State level, not considering further development or plans** based on individual decision rather that decided collectively considering the optimal future grid. A survey respondent recommended using the reference from issued from the TYNDP.

For the **2040** reference grid, survey respondents thought that it should consider the needed reinforcements to connect the necessary level of offshore wind power capacity and reach economy-wide European decarbonisation by 2050; for the electricity sector, requiring full decarbonisation before 2040. A respondent suggested it to be the result of the optimisation of SB-CBA in 2030 time-horizon.

For the **2050** reference grid, as for 2040, one of the respondents suggested it to be the result of the optimisation of the SB-CBA in the 2040 time-horizon. Another described it as the **2050 grid required for a decarbonised Europe**. It was indicated that the reference grid should **assume the use of existing and emerging technologies within the 2050 timeframe**, when socioeconomic beneficial to apply them.

It was also proposed to quantify the needs for onshore reinforcements in the CBA and consider how to treat the build-out of **hybrid interconnection** far out in the future, as this can be influenced by whether other projects materialise.

5.1.6. Counterfactual

Main principles

Survey respondents highlighted a number of key principles for defining a counterfactual. This is of course a challenge, as there is an infinite number or options, the best counterfactual having to be defined considering the main objective of the project – assessing benefits of coordination at sea-basin level with hybrid projects.

To define the counterfactual, the following main principles were suggested by the stakeholders; some parties having opposite views from each other. They believed the counterfactual should:

- Consider **no regional coordination**, i.e. that each MS decides its own buildout.
- Represent a **"business-as-usual without offshore interconnection and hybrids" scenario**, including all RES projects planned on a national level which are not connected through hybrid projects and all pure interconnection projects.
- Be designed working **backwards from a 2050 pan-European grid capable of sustaining climate economy-wide climate neutrality**; avoiding linking the individual basins end in a suboptimal design with too little capacity in high-resource sea basins and too high deployment in low-resource sea basins.
- Allow **both TOOT and PINT concerning offshore-hybrid projects**.
- Be designed by firstly establishing the overall NPV of the reference project and then the delta with the counterfactual, instead of establishing the delta between the reference project and the counterfactual for each indicator.
- **Include existing**/FID-supported **RES** as they are reasonably expected to effectively be present in the reference grid. For "**undecided" RES, it depends on the RES integration** provided by the infrastructure in factual vs counterfactual. In addition, the counterfactual could lead to reduced grid infeed, impacting the overall CBA. Hence making a counterfactual with the **same RES capacities is not per se adequate either** and this also would be artificial.
- Include the RES deployment in the starting grid. If hybrid projects connect some extra offshore RES, the CAPEX and OPEX corresponding to this extra offshore RES should be included in the CAPEX and OPEX of the candidate.
- **Only include point-to-point connections of generation** (or energy hubs) and **interconnectors separately** (no combined configuration). This way the scenario with the offshore integrated assets combining generation and hybrid transmission can be compared to the counterfactual to estimate the additional value added to the system of these integrated assets.

Counterfactual – differences for sea-basin compared to individual projects

The survey respondents considered the following as the main differences between the counterfactual for a sea-basin and an individual project. The main difference considered by survey respondents is the enhanced complexity at sea-basin level, as a sea-basin level counterfactual, compared to individual projects:

- Needs to go **beyond national borders** and address differing MS interests
- Uses different configurations, references and calculation years
- **Merges all existing national plans** and policies
- Considers the possibility of multi-functionality in the form of **hybrid projects** or at a later stage, a meshed grid.
- Will be **less accurate**, having to be complemented with an individual CBA for enhanced accuracy.
- Has **different challenges**, such as defining the starting grid and whether to include offshore RES. For individual projects, the focus is to identify if the project is included in the time-horizon and if it will be assessed as PINT or TOOT.
- Is the **sum of individual projects** (implementing in different timeframes additional discounting if required).

