Projet DRIVER du Fonds de Transition Energétique octroyé dans le cadre de l'appel de Novembre 2020

Délivrable 6 (D6) : Feuille de route technologique en vue de la gestion du futur marché du CO_2 en Belgique

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Date : 30 Septembre 2025

DRIVER

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Note : en accord avec les représentants du SPF Economie, il a été convenu lors de la kick off meeting du projet DRIVER qui s'est tenue le 25 Octobre 2021, que les délivrables du projet peuvent être rédigés soit en français soit en anglais moyennant un résumé en français. Le présent document comprend donc cette section introductive en français, qui résume le contenu du rapport technique (roadmap) qui quant à lui, est rédigé en anglais, permettant une diffusion à un public plus large.

1. Rappel des objectifs du projet DRIVER

Le projet DRIVER (**D**éveloppement d'un modèle de ma**R**ché, **I**nfrastructurel et régulatoire, du CO_2 comme **V**ecteur pour le stockage d'**E**nergie **R**enouvelable) vise le développement de modèles de chaînes de valeur incluant le CO_2 en vue de la production de fuels synthétiques défossilisés permettant de réduire la dépendance aux combustibles fossiles et à terme tendant vers une indépendance énergétique. Le projet intègre les volets économiques, infrastructurels et régulatoires, et prend en compte les spécificités belges tant au niveau énergétique que des infrastructures. Les modèles ont été développés afin de permettre, notamment, la définition d'une roadmap technique donnant les orientations à suivre pour le développement du « marché CO_2 belge », dont les différents indicateurs (énergétiques, économiques, environnementaux, …) pourront servir de base en vue du développement ultérieur d'une plateforme digitale.
Le CO_2 étant au centre du projet DRIVER, une attention particulière se porte sur la chaîne de capture, purification et transport de CO_2, ce dernier pouvant ensuite servir à la production d'autres vecteurs énergétiques tel que par exemple le gaz naturel synthétique (SNG) ou encore le méthanol. Une telle chaîne de procédés est couramment dénommée « CCU » (Carbon Capture & Utilisation). Le CO_2 est donc l'un des éléments d'un réseau énergétique global (cf. illustration du scope du projet DRIVER à la Figure 1) aux côtés des dispositifs de stockage d'énergie renouvelable, de la production et du transport d'hydrogène et de tous les éléments nécessaires pour fabriquer, à partir de ce CO_2, des e-fuels et les transporter.

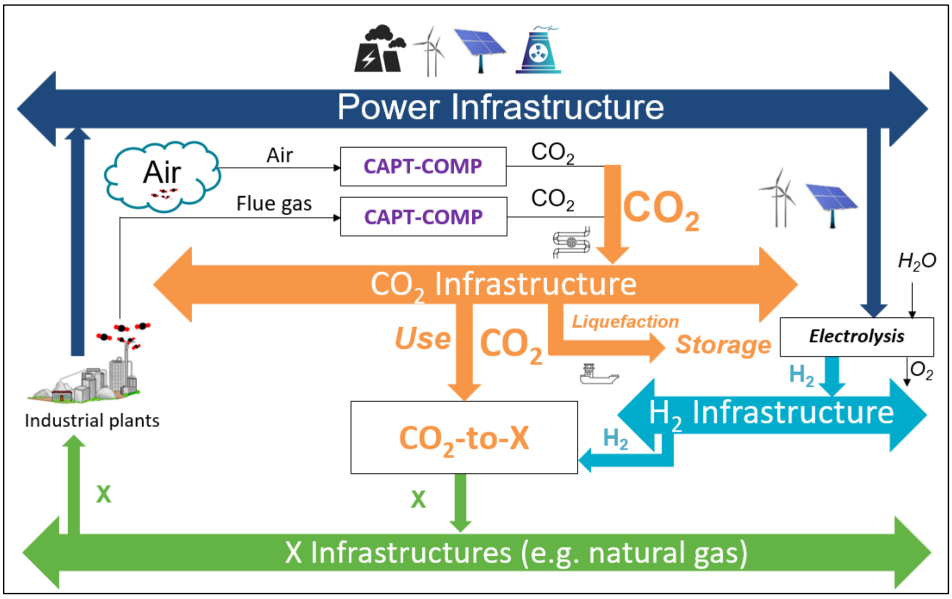

Figure 1 : Illustration du scope du projet DRIVER

Les différents Work Packages (WP) du Projet DRIVER sont illustrés à la Figure 2.

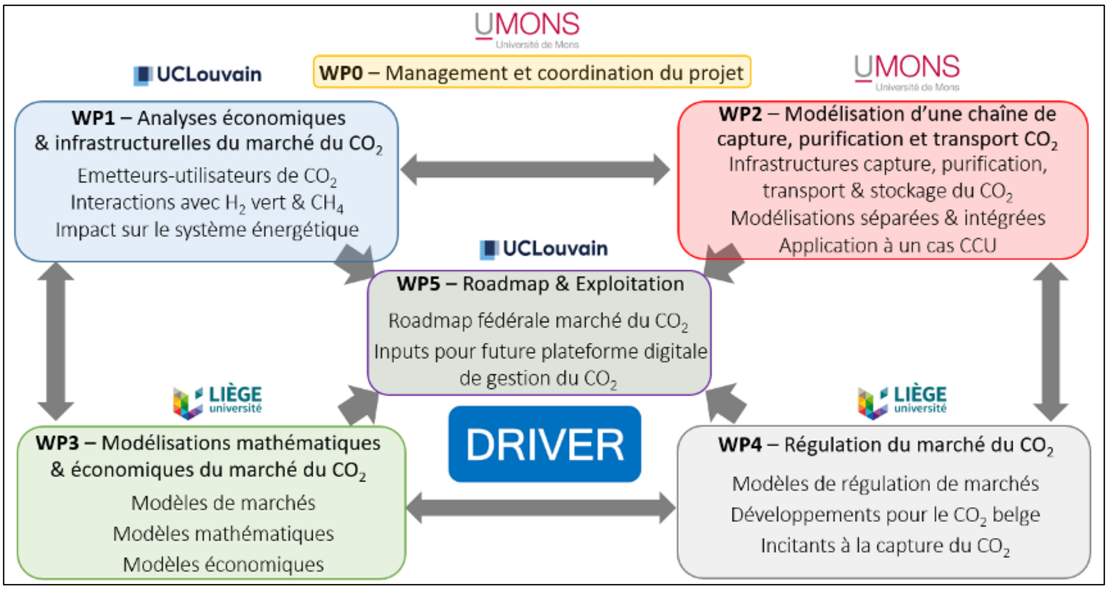

Figure 2 : Work packages du projet DRIVER

D'un budget total de 1 121 659 €, le projet DRIVER, a démarré au 1er Octobre 2021 pour une durée de 4 ans.
Le consortium est composé de 3 universités belges qui mutualisent leurs expertises, à savoir l'Université de Mons (UMONS), l'Université de Liège (ULiège) et l'Université Catholique de Louvain (UCLouvain).

2. Résumé de la feuille de route (délivrable D6)

2.1. Pertinence de la feuille de route

Près de 50 % des émissions actuelles de CO_2 en Belgique sont liées aux secteurs industriels. Par conséquent, en parallèle à l'électrisation et à l'optimisation énergétique, la mise en œuvre d'une chaîne de capture, transport, utilisation et/ou stockage du CO_2 (CCUS) semble obligatoire pour réduire de manière significative les émissions de CO_2 de la Belgique . Cette mise en œuvre nécessitera des infrastructures spécifiques pour capturer, purifier, liquéfier, transporter et stocker le CO_2, et/ou pour l'utiliser comme matière première pour la génération de plusieurs vecteurs énergétiques. Ces chaînes de valeur conduiront à un marché du CO_2 significatif à gérer, mais elles auront également un impact sur le système énergétique belge. De plus, cela nécessitera une coordination adéquate avec des centres d'énergie renouvelable distants (RREH – Remote Renewable Energy Hubs).
La présente feuille de route technologique est donc importante et pertinente pour plusieurs raisons :
- aider à identifier les choix technologiques les plus adéquats en matière de CCUS et de systèmes énergétiques à mettre en œuvre en Belgique est d'une importance majeure, en particulier pour optimiser les technologies elles-mêmes et leurs coûts afin d'assurer la viabilité économique des processus concernés ;
- le marché du CO_2 jouera un rôle clé à court, moyen et long terme en Belgique, mais aussi globalement en Europe, et les technologies clés pour récupérer, valoriser et stocker le CO_2 reposeront sur le CCUS (et éventuellement le DAC) ;
- les technologies auront un impact sur le système énergétique belge et l'utiliseront, et celui-ci s'appuiera sur les RREH ;
- même si la présente feuille de route est davantage axée sur les « aspects technologiques », elle combine les dimensions techniques, économiques, infrastructurelles et réglementaires.

Basée sur les résultats acquis dans le cadre du projet DRIVER, la présente feuille de route a donc été structurée par composantes technologiques, à savoir CCUS & DAC, système énergétique belge et les centres d'énergie renouvelable distants (RREH).

2.2. Résumé des principaux enseignements de la feuille de route

En ce qui concerne les étapes de capture et de purification du CO_2, deux grandes catégories de procédés ont été étudiées plus en détail, à savoir l'absorption-régénération à l'aide de solvants aminés et les technologies cryogéniques (éventuellement hybrides, combinées à l'utilisation de l'adsorption gaz-solide (VPSA-CPU) ou de membranes en tant qu'étape de préconcentration). Le défi pour la première catégorie reste de réduire son coût (consommation élevée d'énergie thermique) et la question concernant les spécifications de transport du CO_2 (nécessité éventuelle de post-traitements), tandis que pour la seconde, il s'agit de continuer à optimiser le processus afin de réduire sa consommation d'énergie électrique.

La prise en compte des techniques cryogéniques est primordiale. En effet, outre le taux de récupération du CO_2 lui-même, le fait que des spécifications de pureté strictes doivent être respectées pour l'injection du CO_2 dans un réseau de pipelines (et/ou pour son transport liquéfié par bateau), nécessitera probablement très souvent l'utilisation d'une telle technologie. L'étude de la liquéfaction du CO_2 est également importante, car il sera transporté par bateau sous forme liquide vers un centre de stockage géologique.

En ce qui concerne l'étape de conversion du CO_2, qui pourrait être intégrée thermiquement à une unité de capture (les avantages d'une telle opération ont été démontrés), une attention particulière a été accordée au méthanol et au méthane, le méthane apparaissant comme le vecteur énergétique présentant le plus grand potentiel.

Quant au captage direct de l'air (DAC), il pourrait avoir un rôle à jouer dans la décarbonation globale à condition que tous les efforts soient faits en amont pour réduire au maximum les émissions de CO_2 à la source. L'émergence du DAC pour les zones non industrielles pourrait être envisagée à l'avenir pour la production de vecteurs énergétiques hydrogéno-carbonés dans les zones où de grandes quantités d'énergie non fossile sont disponibles. En ce qui concerne la Belgique, le rôle des DAC sera certainement limité à court et à moyen terme, en particulier tant que les grands émetteurs industriels de CO_2 n'auront pas encore limité leurs émissions.

En complément des investigations du CCUS, des centres d'énergie renouvelable distants (RREH) ont été étudiés. Les RREH sont des lieux géographiques qui rassemblent les caractéristiques suivantes : (i) disposer d'un potentiel local de génération d'énergie à partir de ressources renouvelables, (ii) avoir une demande locale marginale au regard de la production, (iii) être en lien avec des centres de consommation intensive d'énergie. Parmi les solutions envisagées au niveau de la production locale, il y a celle qui consiste à générer de l'hydrogène vert et à le combiner avec du dioxyde de carbone afin d'en faire, par exemple, du méthane synthétique. Le carbone nécessaire à ce procédé peut être soit prélevé dans l'air (DAC) ou bien acheminé depuis un centre de consommation intensive d'où il aurait été capturé. Ainsi, les RREH offrent des perspectives de valorisation au CO_2 capturé et transporté vers le hub. Une fois ce constat établi, de nombreuses nuances apparaissent selon le choix des scénarios : en premier lieu, la concurrence des solutions classiques (incluant l'importation de gaz naturel pour la production électrique) combinées à la capture suivie de l'enfouissement du CO_2. Lorsque l'enfouissement n'est pas disponible à hauteur des espérances, la contrainte sur le volume des émissions peut faire émerger les RREH en tant que lieux permettant la génération d’énergie neutre en carbone à destination du centre de demande énergétique.

Une analyse plus globale des chaînes de valeur intégrant le CO_2 et divers vecteurs énergétiques, en particulier dans le contexte du système énergétique belge, a également été réalisée. Les résultats montrent que la valorisation complète du CO_2 capté dans le port d’Anvers est techniquement possible, mais irréaliste compte tenu des besoins en hydrogène, de la consommation électrique quasi équivalente à celle du pays en 2021, et des capacités d’électrolyse à installer. Des stratégies de valorisation partielle, alignées sur les importations et la production domestique d’hydrogène, apparaissent plus crédibles : elles réduisent fortement la demande électrique tout en permettant des baisses significatives d’émissions.
Parallèlement, les importations d’électrocarburants renouvelables (e-méthane, e-méthanol, e-hydrogène, e-ammoniac) restent structurelles dans toutes les trajectoires étudiées, représentant jusqu’à 40 % du mix énergétique primaire en 2050. Leur utilisation est différenciée selon les secteurs : le e-méthane pour la chaleur industrielle, le e-méthanol pour la chimie, l’e-hydrogène pour le fret routier, et l’e-ammoniac comme intrant industriel et combustible électrique. Toutefois, leur rôle exact dépendra fortement de l’évolution des coûts et de la demande mondiale. Ces résultats soulignent qu’une stratégie robuste pour la Belgique doit combiner une valorisation pragmatique du CO_2, limitée par la disponibilité en hydrogène, et des importations diversifiées et flexibles d’électrocarburants. Cet équilibre permet de réduire les risques technico-économiques, de soutenir la compétitivité industrielle et de renforcer la sécurité énergétique.

Une analyse axée sur la comparaison des procédés de capture du CO_2 après combustion au sein du système énergétique belge a également été réalisée. Il inclut la possibilité de capture via deux procédés post-combustion (PCCCs) différents : l'absorption-régénération à l'aide de solvant aminé (MEA 30%) et la technologie cryogénique hybride combinée à l'utilisation de l'adsorption gaz-solide (VPSA-CPU). Les paramètres techniques des PCCCs sont adaptés à la concentration de CO_2 dans les fumées de chacun des émetteurs. L’une des particularités de ce modèle est la possibilité d'installer ces procédés à différents taux de capture. Les résultats montrent que la capture de CO_2 chez les émetteurs avec la concentration de CO_2 la plus élevée (les cimenteries, les entreprises sidérurgiques et la centrale biogaz de Knippegroen) est la plus compétitive économiquement. Pour ces émetteurs, la technologie VPSA-CPU est préférée car elle nécessite uniquement de l'électricité comme source d'énergie (contrairement à la technologie par absorption qui a également besoin d'une source de chaleur). Le prix de l'électricité est le principal facteur pour le cout de la capture pour cette technologie, représentant de 60% à 76% des coûts totaux liés au PCCC en fonction du scénario. De plus, à partir des hypothèses choisies, les prix de la capture pour ces émetteurs sont du même ordre de grandeur que l'actuel taxe CO_2 ETS (~75 €/t_{CO2}) pour les scénarios dans lesquels les prix de l'électricité sont les plus bas.

Pour atteindre l'objectif de réduction des émissions à l'horizon 2030, même dans le cas le plus optimiste, la taxe CO_2 qu'il faudrait imposer pour encourager les différents acteurs à investir est supérieure à 200 €/t_{CO2}. Ce cout est partiellement expliqué par la nécessité de capturer du CO_2 chez des émetteurs avec une concentration plus faible de CO_2 dans leur fumées (et donc un cout de capture plus élevé). Ce cout englobe également les couts liés au transport, au post-traitement et à la séquestration du CO_2 ainsi que les ajustements du système énergétique belge (augmentation de la capacité de production électrique disponible par exemple).

Outre les aspects techniques, différents points de réflexion sur les aspects du financement sont également abordés dans la feuille de route. En effet, c'est la chaîne de valeurs dans son entièreté, incluant différentes technologies et différents acteurs, qui doit pouvoir être financée via des mécanismes adéquats. En outre, l'attention est attirée d'une part sur les futurs opérateurs des réseaux de transport du CO_2 et autres vecteurs énergétiques qui veulent s'assurer que ceux-ci seront disponibles en quantité, et d'autre part sur les émetteurs de CO_2 ou producteurs d'énergie renouvelable qui veulent s'assurer que les infrastructures seront bien disponibles pour le transport de ces vecteurs. Une législation favorable, incitante, combinée à des mécanismes de financements européens, font partie des éléments clés de la problématique.
Il est également évoqué que l'acceptation sociale des technologies (telles que le CCUS, les RREH, etc.) est essentielle pour assurer leur déploiement, avec des actions de sensibilisation et d'implication des citoyens. Aucune étude spécifique sur cet aspect n'a été réalisée dans le cadre du projet DRIVER, mais quelques réflexions sur cet aspect sont fournies dans la feuille de route.
Il a été établi que plusieurs facteurs influencent l'acceptabilité sociale des technologies : la perception du risque, le manque de sensibilisation et d'information, l'acceptabilité locale des infrastructures, ou encore les avantages économiques et création d'emplois. Afin d'améliorer cette acceptabilité sociale, différentes stratégies doivent être suivies : une communication claire sur les technologies, la multiplication de cas concrets en Belgique par le biais de projets de démonstration, la transparence des projets et l'augmentation de l'engagement du public, ainsi que la co-construction de projets avec différentes parties prenantes.
Globalement, les acteurs des technologies en question (comme le CCUS) doivent s'inspirer de ce qui se fait dans d'autres secteurs technologiques pour accroître l'acceptation sociale de cette technologie. En outre, des politiques adéquates et des procédures d'autorisation (« permitting ») facilitées amélioreront également l'applicabilité de la technologie.

2.3. Perspectives

Comme perspective de la présente feuille de route, il semble intéressant d'envisager la mise en place d'une « plateforme digitale du CO_2 » en Belgique. Le développement d'une telle plateforme numérique pour la gestion du CO_2 permettrait d'optimiser la chaîne de valeur CCUS et d'améliorer la transparence du marché. Les objectifs d'une telle plateforme pourraient être :

- de centraliser les données sur les émissions de CO_2, les sites de captage, le réseau de transport vers les sites de stockage et/ou les sites d'utilisation du CO_2 ;
- d'assurer un suivi en temps réel des flux de CO_2 afin de garantir une gestion efficace de l'infrastructure (ce suivi en temps réel pourrait être établi en collaboration avec l'opérateur de transport de CO_2, probablement Fluxys) ;
- faciliter les transactions entre les producteurs, les transporteurs et les utilisateurs de CO_2 ;
- disposer d'un soutien réglementaire pour garantir le respect des normes environnementales et économiques.

A cette fin, sur la base de plusieurs plateformes numériques existantes (des exemples sont fournis en annexe de la feuille de route), différentes fonctionnalités devraient être développées: une cartographie interactive, un module de suivi et de reporting, un « CO_2 market place », un cadre réglementaire avec système de gestion et de certification, une gestion-optimisation des infrastructures et, globalement, l'intégration de plusieurs technologies de gestions numériques.
Il sera certainement pertinent pour les autorités belges de s'inspirer de ce qui a déjà été développé par plusieurs entreprises dans d'autres pays afin de construire la plateforme digitale belge de gestion du CO_2.

