Christoph Hank, Marius Holst, Connor Thelen, Christoph Kost, Sven Längle, Achim Schaadt, Tom Smolinka

Site-specific, comparative analysis for suitable Power-to-X pathways and products in developing and emerging countries

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POWER-TO-X COUNTRY ANALYSES

Site-specific, comparative analysis for suitable Power-to-X pathways and products in developing and emerging countries

A cost analysis study on behalf of H2Global

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Christoph Hank
Marius Holst
Connor Thelen
Christoph Kost
Sven Längle
Achim Schaadt
Tom Smolinka

Fraunhofer Institute for Solar Energy Systems ISE

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List of Abbreviations

Abbreviation	Explanation
AC	Alternating current
ASU	Air separation unit
AEL	Alkaline water electrolysis
AUD	Australian dollar
CAPEX	Capital expenditure
CEPCI	Chemical engineering plant cost index
DAC	Direct air capturing
DC	Direct current
EUR	Euro, €
FT	Fischer-Tropsch synthesis process
GIS	Geoinformation system
GST	Goods and services tax in Australia
GW / GWh	Gigawatt / Gigawatt hours
LH_2	Liquid hydrogen
LCoPtX	Levelized cost of a specific PtX product (e.g. ammonia)
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquefied petroleum gas
MeOH	Methanol
MR 2	Tanker with mid-range 2 type definition
MW / MWh	Megawatt / Megawatt hours
OPEX	Operational expenditure
O&M	Operation and maintenance
PEM	Polymer electrolyte membrane electrolysis
PtX / PtL	Power-to-X / Power-to-Liquid
PV	Photovoltaic
PVGIS	Photovoltaic Geographical Information System
RE	Renewable energy
SWRO	Sea water reverse osmosis
SEC	Specific energy consumption
TRL	Technology readiness level
USD	US Dollar
WACC	Weighted average cost of capital

Executive Summary

This study examines the production, transport and supply costs of key Power-to-X products for the year 2030.[1] A total of 39 globally distributed regions in developing and emerging countries were therefore analyzed in terms of their renewables and Power-to-X production and supply cost potential. The comprehensive techno-economic results presented are based on extensive country analyses regarding their renewables generation potential, identification of promising regions, and holistic simulations and optimization of Power-to-X production and supply pathways for each of the identified locations. The main focus was on the analysis of the renewable electricity generation costs in these countries and subsequently a detailed design and simulation-based optimization of Power-to-X chains for the production of **green hydrogen, ammonia, methanol and jet fuel**. For the import scenarios, the long-distance transport of green energy carriers to Germany was considered either in the form of ocean-going vessels or hydrogen pipelines. A central prerequisite was the generation and use of **exclusively dedicated renewables for the production of 100% green hydrogen**. A system based on the production of electricity from variable renewables requires a holistic system design and operation strategy. The methodology used for this purpose includes site-dependent GIS analyses as well as hourly-resolved simulation and optimization of complete Power-to-X supply pathways. Finally, pathway-specific insights are highlighted, and key challenges and geopolitical interdependencies are discussed in the context of global Power-to-X chains.
Overall, the following conclusions for optimal Power-to-X generation can be drawn from the present study:

- Site-specific analyses of regions promising for Power-to-X production are essential for reliable cost estimates. The complex interaction of wind and photovoltaic production profiles, topographical and infrastructural conditions, and also administrative conditions make site-specific analyses indispensable. General assessments for future Power-to-X regions based only on isolated wind or photovoltaic potentials and costs neglect these aspects.
- Total product transport distance can have a decisive influence but is not necessarily a knock-out criterion (cf. the evaluated Australian regions).
- Low levelized cost of renewable electricity generation and associated high full load hours significantly affect electrolysis capacity utilization and total Power-to-X product output.
- Favorable *combined* conditions for wind and PV power generation can be more advantageous in numerous cases than locations with extremely good conditions for only wind or PV at a time. Decent hybrid RE locations lead to higher utilization and lower need for intermediate hydrogen storage.
- Low weighted average cost of capital has a high overall impact on final production and supply costs.

In the overall comparison of all the countries analyzed and the **2030 Power-to-X supply costs** achievable, Brazil and Australia in particular stand out. The local production costs of gaseous green hydrogen in these countries are between 95-110 EUR/MWh (3.17-3.67 EUR/kg H_2). The main reasons here are advantageous wind and PV combinations as well as high plant utilization and comparatively low capital costs. Taking into account the long-distance transport by ship either in the form of liquid hydrogen or ammonia,

[1] The authors thank Christopher Hebling, Ouda Salem, Jan Frederik Braun, Ramy Essam, Diana Bribach, Penelope Krumm for their watchful eyes and invaluable input to the review of this study.

the final supply costs are 171-217 EUR/MWh for liquid H_2 (5.70-7.23 EUR/kg) and 171-172 EUR/MWh in the case of ammonia. In addition to Brazil and Australia, the La Guajira region in northern Colombia is also worth mentioning due to its excellent wind potential and, as a result, the comparatively low Power-to-X production and supply costs. In general, the low levelized cost of renewable electricity in these three countries with 35-47 EUR/MWh$_{el}$ and 41-55 EUR/MWh$_{el}$ for PV and wind power, respectively, can be seen as a main reason for the favorable Power-to-X production cost. In addition to these countries, the countries considered for the MENA region – Morocco, Algeria, Tunisia – can offer above-average conditions for wind and PV electricity generation and Power-to-X production. In particular, the seven regions considered for Algeria and Tunisia consistently show favorable green ammonia and methanol production and supply costs in the range of 190-250 EUR/MWh.

With regard to the **Geographical Information System (GIS) -based infrastructure analyses** for the regions studied, it can be seen that the ports considered for export are mostly of appreciable size and have sufficient draft for the classes of ships considered. However, some of the ports are, as of today, designed only for bulk cargo and will need to be modified to meet the appropriate specifications prior to large-scale green energy exports. These costs were not considered in the assessments. Alternatively, for larger Power-to-X projects, floating offshore terminals could be an alternative, allowing ship loading with limited intervention in local port infrastructure. Furthermore, it should be noted that in some cases huge swaths of land were left out of the analyses because these regions did not have the necessary road and grid capacities (e.g., regions in Namibia, Algeria and Australia). In some of these cases, these areas have high solar irradiance and high wind speeds, which promise potentially very low electricity and Power-to-X production costs.

With regard to the **key challenges and geopolitical dependencies**, and for the time being, it should be noted that Power-to-X projects of significant size in the gigawatt (GW) range will have long planning and construction phases. The realization of the first large-scale projects in the corresponding countries must therefore be initiated now in order to be able to rely on Power-to-X import volumes in at least the single-digit terawatt hour range in the next ten years. In the area of RE technologies and associated component and systems supply, there is a considerable dependence on the Asian market. While this has been almost universally the case for PV components for over a decade, certain parts of the production chain in the wind power industry are also shifting to Asia. In the case of water electrolysis, it is important to avoid a relocation to the Asian market, also because of the ambitious electrolysis capacity targets of the EU (10 million tons of green hydrogen and renewable fuels of non-biological origin, RFNBOs, produced by 2030 within the EU). Therefore, it is important to promote the development of a manufacturing industry for water electrolysis and to scale up the current small-scale hardware manufacturing and move towards gigawatt-scale manufacturing capacities. The aspect of dependency also applies to the purchase of rare earths, more than half of which are sourced from the Asian continent.

In terms of infrastructure bottlenecks, it is also important to not only focus on the Power-to-X generation side, but also to build up downstream process chains that are required for import purposes. Importing ports must have appropriate unloading and local storage infrastructure for Power-to-X products. If there is a pipeline connection for the domestic transport of hydrogen, energy-efficient conversion facilities such as regasifiers for liquid hydrogen or ammonia reformers must be considered. In addition to pipelines, barges and trains are needed for the decentralized transport of Power-to-X products and the development of national transport chains. In addition, the application side needs appropriate storage and refueling infrastructure, as well as a shift to the use of green energy sources and chemicals. All this requires a certain degree of planning certainty as well as seed incentives, which must be created along the entire value chain. The hydrogen value chain broadly covers: i) upstream: green energy and Power-to-X production technologies, ii) midstream: hydrogen, derivatives and carbon dioxide storage and transportation, iii) downstream: end uses, and links with related economic activities [1].

Although, from Germany's point of view, Power-to-X imports will eventually not have the same significance and volumes as expiring fossil imports, it must be emphasized that green hydrogen is a no-regret option in specific parts of the energy system whose supply routes must now be established. Over the next few years, therefore, bilateral agreements between states will still form the first tender roots of a global hydrogen trade. In the years thereafter, from 2030 onwards, trade in hydrogen and its derivatives will then become not only more cost-efficient but more diversified, ensuring the essential security of the energy supply. In combination with the German energy transformation process, this will make it possible to phase out fossil energies entirely within the coming decades. Basically, this study shows that in the medium term, green hydrogen and its derivatives can be produced and supplied at costs that may well be attractive considering the tense geopolitical circumstances related to the market for fossil fuels. The H2Global instrument can shape long-term Power-to-X contracts and reduce risks for investors and producers.

»The complex interaction of wind and photovoltaic production profiles, topographical and infrastructural conditions, and also administrative conditions make site-specific analyses indispensable.«

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1
Introduction

Green hydrogen presents itself as the future feedstock and vector for defossilized energy systems and an increasingly carbon-constraint world. A general consensus in the literature is that green hydrogen and its derivatives will be a part of any future and global energy system [2–5]. Although the extent of hydrogen use in the future economies studied clearly depends on a number of assumptions, such as electrification rate, final energy demand, and as well as the limits of renewables expansion, there is significant demand for hydrogen and derived products in almost all scenarios. These hydrogen requirements relate in particular to the future material and energy needs of hard-to-abate sectors such as the steel industry, aviation, and shipping, but also potentially to the need for long-distance transport of renewable energy in the form of gaseous or liquid hydrogen or other synthetic energy carriers derived from it, such as ammonia and methanol.

Worldwide, dozens of hydrogen strategies and roadmaps have either been released or are in the works. These efforts are supported by pledges of significant funding from both public (more than $70 billion) and private sources (more than $100 billion) [6]. These investments will be necessary in the short to medium term to achieve economies of scale in the installation of green hydrogen technologies, to enable an accelerated market ramp-up, and to gradually displace fossil energy from the market with the first industrial Power-to-X (PtX) plants.

PtX processes for the production of hydrogen and its derived products ("derivatives") involve long conversion chains that are inherently associated with conversion losses. This makes it more important to use the currently limited supply of renewable electricity in cost-optimal and technically feasible PtX pathways as far as possible. Thus, a central question of current assessments is not only which PtX pathways represent the most energy-efficient option for the production of hydrogen and synthetic energy carriers, but also where they should be produced and which transport options emerge as the best option [7–13].

With a focus on Germany, a domestic PtX landscape remains key for the supply of green hydrogen and synthetic products. However, at the same time, it will still be necessary to import significant quantities of PtX products from countries with high RE potential as well as sufficient infrastructure and socio-economic conditions [10,14]. Put simply, these import pathways need to be emphasized today, planned tomorrow, and realized as soon as possible. Enabling a near-term market introduction of PtX technologies to trigger economies of scale for cost degression and to learn from field operations in large-scale plants seems more urgent than ever as global climate warming accelerates [15].

The H2Global Foundation intends to support the market ramp-up of PtX imports. The selection of suitable countries for PtX production is a key step for the successful implementation and application of this instrument and ultimately for the most cost-efficient production and import of hydrogen and derivatives. For this reason, the Fraunhofer Institute for Solar Energy Systems (ISE) was commissioned by the H2Global Foundation to investigate the production and supply costs of key PtX products for a list of pre-selected countries. The comprehensive results presented in this study are based on extensive country analyses regarding their RE generation potential, identification of regions promising for PtX production in these countries, and holistic simulations and optimization of PtX production and supply pathways for each of the identified locations. The results and insights derived can thus not only provide valuable support to the H2Global instrument, but also enrich the scientific and policy discourse and contribute to the deployment of the first large-scale PtX projects in promising countries.

2
Overview

This chapter provides a general overview of the research question, countries analyzed, PtX pathways, and product and transportation scenarios for this study.
More detailed insights into the technological framework and scenarios considered are provided in the subsequent chapter 3.

2.1 Goal and scope of this study

The main objective of this study is the analysis of the technical feasibility and the production costs for specific large-scale green hydrogen and further Power-to-X (PtX) pathways in selected countries for the year 2030.

Definition of "Power-to-X": Power-to-X (PtX) describes the conversion of electricity as primary energy into energy carriers and basic chemicals. Hence, PtX generates heat, energy carriers and fuels as well as raw materials and chemicals [16,17].

An important feature of the systems considered is that only green hydrogen, i.e. production based 100% on variable renewables, is taken into account in the analyses. As a consequence, the need for intermediate hydrogen storage and the influence of dynamic synthesis operations on system design and costs, is analyzed.
The study assesses both the production for the local market and the downstream transport of these PtX products for import to Germany and Europe.
The assessed systems and scenarios cover the entire supply vector starting from the variable generation of renewable electricity, its transport to the site of hydrogen production, and the subsequent liquefaction of hydrogen or its conversion into synthetic energy carriers (Figure 2-1). Depending on the scenario the products are either assumed to be available for local market distribution or transported to Germany via ship or pipeline. The downstream end of the system boundaries is defined by the importing port edge. Any further conversion and utilization of the assessed PtX products has not been the focus of this study.

