Remote Renewable Energy Hubs: Design, Techno-Economic and Financial Perspectives

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PhD Thesis

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Abstract

Meeting global climate targets requires large-scale deployment of low-carbon energy carriers. Yet, renewable energy is often geographically mismatched with demand centers. Remote Renewable Energy Hubs (RREHs) have emerged as a promising solution: these are energy hubs located in areas with abundant renewable resources, designed to produce and export low-carbon energy carriers to distant load centers. This thesis contributes to the design, techno-economic and financial understanding of RREHs through three research questions, each addressed in a dedicated part of the manuscript.

Part I defines the concept of RREHs and formalizes a taxonomy to characterize them. This taxonomy enables systematic comparisons between hub configurations and supports the identification of new hub architectures.

Part II explores novel RREH designs. First, two chapters focus on CO_2 valorization strategies, demonstrating how carbon loops involving Post-Combustion Carbon Capture (PCCC) or Direct Air Capture (DAC) affect system cost and design. Second, a comparative study assesses the techno-economic performance of four hydrogen-derived energy carriers (CH_4, NH_3, H_2, CH_3OH) synthesized in the Algerian Sahara and exported to Belgium. Third, a new RREH concept, based on floating offshore wind and battery transportation, is introduced for high-seas deployment, providing an alternative design.

Part III addresses the financial dimension of RREHs. It quantifies how the Weighted Average Cost of Capital (WACC), which varies across countries, influences hub competitiveness. This part reveals a trade-off between technical potential and financial risk, calling for innovative financing mechanisms and strategic policy support.

Contents

Introduction

1 Introduction

> *The real voyage of discovery consists not in seeking new landscapes, but in having new eyes.*
>
> — **Marcel Proust (1923)**
> In Search of Lost Time

1.1 Context and Motivation

Climate change represents one of the most pressing challenges of our time, threatening human societies and biodiversity alike. To limit global warming, the decarbonization of the energy system is indispensable, as underlined by the IPCC [IPC23]. A large share of this effort will rely on the deployment of renewable energy in electricity generation. However, electrification alone cannot fully address the decarbonization of so-called “hard-to-abate” sectors, such as refineries, maritime transport, and aviation. These sectors require dense, storable, and transportable energy carriers, for which low-carbon synthetic fuels commonly referred to as e-fuels, are promising alternatives [JLK25].

E-fuels are obtained through Power-to-X technologies, which convert low-carbon electricity into hydrogen and hydrogen-derived molecules such as methane (CH_4), ammonia (NH_3), and methanol (CH_3OH). These molecules serve a dual role: they act as low-carbon fuels and as energy vectors that enable storage and long-distance transport of renewable energy. As such, they represent a cornerstone of the future low-carbon energy system [Ber+20; NHB24].

Despite the technical maturity of Power-to-X technologies, their large-scale deployment in energy-demanding regions like Western Europe faces significant limitations. Renewable resource availability is constrained by urbanization, land-use conflicts, and modest solar and wind potential. In addition, spatial competition and public acceptance hinder large-scale renewable projects in densely populated areas [SG22]. This geographic and resource mismatch between load centers and renewable supply motivates the search for alternative approaches.

The concept of Remote Renewable Energy Hubs (RREHs) has been proposed as one such solution [Ber+21]. RREHs are infrastructures located in regions with abundant renewable resources, such as deserts, high-wind areas, or offshore high seas, where renewable energy is harvested, converted, and exported to load centers. This approach creates new opportunities for load centers to decarbonize their economies.

Beyond the scientific motivation, policy and industrial drivers also reinforce the relevance of RREHs. In the European Union, the *Fit for 55* package, the *REPowerEU* strategy, and sectoral regulations such as *FuelEU Maritime* [Eur24b] and *ReFuelEU Aviation* [Eur24a] are expected to generate demand for low-carbon fuels. Industry actors have already responded; for instance, the Belgian shipping company CMB.Tech is developing e-fuels projects in Namibia [CMB24] or the partnership project between notably Siemens, Porsche and HIF for producing methanol in Haru Oni [HIFnd]. These developments illustrate the growing convergence of academic research, policy frameworks, and industrial initiatives around the RREH concept.

1.2 A Brief History of the Concept of RREHs

The origins of this idea can be traced back to Hashimoto et al. [Has+99], who envisioned the export of synthetic methane from Egypt to Japan. In the 2010s, techno-economic assessments refined the concept by analyzing methane exports from North Africa to Northern Europe [FBB15; Ago18]. Later, Berger et al. [Ber+21] evaluated a complete supply chain delivering synthetic methane from Algeria to Belgium.

Since then, the scope of RREHs has significantly broadened. Recent work has introduced CO_2 valorization, through either Direct Air Capture (DAC) or Post-Combustion Carbon Capture (PCCC), in combination with renewable hydrogen [Dac+24; Fon+24]. Other studies explored alternative carriers such as ammonia, methanol, or hydrogen itself [Pfe+23; Ver+23; Lar+24]. The geographical coverage has also expanded, with proposed hubs in Greenland, Chile, and the Arabian Peninsula.

Related conceptual frameworks have also emerged. The *Global Grid* proposes large-scale electricity interconnections between resource-rich regions and demand centers [CEA13; Liu15]. The DESERTEC project is a well-known example, designed to transport North African solar electricity to Europe. The global grid approach can be seen as the interconnection of demand centers and RREHs around the world, with electricity as an export commodity. However, unlike global grid, RREHs could also rely on chemical vectors, which may be more suitable for long-distance transport and storage.

This evolution shows how the concept of RREHs has developed from synthetic methane exports to different designs addressing multiple carriers, geographies, and technological configurations. Nevertheless, with this diversification comes the challenge of comparison and conceptual clarity.

1.3 Research Gaps

The growing body of literature demonstrates the potential of RREHs to contribute to the energy transition. However, several limitations and open questions remain.

Conceptual clarity and diversity of RREHs.

A wide variety of hubs has been proposed, with different import, export, and byproduct commodities, making comparison difficult. For instance, some RREHs integrate CO_2 imports while others rely solely on local capture, and some valorize byproducts such as oxygen or waste heat while others do not. A systematic taxonomy is required to characterize these designs and to support the identification of novel ones.

Novel designs.

Methane is not the only possible export commodity; alternative molecules such as H_2, NH_3, and CH_3OH also show promise. Each presents distinct properties in terms of efficiency, transportability, and integration into end-use sectors. New hub designs synthesizing these molecules, along with systematic quantitative comparisons, are needed to assess their potential.

Additionally, the import of commodities (e.g., CO_2 from industrial regions) and offshore high-seas hubs using batteries as energy vectors challenge conventional RREH designs. These configurations have received limited attention but could significantly expand the role of RREHs in the energy transition. RREHs could be deployed offshore or become large importers of CO_2.

Financial dimension.

Most techno-economic studies tended to oversimplify the financing costs. However, the Weighted Average Cost of Capital (WACC) strongly influences the competitiveness of e-fuels and varies substantially across regions. Ignoring this factor may bias comparisons, favoring locations that appear technically optimal but are not financially viable.

Addressing these gaps requires methodological innovations, such as the development of a taxonomy, as well as techno-economic case studies across diverse geographies and energy vectors.

1.4 Objectives and Research Questions

Building on these identified gaps, the objective of this dissertation is to advance the design, techno-economic, and financial understanding of Remote Renewable Energy Hubs. To this end, the dissertation addresses the following research questions:

- **RQ1.** How can the concept of Remote Renewable Energy Hubs (RREHs) be defined and formalized through a taxonomy that enables comparison and supports the identification of novel designs?
- **RQ2.** How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?
- **RQ3.** What is the role of financing, risk, and the cost of capital (WACC) in the emergence and competitiveness of RREHs?

1.5 Structure of the Thesis

To emphasize the coherence between research questions and individual contributions, the thesis is structured in **Parts**, each corresponding to one research question. Each Part contains one or more chapters based on published or submitted articles.

- **Part I – Conceptualization of RREHs (RQ1)** Chapter 2 introduces a formal definition of the RREH concept and develops a taxonomy for their characterization. This taxonomy enables systematic comparison of hub configurations and supports the identification of novel designs.
- **Part II – Novel RREH Designs (RQ2)** Chapter 3 explores CO_2 valorization loops and their techno-economic implications. Chapter 4 analyzes alternative CO_2 sourcing strategies and their impact on e-methane costs. Chapter 5

compares hub configurations synthesizing different export commodities (H_2, NH_3, CH_3OH, CH_4). Chapter 6 introduces high-seas hubs using floating wind turbines and batteries as energy vectors. Together, these chapters expand the design space of RREHs and evaluate their feasibility.

- **Part III – Financial and Strategic Dimensions (RQ3)** Chapter 7 investigates the role of financing, risk, and the cost of capital (WACC) in RREH competitiveness, highlighting how economic conditions shape the viability of promising locations.

- **Synthesis and Conclusion** Chapter 8 synthesizes the findings and discusses their implications for policy, industry, and future research.

The chapters are presented thematically, according to the research questions addressed, rather than following the chronological order in which the papers were written or published.

1.6 Produced Work

This thesis is based on and complemented by several scientific outputs, grouped into three categories: scientific publications, presentations, and outreach articles. The presentations were delivered in a variety of academic and professional contexts, while the outreach articles were written to introduce the concept of RREHs to a broader audience.

1.6.1 Scientific Publications

- Dachet, V., Benzerga, A., Fonteneau, R., & Ernst, D. (17 March 2023). Towards CO2 valorization in a multi remote renewable energy hub framework [Paper presentation]. Proceedings of ECOS 2023 - The 36th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems, Las Palmas, Spain. doi:10.52202/069564-0172 `https://hdl.handle.net/2268/301033`

- Dachet, V., Benzerga, A., Coppitters, D., Contino, F., Fonteneau, R., & Ernst, D. (2024). Towards CO2 valorization in a multi remote renewable energy hub framework with uncertainty quantification. Journal of Environmental Management, 363, 121262. doi:10.1016/j.jenvman.2024.121262

- Larbanois, A.* , Dachet, V.* , Dubois, A., Fonteneau, R., & Ernst, D. (2023). Ammonia, Methane, Hydrogen and Methanol Produced in Remote Renewable Energy Hubs: a Comparative Quantitative Analysis [Paper presentation]. Proceedings of ECOS 2024 - The 37th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems, Rhodes, Greece. doi:10.52202/077185-0192 `https://hdl.handle.net/2268/310172` *These authors have contributed equally to this work.

- Fonder, M., Counotte, P., Dachet, V., de Séjournet, J., & Ernst, D. (15 March 2024). Synthetic methane for closing the carbon loop: Comparative study of three carbon sources for remote carbon-neutral fuel synthetization. Applied Energy, 358. doi:10.1016/j.apenergy.2023.122606

- Dachet, V., Dubois, A., Miftari, B., Fonteneau, R., & Ernst, D. (19 December 2024). Remote Renewable Energy Hubs: a Taxonomy. Energy Reports, 13, 3112-2120. doi:10.1016/j.egyr.2025.02.040 `https://hdl.handle.net/2268/309761`

- Dachet, V., Maio, A., Counotte, P., Fonteneau, R., & Ernst, D. (2025). Remote Renewable Energy Hubs in the High Seas Using Batteries as Energy Vector. ORBi-University of Liège. https://orbi.uliege.be/handle/2268/327232. https://hdl.handle.net/2268/327232

- Dachet, V., Ooms, G., Lambert, M., & Ernst, D. (2025). On the Importance of the Cost of Capital in the Emergence of Remote Renewable Energy Hubs.

- Dauchat, L.*, Dachet, V.*, Fonteneau, R., & Ernst, D. (2024). Waste Heat Recovery in Remote Renewable Energy Hubs. Proceedings of ECOS 2024 – The 37th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems, Rhodes, Greece. doi:10.52202/077185-0004. *These authors contributed equally.

- Mokeddem, S., Miftari, B., Dachet, V., Derval, G., & Ernst, D. (in press). Distributed e-fuel hubs: Concept and case study. ORBi-University of Liège. `https://orbi.uliege.be/handle/2268/327044`

1.6.2 Presentations

- Dachet, V., Collin, J., & Ernst, D. (2023). Remote Renewable Energy Hubs [Paper presentation]. Total Energies Town Hall, Paris, France. `https://hdl.handle.net/2268/302957`

- Dachet, V., Miftari, B., Colin, J., & Ernst, D. (2023). Remote Renewable Energy Hubs (v2) [Paper presentation]. Invited talk at DTU, Department of Wind and Energy Systems, Copenhague, Denmark. https://hdl.handle.net/2268/306582

- Dachet, V., Miftari, B., Derval, G., & Ernst, D. (2023). Hydrogen as the basis of Remote Renewable Energy Hubs [Paper presentation]. Club Industrie-Université 22/09/23. https://hdl.handle.net/2268/306826

- Ernst, D., Dachet, V., Larbanois, A., Mokeddem, S., Techy, T., & Vassallo, M. (2025). The world of energy: problems, but always with solutions [Paper presentation]. Engie Energy Luncheons, Brussels, Belgium. https://hdl.handle.net/2268/332344

- Dachet, V., & Ernst, D. (2025). Remote Renewable Energy Hub: a concept for improving energy security [Paper presentation]. Working session on decarbonization between the Walloon Parliament (Belgium) and the Parliament of North Rhine Westphalia (Germany), Namur, Belgium. https://hdl.handle.net/2268/329187

1.6.3 Outreach Articles

- Dachet, V., Lokotar, I., & Ernst, D. (2024). Remote Renewable Energy Hubs: A Leadership Opportunity that Europe Must Seize. Confrontations Europe. https://hdl.handle.net/2268/318392

- Dachet, V., & Ernst, D. (2025). Remote renewable energy hubs: a wonderful accelerator of energy transition. Daily Science. https://hdl.handle.net/2268/327608

- Dachet, V., & Ernst, D. (2025). Les centres d’énergie renouvelable distants : un magnifique accélérateur de la transition énergétique. Daily Science. https://hdl.handle.net/2268/327607

Part I

Conceptualization of RREHs

2

A Taxonomy for Remote Renewable Energy Hubs

2.1 The Question

RQ1. How can the concept of Remote Renewable Energy Hubs (RREHs) be defined and formalized through a taxonomy that enables comparison and supports the identification of novel designs?

Remote Renewable Energy Hubs (RREHs) have been introduced in the literature as infrastructures that harvest abundant renewable resources in remote areas and export them to demand centers in the form of e-fuels. However, the diversity of possible hub designs, differing in import/export commodities, by-products, and integration with local opportunities, makes systematic comparison challenging. This raised the need for a formal framework to clearly define and characterize RREHs.

2.2 The Idea

While early studies on RREHs focused on individual supply chains (e.g., methane from North Africa to Europe), no common framework existed to describe their design space.

The key idea behind this work is to introduce a *taxonomy* for RREHs, built on a formal set-theoretic description of imports, exports, by-products, and local opportunities. Such a taxonomy provides clarity and enables systematic characterization of hubs.

This taxonomy allows to compare hubs across studies and ease the identification of novel configurations.

2.3 Contributions of the Paper

The contributions of the paper, published in the journal Energy Reports and titled *Remote Renewable Energy Hubs: A Taxonomy*, can be summarized as follows:

- Introduces a formal definition of RREHs.
- Proposes a taxonomy that enables systematic comparison of hub designs based on imports, exports, by-products, and local opportunities mathematical sets.
- Demonstrates the taxonomy on existing RREH case studies from the literature.
- Provides a procedure for identifying new hub configurations, possibly improving cost efficiency and local integration.

2.4 Author's Contribution

I developed the research idea and designed the formal framework of the taxonomy, carried out the mathematical formulation, and applied it to case studies. I also led the writing of the paper, with revisions and guidance from my co-authors.

2.5 Integration within the Thesis

This paper directly addresses **RQ1** by laying the conceptual foundations of the thesis. The taxonomy serves as a unifying framework especially for the different hub designs (Part II) of this thesis. It thus provides the methodological backbone for the comparative and exploratory studies that follow.

Remote Renewable Energy Hubs: a Taxonomy

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Abstract

Serving the energy demand with renewable energy is hindered by its limited availability near load centres (i.e. places where the energy demand is high). To address this challenge, the concept of Remote Renewable Energy Hubs (RREH) emerges as a promising solution. RREHs are energy hubs located in areas with abundant renewable energy sources, such as sun in the Sahara Desert or wind in Greenland. In these hubs, renewable energy sources are used to synthetise energy molecules. To produce specific energy molecules, a tailored hub configuration must be designed, which means choosing a set of technologies that are interacting with each other as well as defining how they are integrated in their local environment. The plurality of technologies that may be employed in RREHs results in a large diversity of hubs. In order to characterize this diversity, we propose in this paper a taxonomy for accurately defining these hubs. This taxonomy allows to better describe and compare designs of hubs as well as to identify new ones. Thus, it may guide policymakers and engineers in hub design, contributing to cost efficiency and/or improving local integration.

Keywords: Energy Sytems, Remote Renewable Energy Hub, Renewable Energy, Taxonomy

1. Introduction

To decarbonize their energy supply, load centers, i.e., geographical zones with high energy demand, will have to rely on large amounts of renewable energy. Nevertheless, renewable energy produced locally in those load centers, such as Belgium, may be insufficient to cover all energy needs for various reasons [1], such as: (i) limited space to install renewable energy assets notably due to factors such as strong urbanization or geographical constraints and (ii) low-quality renewable energy sources. To address these limitations, Remote Renewable Energy Hubs (RREHs), i.e., energy hubs situated away from those load centers where renewable energy is abundant, offer a solution to the lack of local renewable resources. RREHs have spurred significant research on possible hub development around the globe [1, 2, 3]. They can rely on power-to-X technologies that present a dual advantage [4, 5, 6]. They offer a CO_2-neutral solution to meet energy demand and a means of storing energy generated by renewable sources [7].

Different models of RREHs have been proposed in the literature. Hashimoto et al. [3] proposed a RREH, where CH_4 was produced in Egypt to deliver methane to Japan. However, no techno-economic analysis of the supply chains was carried out. Then, Fasihi and Bogdanov [8] and Fasihi et al. [9] proposed a techno-economic analysis for the production of CH_4 in Northern Africa and delivery in Finland. In Verkehrswende et al. [10], the authors investigate a similar supply chain with delivery in Germany. Berger et al. [11] proposed a techno-economic analysis of a supply chain between the Sahara desert in Algeria and Belgium as a load centre. Dachet et al. [2] performed a techno-economic analysis of introducing a loop involving the export of CO_2 from Belgium to the RREH defined in Berger et al. [11] as proposed by Hashimoto et al. [3]. They highlight the potential of post-combustion carbon capture (PCCC) in Belgium to valorise CO_2 in a RREH. They also investigated another RREH located in Greenland, which has also been proposed as an energy hub for Europe with complementary wind regimes [12, 13]. Fonder et al. [14] explore the same idea with PCCC technologies in complement of DAC devices to produce CO_2 in a RREH located in Morocco. Verleysen et al. [15] have studied a case of RREH exporting NH_3 from Morocco to Belgium. They assessed that the cost of a RREH would be lower than an ammonia hub in Belgium. Moreover, uncertainties on CAPEX and OPEX

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technology costs have also been taken into account in [15]. Larbanois et al. [16] compared four energy vectors, namely hydrogen (H_2), ammoniac (NH_3), methanol (CH_3OH), and methane (CH_4) synthesized in Algeria to meet an energy demand in Belgium.

On top of the interest from the scientific community, several industrial RREH projects are being developped. For example, BP aims to establish an RREH in northern Australia to export e-ammonia, primarily to Japan and South Korea [17]. Another example is CMB.Tech, a Belgian maritime group that plans to develop an RREH in Namibia in partnership with the Namibian government to export e-ammonia as fuel for their vessels [18]. One reason industrial players are interested in RREHs is the policy targets set to drive e-fuel demand. For instance, the European Union aims to decarbonize maritime and aviation transport by replacing part of their fossil fuels with e-fuels [19, 20]. On a larger scale, according to the International Renewable Energy Agency (IRENA), in their scenario for limiting global warming to 1.5°C, e-fuels could contribute up to 12% of the worldwide CO_2 emissions reduction [21]. RREHs producing e-fuels can help to achieve these worldwide CO_2 emmission reduction targets.

It is worth noticing that the global grid approach [22, 23, 24], is closely related to the concept of RREH. Indeed, a global grid would allow to collect renewable energy where it is the most abundant and to meet an electricity demand far away from the harvested zone. The DESERTEC project [25] that repatriates renewable energy through electric cables to Europe is an example of a project to develop a global grid. The global grid approach can be seen as the interconnection of load centres and RREHs around the world with electricity as an export commodity.

There exists a combinatorial number of possibilities to design a hub due to all the technologies that can be considered. This implies a large diversity of hubs, making it difficult to compare different hubs, even if they are located in the same place or aimed at producing the same energy vectors. Indeed, RREHs producing the same energy vectors may also differ in their import commodities which complexifies again their comparison and their description. Moreover, in the literature, there is often a lack of clarity regarding whether the valorization of local opportunities and by-products inherent to this type of infrastructure is taken into account. To address these problems, we propose a taxonomy relying on a mathematical sets formalization to better characterize RREHs. This taxonomy aims to provide a tool for describing and comparing RREH models. Moreover, it may be useful for those seeking to improve the design of new hubs. This taxonomy could also offer new prospects for enhancing the local integration of these hubs. To the best of the authors' knowledge, this taxonomy is the first to formally address the design phase of RREHs, which has not been previously discussed or structured within a given framework.

We define the concept of RREH in the next section. In Section 3, we present our taxonomy and illustrate it with an academic example. In Section 4, we apply the taxonomy to two hubs studied in the literature, demonstrating its effectiveness in describing and comparing hubs. In Section 5, we propose a practical procedure for using the taxonomy to identify new hubs. Finally, Section 6 concludes the paper.

2. Definition and Concept

Definition 1. *An* ***energy hub*** *integrates input and output of commodities, conversion, and storage functionalities, enabling coupling between different energy systems.*

An energy hub can also encompass production/consumption units, and transportation infrastructure, allowing the exchange of multiple energy carriers.

This definition has been adapted from [26], omitting references to sustainable energy. In both definitions, an offshore wind farm or an onshore solar farm are considered as energy hubs whereas this new definition also encompasses an offshore petroleum platform. In this regard, we distinguish the concept of energy hub from the concept of a *renewable energy hub* which is defined in the following way:

Definition 2. *A* ***renewable energy hub*** *is an energy hub that relies on renewable energy sources for energy production.*

Energy hubs can be located anywhere on Earth. However, it makes sense to distinguish energy hubs that are located in remote areas, far from the main centres of population. Notably due to their remote nature, numerous geographical zones with high renewable energy density are yet to be exploited. Additionally, setting energy hubs away from population centres allows the deployment of large infrastructures without impacting the lives of citizens. This leads us to define and focus on what we denote as Remote Renewable Energy Hubs.

Definition 3. *A **Remote Renewable Energy Hub** (RREH) is a renewable energy hub located in a remote area.*

In this definition, we acknowledge that remoteness is a subjective notion, but this is an intentional choice: it allows for the inclusion under the taxonomy described in the following sections of a broad range of energy hubs. Moreover, it underscores the necessity of transportation for the energy produced.

3. Taxonomy

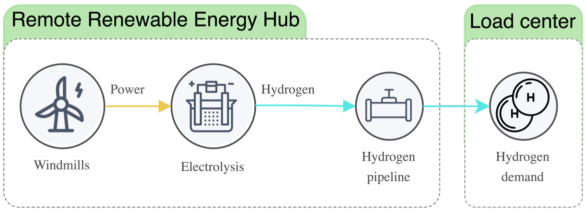

Figure 1: RREH located in Greenland exporting H_2 towards North America.

This section formally defines the taxonomy, and, in particular, explains the purpose of each of its components in the context of a RREH. The first part introduces conceptual mathematical elements that are not related to any particular hub in subsection 3.1. The second part, subsection 3.2, uses these conceptual mathematical elements to derive elements of the taxonomy tailored to any specific hub. To illustrate this, a hypothetical RREH in Greenland is considered. This RREH generates renewable electricty from wind turbines that is used to power an electrolyzer. The H_2 produced by the electrolyzer is subsequently transported via a pipeline to Iceland. A visual representation of this hypothetical hub is provided in Figure 1. Finally, Figure 2 summarizes the components relationships.

3.1. Conceptual mathematical elements

Before instantiating the mathematical elements that constitute an RREH, four conceptual mathematical elements are formally defined, namely $\mathcal{C}, \mathcal{L}, \mathcal{T}$ and $\mathcal{H}$. These are defined as follows:

- $\mathcal{C}$: the set of all commodities that can be exchanged between technologies typically composed of chemical components, electricity and heat.
- $\mathcal{L}$: the set of locations and their specificities in terms of renewable energy potential and energy demand. An element $l \in \mathcal{L}$ is characterised by the triplet $l = (L, P_l, D_l)$ where L is a location and P_l and D_l are respectively the renewable potential and the demand associated with the location L. A location characterised by a high demand and low renewable potential is referred to as a load centre.
- $\mathcal{T}$: the set of all possible technologies. A technology $t \in \mathcal{T}$, associated with a name n, can be seen as a function processing input commodities $\mathcal{C}_t^{in} \subseteq \mathcal{C}$ and converting them into output commodities $\mathcal{C}_t^{out} \subseteq \mathcal{C}$, represented as a 3-tuple $t = \left(n, \mathcal{C}_t^{in}, \mathcal{C}_t^{out}\right)$. Included in the set of technologies $\mathcal{T}$, there are three specific technologies:
  (i) $t^{im} = \left(\text{import}, \emptyset, \mathcal{C}_{t^{im}}^{out}\right)$ models the imported commodities;
  (ii) $t^{ex} = \left(\text{export}, \mathcal{C}_{t^{ex}}^{in}, \emptyset\right)$ models the exported commodities;
  (iii) $t^{op} = \left(\text{opportunity}, \mathcal{C}_{t^{op}}^{in}, \emptyset\right)$ models the locally exploited commodities;
- $\mathcal{H}$: the set of possible flows of commodities. In this set each element $h = \left(c, \mathcal{T}^{out}, \mathcal{T}^{in}\right) \in \mathcal{H}$ is made of three components: a commodity $c \in \mathcal{C}$, a set of technologies $\mathcal{T}^{out} \subseteq \mathcal{T}$ that output the commodity c and a set of technologies $\mathcal{T}^{in} \subseteq \mathcal{T}$ that have as input the commodity c coming from the technologies in $\mathcal{T}^{out}$. Therefore, h denotes a flow of commodity c from each technology contained in $\mathcal{T}^{out}$ to each technology contained in $\mathcal{T}^{in}$. One can observe that the edges follow the convention of hyperedges in this work. This simplifies the taxonomy's readability by reducing the number of edges that need to be defined. Specifically, a single hyperedge represents $|\mathcal{T}^{out}| \times |\mathcal{T}^{in}|$ edges where $|\mathcal{X}|$ corresponds to the cardinality of the set $\mathcal{X}$.

3.2. *Elements of the taxonomy tailored to a specific hub*

Now that the conceptual mathematical elements have been introduced, any RREH r can be formalised as a 7-tuple $r = (\mathcal{L}_r, \mathcal{G}_r, \mathcal{C}_r, \mathcal{E}_r, \mathcal{I}_r, \mathcal{B}_r, \mathcal{O}_r)$ can be characterised by its components:

- $\mathcal{L}_r \subseteq \mathcal{L}$: a set of locations associated with the technologies in the hub. Indeed, to model a RREH, a location or several must be identified. The location determines the RREH's potential in terms of resource availability such as solar, wind, hydropower or geothermia. Moreover, the geographical location of the RREH will influence its competitiveness in the closest load centres.

  In the example provided in Figure 1, the set of locations includes only one location in Greenland that has a high renewable energy potential in wind and a low energy demand due to the low density popultation. Therefore,

  $$\mathcal{L}_r = \{l_1\},$$

  where

  $$l_1 = (\text{Greenland}, \text{high wind potential}, \text{low energy demand}).$$

- $\mathcal{G}_r = (\mathcal{T}_r, \mathcal{H}_r)$: a graph that mathematically formalises the technologies and commodity flows, represented as $\mathcal{T}_r \subseteq \mathcal{T}$ and $\mathcal{H}_r \subseteq \mathcal{H}$. These technologies $\mathcal{T}_r$ are situated in locations depicted in $\mathcal{L}_r$. The relationships between these components form a graph structure, with $\mathcal{T}_r$ denoting the nodes and $\mathcal{H}_r$ representing the edges. Defining $\mathcal{G}_r$ is called designing a RREH. Therefore, designing a RREH consists of finding the technologies (*i.e.* the nodes in $\mathcal{T}$) that compose the RREH and the flows of commodities between these technologies (*i.e.* the edges in $\mathcal{H}$).

  In our Greenland example (cfr. Figure 1), the graph of technologies is defined as:

  $$\begin{aligned}\mathcal{T}_r = \{ & \\ & (\text{Wind}_{l_1}, \{\emptyset\}, \{\text{electricity}\}), \\ & (\text{import}_{l_1}, \{\emptyset\}, \{\text{H}_2\text{O}\}), \\ & (\text{electrolyzer}_{l_1}, \{\text{electricity}, \text{H}_2\text{O}\}, \\ & \{\text{H}_2, \text{O}_2\}), \\ & (\text{export}_{l_1}, \{\text{H}_2\}, \{\emptyset\}) \\ \} & \\ \mathcal{H}_r = \{ & \\ & (\text{Electricity}, \{\text{Wind}_{l_1}\}, \{\text{electrolyzer}_{l_1}\}), \\ & (\text{H}_2\mathbf{O}, \{t^{im}_{l1}\}, \{\text{electrolyzer}_{l_1}\}), \\ & (\text{O}_2, \{\text{electrolyzer}_{l_1}\}, \emptyset), \\ & (\text{H}_2, \{\text{electrolyzer}_{l_1}\}, \{t^{ex}_{l1}\}) \\ \}. & \end{aligned}$$

- $\mathcal{C}_r \subseteq \mathcal{C}$: the set of commodities within the RREH. $\mathcal{C}_r$ can be derived from $\mathcal{G}_r$.

  In our Greenland example (cfr. Figure 1),

  $\mathcal{C}_r = \{\text{electricity}, \text{H}_2\text{O}, \text{H}_2, \text{O}_2\}$.

- $\mathcal{E}_r \subseteq \mathcal{C}_r$: the set of exported commodities. These commodities are input in $t^{ex} \in \mathcal{T}_r$ that are exported to a load centre (*i.e.* to a location $L^{'} \notin \mathcal{L}_r$) in a selected carrier, such as electricity, liquid or gaseous hydrogen. The so-called design process entails determining the necessary processes for producing the exported commodities in $\mathcal{E}_r$.

  In our Greenland example (cfr. Figure 1),

  $\mathcal{E}_r = \{\text{H}_2\}$.

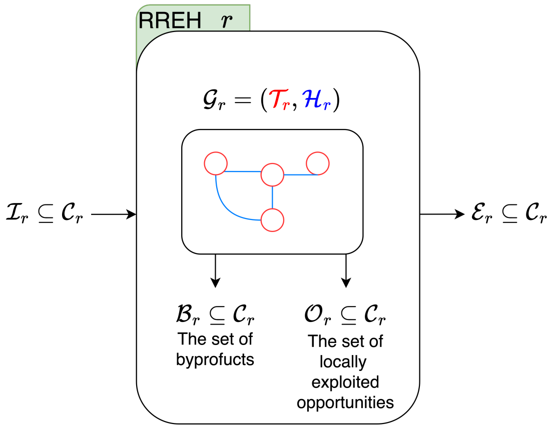

Figure 2: Schematic view of a RREH with the different sets which define it.

- $\mathcal{I}_r \subseteq \mathcal{C}_r$: the set of imported commodities. These commodities are outputted by $t^{im} \in \mathcal{T}_r$. The design of the RREH may also be influenced by the availability of imported commodities in the hub (*i.e.* to a location in $\mathcal{L}_r$). Indeed, it is not necessary to produce all required commodities in close proximity to the RREH. For instance, as demonstrated by Dachet et al. [2], importing CO_2 from the load centre rather than relying on DAC technologies can lead to a reduction in the total system cost. In our Greenland example (cfr. Figure 1), $\mathcal{I}_r = \{H_2O\}$.

- $\mathcal{B}_r \subseteq \mathcal{C}_r$: the set of byproduct commodities. Among all the commodities within the RREH (*i.e.* in $\mathcal{C}_r$), some are byproducts that are never used in any process. More specifically, these byproducts are commodities output by a technology $t \in \mathcal{T}_r$ but not involved into any edge composed of this commodity output by t and included in the input set of any technology $t' \in \mathcal{T}_r$. These byproduct commodities are never used within the RREH however they could be valorised by re-designing the RREH to input them into an existing technology of the hub or a new technology not already considered. Another possibility is to valorize those commodities in a market.

  In our Greenland example (cfr. Figure 1),

  $\mathcal{B}_r = \{O_2\}$.

- $\mathcal{O}_r \subseteq \mathcal{C}_r$: the set of locally exploited opportunities. This set entails the commodities that are input in $t^{opportunity} \in \mathcal{T}_{L'}$ that are exported to meet a local demand (*i.e.* to a location $L^{'} \in \mathcal{L}_r$). In fact, all the commodities within the RREH can represent opportunities for local development, thereby facilitating local integration of the RREH.

  In our Greenland example (cfr. Figure 1), no produced commodity has been used to meet a local demand, hence $\mathcal{O}_r = \emptyset$.

A schematic view of these sets and graph is given in Figure 2 where the set of imported commodities $\mathcal{I}_r$ is processed by the graph of technologies $\mathcal{T}_r$ and the commodities flows $\mathcal{H}_r$ in the RREH producing local opportunities $\mathcal{O}_r$ and by-products $\mathcal{B}_r$ and exporting commodities included in the set of exports $\mathcal{E}_r$.

4. Instantiation

In this section, the taxonomy will be exemplified using a hub located in Algeria, as studied in the literature [1]. This will highlight how the taxonomy can be used to easily describe hubs. Then, a second example from the literature [16] will be presented using the taxonomy to demonstrate how the taxonomy can ease the comparison between them.

The first RREH r_1, coming from [11], is composed of renewable energy production (solar and wind) that powers an electrolyzer to produce hydrogen. From this hydrogen and CO_2 captured via DAC, a methanation process produces methane (CH_4) that is liquefied and exported by boats to Belgium. This RREH is divided into two connected parts:

one located in the Sahara desert for harnessing renewable energy and a second one located on the Algerian coast responsible for the synthesis and export of methane to Belgium. These two parts are connected via a High Voltage Direct Current (HVDC) link. In the taxonomy, this RREH would be expressed as:

- $\mathcal{L}_{r_1} = \{l_1, l_2, l_3\}$
  where
  l_1 = (Sahara desert,
  high renewable potential, low demand),
  l_2 = (Algerian coast, high renewable potential,
  medium demand)},
  l_3 = (From Sahara desert to the coast,
  high renewable potential, low demand)
- $\mathcal{G}_{r_1} = (\mathcal{T}_{r_1}, \mathcal{H}_{r_1})$ is represented in Figure 3 and comprehensively detailed in Table 2.
- C_{r_1} = {electricity, $CH_4(g), CH_4(l), H_2, H_2O, CO_2, O_2$, heat}
- $\mathcal{E}_{r_1} = \{CH_4\}$
- $\mathcal{I}_{r_1}$ = {sea water}
- $\mathcal{B}_{r_1} = \{O_2$, heat}
- $\mathcal{O}_{r_1} = \{\}$.

The comprehensive description is available in Table 2.

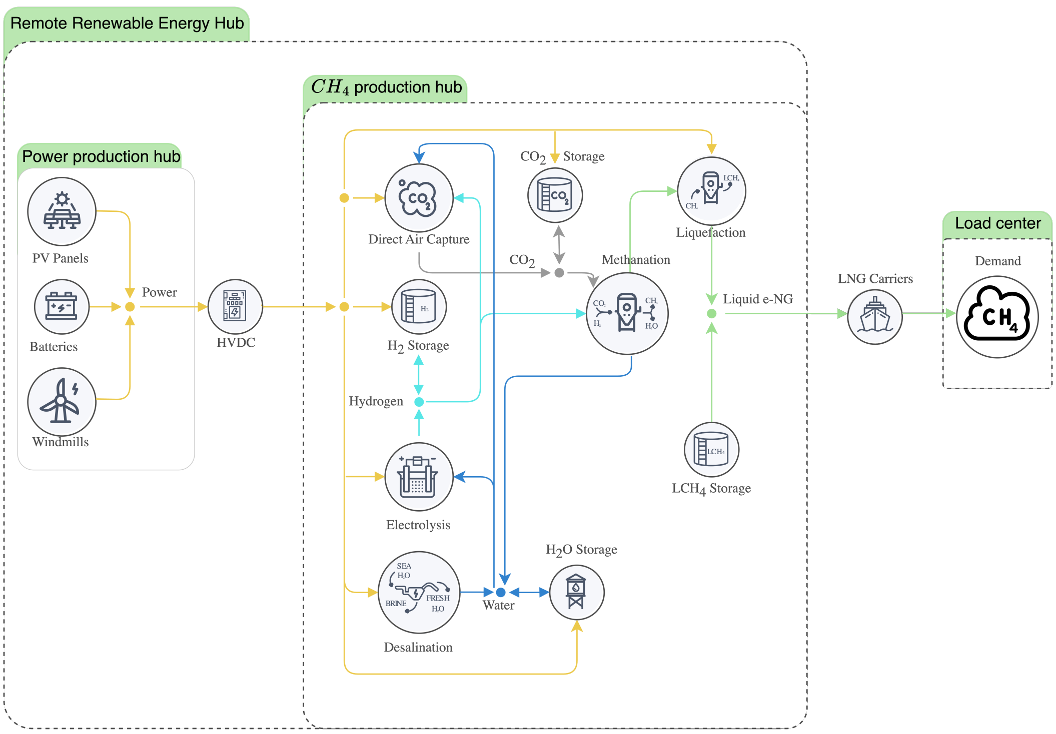

Figure 3: RREH located in Algeria exporting CH_4 to a load center situated in Belgium, adapted from [11].