Technology roadmap for managing the future CO_2 market in Belgium

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Date: 30 September 2025

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1 Introduction

1.1 Belgian CO_2 emitters

The distribution of the greenhouse gases (GHG) varies from one sector to another. GHG quantities emitted in Belgium in 2023 is around 97.92 $MtCO_2e$ (EEA, 2025). Figure 3 shows the distribution of the main GHG for this period. Carbon dioxide is the most emitted in the atmosphere with 86.1%. It is logical to search solution to reduce CO_2 emission. For the other GHGs, methane and nitrous oxide are gases to be monitored as they account for more than 10% of CO2e emissions.

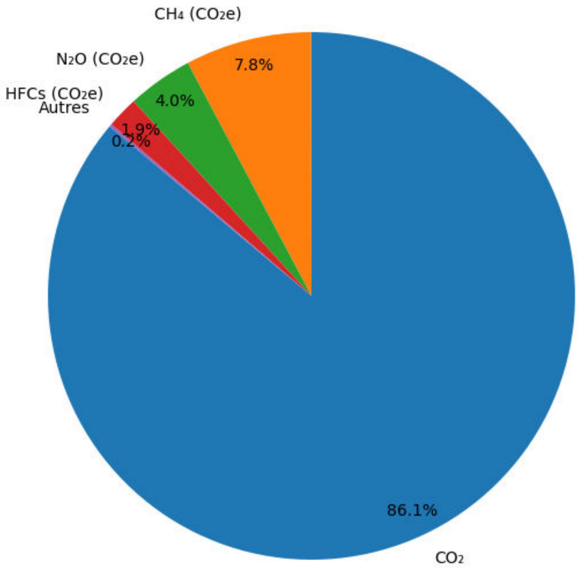


Figure 3: Partition of the principal GHG in Belgium (2023) (EEA, 2025)

As a first step, an analysis of the different sources of emissions can be made. The E-PRTR database and EU ETS database includes the different companies that are subject to the highest emissions of CO_2 or other pollutants. The data is therefore collected in relation to the sectors of activity of the companies. The sectors impacted by the collection of CO_2 emissions data are provided in Annex I of the "Document for the implementation of the European PRTR" (EEA, 2020) for the E-PRTR and in Annex I of the 2003/87/CE Directive (European Parliament & Council, 2003) and a supplement in the Annex of the 2009 Directive (European Parliament & Council, 2009) about aviation for the EU ETS.

One of the major differences between the two databases is that the former has thresholds depending on the pollutant. For CO_2, the threshold is 100 kt of CO_2/year. After a detailed analysis of both databases for Belgium in 2023, the data correspond to 70%. There are several reasons for these differences.

- The for the incineration of municipal and hazardous waste are not covered by the EU ETS. However, it is a significant source of emissions as the CO_2 release exceeds the threshold.
- Biomass energy is considered carbon neutral according to the IEA report (2011) (Tuerk et al., 2011). The EU ETS therefore does not consider such installations for the purpose of valorising their development since biomass is considered advantageous compared to fossil resources.

Due to this threshold in the amount of CO_2 emitted, the E-PRTR data (EPTR, 2024) are far from covering all CO_2 emitters. The data reported by the EU ETS therefore contains a more comprehensive list of CO_2 emitters.

In Belgium, 274 companies in activity in 2023 (excluding aviation) are covered by the ETS. Figure 4 lists the different emission points according to their activity and CO_2 emission in 2023 For this year, emissions reach 35.4 MtCO_2 and the main emitters are located along the Walloon backbone (E42 highway) and around the port of Antwerp and the city of Ghent. Referring to the Pareto principle, which can be summarised as follows "80% of the consequences come from 20% of the causes", 46 companies (corresponding to a 16.5% share) account for 83.5% of CO_2 emissions. Ideally, it is these emitters that should reduce their CO_2 emissions as a priority.

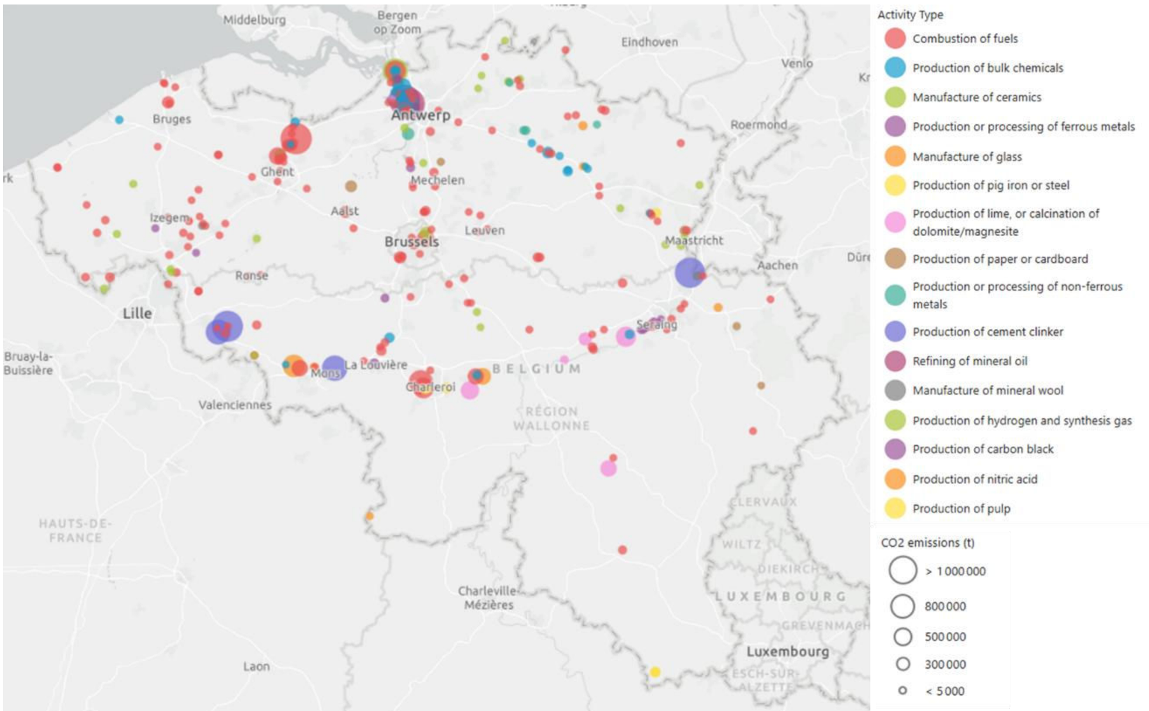


Figure 4: CO_2 emitter by activity covered by EU ETS in Belgium (2023) (DGCA, 2025)

Turning to activities from an ETS viewpoint, the default activity is the combustion activity with a total rated thermal input exceeding 20 MW. In addition, there are nine other specific activities that refer to production or firing capacity. However, only one activity category can be assigned per company. Thus, an enterprise exceeding the capacity as well as the thermal power threshold will have a specific activity. And therefore, enterprises not exceeding the capacity threshold but exceeding the combustion threshold are considered as a combustion activity. Of the 274 companies covered by the EU ETS in Belgium, 178 are involved in fuel combustion.
Most of these facilities are classified under combustion activities, though many fall into specific industrial categories such as cement, lime, power, steel, and refining. For installations not exceeding sector-specific thresholds, the fallback classification remains combustion-based. Meanwhile, emissions from municipal waste incineration, although not included in the ETS, remain substantial as 11 installations emit over 2.6 MtCO_2/year (based on 2023 IEPR data (EPTR, 2024)).
Among the largest emitters in the EU ETS (listed in the Table 1) are various companies with quite different activities. Thus, despite the high annual CO_2 emissions, the flue gases that cause these emissions are quite different. The composition of the gases depends on many factors such as the type of product manufactured by the company, the fuel burnt, the operating conditions, the type of process, etc. Thus, the data collected by the E-PRTR will give an initial idea of the other compounds present in the gaseous emissions.

Table 1: Emitters above 500 kt_{CO2}/year included in the EU ETS for 2023 (DGCA, 2025)

	Company name (Plant type)	**kt_{CO2}/year**
1	Electrabel Knippegroen (Power plant)	3834
2	ArcelorMittal Gent (Steel plant)	3690
3	Total Antwerpen (Refinery)	3283
4	BASF Antwerpen (Chemical plant)	2873
5	Esso (Refinery)	2183
6	CCB Gaurain (Cement plant)	935
7	CBR Lixhe (Cement plant)	798
8	Holcim Obourg (Cement plant)	715
9	CBR Antoing (Cement plant)	704
10	Electrabel Amercoeur-Roux (Power plant)	700
11	Total Olefins Antwerp (Chemical plant)	691

Cross-referencing with UNFCCC national inventory data EEA 2, total CO_2 emissions in Belgium in 2023 reached approximately 84.3 $MtCO_2$ with around -0.36 $MtCO_2$ from Land Uses, Land Use Changes and Forestry (LULUCF), of which nearly half originated from the industrial sector (Figure 5). These industrial emissions are split between energy-related combustion and process emissions, further underlining the importance of tailored mitigation technologies such as CCUS.

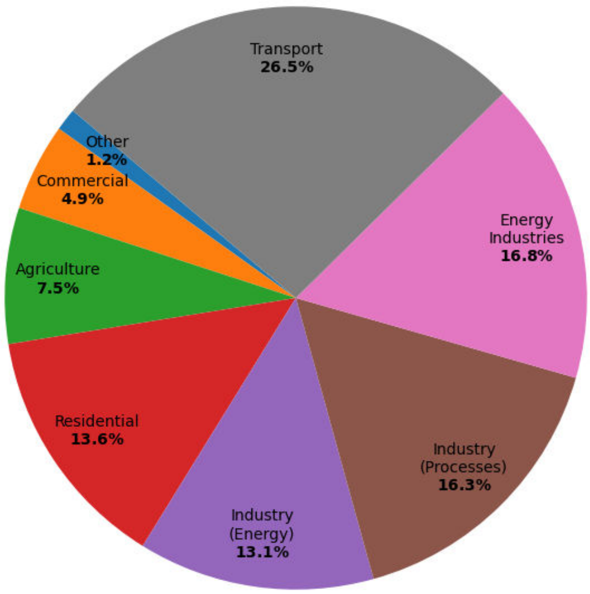


Figure 5: Main sectors of CO_2 emissions in Belgium (2023) (EEA, 2025)

To compare these figures with those of the EU ETS, almost all industrial activities are covered. However, in relation to total emissions, only 42% is covered by the EU ETS. The sectors less affected by CO_2 management are transport and residential, commercial and agricultural heating. This is logical since most of the emissions are from point sources (home heating) or diffuse sources (car transport) which are therefore well below the thermal power required to be included in the EU ETS accounts.

In order to reduce these CO_2 emissions, a set of complementary solutions should be applied, such as the decrease of the energy consumption through energy sufficiency, the use of other fuels than fossil-based ones, the use of renewables and **carbon capture utilization and/or storage (CCUS)**.

1.2 Belgian context on CCUS

On the 19th of June 2024, the Oslo Declaration was signed by several industrials: Antwerp-based firms (Port of Antwerp-Bruges, Air Liquide, BASF, Total Energies, ExxonMobil and Ineos), Ghent-based companies (North Sea Port, Engie and ArcelorMittal), Wallonia-based industrials (Carmeuse, Holcim, Heidelberg Materials and Lhoist) and Norwegian firm Equinor. The latter has robust operations in Belgium and is in partnership with Fluxys for a future pipeline between Zeebrugge and Norway. This initiative aims to put five crucial policy questions on the agenda of Belgian policymakers, namely:

(i) Intra-Belgian Industrial Deal: although CO_2 is a regional competence, the industry is calling for legislative alignment within Belgium. An example is the specific purity requirements for CO_2 transported through pipelines.

(ii) A New spirit of law-making: legislation should provide companies with the flexibility to pursue their own paths toward sustainability, avoiding unnecessary over-regulation that complicates the process.

(iii) De-risking mechanisms to support early movers in the CCUS value chain: since there is currently no profitable business case for CCUS, temporary financial support from the government is essential. In doing so, the industry is advocating for a temporary mechanism to mitigate risks until the market catches up.

(iv) Role of molecules in future energy system: it's crucial that companies maintain the flexibility to pursue sustainable practices. Therefore, policy should be bold in exploring multiple new molecules rather than focusing on just one, so as to ensure that an adequate supply of energy and electricity remains available in the future.

(v) North Sea cooperation: Belgium must be able to cooperate with non-EU North Sea countries, such as the UK, which has large CO_2 storage capacity. Harmonising and consistently maintaining policies, especially regarding specifications, is essential in this context.

Following this Oslo Declaration, it has to be mentioned that CCUS is now explicitely envisaged by the several Belgian governments (namely Federal, Walloon and Flanders ones).

1.3 Technological context on CCUS and DAC

1.3.1 Carbon capture pathways

The capture is possible along different ways that can be more or less easily integrated into the process. Of these ways, two correspond more to existing installations as they are end-of-pipe processes. These are post-combustion and partial oxy-combustion, which is a hybrid process between the former and oxy-combustion. Finally, there is a last possibility, which is pre-combustion. Figure 6 shows the different technologies available to integrate the carbon capture.

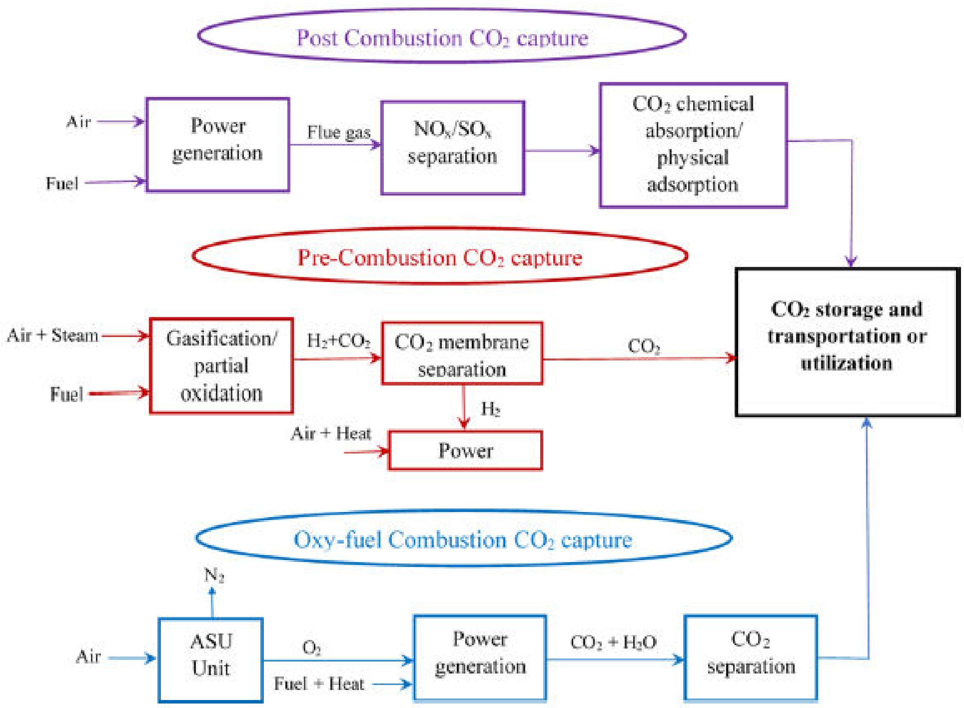


Figure 6 : Schema of technologies to capture CO_2 (Yadav & Mondal, 2022)

1.3.1.1 Pre-combustion

This process consists in burning a fuel decarbonised. In this process, the fuel is firstly converted in a syngas (mix gas composed of H_2 and CO) thanks to oxygen. Secondly, steam is injected with the products to react with CO to form CO_2 and more H_2. This reaction is known as the Water Gas Shift reaction. The CO_2 is then extracted from the gas stream using a capture technique to send only hydrogen into the combustion chamber. Thus, only water is produced during the combustion with oxygen that gives a clean flue gas containing only nitrogen, water and excess oxygen. This process is often associated with medium pressures (between 2 and 7 MPa) and high temperatures (range between 200 and 400°C) as operating conditions. In addition, CO_2 concentrations are generally between 20% and 40%. These operating conditions allow a wide range of possible separation. However, due to the difficulty of adaptation to existing plants, this technology is principally developed on new plants. Moreover, this technology only applies to CO_2 sources related to fuel combustion, which means that it is useless for process emissions.

1.3.1.2 Oxy-combustion

This process applies combustion fed by an oxygen-rich stream. The oxygen is produced in an air separation unit (ASU) using different methods (cryogenics, VSA (vacuum swing adsorption) or membranes). This combustion produces very high temperature flames which means that it is important to ensure that the chambers can tolerate these temperatures. This is one of the reasons, along with the modification of the air inlet to add a pipe from the ASU, that this process tends to be designed if the unit does not already exist. The recycled flue gas prior to combustion can sometimes be mixed with the oxidizer to control combustion. Usually, the concentration of the off-gas is at least 80% without air supply and 75% with more or less 5-10% of air supply.

This high CO_2 concentration in flue gases makes possible to use others capture techniques than these used usually in post-combustion process. The flue gas is conditioned by drying the CO_2, removing O_2 to prevent corrosion in the pipeline, and the other contaminants and inert gases (Ar, N_2, SO_2, and NO_x). However, the production of pure oxygen is very energy-intensive, making the operating cost high.

1.3.1.3 Post-combustion

Post-combustion capture is an end-of-pipe technology to capture the CO_2 from the flue gas produced with the conventional combustion of fossil fuel with air. In one hand the flue gas is decarbonated and in the other hand the CO_2 is concentrated. Usually, the effluent gases have a CO_2 concentration of 5 to 15% for power plants and a maximum CO_2 concentration of 30% for cement plant when the CO_2 is produced by a conventional combustion. However, this technology is very interesting since it can be added to an existing plan.

1.3.2 Carbon capture technologies

There are several available technologies to separate the carbon dioxide from other components of the flue gas. Below is a non-exhaustive list of them:

- absorption by a liquid phase thanks to the affinity of CO_2 for the solvent;
- adsorption on a solid to adsorb the CO_2 from the flue gas;
- membranes that are selective towards specific molecules like CO_2;
- cryogenics process to liquefy the CO_2;
- hybrid technologies are a combination of at least two other techniques.

All these technologies will be briefly described here after.

1.3.2.1 Gas-liquid absorption

Chemical absorption is a process for purifying gases at low and medium partial pressures during the regeneration phase. Generally, the gaseous component to be removed is absorbed by chemical reaction with an adequate solvent. In the present case this solvent is chosen for reacting with CO_2, forming a new chemical species, to transfer it efficiently into the liquid phase. By heating the solution, the solvent is regenerated from the species and the CO_2 is released in gas phase allowing it to concentrate. The most advanced and used solvent is MEA (monoethanolamine) with an aqueous solution containing 30 wt% in amine. However, various research and industrial works are studying the improvement of solvents (mixed amines, sterically hindered amines, demixing solvent, ionic liquids, hot potassium carbonate), equipment or processes in order to reduce operating costs by reducing regeneration energy. (Dubois & Thomas, 2018) show a reduction of up to 30% compared to MEA.

Physical absorption is not related to a chemical reaction but to absorption in a solvent (ex: alcohols) according to Henry's Law. A high partial pressure of the absorbed gas and a low temperature make the absorption more favourable. The energy required to regenerate the solvent is less than that for a chemical solvent, but the process conditions are significatively different (e.g. required temperature for Selexol is 0 - 5°C of Rectisol is -40°C) (Majeed, 2013; Olajire, 2010).