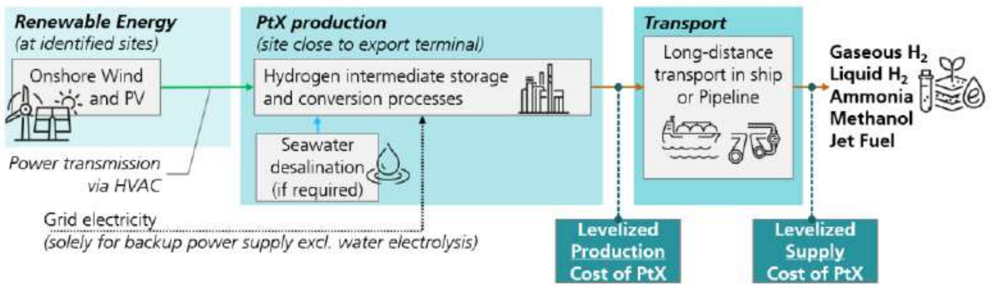

Figure 2-1 – The scope of the assessed Power-to-X supply chains comprises the main phases of renewable electricity production (at identified RE sites), PtX production, and intermediate storage (close to the export terminal) and subsequent transport via ship or pipeline. This study indicates both the levelized production cost of PtX (in the exporting country for local distribution) as well as the levelized supply cost of PtX (at the importing harbor).

One methodological focus of the study was to map the effects of an **operation exclusively with variable renewables** on the system design and ultimately the PtX production costs. For this purpose, site-dependent hourly resolved generation profiles for renewables were used. A simplified static approach based on average annual full load hours was not used, as this would neglect key optimization aspects such as the size of inevitable buffer storage. For the purpose of a holistic PtX optimization procedure, the PtX pathways have been simulated by the toolbox "H2ProSim," which has been continuously developed at Fraunhofer ISE since 2012 and deployed in numerous research projects. H2ProSim makes it possible to individually adapt complex PtX systems to the respective location, to take into account the conditions for renewables and the scenarios, and to select cost-optimal system architectures with the aid of a mature optimization algorithm. A more in-depth description of the methodology is given in chapter 4.

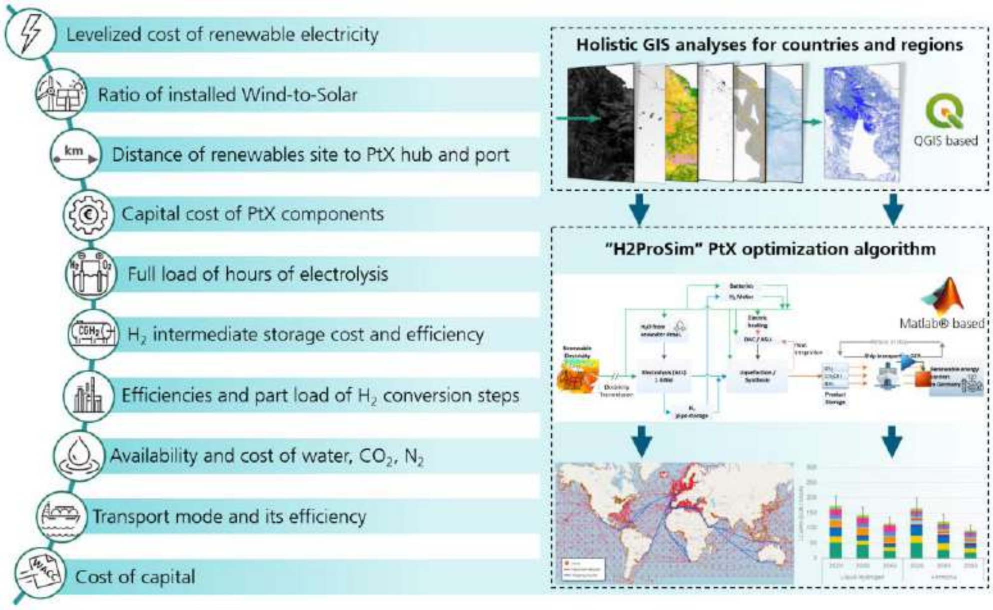

Figure 2-2: The holistic PtX optimization procedure via the Fraunhofer ISE toolbox "H2ProSim" considers a wide range of technological aspects and the effect of an operation exclusively with variable renewables on the production of "true green hydrogen".

Techno-economic assessments and the performance of the pathways considered are, in addition to the assumed technical parameters, highly dependent on numerous boundary conditions, such as technology year, concept of electricity supply and intermediate storage, and RE technologies considered. Therefore, the general framework as well as the scenarios assessed are discussed in chapter 3.
The following section provides an overview of the countries and PtX pathways considered in this study.

2.2 Countries and Power-to-X pathways assessed

The starting point for this study is a set of twelve countries, which were determined by the H2 Global Foundation[2]. For this given set of countries, a well-developed methodology based on comprehensive GIS analyses was used to determine specific sites that are suitable for the construction of dedicated renewable energy capacities due to their meteorological, topographical, and technological conditions.
The PtX pathways assessed included the production of either gaseous or liquid hydrogen (GH_2 and LH_2, respectively), methanol (MeOH), ammonia (NH_3), or jet fuel via the Fischer-

[2] The country selection was based on a dialogue between the German Federal Ministry for Economic Cooperation and Development (BMZ), the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) and the H2Global Foundation. The basis for the decision was, in addition to the basic potential of the countries, existing energy partnerships as well as political and economic initiatives within the countries to participate in the development of international hydrogen markets. The selection of countries, however, does not claim to be complete; rather, the findings should also be transferable to countries with similar conditions for the overarching research project. Countries that are not classified as developing and emerging countries were included as reference countries, since they are (exemplarily) in competition with the developing and emerging countries considered as production locations for green energy carriers.

Tropsch (FT) pathway. These PtX end products are much-discussed synthetic energy carriers, which will be needed in numerous sectors and end applications in a future defossilized energy system [14,16,17]. And this will be the case not only in several decades, when greenhouse gas neutrality is to be achieved, but rather already in the short term, with increasing and in some cases strongly increasing quantities required in the next two decades. Depending on the producing country, the PtX products are assumed to be either available for the local market (no downstream transport) or subsequently transported to Germany. Table 2-1 provides an overview on the resulting product-country matrix.

Table 2-1 - Matrix for the countries and Power-to-X pathways assessed in this project.

	Ammonia		Methanol		Jet fuel		GH_2	LH_2
Use Case:	Local	Export	Local	Export	Local	Export	Export	Export
Transport via	-	*Ship*	-	*Ship*	-	*Ship*	*Pipeline*	*Ship*
Brazil	x	x						x
South Africa	x	x		x				x
Ukraine	x	x					x	
Colombia	x	x		x				x
India	x	x		x	x	x		x
Namibia	x	x		x				x
Tunisia	x	x		x			x	
Algeria	x	x		x			x	
Morocco	x	x		x			x	
Mexico	x	x		x		x		x
Spain	x	x	x	x	x	x	x	
Australia	x	x	x	x	x	x		x

In the case of an assumed long-distance transport of the liquid PtX products ammonia, methanol, jet fuel, and liquid hydrogen, transport via ocean-going vessels is considered. In the case of gaseous hydrogen, transport in international H_2 pipelines is assumed.

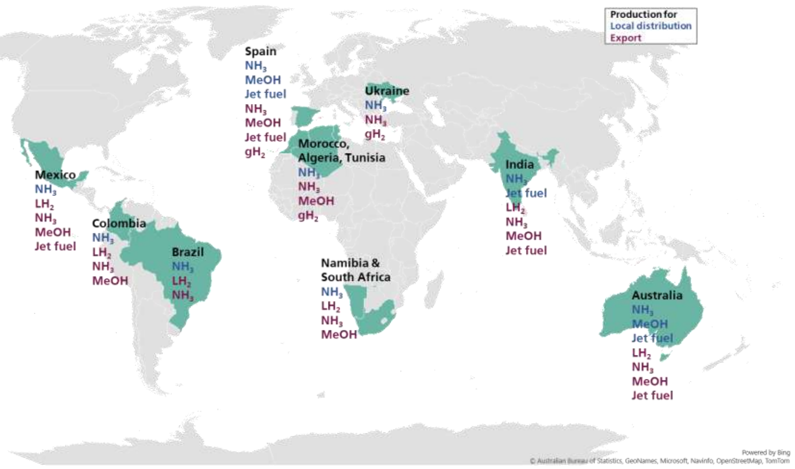

Figure 2-3: Overview map of the analyzed countries and products. Blue for PtX products which are to be supplied to the local market. Purple for export products (background map: bing.com/maps).

3 General Framework

The general framework for this study was briefly addressed in the overview chapter 2. This chapter provides further background information on the systems' overall layout, their technical framework, and the scenario design.

3.1 Layout of the PtX Systems

General system boundaries and target year
The general system boundaries comprise all of the PtX supply vectors (Figure 3-1). Thus, the systems modeled and optimized include renewable electricity production via wind and PV[3], and if necessary, electricity transmission and seawater desalination, followed by the production and intermediate storage of green hydrogen and its derivatives and, depending on the scenario, either their local distribution or subsequent long-distance transport to the target in Germany. For the ship transport scenarios Brunsbüttel has been selected. The port site in Brunsbüttel is currently being developed under accelerated conditions into an energy import hub that can handle LNG and hydrogen (derivatives) on a large scale. In case of the pipeline scenarios the industrial cluster around Mannheim and Munich have been considered as the end point. For this, the system-specific layouts as well as the considered components depend on the evaluated PtX path. A central key parameter for the system optimization was a fixed design size of **1 GW_{el} for the water electrolysis**, which was determined in advance by the H2Global Foundation. This parameter applies to all assessed regions. The corresponding design parameters of the numerous other system components such as dedicated renewables or the syntheses, on the other hand, are specific results of the simulation and optimization process.
The target year of the assessment is a **production start in 2030**, which in turn means that the project planning and construction phase must take place in the preceding years. It is very likely that such an extensive project with RE and electrolysis capacities in the GW range will be divided into several construction phases. Therefore, for the assumptions on technical parameters and costs, care was taken to consider, where possible, cost values before 2030 (~2026/27) for the renewables. For the PtX components, on the other hand, a later construction phase (2027-29) was assumed and, where possible, parameters were adjusted accordingly. At the same time, however, the impression should not be given that year-specific data were available for all components considered, depending on the assumed construction stage. The data available from Fraunhofer ISE, industrial partners, and the literature were not sufficient for this.

System layout for the liquid PtX products
Figure 3-1 depicts the general system layout for the liquid PtX products liquid hydrogen, ammonia, methanol, and jet fuel. Renewable electricity is generated via dedicated onshore wind and PV plants at the sites identified through GIS analyses (section 4.1). The electricity is transported to the location of the PtX production and export hub, which is chosen based on close proximity to an existing port with sufficient draft and capacity (section 4.2). In addition, proximity to the sea was necessary at almost all sites to enable a water supply via seawater desalination. At the location of the PtX Hub, all process engineering steps are localized, starting with seawater desalination and treatment, 1 GW_{el} water electrolysis, product gas separation, and hydrogen intermediate storage in the form of aboveground pressurized tanks. For the downstream liquefaction of green hydrogen necessary infrastructure such as hydrogen liquefaction, ammonia, methanol or Fischer-Tropsch syntheses, and the provision of nitrogen or carbon dioxide are considered. In the case of carbon dioxide supply, the Direct Air Capture (DAC) technology

[3] For better readability, this study will refer to "renewables" in cases where "onshore wind and PV" power generation is meant.

is considered in the main scenarios as specified by the H2Global Foundation. However, capture of carbon dioxide from point sources such as concentrated exhaust gas streams in industry or biogenic processes are also conceivable and are touched upon in a special scenario (c.f. 6.3.4). For the liquid product storage before transport by ship, an intermediate storage facility with a size corresponding to two weeks of production capacity is taken into account in each case. The product is now "at the factory gate" and ready for local distribution (levelized production cost of PtX) or is transferred to appropriate transport vessels and transported to the destination port in Brunsbüttel, Germany (levelized supply cost of PtX). Further conversion of the products back to green hydrogen was not the focus of this study, as the focus was on the PtX products themselves and not exclusively on the transport of the green hydrogen. To allow for a generic annual maintenance interval at the production site, operation of the PtX plants is stopped for one week each year.

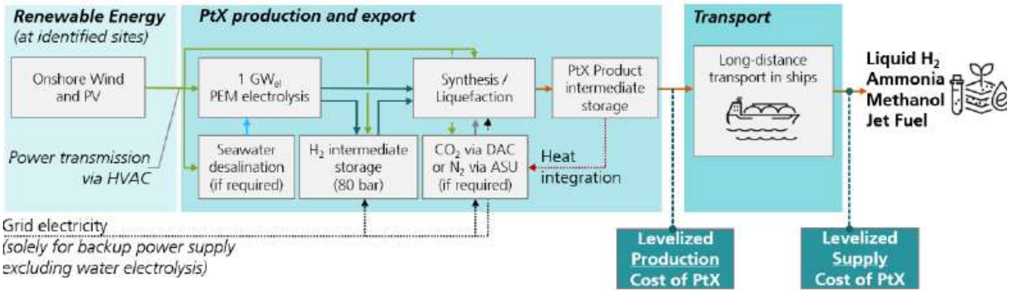

Figure 3-1: System layout for the liquid PtX products liquid hydrogen, ammonia, methanol and jet fuel. Renewable electricity is generated via onshore wind and photovoltaics at sites identified through GIS analyses. Subsequently the electricity is transported to the site of PtX production and export, usually near an existing port with sufficient draft and capacity. Subsequently, the products are either considered for the local market or transported by ship to the target port in Brunsbüttel, Germany.

System layout for gaseous hydrogen

Figure 3-2 illustrates the system structure when the gaseous green hydrogen produced is injected directly into a pipeline and transported from there to the destination in Germany. Information on the types of pipelines considered as well as the assumed costs can be found in section 5.4.2.

Figure 3-2: System layout for the production of gaseous hydrogen and downstream long-distance transport in pipelines.