The second RREH r_2, coming from [16], is composed of renewable energy production (solar and wind) that powers an electrolyzer to produce hydrogen. From this hydrogen and nitrogen (N2) produced via an Air Separation

Unit (ASU), an Haber-Bosch process synthesizes ammoniac (NH_3) in liquid form that is exported by boats to Belgium. This RREH is located and divided at the same locations than the other ones.

The expression of this second hub is avalaible in Table 1 and the comprehensive description is available in Table A.3. The Table 1 also highlights the key differences between these two hubs. As an example, the main differences between these hubs, besides the exported commodity, are the byproducts. The hub exporting CH_4 does not produce Argon whereas the hub exporting NH_3 does.

Table 1: Characteristics and differences of Remote Renewable Energy Hubs r_1 and r_2.

	r_1	r_2	Differences
$\mathcal{L}_r$	$\{l_1, l_2, l_3\}$ l_1 = (Sahara desert, high renewable potential, low demand), l_2 = (Algerian coast, high renewable potential, medium demand), l_3 = (From Sahara desert to the coast, high renewable potential, low demand)	Same as $\mathcal{L}_{r_1}$	-
$\mathcal{G}_r$	$(\mathcal{T}_{r_1}, \mathcal{H}_{r_1})$ (See Figure 3 and Table 2)	$(\mathcal{T}_{r_2}, \mathcal{H}_{r_2})$ (See Figure A.5 and Table A.3)	Different technological and hub structures
C_r	$(\{\text{electricity}, CH_4(g), CH_4(l), H_2, H_2O, CO_2, O_2, \text{heat}\})$	$(\{\text{electricity}, NH_3, H_2, H_2O, N_2, O_2, \text{heat}, Ar\})$	Different energy molecule: CH_4 vs. NH_3, plus presence of Ar in r_2
$\mathcal{E}_r$	$\{CH_4\}$	$\{NH_3\}$	Energy export differs
$\mathcal{I}_r$	{sea water}	Same as $\mathcal{I}_{r_1}$	-
$\mathcal{B}_r$	$\{O_2, \text{heat}\}$	$\{O_2, \text{heat}, Ar\}$	Ar is present in r_2 but not in r_1
O_r	{}	Same as O_{r_1}	-

5. Design and Local Integration

In this section, we first propose, in subsection 5.1, a systematic approach to guide the design process - specifically, identifying the technologies that constitute the RREH and the connections among them - as well as the local integration of a hub. Each step of this approach is then discussed with reference to existing literature on hubs. Then, in subsection 5.2, an example is given to illustrate how to use this approach in practice.

5.1. Systematic approach

The approach is as follows:

1. **Define Export Commodities**: identify the export set $\mathcal{E}_r$ to establish which commodities (e.g., methane, methanol, electricity) the RREH will produce for export.
2. **Select locations**: from all the locations available worldwide, identify those suitable for energy harvesting and transport to define your set $\mathcal{L}_r$.
3. **Construct Technological Graph**: develop a potential technology graph $\mathcal{G}_r$ to describe the required technologies and commodities for producing the items in $\mathcal{E}_r$.
4. **Consider Imports**: assess potential import commodities $\mathcal{I}_r$, especially those scarce locally but obtainable from elsewhere, to potentially reduce the number of technologies required to produce commodities within the RREH for its operation.
5. **Assess Byproducts**: evaluate byproducts $\mathcal{B}_r$ as potential resources that can be integrated into the RREH design to optimize commodity reuse and reduce operational costs.

Table 2: Expression of the full taxonomy where the graph of technologies and flows of commodities $\mathcal{G}_r$ is described by its set of nodes and edges $(\mathcal{T}_r, \mathcal{H}_r)$.

Set	Description
$\mathcal{L}_r$	$\{l_1, l_2, l_3\}$ where l_1 = (Sahara desert, high renewable potential, low demand), l_2 = (Algerian coast, high renewable potential, medium demand)}, l_3 = (From Sahara desert to the coast, high renewable potential, low demand)
$\mathcal{T}_r$	{(PV_{l_1}, {∅}, {electricity}), (Wind$_{l_1}$, {∅}, {electricity}), (Battery$_{l_1}$, {electricity}), {electricity}), (HVDC$_{l_3}$, {electricity}, {electricity}), (electrolyzer$_{l_2}$, {electricity, H_2O}, {H_2, O_2}), (Desalination$_{l_2}$, {electricity, sea water}, {H_2O}), (H_2-Storage$_{l_2}$, {electricity, H_2}, {H_2}), (DAC$_{l_2}$, {electricity, H_2O}, {CO_2}), (CO_2-Storage$_{l_2}$, {electricity, CO_2}, {CO_2}), (Methanation$_{l_2}$, {CO_2, H_2}, {CH_4(g), H_2O}), (CH_4-Liquefaction$_{l_2}$, {electricity, CH_4(g)}, {CH_4(l)}), (CH_4-Storage$_{l_2}$, {CH_4(l)}, {CH_4(l)}), (export$_{l_2}$, {CH_4}, {∅})}
$\mathcal{H}_r$	{(Electricity, {Wind$_{l_1}$, Battery$_{l_1}$, PV_{l_1}}, {Battery$_{l_1}$, HVDC$_{l_1}$}), (Electricity, {HVDC$_{l_1}$}, {Battery$_{l_2}$, electrolyzer$_{l_2}$, Desalination$_{l_2}$, H_2-Storage$_{l_2}$, DAC_{l_2}, CO_2-Storage$_{l_2}$}), (H_2O, {H_2-Storage$_{l_2}$, Desalination$_{l_2}$, Methanation$_{l_2}$}, {H_2-Storage$_{l_2}$, electrolyzer$_{l_2}$, DAC_{l_2}}), (H_2, {H_2-Storage$_{l_2}$, electrolyzer$_{l_2}$}, {H_2-Storage$_{l_2}$, Methanation$_{l_2}$, DAC_{l_2}}), (CH_4(g), {Methanation$_{l_2}$}, {CH_4-Liquefaction$_{l_2}$}), (CH_4(l), {CH_4-Liquefaction$_{l_2}$, CH_4-Storage$_{l_2}$}, {CH_4-Storage$_{l_2}$, t^{ex}}), (O_2, {electrolyzer$_{l_2}$}, ∅), (Heat, {electrolyzer$_{l_2}$}, ∅), (Heat, {Methanation$_{l_2}$}, ∅), (Heat, {CH_4-Liquefaction$_{l_2}$}, ∅)}
$\mathcal{C}_r$	{Electricity, $CH_4(g)$, $CH_4(l)$, H_2, H_2O, CO_2, O_2, Heat}
$\mathcal{E}_r$	$\{CH_4\}$
$\mathcal{I}_r$	{sea water}
$\mathcal{B}_r$	{O_2, Heat}
$\mathcal{O}_r$	{}

6. **Identify Local Opportunities**: use C_r that list available commodities and determine locally valuable ones. One may valorize these and add these to the set O_r to strengthen local integration.
7. **Optimize**: based on the results of step 1-6, optimize the hubs based on your objective criteria and assess the results. If the results are not deemed to be satisfactory, repeat the different steps to identify another hub design.

Step 1 may involve several considerations to determine which molecule to export, including which commodities are easiest to transport over a given distance and the infrastructure available in the load center to meet demand (e.g., CH_4 or H_2 networks).

Step 2, selecting locations, can be approached qualitatively by examining renewable energy potential maps or by identifying existing infrastructure, such as gas terminals, dedicated to the selected export molecule. Alternatively, it can be conducted more quantitatively using combinatorial optimization methods, such as those proposed by Radu et al. [13], to determine optimal locations for energy production.

Step 3 requires consulting the scientific literature to identify the chemical and physical processes necessary for producing a given export molecule. For instance, [16] proposes hubs exporting ammonia, hydrogen, or methanol, each requiring a unique design.

Step 4 may help reduce production costs. For example, [2] demonstrates that importing CO_2 captured at the load center lowers the cost of methane synthesis compared to solely local production via DAC facilities.

Step 5 can also reduce operational costs, as shown by Dauchat et al. [27], who reuse process-generated heat and provide a detailed analysis of its valorization within an RREH, resulting in cost reductions. Additionally, this step may highlight the need for new components, such as Heat Recovery Steam Generators to reduce overall costs [27].

Step 6 helps to prevent project failure, as noted in [28]. Additionally, it can decrease the overall RREH costs, for example, by using the oxygen byproduct from electrolysis to meet the demand of local hospitals. It may also consist in oversizing desalination capacity to benefit from economies of scale to provide water in water-scarce regions. Finally, this step may also highlight the need for new components, such as a water pipe to supply water to nearby farming installations.

Finally, Step 7 advises repeating the steps to refine the RREH design based on criteria such as local integration, number of required processes, or identifying better optimized designs. To model and optimize the RREH, the Graph Based Optimization Language (GBOML) introduced in [29] can be used. GBOML is specifically designed to solve optimization problems represented as graphs, making it well-suited for modeling the technological graph of an RREH.

5.2. *Systematic approach: an example*

The systematic approach proposed in subsection 5.1 is illustrated through an example inspired by [17]. This example is for illustrative purposes only, as designing a new RREH requires significant effort and is beyond the scope of this section. Following the proposed approach, a hypothetical RREH design for methanol production and export to South Korea is considered. The design process follows these steps:

1. **Define Export Commodities**: In this example, the RREH aims to export methanol. Thus, the export set is defined as: $\mathcal{E}_r = \{CH_3OH\}$.
2. **Select Locations**: Australia is a suitable candidate based on renewable energy potential from solar and wind resources and its viscinity to South Korea. Therefore, the set of locations is:

$$\mathcal{L}_r = \{l = (\text{North Australia, high renewable potential, medium demand})\}.$$

3. **Construct Technological Graph**: The methanol synthesis process requires H_2 and CO_2. These can be sourced using an electrolyzer and a carbon capture technology, such as direct air capture (DAC). The electrolyzer requires H_2O and electricity, while DAC requires electricity and water. Since H_2O is scarce in Northern Australia, seawater desalination may be necessary which also requires electricity. The electricity for each process can be generated from a combination of solar panels and wind turbines. The full derivation of this technological graph $\mathcal{G}_r$ is given in Table B.4 while Figure 4 summarizes it.
4. **Consider Imports**: Some required molecules can be imported. For instance, CO_2 could be sourced from Southern Australia, where large emitters are located. Assume that this RREH relies solely on DAC, the set of imports writes as: $\mathcal{I}_r = \{\text{sea water}\}$.

5. **Assess Byproducts**: The process generates heat and O_2. A portion of the heat can be reused in DAC, whereas O_2 has no direct reuse in this context. Thus, the set of byproducts is $\mathcal{B}_r = \{\text{heat}, O_2\}$.
6. **Identify Local Opportunities**: A local opportunity could involve partial utilization of the produced methanol, for instance, in machinery operating in nearby mines. Therefore, the set of locally exploited opportunities is defined as $\mathcal{O}_r = \{CH_3OH\}$.
7. **Optimize**: Define the constraints for each technology in the technological graph. Implement the system using a modeling language such as GBOML [29], then optimize it. Finally, analyze the results to identify the main cost drivers and potential efficiency improvements.

Based on the obtained results, the procedure may be iterated to refine the model. In subsequent iterations, several aspects could be explored, among them (i) incorporating batteries and storage technologies into the technological graph to manage power intermittency and facilitate the operation of must-run technologies, and (ii) introducing an import commodity to evaluate whether reducing reliance on DAC technology lowers costs.

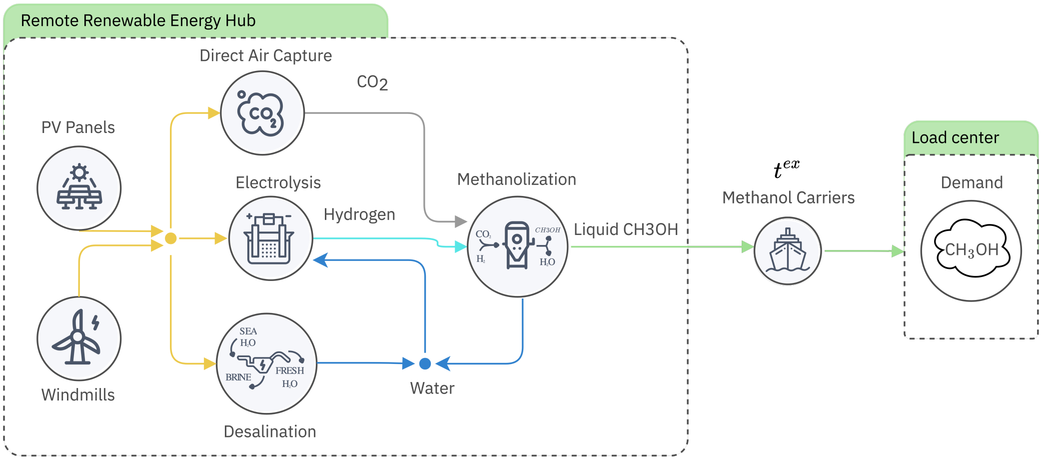

Figure 4: RREH located in Australia exporting CH_3OH to a load center situated in South Korea.

6. Conclusion

This article introduces a definition of the concept of RREHs and a taxonomy to characterize them. It also demonstrates the use of this taxonomy on two examples. This taxonomy can enhance communication within the scientific community and foster research on RREH integration and improved designs.

More specifically, its systematic approach to characterizing RREHs enables more effective comparisons and, if coupled with an optimization procedure, can help identify technologies and interconnections that minimize production costs. It can also help identify missing components of particular interest that contribute to building these RREHs, such as a heat network installation to recover part of the heat from the byproduct set.

While our taxonomy can already be exploited as it is, we believe there are still relevant avenues for enriching it. Although this taxonomy focuses on the qualitative comparison of technical components in RREHs, incorporating in the taxonomy financial aspects — such as different financing models or profit-sharing mechanisms — could broader its scope.

The taxonomy should be complemented by quantitative comparisons, which are necessary for a full comparison of different RREH proposals. Therefore, optimization and modeling techniques complement this taxonomy by enabling the derivation of quantitative values such as energy production costs or marginal costs of CO_2 captured, which are essential for comparing RREH projects.

Social and environmental indicators are also complementary to this taxonomy. These indicators can assess how an RREH project performs in achieving some of the United Nations (UN) Sustainable Development Goals, such as no poverty, decent work and economic growth, and climate action. Furthermore, one could incorporate these indicators into the objectives optimized during the systematic approach proposed to identify new designs.

Lastly, some external factors that are difficult to encompass within a formal framework such as the taxonomy are important to consider. For example, political stability in the region of the RREH can be a determining factor. Indeed, this external factor can significantly impact the financial costs of the project — higher risks may lead to increased borrowing costs — and influence the security of supply for load centers, which might be reluctant to sign long-term contracts.

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Competing interests

The authors declare no competing interests.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the author(s) used ChatGPT and Bard in order to correct the readiness, grammar and spelling of the writing. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

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Appendix A. Example 2

Table A.3: Expression of the full taxonomy for the second example in Section 4, where the technological graph and commodity flows $\mathcal{G}_r$ are defined by their sets of nodes and edges, $(\mathcal{T}_r, \mathcal{H}_r)$.

Set	**Description**
$\mathcal{L}_r$	$\{l_1, l_2, l_3\}$ where l_1 = (Sahara desert, high renewable potential, low demand), l_2 = (Algerian coast, high renewable potential, medium demand)}, l_3 = (From Sahara desert to the coast, high renewable potential, low demand)
$\mathcal{T}_r$	$\{(PV_{l_1}, \{\emptyset\}, \{\text{electricity}\})$, $(\text{Wind}_{l_1}, \{\emptyset\}, \{\text{electricity}\})$, $(\text{Battery}_{l_1}, \{\text{electricity}\}, \{\text{electricity}\})$, $(\text{HVDC}_{l_3}, \{\text{electricity}\}, \{\text{electricity}\})$, $(\text{electrolyzer}_{l_2}, \{\text{electricity}, H_2O\}, \{H_2, O_2\})$, $(\text{Desalination}_{l_2}, \{\text{electricity, sea water}\}, \{H_2O\})$, $(H_2\text{-Storage}_{l_2}, \{\text{electricity}, H_2\}, \{H_2\})$, $(\text{Air Separation Unit}_{l_2}, \{\text{electricity}\}, \{N_2, \text{Ar}\})$, $(N_2\text{-Storage}_{l_2}, \{\text{electricity}, N_2\}, \{N_2\})$, $(\text{Haber Bosch}_{l_2}, \{N_2, H_2\}, \{NH_3\})$, $(NH_3\text{-Storage}_{l_2}, \{NH_3\}, \{NH_3\})$, $(\text{export}_{l_2}, \{NH_3\}, \{\emptyset\})\}$
$\mathcal{H}_r$	$\{(\textbf{Electricity}, \{\text{Wind}_{l_1}, \text{Battery}_{l_1}, PV_{l_1}\}, \{\text{Battery}_{l_1}, \text{HVDC}_{l_1}\})$, $(\textbf{Electricity}, \{\text{HVDC}_{l_1}\}$, $\{\text{Battery}_{l_2}, \text{electrolyzer}_{l_2}, \text{Desalination}_{l_2}, H_2\text{-Storage}_{l_2}, DAC_{l_2}, CO_2\text{-Storage}_{l_2}\})$, $(\mathbf{H_2O}, \{H_2\text{-Storage}_{l_2}, \text{Desalination}_{l_2}, \text{Methanation}_{l_2}\}$, $\{H_2\text{-Storage}_{l_2}, \text{electrolyzer}_{l_2}\})$, $(\mathbf{H}_2, \{H_2\text{-Storage}_{l_2}, \text{electrolyzer}_{l_2}\}, \{H_2\text{-Storage}_{l_2}, \text{Haber Bosch}_{l_2}\})$, $(\mathbf{NH}_3, \{\text{Haber Bosch}_{l_2}, NH_3\text{-Storage}_{l_2}\}, \{NH_3\text{-Storage}_{l_2}, t^{ex}\})$, $(\mathbf{O}_2, \{\text{electrolyzer}_{l_2}\}, \emptyset)$, $(\mathbf{Ar}, \{\text{Air Separation Unit}_{l_2}\}, \emptyset)$, $(\textbf{Heat}, \{\text{electrolyzer}_{l_2}\}, \emptyset)$, $(\textbf{Heat}, \{\text{Haber-Bosch}_{l_2}\}, \emptyset)$,
$\mathcal{C}_r$	$\{\text{Electricity}, NH_3, H_2, H_2O, N_2, O_2, \text{Heat}, Ar\}$
$\mathcal{E}_r$	$\{NH_3\}$
$\mathcal{I}_r$	{sea water}
$\mathcal{B}_r$	$\{O_2, \text{Heat}, Ar\}$
$\mathcal{O}_r$	{}

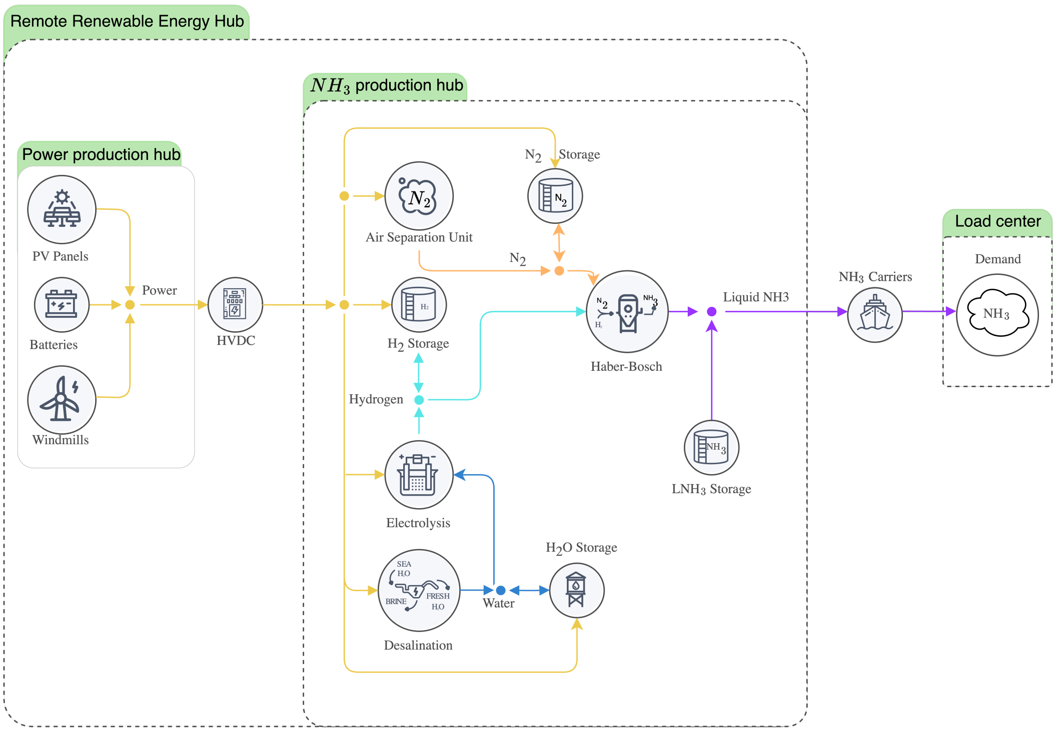

Figure A.5: RREH located in Algeria exporting NH_3 to a load center situated in Belgium, adapted from [16].

Appendix B. Systematic approach example

Table B.4: Expression of the full taxonomy for the example applying the systematic approach in subsection 5.2, where the technological graph and commodity flows $\mathcal{G}_r$ are described by their sets of nodes and edges $(\mathcal{T}_r, \mathcal{H}_r)$. This RREH is designed to produce methanol in Australia for export to South Korea while utilizing part of the production domestically.

Set	Description
$\mathcal{L}_r$	$\{l$ = (North Australia, high renewable potential, medium demand)$\}$
$\mathcal{T}_r$	$\{(PV_l, \{\emptyset\}, \{\text{electricity}\}),$ $(\text{Wind}_l, \{\emptyset\}, \{\text{electricity}\}),$ $(\text{electrolyzer}_l, \{\text{electricity}, \text{H}_2\text{O}\}, \{\text{H}_2, \text{O}_2\}),$ $(\text{Desalination}_l, \{\text{electricity}, \text{sea water}\}, \{\text{H}_2\text{O}\}),$ $(\text{DAC}_l, \{\text{electricity}, \text{H}_2\text{O}\}, \{\text{CO}_2\}),$ $(\text{Methanolization}_l, \{\text{CO}_2, \text{H}_2\}, \{\text{CH}_3\text{OH}, \text{H}_2\text{O}\}),$ $(\text{export}_l, \{\text{CH}_3\text{OH}\}, \{\emptyset\})\}$
$\mathcal{H}_r$	$\{(\text{Electricity}, \{\text{Wind}_l, PV_l\}, \{\text{electrolyzer}_l, \text{Desalination}_l DAC_l\}),$ $(\text{H}_2\text{O}, \{\text{Desalination}_l, \text{Methanolization}_l\}, \{\text{electrolyzer}_l, DAC_l\}),$ $(\text{H}_2, \{\text{electrolyzer}_l\}, \{\text{Methanolization}_l\}),$ $(\text{CH}_3\text{OH}, \{\text{Methanolization}_l\}, \{t^{ex}\}),$ $(\text{O}_2, \{\text{electrolyzer}_l\}, \emptyset),$ $(\text{Heat}, \{\text{electrolyzer}_l\}, \emptyset),$ $(\text{Heat}, \{\text{Methanolization}_l\}, \emptyset),$
$\mathcal{C}_r$	$\{\text{Electricity}, \text{CH}_3\text{OH}, \text{H}_2, H_2O, CO_2, O_2, \text{Heat}\}$
$\mathcal{E}_r$	$\{\text{CH}_3\text{OH}\}$
$\mathcal{I}_r$	$\{\text{sea water}\}$
$\mathcal{B}_r$	$\{O_2, \text{Heat}\}$
$\mathcal{O}_r$	$\{\text{CH}_3\text{OH}\}$

Part II

Novel RREH Designs

This part addresses **RQ2**: *How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?*

To provide a comprehensive answer, Part II is composed of four chapters:

- Chapter 3 explores CO_2 valorization loops.
- Chapter 4 analyzes CO_2 sourcing strategies for e-methane.
- Chapter 5 compares RREHs with different export commodities.
- Chapter 6 introduces high-seas hubs using batteries as energy vectors.

Together, these chapters broaden the exploration of the design space of RREHs and evaluate their techno-economic feasibility.

CO_2 Valorization in Remote Renewable Energy Hubs

3

3.1 The Question

RQ2. How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?

Conventional RREH designs often assume that all required commodities, including carbon, are sourced locally through Direct Air Capture (DAC). However, DAC is expensive and energy-intensive. This raises the question of whether alternative CO_2 sourcing strategies, such as transporting post-combustion CO_2 from industrial centers to RREHs, could improve the techno-economic performance of e-fuel production.

3.2 The Idea

The central idea is that if load centers import energy from where it is abundant, RREHs should also import the commodities that are not abundant at the hub location. Using the taxonomy, this means expanding the *import set* of RREHs, which previous studies often left empty. A key example is CO_2, which is costly to source via DAC. Post-Combustion Carbon Capture (PCCC) technologies, by contrast, can capture CO_2 at high concentrations in industrial exhaust fumes. By making a carbon loop between load centers and RREHs, new opportunities emerge to reduce costs and improve overall system efficiency.

3.3 Contributions of the Paper

The contributions of the paper, published in the journal of Environmental Management and titled *Towards CO_2 valorization in a multi remote renewable energy hub framework with uncertainty quantification*, can be summarized as follows:

- Proposes a novel multi-RREH optimization framework.
- Integrating both DAC and PCCC as CO_2 sources.
- Demonstrates that including PCCC can reduce total system costs by around 10% compared to DAC-only designs.
- Derives a carbon price threshold above which CO_2 valorization technologies become central to industrial decarbonization.
- Highlights the potential of carbon loops in RREHs designs.

3.4 Author's Contribution

I co-developed the research idea with my co-authors. I was responsible for designing and implementing the optimization framework, performing the case study analysis, and interpreting the results. I also led the writing of the manuscript, with feedback and revisions from Professor Ernst and collaborators.

This work was first presented at a conference and later extended for submission to a special issue of a peer-reviewed journal. For this extension, I collaborated with UCLouvain, in particular with PhD. Diederik Coppiters and Prof. Francesco Contino, to integrate their uncertainty analysis tool for CO_2 infrastructures into our case studies.

3.5 Integration within the Thesis

This paper is the first contribution to **Part II – Novel RREH Designs**. It expands the RREH concept by introducing CO_2 valorization loops and multi-hub interactions, directly addressing **RQ2**. Together with the following chapters on alternative carriers and high-seas battery hubs, it broadens the design space of RREHs beyond their original formulation and demonstrates how novel architectures can enhance their techno-economic feasibility.

Towards CO_2 valorization in a multi remote renewable energy hub framework with uncertainty quantification

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ABSTRACT

In this paper, we propose a multi-RREH (Remote Renewable Energy Hub) based optimization framework. This framework allows a valorization of CO_2 using carbon capture technologies. This valorization is grounded on the idea that CO_2 gathered from the atmosphere or post combustion can be combined with hydrogen to produce synthetic methane. The hydrogen is obtained from water electrolysis using renewable energy. Such renewable energy is generated in RREH, which are locations where RE is cheap and abundant (e.g., solar PV in the Sahara Desert, or wind in Greenland). We instantiate our framework on a case study focusing on Belgium and 2 RREH, and we conduct a techno-economic analysis under uncertainty. This analysis highlights, among others, the interest in capturing CO_2 via Post Combustion Carbon Capture (PCCC) rather than only through Direct Air Capture (DAC) for methane synthesis in RREH. By doing so, a notable reduction of 10% is observed in the total cost of the system under our reference scenario. In addition, we use our framework to derive a carbon price threshold above which carbon capture technologies may start playing a pivotal role in the decarbonation process of our industries.

1. Introduction

While the whole world is engaged in a process to decrease greenhouse gas emissions, capturing CO_2 appears more and more as a crucial element to limit global warming. Once it is captured, CO_2 may be either stored (CCS - Carbon Capture and Storage), or valorized (CCU - Carbon Capture and Utilisation), for instance, through synthetic methane generation. In this article, we focus on CCU, where CO_2 is seen as a required ingredient in the process of generating synthetic methane, together with *green* hydrogen, i.e. hydrogen obtained from renewable energy-based electrolysis. This work is mainly related to the following topics that may play an important role in the deep decarbonization of our societies: (i) global grid approaches, (ii) power-to-X technologies, multi-energy systems and energy hub approaches, and (iii) CO_2 quotas markets.

Global Grid approaches [1], [2], sometimes referred to as Global Energy Interconnection approaches [3], are related to the idea of harvesting renewable energy from abundant and potentially remote renewable energy fields to feed the electricity demand in high demand centres. These approaches have mainly been oriented towards solutions using the electricity vector to repatriate energy from energy hubs, and have received a growing interest starting from the DESERTEC concept [4] that focuses on Sahara solar energy resources from the Sahara desert to serve the European electricity demand. More recently, wind from Northern Europe and Greenland has also been identified as a promising resource to be valued within the Global Grid context [5]. Resource and demand configurations combining several types of resources as well as demand time zones show better results [2].

Multi-energy systems approaches [6, 7] exploit the benefits of integrating energy demand and generation, as well as infrastructure. Power-to-X technologies, in particular power-to-CH4 technologies using hydrolysis and renewable energy for producing H2 [8], offer a CO_2 neutral solution to serve gas demand, but also a way to store vast quantities of energy issues from renewable sources [9]. Recently, Berger et al. have proposed a modelling framework [10] for assessing the techno-economics viability of carbon-neutral synthetic fuel production from renewable electricity in remote areas where high-quality renewable resources are abundant. Let us mention that the idea of energy hubs was preexisting the work of Berger et al. [11, 12, 13], however, the contribution of Berger et al. is the introduction of remote energy production, far from the demand as well as the modelling and optimization of the entire supply chains. More recently, Pfennig et al. [14] conducted a techno-economic analysis of numerous regions worldwide for the production of synthetic fuels. Additionally, Hampp et al. [15] performed an analysis presenting various import options of hydrogen-based molecules in Germany. However, these two recent studies only consider sourcing CO_2 from Direct Air Capture (DAC) and did not consider another way for sourcing the CO_2. Moreover, Greenland was not considered as a potential hub in their analyses.

As in our previous work [16] from which this paper is an extended version, we build on top of the Remote Renewable Energy Hub (RREH) approach [10] to propose a multi-hub,

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multi CO_2 sources approach. CO_2 is captured using both Post-Combustion Carbon Capture (PCCC) and Direct Air Capture (DAC) technologies. Hydrogen is produced from electrolysis using renewable energy in a RREH, which is particularly well-suited for producing cheap and abundant renewable energy (e.g., solar energy in the Sahara desert, or wind energy in Greenland). The RREH concept also relies on the following idea: some locations show large amounts of energy consumption while not having lots of renewable energy resources (e.g., Belgium). Conversely, some places have abundant renewable energy and almost no energy demand. In its original formulation [10], the RREH concept suggests using DAC technologies to feed the CO_2 demand at the RREH. In this paper, we include PCCC technologies as an alternative to DAC technologies: in addition or replacement to being captured in the atmosphere, CO_2 emitted in energy-intensive locations may be transported to the RREH to be combined with green hydrogen for producing neutral synthetic methane.

The main contributions of this work are as follows:

- We introduce a loop of CO_2 from the importer of gas to the RREH;
- We model and optimize the entire supply chain to meet the energy demand of Belgium in 2050, considering gas and electricity at an hourly resolution with two RREHs;
- We consider a new potential RREH located in Greenland;
- We provide a detailed techno-economic analysis by scenarios and considering uncertainty for one of them.

2. Scope of the study

We propose a methodology for assessing the techno-economic feasibility of exporting CO_2 into RREH where synthetic CO_2-neutral methane would be generated using locally produced green H2. We formalise an optimisation problem where CO_2 sources are in "competition" to provide CO_2 to the methanation units in the RREH. This methodology is based on a linear program modelling of Belgium's energy system, including gas and electricity demand, main CO_2 emitters and two RREH namely Greenland and Algeria. We rely on previously published approaches to develop our approach [10], and, in particular, we use the GBOML language [17] to model the energy system and to optimize it.

This work, aiming to enhance the value of CO_2, closely aligns with various policy mechanisms implementing a price on CO_2 emissions. These include a carbon tax or participation in carbon markets like the European Union Emissions Trading System (EU ETS)[1] Indeed, the business model of the proposed model is strengthened by these mechanisms because we propose to recycle the CO_2 emitted in the atmosphere (or that could be emitted) rather than paying for it.

On top of the energy system optimization methodology, an uncertainty quantification (UQ) analysis can be performed. Indeed, many technical and economic parameters of the energy system model can influence the system performance, which are often subject to uncertainty due to lack of knowledge (i.e., epistemic uncertainty) or unknown future evolution of the parameters (i.e., aleatory uncertainty) [19].

Several methods exist to characterize parametric uncertainties in the context of energy systems [20], including, among others, interval analysis, fuzzy set theory and Probability Density Functions (PDFs) [21]. In the case of PDFs, the distributions are derived through statistical inference when a lot of data is available, expert judgment in the absence of data, or Bayesian inference when the dataset is limited but expert knowledge is accessible [22].

When input parameters are characterized by distributions and propagated through the system model, the model outputs will also be defined by distributions. Therefore analyses of these output distributions can be performed. In this paper, we used a probabilistic approach technique, called Polynomial Chaos Expansion (PCE). This technique acts mainly as a surrogate for Monte Carlo (MC) simulation allowing to derive statistical moments of output distributions given known (or assumed) input distributions. Moreover, this technique offers a distinct advantage over other surrogate methods (Kriging [23], support vector machines [24], Analysis Of Variance (ANOVA) [25]) by enabling the analytical derivation of global sensitivity indices. These indices allow a decomposition of the variance of the output distribution with respect to the given input parameters.

PCE has already been applied with success in [26] for quantifying the uncertainty associated with the total energy cost of the Belgian energy system, considering 43 uncertain input parameters related to the investment and operating cost of the available technologies. Furthermore, their analysis identified the cost of importing electrofuels as the primary driver of the variance in the total system cost using the analytically-derived global sensitivity indices.

3. CO_2 Valorisation in a Multi-Remote Renewable Energy Hubs Approach

The Remote Renewable Energy Hub concept was first introduced in Berger et al. [10], where the authors proposed a hub for synthesizing CH4 based on hydrogen and CO2 captured from the air thanks to a methanation unit. This concept has emerged within the context of global grid [1] and multi-energy systems approaches. These approaches aim at optimising the generation and utilisation of renewable energy (RE) by both (i) looking for abundant and cheap RE fields, (ii) taking advantage of daily/seasonal complementary of RE, and (iii) using power-to-gas technologies for better addressing RE generation fluctuations and meet

[1] The EU ETS system is described on the European Commission's website: https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en and in [18].

e-fuels demand to act as a substitute for molecules derived nowadays from fossil fuels.

In the original article [10], the methanation unit was supplied with CO_2 by a Direct Air Capture unit, and the energy demand was fulfilled by a single RREH located in Algeria. However, in this paper, we propose to investigate the feasibility of valorizing CO_2 captured through Post Combustion Capture techniques at the energy demand center. Additionally, we deviate from the original paper by introducing a multi-RREH approach, wherein the energy demand center serves as a CO_2 provider to a set of multiple RREH, denoted as $RREH_1, \dots, RREH_h$. Each hub $RREH_i (1 \leq i \leq h)$ has its unique characteristics, such as renewable energy type, potential, distance from the energy demand center, and means of CO_2 transport from the energy demand center, which can affect its competitiveness.