1.3.2.2 Gas-solid Adsorption

One of the main adsorption characteristics impacting the CO_2 capture performances, the CO_2 adsorption capacity related to the affinity of the surface of an adsorbent for CO_2 molecules and the physical attraction between the surface and the CO_2 (heat of adsorption). They are physically absorbed on the surface of the absorbent. The total microporous volume and size of pores also influence the absorption capacity and selectivity. Separation is achieved by the size of the molecules, kinetic or the binding forces.

The separation methods are Temperature Swing Adsorption and (Vacuum) Pressure Swing Adsorption (TSA & (V)PSA) to regenerate the sorbent. There are different materials available such as zeolites, activated carbon, silica gel, MOFs (Metal Organic Frameworks) or carbon nanotubes to adsorb CO_2 (Chiang et al., 2019).

1.3.2.3 Membrane permeation

Membranes are semi-permeable barriers capable of separating substances by various mechanisms (solution/diffusion, adsorption/diffusion, molecular sieve and ion transport). A pressure gradient is exerted on the gas in order to be able to separate CO_2 from the other components. Two or three stages are necessary in order to have a good separation requesting a high energy consumption. Moreover, on the contrary to other technologies as absorption or adsorption, no other fluids (liquid or solid) are needed for performing the separation. There are different membrane materials available to work in different temperature ranges. The higher the operating temperature can be, the more resistant the material must be, but in return the cost is often high. There are therefore membranes made of organic materials (polymers) or inorganic materials (carbon, zeolite, ceramic or metal) (Olajire, 2010); the polymeric membranes are generally used due to the significantly lower costs.

There exist also gas-liquid membrane contactors that are used to separate CO_2 from the other components of the gaseous effluent. Depending on the nature of the liquid phase, the membrane must have more or less chemical and physical resistance to avoid degradation. In addition, the membrane must have a certain selectivity towards CO_2 to allow its diffusion and the liquid phase (solvent) must present a high affinity with CO_2 in order to reach a high absorption rate. For this type of membrane, there is no pressure gradient that is exerted but a concentration gradient. An advantage of this technology is the large gas-liquid exchange surface without flooding problems. However, in order to reach good performances, it is preferable that the pores of the membrane remain dry, which implies overcoming wetting problems (Nogalska et al., 2019).

1.3.2.4 Cryogenics

The cryogenic process allows the purification of a highly concentrated (> 60%) CO_2 gas stream. This purification is done by a succession of cooling and condensation steps in order to extract the other components of the gas. This method is carried out thanks to the difference in the condensation points of the different gases allowing an easy separation. An advantage of this technique is that the CO_2 can be available in liquid form which can facilitate its transport in some cases. However, since it is necessary to decrease the temperatures (-55°C), the energy consumed is high, which significantly increases the operating costs. This separation method can therefore be considered for pre-combustion or even oxy-combustion, which can be found under cryogenic operating conditions (Lockwood, 2014).

1.3.2.5 Hybrid technologies

Hybrid technologies are processes composed of at least two of the above-mentioned processes. More and more hybrid technologies are being studied in order to achieve good performance and overall cost reduction compared to a single technology. Thus, adsorption (VPSA) can be combined with cryogenics to achieve good recovery and excellent purity. In the case of oxy-combustion or flue gas with industrial by-products (hydrogen, carbon monoxide, etc.) a combination of membrane and cryogenics can be applied. It is also possible to mix adsorption with membranes to pre-concentrate the flue gas before purifying it if high purity is not required.

1.3.3 Direct Air Capture (DAC)

Unlike CO_2 capture applied to flue gases from emission points (power stations, cement works, lime kilns, glassworks, etc.) where the concentration is typically between 3% and 30%, the concentration of CO_2 in ambient air is closer to 0.042%. As illustrated on Figure 7, the purpose of Direct Air Capture (DAC) is to capture the CO_2 directly from the ambient air. As with capture applied to point sources, the CO_2 can be then geologically stored (carbon-negative value chain) or converted to another product (fuel, energy vector, chemical product, …).

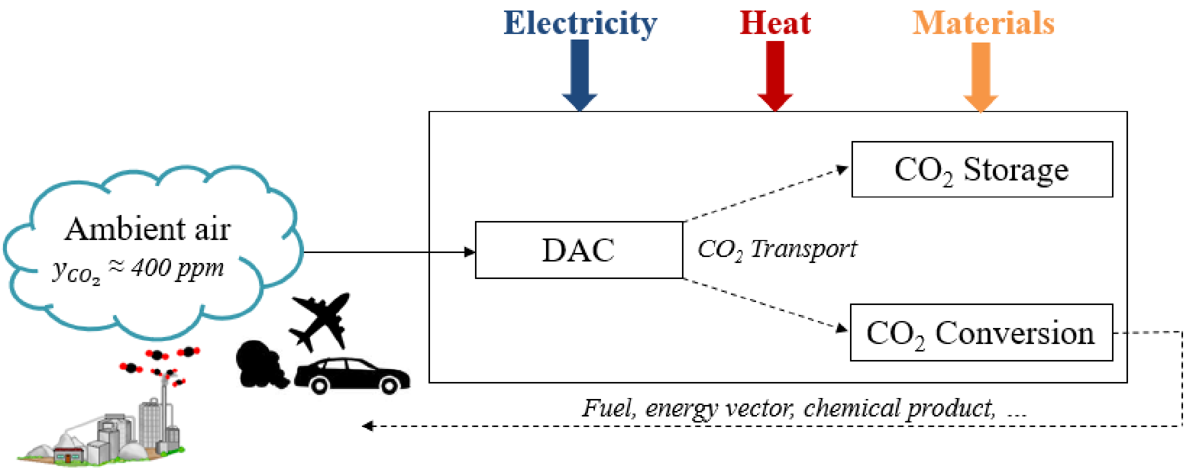


Figure 7: Generic illustration of a DAC process in view of CO_2 storage and/or CO_2 conversion

Capturing the CO_2 from a more diluted source liked the ambient air requires more energy (thermodynamic constraint: maximum work required for separation, see Figure 8).

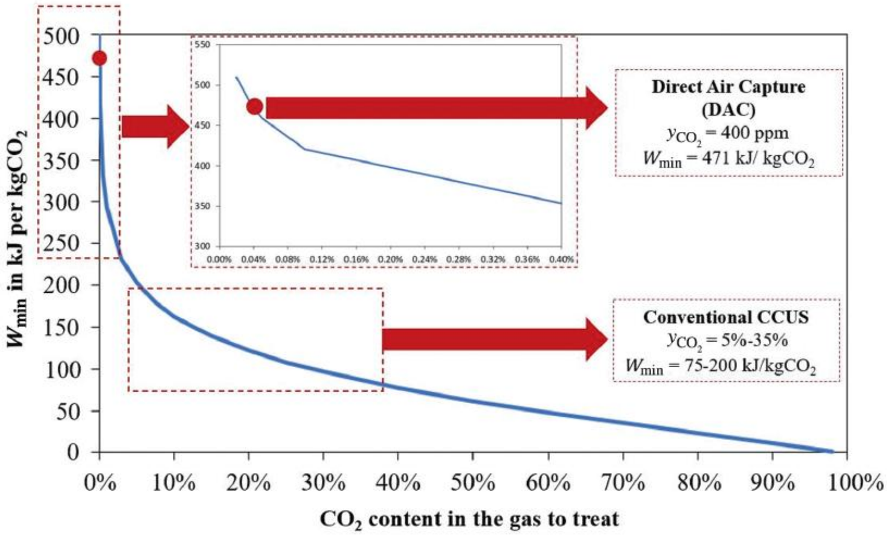


Figure 8: Minimum thermodynamic work for separating the CO_2 as a function of the inlet stream CO_2 content (Chauvy & Dubois, 2022)

As illustrated on Figure 8, considering a separation temperature of 20°C, a capture rate of 90%, and a final CO_2 purity of 99 mol%, the minimum thermodynamic work decreases when the CO_2 content of the gas to treat increases. Specifically, it can be pointed out that capturing CO_2 from the air, with a CO_2 content around 400 ppm, leads to a W_{min} (471 kJ/kg$_{CO2}$) from two to six times higher than in the case of capturing CO_2 from industrial flue gases, with a CO_2 content ranging from 5% to 35%, or even higher, depending on the industrial application (W_{min} ranging from 75 to 200 kJ/kg$_{CO2}$). To this extent, the separation techniques used to recover the CO_2 from the air should be adapted to diluted streams and optimized to minimize their energy consumption. It is worth mentioning that an additional thermodynamic work (amount depending on the pressure level targeted) would be necessary to compress the concentrated CO_2 stream to the final state, covering pressure losses and allowing at the end to inject the CO_2 fluid into storage reservoir.

1.4 Belgian energy system

As a densely-populated and highly-industrialized country with limited local renewable potentials (i.e., mainly solar and wind representing up to 50% of the primary mix by 2050), the transition of Belgium from a fossil-dominated system in 2020 to carbon neutrality in 2050 makes it an intricate case study.

Nowadays, the Belgian whole-energy system is largely based (87% of the primary energy mix) on “conventional fuels” (i.e., oil and oil products (41%), natural gas (25%), uranium (16%) and solid fossil fuels (5%) while the rest mainly accounts for 48 TWh of biomass, 15 TWh of wind and 8 TWh
of solar.

Out of the 423 TWh of final energy consumed (FEC), the industrial sector accounts for 25.5% whereas transport, residential, and services represent 24.4%, 19.1%, and 13.0%, respectively. Another important sector in Belgium is the non-energy sector (18.1% of FEC) (e.g., production of high-value chemicals or fertilizers based on energy carriers).

Looking towards the future, the European Commission foresees no significant decrease in the different end-use demands (see Figure 9). The decrease in the demand of low-temperature heat, primarily used in the residential sector, is attributed to the expected improvement in the insulation of buildings. The sharp increase from 2020 to 2025 in the transport sectors is due to the COVID-crisis that led to significantly reduced demands in 2020. These levels of demand served as inputs for the studies on the Belgian energy system.

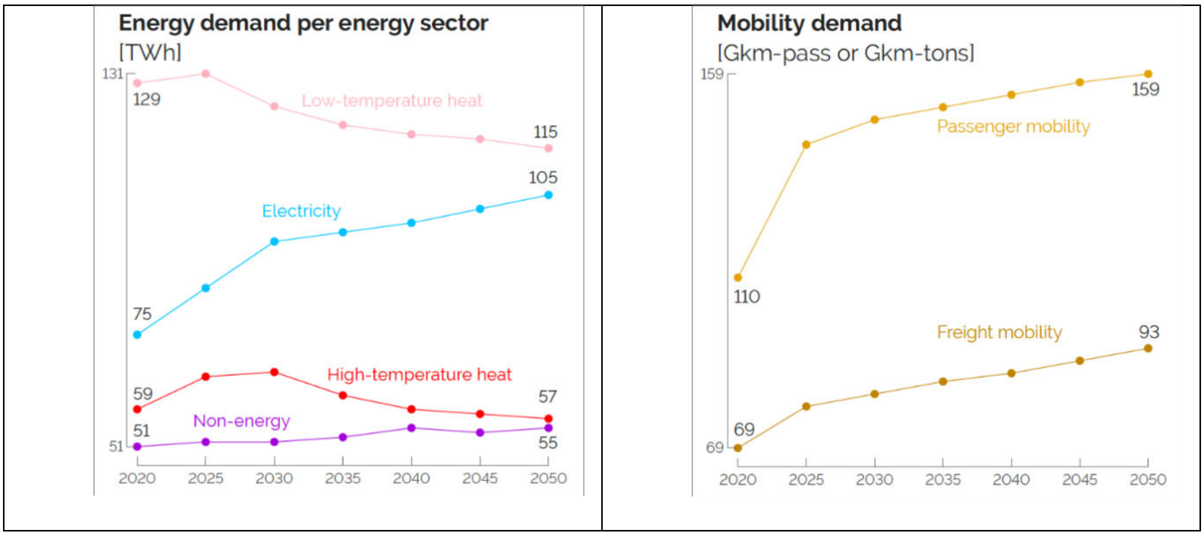


Figure 9: EU reference scenario 2020: energy, transport and GHG emissions: trends to 2050

1.5 Remote Renewable Energy Hubs (RREH)

1.5.1 The concept

The concept of *Remote Renewable Energy Hubs* (RREHs) consists in harvesting renewable energy where it is most abundant in order to synthesize low-carbon, energy-rich molecules that are easier to store and transport, such as methane (CH_4), methanol (CH_3OH), hydrogen (H_2), or ammonia (NH_3) (Dachet et al., 2024a) for serving *Energy Demand Centers* (EDC). These EDC are places combining both a large energy demand and a low potential in terms of renewable energy resources. These energy-rich molecules, when produced via electricity, are also referred to as e-fuels (electro-fuels). Figure 10 illustrates how one could produce e-methane using the concept of RREH.

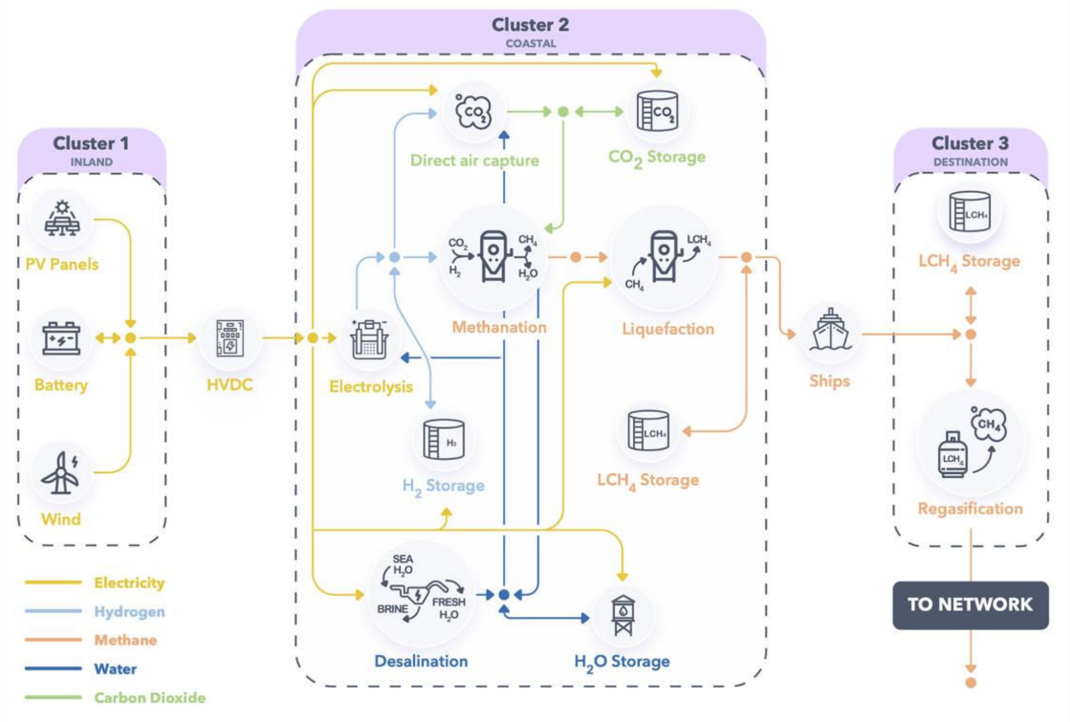


Figure 10: RREH synthesizing methane to be exported towards an energy demand center (Berger et al., 2021). An electrolyser is powered by renewable energy generated from PV and wind turbines. This electrolyser produces hydrogen (H_2), which can be combined with CO_2—captured via DAC (see Section 1.3 for more details)—to produce CH_4 via the Sabatier reaction. The resulting CH_4 in gaseous form can then be liquefied for transport by ship.

These RREHs could provide new import possibilities for Belgium, thus helping the country meet EU objectives such as those set for the use of e-fuels in the maritime sector (European Commission, FuelEU Maritime, 2025) and the aviation sector (European Commission, ReFuelEU Aviation, 2025). Belgium could also see these RREHs as an opportunity to valorize CO_2 captured from its emitting industries (cf. Section 1). Indeed, as suggested in Dachet et al. (2024b), Belgium could export its CO_2 to various RREHs to supply the carbon necessary for the synthesis of e-CH_4, and subsequently import the resulting CH_4.

1.5.2 RREH integration into the Belgium's energy system

In order to evaluate the potential benefits of implementing Remote Renewable Energy Hubs (RREHs) to support the decarbonization of Belgium's energy system, a comprehensive multi-carrier energy system model for Belgium was developed (see Figure 11), with the possibility to export the captured CO_2 to RREHs located in Algeria and Greenland or to CO_2 sequestration sites primarily offshore in the North Sea. The model considers four primary energy commodities: electricity, natural gas (methane), hydrogen, and carbon dioxide. Imports of carbon-based energy carriers such as natural gas and electricity from neighboring countries are also incorporated. Within the RREHs, two types of e-fuels can be produced: hydrogen via green electricity and e-methane through the synthesis of hydrogen and CO_2, the latter sourced either from Belgian emissions or Direct Air Capture (DAC).
A detailed Carbon Capture, Utilization, and Storage (CCUS) chain is embedded in the model. Emissions from the nine largest Belgian emitters in 2023, along with those from carbon-based power plants included in the model, can be captured using two types of post-combustion carbon capture units (PCCCs). These PCCCs are designed to accommodate varying dry CO_2 concentrations across emitters, are configurable to different capture rate levels, and ensure that the captured CO_2 meets the necessary purity and pressure standards for pipeline transport (see Fluxys CO_2 grid on Figure 12).

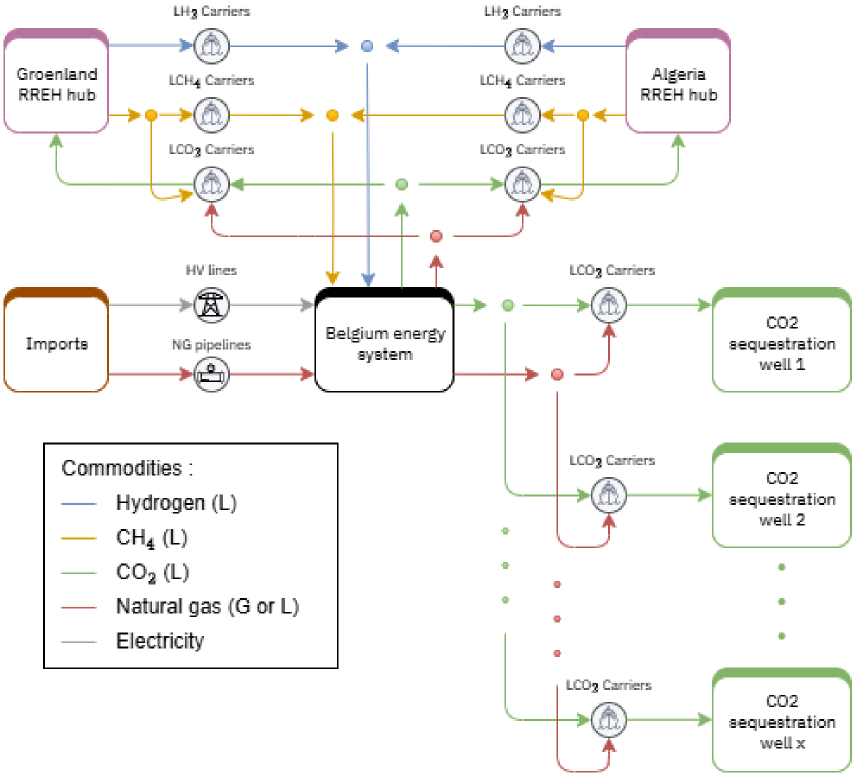


Figure 11: Simplistic representation of the model comprising the Belgium energy system, RREHs and CO_2 sequestration sites.