Transport of renewable electricity and use of grid electricity

To overcome the distance between the RE production site and PtX hub, the use of dedicated grid capacities was assumed as a basic requirement. For most of the countries studied, it would have been unrealistically optimistic to assume existing high-voltage grid capacities capable of handling transmission capacities of more than one gigawatt. For this reason, the costs of such a new power line were taken into account in the economic calculations (section 5.1.2).

All system components primarily run on renewable electricity. The use of grid electricity is only for compressors, pumps, and carbon dioxide and nitorgen supply at times when

RE generation is insufficient. The water electrolysis is turned off at times of insufficient RE generation and, in contrast, is never operated with grid power. The liquefaction and syntheses which rely on a limited varying and sustained hydrogen flow, are fed from the hydrogen buffer, the size of which is to be based on the simulation and optimization process.
For reasons of system dynamics and the need to install certain RE overcapacity, some of the RE electricity generated cannot be fully converted to hydrogen at the PtX hub. This excess electricity is available to be fed into the respective national grid "free of charge".

3.2 Definition of scenarios and sensitivity analyses

In the context of the numerous production sites considered, the various PtX pathways are also illuminated with the help of varying scenario conditions. In addition to the distinction between the "local distribution" case and the "export" case (section 2.2), there are further special scenarios that allow additional insights to be gained from the analyses.

Assessment of "at-gate-hydrogen" generation cost
To discuss the production costs of gaseous hydrogen without further liquefaction, conversion to synthetic fuels, or transportation, all regions in this study were as well analyzed in terms of their local hydrogen production cost potential. The respective results are discussed in section 6.3.2.

Off-grid scenario
In principle, hydrogen is produced at all assessed PtX sites exclusively with electricity from dedicated wind and PV capacities ("true green hydrogen"). The syntheses also run primarily on these renewable sources. Only for certain periods, when wind and sun are not sufficient, backup grid electricity is used for compressors, nitorgen and carbon dioxide capture, seawater desalination, and hydrogen liquefiers. However, this electricity purchase is only a small portion and is discussed in the results.
Therefore, a special scenario highlights a PtX operation for a remote, off-grid site. In this case, a backup power supply is realized by the reconversion of temporarily stored hydrogen into electricity in a fuel cell power plant. The results are presented in section 6.3.3.

Jet fuel: Accounting of generated synthesis "side" products
For the production of jet fuel the Fischer-Tropsch (FT) pathway is considered. Based on fossil sources, the FT synthesis can be seen as a mature technology applied for decades on a large scale. However, if captured carbon dioxide is used as the primary carbon source, a reverse water-gas shift (RWGS) conversion-processes must be considered as an additional process step and still nascent technology[4]. Additionally, the FT process produces a spectrum of light hydro-carbon fuels and products as well as heavy fractions such as jet fuel, diesel and waxes. In order to correctly take this aspect into account, the FT production costs are shown for all relevant regions, both with and without the sale of by-products at locally achievable market prices.

Carbon dioxide: Supply via DAC or concentrated point source
For the PtX pathways dependent on a carbon source (methanol, jet fuel) the carbon is primarily supplied by direct atmospheric capture (DAC) of carbon dioxide. This technology, which is a necessity for a globally closed carbon cycle in addition to biomass-based carbon sources, results in comparatively high carbon supply costs. For this reason,

[4] Another possibility for the use of captured CO_2 in FT synthesis is the use of CO electrolysis, which, however, still has an even lower TRL and is not in the focus of this study.

the PtX production costs with carbon dioxide capture from a concentrated carbon source are also shown for one selected region in a special scenario (c.f. section 6.3.4).

Hydrogen pipelines: Dedicated or EU-wide network
Basically, all gaseous hydrogen scenarios distinguish between transport in dedicated hydrogen pipelines (built especially for this venture) and the potential utilization of a European hydrogen network ("European Hydrogen Backbone"). The latter includes a network of newly built hydrogen pipelines and retrofitted natural gas pipelines that will be rolled out over the coming decades.

Sensitivity analyses
In section 6.3.1, comprehensive sensitivity analyses are also carried using Namibia as a sample region. The sensitivity analyses are carried out with regard to the specific investment costs of central components, the weighted average cost of capital (WACC) and the syntheses dynamics. The PtX pathways analyzed are liquid hydrogen, ammonia, and methanol. Central objective of such sensitivity analyses is to disclose how strongly PtX production and supply costs depend on individual key techno-economic parameters.

4 Methodology

4.1 GIS-based analysis of countries and renewables

To identify potential sites for onshore wind turbines and ground-mounted PV plants a Geographic Information System (GIS) is used. A GIS describes a database which contains spatial data that in combination with appropriate software tools can be managed, modeled, analyzed, and visualized [18].
For this purpose, different (exclusion) criteria for potential sites are defined. These criteria include restricted areas such as nature reserves and military zones. Furthermore, topographical aspects such as the slope angle as well as current land use result in the exclusion of potential areas. Additionally, population density and existing infrastructure are also taken into consideration. An overview of all criteria is summarized in Table 4-1.

Table 4-1: Exclusion criteria for wind and PV sites in the GIS analysis.

Criteria	Value	Description
Nature Reserve	-	General exclusion
Military Zones	-	General exclusion
Topography	< 5°	Maximum inclination
Land Use	-	General exclusion of • Water, snow, and ice areas • Forests • Farmland • Urban areas • Wetlands
Density of Population	< 150 people/km²	Exclusion of densely populated areas
Transmission Grids	< 100 km	Maximum distance to reduce the demand for additional infrastructure requirements
Overland Roads	< 100 km	Maximum distance to reduce the demand for additional infrastructure requirements
Airports	> 5 km	General distance regulation

The application of the respective criteria results in the in- or exclusion of different areas of a country. A subsequent overlay of all criteria leads to available areas for renewable energy sites. From these available areas, regions with the maximum wind and PV potential are selected (see chapter 4.1.6). Thereby, additional soft factors are considered. These include a reduction of the distance to harbors as possible electrolysis sites, a reduction of the distance to major cities from which the required workforce for the construction can be provided, as well as the coverage of different regions of a country [19]. A sample application of the selected criteria as well as the overlay of the excluded areas for the country of Namibia can be found in sections 4.1.1 to 4.1.7.

4.1.1 Nature Reserves and Military Zones

All nature conservation areas are generally excluded from the available areas. This is justified by the fact that the conversion to a sustainable energy system should not take place at the expense of nature conservation. In addition, obtaining construction permits

in such nature conservation reserves is generally unfeasible, although exceptions are occasionally made for current renewable energy and hydrogen projects [20,21].
Military restricted areas are excluded from the available possibilities, as construction permits are generally not issued by the respective governments in these areas. Figure 4-1 shows all nature reserves and restricted military zones of Namibia [20].

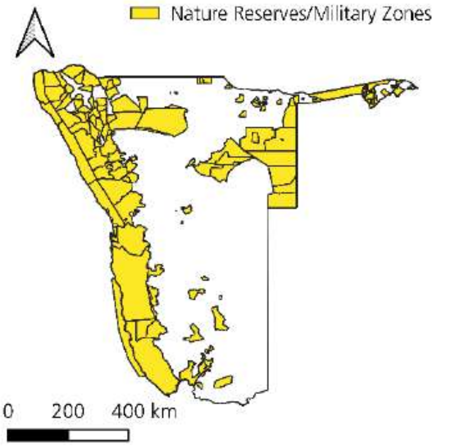

Figure 4-1: National parks and restricted military areas: *Excluded* areas due to declaration as nature reserve or military zone using the example of Namibia.

4.1.2 Topography

For the construction of RE facilities, especially for ground-mounted PV plants, terrain as flat as possible is required. Accordingly, the maximum inclination angle is set to 5° to exclude strongly uneven terrain such as alpine mountains [22]. An overview of the excluded areas due to the topographic characteristics can be found in Figure 4-2.

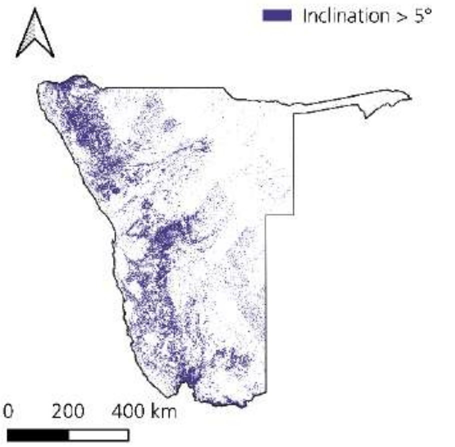

Figure 4-2: Inclination: *Excluded* areas due to unsuitable topography using the example of Namibia.

4.1.3 Land Use

Land use or other natural features can lead to the exclusion of available land for various reasons. These are on the one hand construction, climatic, and environmental aspects such as water, snow, and ice areas. But also forests and wetlands are not suitable as potential areas of construction for renewables. Urban areas are excluded due to the impact on the quality of life for residents [23].

Furthermore, agriculturally used areas are likewise not evaluated as available areas, since in emerging and developing countries in particular, energy production must not be at the expense of food production, which may already be scarce in some cases. An overview of the excluded areas for Namibia due to land use is shown in Figure 4-3.

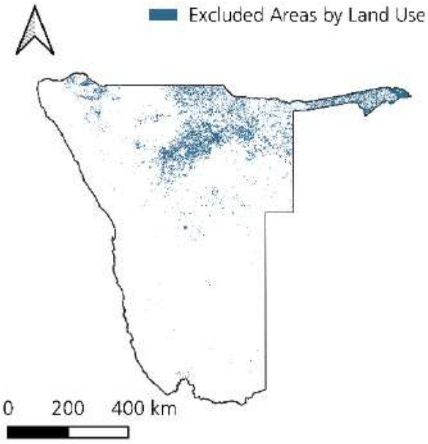

Figure 4-3: Land use: *Excluded* areas due to unsuitable land use using the example of Namibia.

4.1.4 Density of Population

In addition to excluded urban areas, somewhat less populated areas are also excluded from the potential areas in order to minimize negative impacts on the quality of life of residents in rural areas. Accordingly, a maximum population density of 150 inhabitants per square kilometer was specified (Figure 4-4) [24].

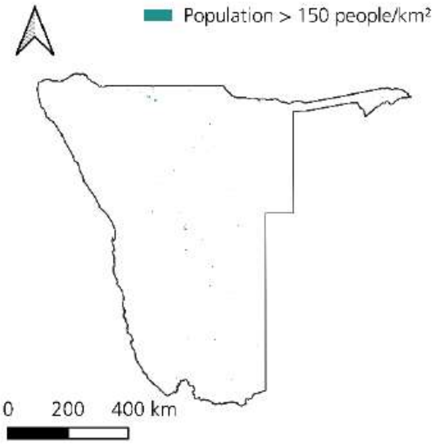

Figure 4-4: Population density: *Excludea* areas due to high population density using the example of Namibia.

4.1.5 Infrastructure

When identifying potential sites for renewables, the existing infrastructure must also be considered. Thereby, attention is paid to the electricity transmission network as well as to overland roads. To reduce the need for additional infrastructure, new routes, and the associated costs, a distance criterion is defined. The possible RE sites may not be located further than 100 km away from both the power transmission grid (> 25 kV) and overland roads. In addition, areas within 5 km of airports are excluded [19,25]. An illustration of the respective infrastructure and the areas included can be found in Figure 4-5 and Figure 4-6.

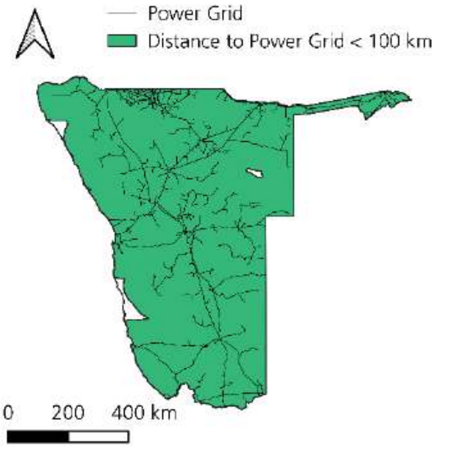

Figure 4-5: Power grid: *Included* areas due to suitable distance to power grid using the example of Namibia.

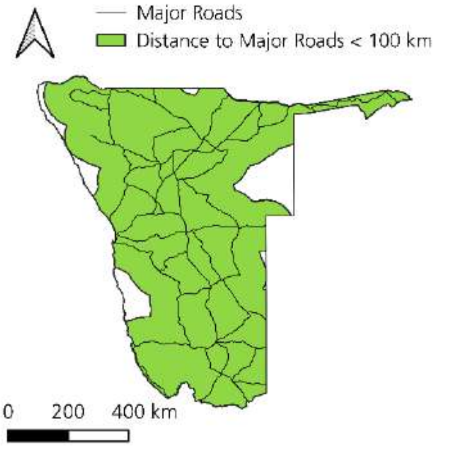

Figure 4-6: Major Roads: *Included* areas due to an acceptable distance to major roads using the example of Namibia.

4.1.6 Renewable Energy Potentials

In order to define the sites with the best potential for renewables, weather data are included in the assessment. The specific yield is used as a measure of solar irradiation for the quality of PV plant sites (Figure 4-7). It displays the amount of power generated per unit of installed PV capacity over the long term and is expressed in kilowatt-hours per installed kilowatt-peak (kWh/kWp). It is thus a typical value to determine the feasibility and potential yield of a solar energy system [26].
For the assessment of locations for wind turbines, the average wind speed at a height of 100 m above ground is applied (Figure 4-8). It measures the average speed of the wind over one year and is a commonly used value to determine the feasibility of a site for wind turbines [27].