Counterfactual potentially meeting the same RES generation level as the scenario where the offshore grid infrastructure is present

Regarding **whether the counterfactual should meet the same RES generation level as the scenario** where the offshore grid infrastructure is present, most respondents believed that the **generation level should remain the same**, nonetheless, highlighted several pointers. Firstly, a survey respondent highlighted that this is key to meet EU climate ambitions, and that the fear of having stranded assets would lead to a downsized grid. Several others stressed that RES capacity should be based on national goals such as emission reduction targets and offshore/onshore RES penetration, to then compare only radial with meshed.

A respondent that disagreed believed that **the generation should differ** as a result of the difference in infrastructure and the RES present should be an accurate forecast of what will be there in either scenario. Another points out that if the counterfactual includes onshore wind and PV, it will be a challenge for offshore generation connected through hybrids to get a positive CBA evaluation compared to the counterfactual, and it will not reflect reality, because the market for those technologies will materialise regardless of the integrated offshore projects.

When asking participants if it should be the same amount of **offshore RES or if some could be replaced by other technologies** such as PV in the counterfactual, the response was divided. Some considered it should be possible to allocate the RES capacity to different technologies, while others highlighted that for e.g., in Germany, legislation states that offshore RES will be at least 70 GW in 2045, independently of the presence of offshore infrastructure and that none of this should be replaced by other technologies in a reference scenario. One respondent indicated that it depends on whether the aim to focus on the overall net zero target in 2050, or to find the optimal offshore wind buildout to get to a connect a certain fixed amount of GWs of offshore wind.

5.1.7. Bidding zones

Market arrangements to be considered

Two survey respondents suggested completely reconsidering the market arrangements and configurations. One defends **not using bidding zones** due to their assumption of positive marginal costs. It is considered that, as in the future, RES with close to zero marginals costs will be the predominant supplier, this could result in an unreliable CBA result. The other believes that **RES projects connected with hybrid assets require the investigation of new options**, for e.g., cross-border two-sided CfDs at country or sea-basin level, or EU financing tools.

Nonetheless, **most stakeholders** believed that the market arrangements to be considered **should include offshore bidding zones**, even be a prerequisite, as the **position published by ENTSO-E is that offshore bidding zones should be the default** when assessing and modelling hybrid or meshed offshore grid projects. It is highlighted however that offshore bidding zones should not cross EEZ borders, as this introduces unnecessary governance complexity.[151]

There is also the question of the **optimal split of the offshore bidding zones**. It is proposed to have **each wind farm be its own offshore bidding zone** to enable the potential of hybrid projects. Alternatively, another stakeholder suggested splitting the **hybrid project into more than one bidding zone** if there is internal congestion on the hybrid.

In addition, the importance of the model not leading to reduced capacity offered at the borders is stressed. It is indicated that if the connection between offshore wind and the mainland is structurally congested, the most effective solution is to define **bidding zone borders at the level of the congestion**. It is stated that assessing the outcomes of these different bidding zone approaches would also be an interesting exercise.

There are **other elements** to be considered in the assessment of costs and benefits that survey respondents identified. Firstly, **the structure of the market** will have an impact, depending on degree of liberalisation, competition, market entry barriers, and market rules for storage and flexibility. Secondly, the level of **interconnection** between participating MS, and the **size of their demand** is especially important when the project output includes services beyond energy production such as balancing. Furthermore, the CBA assessment might also be affected by the **MS renewable potential, connection regimes and wholesale market trends**. Finally, the impact of other **regulatory interventions** also needs to be reviewed, such as renewable energy support schemes (auctions, quotas, etc.) or use of cooperation mechanisms and/or Union Financing Mechanisms.

Bidding zones in the counterfactual

Regarding **having the same set of bidding zones in the counterfactual**, the survey responses were **ambiguous**. Some stakeholders consider bidding zones should not be applied in the counterfactual as they might not reflect the needs in further infrastructure, and they do not exist yet. However, others do not see a reason to differ, and consider that bidding zones could be used in the counterfactual to evaluate whether hybrids could be more beneficial than radial solutions.