Furthermore, the model incorporates the associated costs of CO_2 transport by pipeline, and includes infrastructure for liquefaction and storage, enabling CO_2 to be transported by ship under the appropriate pressure conditions.

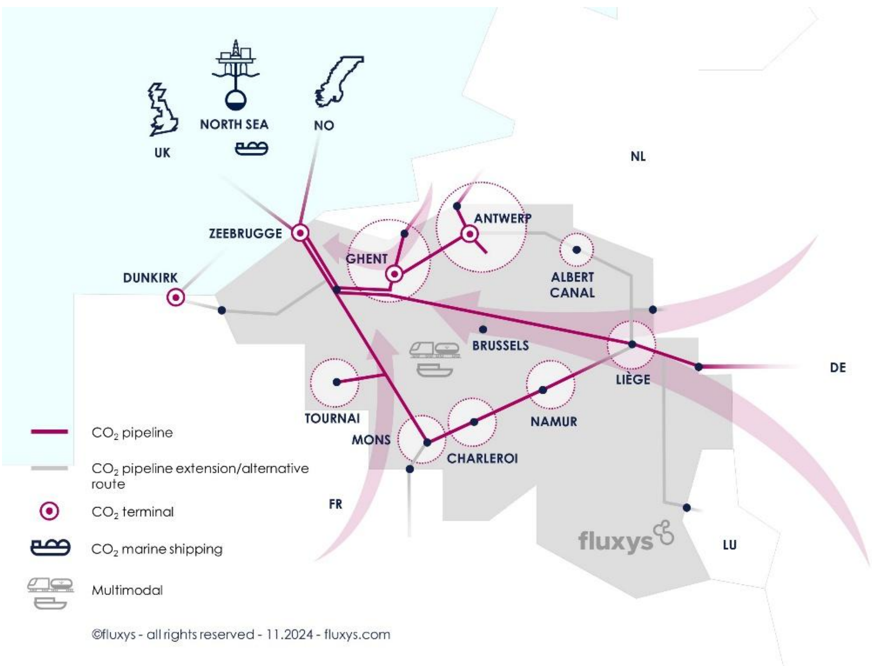


Figure 12: Fluxys CO_2 grid in Belgium for 2025 (Fluxys, 2025).

Nineteen CO_2 wells from the Global CCS Institute were selected and implemented in the model. These wells originate from projects in four countries: UK, Norway, Denmark, and the Netherlands, all of which are expected to become operational by 2030. Figure 13 illustrates the locations of the different projects across these countries. On total, 185.8 Mt of CO_2 can be sequestrated by year.

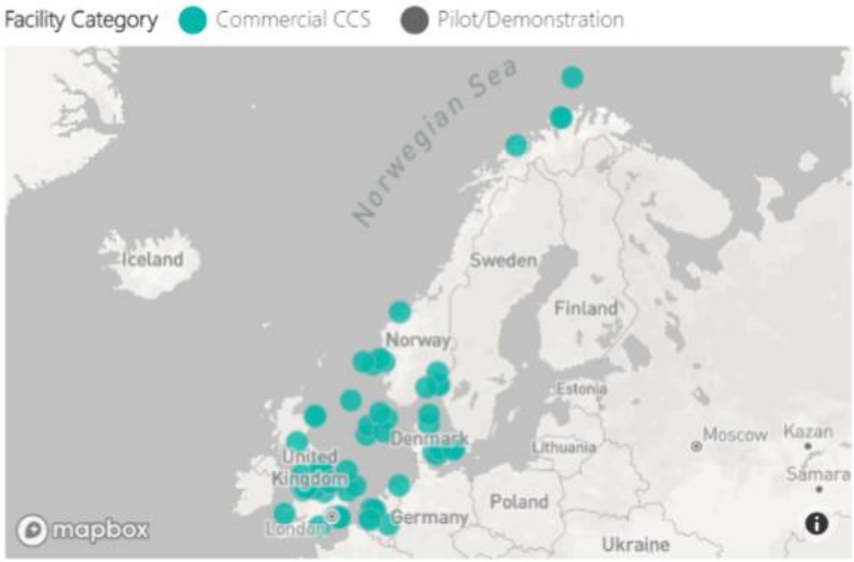


Figure 13: CO_2 sequestration sites assumed to be operational by 2030 (Global CCS Institute, 2023).

2 Roadmap

2.1 Objectives and challenges

As clearly highlighted in Section 1, almost 50% of current Belgian CO_2 emissions are linked to industrial sectors. Therefore, the implementation of CCUS appears as mandatory to significantly reduce the Belgian CO_2 emissions. This implementation will need specific infrastructures for capturing, purifying, liquefying, transporting and storing CO_2, and/or for using it as a feedstock for the generation of several energy vectors. These value chains will lead to a significant CO_2 market to manage and they will have an impact on the Belgian energy system, requiring an adequate coordination with RREH.

The present technology roadmap is therefore important and relevant for several reasons:
- helping to identify the most adequate CCUS and energy systems technological choices to be implemented in Belgium is of major importance, especially to optimize the technologies themselves and their costs to ensure the economic viability of the processes involved;

- CO_2 market will have a key role in the short-, mid- and long- terms in Belgium, but also globally in Europe, and the key technologies to recover, valorize and store CO_2 will rely on CCUS (and possibly DAC);

- the technologies will impact and use the Belgian energy system and it will rely on RREH;

- even if the present roadmap is more focused on "technology aspects", il combines technical, economic, infrastructural and regulatory dimensions.

Based on the results acquired in the framework of the DRIVER project, the present document is therefore structured by technological components, namely CCUS & DAC, Belgium Energy system and Remote Renewable Energy Hubs (RREH).

2.2 CCUS & DAC key recommendations

The key technical recommendations regarding CCUS & DAC as structured by technical blocks, namely: CO_2 capture, CO_2 transport for geological storage, CO_2 conversion, DAC, CCUS technologies social acceptance and some complementary thoughts.

2.2.1 CO_2 capture

As presented in Section 1, there are various ways of capturing CO_2, namely pre-combustion, oxy-combustion and post-combustion, the latter (the most developed at present) having the advantage of not requiring upstream process modification (so-called "end-of-pipe" technology). In terms of CO_2 capture technologies, four main unit operations have been identified: (i) gas-liquid absorption processes, (ii) gas-solid adsorption processes, (ii) the use of separating membranes (gas-gas) and (iv) cryogenic processes.
The gas-liquid absorption technology, in particular using amine solvents, is currently the most mature (TRL of 9) and the most available among technology suppliers (several of which are mentioned in report D1), although the other technologies have interesting potential in the medium or long term, particularly in terms of cost reduction and environmental impact. In all cases, whether for the capture, purification or liquefaction of CO_2, the development of cryogenic systems seems necessary, especially to meet the CO_2 pipelines specifications. It has to be mentioned that a short- and mid-terms, hybrid technologies (e.g. combination of adsorption and cryogenics) are more likely to be used than these technologies alone.

2.2.1.1 Summary of the main lessons learned from simulations of CO_2 capture by the absorption-regeneration process

Although already technologically mature, the absorption-regeneration process with amine-based solvents, involves very high energy consumption. Three ways of reducing this consumption were investigated through 5 scientific papers (experimentally and/or via the development of Aspen Plus® simulations), namely: (i) upstream of the process by increasing the CO_2 content of the flue gases to be treated (by partial oxy-combustion and/or flue gas recirculation), (ii) within the process (by using more efficient and innovative solvent mixtures such as demixing solvents), and (iii) at the configuration level by implementing advanced configurations of the capture process. It emerged that the use of a demixing process such as the mixture of diethylethanolamine (DEEA) and methyl-amino-propylamine (MAPA), or the implementation of an advanced process configuration (Inter-Cooling Absorber + Rich Vapor Compression + Rich Solvent Splitting and Preheating, with methyldiethanolamine (MDEA) + piperazine (PZ) as solvent) are the ways to achieve the greatest reduction in energy consumption in the absorption-regeneration process, namely by **more than 40%** compared with a conventional process using monoethanolamine (MEA) 30 wt.%. Moreover, from an economic point of view, and compared to a basic configuration using MEA, demixing technology offers the advantage of being able to achieve such high energy performance at a more limited investment increase (CAPEX) (+1.6%) than with more advanced process configurations (+8.8%).
Researches on the use of demixing solvents to reduce the energy consumption of the absorption-regeneration capture process is still ongoing, in particular to find alternatives to the DEEA+MAPA demixing mixture, which is even more economical and has a lower risk of degradation.

For more information on how these conclusions were drawn, several scientific communications have been published on that topic in the framework of the DRIVER project: (Costa et al., 2022), (Dubois et al., 2022), (Dubois et al., 2023a), (Dubois et al., 2023b), (Verdonck et al., 2025) and (Verhaeghe et al., 2025).

2.2.1.2 Summary of the main lessons learned from simulations of CO_2 capture-purification using cryogenic and hybrid membrane/adsorption-cryogenic processes

The optimization of a CO_2 purification process (CPU) for oxy-combustion flue gases from cement plants was first investigated. This optimization was based on a multidimensional study of the energy, exergy, economic and environmental impacts (4E analysis) of the process. The results of the optimizations carried out have shown that it is more favorable to increase the CO_2 recovery rate above 90%, from an energy, exergy and economic point of view. In addition, the carbon purification unit with membrane to recover CO_2, compared with other cryogenic processes developed in the literature, enables a significant reduction in electricity consumption. Analysis of the evolution of the cost of capture as a function of CO_2 recovery shows that for a given carbon tax, there is a minimum for the total cost, which comprises the sum of the contributions to the carbon tax for the CO_2 not captured and the cost of capture. As the unit only uses electrical energy, the cost and production of electricity will have a direct impact on the cost of capture as well as on the overall balance in terms of CO_2 avoided. When the price of electricity rises from 50 € to 250 €/MWh, the cost of CO_2 capture increases by almost 250%. An analysis of the uncertainties surrounding the parameters enabled to observe their impact on the results, to define a standard deviation in relation to the optimized points and to demonstrate the robustness of the latter. Taking into account the technical parameter uncertainties, the standard deviation for electricity consumption (3.65 kWh/t_{CO2}), CO_2 recovery (0.09%) and exergy efficiency (0.92%) is limited.

In a second study, a hybrid process combining a vacuum pressure swing adsorption (VPSA) unit and a cryogenic carbon purification unit (CPU) was evaluated to improve the recovery and purity of CO_2 captured from flue gases containing a concentration of CO_2 ranging from 5% to 20%. The VPSA unit preconcentrates the CO_2 and the CPU completes the separation and purifies the CO_2. The study used surrogate models for multi-objective optimization, taking into account energy consumption, cost and CO_2 recovery, which is an efficient approach for studying computationally demanding processes. The results of the study indicate that the hybrid system achieves over 90% CO_2 recovery for the range of flue gas concentrations considered, while producing high purity CO_2 (>99.99%) suitable for transport. The analyses carried out reveal a balance between recovery, electricity consumption and economic viability. A sensitivity analysis identified the parameters influencing energy recovery and consumption, providing guidance for future optimization efforts. The techno-economic analysis highlights the impact of electricity prices and carbon taxes on total costs, identifying an optimum towards higher recovery values in the event of an increase in carbon taxes. In addition, the research highlights the economic feasibility as a function of concentration, emphasizing the attractiveness of concentrations above 10% compared with other technologies, which require higher concentrations. For an electricity price of 75 €/MWh, the total cost of the hybrid CO_2 capture system, taking into account CO_2 emissions with a carbon tax of 100 €/t_{CO2}, for concentrations ranging from 10% to 20%, is 123 € and 80 €/t_{CO2} respectively.

Generally speaking, for such technologies using electricity on a massive scale, the analyses carried out show the importance of having the lowest possible carbon electricity mix in order to maximize the net reduction in CO_2 emissions.

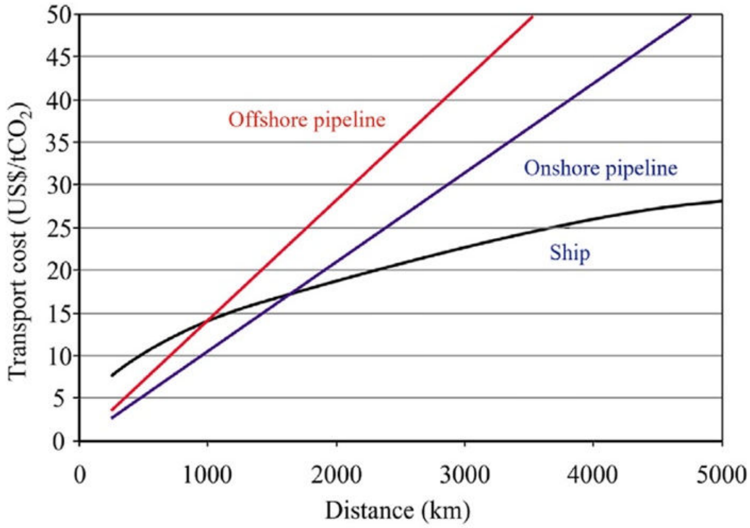
For more information on how these conclusions were drawn, see these scientific publications, published on that topic in the framework of the DRIVER project: (Costa et al., 2024a) and (Costa et al., 2024b).

2.2.2 CO_2 transport for geological storage

For the implementation of CCUS chains, the CO_2 transport step plays a key role, where the CO_2 purity and the possible impact of impurities on its physical-chemical properties are important parameters.

In the case of onshore transport, several analyses show that pipeline transport is the preferred method due to its lower cost at short distance (see Figure 14), with some studies indicating that rail or truck transport may only be economically viable for small quantities of CO_2. Barges are also an option if the capture site is located close to a waterway. Figure 14 shows that ship transport becomes more advantageous than pipelines beyond a certain distance, with optimal transport at pressures of 7 or 15 bar depending on the type of vessel.

Impurities in CO_2, resulting from various industrial processes and from the varying performance of capture technologies, increase energy consumption during compression and can lead to risks of corrosion. Specifications for the maritime transport of CO_2 in liquid form limit the concentration of certain impurities to strict thresholds. CO_2 purification methods, such as the two-flash system and the stripping column, have been proposed to meet these specifications. It should be noted that such strict specifications also apply to pipeline transport (cf. specifications set by the Fluxys operator in Belgium). In order to transport CO_2 in liquid form, it is therefore necessary to look at the CO_2 liquefaction stage, which has been the subject of a specific study in the DRIVER project, taking into account the presence of gaseous impurities, which is particularly innovative compared with what is generally considered in the literature.



Transport costs for onshore pipelines, offshore pipelines and ships, by distance, in US$/ton CO_2. Pipeline costs are given for a CO_2 mass flow of 6 $MtCO_2$/year. Ship costs include intermediate storage facilities, port fees, fuel costs and loading costs. These costs also include additional liquefaction costs beyond compression (Copyright 2005, Cambridge University).

Figure 14: CO_2 transportation costs as a function of the distance and transport mode (Luo et al., 2023)

The CO_2 liquefaction methods studied show that hybrid cycles, combining an open cycle with a Joule-Thompson expansion and a closed cycle with a cooling machine, can reduce energy consumption and improve CO_2 recovery compared with open or closed cycles. In the presence of the maximum threshold of impurities in the pipeline, energy consumption can almost double, from 21 kWh/t_{CO2} to 40 kWh/t_{CO2}, with a maximum recovery of 98%.

Overall, the hybrid cycle is a versatile and efficient solution to the complexities of purifying and liquefying CO_2 from a pipeline.

It should be noted that to meet the specifications for transport by ship, it is necessary to add a distillation column to the liquefaction process. In terms of costs, this CO_2 liquefaction stage adds a contribution of between 7 € and 14 €/t_{CO2} depending on the impurities present in the CO_2,

representing nevertheless a cost of between 2 and 10% of the entire CCUS chain. This range of costs highlights the significant impact that gaseous impurities can have on the overall cost of CO_2 liquefaction. It should also be noted that gaseous impurities lead to a CO_2 loss, which will be invoiced to the CO_2 liquefaction operator.
Globally, the implementation of carbon capture purification liquefaction and storage value chain will imply the establishment of a global CO_2 network at the European scale, as represented on Figure 15.
The final CO_2 network design is still evolving but this network will be initiated from the main CO_2 emitters to the CO_2 storage sites (see Figure 15 (a)) and will certainly evolve as an integrated European network (see Figure 15 (b) focusing on onshore network) connecting also the medium (and eventually small)-size emitters to the main CO_2 network.
The study performed in the framework of the DRIVER project has therefore highlighted the importance of optimizing CO_2 transport and liquefaction strategies to facilitate the deployment of CCUS technologies. One of the perspectives of this work will be to study the chain more completely in order to determine what is the most economically viable: being stricter on the purity of the CO_2 in the pipeline and therefore increasing the purification of the CO_2 leaving the capture unit, or sticking to the current specifications, which implies treating the CO_2 coming out the pipeline to meet the specifications for transportation by ship.

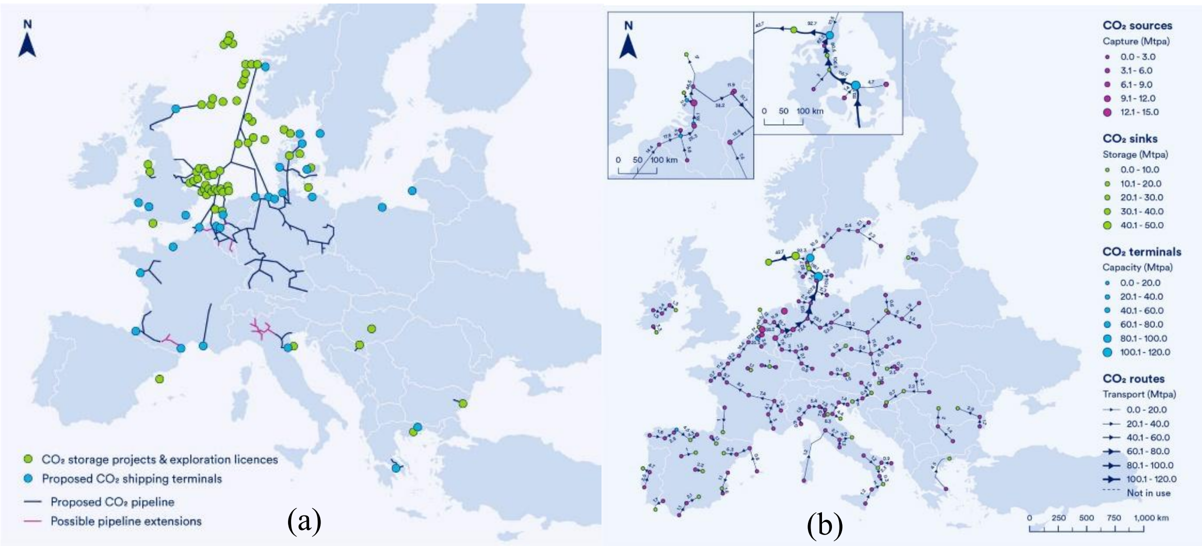


Figure 15: (a) An overview of proposed CO_2 infrastructure in Europe (pipeline routes are illustrative and may not reflect final plans) (Lockwood, 2025), (b) Potential CO_2 transport routes in the EU by 2050 under a modeled net-zero scenario (European Commission, 2024)

For more information on how these conclusions were drawn, see this scientific publication published on that topic in the framework of the DRIVER project: (Costa et al., 2024c).