In order to illustrate the concepts discussed above, we have developed a model for a multi-RREH system based on the following assumptions: (i) the energy demand center is Belgium, encompassing its gas and electricity demands as well as its CO_2 emissions, (ii) there are two RREH: one situated in the Sahara desert with access to solar and wind resources, and another in Greenland benefiting from the high-quality wind fields in the region. A detailed schematic of the resulting system is shown in Figure 1.

We note that the model code with two RREH and one energy demand center system is available online[2] and can be easily extended to add additional RREH and energy demand centers.

4. Modelling

In this section we describe the optimization problem underlying our techno-economic analysis and we describe mathematically the UQ quantification and sensitivity analysis.

4.1. Multi-energy system model optimization

This subsection provides insight into the optimization framework that underlies the multi-energy system model proposed in this work. The GBOML language, introduced in [17], a recently developed language dedicated to the modeling of complex systems exhibiting a graph structure, as multi-energy systems do, will be utilized. GBOML exhibits several advantages; it is open source, easy to use, and allows the construction of a sparse matrix representation of the system.

The optimization problem can be viewed as an optimization on graphs, where a multi-energy system is considered as a set of nodes $\mathcal{N}$ that contribute to the (linear) objective and local constraints, and hyperedges $\mathcal{E}$ are used to model the constraints between nodes, such as those between RREH and the energy demand center in our context.

The formalism utilized in this study follows the framework introduced in [10]. The entire system is defined by sets of nodes $\mathcal{N}$ and hyperedges $\mathcal{E}$. The optimization horizon is denoted by T, with time-steps indexed by $t \in \mathcal{T}$, where $\mathcal{T} = \{1, \dots, T\}$.

A node $n \in \mathcal{N}$ is defined by internal X^n and external Z^n variables, where internal variables describe the specific characteristics of the unit, such as the nominal power capacity installed in the asset. Equality constraints $h_i(X^n, Z^n, t) = 0$ with $i \in \mathcal{I}$ and inequality constraints $g_j(X^n, Z^n, t) \leq 0$ with $j \in \mathcal{J}$, are employed for each $t \in \mathcal{T}$ to model operational constraints.

Each node n has an associated cost function $F^n(X^n, Z^n) = f^n(X^n, Z^n, 0) + \sum_{t=1}^{T} f^n(X^n, Z^n, t)$ that typically represents the capital expenditure and operational expenditure, i.e., CAPEX and OPEX, respectively.

Finally, equality and inequality constraints on hyperedges can be defined as $H^e(Z^e) = 0$ and $G^e(Z^e) \leq 0$ with $e \in \mathcal{E}$ to model the laws of conservation and caps on given commodities.

One can read this type of problem as:

$$
\begin{aligned}
\min \quad & \sum_{n=1}^{N} F^n(X^n, Z^n) \\
\text{s.t.} \quad & h_i(X^n, Z^n, t) = 0, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \forall i \in \mathcal{I} \\
& g_j(X^n, Z^n, t) \leq 0, \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \forall j \in \mathcal{J} \\
& H^e(Z^e) = 0, \forall e \in \mathcal{E} \\
& G^e(Z^e) \leq 0, \forall e \in \mathcal{E}.
\end{aligned} \tag{1}
$$

The main assumptions underlying our model are the following:

- Centralised planning and operation: In this framework, a single entity is responsible for making all investment and operation decisions.
- Perfect forecast and knowledge: It is assumed that the demand curves, as well as weather time series, are available and known *in advance* for the entire optimisation horizon, i.e., $\forall t \in \{1, \dots, T\}$.
- Permanence of investment decisions: Investment decisions result in the sizing of installation capacities at the beginning of the time horizon. Capacities remain fixed throughout the entire optimisation period, i.e., $\forall t \in \{1, \dots, T\}$.
- Linear modelling of technologies: All technologies and their interactions are modelled using linear equations within this framework.
- Spatial aggregation: The energy demands and generation at each node are represented by single points. The topology of the embedded network required to serve this demand locally is not modelled in this approach. This can be viewed as an extension of the copper plate modelling approach used in electrical power systems.

In our problem, all cost functions and constraints are affine transformations of the inputs. More details on the

[2] https://gitlab.uliege.be/smart_grids/public/gboml/-/tree/master/examples

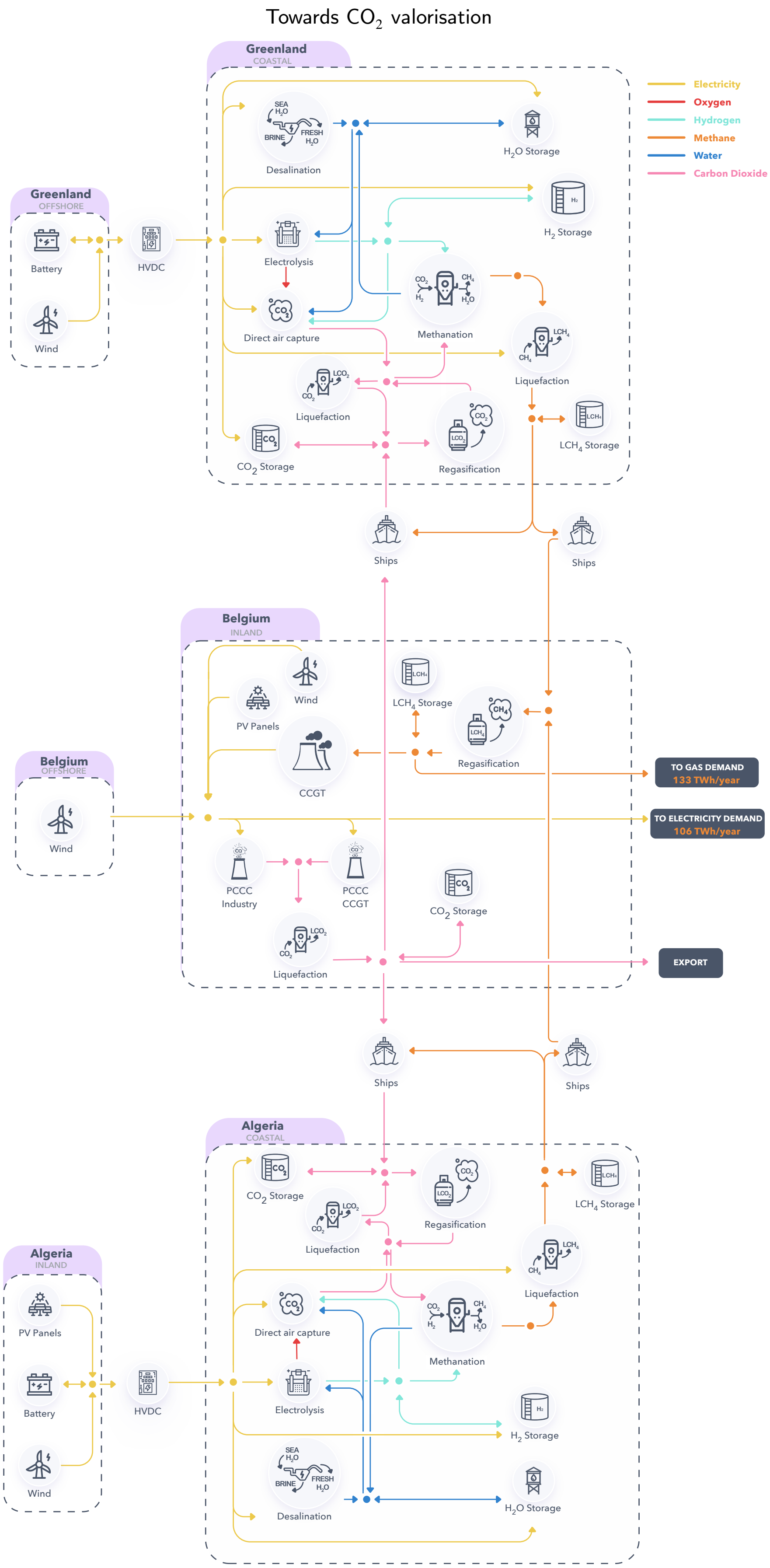

Figure 1: A schematic illustration of the remote energy hub. CO_2 being captured, it may be used to synthesize fuel either locally either in a remote energy hub where renewable energy may be cheaper and more abundant.

constraints of each technology can be found in [27], [10]. Additionally, the local objective function corresponding to the CAPEX is modelled with a uniform weighted average cost of capital (WACC) of 7% for each technology. Let L_n denote the lifetime of technology n and w the WACC. Then, the annual cost $zeta^n$ of investing in technology n writes:

$$\zeta^n = \text{CAPEX}_n \times \frac{\text{w}}{(1-(1+\text{w})^{-\text{L}_n})}. \tag{2}$$

Moreover, a cap on the net CO_2 emissions (*i.e.* release in minus captured from the atmosphere) is added to the model. This latter is defined as

$$\sum_{t\in\mathcal{T}}(\sum_{a\in\mathcal{A}} q^a_{co2,t} - \sum_{c\in C} q^c_{co2,t}) \leq \kappa_{co2}\nu \tag{3}$$

with $\mathcal{A}$ and C representing the sets of technologies that release CO_2 into the atmosphere and those that capture CO_2 directly from the atmosphere, respectively, κ_{co2} represents the CO_2 cap in kilotons per year, and ν represents the number of years covered by the optimization horizon. The shadow price, or marginal cost, which is the dual variable associated with Equation 3 allows for the derivation of a CO_2 cost in €/t. Nevertheless, one should be cautious with the derived shadow prices, as they provide information that is relevant within the context of the model and the various constraints taken into account. A detailed explanation of dual variables as marginal costs in linear programming can be found in [28, Chapter 4].

Finally, GBOML is a convenient tool for modeling the nodes and hyperedges of the optimization problem we described. In the RREH context, the nodes represent all the units composing the RREH, and the hyperedges represent the flows between the units. Moreover, GBOML allows the definition of constraints and objective functions for each node. The readiness of GBOML makes it easy to understand the complex system described by simply reading the code. As an illustration, readers can gain insight into Figure 1 by comparing it with its GBOML implementation, accessible at `https://gitlab.uliege.be/smart_grids/public/gboml/-/tree/master/examples`, to observe its readiness.

4.2. Uncertainty quantification

The optimization problem outlined in subsection 4.1 is defined by several economic parameters that are subject to uncertainty, either due to a lack of knowledge or due to the unknown future evolution of these parameters [19]. The optimization problem $\mathcal{M}$ depending on such random parameters can be defined as a function:

$$\mathcal{M} : \mathbb{R}^M \rightarrow \mathbb{R}, \tag{4}$$

with M equal to the number of random parameters considered. The joint distribution of the random vector $\boldsymbol{X}$ of the random input parameters $\{X_i, i = 1, \dots, M\}$ can be defined as:

$$P_{\boldsymbol{X}}(\boldsymbol{x}) = \prod_{i=1}^{M} P_{X_i}(x_i), \qquad x_i \in \mathcal{D}_{X_i}, \tag{5}$$

where $P_{\boldsymbol{X}}$ is the joint distribution, $\{P_{X_i}\}_{i=1}^M$ are the marginal uniform distributions on the model input parameters (illustrated in Table 1) and $\mathcal{D}_{X_i}$ is the support of X_i.

As the input parameters are defined by a joint distribution, the output parameter of the model will become a random variable as well:

$$Y = \mathcal{M}(\boldsymbol{X}). \tag{6}$$

In this Uncertainty Quantification (UQ) procedure, the goal is to define the mean and standard deviation of the model output, to indicate the expected performance and the variability of the model output with respect to the random input parameters.

In addition, we will perform a global sensitivity analysis to quantify which random input parameters drive the variability of the model output. As this variability can be described by the variance of Y, the task is to allocate Var$[Y]$ to each input parameter X_i. To do so, the Sobol' indices are adopted, corresponding to:

$$S_i = \frac{\text{Var}\left[\mathcal{M}_i\left(X_i\right)\right]}{\text{Var}\left[Y\right]} \tag{7}$$

where $\mathcal{M}_i\left(X_i\right) = \mathbb{E}\left[\mathcal{M}(\boldsymbol{X})\,|X_i\right] - \mathbb{E}\left[\mathcal{M}(\boldsymbol{X})\right]$.

To determine the mean, standard deviation and Sobol' indices on the output of the model, we used PCE. After the construction of the PCE surrogate model, it allows to derive the mean, standard deviation and Sobol' indices analytically. We utilized the open-source Python framework Rheia [29], which allows for easy computation of the PCE as well as analysis of the results. We refer to Sudret et al. [30] for the details on the construction of the PCE and the analytical derivation of the mean, standard deviation and Sobol' indices.

Using the methodology described in Sudret et al. [30], we constructed the PCE using 56 training samples, sampled from the joint input distribution using quasi-random Sobol sampling, resulting in a Leave-One-Out (LOO) cross-validation error below 1% [30]. The process of constructing a PCE has been repeated three times, once for every output of interest, namely total cost, shadow price, and cost of methane. Note that, as for each training sample, the model response for the three outputs of interest is stored, the same set of training samples was reused for the construction of each PCE.

5. Case Study: Belgium

This case study is focused on Belgium with two remote renewable energy hubs: one located in Algeria and another one located in Greenland. We will analyse the techno-economic feasibility of the system while responding to an energy demand composed only of electricity and gas in Belgium.

5.1. Data

The data covers two years, 2015 and 2016, at an hourly resolution, which is necessary to capture the short-term variability of renewable energy production and demand. This granularity is essential for effective energy management and planning [31]. However, real-time system operation requires minute-level resolution for management, which would demand significant computational resources for planning and control over long periods (years). The data have been retrieved from different sources [27], [10]. The renewable energy profiles for Greenland have been specifically produced for use in this study.

Renewable generation profiles

In order to determine the generation profiles of variable energy sources in Belgium we use the data from the transmission system operator (TSO) of Belgium [32]. The profiles for the RREH located in Algeria are extracted with the same methodology as in [10]. For the RREH situated in Greenland, the profiles of renewable energy are extracted thanks to the MAR model [33] and given a power curve for an offshore wind turbine MHI Vestas Offshore V164-9.5MW.

Energy consumption

The energy consumption data is collected for two energy vectors: gas (from the gas system operator of Belgium, Fluxys, [34]) and electricity (from the TSO of Belgium, Elia, [35]) with the same methodology as in [27]. In Figure 2, the data corresponding to the two years is represented, where the signal is aggregated daily. In some cases, gas usage is shifted towards electricity needs, as described in [27, section 4.2.2]. This shift is due to the use of heat pumps, which can help decarbonize heating in Europe. For both energy vectors, industrial and heating demands are taken into account.

The peak power demand is equal to 60.13 GWh/h for both gas and electricity. The energy demand for electricity ranges from 6.42 to 20.29 GWh/h, while that for gas ranges from 5.51 to 39.84 GWh/h. The total energy demand is on average 106.45 TWh/year and 132.65 TWh/year for electricity and gas, respectively.

Uncertainty characterization

The CAPEX are influenced by various uncertainties, such as the evolving and maturing of technologies, the time gap between feasibility study and investment, and unexpected costs [20]. These uncertainties can significantly impact the CAPEX assumptions during the optimization, leading to notable disparities between a deterministic assessment (based on the best estimate) and the real-world results. Consequently, we introduced uncertainty in the CAPEX for CO_2 processing technologies, with more substantial variations for emerging technologies (±30%) and narrower variations for mature technologies (±10%), following the approach proposed by Moret et al. [36]. The specific uncertain parameters are detailed in Table 1.

5.2. Model Configuration

Our model consists of three main components (see Figure 1): the energy demand centre located in Belgium and two Remote Renewable Energy Hubs (RREH) situated in Algeria and Greenland. The RREH in Algeria is modelled as described in [10] with the same techno-economic parameters. The distinction is made with the inclusion of the CO_2 connection between Belgium and Algeria. The RREH in Greenland is similarly modelled, with the exception of the removal of the photovoltaic potential and the modification of the high-voltage direct current (HVDC) line to a length of 100 km rather than 1000 km.

The transportation of CO_2 is achieved through the use of boats, which have a CAPEX of 5M€/kt, a lifespan of 40 years, and an average daily energy consumption of 0.0150 GWh/day. CO_2 transport data was obtained from [37]. The loading and traveling time for these boats are assumed identical to those for liquefied methane carriers [10], *i.e.* 24 and 116 hours, respectively. In order to fill the tank of CO_2 carriers with fuel (liquefied methane), these tanks are loaded when unloading the CO_2 at the RREH. Indeed, at the RREH, synthetic CH4 is available without having undergone any additional transport-related losses.

A CO_2 liquefaction plant has been added in Belgium as well as in Algeria with a CAPEX of 55.8 M€/kt/h, a FOM of 2.79 M€/year, and a lifetime of 30 years. This plant requires 0.014 GWh of electricity to process a kiloton (kt) of CO_2. A CO_2 regasification plant has been established in Algeria with a CAPEX, FOM, and lifetime of 25.1 M€/kt, 1.25 M€/year, and 30 years, respectively. Storage of liquefied CO_2 has been done with the same assumptions as in [10].

Belgium is modelled with an electricity and gas demand as depicted in Figure 2, with various means of production, including wind power, solar power, and a Combined Cycle Gas Turbine (CCGT). The solar potential is limited to 40GW. The wind potential equals 8.4 GW and 8 GW for onshore and offshore capacities, respectively. The techno-economic parameters of each technology deployed in Belgium follow those in [27].

We have also added a CO_2 source that is equivalent to 40Mt CO_2/year, which corresponds to the energy sectors and industrial processes greenhouse gases in Belgium in 2019 [38, Table 4.1.1 (pp. 165- 166)]. We assume that we can install post-carbon capture technologies (PCCC) in these sectors.

In terms of carbon capture technologies, the model has access to direct air capture installed at the RREH, as well as a PCCC in Belgium on the 40Mt of CO_2 per year and a PCCC installation on the CCGT.

As stated in [27], the cost of PCCC is 3150M€/kt/h of CAPEX. The variable operating and maintenance costs (VOM and FOM) have been neglected in this analysis. However, a demand of $0.4125 GWh_{el}/kt_{CO2}$ of electricity is required. The expected lifetime is assumed to be 20 years.

Similarly, according to [10], the cost of DAC is equal to 4801.4 M€/kt/h of CAPEX. Similar to PCCC, VOM and FOM are ignored. The operational requirements for DAC are $0.1091 GWh_{el}/kt_{CO2}$ of electricity, $0.0438 kt_{H2}/kt_{CO2}$ of di-hydrogen, and $5.0 kt_{H20}/kt_{CO2}$ of water. The expected lifetime is assumed to be 30 years.

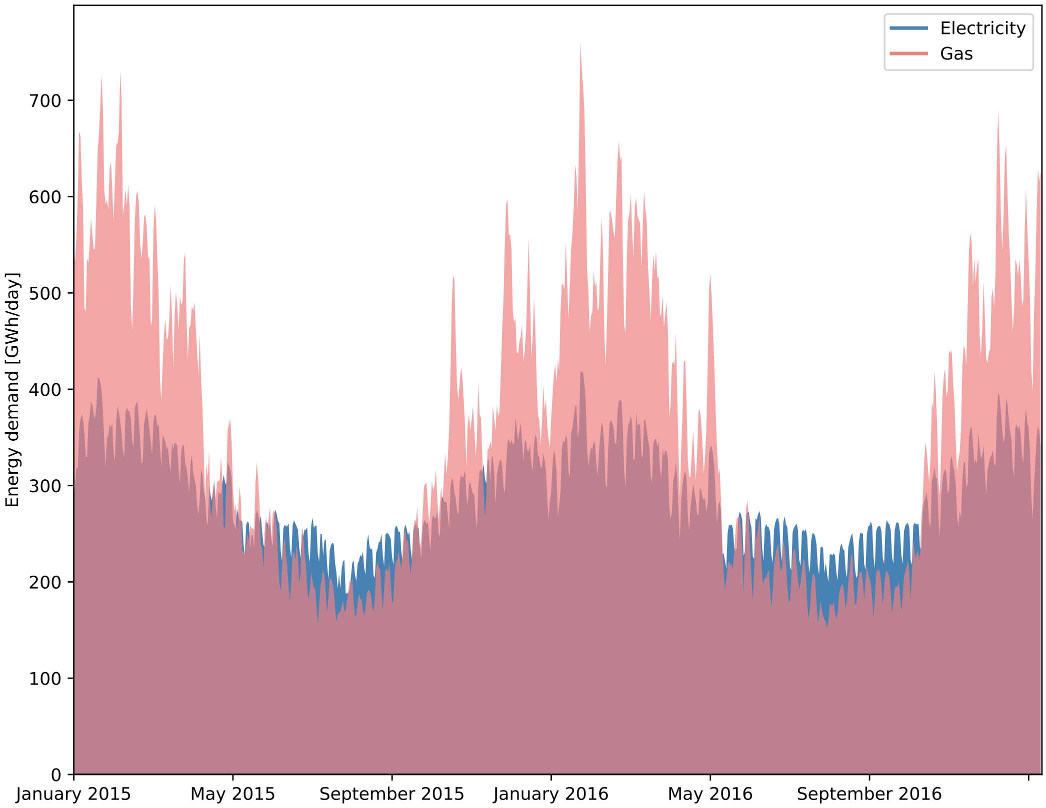

Figure 2: Daily aggregated profiles of electricity and natural gas demand covering the years 2015 and 2016 spanned by the optimisation.

Parameters of the uniform distributions on the CO2 capex costs				
name	variation	min	max	unit
$\text{CAPEX}_{\text{PCCC}}$	±30%	2205	4095	M€/kt/h
$\text{CAPEX}_{CO_2,\text{ liq}}$	±10%	50.2	61.4	M€/kt/h
$\text{CAPEX}_{CO_2,\text{ regas}}$	±10%	22.6	27.6	M€/kt/h
$\text{CAPEX}_{CO_2,\text{ carrier}}$	±10%	4.5	5.5	M€/kt
$\text{CAPEX}_{\text{DAC}}$	±30%	3361	6242	M€/kt/h
$\text{CAPEX}_{CO_2,\text{ liq storage}}$	±10%	2.1	2.5	M€/kt

Table 1
The selected uncertain parameters are all the CAPEX related to the CO_2 infrastructure. A uniform distribution has been assumed for each parameter, with a ±30% variation for emerging technologies and a ±10% variation for mature technologies.

5.3. Scenarios Explored

In this subsection, we explore several scenarios. We describe the variables that are used to differentiate the scenarios

1. Cost or Cap on CO_2: either a cap is set of 0 t/year or a price at 80€/t or 0€/t
2. Cost of energy not served (ENS): either ENS is not allowed or a penalty of 3000€/MWh is imposed for each unit of unproduced energy.
3. Forcing or not the use of a given RREH.

The results are generated with 5 scenarios:

Scenario 1: This scenario seeks to avoid energy scarcity, whatever the cost. Therefore, no ENS is allowed. In addition, a hard constraint is set on CO_2 emissions: a cap on CO_2 is set.

Scenario 2: This scenario follows the same assumptions as scenario 1 except that it does not consider the constraint on ENS. The cost associated with electricity not served equals

Scenario	Cap on CO_2 (kt)	Cost of CO_2 (€/t)	ENS	Cost ENS (k€/MWh)	Objective (M€)
1	0.0	0	No	-	80004.82
2	0.0	0	Yes	3.0	77990.20
3	No	80	Yes	3.0	75437.39
4	No	0	Yes	3.0	72511.43
5	0.0	0	No	-	109441.54

Table 2
Parameters and objective for a 2 years optimization horizon for each scenario.

3000€/MWh, which is a standard value in the electricity context [39].

Scenario 3: This scenario leverages the constraint on CO_2 emissions, and does not force the avoidance of ENS but is penalized by 3000€/MWh not served. A penalty is associated with any CO_2 emission in the atmosphere in the form of a fee equal to 80€/t - a value that reflects the current price of CO_2 in the EU-ETS trading system [40].

Scenario 4: This scenario follows the same assumptions as scenario 3, with the difference that the cost of CO_2 is equal to 0€/t. The aim is to showcase the system's configuration without any considerations for CO_2 emissions.

Scenario 5: This scenario follows the same assumptions as scenario 1, with the difference that the only available RREH is in Greenland.

These scenarios summarized in Table 2 vary in their degree of constraint. Scenario 1 is the most restrictive, with a cap on CO_2 emissions and no allowance for ENS. Scenario 2 allows for ENS, while scenarios 3 and 4 remove the cap and replace it with CO_2 prices of 80€ and 0€ per ton, respectively. Finally, scenario 5 requires the use of the RREH in Greenland, with parameters identical to those of scenario 1.

6. Results and Discussion

In this section, we present and discuss the obtained results. We opt for a cross-scenario analysis, utilizing key indicators and statistics extracted from our model, which we juxtapose with the findings of Berger et al. [10]. This comparison is meaningful due to the shared assumptions between their work and ours, with the exception of the original CO_2 installations introduced in our study. We scrutinize various aspects, including the total system cost, sizes of power and CO_2 installations, CO_2 and CH_4 costs, and the ENS. Additionally, we assess and deliberate upon the influence of uncertainty regarding the parameters of the CO_2 installations. Finally, we compare our findings with those of recent related studies.

6.1. Total cost

The results indicate that the costs associated with enabling the hub in Algeria are substantially lower than those in Greenland, as depicted in Figure 3 (a) where nothing is built in the Greenland hub from scenarios 1 to 4, despite it being available for use. This disparity in costs can be attributed to the over-dimensioning of flexibility assets, particularly the storage capacities, as illustrated in Figure 3 (b). This is primarily applicable to electricity generated solely through wind in Greenland, whereas both solar and wind electricity are generated in Algeria. This implies that the flexibility assets have to play a leading role in maintaining the minimum required electricity delivery in the electrolysis power plant.

Furthermore, a reduction in total costs is observed in the first four scenarios with respect to the objective. This is explained with the order of the scenarios based on their degree of constraint, with scenario 1 being the most constrained and scenario 4 being the least.

6.2. Power installation capacities

All power capacities installations are displayed in Table 3.

The potential in Belgium for solar energy is never reached, while for both wind offshore and onshore, the potential is reached in all scenarios.

From scenario 1 to scenario 2, the only difference being the allowance of ENS, there is an increase in the installation of controllable energy production assets. Indeed, there is a shift in capacity from CCGT to solar energy in Belgium between the first scenario and the second.

Regarding scenarios 1 and 5—similar except for the extent of Greenland's usage in scenario 5—solar energy in Belgium is less developed in scenario 1 than in scenario 5. This emphasizes the system trade-off between importing more or less methane from the RREH when it is cheaper. Importing from Greenland is more expensive and leads to an increase in power capacity installation in Belgium for solar, but it does not reach its maximum potential.

Another comparison can be made with the work of [10], where the capacity installation in the hub for the reference scenario is 4.3GW of solar and 4.4GW of wind. In our case, the reference scenario 1 displays 98.16GW and 95.21GW, respectively. The power installation capacity is multiplied by approximately 22 while providing, on average, 282TWh/year of gas (HHV) to serve the gas demand and part of the electricity demand in Belgium, which is 28.2 times the gas production in the original paper. Therefore, thanks to import of CO2 power requirements within the hub are less important.

6.3. CO_2 installations (transport, capture)

In Table 4, the capacities of the CO_2 capture units and the installations of transport capacity per scenario are displayed. Each time PCCC is activated, we recall that capturing CO_2

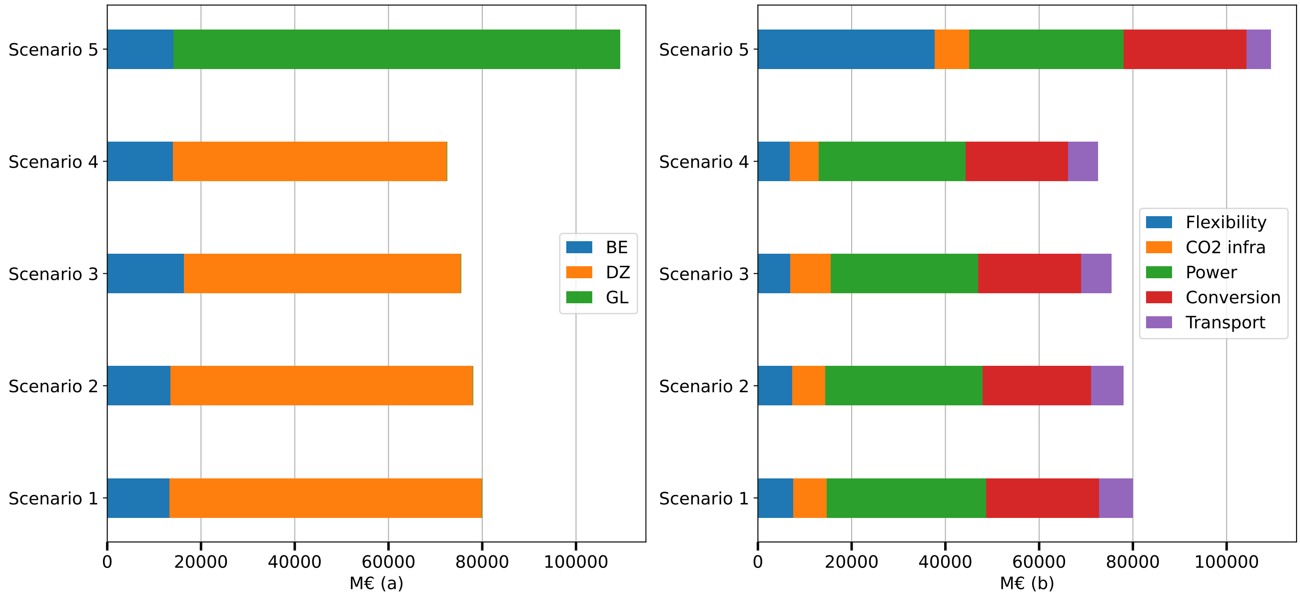

Figure 3: (a): Breakdown of costs per scenario and per cluster (Belgium (BE), Algeria (DZ), and Greenland (GL)). (b): Breakdown of costs per scenario per asset function. Flexibility covers storage capacities, CO_2 infra covers CO_2 capture, storage, and transport, power covers means of electricity production, conversion covers all assets that convert one commodity into another and transport HVDC lines and CH4 carriers. The higher cost of scenario 5 can be attributed to the over-dimensioning of flexibility assets, particularly the storage capacities, as illustrated in Figure 3 (b). This originates from the fact that electricity is generated solely through wind in Greenland, whereas both solar and wind electricity are generated in Algeria.

Scenario	Wind onshore BE	Wind offshore BE	Solar BE	CCGT BE	Wind GL	Wind DZ	Solar DZ
1	8.40	8.00	13.42	19.58	0.00	98.16	95.21
2	8.40	8.00	17.43	15.72	0.00	94.67	91.85
3	8.40	8.00	16.77	15.86	0.00	87.69	84.90
4	8.40	8.00	17.23	15.57	0.00	86.81	84.05
5	8.40	8.00	16.90	19.58	126.48	0.00	0.00

Table 3
Total Power installation in GW per scenario.

is the only means to create gas in our system, and thus a minimum installation is required to support the demand. On the other hand, the DAC is only activated when a CO_2 cap is set (scenario 1, 2 and 5). PCCC has an efficiency of CO_2 capture set to 90%, which means that a direct air capture technology asset is necessary to recover the remaining 10% of emissions in the atmosphere. This leads to a direct consequence, which is that when the DAC is available, the capacity of transport decreases because CO_2 is locally available in the hub. However, the cost of CO_2 capture by PCCC added to transport, liquefaction/regasification of CO_2 is cheaper than the cost of DAC in the RREH. The only way to put PCCC out of business would be to have a distance between the hub and the energy demand centre so long that the transport cost would increase too much.

6.4. Cost of CO_2 derived and Cap of CO_2

From the first, second, and fifth scenarios, we are able to derive shadow prices thanks to the CO_2 cap constraint. These correspond to approximately 177€/tCO2 for the first and second scenarios and 258€/tCO2 for the fifth scenario. This shows that given the system considered, i.e., Belgium and RREH, putting a price of CO_2 equal to 177€ would avoid these emissions in the atmosphere and activate the export of CO_2 to Norway for storage purposes. In scenario 3, where a price of 80€/tCO2 is set, there is no export of CO_2 to Norway. Therefore, a net balance of CO_2 in the atmosphere of approximately 17Mt/year is observed. In scenario 4, where no price is fixed, similar to scenario 3 there is no export of CO_2 to Norway, and there is a net balance of CO_2 in the atmosphere which is equivalent to 24.5Mt/year.

We would like to emphasize that the CO_2 cap in our model only considers the emissions from the industrial and energy sectors, which are fully modeled. It does not account for a part of the emissions resulting from the gas demand served. Of this demand, 32% is attributed to industrial needs, which are included in the statistics of the 40 Mt of CO_2 emitted per year (see subsection 5.2), while the remaining 68% is due to heating and is not covered by our cap. This

Scenario	PCCC	PCCC CCGT	DAC DZ	DAC GL	Carrier DZ	Carrier GL
1	4.11	2.34	1.40	0.00	7.443	0.000
2	4.11	2.00	1.64	0.00	6.552	0.000
3	4.11	1.83	0.00	0.00	9.359	0.000
4	5.00	1.62	0.00	0.00	9.255	0.000
5	4.11	2.98	0.00	1.14	0.000	7.905

Table 4
Capacity, in kt/h, of CO_2 capture technology and transport by hub and per scenario.

Scenario	1	2	3	4	5
[€/MWh]	134.86	136.67	132.92	128.14	187.94

Table 5
Estimation of methane price by retrieving the costs of power installations in Belgium, costs of unserved energy, and costs of exporting CO_2 for storage purposes.

heating gas demand translates to approximately 12.3 Mt of CO_2 emitted per year.

6.5. Cost of CH4 derived

To estimate the cost of CH4 production, we first subtract from the optimal objective function the cost of the means of electricity production in Belgium (PV, on/offshore wind, CCGT), the cost of unserved energy (when applicable), and the cost related to the export of CO_2 for sequestration. All of these costs are subtracted because they do not refer directly to the cost of producing synthetic methane but rather for meeting the electricity demand in the Belgium cluster (cfr Figure 1). Then, we divide the obtained cost by the total energy content (HHV) in CH4 produced at the output of the regasification power plant in Belgium.

These methane costs, listed in Table 5, are compared to the price of 147.9€/MWh of methane (HHV) obtained by Berger et al. [10]. Indeed, the same methodology and assumptions have been taken in order to be able to compare the results. Our scenarios achieve a lower cost for gas production (except for Greenland). This demonstrates that PCCC, which uses smoke with a high concentration of CO_2 combined with transport, is more cost-effective than having only access to a DAC unit, as previously mentioned.

In our system, no fossil gas is available for import to Belgium; only synthetic gas produced from CO_2 capture is used. If fossil gas were still available for import, our model would seek to minimize costs and import as much cheap gas as possible while staying within our carbon budget.

ENS cost discussion

The cost of unserved energy is a fixed parameter in scenarios 2, 3, and 4, but not in scenarios 1 and 5. Instead, a hard constraint is imposed to ensure that electricity demand is always met, resulting in a shadow price associated with the constraint. The maximum shadow price values for scenarios 1 and 5 are 736,139€/MWh and 1,040,501€/MWh, respectively. The significantly higher costs of ENS, in comparison with the 3000€/MWh (usually used in the literature [39]) set for scenarios 2, 3, and 4, are attributed to the peak in electricity and gas demand observed on January 18th at

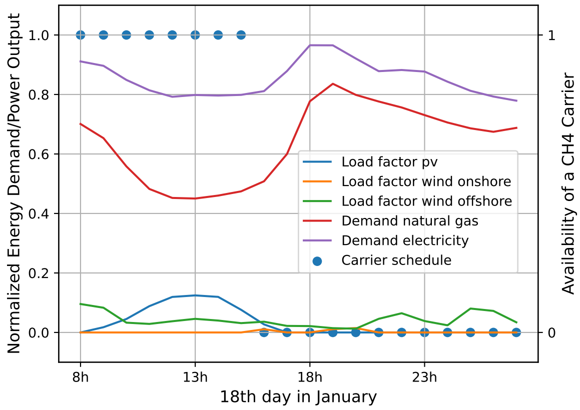

Figure 4: The evening of January 18th led to the maximum shadow price associated with the hard constraint on ENS in scenarios 1 and 5 due to the lack of available renewable energy and high energy demand.

18:00 (as shown in Figure 4), where renewable energy load factors were low. Thus, all energy demand had to be supplied by the CCGT and gas resources.

6.6. Impact of uncertainty in CO_2-related technologies on costs

In this analysis, we replaced the deterministic values for the CAPEX of CO_2-related processes with uniform distributions, as outlined in Table 1. These distributions are then propagated through the multi-energy system optimization model using PCE (subsection 4.2) to determine the statistical moments and global sensitivity indices on the total cost, shadow price and cost of methane.