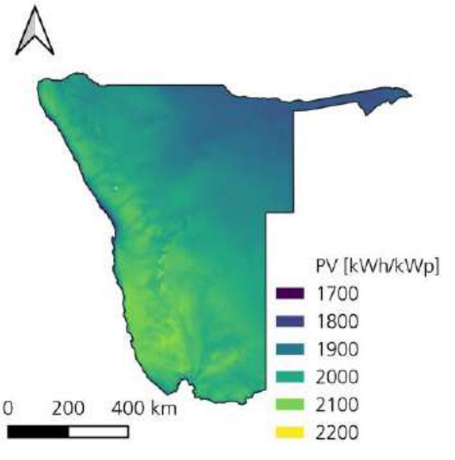

Figure 4-7: Mapping of PV potential using the example of Namibia.

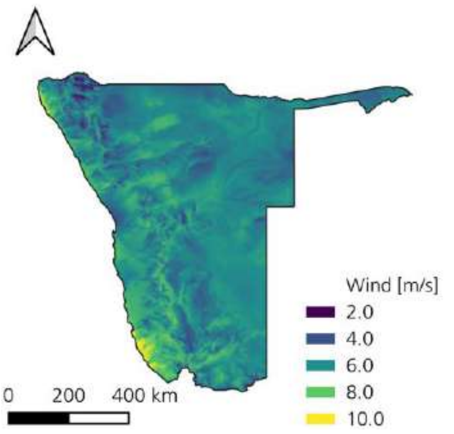

Figure 4-8: Mapping of onshore wind potential in Namibia using the example of Namibia.

4.1.7 Intersection of the Criteria

The areas excluded by the criteria in Table 4-1 are then intersected with the available land areas. In Figure 4-9 and Figure 4-10 the areas excluded according to the criteria are marked in white. The territories that are feasible for the construction of renewable

energy are colored according to the potential for the installation of wind turbines and PV plants respectively [28].
Since both wind and PV plants are to be erected at the same site, it is necessary to define a suitable location for both technologies. Detailed insights into the country-specific region selection can be found in chapter 6.2.

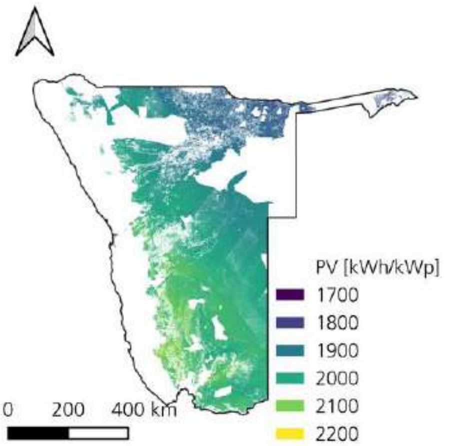

Figure 4-9: Mapping of PV potential using the example of Namibia.

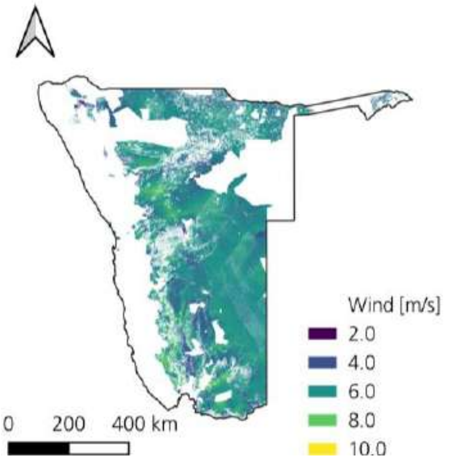

Figure 4-10: Mapping of onshore wind potential in Namibia using the example of Namibia.

4.2 Selection of PtX production site and transport route

4.2.1 PtX production site (PtX Hub)

Based on the identified locations for the renewable energy sources as explained above, the location for PtX production is determined.
For the analysis of maritime transport, it is assumed that PtX production is located at an export harbor. This approach is based on the assumption that larger industrial areas are usually located near ports and thus the basic infrastructure for PtX generation is available. A large number of countries analyzed are also located in arid regions, so a conflict could potentially arise over the use of groundwater for hydrogen production. In order to reduce any negative impact of hydrogen production on water availability, sea water via desalination is used, which is widely available in proximity to harbors.
As a constraint for harbor selection, only harbors within the same country as the wind/PV and with a minimum harbor size of “small” as defined by the World Port Index are considered [29]. A further analysis of the suitability of the harbor (e.g., available space, water depth, etc.) is not performed. In general, detailed infrastructure and site assessments shall be considered for the harbors when developing actual PtX-projects.

4.2.2 Sea transport route

Based on the identified export harbor, the sea route is computed between the export and the import harbor. The calculation is based on a network of commonly used maritime sea routes using the Dijkstra algorithm to find the shortest sea route [30,31]. As import harbor, Brunsbüttel in Germany has been selected. The map in Figure 4-11 shows the ports from the World Port Index (orange dots), the underlaying maritime network (red lines) for the distance calculation, and the resulting shipping routes (blue lines).

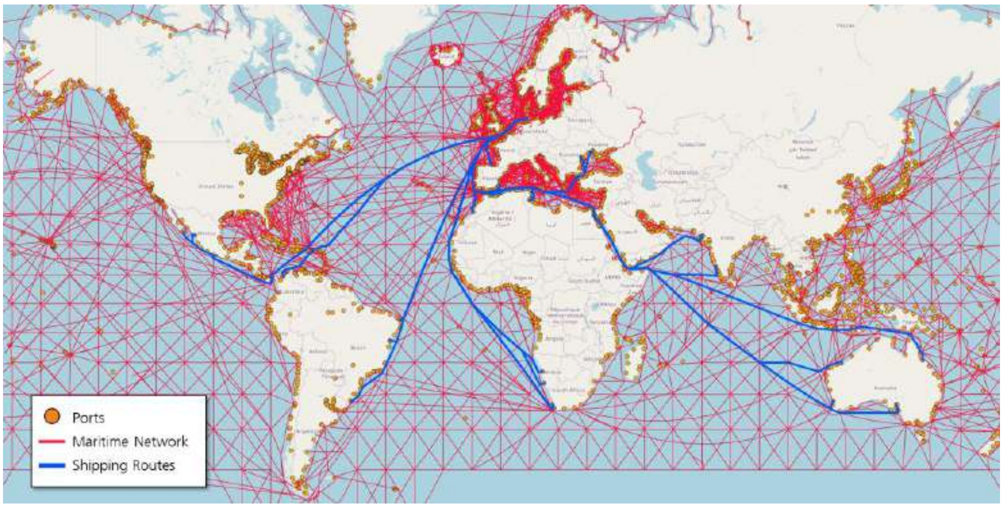

Figure 4-11: Ports from the World Port Index (light green points) [29] and global shipping network as input for the Dijkstra algorithm [30] which has been applied to determine the transport distance [32] (background map: OpenStreetMap).

4.2.3 Pipeline transport route

Pipeline transport distances are determined based on existing natural gas (NG) pipelines and proposed pipelines in the European Hydrogen Backbone Study [33]. As listed in Table 2-1, pipeline transport is analyzed for the locations in Spain, Ukraine, Morocco, Algeria, and Tunisia. The pipeline transport distances are used in the calculations to determine the pipeline costs and transport losses due to recompression.

4.3 Meteorological data and renewables generation profiles

The assessments in this study and the simulated PtX pathways are based on 1-year production profiles (based on a typified 10-year period; more below) with an hourly resolution from onshore wind and PV. For the identified RE locations the production timeseries were obtained from Renewables Ninja, a well-established and peer-reviewed open source webtool that allows estimating RE production and load profiles based on extensive satellite data for any location on the planet. The satellite data used is based on the MERRA-2 dataset[5] [35–37].

Specific system types and installation conditions must be defined in order to create the PV and wind load profiles in RE Ninja. With respect to PV, it is assumed that non-tracking modules face south at northern hemisphere sites and north at southern hemisphere sites. The optimal tilt angle and azimuth is determined based on the specific latitude of the location using an equation-based approach by Jacobson et al. [38]. For generating the wind profiles, an Enercon E112 turbine with a hub high of 124 m has been considered as reference turbine.

Due to the typical fluctuations in power production from renewable energy carriers, the energy yield differs from year to year. This also affects the further calculation of the PtX yield and production costs. In a year with high RE production, PtX production costs tend to be lower than in other years with less wind and PV production. In order to represent a typical year, PVGIS [39] offers the possibility to generate Typical Meteorological Years

[5] The Modern-Era Retrospective analysis for Research and Applications, Version 2 (MERRA-2) is a NASA global atmospheric reanalysis. Beginning in 1980, the goals of MERRA and MERRA-2 are to provide a regularly gridded, homogeneous record of the global atmosphere and to include additional aspects of the climate system, including trace gas constituents such as stratospheric ozone, as well as improved representation of the land surface, land use, and cryospheric processes [34].

(TMY) for specific locations by choosing for each month of the year the most "typical" month out of 10 years of data. However, as PVGIS focuses on solar power generation, the PVGIS methodology for generating the TMY considers solar irradiance, air temperature, and relative humidity, but no further conditions relevant for estimating wind speeds at relevant heights.

Therefore, the methodology of PVGIS has been adapted. The representative year used for the pathway simulations is composed of the individual mean months (January–December) from the years 2010–2019. Table 4-2 shows an example of the methodology. In the table, the monthly capacity factors for the individual years are given. In order to determine which year for each month is chosen, in a first step the mean capacity factor is calculated and in a second step, the year of the respective month closest to the mean value is selected. In the below example, the first month (January) of the time series is from January 2018 and the second month (February) is from February 2016. Variations in total annual electricity yield are a concern primarily for wind energy ("better and worse wind years"), while solar energy provides comparatively constant annual yields from year to year. As variations in wind power production are typically higher, the methodology described above is applied for wind power, and the resulting typical months are used to obtain the data relevant for solar power production. This ensures that monthly data for wind and PV is used from the same years and therefore the same meteorologic situtaitons. This ensures that the monthly wind and solar data sets are based on the same years, and thus each comes from the same meteorological conditions.

Table 4-2: Methodology for the creation of the RE input timeseries generation

							Month						
	Capacity Factor	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	2015	33%	37%	32%	30%	33%	30%	20%	20%	19%	26%	21%	13%
	2016	31%	32%	37%	34%	34%	28%	26%	22%	20%	25%	25%	28%
Year	2017	38%	30%	32%	30%	33%	25%	28%	25%	21%	17%	26%	33%
	2018	34%	29%	42%	35%	30%	29%	31%	19%	24%	27%	28%	22%
	2019	35%	31%	31%	31%	26%	34%	28%	18%	24%	20%	33%	35%
							↓						
	Ø	**1. Step**: The mean value is determined for each month of the years under consideration.											
							↓						
	Mean Value	34%	32%	35%	32%	31%	29%	27%	21%	21%	23%	27%	26%
							↓						
				2. Step: Evaluation, which year of the specific month is closest to the mean value									
							↓						
	Month taken from year:	2018	2016	2016	2019	2018	2018	2016	2015	2017	2016	2017	2016

4.4 Technical simulation and optimization of PtX supply chains

For the calculation, design and optimization of the PtX production and supply paths, techno-economic models for each supply chain were created using the Fraunhofer ISE toolbox H2ProSim ("Hydrogen Process Simulation"). The model structure is depicted in Figure 4-12. It contains a "technical model" of the supply chain as well as an "economic model", and a "genetic optimization algorithm". All three are explained in the following sub-chapters.

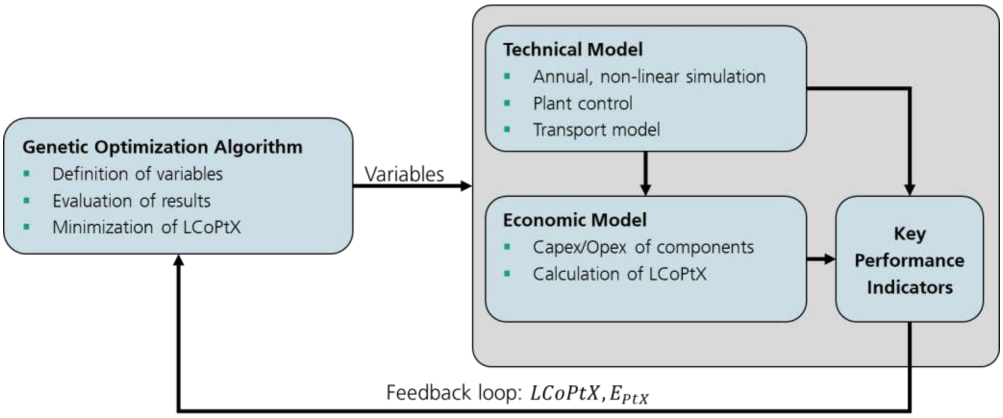

Figure 4-12: Schematic layout of the model structure in H2ProSim.