2.2.3 CO_2 conversion

Concerning the CO_2 utilization, the global market already represented more than 230 Mt_{CO2} annually in 2018, 16% of which was in Europe. Nearly 60% of the world's CO_2 is currently used in the production of urea, 34% for enhanced oil recovery (EOR) and finally everything to do with food and soft drinks (the main uses in Europe), as well as other industries. In conjunction with the development of the green hydrogen sector, other markets will develop in the future. Indeed, once captured, the CO_2 can be used as a raw material and converted to produce value-added chemical products. CCU has a strategic role to play in the decarbonization of energy resources and the transition to a climate-neutral economy. E-methanol, synthetic natural gas (SNG) and e-kerosene are promising ways of converting captured CO_2.

In this context, the aim of the study performed in the framework of the DRIVER project was to propose an optimized and integrated process for converting CO_2 into methanol and to compare it with the process for converting CO_2 into SNG from an energy, economic and environmental point of view. An optimized configuration of the reactor in the CO_2-to-methanol unit was successfully implemented in the Aspen Plus® software and led to the unit being self-sufficient in thermal energy. Thermal integration with an advanced capture unit (cf. advanced, non-demixing configuration, as mentioned in section 2.2.1) has been achieved. It has been shown that in the case of methanol, 5% of the heat requirement can be supplied by the conversion unit while 95% must be supplied via an external steam source. It should be noted that in the case of SNG, all the heat required could be supplied via such thermal integration due to the greater exothermicity of the conversion reaction. The technical and economic assessment of the optimized process showed that methanol is more profitable when used as a feedstock to synthesize other chemicals. As an energy carrier, SNG remains the most attractive. In environmental terms, compared with a reference scenario (no CO_2 capture, products supplied by fossil fuels as is currently the case), a net reduction in CO_2 emissions of 70% in the case of converting CO_2 into SNG and 60% in the case of converting it into methanol has been demonstrated. As for the impact on the depletion of fossil fuels, a reduction of more than 60% was observed in both cases (around 75% for the conversion of CO_2 to SNG and 61% for the conversion of CO_2 to methanol).

Overall, the study has shown that, on the one hand, thinking in terms of energy integration between CO_2 capture and conversion units makes sense from an energy, economic and environmental point of view, and on the other hand that one of the key elements for the implementation of such a value chain remains the importance of having large quantities of green hydrogen available (hence, once again, the importance of an electricity mix that is as carbon-free as possible) and at the most competitive price possible (linked to the price of the electricity used for this production).

For more information on how these conclusions were drawn, see this scientific paper published on that topic in the framework of the DRIVER project: (Djettene et al., 2024).

2.2.4 Direct Air Capture (DAC)

As described in section 1.3.3, capturing CO_2 from ambient air (DAC - Direct Air Capture) requires more energy than capturing it from more concentrated sources such as industrial flue gases. A specific study was therefore performed in the framework of the DRIVER project in order to identify whether it makes sense to implement DAC technologies, both economically and environmentally.

It emerged from this study that DAC technologies are at very different levels of maturity (TRL of 1 to 3 for some, up to 9 for others) and involve various unit operations (adsorption, absorption, etc.), use different types of materials (liquid or solid) and energy types (electrical and/or thermal). Most processes use adsorption (e.g. Climeworks) or absorption (e.g. Carbon Engineering), although more innovative solutions exist that are not at a sufficient TRL level to be marketed.

As far as the environmental performance of DAC technologies is concerned, the “carbon-negative” nature of this technology has been highlighted, particularly when combined with CO_2 sequestration. However, the construction of large-scale DAC plants has an impact on other environmental aspects such as land footprint, water and use of materials.

On the economic side, literature studies provide wide cost ranges, from 80 €/t_{CO2} to 1133 €/t_{CO2} for current estimates, while future DAC costs are expected to fall to between 34 €/t_{CO2} and 260 €/t_{CO2}.

Another study carried out in the DRIVER project looked at the integration of a DAC process with a synthetic natural gas (SNG) conversion unit (DAC - Power-to-Gas (PtG)) and the

associated 4E analysis (energy, exergy, economics and environment). The study also included a quantification of uncertainty. The results of this study show that the DAC-PtG system is autothermal when a two-stage mechanical vapor recompression unit is introduced at the DAC outlet. The energy efficiency is between 51.3% and 52.6% with a standard deviation of 3, the uncertainty being due to the ambient conditions and the heat of desorption.
SNG from DAC-PtG has a lower carbon footprint than fossil methane when the carbon footprint of the electricity supply is less than or equal to 0.12 kg_{CO2-eq}/kWh. The levelized cost of synthetic natural gas (LC_{SNG}) varies between 130 €/MWh and 744 €/MWh, due to the uncertainty of the electricity price and the costs associated with DAC and electrolysis. Therefore, increased production volume, further maturation of these technologies and more demonstration projects are needed to reduce the uncertainty of LC_{SNG}. Future work will take into account intermittent renewable energy sources.
Overall, the key levers that will help to improve the performance of DACs and reduce their costs are related to technological developments (e.g., the development of new technologies, the use of new liquid or solid sorbents, the gas-liquid/solid contactor), energy consumption (e.g. the possibility of using waste heat, the availability of low-cost and low-carbon electricity), and implementation features (e.g. modularity and scaling, energy integration with other process(es)).
In addition to recovering atmospheric CO_2, DAC technologies could eventually supply CO_2 to areas where (CO_2-emitting) industries are not present but where large quantities of low-carbon energy are produced (e.g. solar, wind, geothermal, etc.), making it possible not only to capture CO_2 from the air, but also (for example) to produce green hydrogen, which can be combined with CO_2 to produce a more easily transportable and manageable energy carrier, such as SNG.
As far as the possible application of DAC in Belgium is concerned, it seems clear that at the moment the priority must be to limit CO_2 emissions at source (which are much more concentrated, and therefore offer much better capture performance), and therefore the capture of CO_2 from industrial flue gases. However, given that certain DAC technologies can be added to existing installations (e.g. cooling towers) or take advantage of waste heat that is currently lost, it is possible that certain projects could pop up in the future, particularly in parallel with hydrogen infrastructures (production and transport), enabling this CO_2 to be used to produce another energy carrier.
For more information on how these conclusions were drawn, see these scientific publications, published on that topic in the framework of the DRIVER project: (Chauvy & Dubois, 2022) and (Coppitters et al., 2023).

2.2.5 Complementary thoughts on CCUS

2.2.5.1 Techno-economic thoughts on CCUS

On the 19th of March 2025, the Global CCS Institute organized at Brussels its European Forum on Carbon Capture and Storage (event recording available online). This event has been an opportunity to gain some relevant thoughts for the present roadmap. Here are some of the key elements that was discussed at this event:

- The importance of CCUS infrastructures development was highlighted, and especially the need for finding ways to fund them. Indeed, on one side emitters need a clear message that the transport-storage infrastructures will be available, and on the other the CO_2 transport network-storage operators need to be sure that CO_2 will be captured and injected in the network.
- Financial incentives are mandatory for creating robust business cases and having more FID (Final Investment Decision).

- One of the key elements discussed is the specifications for CO_2 transportation, especially by pipeline. These specifications are naturally important to ensure proper infrastructure management and safety. Nevertheless, they have an influence on the carbon capture-purification technological choices and therefore the cost. As typically used in the shipping industry, specifications are also important for the liquefied CO_2 transportation by ship, but an open question is "who will fix these specifications?". More discussions and collaborations between the different CCUS value chain stakeholders (including between competitors) are needed, without neglecting the "regulatory framework" aspect managed by the authorities (both European and national ones).
- It was also highlighted that even if pipeline transportation will manage a large part of the captured CO_2, the other CO_2 transportation methods (e.g. barge/ships, trains, trucks) should not be neglected, especially for emitters that will not be situated close to the main CO_2 transport network. Moreover, it was emphasized that some Central-European countries (e.g. Croatia, Hungary, …) are working on "onshore CO_2 storage", which allows to significantly reduce the costs of the CCS value chain. Other European countries should be inspired by this approach even if permitting difficulties is still a challenge.
- Another important aspect that still needs to be clarified is the financial risk sharing related to each step of the value chain (capture, transport and storage). In a first step, CO_2 is seen as a waste whose recovery is expensive and does not generate any profit. At a long term, the CO_2 valorization into non-fossil carbon based products will be important to create a real market with profits for each actors.
- The European Commission is working on different aspects related to decarbonation, such as for example the Certification for Carbon Removals credits or for captured biogenic CO_2, but it also wants to strengthen the Innovation Fund and propose an Industrial Decarbonisation Bank, aiming for 100 billion € in funding, based on available funds in the Innovation Fund, additional revenues resulting from parts of the ETS as well as the revision of InvestEU. The EU's Carbon Border Adjustment Mechanism (CBAM) will be also an important tool to put a fair price on the carbon emitted during the production of carbon intensive goods that are entering the EU, and to encourage cleaner industrial production in non-EU countries. The "Carbon Management Challenge", which seeks to drive carbon management projects and infrastructure development to achieve international climate targets, is also to be mentioned.

2.2.5.2 Thoughts on CCUS technologies social acceptance
Besides technical aspects, social acceptance of the CCUS value chain is essential to ensure its deployment, with actions to raise awareness and get citizens involved. No specific study on this aspect was performed in the scope of the DRIVER project but some thoughts on that aspect are provided hereafter, also based on the 2025 European Forum of the GCCSI, such as on several exchanges with CCUS stakeholders. Some relevant information on that aspect can be found in (Witte, 2021). It has been identified that several factors influence the social acceptability of CCUS technologies, such as:

- Risk perception:

Despite low technical risk, several people are afraid about the risk of CO_2 leaks during its transport and storage. They also have concerns about possible environmental impacts and health effects (e.g. captured CO_2 releases to the atmosphere, when solvents are used for the carbon capture etc.).

- Lack of awareness and information:

The exchanges with general public (e.g. during conferences) indicate that compared with renewable energies, CCUS remains little known to the general public. For example, the difference between permanent CO_2 geological storage and the storage of nuclear wastes is not always clear while these two technologies have nothing in common.

- Local acceptability of infrastructures:

Local residents and politics can show opposition to onshore geological CO_2 storage sites. More acceptation could be seen for offshore CO_2 offshore storage but some fear is still perceptible for the CO_2 transportation. Most of the time, the CO_2 valorization into useful products seems more accepted than CO_2 geological storage.

- Economic benefits and job creation:

A greater acceptance of CCUS projects could be envisaged if that promotes local employment and if this is integrated in a sustainable industrial transition.

Based on these thoughts, several strategies can be developed to improve CCUS social acceptability:

- a clear communication on CCUS technologies is crucial. For example, information campaigns explaining environmental and economic benefits of CCUS could be organized;

- complementary to the previous point, the best way to demonstrate the safety and efficiency of CCUS technologies is to increase real-life cases in Belgium through demonstration projects;

- project transparency and increasing the public engagement is also key. Based on what is organized for any other industrial project, the citizens could be consulted from the earliest stages of development (e.g. such information session has been organized for the GO4ZERO project at the Obourg's cement plant of Holcim company);

- the co-construction of CCUS projects with different stakeholders could help to increase the social acceptability (e.g. in addition to the industrial CO_2 emitters, collaboration with NGOs, local authorities, etc.).

Globally, CCUS actors should be inspired by what is done in other technological sectors to increase the social acceptance for this relevant and necessary climate mitigation technology. For example, (Wustenhagen et al., 2007) published a paper introducing the concept of social acceptance of renewable energy innovation. Moreover, adequate policies and facilitated permitting procedures will also enhance the applicability of the CCUS technologies.

2.3 Belgium Energy system key recommendations

2.3.1 Local CO_2 valorization

In 2019, industries in the Port of Antwerp emitted approximately 14.34 $MtCO_2$, representing 15.9% of Belgium's total CO_2 emissions. The target is to halve these emissions by 2030, implying a reduction of 7.17 $MtCO_2$. To explore how the captured CO_2 could be used and its impact on the Belgian energy system, two scenarios are evaluated: (1) full utilization, where all CO_2 is converted via methanation, and (2) partial utilization, where only the CO_2 needed to react with available hydrogen is used, and the rest is permanently stored underground.
Assuming no hydrogen imports and focusing on oxy-fuel combustion capture, full CO_2 utilization would produce 28.17 TWh of synthetic natural gas (SNG) (Figure 16). This process requires 88.8 TWh of electricity, with 99.6% consumed by electrolysers. As a result, the energy demand for CO_2 capture itself is relatively low. However, the electricity needed for electrolysis is significant—comparable to Belgium's total final electricity consumption in 2021. On the

positive side, 23.76 TWh of low-temperature heat is recovered during water electrolysis and methanation, which can be used in the District Heating Network (DHN).

When projected hydrogen imports of 11 TWh by 2030 are considered, both electricity use and heat production decrease. The energy planning optimization model favors maximizing hydrogen imports, as they are more cost-effective than domestic electrolysis, especially given Belgium's limited renewable energy potential. The scenario shown in darker colors reflects this optimized case. Still, the feasibility of securing sufficient electricity for this strategy by 2030 is uncertain. Moreover, ESTD (Energy Storage Technology Database, www.epri.com) estimates a need for 10 GW of electrolyser capacity—a steep increase from Belgium's expected 150 MW.

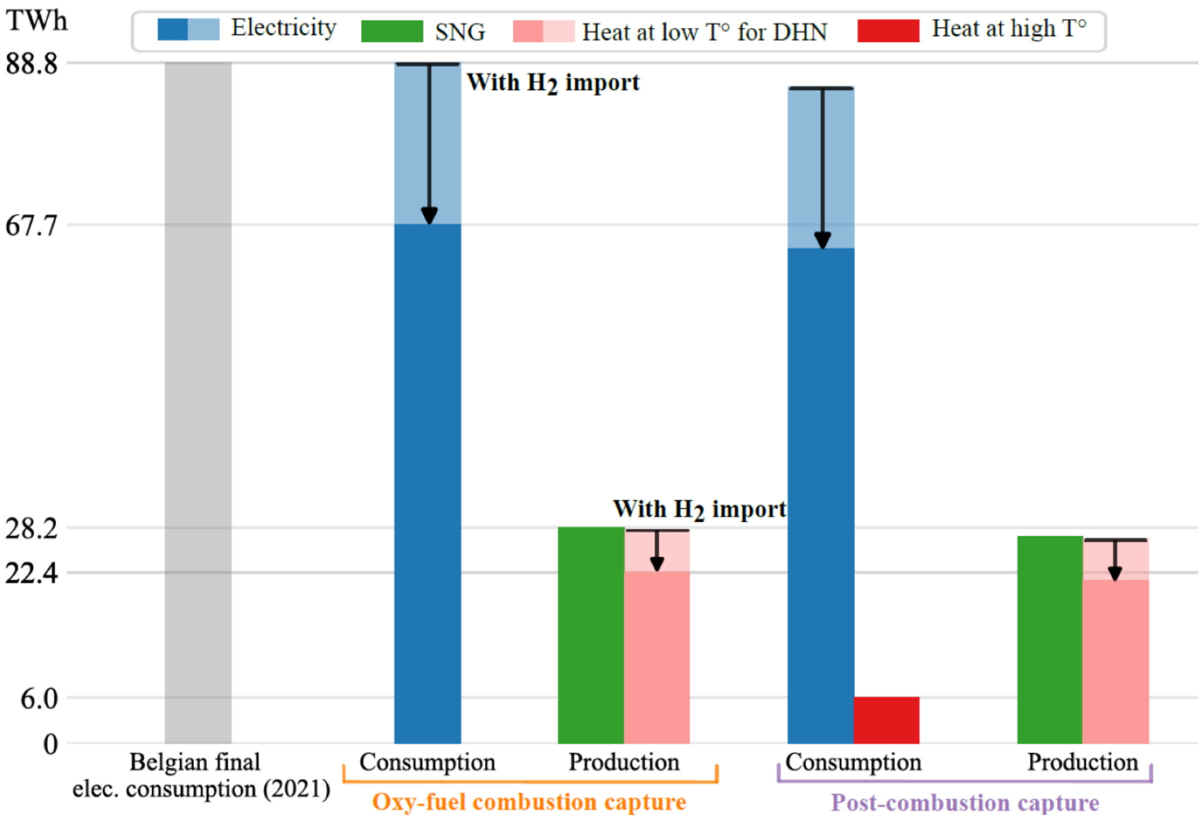


Figure 16: The energy production and consumption of a power-to-gas system supplied with all the captured CO_2 of the industries of the port of Antwerp show the massive electricity consumption by the electrolysers. Abbreviations: synthetic natural gas (SNG), district heating network (DHN), electricity (elec.).

Figure 17 shows the electricity mix required to meet these energy demands. Compared to a scenario without Carbon Capture and Utilization (CCU) in the Port of Antwerp, electricity production increases significantly. This growth is driven by expanded photovoltaic (PV) capacity and increased output from industrial gas CHP and CCGT plants.

The PV capacity reaches its technical maximum—59.2 GW. For context, Europe aims for 600 GW of installed PV capacity by 2030, so Belgium's share would represent nearly 10% of that total—an ambitious figure for such a small and densely populated country. Wind installations also reach their upper limits in all scenarios: 10 GW offshore and 6 GW onshore. Electricity imports are also pushed to their maximum levels.

These shifts in the energy system come with higher costs. The annual cost increase is estimated at €6.4 billion/year for oxy-fuel combustion capture (a 14.8% rise) and €6.5 billion/year for

post-combustion capture (a 14.9% rise). These costs amount to about 1.2% of Belgium's 2022 GDP. While not negligible, these added costs are relatively modest given the scale of emissions reductions and SNG production.
Given the outsized impact of hydrogen production in enabling CO_2 conversion to SNG, a scenario where hydrogen availability in 2030 is limited is also assessed, especially to projected imports and domestic production—11 TWh from imports and 0.65 TWh from local sources, totaling 11.65 TWhH_2.

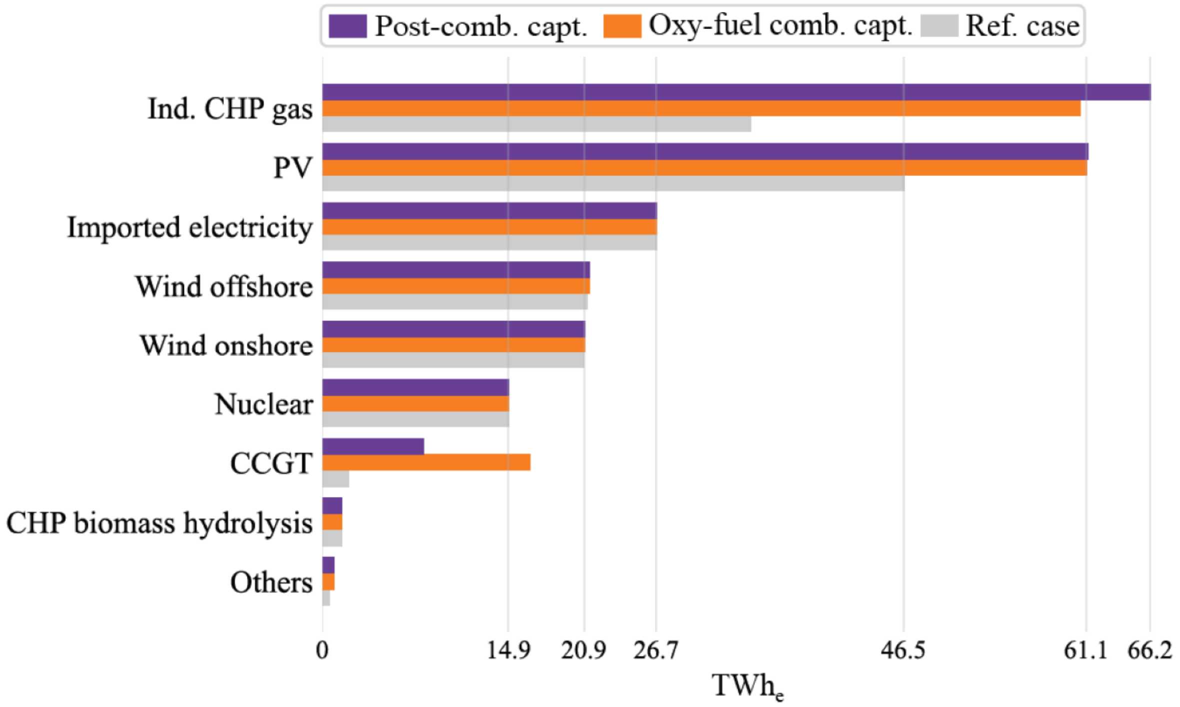


Figure 17: The comparison of the electrical mix with and without power-to-gas in the port of Antwerp illustrates how the important additional electricity requirement is produced, when all the captured CO_2 is used. Abbreviations: combustion (comb.), capture (capt.), industrial (ind.), combined heat and power (CHP), photovoltaic (PV), combined cycle gas turbine (CCGT).