The distribution of the total cost in scenario 1 is characterized by a mean of 79989 M€ and a standard deviation of 699 M€, resulting in a Coefficient of Variation (CoV), ratio between the standard deviation and the mean, of 0.9%. Notably, the mean cost is marginally lower than the deterministic response of 80004 M€. Consequently, there exists a 51% likelihood of realizing a total cost that is equal to or less than this value in practice. It is worth highlighting that this uncertainty in total cost is primarily driven by the probabilistic CAPEX related to the PCCC, as indicated by a global sensitivity index of 0.92 related to this parameter. Additionally, there is a marginal influence from the probabilistic CAPEX associated with the DAC, with a global sensitivity index of 0.07. Therefore, while the overall variance in total cost remains modest, focusing on the bulk manufacturing of PCCC units emerges as the most effective strategy for uncertainty mitigation.

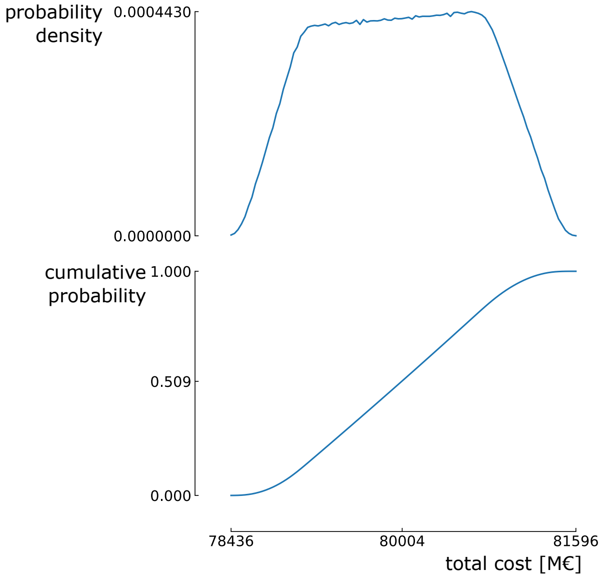

Figure 5: The probability density function (top) and cumulative distribution function (bottom) of the total cost for scenario 1.

The shadow price in scenario 1 follows a distribution characterized by a mean of 177.38 €/tCO2 and a standard deviation of 7.69 €/tCO2, resulting in a CoV of 4.3%. Another observation is that this uncertainty is almost entirely attributable to the distribution of the CAPEX of the DAC, as evidenced by a global sensitivity index of 0.99. The mean value of 177.38 €/tCO2 is marginally lower than the deterministic model response of 177.44 €/tCO2, resulting in a 51% likelihood of observing a value lower than the deterministic response (Figure 6).

Consistent with the distributions on total cost and shadow price, the variance on the cost of methane is relatively limited: A standard deviation of 1.55 €/MWh and a CoV of 1.2% when measured against a mean of 134.68 €/MWh (Figure 7, top). This variance is predominantly driven by the distribution of the CAPEX of the PCCC, as indicated by a substantial global sensitivity index of 0.97. The non-linear response of the energy system optimization model to the range of CAPEX for the PCCC results in a mean methane price below the deterministic value of 134.86 €/MWh. As a result, there is a 53% likelihood of attaining a methane price equal to or below this deterministic value (Figure 7, bottom).

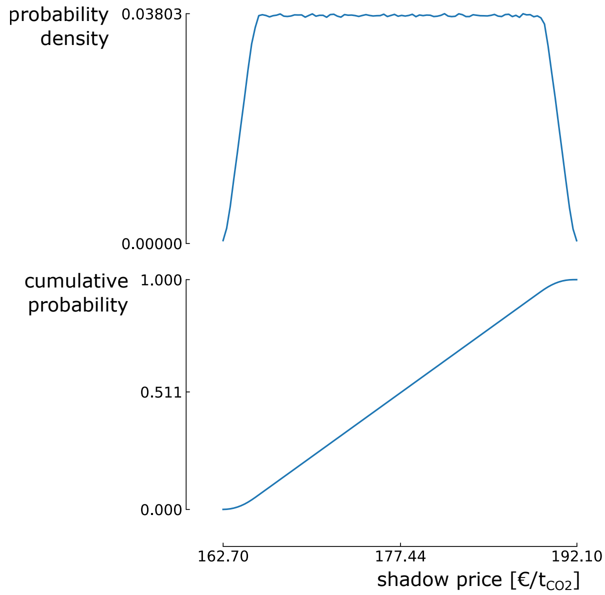

Figure 6: The probability density function (top) and cumulative distribution function (bottom) of the shadow price for scenario 1.

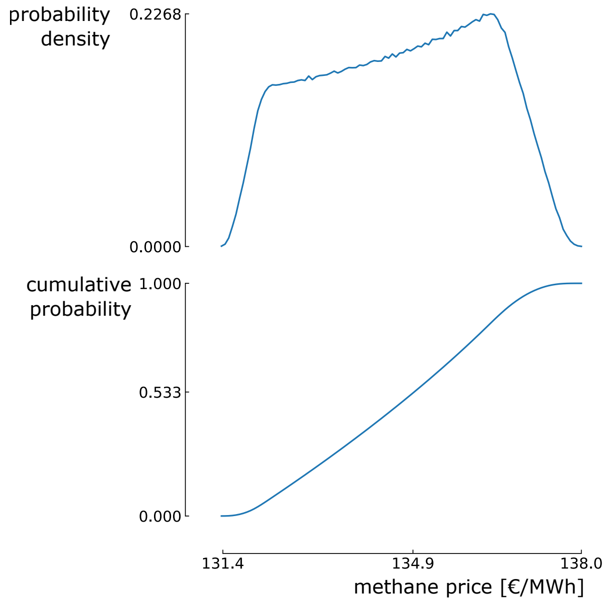

Figure 7: The probability density function (top) and cumulative distribution function (bottom) of the methane price for scenario 1.

6.7. Comparison with other studies

To further compare our results, Hampp et al. [15] found a cost estimate of 78.38 €/MWh for shipping liquid CH4 from Morocco to Germany in 2050 with a WACC of 10%. However, some discrepancies between their methodology and ours should be mentioned: (i) they did not model the energy infrastructure within the country as we did with the HVDC line, (ii) they did not consider the regasification units in the import country, (iii) they only considered one source of CO_2 from DAC, and (iv) we used a WACC of 7% instead of 10% as they did. Pfennig et al. [14] analyzed the cost of different power-to-X fuels, notably CH4. They obtained estimates worldwide ranging from 90 to 150 €/MWh of gas considering the same electrolysis technology as us, namely PEM. They obtained an estimate of more than 120 €/MWh (LHV) for exporting this gas to Germany. The main discrepancies are (i) they did not consider PCCC to source their CO_2, and (ii) they used a WACC of 8%. It is difficult to compare results from other studies due to the numerous assumptions made, such as costs, technologies, perimeters of the model and WACC. This is the reason why we concentrate our comparison on the cost analysis presented in Berger et al. [10], as we adopted identical technical parameters for the shared units in both systems. However, we can observe that the costs of CH_4 derived from [10, 14, 15] are in the same order of magnitude as our reference scenario.

6.8. Relevance for Practical Implementation

Some companies are exploring the implementation of CO_2 loops [41]. Therefore, assessing the relevance of PCCC versus DAC in their business plans is crucial. Generally, capturing CO_2 where it is most abundant is more feasible. Hence, economically, it makes sense to capture CO_2 where CO_2-intensive industries are concentrated. Moreover, this research emphasizes Algeria's competitiveness compared to Greenland as a future hub for Northern Europe.

7. Conclusion

In this study, we introduced a framework for CO_2 valorization in multiple RREH, applied to a case study focusing on Belgium as the energy demand center, along with two RREH in Greenland and Algeria, with the aim of decarbonizing the energy and industry sectors. We modeled and optimized the entire supply chain, obtaining a gas price of €135/MWh (HHV) in our reference scenario. This contrasts with the €150/MWh (HHV) reported in Berger et al. [10], where only direct air capture was considered in the RREH for feeding CO_2 into the methanation process. Our uncertainty quantification method for the capex price of CO_2 installations (transport, capture and storage) indicates that PCCC (*i.e.* capture) contributes the most to the uncertainty. We derive a CO_2 cost of 177 € per ton 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_2 economy between energy demand centers and RREH as we proposed.

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B. Glossary

BE	Belgium
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
DAC	Direct Air Capture
DZ	Algeria
EDC	Energy Demand Center
ENS	Energy Not Served
ETS	Emission Trading System
GBOML	Graph Based Optimzation Modeling Language
GL	Greenland
HHV	Higher Heating Value
LHV	Lower Heating Value
OPEX	Operational Expenditure
PCCC	Post Combustion Carbon Capture
PV	Photovoltaic
RREH	Remote Renewable Energy Hub

Nomenclature

Sets and indices

$\mathcal{E}, e$ set of hyperedges and hyperedge index

$\mathcal{G}$ hypergraph with node set $\mathcal{N}$ and hyperedge set $\mathcal{E}$

$\mathcal{I}^n, i$ set of external variables at node n, and variable index

$\mathcal{N}, n$ set of nodes and node index

$\mathcal{T}, t$ set of time periods and time index

Parameters

$\nu \in \mathbb{N}$ number of years spanned by optimisation horizon

$\kappa_i \in \mathbb{R}_+$ maximum flow capacity of commodity i

$\zeta^n \in \mathbb{R}_+$ annualised CAPEX of node n (flow component)

Variables

$q^n_{it} \in \mathbb{R}_+$ flow variable i of node n at time t

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4 Synthetic Methane for Closing the Carbon Loop: Comparative Study of Three Carbon Sources

4.1 The Question

This chapter contributes to answering **RQ2:** *How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?*

In this paper, the focus is on RREH designs producing synthetic methane (e-methane) while varying the sourcing strategy for CO_2, a key input in the methanation process.

4.2 The Idea

Closing the carbon loop in synthetic fuel production requires sourcing CO_2 from existing emissions. Most previous RREH studies have assumed CO_2 supply exclusively through Direct Air Capture (DAC), which is geographically flexible but costly. Post-Combustion Carbon Capture (PCCC), on the other hand, allows CO_2 to be captured from concentrated industrial flue gases at lower cost, though it is tied to specific emitting sites.

In this chapter, we investigate whether complementing DAC with PCCC, either by importing CO_2 from load centers or by capturing it locally in Morocco, can reduce the delivered cost of e-methane compared to a DAC-only configuration.

This work differs from the previous chapter in two respects. First, the case study is centered on Morocco rather than Algeria. Second, we consider CO_2 sourcing not only as an imported commodity (expanding the import set in the taxonomy) but also as a local opportunity option, effectively altering the technological graph of the hub.

4.3 Contributions of the Paper

The contributions of the paper, published in the journal Applied Energy and titled *Synthetic methane for closing the carbon loop: Comparative study of three carbon sources for remote carbon-neutral fuel synthetization*, can be summarized as follows:

- Modeled a complete energy supply chain from Morocco to Belgium for synthetic methane (e-NG).
- Compared three CO_2 sourcing strategies: (i) DAC in Morocco, (ii) DAC in Morocco combined with PCCC in Belgium with transport, and (iii) PCCC only in Morocco.
- Quantified the impact of each configuration on delivered cost and system design.

4.4 Author's Contribution

This paper was developed as part of an industrial collaboration with TES-H2, whose business model aligns with the concept introduced in my paper presented in the previous chapter. The first draft of the manuscript was prepared by Michael Fonder, while Pierre Counotte adapted my modeling code to the Moroccan case study. I contributed by providing the source code and explanations of it, co-writing the manuscript, and addressing the reviewers' comments. Professor Ernst provided guidance and feedback throughout the process.

4.5 Integration within the Thesis

This chapter contributes to **Part II – Novel RREH Designs (RQ2)**. It relates to the taxonomy by considering CO_2 sourcing as part of the import set or by changing the technological graph of the RREH. By comparing DAC and/or PCCC souring strategies of CO_2, the study demonstrates how novel RREH designs can close the carbon loop while lowering costs.

Synthetic methane for closing the carbon loop: Comparative study of three carbon sources for remote carbon-neutral fuel synthetization

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Abstract

Achieving carbon neutrality is probably one of the most important challenges of the 21st century for our societies. Part of the solution to this challenge is to leverage renewable energies. However, these energy sources are often located far away from places that need the energy, and their availability is intermittent, which makes them challenging to work with. In this paper, we build upon the concept of Remote Renewable Energy Hubs (RREHs), which are hubs located at remote places with abundant renewable energy sources whose purpose is to produce carbon-neutral synthetic fuels. More precisely, we model and study the Energy Supply Chain (ESC) that would be required to provide a constant source of carbon-neutral synthetic methane, also called e-NG (electric Natural Gas) or e-methane (electric methane), in Belgium from an RREH located in Morocco. To be carbon neutral, a synthetic fuel has to be produced from existing carbon dioxide (CO_2) that needs to be captured using either Direct Air Capture (DAC) or Post Combustion Carbon Capture (PCCC). In this work, we detail the impact of three different carbon sourcing configurations on the price of the e-methane delivered in Belgium. Our results show that sourcing CO_2 through a combination of DAC and PCCC is more cost-effective, resulting in a cost of 146€/MWh for e-methane delivered in Belgium, as opposed to relying solely on DAC, which leads to a cost of 158€/MWh. Moreover, these scenarios are compared to a scenario where CO_2 is captured in Morocco from a CO_2 emitting asset that allow to deliver e-methane for a cost of 136€/MWh.

Keywords: Synthetic Methane, Remote Renewable Energy Hub, CO2 Sourcing, Energy Transition

1. Introduction

Global warming is a climate change that is due to large anthropogenic emissions of greenhouse gases, mainly carbon dioxide (CO_2), in Earth's atmosphere. As its effects are detrimental for our societies and ecosystems in general, it has appeared necessary to reduce, and even cancel, the emission of these gases to minimise these effects. Since most of the CO_2 is emitted by burning fossil fuels to generate energy, transitioning our energy production out of these fuels is mandatory.

The main alternatives to fossil fuels are renewable energies such as wind, solar or hydropower, which can be harvested to produce electricity. However, most renewable energy sources are intermittent, and the best sources are located far away from places where this energy is the most needed [1]. As electrical energy is challenging to transport over long distance and to store in large quantities with current technology, innovations are needed to bridge the gap between energy production and consumption locations.

One innovation to bridge this gap could be the employment of an High Voltage DC (HVDC) transmission line for the transportation of energy over long distances. Ongoing investigations into projects aiming to link Morocco with the United Kingdom have been documented by Xlinks [2]. However, this alternative is currently in the early stages of development, and its eventual feasibility remains uncertain.

Another innovation is the concept of Remote Renewable Energy Hub (RREH) for carbon-neutral fuel synthesis that was first laid out by Hashimoto et al. [3]. The idea underlying RREHs is to install power-to-X facilities, that convert electrical energy into chemical energy, at remote locations where renewable energy sources are the most abundant [4, 5], and to transport the converted energy to places where it is needed. A power-to-X facility converts the electrical energy into chemical en-

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ergy by synthesizing energy-dense molecules [6], which are easier to store and transport back to the energy consumption locations than electricity. The molecules typically considered for this kind of application are dihydrogen, ammonia, or methane, each having its own advantages and drawbacks [7].

Among these three molecules, synthetic methane, also called e-methane, holds a particular place. Indeed, it can be used as a simple drop-in replacement within existing energy-demanding installations while decreasing GHG emissions when produced from renewable energy sources, as shown in several case studies [8, 9, 10]. More generally, existing life-cycle analysis of methanation indicate that the Global Warming Potential (GWP) of e-methane produced with renewable energy sources is smaller than fossil natural gas [11, 12]. Benefits of e-methane on GWP are even larger if the methanation is done through catalysts through captured CO_2 rather than from biomass [13, 14].

To be considered as carbon-neutral, catalyst-based e-methane has to be generated from existing CO_2, which must be actively captured prior to being used for methanation. Capturing CO_2 can be done either by filtering it out of ambient air thanks to Direct Air Capture (DAC) technologies [15, 16] or by extracting it directly at the source of emission, in industrial fumes, where it is the most concentrated, by Post Combustion Carbon Capture (PCCC) [17, 18]. Fossil fuel power plants, or cement and steel factories are examples of industries that emit sufficiently large amounts of CO_2 to be considered for PCCC. The high concentration of CO_2 in industrial fumes leads PCCC to be less expensive than DAC for extracting the same amount of CO_2 [19]. However, capturing CO_2 by PCCC needs to be done at the factory that uses the synthesized fuel. The CO_2 then needs to be transported where needed, which induces additional costs. This contrasts with DAC that can be performed anywhere on the planet directly where needed, which eliminates the transportation costs. As changing the source of CO_2 impacts the price of the final commodity produced by an RREH, it is necessary to know which CO_2 source and capture method combination is the most energy-efficient and/or the most cost-effective for a given RREH.

Multiple works have studied Power to Gas (PtG) RREHs in different configurations. For example, Berger et al. [20] studied an RREH located in Algeria designed to produce e-methane to be delivered in Belgium. Dachet et al. [19] built on this work by adding a hub in Greenland and by studying the impact of carbon pricing on the sizing of the system. Hampp et al. [1] performed an extensive study on the opportunity to build RREHs at different places on Earth to deliver energy to Germany. As opposed to the works of Berger et al. [20] and Dachet et al. [19] that focus on e-methane, Hampp et al. [1] consider and compare multiple carriers for energy. However, all these works consider only a single configuration for sourcing the CO_2 required for the methanation process in their study. Therefore, it is impossible to know if the CO_2 sourcing chosen in each of these works is the most effective one.

This paper aims to compare the impact of changing the CO_2 sourcing used to close the carbon loop to the cost of the generated e-methane, and to the sizing of the RREH, which has not been done before. More specifically, we study the impact of three different configurations of CO_2 sources and capture methods on the cost and the sizing of an RREH located in Morocco and designed to produce e-methane to be delivered in Belgium.

We detail the exact scope and configurations considered in our problem statement, in the next section. We detail our model and methodology in Section 3, and analyse our results in Section 4. Section 5 concludes this paper.

The main contributions of this work are as follows:

- We model the whole Energy Supply Chain (ESC) needed to deliver e-methane, produced from salt water and renewable energy in Morocco, to Belgium;
- We consider three different ways of sourcing the CO_2 needed for the methanation in the RREH;
- We provide a detailed analysis of the advantages and drawbacks of each of these sources.

2. Problem statement

In this section, we detail the scope of this work. We consider an RREH located in Morocco whose purpose is to produce e-methane for the Belgian market. The RREH has to produce e-methane from renewable energy sources (for electricity), from salt water and from captured CO_2. The e-methane produced by the hub has to be delivered to Belgium by LNG carriers.

The choice of Morocco for the location of the hub is first motivated by the quality of its renewable energy sources [21]. Second, an RREH requires a significant land area to be deployed, especially for collecting renewable energies. Morocco is also interesting in this regard, since the southern half of the country is mostly a desert with an extremely low existing land use.

We consider three different configurations for capturing the CO_2 required for the methanation process in the

RREH, namely: (i) DAC on site, in Morocco; (ii) PCCC from Moroccan CO_2 emitting asset; and (iii) PCCC from e-methane use in Belgium, with capture losses being compensated by DAC on site, in Morocco.

The purpose of this work is to model the ESC that corresponds to each of these configurations, starting from renewable electricity and salt water in Morocco up to the delivery of e-methane in Belgium, and to provide an insight on the impact each configuration has on the price of the delivered e-methane and on the sizing of the different elements making the ESC.

The ESC necessary to deliver e-methane to Belgium will be designed to be fully autonomous and auto sufficient. To be comparable to previous works [20, 19], the system will be designed to deliver 10TWh of e-methane uniformly over a year in Belgium. The study will be performed with a Weighted Average Cost of Capita (WACC) set to 7% , and with extra contingency costs added to all Capital Expenditures (CAPEX) to factor in for feasibility uncertainties [22]. More precisely, contingency costs of 10% and 30% are to be added to the CAPEX of mature and unproven technologies respectively.

3. Material and method

In this section, we present the method used to carry the study described in the previous section. We first detail the framework used to model and size the desired ESC. We then fix the geographical parameters of our study. Finally, we provide a detailed insight on the setup of the models used to analyse the three CO_2 sourcing configurations considered alongside the parameters used for each part of the model.

3.1. Modelling framework

This study is built on the work of Berger et al. [20] which introduced the use of a Graph-Based Optimization Modeling Language (GBOML) as an optimization framework for multi-energy system models. The GBOML language [23] allows one to model each part of a complex system as a set of nodes interconnected by hyperedges that model the constraints existing between these nodes. In the case of an RREH each node models a specific module of the hub, and each hyperedge models the flow of a given commodity within the hub.

In the GBOML language, the nodes are, in part, modelled by a set of variables that need to be tuned to minimize the objective function of the model while verifying a set of linear constraints specific to each node. For this, each node has to provide an objective to minimize that is a linear function of its variables. The objective function of the whole model is then defined as the sum of all the objectives of its nodes. In this study, we want to minimize the cost of the e-methane delivered in Belgium, and therefore the cost of the hub. As a result, our objective functions will be proportional to the CAPEX and Operational Expenditures (OPEX) of the different modules of the hub.

Since the lifetime of each module is specific, raw CAPEX are not representative of real costs when studying the cost of the hub over a limited time horizon. One method to address this concern, which we employ in this study, involves the use of annualized CAPEX. The annualized CAPEX ζ_m of a module m can be computed from the raw CAPEX, from the life-time L_m of the module and from the WACC w as follows:

$$\zeta_m = \text{CAPEX}_m \times \frac{w}{1 - (1 + w)^{-L_m}} \tag{1}$$

Given that the optimization problem of interest has already been comprehensively formalized by Berger et al. [20], we shall only remind ourself of the set of assumptions made by prior studies to model and size an RREH within this framework:

- All technologies and their interactions are modelled using linear equations;
- The infrastructures and networks needed to transport and process commodities within a single node are not modelled;
- Curves modelling the boundaries of the model, such as the renewable energy load factors and the energy demand, are assumed to be known in advance for the whole optimization time horizon;
- The sizing of the modules is assumed to be constant over the whole time horizon considered;
- Sizing the whole hub with an optimization framework assumes that all planning, investment and operation decisions are made by a single entity.

3.2. Geographical parameters

One of the aspects that heavily impact any study of an RREH is the location of its different components. As mentioned in the problem statement, this study focuses on an RREH located in Morocco with a e-methane terminal in Belgium. In this part of the document we detail the choice of location of all the parts of the hub and the constraints that result from this choice.

The precise location of the different modules of the hub is mapped in Fig. 1. The delivery terminal is set

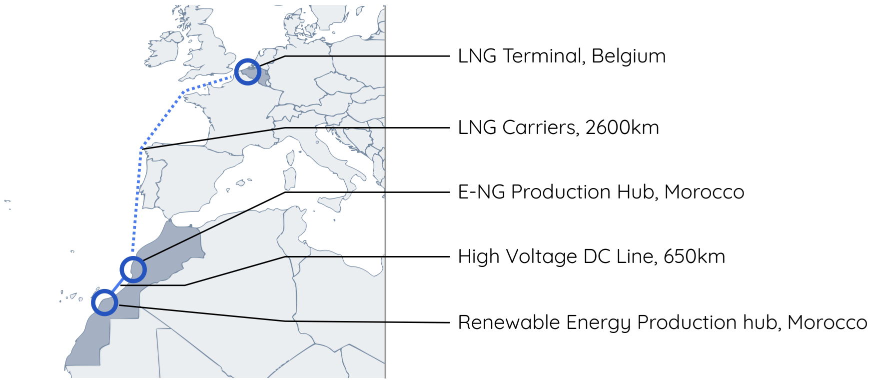

Figure 1: Geographical location of the different parts of the ESC studied in this work.

to be in the Belgian harbour of Zeebrugge as it already features LNG terminals. We build our study on a renewable energy capture hub located on the Atlantic coat in the Western Sahara desert. We consider this location because it has excellent wind and solar energy sources, and because it is mostly empty, which leaves a lot of room to deploy large fields of windmills and solar PV panels. Finally, we set our e-methane production hub to be near the Moroccan city of Safi. By doing so, the e-methane production hub is located near a pool of available workforce, which is required to run the hub, near the coast, which is needed to export the produced e-methane by carriers, and near a large coal-fired power plant [24], which can provide a valuable source of CO_2 for PCCC. It is worth noting that the Safi power plant is sized to deliver 10TWh of electricity over a year [24], and is therefore a source of CO_2 large enough to feed the methanation process of the hub studied in this work. In this study, we consider PCCC applied to the Safi coal-fired power plant. However, our results should be similar to PCCC applied to another CO_2 emitting asset, like a steel plant or a cement plant (also present in Safi [25]). In addition, the area of Safi has a lot of available space for large industrial projects, which is a requirement due to the sheer scale of the hub considered.

With such a setup, the power and e-methane production hubs are separated by 650 km, and need to be connected by a HVDC line. Since the power production hub is also on the coast, the HVDC line can be installed offshore to get the shortest connection distance. The e-methane production hub and the LNG terminal in Belgium are separated by 2600 km, and require connection by LNG carriers. We estimate that 100 hours are required to connect Safi to Zeebrugge by carrier.

3.3. Model

Despite being close to the works of Berger et al. [20] and Dachet et al. [19], the RREH model used in this study features some differences. In this section, we first explain the fundamental principles of the hub, and then highlight the key differences with existing works. We would like to emphasize that we open-sourced the code used for the hub to provide all the details required to reproduce this work[1].

3.3.1. Hub principle

As detailed in the previous section, the whole ESC necessary to deliver e-methane, synthesized from renewable energy sources in Morocco, in Belgium is made up of the three main hubs illustrated in Fig. 2. First, the power production hub is made of three nodes; the solar PV panel farm, the windmill farm, and a pack of batteries used to smooth out variations inherent to renewable energy sources. The power production hub is used to deliver the electricity needed to capture CO_2 in Morocco, and to synthesize e-methane. The power profiles used to model the renewable energy production over the optimization time horizon were obtained from the *renewable.ninja* website [26, 27, 28].

Second, the e-methane production hub, which takes electricity and a source of CO_2 as inputs, is responsible for synthesizing e-methane from salt water and CO_2. This hub gets the clean water required for electrolysis from a reverse osmosis water desalination module. This fresh water then passes through an electrolysis module to produce the hydrogen needed by the hub. The core of this hub, the methanation unit, consumes both hydrogen and CO_2 to synthesize e-methane with the Sabatier

[1] https://gitlab.uliege.be/smart_grids/public/gboml/-/tree/master/examples/synthetic_methane_morocco

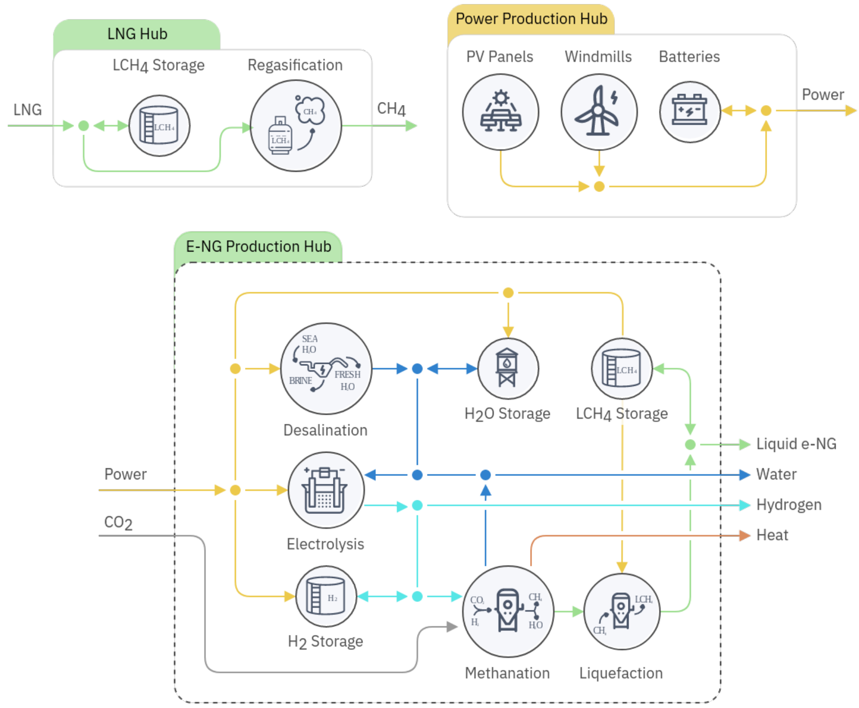

Figure 2: Illustration of three major modules that are part of our ESC and that are common for all CO_2 sourcing configurations. The LNG hub features the infrastructures necessary to receive liquefied e-methane from carriers for the end delivery. The module will be installed in Belgium. The power production hub groups all the elements required to provide renewable power coming from energies to other elements of the ESC. Finally, the e-methane production hub takes power and CO_2 as inputs and produces liquid e-methane, water, hydrogen, and heat as outputs. These outputs can be consumed by other elements of the ESC, such as DAC units.

reaction. This node has two byproducts that can be used at other places in the ESC: fresh water and low-grade steam heated to 300°C. Lastly, the synthesized e-methane is liquefied for transportation. In addition, water, hydrogen, and liquefied e-methane storage nodes are added to buffer flow variations of each commodity.

Third, the LNG hub in Belgium is simply made of two nodes: one liquefied e-methane storage and one e-methane regasification node to deliver the e-methane in a gaseous form.

The model of the complete ESC necessary to produce e-methane from CO_2 capture by DAC units in Morocco is illustrated in Fig. 3. The one for CO_2 sourced from a CO_2 emitting asset PCCC is given in Fig. 4, while Fig. 5 illustrates the model of the CO_2 sourcing configuration implying PCCC in Belgium and DAC in Morocco. In all of these models, CO_2 transits as a gas, excepted for storage and carrier transportation where it needs to be liquefied.

3.3.2. Our adaptations

Although we use the same nodes with the same parameters as Berger et al. [20] and Dachet et al. [19] for most nodes of the model, we need to adapt some parameters of the reference model for our study. Since Berger et al. [20] already detail all the parameters of their model, we only focus on our adaptations to these parameters hereafter.

As required by our problem statement, we add a contingency cost to the CAPEX of all nodes. This contingency cost, which was not considered in previous works, is equal to 10% of the CAPEX for well-established technologies, and 30% of the CAPEX for less mature technologies. The technologies that we consider to be less mature regarding the scale of the RREH are the following: large-scale battery packs, HVDC lines, electrolysis units, methanation units, and CO_2 capture technologies.

Modifications are also carried out to the methanation node when compared to the original node proposed by Berger et al. [20]. First, we align our CAPEX with the 300k€/(MWH CH_4/h) proposed by Gorre et al. [29]. Second, we add an output for the residual heat produced by the Sabatier reaction as it can also be valued. Indeed, Coppitters et al. [30] showed that this heat can be recycled in the hub to lower the heat energy required by

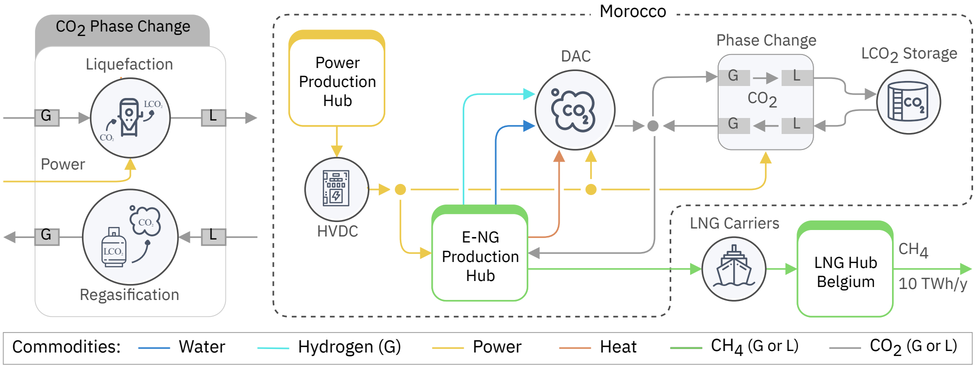

Figure 3: Illustration of the hub design used for our first CO_2 sourcing configuration. The CO_2 is captured by DAC units at the place where the methanation is performed.

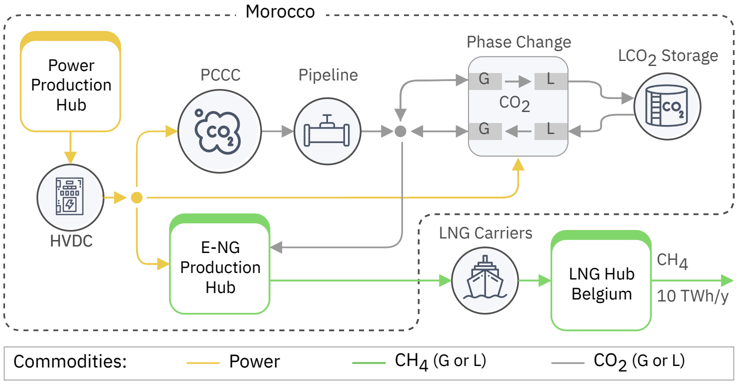

Figure 4: Illustration of the hub design used for our second CO_2 sourcing configuration. The CO_2 is captured by a PCCC unit placed at a local CO_2 emitting asset, in Morocco. The CO_2 is transferred to the methanation plant by pipeline.

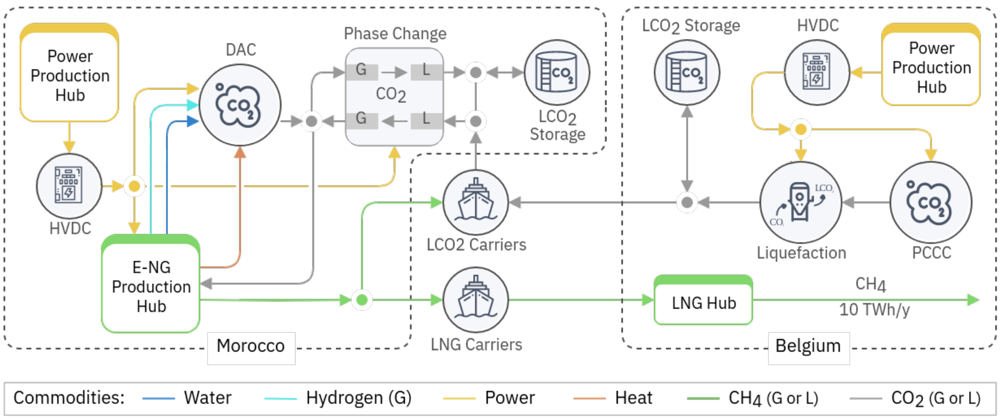

Figure 5: Illustration of the hub design used for our third CO_2 sourcing configuration. The CO_2 is captured by PCCC at places where e-methane is used in Belgium. This carbon is transferred to the methanation hub by liquefied CO_2 carriers. The electricity required for the PCCC units is provided by a small renewable energy power hub. Since PCCC cannot capture all the emitted CO_2, the missing CO_2 required for methanation is captured by DAC units on site, in Morocco.

solid sorbent DAC units. According to their work, the Sabatier reaction produces 2.1MWh of usable heat energy per ton of synthesized CH_4.

Using a heat source of 300°C to regenerate a sorbent is only possible for solid sorbents. Indeed, solid sorbents only require to be heated to 100°C to regenerate [30], whereas liquid sorbents need to be heated to 900°C [20]. Therefore, as opposed to preceding works [20, 19], we use solid sorbent DAC units in our model, and rely on the data of the Danish Energy Agency [31] for their specifications. In addition to using recirculated heat, the system has the ability to burn hydrogen to provide heat for the sorbent regeneration.

A last minor change of in our model when compared to previous works is the cost of liquefaction, storage and regasification of CO_2. The source used in previous works [32] dates from 2004, which is significantly older than most of our sources. To uniformize cost estimates, we adjusted the estimates of Mitsubishi Heavy Industries, LTD [32] by taking inflation between 2004 and 2021 into account.

All the techno-economic parameters for each modeled technology are listed in the tables available in the Appendices.

4. Results

With the study and the model being defined, we can analyse the results of the optimization process. In this section, we first analyse the three CO_2 sourcing configurations from a cost perspective. We then analyze them from an energy perspective. Finally, we discuss the results obtained in this work.

4.1. Costs analysis

The cost for delivering CH_4 to Belgium for our three CO_2 sourcing configurations are detailed in Tables 1 and 2. The price for the commodities produced by the hub is given in Table 3. Producing and delivering 1MWh of CH_4 costs 124.47€ without factoring in costs related to CO_2 sourcing. The largest part of this cost is due to the renewable energy capture (53.43€/MWh CH_4), electricity transportation (11.86€/MWh CH_4), and water electrolysis (35.42€/MWh CH_4).