4.4.1 Technical Model

The technical model contains the components of the PtX supply chains. For each components individual models are created which are based on characteristic performance curves, conversion efficiencies, and mass and energy balances. In addition, if required, a control unit is part of the component model. For example, the electrolysis model contains a control unit, which defines the system states such as standby, startup, operation and shutdown in relation to the input power.
The individual models are interconnected according to the PtX system structure. A higher-level plant control unit distributes the renewable power generated and ensures that the components operate within their respective operating limits. For example, when the maximum pressure is reached in the intermediate hydrogen storage, the electrolysis is switched to standby mode. In the power distribution of the control unit, electrolysis is the flexible load. Power demands from the balance of plant (P_{BoP}) components and synthesis/liquefaction ($P_{Conversion}$) are supplied by RE power (P_{RE}) and are prioritized before electrolysis ($P_{Electrolysis}$):

$$P_{BoP} = P_{GasPurification} + P_{Compressors} + P_{cooling} + P_{Desalination} + P_{DAC/ASU}$$

$$P_{Electrolysis} = P_{RE} - P_{Conversion} - P_{BoP}$$

Figure 4-13 shows a sample result of RE power production (green curve), electrolysis power consumption (blue curve), and balance of plant (compression, desalination, liquefaction/ synthesis, etc.) power consumption (red curve). Due to potential oversizing of RE in respect to the power consumption of the plant, at certain times more power is produced than needed (lower picture, yellow curve). The excess power over the year is calculated as follows:

$$P_{ExcessPower} = P_{RE} - P_{Electrolysis} - P_{Conversion} - P_{BoP}$$

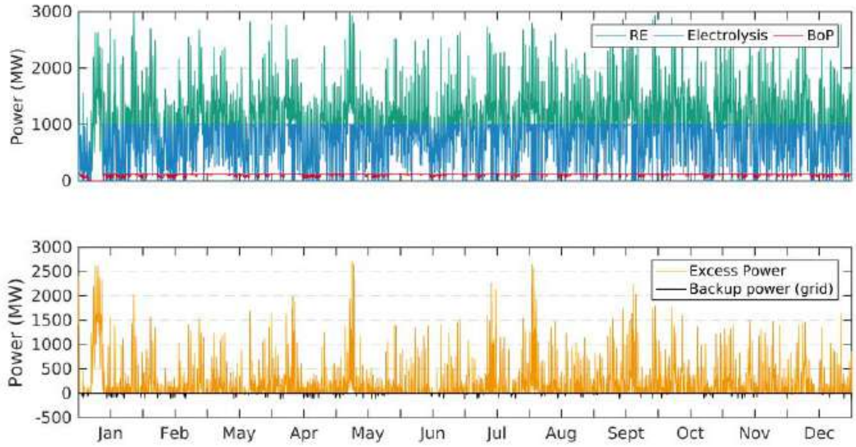

Figure 4-13: Top: Variable RE power generation, electrolysis, and balance of plant power consumption; bottom: Excess power due to overdimensioning of RE.

Hydrogen is produced in relation to the amount of power input into the electrolysis and the assumed electrolysis efficiency. Following the electrolysis produced hydrogen is purified and dried and subsequently led to one of the conversion steps either liquefaction or one of the syntheses processes. If more hydrogen is produced than is needed in the conversion steps, the remaining hydrogen is compressed and stored in an intermediate hydrogen storage facility from where it can be drawn at a later time.

Hydrogen conversion via liquefaction or synthesis is possible in a certain operation window. In particular, synthesis processes running at high temperatures and high pressures cannot be operated in a high dynamic mode. During times with no hydrogen production, hydrogen must be taken from the intermediate buffer storage. There is no intention to shut down the synthesis or liquefaction process due to insufficient RE and hydrogen production. Only once per year, a one week maintenance interval is considered for the synthesis and liquefaction facilities. The start of the maintenance interval is randomly chosen.

In Figure 4-14 the sample operation over one simulated year of hydrogen liquefaction and intermediate hydrogen storage is depicted. It shows liquefaction (yellow curve) operating in the defined operation window and the hydrogen storage pressure (blue curve) over the course of the year. During the maintenance interval, hydrogen production is possible until the storage is at maximum pressure.

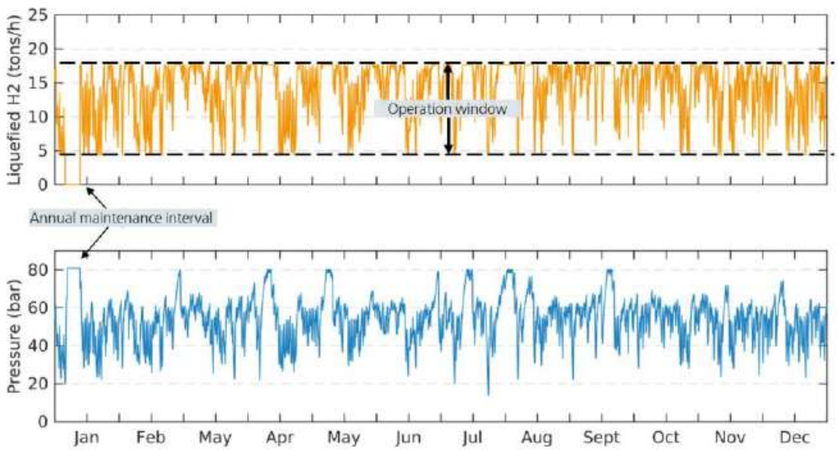

Figure 4-14: Sample simulation result of the mass flow of liquid hydrogen (top) and intermediate hydrogen storage pressure (bottom).

The produced PtX product is stored in intermediate storage before transportation by ship. The process chain step of ship transport takes place in a time-resolved operating sequence. Due to the variable production of the PtX products, the storage level varies, as does the loading time of the ships. In normal operation, it is assumed that loading the transport vessel takes 24 hours [40]. However, the loading time can also be extended if the PtX storage is empty. In this case, loading continues until the transport ship is fully loaded. At the import location, also 24 hours of unloading have been assumed. The number of transport vessels is a variable and is selected by the optimization algorithm depending on the PtX project size and the size of the vessels suitable for the particular PtX product. The simulation of the transport process is time resolved. If more than one ship is selected, it is taken into account that only one of the ships can be loaded at a time and the others have to wait in the meantime, as shown in Figure 4-15. Simultaneous loading of several transport vessels does not take place.

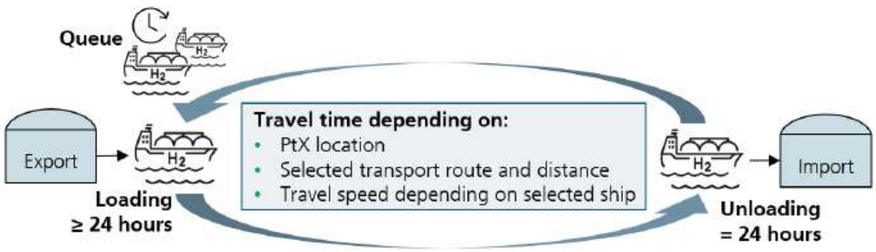

Figure 4-15: Schematic layout of time-resolved modelling of the sea transportation processes.

For dedicated pipeline export, recompression is required after a certain distance along the pipeline route. For the present assessment, recompression is assumed after 300 km. As it is the case for conventional natural gas pipelines, recompression power demand is produced by a fraction of the transported hydrogen.
More information on the technical and economic parameters considered for shipping and pipeline processes can be found in section 5.4.

4.4.2 Economic Model

In order to determine the production and supply costs of the PtX products, an economic model is applied. The economic model contains cost parameters such as the specific investment cost and operational costs for all components of the supply chains, which are defined in chapter 5. These values are based on literature, manufacture information, and expert knowledge. As the economic model is linked to the technical model, results of the annual simulation of the system (e.g., components sizing, amount of produced PtX product, ship fuel demand, external power supply) are used in the economic model for calculation of each PtX projects economic efficiency. The levelized costs of the PtX-products $LCoPtX$ costs are calculated based on the annuity method, as follows [41]:

$$LCoPtX\left(\frac{EUR}{MWh}\right) = \sum_{i=1} \frac{CAPEX_i * ANF + OPEX_i}{E_{PtX}}$$

$$ANF = \frac{WACC(1+WACC)^{n_i}}{(1+WACC)^{n_i} - 1}$$

where $CAPEX$ are the investment costs for each component i of the supply chain, $OPEX$ are the annual operation costs (fixed and variable), E_{PtX} the total PtX energy amount (related to the lower heating value) exported / produced, and ANF the annuity factor. The latter is defined with $WACC$ as the weighted average cost of capital and n the technical lifetime specified for each component. Residual values of individual components after the end of the plant operating life are not considered in this study.

The PtX costs in this study are mainly given in costs per energy (EUR/MWh) based on the lower heating value. This ensures comparability among the different PtX carriers. The LCoPtX presented in this study are distinguished into the LCoPtX at the PtX production site - the “PtX production cost” - and the LCoPtX after international transport of PtX to the point of import - the “PtX supply cost”.

4.4.3 Genetic Optimization Algorithm

The Genetic Optimization Algorithm is a model consisting of several variables and boundary conditions that influence the PtX production amount and PtX production costs. Due to different RE production profiles, each location has different conditions. In order to determine the lowest PtX production and supply costs and to find a system layout that is within the defined boundary conditions (e.g., electrolysis capacity, no shutdown of syntheses), an evolutionary, “genetic” optimization algorithm is applied.
Evolutionary optimization algorithms have established themselves as a powerful optimization technique. Here, an optimal solution is not determined by a numerical linear optimization but rather is found by randomized search heuristics. This approach prevents the algorithm from getting stuck in a local minimum. Improvement is obtained step by step, i.e., over many generations, by attempting possible solutions. In order to find the best solution within the given boundary conditions, a high number of solution attempts must be calculated over many generations / iterations.
The optimization algorithm can adapt selected variables, such as installed capacities of wind and PV, with the objective to minimize PtX production costs. As a basis for each scenario, an installed electrolysis capacity of 1 GW is considered. The system is designed around this fixed variable. Table 4-2 lists the optimization objectives, the optimization variables, and the boundary conditions.

Table 4-3: Objectives, variables, and boundary conditions for the system optimizations.

	Ship Export	Pipeline Export	Local Production
Optimization objectives	$\min LCoPtX$ $\max E_{PtX}$		
Fixed variable	1 GW_{el} electrolysis		
Optimization variables	• Installed wind • Installed PV • Volume H_2 buffer Storage • Capacity syntheses/ Liquefaction • Capacity PtX storage • Number of transport vessels	• Installed wind • Installed PV	• Installed wind • Installed PV • Volume H_2 buffer Storage • Capacity synthesis/ Liquefaction
Boundary condition	Minimal part load operation of synthesis/ liquefaction	n/a	Minimal part load operation of synthesis/ liquefaction

Although the focus in this study is on the lowest LCoPtX, a multi-objective optimization is carried out, focusing on not only minimizing the LCoPtX, but also maximizing the PtX energy amount. The two optimization objectives are conflicting, meaning that an optimum with respect to all requirements is not achievable with one solution. Instead, a set of solutions is determined as a result of the multi-objective optimization algorithm. One solution represents the minimal LCoPtX, another the maximum PtX energy amount.

Between the two outcomes, numerous results will arise that represent a compromise between the two objectives. This is the so-called Pareto front of a multi-objective optimization. An example of a Pareto front is depicted in Figure 4-16.

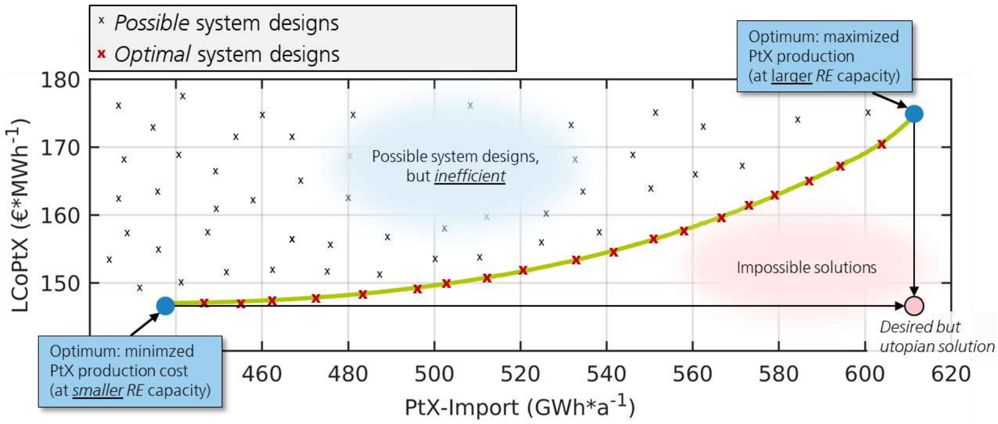

Figure 4-16: Pareto front as a result of the optimization process for a (sample) PtX scenario: by varying the system design parameters innumerably, a multitude (solution cloud) of possible system designs and resulting LCoPtX and PtX production and import quantities results. The most favorable system layouts result in the Pareto Front (green line).

5 Techno-economic parameters

This chapter gives an insight to the techno-economic assumptions that serve as the central basis for the simulation and optimization of the various PtX supply vectors and the assessed scenarios. The structure of this chapter is based on the logical sequence of a PtX system, starting with renewable power generation via wind and PV and ending with the transport of the finished PtX product to its target location.

5.1 Wind and PV

5.1.1 Renewable Energy Sources

The global weighted average total costs for onshore wind turbines decreased by 74% – from about 5,000 EUR/kW to about 1,400 EUR/kW – in the period from 1984 to 2021. The main drivers for the reduction of the specific costs are the costs of the wind turbines themselves, mainly based on an increasing plant sizes as well as rising production capacities [42]. In individual countries, however, there are serious differences in the realization costs of wind farm projects. The CAPEX for the construction of wind farms in India, for example, is significantly lower at 1,200 EUR/kW than in Spain at 1,500 EUR/kW. The OPEX of wind energy plants depends on the full load hours and varies between 0.014 EUR/kWh and 0.017 EUR/kWh in India and Spain, respectively. This is based on the fact that the wear and tear of the plants is caused in particular by utilization in form of full load hours [42–44]. For comparability, wind turbines of the type Enercon E112 with a nominal power of 4.5 MW are used for all sites. A lifetime of 25 years is assumed for the wind power plants. [43,44]

Table 5-1: Country-specific economic parameters considered for PV and wind.