In this case, domestic hydrogen production drops by 98% compared to the full utilization scenario (Figure 18). As electrolysers are the primary consumers of electricity, overall electricity use drops by 97%, despite the CO_2 capture energy demand remaining unchanged. Total energy production falls from 43.7 TWh to 7.5 TWh. Because the energy needed for CO_2 capture is small compared to that for electrolysis, the changes in the electricity mix are relatively minor when CO_2 utilization is matched to available hydrogen.

In summary, full local CO_2 valorization via methanation is technically feasible but heavily constrained by hydrogen availability. Without hydrogen imports, converting all captured CO_2 in Antwerp's port would require 88.8 TWh of electricity, close to Belgium's entire final electricity use in 2021. This strategy demands 10 GW of electrolyser capacity—a sharp leap from the projected 150 MW by 2030—and assumes unrealistic domestic renewable expansion (e.g. 59.2 GW PV, 16 GW wind). While the full CO_2 valorization scenario yields 23.76 TWh of low-temperature heat, recoverable during water electrolysis and methanation, it would require the development of district heating infrastructure to absorb this waste heat and improve overall system efficiency, but only if electrolyser-based hydrogen production is pursued at scale. Therefore, it is recommended to focus on partial utilization strategies that align with realistic hydrogen availability (e.g. 11.65 TWh H_2 from imports and local sources combined).

This approach avoids overextension of the power grid and reduces capital burden while still enabling CO_2 emissions reductions through combined utilization and storage.

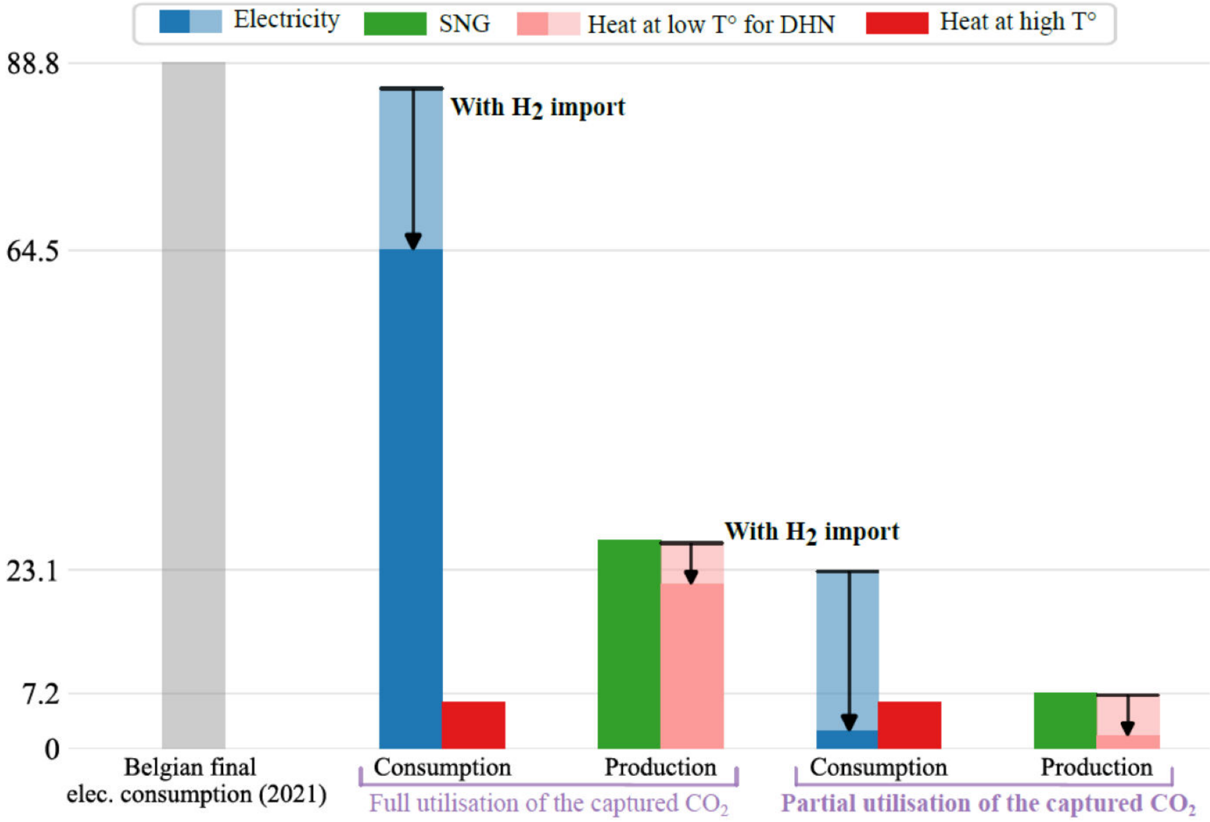


Figure 18: Comparison of the energy consumption and production between using 26.4% (1.9 MtCO2) of the captured CO_2 (on the right) and using all the captured CO_2 (on the left). The capture technology used is the post-combustion capture. Abbreviations: synthetic natural gas (SNG), district heating network (DHN), electricity (elec.).

2.3.2 Role of importing carbon-based electrofuels

As shown in previous section, even when CO_2 valorization is prioritized locally, substantial imports of e-methane remain necessary. This section examines the role of renewable molecule imports—such as e-methane—within the Belgian energy system. It identifies the main drivers of these imports through a strictly techno-economic lens, based on cost optimization. Given the significant uncertainties surrounding electrofuel imports, the technical, economic, availability, and demand-related uncertainties throughout the transition are considered.

Considering the uncertainties that pervade the energy transition, the total transition costs range between €660 billion and €2,050 billion. Among all parameters, the uncertainty on the cost of purchasing electrofuels has the largest impact on the total transition cost. Electrofuels are consistently imported across all scenarios, though the extent varies. For example, in the reference case without nuclear SMRs, imports reach 152.9 TWh—41% of the primary energy mix—by 2050, at an average cost of €93/MWh. Over the full transition period, this amounts to €273 billion in cumulative operational expenditures (OPEX), or 25% of the total transition cost. The uncertainty around renewable electrofuel imports throughout the transition play an important role on their utilization. While overall imports increase, trends differ across carriers (Figure 19). E-methane, a renewable substitute for fossil gas, begins displacing it as early as 2025 in some scenarios, reaching 163 TWh by 2050. Its use grows steadily, mainly in industrial combined heat and power (CHP) systems and boilers. E-hydrogen becomes the dominant hydrogen source, reaching median and peak values of 13.0 TWh and 42.1 TWh by 2050, mostly for mobility. Fuel cell trucks frequently become the preferred option, and in some scenarios, they replace battery-electric vehicles (BEVs) and compressed natural gas (CNG) buses altogether.

Local methanol production via methanolation can provide up to 17.8 TWh, or 33% of total methanol supply. Imported e-ammonia becomes cost-competitive early on, replacing fossil ammonia and Haber–Bosch production. While its primary role is to meet a modest non-energy demand (NED) of ~10 TWh by 2050, its imports vary depending on the need for ammonia-fueled combined-cycle gas turbines (CCGTs). Starting in 2035, e-ammonia exhibits the highest uncertainty among the four electrofuels, with an interquartile range (IQR) of ~50 TWh. In extreme cases, it becomes the dominant electrofuel, reaching 167 TWh, or 45% of the primary energy mix.

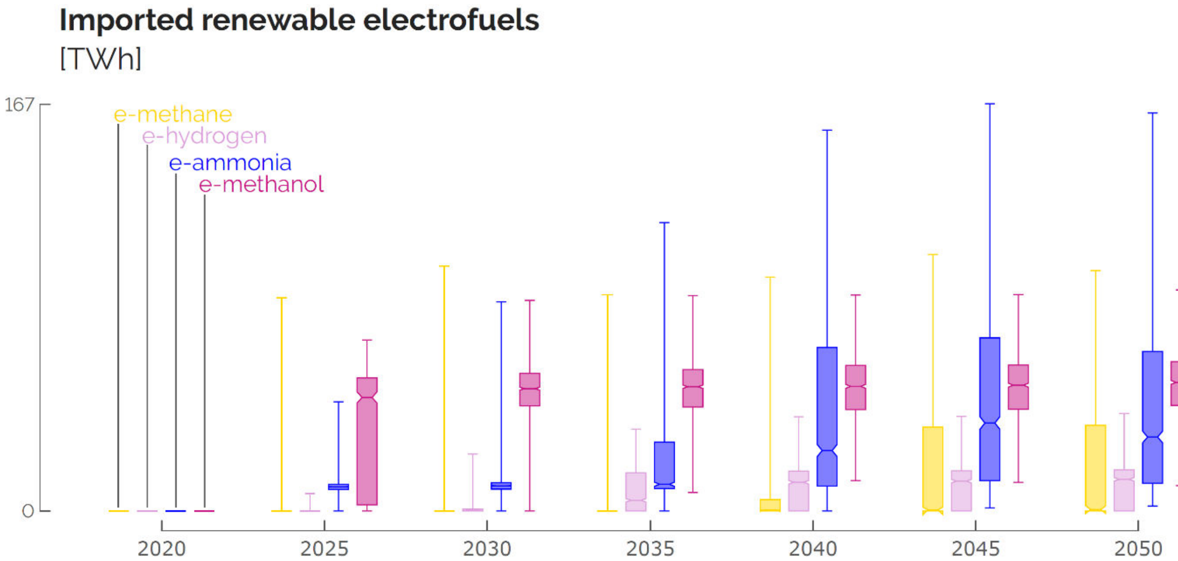


Figure 19: Distribution of the imported renewable electrofuels over the transition. Starting from no electrofuel in 2020, their respective import rises progressively along the transition at different growth rates and with different ranges of values.

E-methanol, meanwhile, becomes the primary source for methanol demand. Biomass-to-methanol pathways contribute only to ~5% of average demand. Its non-energy use accounts for about 3% of consumption, while 95% is used for high-value chemicals (HVC) through the Methanol-to-Olefins (MTO) process. The remaining 2% supplies freight transport via boats and trucks.

Industrial EUD (Energy Use Demand) is the main driver of uncertainty in e-methanol imports. The model selects e-methanol as the primary low-emission option to meet the HVC NED, so lower industrial demand reduces imports and vice versa.

For e-hydrogen, import levels depend on several factors, particularly in the transport sector. E-hydrogen is mainly used in fuel cell trucks (63.5% of road freight), followed by fuel cell cars and buses. Lower CAPEX for fuel cell engines increases imports. Biofuel costs also play a significant role, as biodiesel trucks provide 27.6% of road freight. CNG buses dominate public transport (34.9%), followed by fuel cell (11.2%), biodiesel (27.8%), and hybrid biodiesel (26.1%) buses. The CAPEX of electric vehicles is another important factor—cheaper BEVs reduce demand for fuel cell cars, which represent 13.7% of passenger mobility.

Deploying nuclear SMRs significantly reduces e-ammonia imports. Ammonia CCGTs are the main consumers of e-ammonia by 2050, but SMR-generated electricity (at €40/MWh vs. €151/MWh for e-ammonia CCGTs) displaces them. With higher electrofuel costs, e-ammonia

imports can drop to 2.0 TWh—a 95.4% reduction from the reference case. The cost of imported renewable electricity in 2050 also affects e-ammonia demand, particularly when it is low.
E-methane imports are most sensitive to industrial EUD. Industrial gas CHPs and boilers meet, on average, 25.6% and 6.1% of high-temperature heat demand. Though less impactful, SMR deployment still matters—it enables electrification via industrial heaters, reducing reliance on e-methane. Local biomass availability also plays a role by supporting bio-hydrolysis for renewable methane production.
Interestingly, electrofuel and fossil fuel costs have opposite effects on e-methane imports. Higher electrofuel prices increase e-methane use, while lower prices favor fossil methane. Within the techno-economic optimization model (EnergyScope), costlier electrofuels reduce imports overall—especially e-ammonia—leading to a shift toward more efficient options like industrial methane-CHP for electricity. Initially running on fossil gas, these CHPs consume more e-methane by 2050. In contrast, when electrofuels are cheaper, the model favors higher imports, particularly of e-ammonia. This enables the system to use more emissions-intensive but low-cost resources (e.g., coal in industrial boilers), which supply ~24% of high-temperature heat in 2050 while staying within the CO_2 budget.
Although heavy coal use in Belgium by 2050 seems unlikely, the model includes it if emissions remain within budget. Fossil fuel prices, particularly natural gas, also influence outcomes. If gas becomes more expensive, imports fall, investment in methane-based systems declines, and e-methane demand drops by 2050.
In summary, it is recommended to secure diverse and flexible import contracts for renewable molecules, with the ability to adapt to volatility in cost, supply, and demand. As the price of imported e-fuels alone shifts the total system cost by hundreds of billions of euros, and, similarly, industrial energy demand and vehicle CAPEX assumptions heavily influence technology pathways. Using robust decision-making frameworks is also recommended to plan infrastructure that can pivot based on cost and demand realities. Avoid locking in long-lived technologies that are vulnerable to external uncertainties. Finally, as e-methanol serves both non-energy high-value chemical (HVC) needs (95%) and freight transport (2%), and industrial demand for chemicals drives import volumes, another recommendation is developing an integrated methanol strategy that accounts for domestic production via methanation (~17.8 TWh potential) and links to chemical industry and logistics planning.

2.4 Remote Renewable Energy Hubs (RREH) key recommendations

This section discusses a set of results derived from the different modeling works involving RREHs and developed during the DRIVER project. Two main approaches have been implemented: the first approach follows a futuristic approach, where the potential interest in capturing CO_2 via Post Combustion Carbon Capture in Belgium rather than to rely on Direct Air Capture for methane synthesis in RREH is evaluated. In this first approach, it is also assumed that synthetic methane from the RREH is the only source of gas.

The second approach considers a much closer time-horizon, and aims to determine the optimal energy mix for Belgium in 2030 while adhering to its CO_2 emission target. To account for the evolution of final energy demands for electricity, hydrogen, and natural gas, the annual consumption values are derived from the National Trends 2030 scenario of the Ten-Year Network Development Plans (TYNDP) prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) and Gas (ENTSOG). By 2030, Belgium aims to reduce its annual greenhouse gas emissions to 64.3 Mt CO_2 equivalent (Indicators, 2024). This study considers only CO_2 emissions (excluding other greenhouse gases such as CH_4) and assumes that 85% of annual greenhouse gas emissions correspond to CO_2, resulting in a CO_2 emissions budget of 54.66 Mt per year.

Three scenarios were developed to explore the impact of renewable energy potential and access to sequestration on Belgium's energy mix. The first, the Base Case, assumes the maximum deployment of renewable technologies, including photovoltaic (PV) and onshore wind, alongside the extension of the nuclear fleet based on the High scenario of Elia's Adequacy and flexibility study for Belgium 2024 - 2034 (Elia, 2024), with full access to CO_2 sequestration sites. The second scenario, Limited Low Carbon Production, is based on the Central scenario from the same Elia's study with constrained renewable potential and no nuclear extension after 2025. The third scenario, Limited CO_2 Sequestration Access, assumes that only 10% of total sequestration capacity is available to Belgium, reflecting shared use among Northern and Western European countries. Table 2 summarizes the differences between these scenarios.

Table 2: Potential considered for low carbon production technologies and CO_2 sequestration for each scenario.

	PV GW	Wind onshore GW	Wind offshore GW	Nuclear power plants GW	CO_2 sequestration Mt
Scenario 1: Base case	18.00	6.90	5.76	4.10	185.80
Scenario 2: Limited Low Carbon Production	14.50	5.60	5.76	2.10	185.80
Scenario 3: Limited CO_2 Sequestration Access	18.00	6.90	5.76	4.10	18.58

2.4.1 Serving the gas demand using 100% synthetic methane

The CO_2 valorization framework developed in the first approach has been applied to Belgium as energy demand center, along with two RREH in Greenland and Algeria (see Figure 20), with the aim of decarbonizing the energy and industry sectors.

This model allows, among other, to determine whether PCCC has an advantage – or not – on DAC, and also to arbitrate between the two RREHS locations in the process of decarbonizing (part of) Belgium. The entire supply chain has been modeled, and a resulting gas price of €135/MWh has been obtained, to be compared with a previously obtained price of €150/MWh in a setting where only Direct Air Capture was considered in the RREH for feeding CO into the methanation process (Berger, 2021). In this context, a CO_2 cost of 177 €/ton is computed to achieve emission reduction in the industrial and energy sectors in Belgium. Comparatively, the Greenland hub is less competitive than Algeria, with a methane cost of 188 €/MWh. The cost efficiency of PCCC installations in emitting countries supports the notion of investing in CO_2 infrastructure and establishing a circular CO economy between energy demand centers and RREH as proposed. However, an uncertainty quantification method for the CAPEX prices of CO_2 installations (transport, capture and storage) indicates that PCCC (i.e. capture) contributes the most to the uncertainty.