Capturing and transporting CO_2 to the e-methane production hub creates additional costs that range from 11.57€/MWh CH_4 for the PCCC in Morocco to 33.46€/MWh CH_4 for DAC on site, which is the most expensive way to source CO_2 to the hub. Therefore, delivering 1MWh of e-methane in Belgium costs a total of 136.04€ when sourcingCO_2 from PCCC in Morocco, 145.51€ when sourcing CO_2 from PCCC in Belgium, and 157.93€ when sourcing CO_2 from DAC on site. For comparison, regular fossil natural gas has been exchanged at prices well above these costs for several months during the 2022 energy crisis in Europe (up to 342€/MWh in August 2022).

CO_2 coming from DAC on site seems to also be more expensive than PCCC CO_2 imported from Belgium. As a result, the methanation uses as much CO_2 from Belgium as possible in the configuration where CO_2 can be sourced either from DAC on site or from PCCC in Belgium. This leads the fraction of CO_2 coming from Belgium used for methanation to be equal to the efficiency of the PCCC process (90% in our model).

In order to be exhaustive, we tested an alternate model where CH_4 and CO_2 are transported through offshore pipelines for the configuration where part of the CO_2 comes from PCCC in Belgium. In this case, the price of e-methane delivered in Belgium rises to 151.24€/MWh, which is more expensive than transportation by carriers.

4.2. Energy analysis

Table 4 gives some key statistics related to energy within our model. This table shows that the efficiency of the hub, that is the ratio between the energy contained in the e-methane delivered in Belgium and the energy captured by windmills and solar panels, lies around 50% with small variations depending on the CO_2 sourcing configuration. The highest efficiency, 51.26%, is obtained by the CO_2 sourcing that combines PCCC in Belgium and DAC in Morocco and beats the efficiency of simple PCCC in Morocco. This observation, which may be surprising at first glance, can be explained by the use of heat recirculation. As shown in the last column of the table, a large part of the heat required for DAC can be provided by the Sabatier reaction. In the case of joint PCCC and DAC, the Sabatier reaction can even provide all the heat required for DAC, which lowers the energy input required for carbon capture when compared to PCCC alone. However, it is worth noting that the CO_2 sourcing involving PCCC in Morocco has residual heat that is not used in our model, but that could be valued for other applications, which would virtually increase the efficiency of the hub.

The Table 4 also shows the fraction of available renewable energy that is not used by the hub. For windmills, the energy curtailment rises to 25%, while all the available solar energy is used. This observation is identical for all CO_2 sourcing configurations. We believe

ECS Elements	CH_4 Production Free CO_2 (€/MWh CH_4)	CO_2 Sourcing DAC MA (€/MWh CH_4)	CO_2 Sourcing PCCC MA (€/MWh CH_4)	CO_2 Sourcing PCCC BE + DAC MA (€/MWh CH_4)
Solar PV Field	10.43	1.23	0.37	0.11
Windmill farm	43.00	4.02	1.9	0.20
Batteries	4.06	1.49	-0.05	0.33
HVDC	11.86	1.12	0.50	0.06
CO_2 capt. + transport.	0.00	21.61	8.39	20.09
Desalination plant	0.11	0.66	0.00	0.16
Water storage	0.05	0.00	0.00	0.00
Electrolysis plant	35.42	2.89	0.29	0.05
H2 storage	4.55	0.44	0.17	0.02
Methanation plant	7.75	0.00	0.00	0.01
CH_4 liquefaction	5.09	0.00	0.00	0.01
CH_4 storage (Morocco)	0.23	0.00	0.00	0.00
CH_4 carriers	0.67	0.00	0.00	0.00
CH_4 storage (Belgium)	0.23	0.00	0.00	0.00
CH_4 regasification	1.02	0.00	0.00	0.00
Total cost	124.47	33.46	11.57	21.04
CH_4 cost	124.47	157.93	136.04	145.51

Table 1: Breakdown of the cost for delivering 1MWh of CH_4 in Belgium depending on the source of CO_2 used for the methanation process. The cost given for the "CO_2 capt. + transport." line encompasses all the infrastructures required to capture and transport the CO_2 back to the e-methane production hub. This line is detailed in Table 2 for each CO_2 sourcing configuration individually. The other costs induced by a CO_2 sourcing, which listed in the table, detail the costs of feeding the appropriate commodities (electricity, water,...) to a given CO_2 sourcing configuration with the hub.

that the discrepancy between the curtailments of solar and wind power can be explained by a difference in regularity of the energy sources. Indeed, the available solar power is pretty regular from a day to the other whereas wind power fluctuates more.

In addition to these insights, we computed the load factor for different parts of the system. Windmills and PV panels have a load factor of 41.4% and 25.5% respectively. Electrolysis units have a load factor of about 81%, while desalination and methanation units are used at full capacity all the time by design. These load factors are similar for all CO_2 sourcing configurations.

Finally, Table 5 shows the capacity that needs to be installed for delivering an average power of 1MW of e-methane to Belgium for various modules of the hub. Since the model is fully linear, these capacities scale linearly with the desired power of e-methane to be delivered. It is interesting to note that the biggest consumers of fresh water are by farDAC units according to numbers given in this table.

4.3. Results discussion

All the results presented in this section are directly linked to our hypothesis and to our model. Our observations and analysis may be slightly different when considering some additional factors. In this section, we discuss how some factors that could impact the results presented in this work.

First, our model does not factor in for the economies of scale that could come with the deployment of a large RREH. Indeed, most of the current cost estimated are projections based on existing prototypes or units that are of small scale or still at experimental stage. Therefore, it seems reasonable to assume that the overall cost of modules would fall if manufactured in large quantities.

Second, the efficiency of PCCC can vary depending on the industry on which CO_2 capture is performed [9]. As little data are available on the type and capacity of industries that may use the delivered e-methane in Belgium, we had to make an educated assumption on the efficiency of PCCC. Real-world deployments may lead to efficiencies different to the assumptions made in this work, and could change our observations. Indeed, if the efficiency of PCCC drops to steeply, costs associated to PCCC may rise to a point where the balance between PCCC in Belgium and DAC in Morocco has a different optimum.

DAC MA CO_2 sourcing elements	Cost (€/Mwh)
DAC (Morocco)	21.61
CO_2 storage (Morocco)	0.0
Total cost	21.61

(a) DAC in Morocco

PCCC MA CO_2 sourcing elements	Cost (€/Mwh)
PCCC (Morocco)	8.08
CO_2 storage (Morocco)	0.3
CO_2 pipe	0.01
Total cost	8.39

(b) PCCC from a CO_2 emitting asset in Morocco

PCCC BE + DAC MA CO_2 sourcing elements	Cost (€/Mwh)
Solar PV field (Belgium)	1.12
Windmill farm (Belgium)	2.36
Batteries (Belgium)	1.16
HVDC (Belgium)	0.24
PCCC (Belgium)	7.07
CO_2 liquefaction (Belgium)	0.14
CO_2 storage (Belgium)	0.44
CO_2 carriers	1.77
DAC (Morocco)	5.28
CO_2 storage (Morocco)	0.45
CO_2 regasification (Morocco)	0.06
Total cost	20.09

(c) PCCC in Belgium completed by DAC in Morocco

Table 2: Breakdown of the cost for sourcing CO_2 to the methanation process for our three different sourcing configurations. The electricity required for the PCCC in Belgium is provided by a small renewable energy hub installed in Belgium.

Commodity	Cost [€]
Hydrogen [t]	3210.69
Water [t]	1.17
CO_2- DAC MA [t]	256.28
CO_2- PCCC MA [t]	72.28
CO_2- PCCC BE + DAC MA [t]	136.62
Wind power - MA [MWh]	30.19
Solar power - MA [MWh]	22.89
Wind power - BE [MWh]	65.47
Solar power - BE [MWh]	58.51

Table 3: Cost of the commodities produced by our ESC model. Due to limitations, the price given for CO_2 sources using DAC correspond to the upper bound price that happens when all the heating energy comes from hydrogen. The production costs for power, water, and hydrogen are independent of the CO_2 sourcing configuration.

Third, we modelled the hub to be self-sufficient. As shown in the previous section, this implies to synthesize hydrogen to provide heat to DAC units when the heat resulting from the Sabatier reaction is not sufficient, which increases the cost of the hub. However, the low-grade heat required to regenerate solid sorbents in DAC units is a common industrial byproduct that is often considered as a waste due to a lack usecase, but that can find a use within the hub. As a result, importing heat from a neighbouring industry could make the price of the configuration relying on DAC units more competitive price-wise when compared to other configurations of CO_2 sourcing.

Fourth, the ability of DAC units to provide a CO_2 source that does not need a dedicated supply chain is a practical advantage over PCCC that does not appear when simply looking at numbers. A simpler supply chain for the production of e-methane is also probably a more robust one as fewer elements come into play. This could lead to a higher reliability of the whole supply chain, which has an economic value that is not taken into account in our model.

Lastly, we need to discuss the carbon neutrality of the synthetic methane in the scenario implying PCCC on an existing CO_2 emitting asset. While the other scenarios are clearly carbon neutral due to the complete recapture of CO_2 emitted by the use of e-methane, performing PCCC on an existing CO_2 emitting asset can only be considered to be carbon neutral if this asset was installed prior to or is operated independently from the RREH. As assets have a limited lifetime, 35 years in the case of a coal-fired power plant [33], this scenario could be seen as an intermediate step towards one of the two others scenarios since it offers the opportunity to get an operating RREH in a short term and under a cost-effective budget. Furthermore, in all scenarios, emissions of CO_2 in Belgium are covered by CO_2 withdrawal or avoided emissions. Therefore, the carbon neutrality of e-methane should be recognized by the exchange of emission permits between Belgium and Morocco, which in turn will incentivize the use of e-methane in Belgium.

CO_2 Sourcing Configuration	ESC- Global Efficiency [%]	Wind - Fraction of Curtailment [%]	PV - Fraction of Curtailment [%]	DAC - Part of Recycled Heat[%]
DAC MA	48.44	25.17	0.0	65.41
PCCC MA	51.10	25.17	0.0	N/A
DAC MA + PCCC BE	51.26	25.14	0.0	99.99

Table 4: Insight of some key figures related to energy within our model. The first column gives the ratio between the energy delivered in Belgium in the form of CH_4 and the captured renewable energy. The second column gives the fraction of available wind energy that was not used by the model. The third column gives the fraction of available solar energy that was not used by the model. The last column gives the fraction of heat energy required by DAC that comes from recirculated heat rather than from hydrogen.

ECS Elements	CH_4 Production Free CO_2 [/MW CH_4]	CO_2 Sourcing DAC MA [/MW CH_4]	CO_2 Sourcing PCCC MA [/MW CH_4]	CO_2 Sourcing PCCC BE + DAC MA [/MW CH_4]
PV Capacity [MW]	2.1389	0.2514	0.0769	0.0226
Windmill capacity [MW]	3.4660	0.3238	0.1528	0.0162
Battery capacity [MWh]	1.1266	0.4182	-0.0188	0.0909
Battery throughput [MW]	0.1469	0.0469	0.0007	0.0110
HVDC line capacity [MW]	2.3105	0.2178	0.0983	0.0110
Desalination units [MW]	0.1508	0.9468	0.0000	0.2257
Electrolysis units [MW]	2.1717	0.1774	0.0179	0.0029

Table 5: Capacity of several modules of the hub required to deliver an average power of 1MW of e-methane in Belgium.

5. Conclusion

In this paper, we consider the sizing and the cost of an ESC designed to synthesize e-methane from renewable energy sources in an RREH in Morocco and to deliver it in Belgium. Synthesizing e-methane requires a source of CO_2. In this work, we considered three different configurations for sourcing the required CO_2 to the RREH, and studied their impact on the sizing and the cost of the RREH, and by extension on the cost of the e-methane delivered in Belgium. The three different configurations considered for capturing the CO_2 are (i) DAC on site, in Morocco; (ii) PCCC from Moroccan CO_2 emitting asset; and (iii) PCCC from e-methane use in Belgium, with capture losses being compensated by DAC on site, in Morocco.

We modelled and optimized the ESC corresponding to the three configurations using the GBOML framework. Results show that DAC is more expensive than PCCC generally speaking. This is in part due to the heat required to regenerate the sorbent of DAC units. Indeed, the CO_2 sourcing relying only on DAC units leads to a price of 157.93€/MWh of e-methane delivered in Belgium, while the configuration relying on PCCC from Moroccan CO_2 emitting asset lead to of price of 136.04€/MWh. The hybrid configuration, which implies PCCC in Belgium and DAC in Morocco, leads to an intermediate price of 145.51€/MWh of e-methane delivered in Belgium. The price for CO_2 induced by this configuration is still lower than the one of CO_2 captured by DAC on site despite the additional costs induced by the transportation of CO_2 between Belgium and Morocco. These costs, which are estimates based on conservative projections on technology costs by the year 2030, can be expected to decrease with every technological breakthroughs linked to elements of the RREH.

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Acronyms

CAPEX Capital Expenditures. 3, 5

CO_2 carbon dioxide. 1–10

DAC Direct Air Capture. 2, 3, 5–10

ESC Energy Supply Chain. 2–5, 9, 10

GWP Global Warming Potential. 2

HVDC High Voltage DC. 1, 4, 5

OPEX Operational Expenditures. 3

PCCC Post Combustion Carbon Capture. 2–10

PtG Power to Gas. 2

RREH Remote Renewable Energy Hub. 1–5, 8–10

WACC Weighted Average Cost of Capita. 3

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Appendices

The tables (6, 7, 8, 9, 10) have been adapted from Berger et al. [20] to encompass all the technologies used in this study. Economical costs of storage components are presented in two separate tables—one considering the flow and the other focusing on the stock of commodities. For readers interested in a comprehensive mathematical formulation of the constraints and objective functions related to these parameters, we recommend referring to Berger et al. [20].

	CAPEX	FOM	VOM	Lifetime	Contingency
Battery Storage	142.0	0.0	0.0018	10.0	0.3
[34]	M€/GWh	M€/GWh-yr	M€/GWh	yr	-
Compressed H_2 Storage	45.0	2.25	0.0	30.0	0.1
[34]	M€/kt	M€/kt-yr	M€/kt	yr	-
Liquefied CH_4 Storage	2.641	0.05282	0.0	30.0	0.1
[35]	M€/kt	M€/kt-yr	M€/kt	yr	-
Liquefied CO_2 Storage	2.3	0.0675	0.0	30.0	0.1
[36]	M€/(kt/h)	M€/(kt/h)	M€/kt	yr	-
H_2O Storage	0.065	0.0013	0.0	30.0	0.1
[37]	M€/kt	M€/kt-yr	M€/kt	yr	-

Table 6: Economic parameters used to model storage nodes (stock component, 2030 estimates).

	CAPEX	FOM	VOM	Lifetime	Contingency
Battery Storage	160.0	0.5	0.0	10.0	0.3
[34]	M€/GW	M€/GW-yr	M€/GWh	yr	-
Compressed H_2 Storage	45.0	2.25	0.0	30.0	0.1
[34]	M€/kt	M€/kt-yr	M€/kt	yr	-
Liquefied CH_4 Storage	2.641	0.05282	0.0	30.0	0.1
[35]	M€/kt	M€/kt-yr	M€/kt	yr	-
Liquefied CO_2 Storage	0.0	0.0	0.0	30	0.1
[36]	M€/(kt/h)	M€/(kt/h)	M€/kt	yr	-
H_2O Storage	1.55923	0.0312	0.0	30.0	0.1
[37]	M€/(kt/h)	M€/(kt/h)	M€/kt	yr	-

Table 7: Economic parameters used to model storage nodes (flow component, 2030 estimates).

	η^S	η^+	η^-	σ	ρ	ϕ
Battery Storage	0.00004	0.959	0.959	0.0	1.0	
[34]	-	-	-	-	-	
Compressed H_2 Storage	1.0	1.0	1.0	0.05	1.0	1.3
[34]						GWh_{el}/kt_{H_2}
Liquefied CO_2 Storage	1.0	1.0	1.0	0.0	1.0	0.105
[36]						GWh_{el}/kt_{CO_2}
Liquefied CH_4 Storage	1.0	1.0	1.0	0.0	1.0	
	-	-	-	-	-	
H_2O Storage	1.0	1.0	1.0	0.0	1.0	0.00036
[37]						GWh_{el}/kt_{H_2O}

Table 8: Technical parameters used to model storage nodes. The η^S corresponds to the self discharge rate, η^+ the charge efficiency, η^- the discharge efficiency, σ the minimum inventory level, ρ the maximum discharge-to-charge ratio and ϕ the conversion factor.

	ϕ_1	ϕ_2	ϕ_3	ϕ_4	μ	$\Delta_{+,-}$
HVDC Interconnection	0.9499					
[38, 39]	-					
Electrolysis	50.6	9.0	8.0		0.05	1.0
[40]	GWh_{el}/kt_{H_2}	kt_{H_2O}/kt_{H_2}	kt_{O_2}/kt_{H_2}		-	-/h
Methanation	0.5	2.75	2.25	0,1345	1.0	0.0
[40, 41]	kt_{H_2}/kt_{CH_4}	kt_{CO_2}/kt_{CH_4}	kt_{H_2O}/kt_{CH_4}	GWh_{heat}/GWh_{CH_4}	-	-/h
Desalination	0.004				1.0	0.0
[42]	GWh_{el}/kt_{H_2O}				-	-/h
Direct Air Capture	0.15	5.0	1.46	0.2	1.0	0.0
[31]	GWh_{el}/kt_{CO_2}	kt_{H_2O}/kt_{CO_2}	GWh_{heat}/kt_{CO_2}	GWh_{heat}/kt_{CO_2}	-	-/h
Post Combustion Carbon Capture	0.4125				0.0	1.0
[31]	GWh_{el}/kt_{CO_2}				-	-/h
CH_4 Liquefaction	0.616				0.0	1.0
[43]	GWh_{el}/kt_{LCH_4}				-	-/h
LCH_4 Carriers	0.994					
[44]	-					
LCH_4 Regasification	0.98					
[43]	-					
CO_2 Liquefaction	0.014	.99			0.0	1.0
[31]	GWh_{el}/kt_{LCO_2}				-	-/h
LCO_2 Carriers	0.99	0,0000625				
[31]	-	$(GWh/h)/kt_{CO_2}$				
LCO_2 Regasification	0.98					
[31]	-					
Pipe CO_2	0.00002					
[31]	$GWh/kt_{CO_2}/h$					

Table 9: Technical parameters used to model conversion nodes. The ϕ_i represents the conversion factors, μ the minimum operating level , $\Delta_{+,-}$ the maximum ramp-up/ramp-down rate.

	CAPEX	FOM	VOM	Lifetime	Contingency
Solar Photovoltaic Panels	380.0	7.25	0.0	25.0	0.1
[45]	M€/GW_{el}	M€/GW_{el}-yr	M€/GWh_{el}	yr	-
Wind Turbines	1040.0	12.6	0.00135	30.0	0.1
[46]	M€/GW_{el}	M€/GW_{el}-yr	M€/GWh_{el}	yr	-
HVDC Interconnection	480.0	7.1	0.0	40.0	0.3
[47, 48]	M€/GW_{el}	M€/GW_{el}-yr	M€/GWh_{el}	yr	-
Electrolysis	600.0	30.0	0.0	15.0	0.3
[49]	M€/GW_{el}	M€/GW_{el}-yr	M€/GWh_{el}	yr	-
Methanation	300.0	29.4	0.0	20.0	0.3
[40, 50]	M€/GW_{CH_4} (HHV)	M€/GW_{CH_4}-yr (HHV)	M€/GWh_{CH_4} (HHV)	yr	-
Desalination	28.08	0.0	0.000315	20.0	0.1
[51]	M€/(kt_{H_2O}/h)	M€/(kt_{H_2O}/h)-yr	M€/kt_{H_2O}	yr	-
Direct Air Capture	6000.0	300.0	0.0	20.0	0.3
[31]	M€/(kt_{CO_2}/h)	M€/(kt_{CO_2}/h)-yr	M€/kt_{CO_2}	yr	-
Post Combustion Carbon Capture	3150.0	0.0	0.0	20.0	0.3
[31]	M€/(kt_{CO_2}/h)	M€/(kt_{CO_2}/h)-yr	M€/kt_{CO_2}	yr	-
CH_4 Liquefaction	5913.0	147.825	0.0	30.0	0.1
[52]	M€/(kt_{LCH_4}/h)	M€/(kt_{LCH_4}/h)-yr	M€/kt_{LCH_4}	yr	-
LCH_4 Carriers	2.537	0.12685	0.0	30.0	0.1
[53]	M€/kt_{LCH_4}	M€/kt_{LCH_4}-yr	M€/kt_{LCH_4}	yr	-
LCH_4 Regasification	1248.3	24.97	0.0	30.0	0.1
[54]	M€/(kt_{CH_4}/h)	M€/(kt_{CH_4}/h)-yr	M€/kt_{CH_4}	yr	-
CO_2 Liquefaction	55.8	2.79	0.0	30.0	0.1
[31]	M€/(kt_{LCO_2}/h)	M€/(kt_{LCO_2}/h)-yr	M€/kt_{LCO_2}	yr	-
LCO_2 Carriers	5	0.0	0.0	40.0	0.1
[31]	M€/kt_{LCO_2}	M€/kt_{LCO_2}-yr	M€/kt_{LCO_2}	yr	-
LCO_2 Regasification	25.1	1.25	0.0	30.0	0.1
[32]	M€/(kt_{CO_2}/h)	M€/(kt_{CO_2}/h)-yr	M€/kt_{CO_2}	yr	-
Pipe CO_2	2.3	20.0	0.0	40.0	0.1
[31]	M€/kt_{CO_2}/km	M€/kt_{CO_2}-yr	M€/kt_{CO_2}	yr	-

Table 10: Economic parameters used to model conversion nodes (2030 estimates).

5 Comparative Analysis of Hydrogen-Derived Energy Carriers

5.1 The Question

This chapter addresses **RQ2**: *How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?*

In particular, the focus here is on the export commodity set of the taxonomy. Earlier RREH studies concentrated on methane (CH_4) as the primary synthetic fuel. However, other hydrogen-derived carriers, such as ammonia (NH_3), hydrogen (H_2), and methanol (CH_3OH), present distinct techno-economic properties. Understanding their relative performance is crucial for identifying the most promising export pathways.

5.2 The Idea

The central idea of this study is to extend the work of Berger et al. [Ber+21], which evaluated an RREH exporting methane from the Algerian Sahara to Belgium. While methane offers drop-in compatibility with existing infrastructure, other molecules can have different advantages.

For example, ammonia, hydrogen, and methanol may provide more efficient and cost-effective alternatives. Each export commodity implies a different hub configuration, with a distinct technological graph, conversion efficiencies, and transport requirements. By applying a consistent modeling and optimization framework across all cases, we can directly compare their production costs and energy efficiencies.

5.3 Contributions of the Paper

The contributions of the paper, published in the ECOS 2024 conference and titled *Ammonia, Methane, Hydrogen and Methanol Produced in Remote Renewable Energy Hubs: a Comparative Quantitative Analysis*, can be summarized as follows:

- Modeled four entire supply chains of RREHs for the export of H_2, NH_3, CH_3OH and, CH_4.
- Analyzed the cost and efficiency for each exported e-fuel.

5.4 Author's Contribution

I proposed the original idea of the paper and co-wrote it with Antoine Larbanois. Antoine Larbanois implemented the software underlying the results during his Master's thesis, under my supervision and that of Prof. Ernst in the lab. The work is based on feedback from Professor Ernst and other collaborators. The article was presented at the ECOS 2024 conference.

5.5 Integration within the Thesis

This paper constitutes the third contribution to **Part II – Novel RREH Designs**. It expands the RREH concept by broadening the export set possibilities and analyzing the techno-economic feasibility of each selected e-fuel.

Ammonia, Methane, Hydrogen and Methanol Produced in Remote Renewable Energy Hubs: a Comparative Quantitative Analysis

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Abstract

Remote renewable energy hubs (RREHs) for synthetic fuel production are engineering systems harvesting renewable energy where it is particularly abundant. They produce transportable synthetic fuels for export to distant load centers. This article aims to evaluate the production costs of different energy carriers, and includes a discussion on advantages and disadvantages in terms of technical performance. To do so, we extend the study of Berger et al. [1] which focuses on methane (CH_4) as energy carrier and introduce three new carriers: ammonia (NH_3), hydrogen (H_2) and methanol (CH_3OH). The four different RREHs are located in the Algerian Sahara desert and must serve to the load center, Belgium, a constant electro-fuel demand of 10 TWh per year. The modelling and optimisation of these systems are performed using the modelling language GBOML (Graph-Based Optimisation Modelling Language). Our findings reveal that the three new RREHs, each with its respective carrier (ammonia, hydrogen, and methanol), are all more cost-effective than the methane-based system. Ammonia demonstrates the most favourable cost-to-energy exported ratio.

Keywords: Remote Renewable Energy Hub, Power-to-X, Energy Systems Optimisation, Synthetic Fuel

1. Introduction

To decarbonise its energy infrastructure, Europe must harness substantial quantities of renewable energy (RE) sources. Nevertheless, several European nations are struggling with constraints related to the exploitation of locally available RE resources, posing a challenge in meeting the continent's energy demands. These limitations are stemming from a confluence of factors, including spatial constraints for RE infrastructure deployment and low-quality RE resources, especially in countries like Belgium which are densely populated [2].

The Remote Renewable Energy Hub (RREH) concept has emerged as a compelling solution in response to these constraints. Situated in regions far away from major population centres, RREHs harness the benefits of abundant and cost-effective RE sources, thereby mitigating the shortfall in local renewable resources within Europe. These energy production systems convert substantial amounts of electricity from remote renewable resources into high-energy-density molecules, which can be transported to urban load centres. These molecules can for example serve as crucial raw materials for industrial sectors or function as dispatchable sources of electricity generation.

Although there are many open research questions related to these hubs [1, 3, 4, 5], a predominant question concerns the types of energy-rich molecules that should preferably be synthesized in those. As a step to answer this question, we conduct a comparison between the methane-based system introduced by Berger et al. [1] and three new energy carriers: ammonia (NH_3), hydrogen (H_2) and methanol (CH_3OH), with the aim of identifying a more cost-effective synthetic fuel supply chain. According to Berger et al. [1], the methane's results showed a cost of approximately 150€/MWh (HHV) with costs estimated at 2030 for a system delivering 10 TWh of e-gas annually.

Our findings reveal that the three new RREHs, each with its respective carrier (ammonia, hydrogen, and methanol), are all more cost-effective than the methane-based system. Ammonia demonstrates the most favourable cost-to-energy exported ratio at 107€/MWh (HHV). This arises from its superior efficiency throughout the studied supply chain. The findings demonstrate that it is less expensive to combine

*These authors contributed equally to this work.

hydrogen with nitrogen taken from the air using an air separation unit system, rather than using carbon dioxide captured by a direct air capture device.

This article is organized as follows: Section 2 introduces the case studies and the optimization framework, Section 3 details the results. Lastly, Section 4 serves as the conclusion.

2. Case studies

In this section, we give a detailed overview of the energy systems that are compared in this case study. We start by detailing the characteristics of the original RREH designed in [1], whose exported energy carrier is methane. Then, using this case as a reference, we detail the three other scenarios. For better transparency and comparability, we follow by integrating these four scenarios in the framework proposed by Dachet et al. [6]. Finally, we give a brief overview of the optimisation framework that was used to derive the results presented in Section 3.

2.1. RREH in Algeria

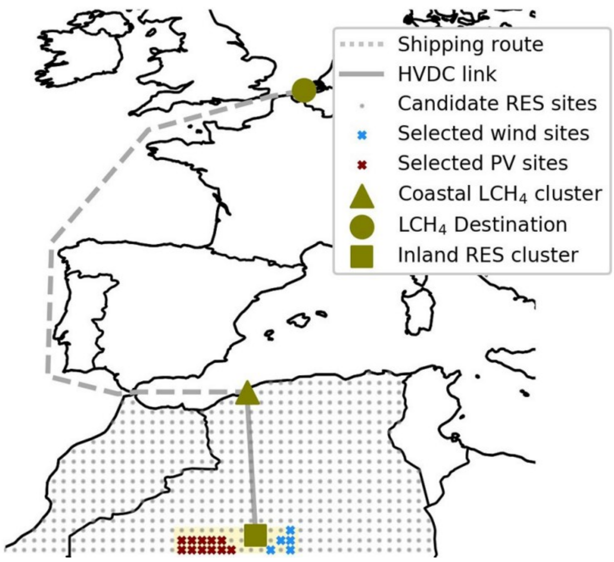

Figure 1: The configuration of the RREH, depicted in this picture sourced from [1],

consists of three regions: firstly, the Algerian inland where renewable electricity is produced, secondly, the Algerian coast where the electricity is converted into e-fuel, and finally, Belgium where the e-fuel is delivered.

In this article, the remote hub system configuration is formed by three distinct geographical areas as show in Figure 1. The Algerian inland is used for harnessing the abundant renewable resource reservoirs through the utilization of photovoltaic panels and wind turbines. The electricity generated is then channelled with an HVDC interconnection to the coastal region of Algeria, to be converted through different technological processes into e-fuels. In each RREH studied, storage units are used to provide flexibility between processes. In particular through the use of lithium-ion batteries, gaseous hydrogen tanks as well as tanks of different commodities. Subsequently, the resultant e-fuels are shipped to the load centre. During maritime transport, each energy carrier is considered both as fuel and as a cargo. The load center's demand remains consistent across all the studied systems: consistently consuming 10 TWh (HHV) of e-fuel each year.

2.2. Reference scenario: RREH for methane production

In this RREH, methane is synthesized by combining hydrogen with carbon dioxide harvested using Direct Air Capture technologies (DAC).

These DAC units operate according to the process proposed by Keith et al. [7]. This process consists of two interconnected chemical loops. In the first loop, CO_2 from the atmosphere is captured in contactors using an aqueous solution to form dissolved compounds. In the second loop, these compounds then react with Ca_{2+} to produce $CaCO_3$. The latter is calcined to release CO_2 and CaO. CaO is then hydrated to produce $Ca(OH)_2$, which regenerates Ca_{2+} by dissolving $Ca(OH)_2$. Calcination is carried out by burning hydrogen (originally, the fuel is methane) produced by the electrolyzers. Moreover, an electricity consumption is needed to powers fans that drive air through the contactors, pumps maintaining the flow of the aqueous solution, and compressors compressing the CO_2 flow to 20 bars. Additionally, the unit consumes freshwater to create the aqueous solutions, counteract natural evaporation in the contactors, and produce steam for the hydration of CaO.

Hydrogen is produced using proton exchange membrane (PEM) electrolyzers [8] (which also produce pure oxygen). These units can be supplied with intermittent electricity without any power ramp-up constraints. Furthermore, they are supplied with desalinated seawater, coming from reverse osmosis units to produce freshwater [9]. This technology uses a porous membrane to filter seawater, creating a pressure difference that allows the recovery of freshwater on the other side of the membrane. Electricity is needed to pump seawater and drive the fresh water.

The combination of hydrogen and carbon dioxide takes place in a methanation unit following an exothermic reaction, generating both methane and water vapor. Furthermore, it is considered that the production of synthetic methane can be flexible, without any power ramp-up constraints. However a minimum operating capacity of 40% of its nominal capacity is assumed [10]. Methane production directly feeds into a liquefaction unit, which increases the volumetric density of the e-fuel for maritime transportation. In addition to a need for methane, this unit is powered by electricity. The technology uses compressors and pumps to gradually compress and cool the methane flow, which is then expanded and transformed into liquid through the Joule-Thomson effect. Power ramp-up constraints are taken into account to ensure uninterrupted operation. Once delivered to Belgium, the methane undergoes regasification where the heat required for the phase change comes from the combustion of a portion of the methane (2%) [11].

All the mentioned technologies are interconnected, and these connections are symbolized by various commodities, including electricity, hydrogen, water, carbon dioxide, and methane. Figure 2 depicts a graphical representation of the interconnections and the technologies involved in the RREH's methane production process.

2.3. *RREH for ammonia, hydrogen and methanol production*

In the ammonia RREH, the hydrogen produced by electrolyzers is associated with pure nitrogen. For this purpose, an air separation unit is used to separate ambient air into nitrogen, oxygen, and argon through cryogenic distillation [12]. The unit relies on electricity to operate its pumps and compressors. Furthermore, power ramp-up constraints are used to force the unit to operate continuously. The Haber-Bosch process is used to synthesize ammonia (in liquid form) by combining nitrogen and hydrogen under high pressure and high temperature using a catalyst. The existence of a "Hot standby" mode which allows maintaining the reactor at an optimal temperature when its supply is insufficient induces a minimum operating threshold of 20% [12], without power ramp-up constraints. During delivery in Belgium, ammonia also undergoes regasification with an energy loss of approximately 2% of the energy content (same assumption as methane).

In the hydrogen RREH, hydrogen is not associated with any other molecule. During its production via electrolyzers, hydrogen is directly liquefied and then transported by sea. The liquefaction unit operates continuously and the amount of electrical energy required to liquefy 1 kg of hydrogen is estimated at 12 kWh [13], resulting in an energy loss of approximately 30%. Hydrogen undergoes regasification in Belgium, following the same process as previous e-fuel. However, no energy loss is assumed during this process [13].

Finally, the methanol model is quite similar to the methane model (described in Subsection 2.2), with the difference that it does not require liquefaction or regasification units since methanol is liquid at the ambient temperature. The process of converting carbon dioxide and hydrogen into methanol is an exothermic reaction that occurs at a temperature of approximately 250°C. Additionally, methanol synthesis requires steam at 10 bars and heated to 184°C [12]. This steam is modeled as a water consumption (water production at the reactor outlet deducted) and a quantity of burned hydrogen. In addition, electricity is necessary to operate auxiliary equipment Furthermore, it is estimated that the synthesis unit has also a "Hot standby" mode that allows maintaining the reactor at the right temperature and pressure conditions. This sets a minimum operating constraint at 10% [12] and allows quick power variations with constraints.

In Figure 2, you can find representations of all technologies and the connections that link them across the various RREHs.

2.4. *Inclusion in the RREH taxonomy*

To improve the understanding of the key discrepancies between hubs, an RREH can be categorized employing the taxonomy detailed in Dachet et al. [6]. This taxonomy is instantiated across the four hubs developed in this study. It allows to characterize an RREH with:

- $\mathcal{L}$: A set of locations associated with the technologies in the hub.
- $\mathcal{G}$: A graph formed by technologies and commodity flows. These technologies are situated in locations depicted in $\mathcal{L}$.
- $\mathcal{C}$: Denotes the set of exchanged and produced commodities within the graph.
- $\mathcal{I}$: The set of imported commodities in the hub.
- $\mathcal{E}$: The set of exported commodities to the load center.
- $\mathcal{B}$: The set of byproducts commodities. These byproducts are commodities output by a technology that are not fully exploited by another technology - they could be however partially exploited.

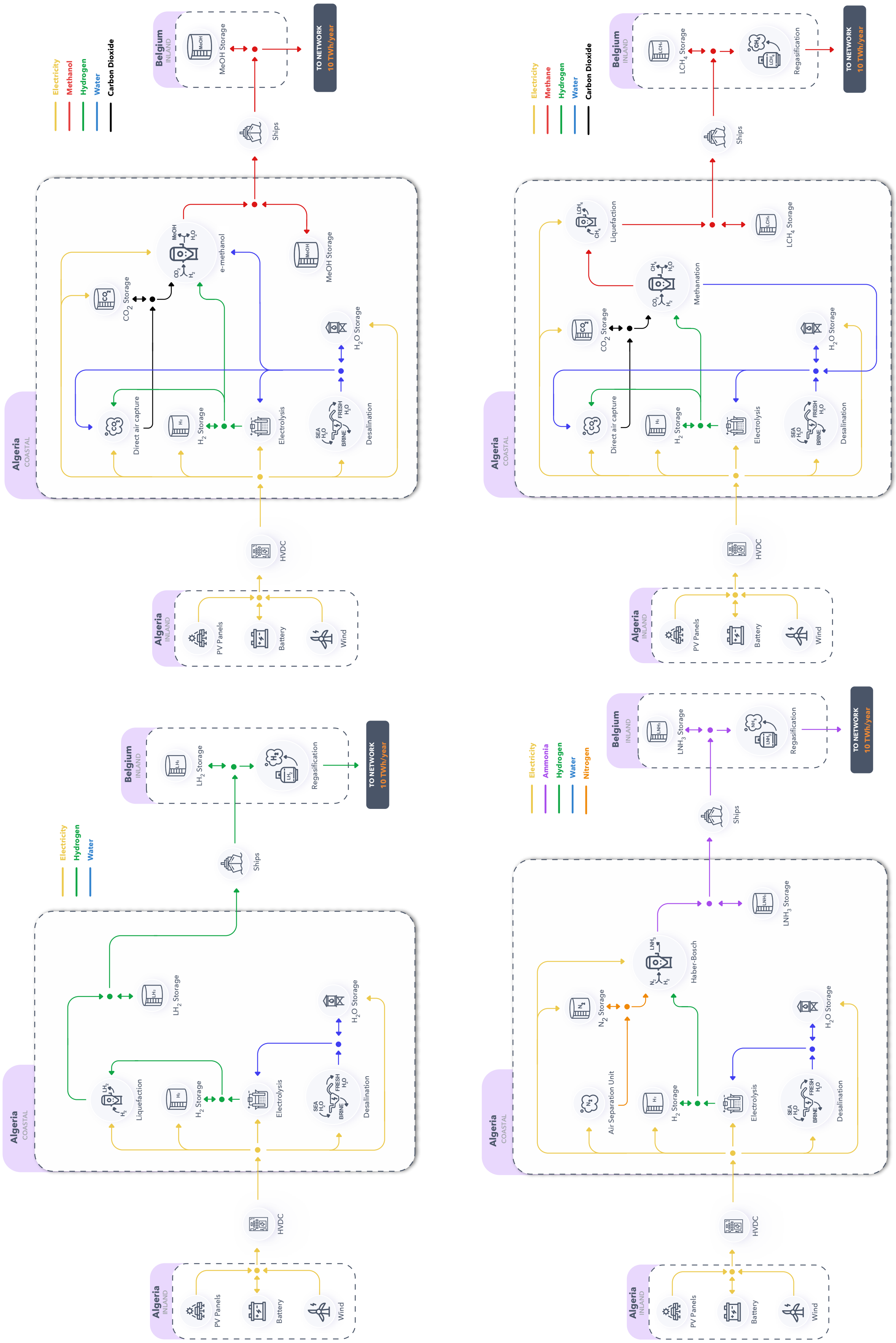

Figure 2: Graph illustrating the 4 RREHs for the 4 potential energy carrier candidates. Each technology is depicted as a node, and each connection is denoted by a hyper-edge.