When asked to highlight any other concerns, one stakeholder stated that the main shortcoming with the sea-basin approach was that it may be sub-optimal at a pan-European level. Another defended the importance to including **sector coupling perspectives** and other energy carriers like hydrogen in the CBA.

5.1.8. Interview insights for SB-CBA design

Nine interviews were conducted with four TSOs, one EU association, two developers and two NRAs. The interview process provided key insights regarding the stakeholders' main concerns and priorities regarding the design of the SB-CBA. The interviews confirmed that most stakeholders consider **ENTSO-E's CBA 3.0** and the **TYNDP scenarios** as an adequate basis and first step towards a SB-CBA. Potential improvements highlighted during the interviews to the design and indicators of the CBA 3.0 were:

- To explore considering the developments needed for a meshed grid (not only for hybrid networks).
- To explore addressing sector coupling indicators or options from different sectors. PtX options, if built onshore, offshore, or combined with wind, will result in different offshore infrastructure needs. Nonetheless, the implementation of an indicator to reflect this was questioned since the scope that the guidelines can have with regard to PtX is limited as TSOs should not focus on demand and are not involved in commercial activities.

[151] https://www.entsoe.eu/2021/07/14/entso-e-position-on-offshore-development-summary-of-recommendations/
https://www.entsoe.eu/2020/10/15/entso-e-position-paper-on-offshore-development-market-and-regulatory-issues/

- To consider including indicators that assess the landing point efficiency, to incentivise the better utilisation of landing points.

- To assess whether to dismiss benefit indicators for AC that might not be appropriate for DC infrastructure such as impact on grid losses.

In terms of costs to include, three more costs items were mentioned by interviewees and discussed in depth: 1. System operation costs, 2. Reserve dimensioning costs, and 3. Costs of additional onshore infrastructure. Firstly, **system operation costs** were highlighted as costs that, despite traditionally not being included in CBAs, could be an interesting addition to account for a potential increased need for ancillary and balancing services as large offshore units are integrated. While, day-ahead markets currently host the largest share of transactions (in volume), liquidity might move to other markets in the future such as balancing, reactive power control or intraday.

Secondly, accounting for **reserve dimensioning costs** was suggested as a potential addition to the CBA methodology. With large offshore farms and hybrids, the largest incident will probably increase compared to the current n-1 design, meaning there could be risk for an incident that needs higher reserves than what TSOs currently have procured. The dimensioning costs would include the need to increase the procurement of reserves or explore other alternatives such as sharing reserves with neighbouring MS, demand curtailment or shedding with PtX units.

Thirdly, how to assess the **cost of additional onshore infrastructure** to transfer the offshore power was addressed by most interviewees. Increased onshore infrastructure is assumed to be needed by most stakeholders interviewed, nonetheless, one TSO challenged this, highlighting that a reduction in onshore infrastructure needs could occur, and should be considered in the CBA assessment.

When asked about **ex-post compensations** to reallocate costs according to realised benefits, the risk of external factors is highlighted, like the addition of another interconnection impacting the revenue streams is highlighted. Therefore, if there is to be a reallocation of costs, it would require a solid legal basis, potentially involving third countries.

Stakeholders interviewed also considered that **non-monetisable benefits** should be at the forefront of the discussions, as these can be substantial in the future. Some examples of elements to assess qualitatively were provided:

- The stability of the frequency

- The effect on innovation if there is the development of certain key technologies such as DC breakers. Innovation is a key reason why energy island hubs are being developed despite being more expensive than other types of projects, and this is also to be considered.

- Environmental concerns like CO2 emissions or other externalities such as having to lay cables in highly sensitive areas around the coast with nature protected areas.

Regarding the **counterfactual**, stakeholders expressed doubts regarding what the counterfactual should be to capture the whole value of a hybrid, which is a dual-purpose asset. It is agreed that the assumptions for the counterfactual should align with the objectives established in regulation, and it was stressed how offshore parks should not be compared with the onshore options. The reason is that offshore generation will be more expensive, yet it has the potential to connect significantly more future generation capacity.