	PV		Wind		WACC
Country	CAPEX [EUR/kW]	OPEX [EUR/kW]	CAPEX [EUR/kW]	OPEX [EUR/kWh]	mean [%]
Algeria	650	13	1,400	0.016	7.00
Australia	600	12	1,300	0.015	5.75
Brazil	550	11	1,300	0.015	6.50
Colombia	650	13	1,500	0.017	7.00
India	600	12	1,200	0.014	8.00
Mexico	600	12	1,400	0.016	6.75
Morocco	650	13	1,500	0.017	7.00
Namibia	650	13	1,500	0.017	7.00
South Africa	650	13	1,500	0.017	7.00
Spain	600	12	1,500	0.017	5.75
Tunisia	650	13	1,500	0.017	7.00
Ukraine[6]	600	12	1,500	0.017	6.00

The PV plants used are non-tracking systems with the angle and azimuth aligned for each region according to achieve the maximum yield.
For PV plants, global weighted average CAPEX shows an even faster cost degression, of more than 80% from 2010 to 2021, with the 2010 average of about 4,500 EUR/kW

[6] The assumptions and framework made for Ukraine refer to the time before the Russian war of aggression began.

falling to about 800 EUR/kW in 2021. This is primarily due to an expansion of global PV module production [42,43]. The country-specific investment costs for PV plants vary between 550 EUR/kW in Brazil and 650 EUR/kW in Colombia, for example. Since the country-specific differences for PV plants are already considered in the CAPEX, the OPEX values are calculated as a share of 2% of the CAPEX (see Table 5-1). For solar systems, a lifetime of 30 years is assumed [43].
Table 5-1 lists the country-specific economic parameters for PV and wind. The differences among countries result from the availability of certain production facilities in specific countries as well as their experience with the technology and with the realization of projects in the required dimensions. Furthermore, the variations in specific labor and production costs as well as costs for logistics have a major influence on the country-specific expenditures [45].
The weighted average cost of capital (WACC) of a country depends primarily on the costs incurred when acquiring capital. These costs include interest on loans and bonds as well as dividends paid to shareholders. Additional factors are the overall economic situation and creditworthiness as well as a country's regulation and tax framework. Table 5-1 lists the mean WACC for PV and wind technologies within each country resulting from these assumptions [42,43,46,47]. At this point, it should be noted that due to the lack of a better database, the WACCs identified here were also assumed for the other PtX process components such as electrolysis, storage and synthesis. However, since the important aspect of "country-specificity" remains considered, it is assumed that no major inaccuracy is carried over into the results.

5.1.2 Power transmission between RE and PtX site

The renewable generation site and the PtX hub are not always in the same location. Therefore, power transmission was considered where necessary. Since high levels of power (> 1 GW_{el}) must be transmitted, it cannot be assumed that the existing transmission grid (if existent) has sufficient capacity. Therefore, costs for a project-specific transmission grid are considered. Due to the limited data available, it was not possible to take country-specific investment costs into account. The necessary length of the transmission grid is determined in the country-specific analyses. Since a direct connection is not possible in most cases, a detour factor of 1.2 is assumed, to account for terrain-dependent detours. Table 5-2 lists the technical and economical parameters for the project-specific transmission grid.

Table 5-2: Technical and economic parameters considered for power transmission via a project-specific transmission grid.

Parameter	Value	Unit
Transmission losses	1.1	%/100km
Transformer Efficiency (beginning and end of grid)	99.5	%
CAPEX	190.000	EUR/(km*GW)
OPEX	0.2	% of CAPEX
Lifetime	40	Years
TRL	9	
Relevant sources: Grid efficiency, cost, and lifetime: [48]		

5.2 Hydrogen production

5.2.1 Water electrolysis

An electrolysis capacity of 1 Gigawatt is the basis for all calculations in this study. Polymer electrolyte membrane (PEM) electrolysis has been selected due to its high dynamic response to variable input power from wind and solar and its high-pressure production of hydrogen, which reduces the demand for downstream compression significantly compared to atmospheric hydrogen production. However, it should be noted that the PtX concept can also be realized based on alkaline technology.
At nominal load and with a specific energy consumption (SEC) of 52 $kWh_{el}/kg\ H_2$ (64.1% based on hydrogen LHV), the 1 GW electrolysis system has a maximum daily production rate of 463 t H_2. Industry technology targets or certain literature refer in part to lower SEC (e.g., 48 kWh/kg H_2) [49,50]. However, these published values usually apply only to optimum operating conditions and do not take into account unavoidable degradation over the lifetime of the electrolysis system. Therefore, the slightly increased value used in this study represents an average SEC value over the 30-year lifetime of the PEM system. With regard to the investment costs, 750 EUR/kW (1625 EUR/kg/d) have been considered for the electrolysis plant. Of these 500 EUR/kW have been considered for the electrolysis main equipment and additional 250 EUR/kW have been added to include as well secondary costs such as engineering, commissioning and construction [50]. For the PEM electrolysis stacks a replacement after 85,000 operating hours is considered as an additional operational cost. It must be mentioned that assumptions regarding investment costs of electrolysis plants are subject to a high degree of uncertainty and depend on many factors, such as the country of installation and whether the plant will be set up on a “brown or greenfield” [51,52]. For this reason, the electrolysis CAPEX is one of the parameters subjected to a detailed sensitivity analysis (cf. 6.3.1). Although further use may offer added economic value in appropriate cases, the oxygen produced during electrolysis is not considered further in this study.

Table 5-3: Technical and economic parameters considered for 1 GW_{el} PEM electrolysis

Parameter	Value	Unit
Technology	PEM electrolysis	-
Rated input power	1,000	$MW_{AC,Input}$
Rated hydrogen production rate	19.3	tons/h
SEC at rated production	52	kWh/kg
Hydrogen production pressure	30	bar
Lower part load limit	10	%
Water demand	15.0	kg $H_2O_{freshwater}$/kg H_2
CAPEX	1625	EUR/kg/d
	750	EUR/kW_{AC}
OPEX	15	EUR/(kW_{AC}*a)
System lifetime	30	years
Stack lifetime	85,000	Operating hours
TRL of PEM	8-9	-

Relevant sources:
SEC at rated production: [49,50]
Hydrogen production pressure: [53]
Lower part load limit: [52]
CAPEX: [49,51–54]

OPEX: [50,51,53,54]
Stack Lifetime: [53,54]

5.2.2 Hydrogen intermediate storage and compression

For the production of liquid hydrogen, ammonia, methanol, and e-fuels, intermediate hydrogen storage is required as a buffering element between electrolysis and downstream conversion. Hydrogen liquefaction and synthesis processes have only limited dynamics compared to electrolysis, which means that operation is only possible in certain load ranges and a continuous operation within these ranges requires a steady hydrogen supply. The hydrogen intermediate storage system thus acts as a buffer element and supplies the conversion steps with hydrogen even during periods without electrolytic hydrogen production.

Typically, low amounts of up to several tons of gaseous hydrogen are stored in overground buffer steel tanks at pressures of up to 100 bar. However, this solution comes with high investment costs of more than 500 EUR/kg of hydrogen storage capacity [55,56]. The most cost-effective storage solution for large amounts of pressurized hydrogen storage is underground salt caverns, which come with investment costs of below 10 EUR/kg of hydrogen storage capacity [55]. However, underground salt caverns require special geological structures which are not generally available. In addition, planning and construction can take up to 10 years [55,57].

As an alternative to the above-mentioned storage facilities underground pipe storage has been assumed in this study as intermediate hydrogen storage solution. Underground pipe storage is commonly used for storage of natural gas and the principle of installation is the same as for pipelines, which are laid side by side. In principle, such pipe storages are also conceivable for hydrogen, but they have not yet been implemented because the need for such large storage capacities has not yet arisen. Typically, pipe storages are operated at pressures of up to 100 bar [58,59]. Specific investment costs for hydrogen-capable underground pipe storage are expected to be between 250 EUR/kg and 500 EUR/kg [56,59].

Table 5-4: Technical and economic parameters considered for underground pipe storage of hydrogen

Parameter	Value	Unit
Storage volume	Optimization Variable	m³
Max. working pressure	80	bar
Min. working pressure	10	bar
CAPEX	2,100	EUR/m³
	330	EUR/kg_{gross}
OPEX	1	% of CAPEX/yr
Lifetime	40	years
TRL (hydrogen pipe storage)	3-5	

Relevant sources:
CAPEX: industry reference; [56,58,59]
OPEX: own assumption
Lifetime: [54,58]

Due to the higher storage pressure compared to that of hydrogen production, a hydrogen compressor is required prior to storage. The compressor compresses the hydrogen from an electrolytic production pressure of 30 bar to a maximum storage pressure of 80 bar. Technical and economic data are listed in Table 5-5. To cover the maximum hydrogen production capacity of 19.3 ton H_2/h it is assumed that five compressors operate in parallel (3.7 ton H_2/h each). This ensures a redundancy of the compression system and reduces the part load capability without increasing specific power consumption. Each compressor has two compression stages with an intercooling. Equipment costs are derived from Grünäugl et al. [60] and adapted based on internal data.

Table 5-5: Technical and economical parameters considered for hydrogen compression towards intermediate storage system [56,60,61].

Parameter	Value	Unit
Total rated mass flow	19.3	tons/h
Input pressure	30	bar
Output pressure	80	bar
Number of stages	2	-
Specific Power Consumption	0.4	kWh/kg
CAPEX	1,295	EUR/(kg/h)
OPEX	4	% of CAPEX/yr
Lifetime	30	years
TRL	9	

Relevant sources:
CAPEX: [60,62]; industry references
OPEX: [56]
Number of stages: based on [63]
Specific Power Consumption: calculated based on isentropic process

5.2.3 Water supply via desalination

In addition to electricity, water is required to produce hydrogen. The stoichiometric water demand for the production of hydrogen is 8.9 kg H_2O/kg H_2. Due to water loss during the fine purification process to produce fully deionized water and the water contained in the saturated hydrogen and oxygen product flows after electrolysis, the initial freshwater demand is assumed to be around 15 kg H_2O/kg H_2 [64–66]. It should be noted that the freshwater demand depends on several factors like technology supplier and water quality.
A sustainable production of green hydrogen must also include the aspect of water supply. Negative effects of water consumption on the local population and environment should be avoided [67]. Figure 5-1 shows the global aridity index by Zomer et al. [68] which takes into account the mean annual precipitation and the mean annual reference evapotranspiration. For countries with high humidity (Colombia, Brazil, Ukraine), it is assumed, that fresh water can be supplied by an existing grid. Due to many influencing factors, reliable data on local water costs are not available in the literature. For the present analysis, 2 EUR/m³ H_2O have been assumed [69]. For countries in arid regions (Algeria, Australia, India, Mexico, Morocco, Namibia, Spain, and South Africa), dedicated desalination of seawater is considered for freshwater production.

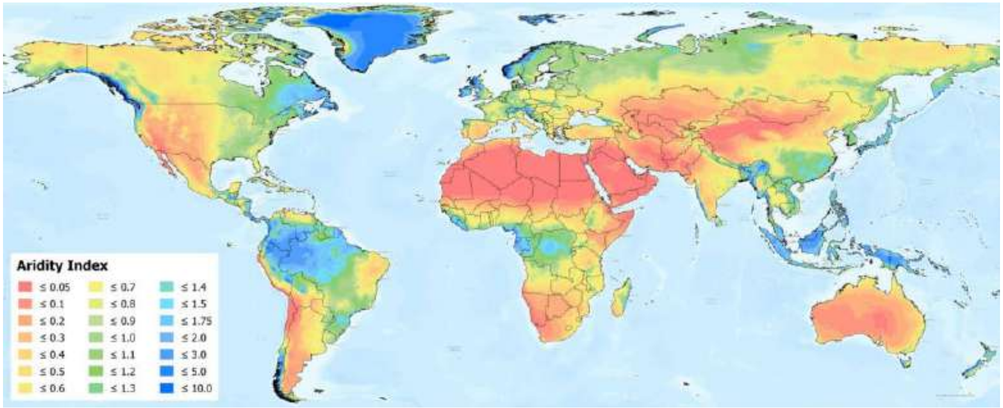

Figure 5-1: Global Aridity Index by Zomer et al. [68]. Please note: A higher aridity index (green/blue colors) represents more humid regions, while low aridity index (yellow/brown/red colors) represents higher aridity (the figure is licensed under a Creative Commons Attribution 4.0 International License; https://creativecommons.org/licenses/by/4.0/; no changes have been made).

For the desalination of sea water reverse osmosis (SWRO) is considered. For several years, SWRO has been the dominant desalination technology thanks to its low electrical power demand and the fact that no thermal energy is required [70]. Sea water desalination is a technically mature technology. Currently, the biggest challenge is the disposal of brine, which could harm underwater habitats, so special attention should be paid to proper brine distribution in the area of discharge.

Table 5-6: Technical and economic parameters considered for sea water reverse osmosis.

Parameter	Value	Unit
Specific energy consumption	3.6	kWh/m³
CAPEX	1,640	EUR/(m³*d)
OPEX	128	EUR/(m³*d)/yr
Lifetime	30	years
TRL	9	
Relevant sources: [71,72]		

5.3 Hydrogen conversion

The gaseous hydrogen coming from electrolysis and intermediate storage is converted in the hydrogen conversion steps to the final PtX products of liquid hydrogen, ammonia, methanol and the FT product mix or FT-based jet fuel. Table 5-7 lists the technical and economic parameters for the corresponding hydrogen conversion steps hydrogen liquefaction, ammonia synthesis, methanol and Fischer Tropsch synthesis. The ability to respond to a fluctuating hydrogen feed with a partial load response and the respective partial load window depend on the conversion technology.