- O: The set of locally exploited opportunities. These locally exploited opportunities are commodities that supply a local demand (different than the load center).

In order to enhance the readability of the sets describing the hubs, some notational liberties have been taken compared to the taxonomy of Dachet et al. [6]. The sets are all listed in Table 1.

As depicted in Table 1, the sets characterizing the hubs share significant similarities, even if they relate to different export commodities. Nevertheless, technologies such as DAC and ASU introduce new flows that generate different exchanged commodities than the exported product, such as nitrogen or carbon dioxide. Moreover, it is worth noticing that ASU also enables the production of an additional byproduct, namely argon.

In addition, this taxonomy highlights distinct commodities across the different RREHs. An example of common commodity across all the hubs is the water produced by the desalination units. One could integrate a demand of water close to the hub. This production of drinking water would extend the set of exploited local opportunities. Besides, it may help to face water scarcity in the phase of changing climate patterns and population growth.

2.5. Optimising the system with GBOML

Following the optimisation framework introduced by Berger et al. [1], the studied energy systems are represented in a hyper-graph format. Within this format, interconnected nodes refer to subsystems, such as different technologies, facilities, or processes.

Each node represents an optimization sub-problem, where optimisation procedures are executed to determine the optimal values of capital expenditure (capex) and operating expenditure (opex) parameters for the various technologies. This optimisation process is conducted while meeting the energy demand from the load center.

Nodes are defined by internal variables (such as capacities), external variables (such as commodity production), parameters (such as capex/opex), by constraints and objective functions. The connections between these nodes are established through hyper-edges, which represent flows of commodities. They impose conservation constraints on each commodity.

Furthermore, the models are constructed using the Graph-Based Optimization Modeling Language (GBOML), a language specifically designed for modeling the optimization of multi-energy systems based on graphs, as introduced in Miftari et al. [14].

The global parameters used for modelling were retained from the methane-based model to maintain a comparable foundation with the new carriers. These parameters have a capital cost rate of 7% and a temporal horizon of 5-years, at hourly resolution. Moreover, different economic and technical parameters (2030 estimate) used for node modelling are gathered in Table A.5 to Table E.9, see appendices of this document.

3. Results and discussions

In this section, we present the costs associated with each vector and we perform a comparative analysis in terms of costs, installed capacities, and overall efficiencies of the vectors. Then, we discuss the results obltained.

3.1. Results and comparative analysis of e-fuels

The findings indicate that producing 10 TWh annually of synthetic methane from renewable sources in the Algerian desert results in an overall cost of 7.5 billion euros, equivalent to a rate of 150 €/MWh. Shifting the production focus from methane to ammonia brings the total cost down to 5.4 billion euros, corresponding to 107 €/MWh. For the cases of hydrogen and methanol, production costs are 6 billion euros and 7.2 billion euros, respectively, translating to 120 €/MWh and 143 €/MWh.

Figure 3 depict how technologies contribute to the total production cost of each e-fuel. Across all models, wind turbines stand out as the most significant cost component, accounting for approximately 30% of the total costs, closely followed by electrolyzers with a contribution of around 20%. Overall, technologies related to electricity production, transmission, and storage represent the highest costs, ranging between 55% and 60%.

The results in Table 2 illustrate the costs of each fuel per phase. Notably, each gaseous molecule has a lower cost than a gaseous phase due to the efficiency of the regasification unit and its cost to implement. These findings highlight that among the synthetic fuels considered, ammonia is the most economical option, with a cost of 107€/MWh. After that is hydrogen at 121€/MWh, followed by methanol and methane at 143€/MWh and 150€/MWh, respectively.

The different installed capacities are depicted in Figure 4. The model employing methane as the carrier gas requires the highest installed RE capacity at 8.57 GW for photovoltaic panels and wind turbines. In comparaison, the methanol model requires 8.25 GW, the ammonia-based model requires 6.26 GW, and the hydrogen model necessitates 6.94 GW. Additionally, the

RREH	Methane	Methanol	Hydrogen	Ammonia
$\mathcal{L}$	{Sahara desert, Algerian coast}			
$\mathcal{G}$	All Technologies and commodity flows are represented in Figure 2			
$\mathcal{C}$	{Electricity, H_2, H_2O, CO_2, CH_4, O_2, heat}	{Electricity, H_2, H_2O, CO_2, CH_3OH, O_2, heat}	{Electricity, H_2, H_2O, O_2, heat}	{Electricity, H_2, H_2O, N_2, NH_3, O_2, heat, Ar}
$\mathcal{I}$	{air, sea water}			
$\mathcal{E}$	{CH_4}	{CH_3OH}	{H_2}	{NH_3}
$\mathcal{B}$	{heat, O_2}			{heat, O_2, Ar }
$\mathcal{O}$	$\emptyset$			

Table 1: Table characterizing the different RREHs according to the taxonomy presented by Dachet et al. [6]

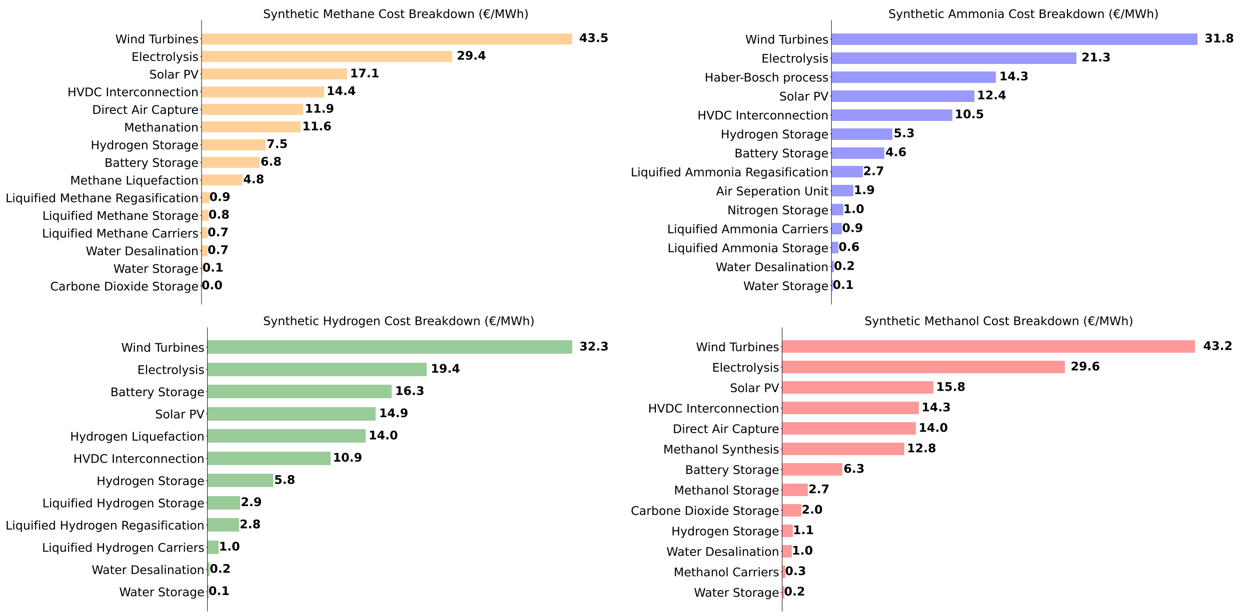

Figure 3: Contributions to the cost of each e-fuel synthesized in an RREH. All contributions roughly sum to 150€/MWh for methane, 107€/MWh for ammonia, 121€/MWh for hydrogen and 143€/MWh for methanol.

	NH_3	CH_3OH	H_2	CH_4
Liquid	103	143	118	146
Gazeous	107	-	121	150

Table 2: Costs in euro per MWh per e-fuels and phase produced in RREHs.

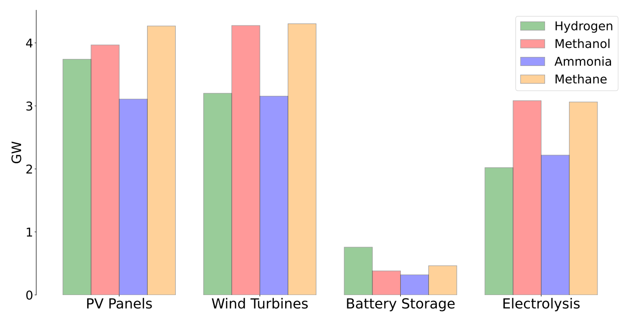

Figure 4: GW-scale capacities from RREHs to meet an annual demand of 10 TWh of e-fuels at the load centre.

methane and methanol models require 3.06 and 3.08 GW of electrolysers, while the ammonia and hydrogen models require 2.22 GW and 2.0 GW, respectively. It is worth mentioning that the power requirements can reflect the overall model efficiency, i.e., the ratio between renewable electricity production and effective e-fuel production (see Table 4). The overall efficiency is 44% for methane, 43% for methanol, 60% for ammonia, and 55% for hydrogen. Most of the energy losses primarily stem from electrolyzers, where efficiency is assumed to be around 75% [12], and synthesis units. Specifically, the ammonia synthesis unit achieves an efficiency of 82% [12], while that of methanol and methane falls below 80% [12, 10]. Hydrogen liquefaction results in a 30% [13] loss but does not require the use of additional equipment such as DAC (Direct Air Capture) device or an ASU (Air Separation Unit) device. Concerning battery capacities, the hydrogen model has the highest requirement at 0.76 GW, while the ammonia and methanol models are around 0.3 GW, and the methane model requires 0.46 GW of power. It should be noted that the power required for the battery is higher with the hydrogen model. This is due to the significant electricity demand needed for the liquefaction process, which must receive a continuous power supply even when electricity production is intermittent.

	NH_3	CH_3OH	H_2	CH_4
TWh	0.35	0.07	0.39	0.50
Km^3	224.06	46.84	244.92	319.80

Table 3: Storage capacities of gaseous hydrogen at 200 bars and ambient temperature from RREHs for fulfilling an annual 10 TWh e-fuel demand at the load center

Furthermore, it is possible to compare the ability of energy models to accommodate power fluctuations arising from intermittent sources by examining the hydrogen storage requirements (as well as batteries), as presented in Table 3, with storage expressed in TWh (HHV) and also in m^3 considering a density of 40 g/l [12]. These compressed gaseous hydrogen storage facilities at 200 bars and room temperature introduce flexibility between electrolyser output and synthesis units. The demand for compressed hydrogen storage is more substantial for the methane model, requiring over 300,000 m^3, while the methanol model necessitates less than 50,000 m^3. The ammonia and hydrogen models, on the other hand, hover around 230,000 m^3. Differences in the storage of gaseous hydrogen or in batteries result from the processes attributes as well as commodities requirements (see Table A.5). Flexibility parameters are determined by ramp up/down constraints as well as minimum operating levels. Some processes are assumed to operate in a constant mode (Desalination units, DAC, ASU, and Liquefaction units), while others are considered flexible (Electrolysis and Synthesis units).

3.2. Discussion

This study has extended the one conducted by Berger et al. [1] by examining alternative energy carriers. It has demonstrated that the three new RREHs, each with its respective vector (ammonia, hydrogen, and methanol), are all more cost-effective than the methane-based system, with cost savings of 28%, 20%, and 5%, respectively. It is established that the RREH system utilising ammonia is the most economical system. Synthesizing ammonia by combining hydrogen with nitrogen, which makes up over 80% of air composition, outperforms the alternative of pairing hydrogen with carbon dioxide due to its lower concentration in the atmosphere (0.04%). This contrast is exemplified in Figure 3, wherein technologies related to the ASU and nitrogen storage account for a mere 2.7%, whereas DAC and carbon storage in methane and methanol models contribute to around 10% of the overall system cost.

	NH_3	CH_3OH	H_2	CH_4
%	60	43	55	44

Table 4: Overall efficiency for each RREH which represents the ratio between renewable electricity production and effective e-fuel production.

The hydrogen-based system, while avoiding the need for the aforementioned nitrogen and carbon technologies, necessitates a liquefaction unit resulting in a 30% energy loss. The enhanced efficiency inherent in the RREH ammonia system translates into a reduced requirement for installed electric capacity — an imperative aspect given that higher capacity installations correspond to elevated costs, as illustrated in Figure 3.

By comparing the methane and methanol models, the latter stands out due to the absence of a liquefaction (and regasification) unit, especially considering that this unit operates continuously and compels methanation to operate the same way. This leads to greater storage capacities, as seen with Table 3. Furthermore, this requirement for liquefaction facilities translates into an increase in electricity production capacity. The findings shows an higher photovoltaic capacity for the methane production model compared to the methanol production model (see Figure 4).

Using technologies that can adapt to the intermittent characteristics of renewable energy sources, such as flexible liquefaction units, is essential to minimize storage requirements. Storing hydrogen in gaseous form presents a disadvantage due to its inherently low volumetric density. This characteristic could necessitate substantial storage volumes (depending on the demand from the load centre). Therefore increase the safety risk, particularly considering hydrogen's susceptibility to leaks and high flammability owing to its extensive flammability range and low activation energy [15].

4. Conclusion

In this article, we conducted a comparative study of four e-fuels in the context of RREH (Remote Renewable Energy Hub). We examined a specific case related to the production of these e-fuels in Algeria and their deliveries in Belgium. Our study was based on the modeling and optimization framework proposed by Berger et al. [1], who had previously studied the production cost of synthetic methane, with an estimated cost of approximately 150 €/MWh (HHV) for the year 2030.

We developed three new RREHs, each using a different e-fuel: ammonia, hydrogen, and methanol. This comparative study focused on production costs throughout the supply chain, as well as the technical performance. The new models all succeeded in producing their e-fuels at lower costs, respectively 107 €/MWh, 121 €/MWh, and 143 €/MWh (HHV).

The export of ammonia helped reduce costs due to its superior efficiency. On one side, by avoiding hydrogen liquefaction, and on the other side, by combining hydrogen with nitrogen rather than carbon dioxide (captured from the air). This improved efficiency resulted in a lower installed capacity of RE (PV and wind turbines). To meet an annual demand of 10 TWh of e-fuel (HHV), approximately 6 GW of RE are needed for ammonia and 9 GW for methane (model which requires the most RE).

We also assessed the models' ability to handle fluctuations in intermittent production means by analyzing storage capacities, both in lithium-ion batteries and compressed hydrogen storage. The results have shown significant disparities between the models storage needs, with differences of up to six times for compressed hydrogen capacities and approximately three times for batteries.

Moreover, these novel e-fuels, investigated within the framework of RREH, continue to be costlier than their fossil-based counterparts. Nevertheless, considering past energy crises, there is no assurance that this cost advantage will persist over the long term.

Finally, we did not consider structural or parametric uncertainty, nor did we seek to identify near-optimal conditions that could better satisfy other criteria, e.g., environmental, than purely economic ones. Therefore, sensitivity analysis [16] and near-optimal space exploration techniques [17] could be applied in future work to potentially provide additional information to this study.

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Glossary

- ASU : Air Separation Unit
- CAPEX : Capital Expenditure
- DAC : Direct Air Capture
- GBOML : Graph-Based Optimization Modeling Language
- HHV : Higher Heating Value
- HVDC : High Voltage Direct Current
- OPEX : OPerating EXpenditure
- PEM : Proton Exchange Membrane
- PV : Photovoltaic
- RE : Renewable Energy
- RREH : Remote Renewable Energy Hub

Competing interests

The authors declare no competing interests.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the author(s) used ChatGPT in order to correct the readiness, grammar and spelling of the writing. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

Code and Data Availability

We would like to emphasize that we open-sourced the code and data used to produce this work https://gitlab.uliege.be/smart_grids/public/gboml/-/tree/master/examples/

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Appendix A. Technical parameters used to model conversion nodes

	Conversion factor	Minimum level production	Ramp up&down
HVDC Interconnection [18]	0.9499	-	-
Electrolysis [10]	50.6 GWh_{el}/kt_{H_2} 9.0 kt_{H_2O}/kt_{H_2}	0.05	1.0 /h
Methanation [10] [19]	0.5 kt_{H_2}/kt_{CH_4} 2.75 kt_{CO_2}/kt_{CH_4} 2.25 kt_{H_20}/kt_{CH_4}	0.4	1.0 /h
Haber-Bosch [12]	0.32 GWh_{el}/kt_{NH_3} 0.18 kt_{H_2}/kt_{NH_3} 0.84 kt_{N_2}/kt_{NH_3}	0.2	1.0 /h
e-CH_3OH [12]	0.1 GWh_{el}/kt_{CH_3OH} 0.209 kt_{H_2}/kt_{CH_3OH} 1.37 kt_{CO_2}/kt_{CH_3OH} 0.93 kt_{H_2O}/kt_{CH_3OH}	0.1	1.0 /h
Desalination [20]	0.004 GWh_{el}/kt_{H_2O}	1.0	0.0 /h
Direct Air Capture [7]	0.1091 GWh_{el}/kt_{CO_2} 0.0438 H_2/kt_{CO_2} 5.0 H_2O/kt_{CO_2}	1.0	0.0 /h
Air Separation Unit [21]	0.1081 GWh_{el}/kt_{N_2}	1.0	0.0 /h
CH_4 Liquefaction [22]	10.616 GWh_{el}/kt_{LCH_4}	1.0	0.0 /h
H_2 Liquefaction [23]	12 GWh_{el}/kt_{H_2}	1.0	0.0 /h
LCH_4 Carriers [24]	0.994	-	-
LH_2 Carriers [25]	0.945	-	-
LNH_3 Carriers [25]	0.994	-	-
CH_3OH Carriers [25]	0.993	-	-
LCH_4 Regasification [22]	0.98	-	-
LNH_3 Regasification Assumed	0.98	-	-
LH_2 Regasification [13]	1.0	-	-

Table A.5: Technical parameters used for modeling conversion nodes (2030 estimate)

Appendix B. Technical parameters used to model storage nodes

	Conversion Factor	Self-discharge Rate	Charge Efficiency	Discharge Efficiency	Discharge-to -charge ratio	Minimum inventory level
Battery Storage [26]	-	0.00004	0.959	0.959	1.0	0.0
H_2 Storage (200 bars) [26]	1.3 GWh_{el}/kt_{H_2}	1.0	1.0	1.0	1.0	0.05
Liquefied CO_2 Storage [27]	0.105 GWh_{el}/kt_{CO_2}	1.0	1.0	1.0	1.0	0.0
Liquefied CH_4 Storage Assumed	-	1.0	1.0	1.0	1.0	0.0
Liquefied NH_3 Storage [13]	-	0.00003	1.0	1.0	1.0	0.0
Liquefied H_2 Storage [28]	-	0.00008	1.0	1.0	1.0	0.0
CH_3OH Storage [26]	-	1.0	1.0	1.0	1.0	0.0
H_2O Storage [9]	0.00036 GWh_{el}/kt_{H_20}	1.0	1.0	1.0	1.0	0.0
N_2 Storage Assumed	0.1081 GWh_{el}/kt_{N_2}	1.0	1.0	1.0	1.0	0.0

Table B.6: Technical parameters used for modeling storage nodes (2030 estimate)

Appendix C. Economic parameters used to model conversion nodes

	CAPEX	FOM	VOM	Lifetime
Solar Photovoltaic Panels [29]	380.0 M€/GW_{el}	7.25 M€/$GW_{el} - yr$	0.0 M€/GWh	25.0 yr
Wind Turbines [29]	1040.0 M€/GW_{el}	12.6 M€/$GW_{el} - yr$	0.00135 M€/GWh	30.0 yr
HVDC Interconnection [30]	480.0 M€/GW_{el}	7.1 M€/$GW_{el} - yr$	0.0 M€/GWh	40.0 yr
Electrolysis [12]	600.0 M€/GW_{el}	30 M€/$GW_{el} - yr$	0.0 M€/GWh	15.0 yr
Methanation [28]	735.0 M€/GW_{CH_4}	29.4 M€/$GW_{CH_4} - yr$	0.0 M€/GWh_{CH_4}	20.0 yr
Haber-Bosch [12]	6825.0 M€/kt_{NH_3}/h	204.75 M€/$kt_{NH_3}/h - yr$	0.000105 M€/kt_{NH3}	30.0 yr
e-CH_3OH [12]	57252.80 M€/kt_{CH_3OH}/h	158.31 M€/$kt_{CH_3OH}/h - yr$	0.0 M€/kt_{CH3OH}	30.0 yr
Desalination [31]	28.08 M€/kt_{H_2O}/h	0.0 M€/$kt_{H_20}/h - yr$	0.000315 M€/kt_{H2O}	20.0 yr
Direct Air Capture [7]	4801.4 M€/kt_{CO_2}/h	0.0 M€/$kt_{C0_2}/h - yr$	0.0207 M€/kt_{C02}	30.0 yr
Air Separation Unit [21]	850.0 M€/kt_{N_2}/h	50.0 M€/$kt_{N_2}/h - yr$	0.0 M€/kt_{N2}	30.0 yr
CH_4 Liquefaction [32]	5913.0 M€/kt_{LCH_4}/h	147.825 M€/$kt_{LCH_4}/h - yr$	0.0 M€/kt_{LCH4}	30.0 yr
H_2 Liquefaction [13]	45000.0 M€/kt_{LH_2}/h	1125.825 M€/$kt_{LH_2}/h - yr$	0.0 M€/kt_{LH2}	40.0 yr
LCH_4 Carriers [33]	2.537 M€/kt_{LCH_4}/h	0.12685 M€/$kt_{LCH_4}/h - yr$	0.0 M€/kt_{LCH4}	30.0 yr
LH_2 Carriers [25]	14.0 M€/kt_{LH_2}/h	0.07 M€/$kt_{LH_2}/h - yr$	0.0 M€/kt_{LH2}	30.0 yr
LNH_3 Carriers [25]	1.75 M€/kt_{LNH_3}/h	0.09 M€/$kt_{LNH_3}/h - yr$	0.0 M€/kt_{LNH3}	30.0 yr
CH_3OH Carriers [25]	0.69 M€/kt_{CH_3OH}/h	0.04 M€/$kt_{CH_3OH}/h - yr$	0.0 M€/kt_{CH3OH}	30.0 yr
LCH_4 Regasification [11]	1248.3 M€/kt_{LCH_4}/h	29.97 M€/$kt_{LCH_4}/h - yr$	0.0 M€/kt_{LCH4}	30.0 yr
LNH_3 Regasification Assumed	1248.3 M€/kt_{LNH_3}/h	29.97 M€/$kt_{LNH_3}/h - yr$	0.0 M€/kt_{LNH3}	30.0 yr
LH_2 Regasification [13]	9100.0 M€/kt_{LH_2}/h	27.8 M€/$kt_{LH_2}/h - yr$	0.0 M€/kt_{LH2}	30.0 yr

Table C.7: Economical parameters used for modeling conversion nodes (2030 estimate)

Appendix D. Economic parameters used to model storage nodes (flow component)

	CAPEX	FOM	VOM	Lifetime
Battery Storage [26]	160.0 M€/GW	0.5 M€/GW-yr	0.0 M€/GWh	10.0 yr
Liquefied CO_2 Storage [27]	48.6 M€/(kt/h)	2.43 M€/(kt/h)-yr	0.0 M€/kt	30 yr
Liquefied NH_3 Storage [12]	0.10 M€/(kt/h)	0.001 M€/(kt/h)-yr	0.0 M€/kt	30 yr
CH_3OH Storage [26]	0.0625 M€/(kt/h)	0.0 M€/(kt/h)-yr	0.0 M€/kt	30 yr
H_2O Storage [9]	1.55923 M€/(kt/h)	0.0312 M€/(kt/h)-yr	0.0 M€/kt	30 yr

Table D.8: Economic parameters used to model storage nodes (flow component)

Appendix E. Economic parameters used to model storage nodes (stock component)

	CAPEX	FOM	VOM	Lifetime
Battery Storage [26]	142.0 M€/GWh	0.0 M€/GWh-yr	0.0018 M€/GWh	10.0 yr
H_2 Storage (200 bars) [26]	45.0 M€/kt	2.25 M€/kt-yr	0.0 M€/kt	30 yr
Liquefied CO_2 Storage [27]	1.35 M€/kt	0.0675 M€/kt-yr	0.0 M€/kt	30 yr
Liquefied CH_4 Storage [34]	2.641 M€/kt	0.05282 M€/kt-yr	0.0 M€/kt	30 yr
Liquefied NH_3 Storage [21]	0.867 M€/kt	0.01735 M€/kt-yr	0.0 M€/kt	30 yr
Liquefied H_2 Storage [13]	25.0 M€/kt	0.5 M€/kt-yr	0.0 M€/kt	30 yr
CH_3OH Storage [26]	2.778 M€/kt	0.0 M€/kt-yr	0.0 M€/kt	30 yr
H_2O Storage [9]	0.065 M€/kt	0.0013 M€/kt-yr	0.0 M€/kt	30 yr
N_2 Storage Assumed	45.0 M€/kt	2.25 M€/kt-yr	0.0 M€/kt	30 yr

Table E.9: Economic parameters used to model storage nodes (stock component)

6 Remote Renewable Energy Hubs in the High Sea

6.1 The Question

This chapter contributes to answering **RQ2:** *How can different RREH designs, including CO_2 valorization loops, choices of export commodity (H_2, NH_3, CH_3OH, CH_4), and high-seas battery hubs, be compared in terms of efficiency, cost, and feasibility?*

Here, we expand the design space of RREHs by introducing and analyzing a novel class of offshore designs, which both extends the range of possible locations for RREHs and changes the export commodity by using batteries as energy vectors.

6.2 The Idea

The concept of Remote Renewable Energy Hubs (RREHs) has so far mostly referred to onshore infrastructures, harvesting solar or wind power and converting it into synthetic fuels for export. This chapter explores a new class of hubs, *Remote Renewable Energy Hubs in the High Seas (REHS)*, that operate in far-offshore environments where wind resources are abundant and continuous.

In these remote marine areas, traditional means of energy conversion and transport such as high-voltage cables or Power-to-X technologies may be difficult to install or inefficient due to ocean depth, harsh conditions, and infrastructure costs. Instead, this chapter proposes the use of unmoored floating wind turbines (UFWTs) coupled with Lithium-ion NMC955 battery packs. These batteries serve as the energy vector: charged offshore, then transported to shore by vessels, where they are unloaded and replaced by empty packs.

In terms of the taxonomy proposed in Chapter 2, this new design modifies both the **export set** (charged batteries instead of fuels or electricity) and the **location type** (offshore instead of onshore). It challenges conventional assumptions about hub siting and vector choice, and opens new possibilities for sovereign access to energy in international waters.

6.3 Contributions of the Paper

The contributions of the submitted paper, titled *Remote Renewable Energy Hubs in the High Seas Using Batteries as Energy Vector*, can be summarized as follows:

- Proposes the novel concept of a **Remote Renewable Energy Hub in the High Seas** (REHS), where wind energy is harvested by unmoored floating turbines and exported using maritime battery logistics.
- Introduces a cost and performance assessment methodology of the REHS.
- Applies this framework to a parametric analysis with 2030 cost projections and evaluates performance across distances from 150 km to 400 km offshore.
- Highlights how REHS design shifts both the *export vector* and *location type* in the RREH taxonomy, further expanding the design space.

6.4 Author's Contribution

I developed the REHS concept together with my co-authors. I participated in the modeling and design of the system components, collaborated on the cost and performance estimation methodology, and co-wrote the article. Dr. Fonteneau and Prof. Ernst provided feedback.

6.5 Integration within the Thesis

This chapter is part of **Part II – Novel RREH Designs (RQ2)**. It contributes to expanding the taxonomy and techno-economic understanding of RREHs by introducing a completely new class of offshore hubs that use batteries instead of chemical energy vectors. The REHS represents a boundary-pushing case for decentralization and modular deployment of renewable energy systems.

Remote Renewable Energy Hubs in the High Seas Using Batteries as Energy Vector

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Abstract

In this paper, we propose a new Remote Renewable Energy Hub (RREH) concept for enabling the harvesting of renewable wind energy in the high seas. This new concept of RREH uses unmoored wind turbines for harvesting energy from the abundant far offshore wind resources and brings this energy back to the coast using Lithium-ion NMC955 batteries. We name this new concept Renewable Renewable Energy Hub in the High Seas, or REHS in short. The presentation of this concept comes with a methodology for assessing both the cost of the energy produced and the load factors of this REHS. The methodology is tested using parameter estimates for CAPEX and technical parameters associated with the different components of the whole supply chain estimated for 2030. Following this methodology, we obtain estimates of the cost of electricity originating from the REHS ranging from 160$/MWh to 204$/MWh depending on the distance from the coast, from 150 km to 400 km.

Keywords: Renewable energy, High seas, Remote renewable energy hub, Electricity, Wind power, Energy transition

1. Introduction

Global warming has emerged as a threat to our modern civilization as well as to biodiversity [1]. This climate change is mainly due to anthropogenic emissions of greenhouse gases in Earth's atmosphere [2]. Those emissions could significantly be reduced notably by using substitutes to fossil fuel combustion for energy purpose. In this context, transport and heating systems are in the process of being electrified and renewable energies, particularly solar and wind, are developing rapidly [3]. However, technologies for harvesting renewable energy come with their own set of issues. Among these issues, the low energy density of renewable energy sources necessitates the deployment of infrastructure over extensive areas. Public acceptance and land usage conflicts can limit their implementation in populated areas as well [4].

Issues linked to the exploitation of renewable energy sources onshore can be partly addressed by deploying floating wind turbines in the high seas where wind is abundant and more constant over time than onshore wind [5]. At an average wind velocity higher than inland, wind turbines could have a capacity factor reaching higher values than those usually encountered in current onshore wind farms [5]. High seas territories may thus offer promising red areas to harvest wind energy of higher quality than inland. Moreover, according to international laws [6], vessels from any country are free to pass through high seas, which means that any country with access to the sea could exploit renewable energy in remote offshore locations. This observation suggests that collecting energy in the high seas would allow countries to remain sovereign regarding their energy supply.

Producing electricity in the high seas nevertheless involves numerous technical constraints. Among them, the extreme depths in these areas imply that classical foundations of offshore wind turbines cannot be built. Unmoored Floating Wind Turbines (UFWT) and turbines equipped with suction anchors can address this issue. Moreover, installing energy production facilities in remote locations comes with the issue of energy transportation over long distances. This transport may be problematic, implying large investments and energy losses. In order to transport this produced energy, an alternative to electricity is the use of Power-to-X technologies [7, 8, 9]. Power-to-X technologies

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consist in producing a given fuel X, for example methane, thanks to electricity and different chemical and physical processes. The produced fuels with electricity are called e-fuels (for electrical fuels). These e-fuels offer several advantages among them: (i) they offer long-term storage possibilities (these fuels are easily storable in comparison with electricity), (ii) they can easily be transported (for example, methane transportation is a mature technology) and (iii) they can be considered as low-carbon fuels. For e-fuels to be considered low-carbon, they must be produced using low-carbon electricity sources, such as solar, wind, nuclear, or hydro power. The sourcing of CO2, which is necessary for some e-fuels, must also rely on this low-carbon electricity [10, 11]. Former research focused on producing energy in remote locations and transporting it with power-to-X technologies leading to the emergence of the concept of Remote Renewable Energy Hubs (RREH), a term first coined in [12].

We note that earlier to the apparition of the concept of RREH, researchers have focused on using long electrical lines/cables for transporting the renewable energy harvested in remote locations to the load. In this respect, it is worth mentioning the Desertec project that aims at importing high quality solar energy from North Africa to Europe [13]. Such projects led to the concept of Global Grid proposed by Chatzivasileiadis et al. [14], which is a globally interconnected electricity transmission network that allows to tackle renewable energy intermittency issues as well as to exploit high quality renewable energy resources. More details about the feasibility of the Global Grid are given by Yu et al. [15].

The specific characteristics of remote Renewable Energy Hubs in the high Seas (REHS) present challenges that make power-to-X technologies and transmission lines complex solutions for transferring energy to onshore locations [16]. These challenges arise due to a variety of factors unique to remote offshore locations. First, for power-to-X technologies, one should note that, even when deployed onshore, these technologies incur significant costs and result in energy losses exceeding 50% [11]. We expect those costs and losses to increase if these technologies are installed on offshore platforms. Indeed, regarding costs, we anticipate that adapting existing Power-to-X technologies for a high-sea environment would be expensive. Additionally, maintenance costs are likely to be significantly higher than for onshore installations. Furthermore, technical constraints imposed by the marine environment, such as those affecting pipes containing chemical components or electrolyzers, could reduce process efficiency. Second, using long transmission lines to transfer this energy to shore would also not be an effective solution. Indeed, unlike classical offshore wind turbines, REHS would be located at a distance of hundreds of kilometers from the coast. Ocean depth would make difficult and economically not interesting to connect with cables these wind turbines to continental electricity grids. Instead of using long transmission lines or power-to-X facilities, electrical energy produced by floating wind turbines could be stored in battery packs (e.g. a standard maritime container filled with batteries). These battery packs would be directly attached to the floating wind turbine. When fully charged, battery packs would be transferred to shore by a means of transport, such as a boat. These means of transportation would also bring back discharged batteries from shore to the floating wind turbines. Therefore, if we apply the taxonomy for characterizing RREH proposed by Dachet et al. [17] to the REHS, the import/export commodity would be uncharged and charged battery packs. We note that this taxonomy also associates a set of locations to a RREH. The type of locations for the hubs studied in this paper differ from those of other RREHs [12, 11] because the hub locations are offshore rather than onshore.

In this paper, we describe and analyze an REHS that allow to harvest wind energy in the high seas and bring this energy to shore by means of Lithium-ion NMC955 battery packs. Figure 1 represents the proposed REHS composed of the three main blocks: production, transportation and delivery. The rest of the paper is organized as follows. In Section 2, we describe the REHS, as well as the different components used in it and its characteristics. In Section 3, we introduce the methodology to estimate electricity cost and load factors related to this REHS. In Section 4, we present and discuss the electricity costs and load factors derived. Finally, Section 5 concludes the paper and provides future research directions.

2. Remote renewable energy hubs in the high seas

In this section, we describe the components, associated costs and energy losses of the proposed REHS based on 2030 cost and properties estimates for UFWT and batteries.

As illustrated in Figure 1, the REHS consists of three parts: production, transport, and delivery. The production hub harvests renewable energy in remote offshore locations, after which the energy can be transported to shore and finally delivered to the electrical network.