Stakeholders also presented further suggestions regarding **reference grid** during the interviews. Firstly, it was recommended to involve NRAs in the reference grid decision process to add scrutiny, apart from the TSOs. NRAs can provide insight and validate the reference grid by considering the advancements and delays in the projects, allowing to reach a more likely reference grid. Furthermore, not differentiating between onshore and offshore grid investments was suggested, as well as assuming inelastic demand for most segments, with some elasticity allowed, for instance, for EV charging.

5.2. Sea-Basin Cross-Border Cost Sharing (SB-CBCS)

5.2.1. SB-SBCS structure

Some stakeholders believe that the preferred solution is to let **MSs negotiate** the infrastructure costs if projects aim at applying for any type of financial support from the EU, also if parts of the Sea Basin territory is outside the EU and EEA.

However, most survey respondents support using a SB-CBCS and believe that if the design is flexible enough, it can contribute to getting hybrid projects off the ground. In terms of structure, the three main pillars of a traditional CBA (**Market-benefit, Monetarization of increased SoS, Monetarization of reduced emissions**) are proposed to be the **main items to be considered** also in an offshore CBCS-methodology.

One stakeholder suggests using the distribution of benefits between MSs from the SB-CBA to set up a **separate fund for the landlock countries to contribute** to the SB offshore projects. Another stakeholder highlights that the tool should **support countries that have already agreed on cooperating on specific projects**.

5.2.2. Sharing of costs between Member States

Cost sharing options SB-CBCS

When assessing the cost sharing options between Member States, the first question that arises is which costs should be in scope, one stakeholder proposing, for instance, the binding of investment and operation costs together.

Regarding allocation-of-cost methodologies proposed, several survey respondents suggest having MSs directly involved in developing individual projects to **negotiate** their cost sharing options. Having **flexibility** to select alternative cost distributions is considered key to ensure continued development of favourable solutions, both inside and outside the framework of the SB-CBCA. MSs that do not arrive to agreements can always use the SB-CBCS guideline principles.

Other stakeholders consider that, despite potential complexity, the fairest approach is to have costs **prorated according to energy usage or distributed according to the benefits received.** It is proposed to have, as a minimum, an assessment of captured Socio-Economic Welfare for involved MS, and avoid arbitrary options that may create low cost-benefit for one party, and high cost-benefit for another.

Furthermore, stakeholders highlight the need to **avoid double-counting and double-remuneration by network tariffs and congestion income**, as well as considering the ownership in relation to cost allocation and captured benefits. In addition, using climate impact or local emission reduction indicators as a **complementary source** to support the cost sharing decision is proposed, assessing the contribution to EU RES goals.

The application of an **ex-post financial correction** for part of the project costs is suggested to ensure that the cost-sharing does not only rely on sensitive scenario-based calculations, as for instance, as a small change in fuel costs could result in the activation of one generation over another, potentially changing the CBA result. An option suggested is to reflect deviations of realised investments in subsequent investments.

Cost sharing criteria SB-CBCS

When asked about the criteria to define which MS benefits should be included in the CBCS, the **views were mixed** regarding whether there should be a minimum threshold that conditions which MS are to be included. Several stakeholders considered that there should be **no threshold** as it has the risk of being **arbitrary** and **small countries would** perceptually **benefit** even at low shares of the overall (high) benefit. Others did consider that there **should be a minimum threshold** (e.g., like 10% for CBCA) to avoid too detailed investigations of lesser cost-benefit-values and ensure minor landlocked beneficiaries do not stall hybrid projects. If needed, smart thresholds can also be a possibility, for instance, having different criteria for countries directly involved (landing points) and others.

Other criteria were also proposed to assess the benefits more broadly, such as using the imported flow share, sustainability indicators, socio-economic welfare, technological asymmetry or security of supply indicators already quantified in existing CBA methodologies.