5.3.1 Liquefaction and Syntheses

Hydrogen liquefaction: Hydrogen liquefaction can be seen as a mature technology used worldwide with commercial plant capacities of up to 50 t LH_2/d. In 2010, the global installed liquefaction capacity was well below 400 t LH_2/d, which is already within the range of capacities discussed for this study [73]. Hydrogen liquefaction is an energy-intensive process with SEC of 10 kWh_{el}/kg LH_2 as the state of the art (the SEC of the liquefaction plant in Leuna (GER) is 11.9 kWh/kg LH_2 [74]). Several investigations indicate that large-scale liquefiers will most probably be able to reach electricity consumption rates as low as 6.0 $kWh_{el}/kg\ LH_2$ and below. In the past, highly innovative concepts have been presented for SEC reduction down to 4.0 $kWh_{el}/kg\ LH_2$ [75]. This is mainly envisioned due to a high thermal integration and synergy effects in case of large-scale liquefaction concepts. The technical parameters for the liquefaction in this study are based on the IDEALHY project, which is developing a concept for a liquefaction plant (40 t LH_2/d) with a SEC of 6.8 $kWh_{el}/kg\ LH_2$ at rated load. The IDEALHY concept features a high dynamic range with 25% of the nominal load at an increased SEC of 10.3 $kWh_{el}/kg\ LH_2$ [74]. After liquefaction liquid hydrogen is provided at an absolute pressure of 2 bar, 23 K and a purity of 100%. Losses of hydrogen are considered with 1.65%, mainly caused at the feed gas compression step.

Ammonia synthesis: The Haber-Bosch process is the most common synthesis method for ammonia. The iron oxide based catalyst enables an exothermic reaction of nitrogen and hydrogen at temperatures between 400-600°C and pressures of 200-400 bar. The exothermic ammonia formation provides the necessary energy to preheat the reactor feed stream consisting of nitrogen and hydrogen. The ammonia product stream is liquefied (-33°C) by cooling from the evaporation of nitrogen coming from the air separation units (ASU). Due to the high pressures and temperatures, the Haber-Bosch process has significantly lower dynamic capabilities than, for example, hydrogen liquefaction. However, there are concepts and pilot plants which describe a partial load window of 60% of the rated capacity without significant efficiency losses [76]. These concepts are currently in the development and demonstration stage. Conversion parameters and energy requirements for this study are based on in-house Aspen simulation and are listed in Table 5-7 along with the economic assumptions.

Methanol synthesis: Conventional methanol synthesis is also a mature and globally deployed technology with plant capacities in the megaton range. Conventional methanol synthesis uses a synthesis gas consisting mainly of carbon monoxide, carbon dioxide and hydrogen, which is produced on the basis of steam reforming of fossil precursors such as natural gas or coal. Synthesis is operated at elevated pressures of 50-100 bar and temperatures of 200-300°C over a $Cu/ZnO/Al_2O_3$ catalysts. In case of captured carbon dioxide and renewable hydrogen as the primary carbon feedstocks the synthesis as well as the whole process layout have to be adapted to new kinetics and energy balance. Carbon dioxide methanol synthesis has been further developed over the past decades and first commercial plants at industrial scale are in operation [77,78]. A kinetic model (for commercial $Cu/ZnO_2/Al_2O_3$ catalysts) developed at Fraunhofer ISE and implemented in an Aspen simulation for a 100 kt/yr methanol plant leads to conversion parameters and energy demands assumed in this study. (cf.Table 5-7), [79,80]. The reactor system is operated at a pressure of 70 bar and a temperature of 250 °C. Heat integration via pinch-analysis enables pre-heating of the educt streams carbon dioxide and hydrogen as well as the purification of the synthesis product output. The remaining excess heat (0.09 kWh_{th}/kg MeOH) released below the internal heat utilization range (<65 °C) is assumed to be available for the DAC modules' thermal energy demand. With regard to dynamic synthesis operation, there are also numerous R&D developments in the field of methanol synthesis which aim to enable more dynamic but still stable and efficient synthesis operation. In addition, there are first commercial suppliers for medium scale dynamic process concepts in the MW range [81,82]. Due to the milder reaction conditions, a slightly larger dynamic window than for ammonia synthesis is assumed in this study. The technical and economic parameters for the methanol synthesis considered in this study can be found in Table 5-7.

Fischer-Tropsch synthesis: The Fischer-Tropsch (FT) process is considered as another PtX pathway in this study. Based on fossil synthesis gas, the FT process has been used on a large industrial scale for the production of hydrocarbons for many decades and is technically mature. If carbon dioxide is to be used as a carbon source instead of CO-containing syngas, a further process step is required upstream of the FT reactor to

convert the carbon dioxide into carbon monoxide. A reverse water-gas shift (RWGS) reactor is necessary for conversion of carbon dioxide into carbon monoxide. The endothermic reaction also consumes some of the feed hydrogen and produces water as a byproduct. The RWGS reactor is currently being tested on a demonstration scale and can be regarded as having a TRL of 6 [83–85]. Another technology option to operate FT synthesis with carbon dioxide as initial feed is the use of a high-temperature CO-electrolysis, which can convert carbon dioxide and water vapor at temperatures above 800°C to a synthesis gas [86–88]. However, the solid oxide system does not yet have the necessary dynamics for exclusive operation with volatile RE, which is why this technology combination (CO electrolysis + FT reactor) is not considered further in this study.
Depending on the operating parameters, the catalyst used and the hydrogen to carbon ratio, the product spectrum from FT synthesis can be adapted to short or long chain hydrocarbons. Jet fuels belong to the long-chain middle distilates and are formed at reaction conditions of 200-240°C and 30bar [89]. One challenge in the FT process is to "trim" the resulting product spectrum so that a large product quantity corresponds to the desired product - in the present case jet fuel – without sacrificing overall efficiency. To adjust the final product ratio, the FT synthesis step is followed by a cracker, which breaks up and recirculates short hydrocarbons, and a distillation, which splits the remaining product fractions and separates by-products. The carbon dioxide based FT concept considered in the present study is based on the process concept of Schemme et al. and results in the product fractions of 38 wt.% jet fuel and 62 wt.% diesel fuel [83]. When calculating the production costs of FT based PtX products, it is therefore relevant to distinguish between the production costs for the FT mix (diesel + jet fuel) and the production costs for the jet fuel alone. For the latter, as described in Section 3.2, this study assumes that the diesel byproduct is sold at locally achievable market prices. In the results section, both the production and supply cost for the FT mix and the cost isolated for jet fuel will be discussed. Due to the complex process with a large number of process steps, the FT path considered in this study is assigned a comparatively small dynamic window. For the FT path, Table 5-7 also shows the key technoeconomic parameter assumptions.

Table 5-7: Technical and economic parameters considered for hydrogen conversion technologies.

Parameter	Value				Unit
	Hydrogen Liquefaction	**Ammonia Synthesis**	**Methanol Synthesis**	**Fischer-Tropsch**	
			CO_2 based	CO_2 based (incl.RWGS)	
Rated capacity	Optimization variable				t/d
Operating pressure (inlet)	20	250	70	30	bar
Operating temperature (outlet)	-253	550	255	210	°C
SEC	6.780	0.009	0.180	0.303	kWh_{el}/kg product
H_2 demand	1.017	0.180	0.195	0.480	kg H_2/kg product
N_2 demand	-	0.830	-	-	kg N_2/kg product
CO_2 demand	-	-	1.430	3.056	kg CO_2/kg product
Lower part load limit	25	80	60	90	% of rated production
CAPEX	See Figure 5-2				
OPEX	4	4	4	4	% of CAPEX/yr
Lifetime	30	30	30	30	years
TRL	9	9	8-9	FT: 9 RWGS: 6	

Relevant sources:
Hydrogen Liquefaction: [54,74]
Ammonia Synthesis: [54,91], in-house Aspen simulation
Methanol Synthesis: [54,79,80,83], in-house Aspen simulation
Fischer-Tropsch: [54,83]

Size-dependent investment costs were taken into account for the hydrogen conversion paths. Figure 5-2 shows the corresponding cost curves for hydrogen liquefaction [54,74], ammonia [54,91], methanol [54,79,80,83], and Fischer-Tropsch synthesis [54,83].

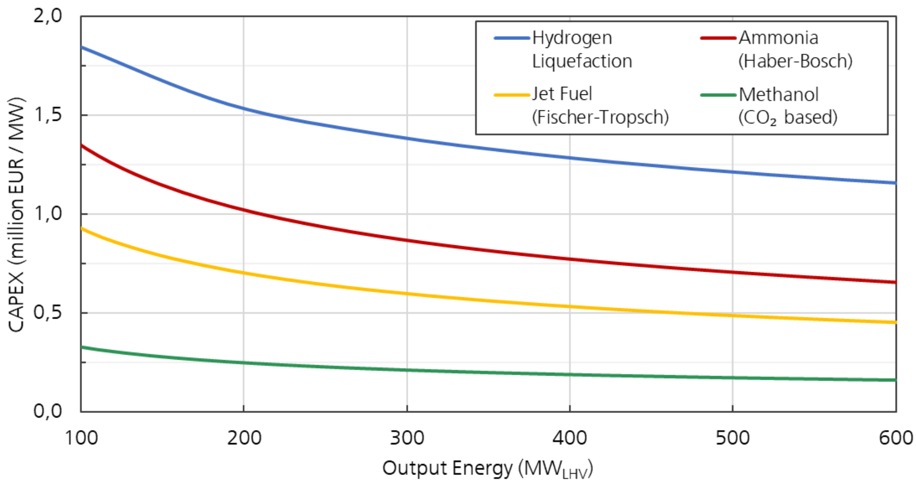

Figure 5-2: Cost curves for hydrogen liquefaction, ammonia, methanol, and Fischer-Tropsch synthesis applied in this study.

5.3.2 Supply of carbon dioxide and nitrogen

Carbon sourcing: The production of methanol and Fisher Tropsch products requires a carbon source. For the present assessment, carbon dioxide from low-temperature DAC is used for the production of methanol and Fischer Tropsch products. Currently, atmospherically captured carbon dioxide and carbon from certain biogenic sources are the only carbon sources that have some likelihood of meeting the 70% greenhouse gas savings compared to the reference for renewable fuels of non-biological origin (RFNBO) as defined in the last REDII's Delegated Acts. However, in certain cases and especially if double-counting is avoided, capturing carbon dioxide from point sources may also be possible, which in most cases allow significantly lower capture costs. DAC technology, on the other hand, still results in relatively high capture costs, but enables location independent sourcing of carbon. Moreover, together with biogenic sources, DAC is the basis for globally closed carbon cycles in the energy and fuel sectors. The technological maturity of DAC technology is at pilot scale (TRL 5-7) in both the low and high temperature ranges with the first (pre-)industrial scale plants planned (TRL > 6). Both low and high temperature DAC require certain technological boundary conditions which can offer certain advantages depending on the scenario and location. While LT-DAC technology is modular in design and can also be powered 100% from renewable sources if required, HT-DAC technology offers an overall lower energy requirement and the potential for larger scales. In the case of the latter, however, part of the energy supply is so far covered by natural gas, which at least limits its site independence [92–95]. In this study, it is assumed that part of the thermal energy demand of the DAC modules is covered by heat integration from methanol or Fischer-Tropsch synthesis [83,96]. The remaining thermal energy demand is covered by heat pumps, which are supplied with electricity from renewables. The techno-economic data provided both by manufacturers and on the basis of scientific literature vary significantly in some cases; in particular, the data on investment costs differ greatly. For this reason, the specific investment costs of the DAC technology are subjected to a sensitivity analysis in this study in order to be able to map their influence on the PtX supply cost (cf. section 6.3.1). In addition, for one selected region a scenario is discussed in which much more cost-effective carbon point sources are used instead of DAC (cf. section 6.3.4).

Table 5-8: Technical and economic parameters of low-temperature Direct Air Capture (LT-DAC) for sourcing of carbon dioxide.

Parameter	**Value** (pathway dependent)		**Unit**
	Methanol	**Fischer-Tropsch**	
Electricity demand (w/o heat integration & heat pumps	0.50	0.50	$kWh_{el}/kg\ CO_2$
Thermal demand (*w/o* heat integration & heat pumps	1.81	1.81	$kWh_{th}/kg\ CO_2$
Thermal demand (*after* heat integration & with heat pumps)	1.74	0.00	$kWh_{th}/kg\ CO_2$
Heat pump: coefficient of performance	2.51	2.51	
Total electricity demand of integrated DAC	1.19	0.50	$kWh_{el}/kg\ CO_2$
Production rate	Based on synthesis capacity		t/d
Specific investments costs	500		EUR/(ton*yr)
Fixed operation costs	4		% of CAPEX/yr
Lifetime	25		Year
TRL	5-7		

Relevant sources:
General energy demand: [96]
Heat integration potential: methanol: in-house Aspen simulation; Fischer-Tropsch: [83]
Heat pump COP: [96]
DAC costs: [95,97,98]

Nitrogen sourcing: For the production of ammonia, nitrogen is supplied via air separation units (ASU) where atmospheric air is split into its primary components by means of a cryogenic distillation process. The location-independent ASU process is technologically mature and in use worldwide on an industrial scale (TRL 9). The economic parameters for ASU are given in Table 5-9.

Table 5-9: Technical and economic parameters of air separation units (ASU) for sourcing of nitrogen.

Parameter	**Value**	**Unit**
Production rate	Based on synthesis capacity	t/d
Specific energy consumption	0.56	$kWh_{el}/kg\ N_2$
Specific investments costs	129	EUR/(ton*yr)
Fixed operation costs	2	% of CAPEX/yr
Lifetime	30	Year
TRL	9	

Relevant sources: [8,99,100]

5.3.3 Backup power supply from local grid

While electrolysis switches to standby during periods of low wind and PV production, processes such as hydrogen liquefaction or the syntheses processes have a limited part-load capability. Even when no wind or PV power is available, these processes need to be supplied with electrical power to run peripheral components such as compressors and pumps. It is therefore assumed that these processes are primarily supplied from the local RE. However, at times of low RE production and outside the part load range, these less-flexible processes can be supplied with grid power. The country specific data shown in Table 5-9 were used for the cost of electricity purchase [101].
It should be noted that grid electricity is only used to supply must run capacities during times without sufficient RE power production. The electrolysis is not supplied with grid power.