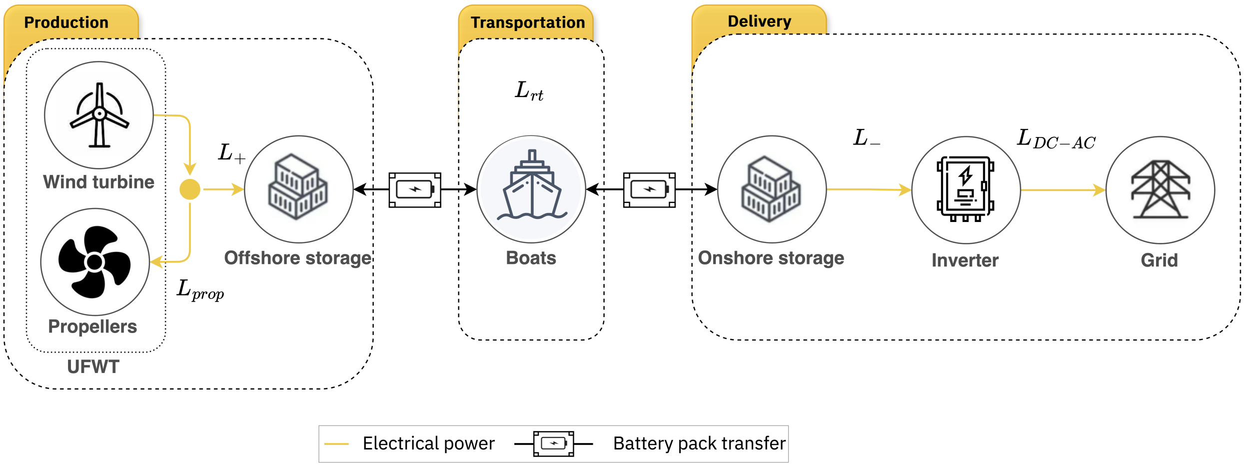

Figure 1: Representation of the components associated with a Remote Renewable Energy Hub in the High Seas, using batteries as the energy vector. The hub is subject to energy losses, which are detailed in Section 2. For example, the symbol L_{prop} denotes the energy consumption of the propellers of the UFWT.

In this proposed REHS, the production part consists of Unmoored Floating Wind Turbines (UFWT), which produce electrical energy. This energy is stored in battery packs located on the floating structure.

The transportation part involves a boat making round-trips between the production hub and the seaport. Initially, the boat departs from the seaport carrying uncharged batteries. The majority of its cargo consists of discharged batteries, with only a few charged batteries required for the journey to the production hub. At the production hub, the boat uses its cranes to exchange the uncharged batteries for charged batteries from the wind turbines. It then returns to the seaport with the charged batteries. Generally, the boat operates in cycles between the production hub and the seaport, transporting charged battery packs from the production hub and returning with discharged battery packs from the seaport in a continuous loop. At the seaport, cranes are again used to store the charged batteries onshore and replace them with discharged batteries. A cycle consists of bringing charged batteries to the coast and returning discharged batteries to the production hub.

The delivery part refers to the onshore destination where the battery packs are stored to supply electrical energy to the grid through an inverter. Eventually, the onshore charged batteries are discharged to inject electrical power into the grid. Figure 1 illustrates the organisation and components of this proposed REHS.

2.1. Components

Unmoored floating wind turbine

An unmoored floating wind turbine (UFWT) consists in a wind turbine mounted on a floating structure that ensures buoyancy balance and that is connected to propellers to provide stability. Figure 2 provides an illustration of an UFWT proposed by Raisanen et al. [18].

The propellers consume electricity and should be operated at a regime the maximizes the net power generation. In this respect, we refer to the work of Connolly and Crawford [19] that proposes a model of UFWT aiming at identifying the optimalregime of propellers. In the context of our REHS, the wind turbines are assumed to be equipped with battery packs in order to store electricity produced by the turbines. Battery packs would be attached to the emerged bottom of the floating structure in order to facilitate its replacement when loaded on a means of transport. The battery packs are discussed in more details below.

Another aspect to consider is the possibility to make clusters of several UFWTs that would be connected through rigid connections. These connections would ensure stability and could ease the access to the battery packs by having only one location to board them on the boat.. Bae and Kim [20] proposed a detailed analysis for the aerodynamics of such a system and modeled the interactions between UFWTs and the connections. Nevertheless, isolated wind

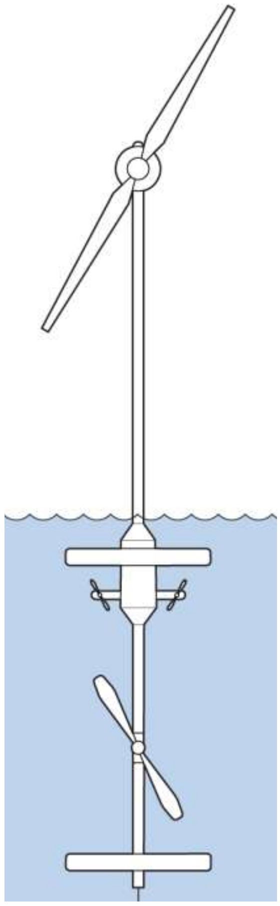

Figure 2: Illustration of an UFWT [18].

turbines could be easier to manufacture because no connections are needed. An extensive study could be carried out to determine the most cost-effective configuration.

To ensure a better stability, another possibility could be the use of suction anchors. Such anchors would also limit electrical power consumption for propulsion. Suction anchor operation is based on water pressure. The suction anchor first penetrates in the seabed. Then, suction occurs: a remotely operated vehicle pumps water out of the top suction port, driving the suction anchors deeply into the seabed. Suction anchors can be retrieved by reversing the installation process [21]. More details about the functioning of suction anchors are given by Naji Tahan [22].

An important issue to consider is the potential for severe weather events to cause damage to the production hub. Therefore, UFWTs should be capable of escaping critical zones. This can be achieved through an operational strategy that ensures sufficient electrical energy is always available in the batteries to provide adequate propulsion for the UFWT. Weather forecasts, typically available a few days before a storm's arrival, should be used in such a context to prevent damage to the production hub.

Another possible issue comes from the interactions with ocean waves that could cause a substantial increase in mechanical fatigue of the floating wind turbine structure compared to an onshore wind turbine. We refer the reader to Saenz-Aguirre et al. [23] for more information about this topic.

In the study reported in Section 4, the UFWTs are assumed to be single units equipped with propellers that provide a constant power production with an average capacity factor $CF = 0.50$ for every wind turbine [5]. The CAPEX of the UFWT is estimated at 2.53 M$ per MW, based on [24] 2030 forecast, where only the cost of turbines and foundation are retained. The other costs being related to electrical connections, substations or export cables usually required between the wind turbine and the grid, have been excluded due to the use of battery packs.

Two losses are considered during the operation of UFWT. The first one, called L_{wasted} occurs when operational constraints prevent batteries from being charged during the cycle time. This can happen when they are fully charged or when they are exchanged with discharged ones. In this latter case, the energy that could have been stored is lost because the charging process is interrupted. This energy is therefore wasted.

The second one, called L_{prop} is related to the electrical power produced by the UFWT consumed by the propellers. The ratio of the electrical power consumed by the propellers and the electrical power produced by the UFWT is denoted by the symbol η_{prop}. We will assume that η_{prop} is equal to 0.5. Connolly and Crawford [25], Xu et al. [26] show losses from 20 to 80 % of the power produced by a classic wind turbine. Hence, 50% seems a reasonable assumption given the technological improvement that can achieved until 2030.

Battery Pack

The battery pack is assumed to conform to maritime transport container standards [27]. Battery packs will be located at the base of the UFWT (see Section 2.1). They can be loaded and unloaded onto various modes of transport to travel to the coast, where they will be discharged to supply power to the grid. These battery packs, coupled with a transport method, act as a means of transporting electrical energy, similar to power lines. Of course, using battery packs as an energy vector, can only be credible if we have access to low-cost, energy-dense batteries. In recent years, a sharp decrease has been observed in the cost of batteries. For example, the cost of batteries in 2023 was only 17% of the cost in 2013 [28]. In April 2024, a record low cost of \$104.3/kWh was reported for Li-NMC batteries [29]. This decrease in cost is expected to continue according to Orangi et al. [30], who conducted a thorough analysis of the determinants of battery costs and projected that the cost of Li-NMC battery packs could decrease to \$53.4/kWh by 2030 for Lithium-ion NMC955 technology with an energy density of 316 kWh/ton. In this work, we will consider this Lithium-ion NMC955 technology to fill our containers and we will assume as projected cost and energy density for 2030, the values just mentioned. The approximate maximum payload of a maritime container is around 30 tons [31]. We assume that 28 tons are allocated for energy cells and 2 tons for electronics. Therefore, the embedded energy in our battery pack is estimated at 316 kWh/ton · 28 tons = 8.85 MWh.

A standard container costs approximately \$7,000 [27], although the price is expected to be higher due to the specific requirements for handling batteries. However, this increase is considered negligible due to its likely small contribution to the total cost of a battery pack in this study. Consequently, we will use as estimate for the total cost of a battery pack \$53.4/kWh · 8850 kWh + \$7000 = \$479,590.

We note that volume is not a constraint for storing energy in a container. Indeed, assuming a volumetric energy density of 0.260 MWh/m^3 for lithium-ion batteries [32], and given that a container has a volume of approximately 66.71 m^3, it could theoretically store 17 MWh of energy if fully packed with batteries. This is significantly higher than the 8.85 MWh we derived using to the maximum payload constraint.

Charge and discharge losses are denoted as L_+ and L_-, respectively. These losses occur during the charge and discharge of the battery pack. The efficiency of charge and discharge of battery packs is considered constant and equal to $\eta_+ = 95.9\%$ and $\eta_- = 95.9\%$, respectively [11, 32]. The self-discharge of the battery packs is neglected [32].

The lifetime of the battery pack is assumed to be 30 years, based on the Lithium-ion NMC 2030 estimate [32].

Boats

Boats are the transportation method considered for transferring the battery packs (see Figure 2.1). These boats are assumed to be equipped with cranes for loading and unloading the battery packs. They are also assumed to be electric and powered by the transported battery packs. The round-trip energy consumption of the boats is L_{rt}, and their energy consumption depends on their cargo capacity (i.e., the payload they can transport). The energy consumption C of the boat, expressed in MWh of electricity per ton-km, is calculated based on the expression proposed by the Danish Energy Agency [33]. This expression, originally in MJ of fuel per km, has been modified to fit the required units, to take into account the efficiency of an electrical engine and is applicable for boat velocities around 24 km/h. It now reads:

$$\mathrm{C} = 2.485 \cdot 10^{-6} + \frac{49}{324 \cdot m}, \tag{1}$$

where C is the consumption of the boat in MWh/ton-km and m is the weight of transported load in tons. The CAPEX of the different boats considered in this study is, by using the model presented in [33], estimated to be equal to \$4,350/ton. The boat is assumed to be equipped with cranes to load and unload the batteries. The cranes consume energy for loading and unloading the batteries. The amount of energy consumed during one cycle is denoted by the symbol L_{crane}. The value of L_{crane} is calculated by estimating the energy required to lift the batteries to a specific height when loading/unloading the boat, see Appendix A.4.

Inverter

At the coast, an inverter is responsible for converting DC to AC current to inject electricity into the grid. The CAPEX of the inverter is neglected, but a loss L_{DC-AC} occurs during this conversion. The inverter's energy efficiency η_{DC-AC} is considered constant and equal to 97% [34].

Cycle Time

The cycle time for the REHS is the time for the boat to bring a battery pack from the production hub to the sea port and back. It includes the travel time from the production hub to the sea port and the time for loading and unloading the battery packs. Time needed to join one UFWT after the other once reaching the hub is assumed negligible.

3. Methodology

In this section, we begin by providing an overview of the methodology used to calculate the energy injected into the grid (Section 3.1). Subsequently, we briefly discuss two metrics - load factors and costs - in Section 3.2 and Section 3.3, which will be used later to compare different REHSs. Further details on the calculations are given in Appendix A.

3.1. Energy injected into the grid

A boat is responsible for the round-trip transportation of batteries between offshore locations and the coast. A cycle involves exchanging batteries at the REHS, returning to the coast, exchanging batteries at the coast, and transporting them back to the REHS. The time required to complete a cycle, denoted as t_{cycle}, is referred to as the cycle time. Each hub studied is characterized by two parameters: the installed power capacity of UFWTs, denoted as P, and the distance d between the hub and the coast. Let E_{cycle} represent the amount of energy produced by the UFWTs during a cycle. This amount of energy can be calculated as follows:

$$E_{cycle} = P \cdot t_{cycle} \cdot CF, \tag{2}$$

where CF is the capacity factor of the installed power capacity at the REHS. Appendix A proposes a strategy for sizing the various components associated with the REHS based on P and d and for estimating the losses and costs associated with each component. From this, the total energy losses per cycle L of an REHS can be derived in a straightforward way by summing up the different energy losses per cycle, see Section 2 for a reminder of the different energy losses. Consequently, the energy injected into the grid per cycle, E_{grid} is estimated as follows:

$$E_{grid} = E_{cycle} - L. \tag{3}$$

We note that from the values of E_{grid} and t_{cycle}, it is straightforward to compute the energy injected into the grid over a given duration.

3.2. Load Factors

One of the main metric to compare different REHS is the load factor π. It is defined as

$$\pi = \frac{E_y}{P \cdot t_y} = \frac{E_{grid}}{P \cdot t_{cycle}} \tag{4}$$

where E_y and E_{grid} is the energy injected to the grid per year and to the grid per cycle, respectively. t_y and t_{cycle} are the number of hours in a year or in a cycle, respectively, P is the power installed in the REHS. To compute how much energy can be delivered to the grid E_{grid} per cycle, Equation 3 is used.

3.3. Cost

The second metric considered is the cost per MWh of electricity injected into the grid. To estimate this cost, we first calculate the sum of the annualized investment costs related to production ($A_{production}$), storage ($A_{storage}$), and transport ($A_{transport}$) in the hub, resulting in a total annualized cost of:

$$A = A_{production} + A_{storage} + A_{transport}. \tag{5}$$

From the value of A, we derive the cost per MWh injected into the grid, c, using the following equation:

$$c = \frac{A}{E_y}, \tag{6}$$

where E_y represents the yearly energy injected into the grid. The CAPEX and lifetimes for production, storage and transport are summarized in Table 1. While this methodology only considers CAPEX for estimating the cost of energy, it accounts for OPEX associated with energy losses, as these are included in the term E_y. For the calculation of annualized costs, a Weighted Average Cost of Capital (WACC) of 7% is used. Note that the computation of total annualized costs excludes the cost of the DC/AC converter located onshore, which we assume could be provided at no cost by the Transmission System Operator. Furthermore, its cost is considered negligible compared to the costs of the boat, UFWTs, and batteries. Similarly, the cost of storing batteries onshore is neglected, as it is assumed to be minimal.

4. Case studies

In this section, the REHS proposed in Section 2 is quantitatively analyzed using some parameters estimates for the costs and physical properties of the components. The results for the costs and load factors presented here are derived using the methodology outlined in Section 3, which is further detailed in Appendix A. The code to reproduce the results is available online[1].

We examine three different cases for this REHS that differ by the parameter d, the distance between the production hub and the seaport. The different distances considered are 150, 400, and 2000 km. In Appendix A, all the details required to derive the sizing of the REHS with respect to the distance and a fixed power installation $P = 100$MW are provided. Table 2 summarizes the distances and the derived boat capacities.

Table 1: Technical considerations: lifetime forecast in 2030, Capital Expenditure (CAPEX), velocity of the component.

Component	Lifetime [years]	CAPEX	Velocity [km/h]	References
UFWT	30	2500000 \$/MW	/	[24]
Battery pack	30	54.19 \$/kWh	/	[30] [32]
Boat	20	4400 - 0.0055 m\$/ton	24	[33]

4.1. Results

Results are presented in Table 2. They show that the closer the production hub from the sea port, the lower the cost. Thus, the optimal configuration in Table 2, is the hub located at 150 km, with a boat cargo capacity of 1,016 tons, and it achieves a cost of \$160/MWh for electrical energy injected into the grid. In terms of load factors, they are similar and ranging from 16.7% to 17.4%. In order of magnitude they are a little bit smaller than load factors observed for onshore wind turbines in Europe [35].

In Table 3, one can see that the share of cost depends on the distance to shore. This can be explained by the fact that the installed wind capacity is fixed at 100 MW; the closer to the coast, the shorter the cycle time. The shorter the

[1] https://github.com/VicD1999/REHS/tree/main

cycle time the less energy storage needed. Therefore, the closer the UFWTs are to the shore, the more they account for the majority of the REHS's cost, and the farther they are, the more the batteries contribute to the cost of energy. We note that the cost of boats is negligible in comparison with the two other technologies (UFWT and batteries).

In Table 4, the losses that occur during the supply chain are listed. We can see that the losses due to the crane operations are negligible. The biggest loss is related to the propeller to ensure the stability of the UFWT.

Table 2: Results for REHS located at different distances form the shore.

d [km]	m [ton]	π [%]	c [\$/MWh]
150	1016	17.4	160
400	2709	17.3	204
2000	13544	16.7	497

Table 3: Share of costs per component in the REHS.

d [km]	UFWT [%]	Batteries [%]	Boat [%]
150	83.9	16.1	0.0
400	66.1	33.9	0.0
2000	28.0	72.0	0.0

Table 4: REHS: energy losses per cycle in MWh for each operation with respect to the distance to shore.

d [km]	E_{cycle}	L_{wasted}	L_{prop}	L_{+}	L_{crane}	L_{rt}	L_{-}	L_{DC-AC}	E_{grid}
150	673.5	48.5	312.5	12.8	0.0	46.1	12.3	7.2	234.0
400	1796.1	129.5	833.3	34.2	0.0	126.4	32.8	19.2	620.8
2000	8980.6	647.3	4166.7	170.8	0.0	739.5	163.8	92.8	2999.7

4.2. Discussion

The load factors and cost estimations for the REHS are based on several assumptions previously described. Among them, a proposed assumption is that the time for the boat to pass by each wind turbine of the wind farm can be neglected. In order to determine whether this assumption is reasonable, we made side computations to determine the ratio between the time to pass by each wind turbine of the wind farm, which was previously neglected to study the REHS, and the cycle time, which corresponds to the sum of the travel time from the production hub to the sea port (and vice versa) and the time for loading and unloading the battery packs. This ratio is equal to 0.19%, 0.93% and 2.5% for the distance d = 2000 km, 400 km and 150 km, respectively. Given these estimates, the assumption seems reasonable.

As can be observed in Table 4, the hugest loss of energy is due to the propellers that must ensure spatial stability of the UFWT. Therefore, improvements in order to decrease the energy consumption of this technology could improve significantly the cost and load factors for this REHS. Regarding the energy losses related to L_{wasted}, which are significant, these could be reduced if the operations related to the loading and unloading of the batteries onto the boats were faster. Additionally, we note that the losses related to the cranes are negligible. Finally, improved charge and discharge of the batteries could also have a significant beneficial effect on overall losses, even though battery losses represent only half of those related to ship propulsion.

Larbanois et al. [36] provide cost estimates for e-fuels produced in the Sahara Desert and exported to Europe, ranging from 107€/MWh for hydrogen to 150€/MWh for methane. They are using the same WACC of 7% as in this study. Using the mean exchange rate of 1€ = 1.11$ from 2023 [37], these e-fuel costs amount to 118.7$/MWh to 166.5$/MWh. The cost estimates of electricity exported onshore and produced in production hub at a distance of 150 km, amounting to 160$/MWh, demonstrate the potential of these REHS to produce energy that could compete, in terms of cost, with low-carbon e-fuels produced onshore in RREH.

International Energy Agency [38] determine the Levelized Cost of Electricity (LCOE) for zero-emissions dispatchable technologies in 2030. For instance, they estimate the cost of electricity produced by hydropower to range from 50 to 130 $/MWh. The cost of electricity produced in our studied REHS is too expensive and falls outside this range. However, if the WACC is decreased to 5% and we consider a distance to shore equal to 150 km, the cost falls within this range to become equal to 129$/MWh.

The most cost effective configuration considered is the one with the production hub located at a distance of 150 km from the onshore delivery place. In order to further lower the overall costs, that distance could be reduced to just a few tens of kilometers, similar to the range typically reached by conventional offshore wind farms [39]. This would allow to harness wind power near coastal areas where sea depths prevent the building of conventional offshore wind turbines. Production costs of electricity produced from wind power exploitation highly depend on the capacity factor (CF). This CF is associated to the region where the production hub is set up. A CF related to areas close to the coast is likely much lower than the one observed in high seas [40]. Hence, a trade-off emerges regarding this distance to shore and available CF. The distance should be chosen small enough to reduce costs of transportation while maintaining a sufficiently high wind quality.

Additionally, the longest distance to the shore considered (i.e., 2000 km) results in high costs, outside the range of other zero-emissions dispatchable technologies in 2050 discussed above [38]. A potential way to mitigate these costs, particularly those related to the transport, would be to use production hubs in the high seas as recharging stations for cargo ships. Specifically, electric cargo ships could be recharged at sea. Developing offshore recharging facilities could accelerate the decarbonization of maritime transportation. Installing recharging platforms in the high seas could also address the limited range of electric vessels. It is worth noting that a study on offshore charging stations has already been conducted by Yang et al. [41]. Another possibility could be to take advantage of cargo ships that pass close to the production hub while transporting merchandise, using them to transport some of the battery packs.

Furthermore, it is important to acknowledge that the closest distance considered in our study (150 km) is not legally classified as the high seas, according to [42]. Legally, the high seas begin outside the exclusive economic zone (EEZ), which extends up to 370.2 km from the coast. Therefore, a hub located 150 km from shore is likely within the EEZ, not the high seas. This is why we included a distance of 400 km from the coast in our study. However, in certain cases, such as for Belgium, the legal high seas may not be reachable even at 400 km due to EEZ of neighboring countries like the United Kingdom. Consequently, we also considered a distance of 2000 km to ensure the hub is located in the legal high seas. Additionally, for a hub located 150 km offshore, it is unlikely that fixed-foundation offshore wind turbines could be installed due to the depth of the sea. Therefore, the concept of a hub using floating or unmoored wind turbines is more appropriate at this distance. We propose to distinguish between "technical high seas" and "legal high seas," where the former refers to locations where fixed foundations are technically challenging to construct, even if they are within the EEZ.

Lastly, REHS could be further optimized by loading and unloading the batteries onto the boat during periods of low wind activity, provided batteries reach a specified loading threshold. This strategy aims to augment the mean capacity factor (CF) and ensure that battery management operations are conducted under favorable weather conditions.

5. Summary and conclusion

In this paper, we proposed a Remote Renewable Energy Hub in the High Seas (REHS) based on battery packs to deliver electricity generated from wind in the high seas to continental grids. In this REHS, which relies on boat transportation, the cost of injected electricity ranges from 160 to 497 $/MWh, with load factors between 16.7% and 17.4%, depending on the distance to shore, from 150 km to 2000 km.

These costs were determined based on simplified assumptions. As future work, we suggest developing more complex optimization models to identify the most promising energy supply chain. Numerous variables, subject to trade-offs between energy efficiency, delivery time, and cost, need to be considered in determining the optimal configuration. Moreover, this optimization model should help to identify the best places to harvest wind energy in the high seas. Indeed, some locations may exhibit higher capacity factors for the UFWTs than the one considered in this study. However, higher capacity factors could induce higher energy consumption of the UFWTs' propellers due to difficult weather conditions to stabilize the UFWTs.

Technological advancements in the components that constitute this REHS could enhance its cost efficiency. Specifically, we believe that there are two important lines of research in this context. The first concerns the energy consumption of the propellers of unmoored floating wind turbines. These propellers represent the greatest loss in the entire energy supply chain. Therefore, conducting research to improve propeller technology, or find alternatives, such as suction anchors, seems very promising. The second line of research concerns batteries. It is clear that developing batteries that are not only cheaper but also have reduced losses and higher energy density would be very useful in reducing the cost of electricity generated.

In addition to technological advancements, the large-scale deployment of UFWTs depends on the establishment of industrial production lines. This industry could be fully automated, from manufacturing to real-time operation. Large coastal factories could produce UFWTs and deploy them directly at sea upon completion. These turbines would then be capable of autonomously locating and positioning themselves at optimal sites within the production hub.

Moreover, there are several regulatory challenges associated with the deployment of REHS. While international law grants all countries the freedom to harvest renewable energy in the high seas, this could lead to competition over locations with high-quality wind resources. Such overlap may result in legal disputes, which should be carefully anticipated and mitigated to avoid conflict.

Finally, it should be emphasized once again that the estimated costs reported in this paper are for the year 2030. Therefore, if the downward trend in clean technology prices continues beyond 2030, as expected given the trend observed over the past few decades, these costs could continue to decline. A point in time could then be reached when this REHS would have lower costs than conventional electricity generation methods. Furthermore, the implementation of carbon pricing mechanisms could further improve the profitability of these systems, potentially making them competitive with conventional fossil fuel-based electricity producers sooner.

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Competing interests

The authors declare no competing interests.

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Appendix A. REHS efficiency and cost estimates calculation details

In this section, the methodology followed to determine the efficiency and cost estimates for the REHS, represented in Figure 1, is detailed.

Appendix A.1. Sizing the REHS

To determine the efficiency and cost estimates of the REHS, the sizes of its components need to be established. These components include the wind farm's installed power (P), the mass of battery packs required to store the produced energy, and the cargo capacity of the transport means (*i.e.* the boat cargo capacity). For this study, the wind farm's installed power is fixed at $P = 100$MW. As we will see, the mass of the battery packs and the cargo capacity can be derived from P and the distance between the production hub and the shore, denoted by d.

The time required to travel this distance, referred to as the round-trip time (t_{rt}), is given by:

$$t_{rt} = \frac{2d}{v_{bo}}, \tag{A.1}$$

where v_{bo} is the boat velocity.

Under the assumption that the wind farm has a constant load factor CF during the round-trip time, the maximum energy that could be stored in batteries during this time is equal to:

$$E = P \cdot t_{rt} \cdot CF \cdot \eta_{+} \cdot (1 - \eta_{prop}), \tag{A.2}$$

where P, t_{rt}, CF, η_{+}, and η_{prop} represent the wind farm's installed power, the round-trip time, the wind capacity factor, the charge efficiency of the batteries, and the efficiency of the propeller (i.e., the ratio of electrical power used to stabilize the UFWT).

In this REHS, we assume the batteries located next to the wind turbines have a storage capacity E and, hence, that the wind park can fully charge them during the round trip time t_{rt} assuming a capacity factor CF during this time. From these assumptions, we can derive the mass m of batteries installed at the wind park:

$$m = E \cdot \mu, \tag{A.3}$$

where μ is the battery pack energy density. In this REHS, the total mass of batteries required is assumed to be three times m, as battery packs are needed simultaneously in three locations: (a) at the UFWT, (b) on the boat making the round trip between the hub and the shore, and (c) at the shore, where the batteries discharge energy into the grid.

Moreover, we also assume in this REHS that only one single boat, whose capacity is m tons, will bring in one single trip all the batteries located at the wind farm to the coast. During its trip back, the boat will bring the m tons of empty batteries taken from the coast back to the wind farm.

As summary, one of the main parameter determining the sizing of the system is P. From this parameter and the distance d, the parameter m can be computed using Equation A.2 and Equation A.3. The total mass of the batteries is equal to $3m$ and the cargo capacity equal to m.

Appendix A.2. CAPEX of the REHS

In this REHS, the CAPEX considered includes the costs of production, storage and transportation, corresponding to the UFWT, batteries, and boat. The CAPEX values and lifetimes of these components are provided in Table 1.

For each component i, the annualized cost A_i is estimated as:

$$A_i = \frac{CAPEX_i \cdot w}{1 - (1 + w)^{-L_i}}, \tag{A.4}$$

where $CAPEX_i, L_i, w$ represent the capital expenditure of component i, the lifetime of component i, and the WACC, respectively.

From this generic equation Equation A.4, we can specify the production costs, $A_{production}$, expressed in \$/year, are defined as:

$$A_{production} = \frac{p_w \cdot P \cdot w}{1 - (1 + w)^{-T_w}}, \tag{A.5}$$

where p_w, P, T_w, w represent the price per MW of UFWT, the installed capacity, the lifetime of the UFWT and the WACC, respecticely.

Similarly, storage costs, $A_{storage}$, expressed in \$/year, are defined as follows:

$$A_{storage} = 3 \cdot \frac{p_{ba} \cdot m \cdot \mu \cdot w}{1 - (1 + w)^{-T_{ba}}} \tag{A.6}$$

where $p_{ba}, m, \mu, T_{ba}, w$ represent the price per MWh of the battery, the mass of batteries in the REHS, the energy density of the batteries, the lifetime of the batteries, and the WACC, respectively. The factor 3 is related to the sizing assumption that battery packs are required at three locations: the UFWT, the boat, and the delivery place.

Transportation costs, $A_{transport}$, expressed in \$/year, are defined as follows:

$$A_{transport} = \frac{CAPEX_{bo}(m) \cdot w}{1 - (1 + w)^{-T_{bo}}}, \tag{A.7}$$

where $CAPEX_{bo}(m), T_{bo}, w$ represent the CAPEX associated with a boat of cargo capacity m, the lifetime of the boat, and the WACC, respectively.

The total annualized CAPEX, A, is derived as the sum of the annualized production and transportation CAPEX:

$$A = A_{production} + A_{storage} + A_{transport} \quad . \tag{A.8}$$

In our calculations, a WACC of 7% is used.

Appendix A.3. Number of cycles per year

For computing the number of cycles per year, we assume, as done earlier, that a single boat is responsible for transporting the batteries between the production hub and the shore.

Cycle time

Here, we are interested to know the time required for a fully cycle of the boat, called cycle time, that can be defined as the time between two successive arrivals of the boat at the port.

We assume that this cycle time, t_{cycle}, is equal to:

$$t_{cycle} = t_{rt} + t_{lu}, \tag{A.9}$$

where t_{rt}, t_{lu} correspond to the round-trip time defined in Equation A.1, and the sum of loading/unloading time. This time t_{lu}, can be estimated as: $t_{lu} = 4rm$, where r, m correspond to the time for loading and unloading the batteries on the boat per ton and the mass of batteries, respectively. The factor 4 accounts for the following steps performed in the production hub and at the coast: (i) battery packs are first unloaded from the boat (ii) battery packs are loaded onto the boat. We note that half of the time of t_{lu} could have been used to charge additional batteries. But this would not influence much the results since, for all the hubs studied in this paper, t_{lu} which depends on the battery sizing parameter m accounts for less than 3% of the round-trip time t_{rt}.

We note that by using this expression for the cycle time, we neglect the time required for the boat to pass by each UFWT in the production hub of the REHS.

Number of cycles per year

The total number of cycles the boat can complete in a year, n_c, is estimated by dividing the total number of hours in a year by the cycle time:

$$n_c = \frac{t_y}{t_{cycle}}, \tag{A.10}$$

where t_y represents the total number of hours in a year and t_{cycle} the cycle time expressed in hours.

Appendix A.4. Energy losses

In this subsection, we will estimate the different losses per cycle alongside the supply chain. In the production units, that is composed of UFWTs, there is first a waste of energy called L_{wasted} that occurs because the batteries cannot be charged during the period that corresponds to their loading and unloading onto the boat. Additionally, there is a loss of energy in the propellers, L_{prop}, required to stabilize the UFWTS when the wind turbines produce electricity. We will also consider a loss of charge L_+ when charging the batteries. When leaving the platform the batteries contain an amount of energy E. This energy will incur a loss of L_- during discharge for any use. When loading and unloading the batteries onto the boat, both in the production hub and at the coast, a loss L_{crane} is considered. Once on the boat, part of this energy E is used to power the boat for its trip to the coast and later back to the production hub. This loss for the round trip is called L_{rt}. The batteries arrive onshore, where they are discharged into the grid until enough energy remains in the batteries to lift them back onto the boat and for the trip back to the production hub. The energy injected into the grid will undergo an additional loss, L_{DC-AC}, to convert from DC to AC current.

Discarded Energy

The batteries will be fully charged after the round trip time t_{rt}, see Equation A.1. Hence, the energy produced by the UFWTs during the loading/unloading time t_{lu}, see Equation A.9 will be discarded. This corresponds to an amount of energy L_{wasted} equal to:

$$L_{wasted} = P \cdot t_{lu} \cdot CF. \tag{A.11}$$

P, t_{lu}, CF are the wind farm installed power, the loading/unloading time and the capacity factor, respectively.

Propeller energy consumption

Part of the energy produced by the UFWTs, instead of being stored in the batteries, is lost in the propeller. This loss is expressed as

$$L_{prop} = P \cdot t_{rt} \cdot CF \cdot \eta_{prop}, \tag{A.12}$$

where P, t_{rt}, CF, and η_{prop} represent the wind farm's installed power, the round-trip time, the wind capacity factor, and the fraction of the electrical power produced by the UFWT which is consumed by the propeller.

Energy losses when charging

A charge efficiency of η_+ is considered during battery charge [32], resulting in a charging loss of:

$$L_+ = P \cdot t_{rt} \cdot CF \cdot (1 - \eta_{prop}) \cdot (1 - \eta_+), \tag{A.13}$$

where P, t_{rt}, CF, and η_{prop} represent the wind farm's installed power, the round-trip time, the wind capacity factor, and the fraction of the electrical power produced by the UFWT which is consumed by the propeller.

Discharge energy losses

A discharge efficiency η_- is considered during battery discharge [32]. Our system is designed so that when leaving the platform with the energy E, the battery will arrive again at the platform with a level of energy equal to 0. Hence the discharge losses are equal to:

$$L_- = (1 - \eta_-) \cdot E, \tag{A.14}$$

where E is the amount of energy stored in the batteries.

Crane energy consumption

We assume that every time a battery is loaded on a boat or unloaded from a boat, it needs to be lifted to a hight h that we will chosen as being equal to 30m. Hence, since we have a mass of battery m that needs to be lifted four time to this height over a cycle, we assume that the crane energy consumption over a cycle is:

$$L_{crane} = 4 \cdot m \cdot g \cdot h \cdot (1/\epsilon_{elec}) \tag{A.15}$$

where m is the mass of the battery packs transported, g is the gravitational acceleration, h is the lifting height and ϵ_{elec} is the efficiency of the electrical motors of the crane.

Boat energy consumption

The energy consumption for the round trip transportation can be evaluated based on

$$L_{rt} = 2d \cdot m \cdot C, \tag{A.16}$$

where C is defined in Equation 1, m is the mass of the battery packs transported, and $2d$ represents the round-trip distance (twice the distance from the hub to the shore).

Conversion energy losses

Energy losses occur during the conversion of electricity from DC in the battery packs to AC for injection into the grid, with an efficiency η_{DC-AC} assumed. This results in

$$L_{DC-AC} = (1 - \eta_{DC-AC}) \cdot (E - L_- - L_{rt} - L_{crane}), \tag{A.17}$$

where this loss applies only to the net energy output of the battery. Additionally, it is indirectly assumed that both the crane and the boat use DC electric motors.

Appendix A.5. Net electricity export per cycle and per year

Due to all the losses considered in Appendix A.4, only a part of the energy stored in the batteries per cycle, E, is injected into the grid, denoted as E_{grid}. From this energy injected into the grid, we derive the annual energy export.

Net electricity export per cycle

Therefore, during one cycle, the net energy brought to the shore, accounting for all losses, is given by:

$$E_{grid} = E - L_{crane} - L_{rt} - L_- - L_{DC-AC}. \tag{A.18}$$

Annual electricity export

The annual energy transported to the shore, E_y, in MWh/year, is calculated as:

$$E_y = E_{grid} \cdot n_c, \tag{A.19}$$

where n_c is the number of cycles per year, as computed in Appendix A.3.

Appendix A.6. Price per MWh

The cost per MWh of electricity injected into the grid can be derived using the annualized cost of the REHS, A, computed in Appendix A.2, and the annual energy transported to the shore, E_y, calculated in Appendix A.5. The price per MWh is expressed as:

$$c = \frac{A}{E_y}, \tag{A.20}$$

where c represents the cost per MWh of electricity delivered to the grid.

Appendix A.7. Load factor of the REHS

The load factor of an REHS, π, a metric representing the use of the installed power capacity over a year, is given by:

$$\pi = \frac{E_y}{t_y \cdot P}, \tag{A.21}$$

where E_y is the annual energy transported to the shore, t_y is the number of hours in a year, and P is the installed power capacity at the hub.

Appendix B. Variables definition

Table B.5: Constants used for cost and load factors estimates of the REHS. Values taken from: [5, 43, 29, 44, 32, 33, 26, 34, 24, 45, 46].

Constant	Name	Value	Unit
v_{bo}	Boat velocity	24	km/h
μ	Battery pack energy density	207	kWh/ton
p_{ba}	Battery pack price	105.196	\$/kWh
η_{+}	Charge efficiency	0.959	-
η_{DC-AC}	DC-AC conversion efficiency	0.97	-
η_{-}	Discharge efficiency	0.959	-
ϵ_{elec}	Electric motor efficiency	0.9	-
r	Loading rate	$2.4 \cdot 10^{-4}$	h/ton
η_{prop}	Propeller efficiency	0.5	-
p_w	UFWT cost	$2.5 \cdot 10^{6}$	\$/MW
CF	Wind capacity factor	0.50	-
w	Weighted Average Capital Cost (WACC)	0.07	-
P	Wind farm installed power	100	MW
t_y	Number of hours in a year	8760	h

Table B.6: Parameters that change across the different distances from the production hub to the shore considered.