5.2.3. Interview insights for SB-CBCS design

Stakeholders advocated for the approach of **cost-sharing based on negotiations between countries with SB-CBCS as a basis** for the cost-sharing. The interview process brought forward a number of suggestions for the design of the guideline.

There was no unanimous view regarding whether **MSs not directly involved in a project but benefiting from it should be included in the cost allocation calculations**, and if involved, what minimum threshold should condition which MSs are included. Apart from the considerations presented in the survey replies, a TSO highlighted that if the threshold is too high with respect to the size of the country, it would result in small countries with high benefits per inhabitant not contributing.

Several TSO representatives believed that these negotiations should be **limited only to involved MSs**. It was considered that when third parties get involved, decisions regarding the planning of new infrastructure move towards risk preparedness resulting in significant resources potentially spent on avoiding risks. Furthermore, enhanced uncertainty associated with sharing costs beyond the MSs involved was also a concern, as it meant the possibility of also being considered in other MSs cost-sharing calculations. The interviewed TSOs preferred the certainty of having each country to cover the costs of their responsibility area.

The information on the project benefits and results would be shared with other MSs but sharing costs information should not be required. Furthermore, **cost-sharing with MSs not directly involved might be a barrier** to building more offshore infrastructure, as these countries might not value the benefits and not willing to contribute. A non-binding CBCS could be an initial step towards building a common understanding, nonetheless, disagreements on the negotiations could hamper arriving to a pan-European and optimal solution.

Some stakeholders were able to share their experiences with cost sharing of bilateral interconnector projects. A positive experience with a bilateral agreement resulting in a 50-50 split between two MSs to develop an energy hub was described by a TSO. How an agreement was reached based on negotiations with both TSOs and regulators of involved MSs was also explained. This TSO supported cost sharing not necessarily having to be a 50-50 split or each MS paying strictly what is built in its country, but rather deciding based on the benefits, calculated considering a significant number of climate years to properly assess security of supply. This is particularly important as the level of available generation capacity in some MSs is strongly dependant the hydrological situation or on wind.

Regarding other alternatives to cost sharing, **a climate-impact based approach was suggested**. As national CO2 reduction targets are derived from European targets that are based on GDP per capita, GDP per capita could be used for an allocation mechanism. For example, having x% of costs allocated directly to the hosting MS/TSOs of a project, and having 100-x% of costs allocated to all EU27 MS/TSOs, shared on a GDP per capita basis.

TSOs agree on the need to explore the sensitivity of the benefits against the assumptions used, e.g., fuel costs, to assess cost allocation robustness and how the results would change. Benefits might also change in time; therefore, it could also be interesting to explore hedging possibilities, with mechanisms like CfDs, or ensure all parties accept the risk if no hedging mechanisms are applied. Another alternative to be considered is to explore a mechanism that detaches cost allocations from the benefits to reduce these sensitivities.

Finally, developers highlight that it is key for the industry to be able to sign corporate Power Purchase Agreements (PPAs). Contracts for difference (CfDs) may shift most of the power trading to the wholesale market, therefore, limiting the availability of PPAs, and removing the access of low-cost power to the industry.

5.3. Recommendations on coordination of offshore wind energy generation and transmission infrastructure CBA and CBCA

5.3.1. Coordination between offshore RES and transmission infrastructure CBAs

The survey provided a list of elements for stakeholders to check which they considered needed to be considered/coordinated between the offshore renewable energy generation and transmission infrastructure CBA. Arranged from most voted to least, the results were the following, with considerations on the reference scenario positioned as the most critical element to coordinate:

Reference scenarios	x10
Consideration of operation & maintenance costs	x9
Cost types considered	x9
Counterfactuals	x9
Bidding zone configurations	x8
Emission allowance prices / cost of carbon	x8
Consideration / exclusion of non-monetised benefits	x7
Benefits / KPIs considered	x7
Discount rate	x6
Assets eligible for CBCA	x5
Quantification / Monetisation approach	x5

All the options provided were checked by at least 5 stakeholders, illustrating that alignment on **all the above would be ideal** to arrive at the optimised solution between offshore generation and transmission infrastructure (onshore and offshore). Survey respondents also comment on the fact that in practice, this **could be challenging**. To overcome this, it is suggested that, if there are support-schemes for offshore generation, the evaluation of these should be based on the same assumptions as the transmission, potentially including in the CBCS-guidance which assumptions to be coordinated.