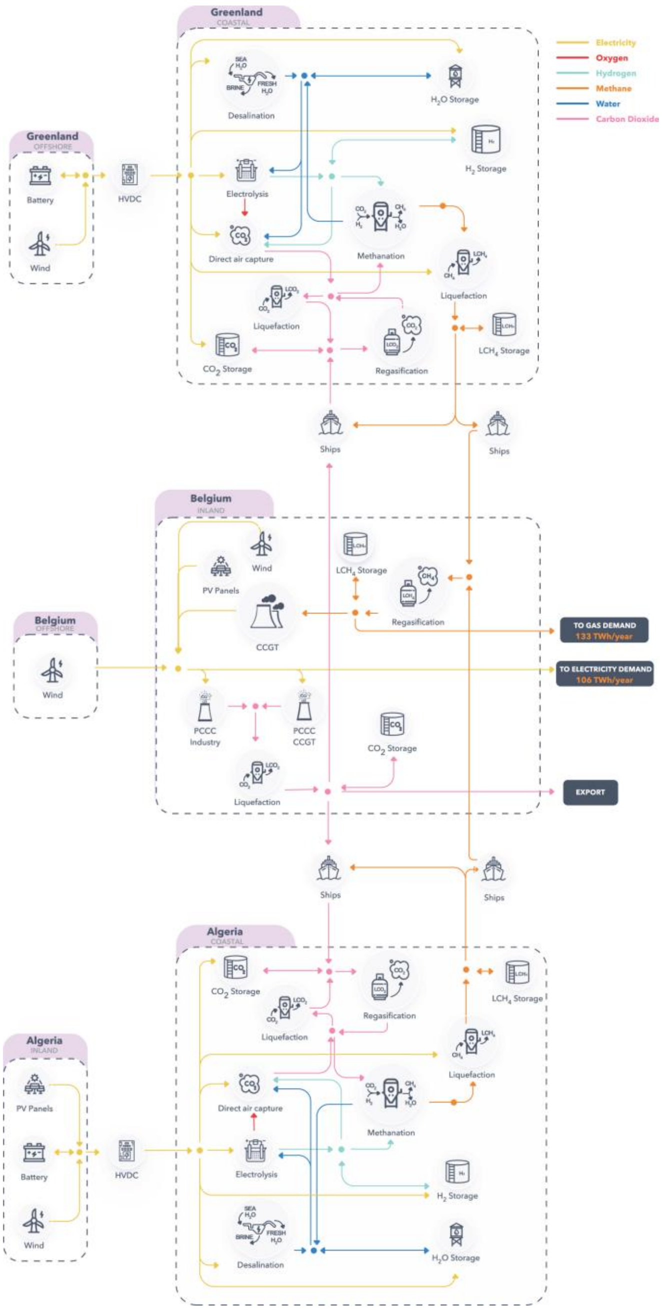


Figure 20: Schematic illustration of the model considered in the first approach: Belgium as Energy Demand Center, Greenland and Algeria as potential energy hubs.

2.4.2 A closer look at the interaction between RREHs & CCUS chain in Belgium

2.4.2.1 RREH vs CO_2 sequestration

The energy mix for Belgium is summarized across six key metrics presented in Figure 21: low carbon production, fossil-fuel-based production, energy imports from neighboring countries, annual CO_2 captured by post-combustion carbon capture systems (PCCCs), annual CO_2 sequestered, and energy imports from remote renewable energy hubs (RREH). Low carbon production includes annual outputs from photovoltaic (PV) systems, wind turbines, biomass power plants, biomethane plants, and fuel cells. Fossil fuel-based production aggregates outputs from combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), combined heat and power (CHP) systems, waste-to-energy plants, and steam methane reformers (SMR).

Energy imports from neighboring countries encompass annual imports of electricity and natural gas, while energy imports from RREH include annual imports of hydrogen and synthetic gas.

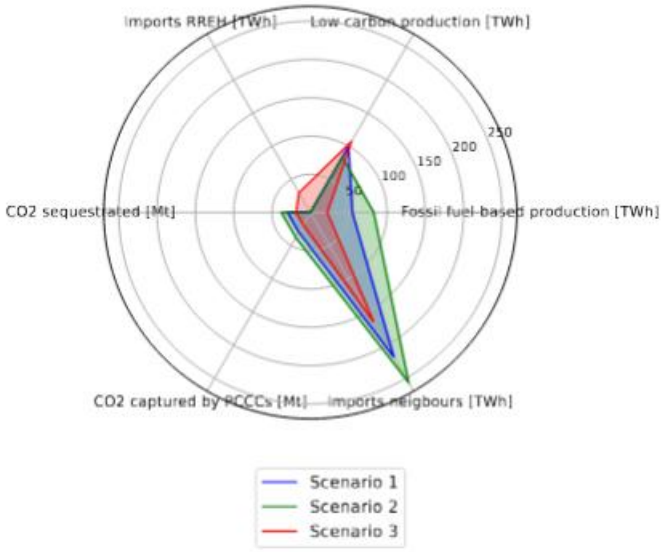


Figure 21: Summary of the energy mix in all 3 scenarios.

In all scenarios, the maximum feasible deployment of renewable energy technologies is achieved. Nevertheless, energy imports from neighboring countries—particularly natural gas—continue to account for a significant share of total energy consumption. Moreover, no CO_2 is converted into synthetic CH_4 within Belgium. This is primarily due to the limited availability of renewable electricity relative to the overall electricity demand. Within the Belgium energy system, hydrogen production is almost entirely based on steam methane reforming (SMR), with the associated CO_2 emissions being captured.

When sufficient CO_2 sequestration capacity is available, it becomes the preferred option for handling captured CO_2. However, this approach requires a substantial amount of sequestration capacity—29.86 Mt and 37.85 Mt of CO_2 per year in the first and second scenarios, respectively. Given that only 185.8 Mt of total CO_2 sequestration capacity is available, it is unlikely that Belgium will be able to secure the necessary capacity by 2030. Nonetheless, these results highlight the critical importance of securing CO_2 sequestration sites, as this remains the most cost-effective solution among the options considered in the model.

In the scenario where CO_2 sequestration is limited to 18.58 Mt (Scenario 3), RREH projects in Algeria begin producing hydrogen and synthetic CH_4 for import. Direct Air Capture (DAC) is preferred as the primary source of CO_2 for the production of synthetic CH_4 within the RREH system. This synthetic CH_4 is exclusively used to transport CO_2 to designated sequestration sites. Furthermore, hydrogen is entirely sourced from RREH to meet the final hydrogen demand in Belgium, where it is also used to generate electricity via fuel cells after importation. Based on the hourly marginal costs of each energy vector (further details are provided in (Dachet et al., 2024b)), the average cost for each energy vector was calculated, as presented in Table 3. However, the costs associated with grid infrastructure for electricity, as well as network infrastructure for hydrogen and natural gas, are not fully accounted for in these marginal costs, since such infrastructures are not included in the current model.

Table 3: Average cost of each energy vector for the final consumer across the different scenarios.

	Scenario 1	Scenario 2	Scenario 3
Electricity mean cost (c€/kWh)	12.52	14.35	27.75
Natural gas mean cost (€/MWh)	34.22	34.22	34.22
Hydrogen mean cost (€/kg)	3.77	3.92	5.54

In the first two scenarios without RREH, the average cost of electricity falls within the range of current electricity prices in Belgium (between 13.48 c€/kWh and 20.23 c€/kWh as of June 2025). The mean cost of hydrogen in these scenarios is 3.77 €/kg and 3.92 €/kg, respectively—approximately twice the cost of grey hydrogen, yet lower than that of blue hydrogen, which can reach a minimum of 5 €/kg in Europe. The cost of natural gas remains unchanged, as it is determined by the import price fixed within the model.

Although the third scenario demonstrates that RREH can be used to meet the 2030 emissions targets, it also significantly increases the overall cost of energy compared to scenarios without RREH. Nonetheless, it is worth noting that the hydrogen cost in this case—derived from renewable sources—is "only" 5.54 €/kg, which is considerably lower than the current cost of domestically produced green hydrogen in Belgium (ranging between 10 and 15 €/kg). Electricity costs in this scenario are substantially impacted by the use of fuel cells powered by green hydrogen, leading to an average electricity price that exceeds the typical range observed in Belgium.

2.4.2.2 CO_2 capture within Belgium

Figure 22 illustrates the amount of CO_2 captured by each type of PCCC installed at the capture rate specified for each scenario. In the Base Case and Limited Low Carbon Production scenarios, three configurations of PCCCs are installed: two VPSA CPUs with capture rates of 95% and 90%, and one MEA (30 wt.%) with a biomass boiler achieving a capture rate of 92.5%. Among these, the VPSA CPU with a capture rate of 95% captures the largest amount of CO_2 in both scenarios, with an annual capture of 20.31 Mt. This configuration is used to capture CO_2 emissions from sources with flue gas concentrations above 10%, such as cement and steel plants, refineries, and biomass power plants. For emitters with flue gas CO_2 concentrations below or equal to 10%, the VPSA CPU with a capture rate of 90% and MEA with a capture rate of 92.5% are preferred.

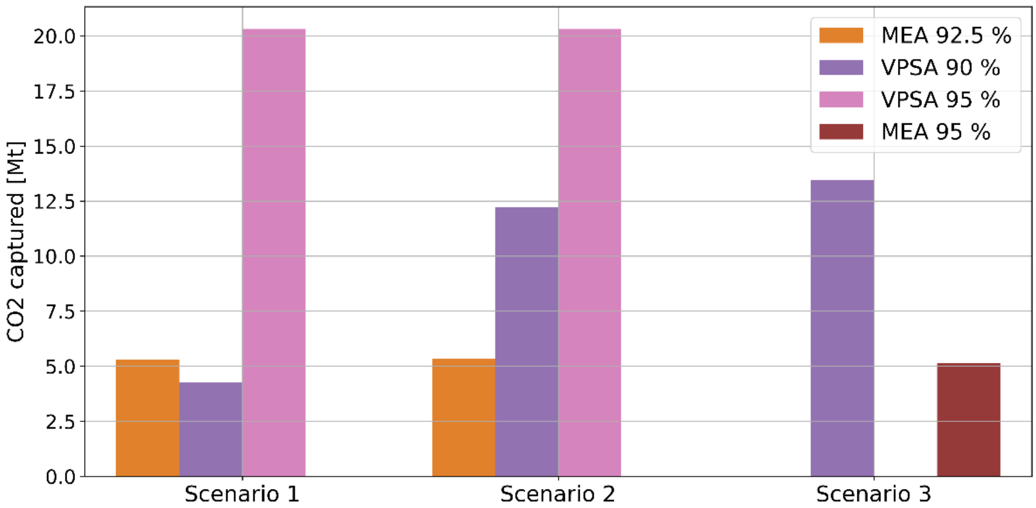


Figure 22: Quantity of CO_2 captured by each configuration of PCCC installed in each scenario.

In both scenarios, the maximum amount of CO_2 captured using the PCCC MEA with a biomass boiler is nearly achieved, capturing 5.29 Mt and 5.33 Mt in the Base Case and Limited Low Carbon scenarios, respectively. This includes CO_2 captured from steam methane reformers (SMR), which have a CO_2 concentration of 5% in their flue gas. The VPSA CPU with a capture rate of 90% captures CO_2 emissions from sources with a CO_2 concentration of 10%, such as waste power plants and chemical plants. Additionally, it captures the remaining CO_2 from emitters with a CO_2 concentration of 5% to meet the CO_2 budget target. In the Base Case scenario, this amounts to 4.25 Mt of CO_2 annually, with SMRs being the only emitters with a 5% CO_2 concentration partially captured by this configuration. In contrast, the Limited Low Carbon Production scenario captures 12.21 Mt of CO_2 using this configuration. In this case, emissions from CCGTs are also captured due to their increased electricity production in this scenario.

For the Limited CO_2 Sequestration Access scenario, only two configurations are installed to capture CO_2: the VPSA CPU with a capture rate of 90% and the MEA using a biomass boiler with a capture rate of 95%. In this scenario, nearly all emitters with CO_2 captured have flue gas CO_2 concentrations of 15% or higher. As in the other scenarios, the maximum CO_2 captured by MEA with biomass is almost achieved at 5.14 Mt. This configuration captures CO_2 from emitters with CO2 concentrations of 15%, such as the ESSO refinery and biomass power plants. The remaining CO_2 is captured from emitters with flue gas CO_2 concentrations above 10%, such as cement and steel plants and refineries, amounting to 13 Mt of CO_2. Additionally, 60 kt of CO_2 is captured from waste power plants to meet the CO_2 budget target.

Table 4: Range of the costs of CO_2 capture for each PCCCs installed in each scenario.

Emitters CO_2 concentration %	Scenario 1: Base Case Type	Capture rate %	Cost €/t_{CO_2}	Scenario 2: Limited Low Carbon Production Type	Capture rate %	Cost €/t_{CO_2}	Scenario 3: Limited CO_2 Sequestration Access Type	Capture rate %	Cost €/t_{CO_2}
20	VPSA CPU	95	64.29 - 68.07	VPSA CPU	95	70.23 - 73.79	VPSA CPU	90	106.79 - 111.33
15	VPSA CPU	95	75.58 - 78.71	VPSA CPU	95	82.44 - 84.57	VPSA CPU	90	123.95 - 125.27
							MEA	95	124.75 - 127.05
10	VPSA CPU	90	98.65 - 119.88	VPSA CPU	90	107.28 - 123.37	VPSA CPU	90	177.78
5	MEA	92.5	172.94	MEA	92.5	175.71	-	-	-
	VPSA CPU	90	181.94	VPSA CPU	90	196.99 - 201.46			

These results can be explained by examining Table 4, which shows the range of CO_2 capture costs for each technology based on CO_2 concentrations in the flue gas, and Figure 23 presenting the PCCCs'cost breakdown across scenarios. From the table, the cost of CO_2 capture increases as the CO_2 concentration of emitters decreases across all scenarios. The cost breakdown for PCCCs reveals that the main cost drivers are the electricity consumption for VPSA CPUs and the cost of PCCCs and boiler for MEA systems. As CO_2 concentrations decrease, more electricity is required to capture CO_2. For instance, in the Base Case and Limited Low Carbon scenarios, the electricity consumption for CO_2 concentrations of 5% is so high that the cost of capture using VPSA CPUs exceeds that of MEA systems. In the Limited Sequestration Access scenario, MEA systems become more cost-competitive for CO_2 concentrations of 15%, as the cost of electricity is significantly higher.

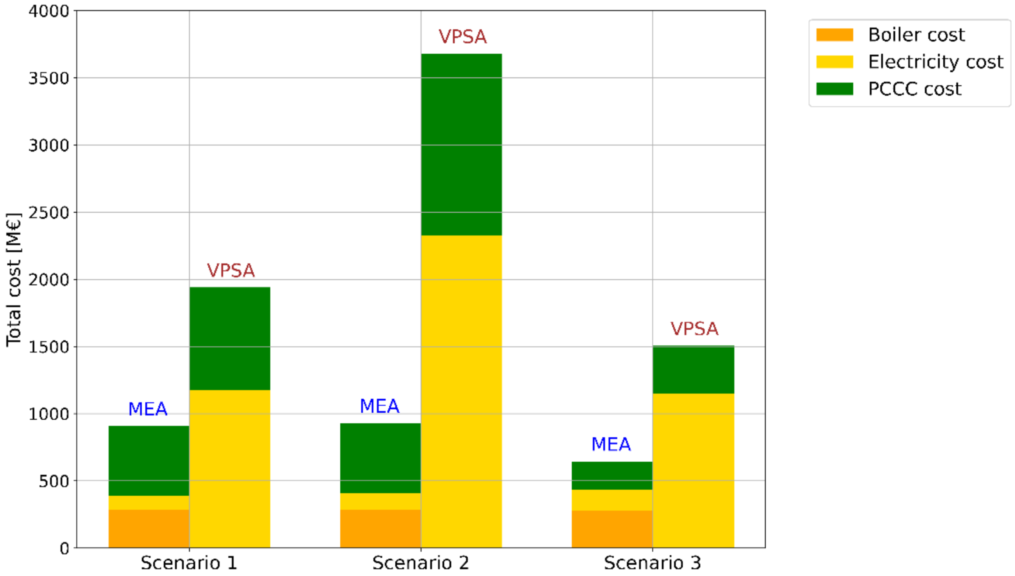


Figure 23: Breakdown of the costs of each type of PCCC across the different scenarios.

By analyzing the dual variable associated with the CO_2 quota constraint, a marginal cost for CO_2 can be determined. This marginal cost can be interpreted as the equivalent CO_2 tax that would need to be applied to achieve the same energy mix without enforcing the CO_2 quota constraint. Table 5 presents the CO_2 tax for each scenario.

Table 5: CO_2 tax for each scenario.

	CO_2 tax €/t
Scenario 1: Base Case	214.83
Scenario 2: Limited Low Carbon Production	224.56
Scenario 3: Limited CO_2 Sequestration Access	765.12

As anticipated, the Limited CO_2 Sequestration Access scenario exhibits the highest CO_2 tax at 765.12 €/t of CO_2. However, even the Base Case and the Limited Low Carbon scenarios feature relatively high CO_2 taxes (214.83 and 224.56 €/t respectively) when compared to the actual CO_2 tax, which was 69.47 €/t as of December 25, 2024.

3 Conclusions & Perspectives

3.1 Conclusions

As the CCUS field is constantly evolving, regular monitoring and technology watch are necessary to refine the various indicators generated (energy, economic and environmental). In addition, developments in the CO_2 market and its regulation (ETS in particular), as well as developments in CCUS and DAC projects in general (current and new projects), will have a major impact on the deployment of CCUS chains.

In terms of CO_2 capture-purification stages, two main categories of processes have been more deeply investigated, namely absorption-regeneration using amine-based solvents, and cryogenic technologies (possibly hybrids, combined with the use of gas-solid adsorption (VPSA-CPU) or membranes as pre-concentration). The challenge for the first category remains to reduce its cost (high thermal energy consumption) and the question regarding the CO_2 transport specifications (possible need for post-treatments), while for the second to continue optimizing the process in order to reduce its (exclusively) electrical energy consumption. Consideration of cryogenic techniques is of paramount importance. Indeed, besides the CO_2 recovery rate itself, the fact that strict purity specifications have to be met for the injection of CO_2 into a pipeline network (and/or for its liquefied transport by ship) will probably very often necessitate the use of such technology. Investigating the liquefaction of CO_2 is also important, as it will be transported by ship to a geological storage hub in liquid form.
Concerning the CO_2 conversion stage, which could be thermally integrated with a capture unit (the benefits of such an operation have been demonstrated), particular attention has been paid to the methanol and methane routes, with methane emerging as the energy vector with the greatest potential.

Regarding Direct Air Capture (DAC), it could have a role to play in global decarbonization provided that every effort is made upstream to reduce CO_2 emissions at source as much as possible. Emergence of DAC for non-industrial areas could be envisaged in the future for the production of hydrogen-carbon-based energy vectors in areas where large amount of non-fossil based energy is available. Regarding Belgium, the role of DAC will be certainly limited at short and mid-terms, especially as long as large industrial CO_2 emitters have not yet limited their emissions.

In addition, and complementary to the CCUS investigations Remote Renewable Energy Hub (RREH) have been studied. Injecting CO_2 captured in Belgium into sequestration sites is preferred over exporting it for use in RREH; however, a large volume of CO_2 must be sequestered to meet the 2030 reduction target (between 30 and 38 Mt of CO2 by year depending on the number of renewable technologies deployed). The use of RREH only appears when there is limited access to CO_2 sequestration sites, which is a more realistic scenario. CO_2 consumed within the RREH only come from DAC installed in the RREH, while carbon capture in Belgium from Post Combustion Carbon Capture (PCCC) is essentially destined for export to sequestration sites. RREH mainly produces green hydrogen, which is very expensive, though still much less costly than green hydrogen produced in Belgium. However, the overall cost of electricity increases due to the use of hydrogen in its production in this scenario.

Regarding the post-combustion carbon capture units, the outcomes are highly dependent on the cost of electricity. In the first two scenarios, where electricity prices remain close to current prices, PCCC with VPSA CPU operating at a 95% capture rate is favored for industries with

CO_2 concentrations above 10%. As electricity demand increases when CO_2 concentration in the flue gas decreases, VPSA CPU with a 90% capture rate is preferred for industries with CO_2 concentrations of around 10%, while MEA combined with a biomass boiler is preferred for CO_2 concentrations of 5%. Only VPSA CPU with a 95% capture rate achieves cost competitiveness when CO_2 concentration in the flue gas reaches 20%, with capture costs at or below 70 €/t. In the last scenario, where electricity prices are high, capture is only used for industries with CO_2 concentrations equal to or above 10%. In this case, VPSA CPU with 90% efficiency is preferred for 20% CO_2 concentration, while capture costs for MEA at 95% and VPSA CPU at 15% CO_2 concentration remain close.