Parameter	Name	Unit
$CAPEX_{bo}$	Boat capex	\$/ton
d	Distance between the production hub and the shore	km
n_c	Number of cycles in a year	cycle
m	Cargo capacity / total mass of battery packs	ton
A	Annualized CAPEX cost	\$/year
C	Transportation consumption	kWh/ton-km
t_{cycle}	Cycle time	h
t_{rt}	Round trip time	h
t_{lu}	Time for loading and unloading batteries on the mean of transport	h

Part III

Economic and Financial Dimensions

7 Financing, Risk, and the Role of Capital Costs

7.1 The Question

RQ4. What is the role of financing, risk, and the cost of capital (WACC) in the emergence and competitiveness of RREHs?

Most techno-economic assessments of Remote Renewable Energy Hubs (RREHs) have focused on technical efficiency and renewable resource quality, but have oversimplified a critical economic dimension: the cost of capital. The Weighted Average Cost of Capital (WACC) is a key determinant of project viability, reflecting the risks of investing in specific regions.

This raises a crucial question: how do financing conditions, expressed through WACC, alter the relative attractiveness of potential RREH locations, and what trade-offs exist between resource abundance and investment risk?

7.2 The Idea

While countries with high-quality renewable resources (e.g., desert regions, offshore wind) appear promising candidates for RREHs, their financing conditions often differ substantially from those of stable, industrialized economies. High WACC values can offset technical advantages by raising the cost of capital-intensive infrastructure.

The idea of this study is therefore to integrate country risk into the WACC used for the techno-economic modeling of RREHs. The trade-off between renewable energy potential and economic risk is then analyzed for several locations, allowing the identification of areas where RREHs are both technically and financially attractive.

7.3 Paper's contributions

The contributions of the submitted paper, titled *On the Importance of the Cost of Capital in the Emergence of Remote Renewable Energy Hubs*, can be summarized as follows:

1. Developing a methodology to obtain a country-specific Weighted Average Cost of Capital (WACC) for use in the techno-economic optimization of RREHs.

2. Conducted case studies in seven countries, comparing renewable potential with financing conditions.

3. Demonstrated that some technically promising locations are not economically viable under realistic WACC assumptions.

4. Highlighted the need for innovative financing mechanisms and international cooperation to enable RREH deployment in high-resource but high-risk regions.

7.4 Authors' contributions

This paper is a collaboration with Professor Marie Lambert, a finance expert from the HEC business school, who helped me develop the methodology for incorporating country risk into the WACC. Mr. Gilles Ooms assisted in developing the software and drafting the article. Professor Ernst provided feedback.

7.5 Integration within the thesis

This chapter constitutes the sole contribution to **Part III – Economic and Financial Dimensions** and addresses RQ3, which investigates the role of financing, risk, and the cost of capital (WACC) in the emergence and competitiveness of Remote Renewable Energy Hubs (RREHs).

On the Importance of the Cost of Capital in the Emergence of Remote Renewable Energy Hubs

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Abstract

Remote Renewable Energy Hubs (RREHs) enable the harvesting of renewable energy in regions where it is most abundant. From this harvested renewable energy, RREHs allow the synthesis of e-fuels (electrical-fuels), such as CH_4 and NH_3, for export to load centers. Load centers are locations characterized by high energy consumption but often limited renewable energy potential. As a result, these load centers have difficulties in meeting their energy demands through only renewable sources. RREHs offer new opportunities for load centers to decarbonize their energy consumption. Many locations worldwide have significant technical potential for RREHs installation due to their vast renewable energy sources. Once a suitable location is identified, the RREH must be properly sized and operated. This involves determining the optimal capacities for each technology (e.g., battery storage capacity) and defining operational strategies (e.g., when to charge or discharge the battery). To size and operate a hub optimally, both technical and economic parameters must be considered. One key economic factor in hub optimization is the Weighted Average Cost of Capital (WACC), which can significantly impact the economic viability of potential projects in a given location. In this paper, we model the entire energy supply chain for synthetic gas production across various countries and its export to Northern Europe (Belgium). We analyze the trade-off between WACC and load factors to minimize the cost of synthetic fuel production and identify the most promising locations. Our results indicate that while some countries may be technically promising, they may not be economically attractive. This highlights the need for innovative financing mechanisms in regions with high load factors but less favorable economic conditions in order to install RREHs at a lower cost.

Keywords: Energy Sytems, Remote Renewable Energy Hub, Renewable Energy, WACC

1. Introduction

To address climate change, transforming our energy systems from fossil-based energy systems to a low-carbon energy mix is one of the most important levers to pull. As highlighted by IPCC [17], expanding renewable energy production is essential to achieve this transformation. However, since some sectors are difficult to electrify, complementing this transition in the electricity mix with the synthesis of low-carbon fuels is essential for decarbonizing these hard-to-abate sectors [26, 29, 27].

Low-carbon synthetic fuels are produced using power-to-X technologies [12]. These technologies convert low-carbon electricity into a molecule X, such as hydrogen (H_2) via electrolysis, or further into molecules like methane (CH_4), ammonia (NH_3), or methanol (CH_3OH) through synthesis processes. Power-to-X has a dual benefit: first, the molecules produced are low carbon, and second, these high energy density molecules can store and transport energy efficiently [14, 23, 21]. Such molecules are often referred to as e-fuels (electro-fuels).

In load centers such as Western Europe, there are challenges in producing renewable energy for power-to-X purposes [2]. Indeed, the potential of renewable energy is limited due to lack of space availability because of strong

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urbanization and geographical constraints. It is also limited due to the low-quality of renewable energy sources. To address these limitations the concept of Remote Renewable Energy Hubs (RREHs) has been proposed. These hubs make it possible to harvest renewable energy in regions with abundant resources and export e-fuels to demand centers such as the European Union (EU), potentially reducing infrastructure needs and costs [22].

To the best of the author's knowledge, the first reference in the scientific literature discussing RREHs is [15]. It proposes the export of energy, as e-CH_4, from Egypt to Japan; however, no techno-economic assessment was conducted. Then Fasihi et al. [12], proposed a techno economic assessment for export of e-CH_4 from North of Africa towards Finland. In [1], they did a similar analysis but with export towards Germany.

More recently, Berger et al. [3] proposed an RREH exporting e-CH_4 from Algeria to Belgium. Building on this, Fonder et al. [13] and Dachet et al. [5] suggested a similar hub but with the additional option of importing CO_2 from load centers where it is more abundant. Furthermore, Larbanois et al. [18], Pfennig et al. [24], Verleysen et al. [30] extended the scope of export commodities beyond e-CH_4 to include NH_3, CH_3OH, Fischer–Tropsch liquids, and H_2.

The growing number of RREHs discussed in the literature has motivated the development of a taxonomy to characterize them [6]. This taxonomy relies on a technological graph in which nodes represent the different production units of an RREH, and hyperedges represent the exchange of commodities between them. Based on this graph, the taxonomy identifies distinct sets of commodities: imports, exports, byproducts, and local opportunities. For instance, Berger et al. [3] considers no import commodities and defines e-CH_4 as the export commodity, whereas Fonder et al. [13], Dachet et al. [5] propose the same export commodity but also include the import of CO_2.

Nevertheless, these studies overlooked some economic parameters that can have significant impact to the cost of e-fuel production. Indeed, as mentioned in Egli et al. [11], the Weighted Average Capital Cost (WACC) is often used as an estimate for the cost of capital that a company should pay to raise capital to finance a project.

In this paper, the impact of this cost of capital on the cost of e-fuel synthesis in RREHs is investigated. To do so, case studies in 7 different locations are performed. The trade off between renewable energy potential and low risk economic environment is discussed.

The rest of the article is organized as follows: in Section 2, the modeling framework of the energy systems is discussed (cfr. subsection 2.1) as well as the methodology to evaluate the WACC is discussed (cfr subsection 2.2). In Section 3, the case studies are introduced. In Section 4, the results are introduced and discussed. Section 5 concludes this paper.

2. Methodology

This section describes the modeling framework used to size and operate the RREH, as well as the methodology for computing the WACC.

2.1. Modeling Framework: GBOML

In this study, the Graph-Based Optimization Modeling Language (GBOML) [20] is used to model the economic and technical aspects of RREHs. The GBOML framework is open source and particularly suited for energy systems. Indeed, energy systems can be viewed as graphs, where nodes represent technologies and hyperedges represent the exchange of commodities between these technologies.

The objective is to minimize the total cost of the system, which corresponds to the sum of the CAPEX and OPEX of each node, subject to various equality and inequality constraints representing physical and operational limitations over a given time horizon.

A detailed explanation of the optimization problem solved can be found in Berger et al. [3]. The same methodology is employed in this study.

The underlying modeling assumptions are the following:

- **Central Planning and Operation:** Investment decisions are made by a single entity that also operates the system, with the objective of minimizing total system costs while meeting the energy demand.
- **Perfect Foresight and Knowledge:** The single entity is assumed to have perfect foresight and knowledge. Future weather events, demand patterns, and all technical and economic parameters are known with certainty.

- **Investment and Operational Decisions:** A static investment model is used. Investment decisions are made at the beginning of the time horizon, and assets are considered immediately available. Operational decisions are made at an hourly resolution. Both investment and operational decisions are determined simultaneously.
- **Technology and Process Models:** All objective functions and constraints are linear.

Because different technologies have different lifetimes, the CAPEX must be adjusted to avoid favoring technologies with shorter lifetimes and lower upfront costs over those with higher CAPEX but longer operational life. To address this, an annualized CAPEX is computed. The annualized CAPEX ζ_i of a technology i can be calculated from its raw $CAPEX_i$, lifetime L_i, and the WACC as follows:

$$\zeta_i = \mathrm{CAPEX}_i \times \frac{WACC}{1-(1+WACC)^{-L_i}} \quad . \tag{1}$$

This annualized CAPEX represents the annual cost for borrowing the CAPEX over the lifetime of the technology, while paying an interest rate of $WACC$. This formulation yields an equivalent annual cost, which can be interpreted as the constant yearly payment required to finance the investment over its lifetime at the given WACC. It facilitates comparability across technologies of varying lifetimes, but also implicitly assumes reinvestment over the long-term horizon and may therefore underestimate the relative burden of long-lived assets compared to repeated short-lived ones. This limitation should be kept in mind when interpreting the results.

2.2. WACC estimation

In this section, the concept of the Weighted Average Cost of Capital (WACC) is introduced along with the methodology used to compute it. Subsequently, the procedure to derive a country-specific WACC is explained.

The WACC represents an estimate of the minimum return required on the assets by the capital providers. Since directly determining the return on an asset can be complex, it is more practical to compute the WACC from the company's liabilities. This value can then be used to evaluate whether a company should invest in a new project. If the expected return of the project exceeds the company's minimum return, the investment may be considered value-adding and the company could decide to invest in it.

WACC is generally computed as:

$$WACC = \left(\frac{E}{E+D} \times R_e\right) + \left(\frac{D}{E+D} \times R_d \times (1-T_c)\right) \quad , \tag{2}$$

where E is the market value of equity (i.e., the total value of shares held by shareholders), D is the market value of debt (i.e., the total borrowed capital), R_e is the cost of equity, R_d is the cost of debt, and T_c is the corporate tax rate.

The cost of equity, R_e, represents the required rate of return for equity investors and is typically higher than the cost of debt, R_d, as debt providers are reimbursed first in case of bankruptcy, while shareholders are the last to recover their capital. However, if a company borrows excessively, this increases its financial risk, potentially raising R_d above R_e. The proportions $\frac{E}{E+D}$ and $\frac{D}{E+D}$ define the capital structure of the company. An optimal capital structure can reduce the overall cost of capital by minimizing the WACC. Finally, the term $(1-T_c)$ reflects the adjustement applied to the cost of debt thanks to the tax shield T_c on interest payments, as debt expenses are tax-deductible in many jurisdictions.

Estimating the parameters in Equation 2 (e.g., R_e, R_d) is not straightforward due to limited availability of public financial data. A common practice is to identify a set of comparable firms within a sector and extract these values from their financial statements. In this study, publicly available data from [9] is used, which provides the WACC and its components for specific sectors in the United States.

To account for country-specific investment risks,Equation 2 is adapted as follows:

$$WACC_{USD} = \left(\frac{E}{E+D} \times (R_e + CRP)\right) + \left(\frac{D}{E+D} \times (R_d + ADS) \times (1-T_c)\right) \quad , \tag{3}$$

where CRP is the Country Risk Premium and ADS is the Adjusted Default Spread, both retrieved from [7], which estimates them from the perspective of a U.S. investor.

It is assumed that project finance is employed, i.e., that a Special Purpose Vehicle (SPV) is created in the target country. An SPV is a subsidiary company established specifically to implement a single project. This structure limits the financial exposure of the parent company to the capital it injects into the SPV. For further details on project finance, see [28]. Since the SPV is assumed to generate its cash flows in the host country, the corresponding country-specific tax rate T_c from [7] is applied. Moreover, the cash flows generated by the project are assumed to be repatriated in the home country of the investor.

It is important to note that using CRP as an equity risk premium is an approximation. The value reflects country-level rather than sector-specific risk. Similarly, ADS captures the country's borrowing risk, not that of a particular sector or project. These are proxies that allow us to make use of open data rather than relying on proprietary financial datasets or firm-level data, which are difficult to access, particularly for hydrogen projects in emerging markets. Nonetheless, this methodology offers a reasonable approximation to account for location-specific risk.

An overview of the parameters used in Equation 3, their specificity, and sources is provided in Table 1.

Finally, the economic parameters in our model are expressed in euros, while the values from [7, 9] are reported in U.S. dollars. Therefore, the WACC computed in USD ($WACC_{USD}$) is converted to euros using the Fisher equation:

$$WACC_{EUR} = \frac{(1 + WACC_{USD})}{1 + \pi_{US}} \cdot (1 + \pi_{EUR}) - 1 \quad , \tag{4}$$

where π_{US} and π_{EUR} represent the inflation rates in the United States and the Euro Area, respectively. These are sourced from [16].

Parameter	Sector or Country Specific	Source
$\frac{E}{E+D}$	Sector (Green Energy, US)	[9]
R_e	Sector (Green Energy, US)	[9]
CRP	Country specific	[8]
$\frac{D}{E+D}$	Sector (Green Energy, US)	[9]
R_d	Sector (Green Energy, US)	[9]
ADS	Country specific	[8]
T_c	Country specific	[8]

Table 1: Overview of parameters, their specificity, and data sources used in financial modeling.

3. Case Studies

The case studies evaluating the cost of methane synthesis in RREHs follow the same system design as in [3]. However, CAPEX and OPEX values have been updated using the most recent data from [10] and are provided in Table A.3. A schematic representation of the technologies involved is shown in Figure 1. The code used to perform the simulations and reproduce the results is open-source and publicly available online[1].

The RREH is divided into two parts: a power production hub and a CH_4 production hub. The power hub integrates onshore or offshore wind turbines (depending on the location), photovoltaic (PV) panels, and a battery. Curtailment of renewable energy production is allowed.

The electricity generated is transmitted via a High Voltage Direct Current (HVDC) link to the CH_4 production hub, where e-CH_4 is produced through methanation (Sabatier reaction). This process uses hydrogen generated via electrolysis (powered by the renewable energy hub) and CO_2 captured from the atmosphere. A desalination unit is also modeled to supply water for the electrolysis process. The synthetic CH_4 is subsequently liquefied and exported via ships.

The main differences between case studies lie in the locations considered, which result in different renewable energy load factors (evaluated over five years based on [25]), differentiated WACC values (in one of the scenarios), and varying ship travel times to the final destination (Belgium).

[1] https://github.com/GBOML/GBOML-examples

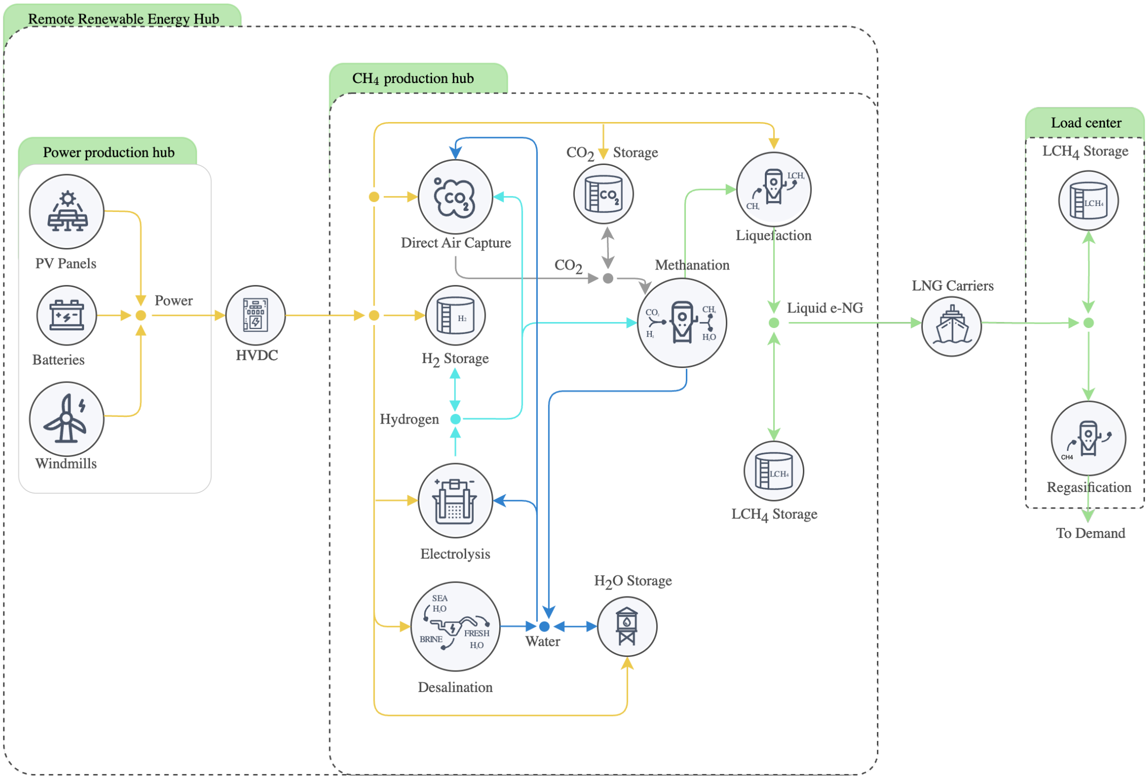

Figure 1: The RREH supply chain modeled. The RREH can be divided into three parts: production, conversion and export facilities.

The parameters for each location are summarized in Table 2. Additionally, for the two European countries (Germany and Spain), liquefaction, maritime transport, and regasification units from Figure 1 are excluded, as direct injection into the European gas grid is assumed. For the remaining countries, transport via ships traveling at 19 knots and regasification before delivery to Belgium is modeled.

All scenarios assume a constant energy demand equivalent to 10 TWh per year.

Country	WACC	Travel Time
Algeria	10,67%	116
Argentina	15,79%	390
Belgium	6,13%	-
Chile	6,28%	390
Germany	5,36%	-
Greenland	5,69%	116
Namibia	9,36%	312
Spain	7,08%	-

Table 2: WACC per country.

The locations considered are Algeria, Argentina, Chile, Germany, Greenland, Namibia, and Spain. Below, the rationale for selecting these locations is discussed.

The area near Málaga in Spain is selected to represent a location closer to major European demand centers, with high renewable energy potential and access to the European gas network. It allows for a comparison between domestic supply within EU zones and external sources.

The region near Bremerhaven in Germany provides another perspective on domestic e-fuel synthesis, although it has lower renewable energy potential compared to Spain and RREHs.

The southern region of Namibia, near the South African border, is chosen due to its hydrogen Memorandum of Understanding with Belgium as part of the national hydrogen strategy of Belgium, and its abundant renewable energy resources. It is also representative of Southern Africa more broadly.

The locations of Chile and Argentina, near the southern tip of South America, are identified in [24] as having high renewable energy potential, with direct access to the Atlantic Ocean for export to Belgium.

Two different scenarios are performed: the first applies a common WACC of 7%, while the second applies a differentiated WACC per country, computed using the methodology described in subsection 2.2.

4. Results and Discussion

As shown in Figure 2, in the scenario where the WACC is constant across countries, Algeria has the lowest production cost of e-methane at 153€/MWh, while the highest cost is found in Germany at 203€/MWh. In this constant WACC scenario, only the renewable energy potential and distance to the energy demand center matters. Therefore, RREH to harness high quality renewable energy potential makes sense even when accounting for additional costs such as liquefaction and maritime transport.

However, in the differentiated WACC scenario, the picture changes. Germany's cost to produce and export e-methane to Belgium drops to 180€/MWh, whereas Algeria's cost increases to 192€/MWh.

Three countries emerge as more favorable under differentiated WACC: Chile, Greenland, and Germany. Chile becomes the location with the lowest cost of methane synthesis, reaching 153€/MWh which is identical to Algeria's cost in the constant WACC scenario. Greenland also proves competitive, with a cost of 166€/MWh, which is lower than those of Algeria, Namibia, and Argentina.

Spain and Germany exhibit similar production costs, at 182€ and 180€/MWh, respectively. This suggests that installing renewable energy hubs within Europe, rather than RREHs in Algeria, Namibia or Argentina, may be advantageous, especially when considering Belgium as importing country. Indeed, Belgium participates in shared institutions such as the EU, NATO, OECD, and the Eurozone, which facilitate cross-border exchanges and collaboration between countries participating in these institutions.

By contrast, Algeria, Namibia, and Argentina perform worse under the differentiated WACC scenario. Their production costs increase by 26%, 17%, and 65%, respectively. Exhibiting significant rises relative to the constant 7% WACC. The case of Argentina is particularly concerning: the cost nearly doubles compared to Chile, despite the two locations being geographically close (southern South America).

While the constant WACC scenario provides a purely technical comparison of locations, the differentiated WACC scenario incorporates investment risk. This raises the question: is it possible to reduce the WACC in technically attractive locations to make them economically viable?

First, let us recalling that the WACC and especially the differentiated WACC takes into account several risks for the investors: business risk, financial risk and political risk. Nevertheless, not all investors have the same investment criteria. Some may be motivated by environmental, social, and governance (ESG) considerations or long-term strategic interests, leading them to accept lower returns. Identifying and attracting such investors can reduce the effective cost of capital, thereby lowering the WACC and making RREHs more economically viable.

Second, consider the formulation of Equation 3. The ADS, used to estimate the local credit spread (or the risk premium on debt), is a proxy for a country's borrowing risk. However, this proxy introduces a potential bias. In practice, the cost of debt for a project may differ substantially from that of sovereign debt. For example, if local banks or development finance institutions in Argentina can provide loans at more favorable conditions than suggested by the country's sovereign risk, Argentina may become a more attractive location for RREH deployment than the model currently indicates. In order to reduce such potential bias, one could use the credit spread of a publicly traded company from the country.

Calcaterra et al. [4] discussed the importance of reducing the cost of capital in developing countries in order to accelerate the energy transition and achieve climate neutral policies. However, they assess that more renewable energy assets are installed in developing countries if they get access to cheaper capital than they have actually. Nevertheless, they acknowledge the challenges in achieving these reductions of cost. Indeed, as an example, the CRP that an investor adds for its return on equity depends notably on the risk of currency changes which depend notably on inflation. Therefore, independent central banks that may mitigate inflation thanks to effective monetary policy are essential institutions to decrease the cost of capital in emerging markets.

De-risking RREH project can also be a possibility to decrease the WACC. This can be done with off-taker that provide guarantees of buying the e-fuel over a given period at a given price. More complex mechanisms can be imagined. For example, Matthäus and Mehling [19] proposes a de-risking strategy for renewable energy investments in developing economies. They propose that renewable energy projects use a multilateral guarantee mechanism involving donor countries, the host country, investors, developers, and international financial institutions. This mechanism helps reduce the cost of capital in developing countries and demonstrates how it can accelerate decarbonization in the developing world, with potential global savings of up to $1.5 trillion by 2030.

Finally, this paper focuses on e-CH_4, however other e-fuels such as ammonia or methanol may also emerge as viable alternatives. The analysis presented here can be extended to other e-fuels, as the cost of capital would similarly affect different locations regardless of the specific e-fuel supply chain considered. Indeed, as shown in [18] for H_2, CH_4, CH_3OH and NH_3, the most capital-intensive assets tend to be installed in comparable capacities across different e-fuels.

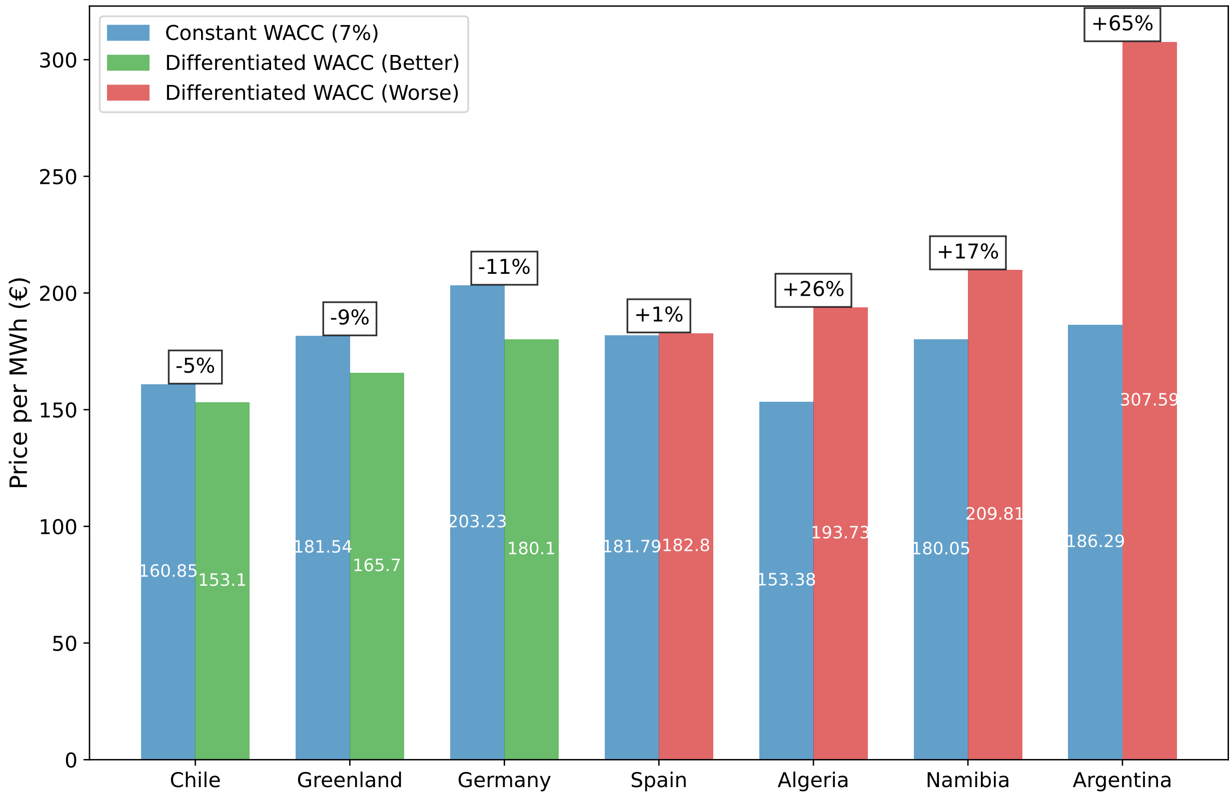

Figure 2: Price per MWh per country under constant and differentiated WACC Scenarios. Countries are ranked by increasing cost of energy for the differentiated WACC scenarios. Percentage changes indicate the impact of differentiated WACC on energy costs.

5. Conclusion

In this study, case studies are conducted for seven locations to assess the feasibility of e-methane production. The entire supply chain is modeled as a linear program and optimized at an hourly resolution over a five-year time horizon. These case studies help to better understand the role of the cost of capital or Weighted Average Cost of Capital (WACC) in the emergence of RREHs. The results demonstrate that WACC significantly affects the economic viability of such projects.

Nevertheless, due to the difficulty of obtaining accurate financial data and the challenges of properly capturing the cost of capital, it is not possible to definitively identify which countries will become leading exporters of low-carbon synthetic fuels. Nonetheless, the results highlight promising candidates. For example, Chile combines high-quality renewable energy resources with a relatively stable economic environment.

This study suggests focusing on locations where both strong renewable potential and favorable financing conditions are met or developing strategies to reduce the cost of capital. Potential strategies include accessing subsidy programs, securing large offtakers to reduce revenue uncertainty and improve financing terms, and attracting impact investors.

Finally, since WACC plays a critical role in evaluating project viability, it is recommended to systematically conduct uncertainty analyses on this parameter to assess its influence. Focusing solely on technically promising locations without considering financial risk may obscure other key factors that determine the emergence of successful RREHs.

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Competing interests

The authors declare no competing interests.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the author(s) used ChatGPT in order to correct the readiness, grammar and spelling of the writing. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

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Appendix A. Annexes

Technology	CAPEX	FOM	VOM	Lifetime [yr]
Solar Photovoltaic Panels[b]	380.0 M€/GW_{el}	9.5 M€/GW_{el}–yr	0.0 M€/GWh_{el}	25.0
Onshore Wind Turbines[b]	1110.0 M€/GW_{el}	13.4 M€/GW_{el}–yr	0.00144 M€/GWh_{el}	30.0
Offshore Wind Turbines[b]	1800.0 M€/GW_{el}	39 M€/GW_{el}–yr	0.00389 M€/GWh_{el}	30.0
Battery Storage (Flow)[a]	160.0 M€/GW	0.5 M€/GW-yr	0.0 M€/GWh	10.0
Battery Storage (Stock)[a]	142.0 M€/GWh	0.0 M€/GWh-yr	0.0018 M€/GWh	10.0
HVDC[a]	480.0 M€/GW_{el}	7.1 M€/GW_{el} – yr	0.0 M€/GWh	40.0
Electrolysis[a]	600.0 M€/GW_{el}	30 M€/GW_{el} – yr	0.0 M€/GWh	15.0
Methanation[a]	735.0 M€/GW_{CH_4}	29.4 M€/GW_{CH_4} – yr	0.0 M€/GW_{CH_4}	20.0
Desalination[a]	28.08 M€/kt_{H2O}/h	0.0 M€/kt_{H2O}/h – yr	0.000315 M€/kt_{H2O}	20.0
Direct Air Capture[a]	4801.4 M€/kt_{CO2}/h	0.0 M€/kt_{CO2}/h – yr	0.0207 M€/kt_{CO2}	30.0
CH_4Liquefaction[a]	5913.0 M€/kt_{LCH_4}/h	147.825 M€/kt_{LCH_4}/h – yr	0.0 M€/kt_{LCH_4}	30.0
LCH_4Carriers[a]	2.537 M€/kt_{LCH_4}/h	0.12682 M€/kt_{LCH_4}/h – yr	0.0 M€/kt_{LCH_4}	30.0
LCH_4Regasification[a]	1248.3 M€/kt_{CH_4}/h	29.97 M€/kt_{CH_4}/h – yr	0.0 M€/kt_{CH_4}	30.0

Table A.3: Economical parameters used for modeling conversion nodes (2030 estimate). The HVDC line CAPEX includes the cost of two substations and assumes a transmission length of 1000 km.
[a] Data reused from Berger et al. [3].
[b] Data reused from Danish Energy Agency [10].

Conclusion

8 Conclusion

The transition to a low-carbon energy system requires not only technological innovation but also systemic reconfiguration of how and where we produce and deliver energy. This dissertation has argued that Remote Renewable Energy Hubs (RREHs) represent a promising concept to overcome the spatial and temporal mismatch between renewable resource availability and energy demand.

Through a compilation of articles, this work has advanced the understanding of RREHs along three dimensions:

- Conceptual clarity (RQ1): A taxonomy was developed to define and formalize RREHs, enabling systematic comparison between different hub designs. This taxonomy highlights the diversity of possible designs, and provides a tool for identifying new hub designs.

- Novel designs (RQ2): CO_2 valorization loops demonstrated that synergies between load centers and hubs can reduce costs and create new circular carbon pathways. Comparative CO_2 sourcing strategies revealed that hybrid approaches (DAC + PCCC) outperform single-source assumptions. Comparative techno-economic analyses of hydrogen, ammonia, methanol, and methane demonstrated that carrier choice could strongly influence the cost-effectiveness and efficiency of RREHs energy exports. Ammonia emerged as particularly competitive, underscoring the need to align carrier selection with infrastructure readiness, industrial demand, and transport logistics. Finally, the high-seas hub (REHS) concept illustrated how battery-shuttling could unlock access to far-offshore wind, broadening the geography of feasible hubs.

- Financing and cost of capital (RQ3): By developing a methodology to account for country risk in the Weighted Average Cost of Capital (WACC) in RREH modeling, this work demonstrated that financing conditions can be as decisive as resource quality. Case studies revealed that technically attractive regions may be economically unattractive due to capital costs, highlighting the critical role of innovative financing mechanisms and international cooperation in making RREHs viable.

8.1 Outlook

Although this dissertation helps in understanding the techno-economic perspectives of Remote Renewable Energy Hubs (RREHs), several areas of research appear particularly welcome to further advance knowledge on the concept and enable its deployment at scale.

First avenue: Improving hub siting and quality assessment.

Building on the taxonomy developed in this thesis, future research could focus on automating the selection of suitable locations. Developing criteria for evaluating the quality of an RREH would also be valuable. Among such criteria, the following appear to be the most relevant:

- C1 – Renewable energy potential,
- C2 – Land availability,
- C3 – Available infrastructure,
- C4 – Financing and competitiveness, and
- C5 – Energy sovereignty.

While C1 and C2 are already embedded in the taxonomy through the set of locations, they could be automatically assessed using methodologies such as those developed in [Pfe+23; Ber+22]. Further work is needed to operationalize C3–C5, which would enable systematic search of hubs.

Second avenue: Understanding trading opportunities and market design.

As is the case for oil and gas, the international trading of e-fuels will play a key role in shaping new energy exchange routes between countries. Creating market-based models to anticipate and understand future trade flows of e-fuels is therefore a promising direction for future work.

In addition to international trade, other trading opportunities deserve attention. For instance, producing hydrogen notably requires electrolysers, which can modulate their electricity consumption. If the RREH is connected to a local electricity grid, the demand flexibility of the electrolyser could be leveraged to participate in capacity markets and provide ancillary services to the grid [Joh+25]. Another example concerns the valorization of byproducts, e.g. oxygen produced via electrolysis, which could represent a new source of revenue for RREH developers. Exploring alternative revenue streams could strengthen the overall economics of the project and, in turn, its bankability.

Third avenue: Financing mechanisms and risk mitigation.

New financing mechanisms are welcome to improve the investment conditions for RREHs located in high-risk regions. Since many high-potential RREH sites are in developing countries, there is a strong need for interdisciplinary research, especially in collaboration with political scientists, to design international partnerships and risk-sharing mechanisms.

Even in developed countries, the cost of e-fuels is expected to remain higher than their fossil-based counterparts. Blended finance, sovereign guarantees, and other de-risking instruments could help reduce the Weighted Average Cost of Capital (WACC) and thereby improve project viability. These financing mechanisms could also be integrated into the taxonomy proposed in this thesis, further enriching the conceptual framework.

Fourth avenue: Regulation and certification schemes.

Regulatory frameworks and certification schemes will be instrumental in enabling the uptake of e-fuels. On one hand, regulation can stimulate demand by setting mandatory targets for the share of fuels coming from e-fuels (e.g., FuelEU Maritime, ReFuelEU Aviation). Regulation can also correct market inefficiencies by internalizing externalities through carbon pricing and other policy instruments. Further research is required to align these instruments with the energy needs of hard-to-abate sectors.

On the other hand, certification schemes are needed to ensure transparency in the trading and use of e-fuels. They are important for rewarding early adopters of low-carbon fuels, verifying the renewable origin of fuels, and ensuring that policy targets are met credibly and efficiently.

Fifth avenue: Integrating the geopolitical dimension.

Although not covered in this thesis, the geopolitical dimension could have a significant impact on the emergence of RREHs. As new energy dependencies and strategic alignments emerge from e-fuel trade, geopolitical analysis will be critical. This avenue directly connects to the fifth criterion in first avenue: C5 – Energy sovereignty. While the first four criteria (C1–C4) are more technical or economic in nature and can be more easily quantified, C5 touches upon political stability, control over energy supply chains, and national security considerations—all of which are inherently geopolitical.

To better capture these aspects, the taxonomy developed in this thesis could be extended to integrate indicators of political risk, international governance frameworks, and strategic partnerships.

However, defining such criteria presents methodological challenges, as geopolitical factors are often qualitative, context-dependent, and difficult to quantify. Interdisciplinary approaches will be required.

8.2 Final Remarks

The production of e-fuels will be essential if we are to fully transition our economies to low-carbon economies and meet climate targets. The concept of RREH could play a key role in enabling this transition, offering several advantages: harvesting renewable energy where it is most abundant, transforming non-productive land into productive assets, and allowing parallel development in multiple locations, thus potentially accelerating the energy transition. However, numerous questions remain about how RREHs will emerge and how to ensure that their output is directed toward the sectors that need e-fuels most—namely, the so-called hard-to-abate sectors.

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