Regarding other elements to consider, the **economic lifetime** is emphasised, as currently different assumptions for specific assets exist and there is a need to arrive to an agreement on this before conducting a CBA.

In general, it would be beneficial to have the **same input for both CBAs**, and a provision could be implemented to require a justification if there is a difference between them. Stakeholders especially stress the importance of having **shared reference scenarios and input data** for bidding zone configurations. They emphasise the need for the **CBAs to reflect the combined project**, as this is the strength of a hybrid project, even part of the same assessment to ensure correct accounting and the avoidance of double counting.

5.3.2. Coordination between offshore RES and transmission infrastructure CBCA

The survey also provided a list of potential elements to coordinate between offshore RES and transmission infrastructure CBCAs for stakeholders to check. See results below, with network tariffs and public support such as state aid considered the most important elements to be considered.

Network tariffs	x8
Public support: State aid (e.g. National or cross-border support schemes)	x8
Statistical transfers	x6

Public support: grants (e.g. CEF funding) x6

Cost-benefit allocation rules (50/50, where benefits accrue, etc) x6

Inclusion of non-hosting Member States x6

Existing allocation mechanisms (e.g. congestion income and ITC mechanism-related transfers) x6

Similarly to what was indicated for the CBA, stakeholders consider that to find an optimised solution for the CBCA, the evaluation should be done based on the **same assumptions**, in this case, particularly on **network tariffs and allocation mechanisms**. From the elements to coordinate from the list above, stakeholders commented the following:

Ensure enough certainty of net benefits for coordinating the **inclusion of non-hosting MS.**

Whereas **national grants** for infrastructure should **not be included** in the CBCA of infrastructure as it is up to the relevant authorities in a Member State to decide on how costs are recovered, **support schemes for offshore renewable generation should be considered** in the CBA and CBCA as these are additional CAPEX or OPEX (depending on the support scheme) for the hosting Member State to ensure investment in offshore renewable generation.

Statistical transfers should be considered in the CBCA for infrastructure as this might include a financial settlement between Member States for (part of) offshore RES and infrastructure. However, when approaching the target year 2050 **RES credits will become less relevant (RES credits, known as Guarantees of Origin in Europe, or more generally Energy Attribute Certificates, will have low value most of the MSs can be assumed to have transitioned to Net Zero, hence the relevance of RES credits as a stimulating instrument diminishes), and cost allocation should not be (partially) based on statistical transfers**.

Despite offshore RES and transmission infrastructure CBCAs having to be as consistent as possible, it is indicated that the funding, costs and revenues are inherently different between generation and transmission. Therefore, treating them jointly might have the risk of added complexity, unbundling challenges and reduced transparency.

Survey respondents also suggested other elements to be coordinated such as ITC, a financial compensation between TSOs for the use of the onshore grid of other Member States. It is considered that the **ITC should ensure sufficient coverage of onshore grid utilisation for flows due to offshore RES, or the CBCA should consider the ITC to prevent double financial settlement for onshore grid utilisation**.

When asked **what to address to improve consistency and coordination** between the Connecting Europe Facility CBA guideline (generation) and the ENTSO-E CBA methodology 3.0 draft and implementation guidelines (transmission), stakeholders emphasised having shared input data and assumptions for scenarios, CO2 prices, and definition of the factual and counterfactuals.