A more global analysis of value chains integrating CO_2 and various energy carriers, especially in the context of the Belgian energy system, has also been performed. The results show that while full local CO_2 valorization in the Port of Antwerp could theoretically convert 14 $MtCO_2$ into about 28 TWh of synthetic natural gas, the resources required are disproportionate: nearly 90 TWh of electricity—almost equal to Belgium's entire final electricity use in 2021—and around 10 GW of electrolyser capacity, compared to just 150 MW expected by 2030. Achieving this would also imply deploying solar and wind power near their technical and spatial limits for a small and densely populated country. Although such a strategy would generate nearly 24 TWh of low-temperature heat that could, in principle, feed district heating networks, its practical implementation is doubtful without massive infrastructure development. Partial CO_2 utilization, matched to expected hydrogen imports (roughly 11–12 TWh from imports and domestic production combined), emerges as the more realistic pathway.

At the same time, the analysis makes clear that Belgium cannot achieve its climate goals through local production of energy carriers alone. Renewable electrofuel imports—including e-methane, e-methanol, e-hydrogen, and e-ammonia—play a structural role across all modeled scenarios. In the reference case without nuclear SMRs, imports reach 152.9 TWh by 2050, equal to about 41% of Belgium's primary energy mix; in alternative scenarios, volumes can rise or fall depending on technology costs and demand assumptions. Their role is differentiated across sectors: e-methane is mainly used in industrial boilers and combined heat and power plants, displacing fossil gas in high-temperature heat applications; e-methanol is directed primarily toward the chemical industry, where about 95% of demand comes from high-value chemical production via methanol-to-olefins, with a smaller role in freight transport; e-hydrogen is absorbed mostly by road freight, especially fuel-cell trucks, but also supports buses and niche industrial uses; and e-ammonia serves both as a feedstock for non-energy uses (around 10 TWh by 2050) and as a fuel for power generation in combined-cycle gas turbines when electricity flexibility is required. The exact balance between these fuels depends strongly on global market conditions: lower costs for fuel-cell vehicles boost hydrogen demand, while expanded nuclear deployment suppresses e-ammonia use by providing cheap, low-carbon electricity.

These findings underline that Belgium's decarbonization strategy must combine realistic domestic CO_2 utilization, constrained by hydrogen availability and renewable potential, with flexible and diversified import strategies for renewable electrofuels. Pursuing this dual approach avoids overstretching the electricity system, balances domestic investments with international sourcing, and allows adaptation to global market volatility.

Some key points of the DRIVER project roadmap are summarized in Figure 24.

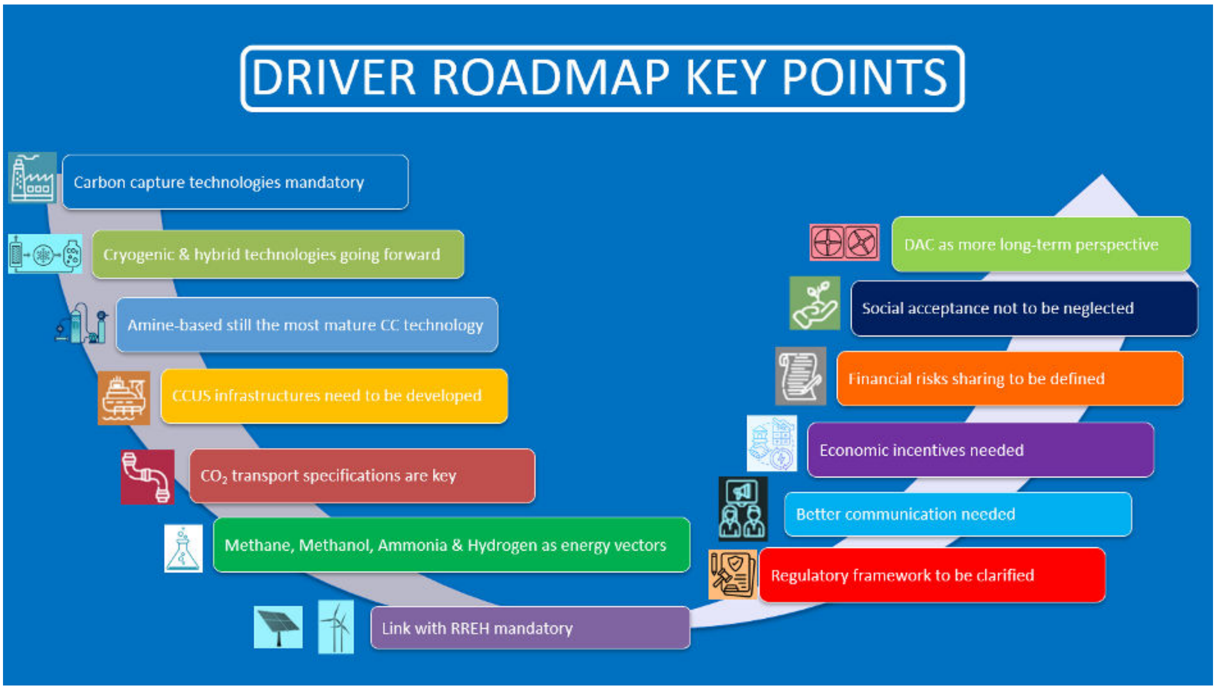


Figure 24: Key points summarizing the DRIVER roadmap

3.2 Perspectives: Digital Platform Creation

As perspectives of the present roadmap, it seems interesting to consider the establishment of a "CO_2 digital platform" in Belgium. The development of such digital platform for CO_2 management would optimize the CCUS value chain and improve market transparency. The objectives of such platform could be:

- to centralize the data on CO_2 emissions, capture sites, transport network to storage sites and/or CO_2 utilization sites;
- having a real-time monitoring of CO_2 flows to ensure efficient infrastructure management (maybe such real-time monitoring could be established in collaboration with CO_2 transport operator, maybe Fluxys);
- to facilitate the transactions between CO_2 producers, transporters and users;
- to have a regulatory support to ensure compliance with environmental and economic standards.

For such purposes, based on several existing digital platforms (see examples in annex), the following key features should be developed:

- interactive mapping: having the location of emission sources, capture infrastructures and storage sites, such as the real-time visualization of transport networks and CO_2 flows (cf. Fluxys);
- a monitoring and reporting module: monitoring of CO_2 emissions captured and used, including a customized dashboards for industrials, public authorities, but also for researchers on that thematic;
- a CO_2 marketplace: allowing to facilitate the connection between CO_2 emitters and users (e.g. e-fuels producers), such as dynamic pricing based on supply and demand for captured CO_2, also depending on the Belgian energy system status;

- a regulatory framework, management and certification scheme: a specific tool could be developed for declaring captured CO_2 emissions, integrating carbon credit tracking, also with the European ETS (Emission Trading Scheme);

- the infrastructures optimization: having planning algorithms to optimize CO_2 transport, storage and/or utilization, but also for predictive analyses to anticipate capacity requirements and improve investment efficiency;

- the integration of several digital technologies: big data and AI (Artificial Intelligence) for the analysis of CO_2 flows and the optimization of transport routes, such as blockchain for the traceability of CO_2 exchanges and secure transactions, and maybe also IoT (Internet of Things) and sensors for real-time data collection on infrastructures, enabling also quick risk identification and mitigation.

It will be certainly relevant for the Belgian authorities to take inspiration of what has already been developed by several companies in other countries in order to build the Belgian CO_2 management digital platform.

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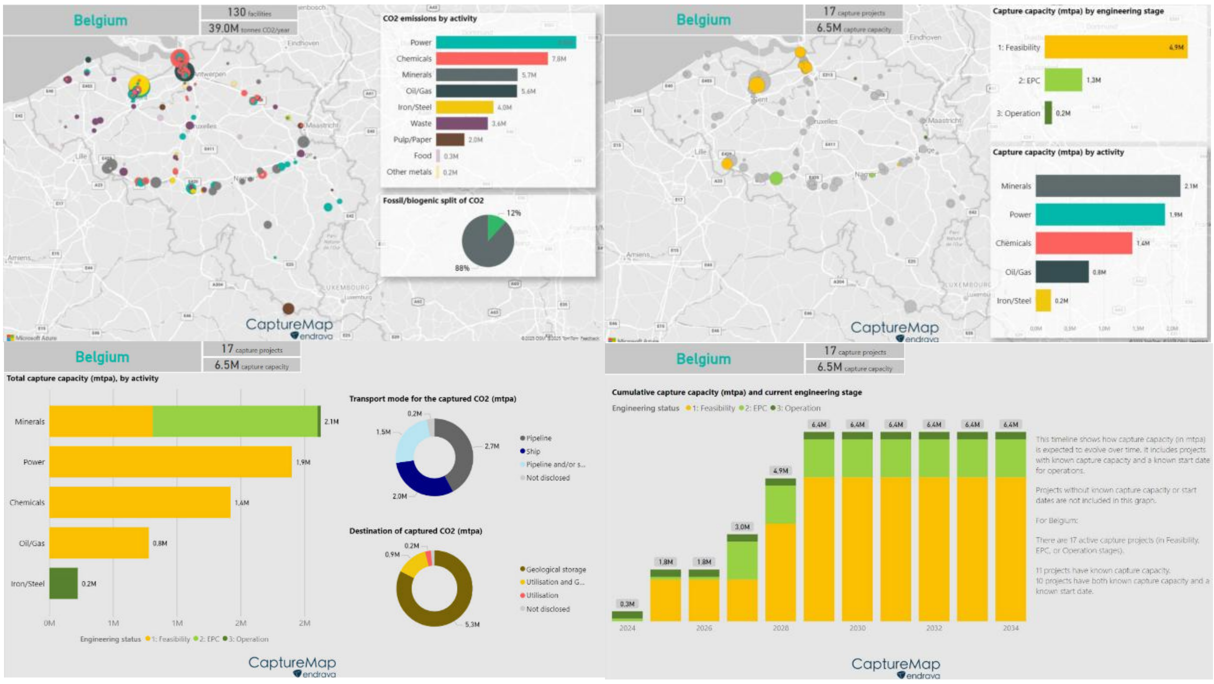
5 Annex – Examples of CO_2 management digital platforms

Endrava CaptureMap - https://www.capturemap.no/

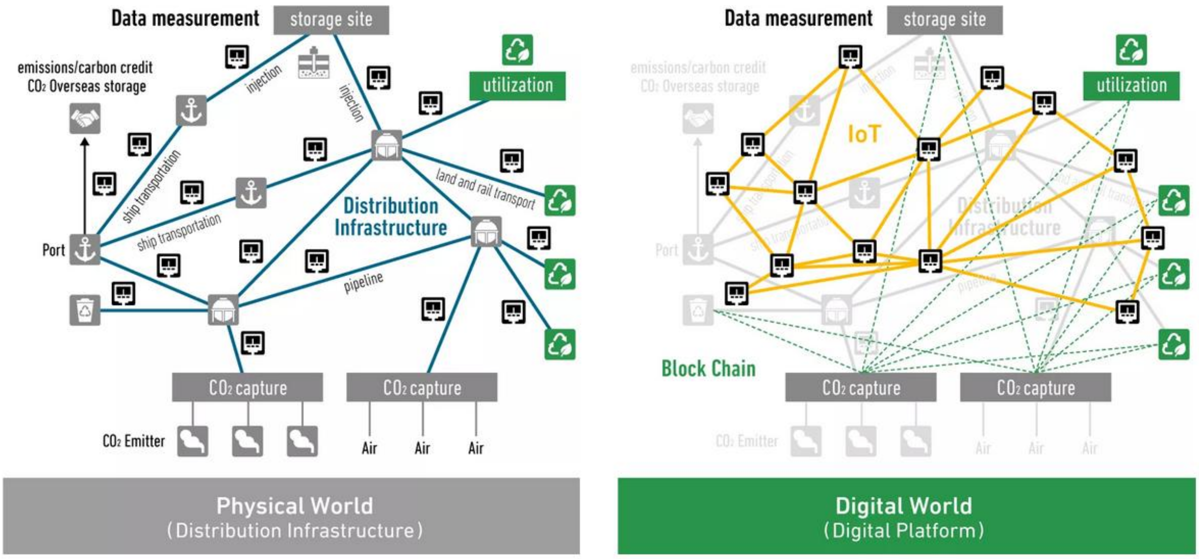
Endrava is a climate-tech company founded in 2016 and based in Oslo (Norway),
CaptureMap is the world's most accurate, global overview of large CO_2 emitters and carbon capture projects. All based on public data. Illustration of free samples of Endrava Capturemap Belgian data, potentially useful for the future definition of a CCUS Belgian digital platform, is provided here below:



MHI CO2NNEX® Digital Platform - https://www.mhi.com/business/solutions/ccus/value-chain.html

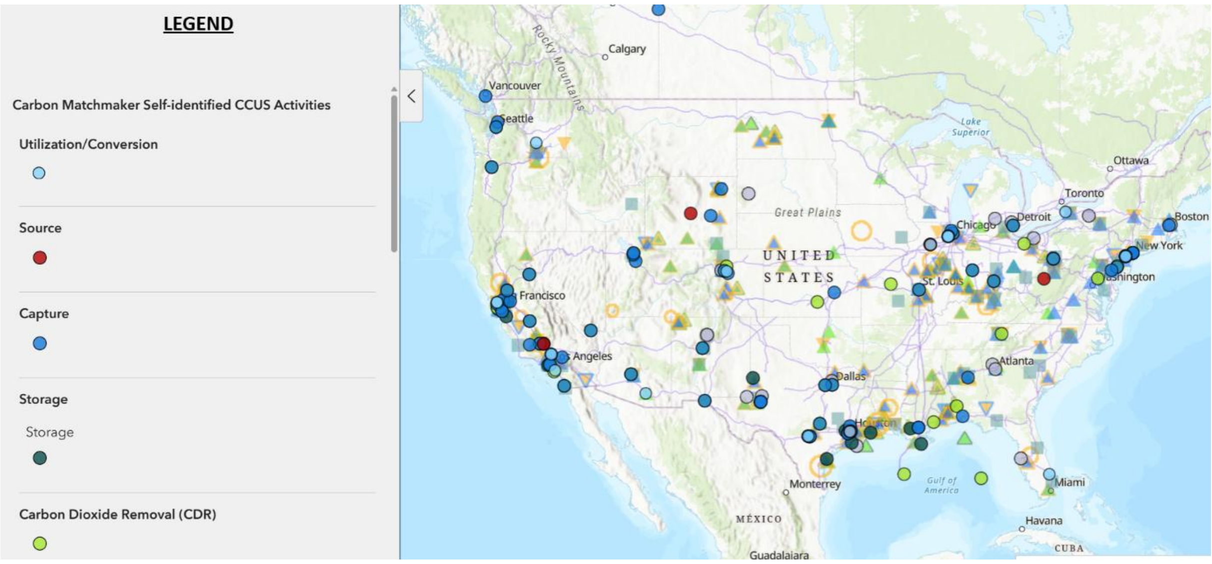
MHI (Mitsubishi Heavy Industry) is developing "CO2NNEX® Digital Platform" for the visualization of the CCUS value chain, accelerating the actions towards the realization of a carbon neutral society. By enabling the management of track records (traceability) of CO_2, management and transfers of the environmental value entailed in CO_2, visualization and streamlining of the CO_2 supply chain, efficiently matching CO_2 suppliers (emitters) with its users and adjusting the balance between demand and supply, aligning both the digital layer and physical layer, the optimization of the entire value chain and maximization of the CO_2 transaction is performed.

An illustration is provided hereafter:

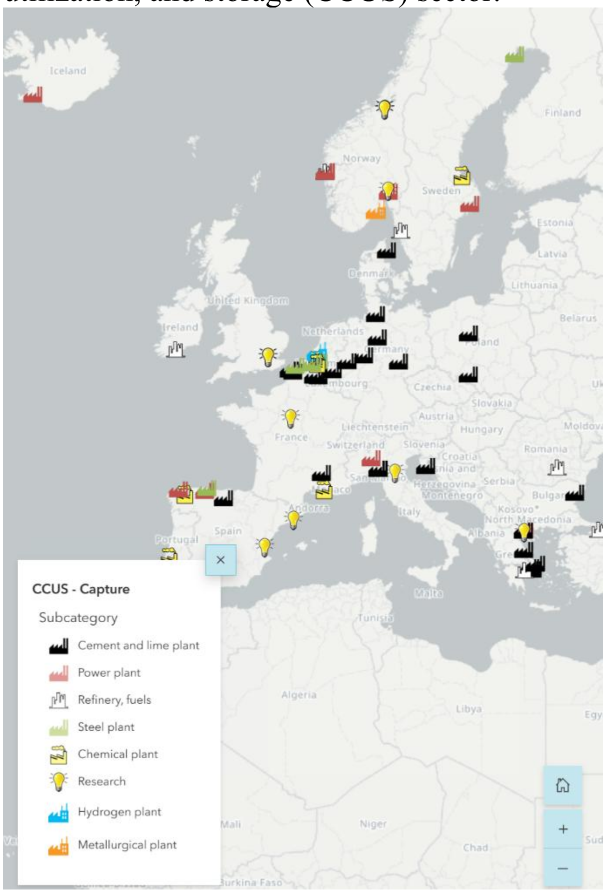


Baker Hughes CarbonEdge:
https://www.bakerhughes.com/carbon-capture-use-and-storage-ccus-solutions/project-design-services/carbonedge-endtoend-digital-solution-ccus-operations
Baker Hughes is proposing CarbonEdge™, powered by Cordant™, as digital CCUS end-to-end solution with real-time, accurate, and actionable data from
Presented as industry's first risk-based CCUS digital solution, CarbonEdge gives complete and accurate data to support reliable measurement, monitoring, and verification (MMV) of CO_2 as it is captured, transported, and sequestered underground. CarbonEdge integrates digital monitoring, risk management, and reporting with expert engineering to bridge operational gaps, support real-time data processing, and make smarter decisions:

Carbon Matchmaker:
https://www.energy.gov/fecm/carbon-matchmaker
Carbon Matchmaker is an online information resource designed to connect users across the carbon capture, utilization, and storage (CCUS) as well as carbon dioxide removal (CDR) supply chains. It provides a teaming mechanism to support geographically diverse CCUS and CDR projects across the United States, while also raising awareness and promoting the development of regional carbon management hubs, including integration with hydrogen hub initiatives where relevant. In addition, Carbon Matchmaker offers community, industry, and technology stakeholders both domestically and internationally access to carbon dioxide supply and demand maps for current and planned projects. It also highlights past and ongoing DOE-funded carbon management projects through a geospatial mapping tool.



<u>Industrial Carbon Management interactive stories:</u>
https://webgate.ec.europa.eu/cineaportal/apps/storymaps/stories/9340ba62369c4f15bc99662070691120
A new tool has been launched to help discover EU-funded projects in the carbon capture, utilization, and storage (CCUS) sector.



Industrial carbon management (ICM) encompasses a portfolio of technologies aimed at managing and reducing CO_2 emissions from industrial and energy production facilities, as well as removing CO_2 from the atmosphere. This includes capturing CO_2 for storage (CCS), capturing CO_2 for utilization (CCU), or removing CO_2 directly from the atmosphere, where permanent storage involves either biogenic or atmospheric CO_2. A crucial element linking these different pathways together is the CO_2 transport infrastructure. To demonstrate the joint EU support for industrial carbon management and the synergies between the programs managed by CINEA, the Agency has introduced a new digital tool. This interactive platform allows users to explore how EU funding is distributed across the CCUS sector, identify supported projects, and understand how these initiatives are driving European clean-tech innovation, advancing climate-friendly solutions, and improving both the environment and the quality of life for EU citizens.