In addition, stakeholders proposed several strategies to avoid double counting of economic, environmental and other costs and benefits between offshore transmission and generation when conducting CBAs:

- Explicitly identifying how much of **environmental** or other benefits are **accounted in the economic analysis** and **discount the same proportion** in specific environmental analysis.
- Having a clear **distinction between generation and infrastructure assets**, and **consumer-, producer- and congestion-rents.**
- **Only accounting for charges** and **revenues** if they relate to the **projects** and are designated to cover the costs concerned.
- **Plan simultaneously transmission and generation** infrastructure at international level, avoiding patching national and international planning elements.

- **Increase coordination and consistency** between both exercises. Currently, for the infrastructure part, surplus for generation is allocated to generation and this is cross-checked with costs. Such a method avoids double-counting.

The Connecting Europe Facility Funds for PCIs, PMIs and cross-border RES

The Connecting Europe Facility (CEF) is a key funding instrument for targeted investments at the EU level focusing on transport, energy and digital infrastructure as well as renewable energy. Concerning energy infrastructure, nine priority corridors and three priority thematic areas have been identified for intervention in the revised TEN-E framework, one is CEF for Energy (CEF-E) that supports the implementation of the linking the energy infrastructure of EU Member States. CEF-E supports the implementation of PCIs in these areas as a main financing source.

Under the revised CEF Regulation, the mechanism also lists and supports **cross-border renewable energy projects,** aiming to enable Member States to reach their RES targets and ensure the cost-effective deployment of renewables in the Union, using the cooperation mechanisms mentioned above.[152] The cross-border projects are assessed following the Commission's 2021 methodology for conducting CBAs[153] before they can apply for CEF funding.

The EU Renewable Energy Financing Mechanism

Stemming from article 33 of the Governance Regulation (EU) of the Clean Energy for all Europeans Package, the Mechanism has been in force since September 2020. It links countries that voluntarily pay into the mechanism (called **contributing countries**) with countries that agree to have new projects built on their territory (**hosting countries**).

Via the mechanism, contributing countries can finance renewable energy projects elsewhere that are potentially more cost effective than building them on their own soil (for which the perfect example are offshore windfarms e.g. in the case of landlocked countries)[154].

State aid rules do not apply to either of the participating parties in the mechanism, and there is no direct link or negotiation between contributing and hosting countries.

5.3.3. Interview insights regarding coordination between generation and transmission infrastructure CBAs and CBCAs

The interview process provided key information about the stakeholders' main concerns and priorities regarding the coordination of offshore wind energy generation and transmission infrastructure CBAs and CBCAs.

How to assess **integrated projects with hybrid transmission** infrastructure is the main topic of discussion. Developers disagree on how to assess the benefits of these projects: a) whether to plan generation and transmission infrastructure together, as when deciding the capacity of an interconnector, the wind capacity has to be considered; b) or separately, to not combine regulated interconnector assets with market generation assets. Stakeholders do agree on needing to have clear definitions and mechanisms to **avoid double counting** and considering the regulatory framework to ensure **unbundling**.

Ownership is one of the main concerns. Nonetheless, there is agreement on the need for a clear determination of what assets are part of the client connection and which part of the TSO infrastructure. For instance, storage is seen as infrastructure by some parties, while others argue that its business case is market based (arbitrage or ancillary service provision) and not regulated (through network tariffs).

To facilitate the coordination, it is suggested for the guideline to specify what costs to include. Stakeholders interviewed agreed that these **costs should include the onshore investments** needed to connect the offshore capacity. However, there is also acknowledgement that there would need to be clear boundaries and methods to determine exactly what costs for onshore

[152] EUR-Lex - 32022R0342 - EN - EUR-Lex (europa.eu)
[153] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SWD:2021:0429:FIN:EN:PDF
[154] https://energy.ec.europa.eu/topics/renewable-energy/financing/eu-renewable-energy-financing-mechanism_en

reinforcements and connections could be included. This could be a challenge as determining the eventual purpose of what is built onshore can be complex.

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