Table 5-10: Country specific electricity grid costs (basis June 2022) for backup power supply of certain PtX components. The electrolysis is supplied with 100% renewable electricity all year round.

Country	Electricity costs [EUR/MWh]
Algeria	33
Australia	170
Brazil	158
Colombia	131
India	102
Mexico	171
Morocco	99
Namibia	113
South Africa	68
Spain	140
Tunisia	95
Ukraine	83

5.3.4 Intermediate PtX Storage

The size of the intermediate storage is an optimization variable and thus determined for each scenario calculation. In the case of local utilization of the PtX product (no export), the storage is sized based on a 14-day rated production of the liquefaction/synthesis.

Table 5-11: Economic parameters of intermediate PtX storage

Parameter	Value				Unit
	LH_2	NH_3	MeOH	FT	
Storage volume	Optimization variable				m³
Product storage pressure	atm.	atm.	atm.	atm.	bar
Product storage temperature	-253	-33	ambient	ambient	°C
Storage density	71	682	794	763	kg/m³
CAPEX	25,000	990	130	290	EUR/ton

Fixed OPEX	2	2	2	2	% CAPEX/yr
Boil-off rate	0.1	-	-	-	%/d
Lifetime	30	30	30	30	years
TRL	7-8	9	9	9	

Relevant sources:
Liquid hydrogen: [54,61,62,102–104]
Ammonia: [62,102,104]
Methanol: [62,102,104]
Fischer-Tropsch and jet fuel: [102]

5.4 Transport of products

5.4.1 Shipping

The parameters for the sea transport of the PtX products are listed in Table 5-11. It is assumed that the transport vessels are running on conventional engines using marine gas oil (MGO) as propulsion fuel. Costs of 1.05 EUR/kg of MGO have been assumed based on the Rotterdam bunker prices (20.10.2022). A propulsion efficiency of 50 % has been assumed for all transport vessels.

For the transportation of **liquid hydrogen**, the conceptual design of Kawasaki Heavy Industry of a 160,000 m³ (~11kt H_2) transport vessel has been considered. The technology for the transportation of cryogenic hydrogen is comparable to the transportation of liquid natural gas (LNG). However, due to the lower temperature, specially designed tanks must be used. Today, only one much smaller LH_2 transport vessel with a much lower capacity (90 tons) is in operation and transports liquid hydrogen from Australia to Japan. So far, reliable cost data for large-scale LH_2 carriers are not available and are subject to a high degree of uncertainty. Derived from data from Kamiya et al. [105], investment costs for a 160,000 m³ LH_2-carrier are in the range of 440 million EUR [40], whereas other publications determine investment costs of 162.5 million EUR based on LNG carriers (Raab et al. [106]). Based on information from Kawasaki a boil-off rate of 0.2 %/d has been assumed [107].
Ammonia sea transport is an established process to supply ammonia for the production of fertilizer. The transport of ammonia uses LPG carriers, which are available in a wide range of transport capacities (up to 90,000 m³). In this study an ammonia transport vessel with a transport volume of 84,000 m³ is considered. Investment costs are determined based on Seo et al. [108] and Jordan [109].
Methanol is transported with chemical tankers, which are equipped with special tanks and nitrogen-inerting systems for the safe transport of chemicals. Typical chemical tankers have a transport capacity of 50,000 deadweight tons (dwt), resulting in a volume of around 55,000 m³.
For the transportation of **Fischer Tropsch products,** medium range (MR) product tankers are considered. These vessels can carry a wide range of refinery products and are able to call at most ports. Due to the lower safety requirements compared to chemical tankers, investment costs are lower. The investment costs for the considered 50,000 dwt tanker are 40 million EUR [109]. The rated engine power and ship speed are determined based on propulsion data from MAN Energy Solutions [110,111].

Table 5-12: Technical and economic parameters for transport vessels

Parameter	Value				Unit
	LH_2	**NH3**	**MeOH**	**FT**	
Number of transport vessels (-)	Optimization variable				-
Vessel type	LH_2 carrier (concept)	LPG carrier	Chemical tanker	MR 2 product tanker	-
Transport volume	160,000	84,000	55,000	67,000	m^3
Transport capacity	11,360	57,288	43,676	49,593	tons
Ship speed	16	15	15	15	knots
Boil-off rate	0.2	-	-	-	%/day
Rated engine power	25	13.3	7.8	7.8	MW
Capex	440	62	50	40	million EUR
Fixed opex	4				$\%_{Capex}$/yr
Lifetime	25				years
TRL	4-5	9	9	9	

Relevant sources:
Liquid hydrogen: [40,54,62,103–105,107,111,112]
Ammonia: [62,104,108,109,112]
Methanol: [62,104,109,110]
Fischer-Tropsch: [109,110]

5.4.2 Pipeline Transportation

Pipeline transportation of gaseous hydrogen is based on the same principle as transportation of natural gas, which is well-established. In the future, the natural gas (NG) grid should be used to transport hydrogen. Currently, small hydrogen pipeline grids already exist, and are used to supply industrial consumers.
For the analysis of hydrogen transport in pipelines, two approaches are distinguished in this study. A "dedicated pipeline" approach presumes the construction of a new hydrogen pipeline dedicated to each project. The second approach assumes a "EU-wide hydrogen pipeline network" and is based on data from the European hydrogen Backbone (EHB) initiative, an industrial consortium announcing a European hydrogen pipeline network.
The basis for both approaches is the transport distance from the point of hydrogen production to Germany. The pipeline routing from the different hydrogen production sites to Germany is depicted in Figure 5-3. It is based on existing NG pipelines and plans for a European hydrogen network.

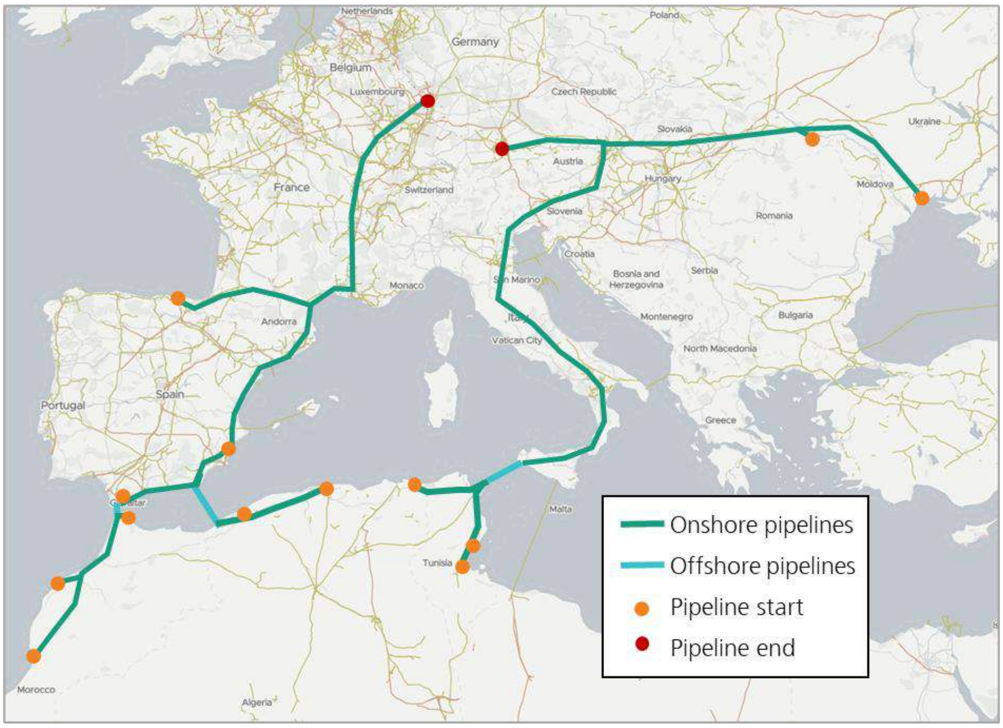

Figure 5-3: Considered pipeline routing towards Germany (background map: Open Infrastructure Maps).

Table 5-13 lists the pipeline distances for the calculation of transport costs. Here, a detour factor of 1.1 has been taken into account. As a starting point for the pipeline, the specific electrolysis location is presumed to be at the determined port (with the exception of Czernowitz ("Chernivtsi", Ukraine), as this location is located far inland). As the potential endpoint for the pipeline transportation analysis, the industrial cluster around Mannheim and Munich has been selected.

Table 5-13: Pipeline transport distances for gaseous hydrogen import.

Country	Location	Onshore pipeline length (km)	Offshore pipeline length (km)	Comment
Algeria	Berriane	2490	210	End of pipeline in Mannheim area; offshore pipeline routing next to Medgaz pipeline
	In Salah	2130	210	
	Oran	2080	210	
	In Amenas	2370	160	Routing through Tunisia
Morocco	Tan-Tan	3135	45	End of pipeline in Mannheim area; offshore pipeline routing next to Maghreb-Europe Gas Pipeline
	Marrakesch	2950	45	
	Figuig	2400	45	
Spain	Pedrola	1580	0	End of pipeline in Mannheim area
	Albacete	1740	0	
	Gibraltar	2350	0	

Tunisia	Sfax	2625	160	End of pipeline in Munich area; offshore pipeline routing next to Trans-Mediterranean pipeline
	Skhira	2750	160	
	Medenine	2750	160	
Ukraine	Mykolajiw	1870	0	End of pipeline in Munich area
	Odessa	1870	0	
	Czernowitz	1240	0	

Dedicated pipeline

The "dedicated pipeline" approach assumes a newly constructed pipeline that is built exclusively for the PtX project and for transporting the green hydrogen from the production site to Germany. Recompression is required due to pressure losses along the pipeline, assuming a distance of 300 km between each recompression station. A pipeline diameter of 36 cm was determined to be sufficient for the maximum hydrogen production rate of the $1GW_{el}$ electrolysis and with an assumed pipeline pressure range of 30-80 bar. For recompression along the pipeline, compression stations with costs of 3.4 million EUR per MW (based on the LHV of the hydrogen flow rate) are assumed [33]. For powering the compressors transported hydrogen is re-electrified in a fuel cell at assumed electrical efficiency of 50 %, leading to a loss of transported hydrogen.

Table 5-14: Technical and economic parameters for dedicated pipeline transport [33,54,56,113–116].

Parameter	Value		Unit
	Onshore	**Offshore**	Unit
Pipeline start pressure	80		bar
Pipeline end pressure	30		bar
Distance between compressor stations	300		km
Power origin for recompression	Transported hydrogen (fuel cell, 50% efficiency)		n/a
Pipeline Diameter	0.36 (based on max. H_2 production rate, distance between compressor stations and min. and max. pressure)		m
Distance between compressor stations	300		km
CAPEX Pipeline	570	1990	EUR/m
OPEX Pipeline	1	2	%/year
Lifetime	40	40	Years

Relevant sources:
CAPEX: [114,115,117]
Lifetime: [33,54,113]

EU-wide hydrogen pipeline network

The approach, which assumes that an EU-wide hydrogen pipeline network is available to transport the green hydrogen produced, uses data published by the European Hydrogen Backbone Initiative [33]. For onshore and offshore pipeline transportation ranges of 0.11-0.21 EUR/kg/1000km (median: 0.15 EUR/kg/1000km) and 0.17-

0.32 EUR/kg/1000km (median: 0.22 EUR/kg/1000km) are listed, respectively. In addition to the pipeline investment and repurposing costs, the figures include costs for recompression stations and the power costs to run the compressors. The study assumes that power is taken from the grid and no hydrogen is re-electrified. Thus, no hydrogen losses occur during the transport.

Table 5-15: Hydrogen transport costs based on an existing hydrogen pipeline network [33].

Parameter	Value		Unit
	Onshore	**Offshore**	
Specific hydrogen transportation costs	0.15	0.22	EUR/kg/1000 km

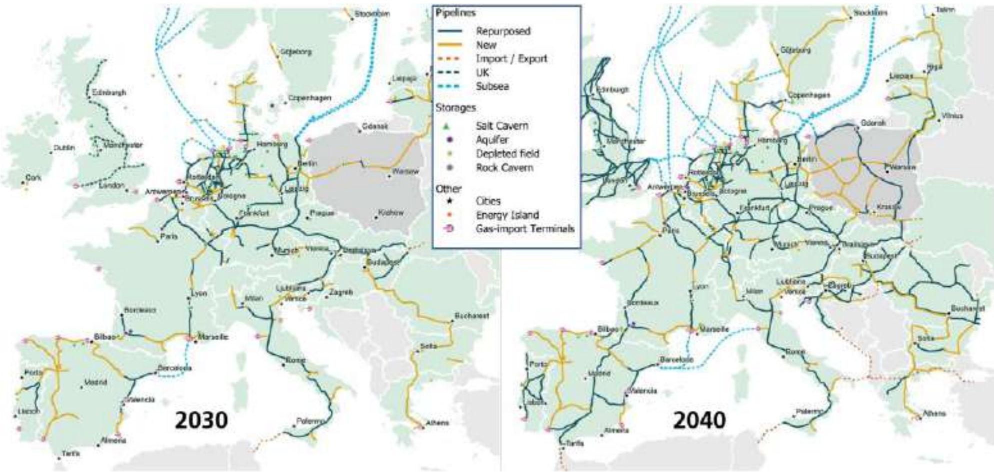

Figure 5-4: Expansion of the European hydrogen pipeline network in 2030 and 2040. Map provided by European Hydrogen Backbone.

5.5 Further cost elements for PtX plants

For the PtX plants further cost elements have been considered.
For plant engineering and design, project management, permits and additional required infrastructure additional costs of 20% of the plants total investment costs have been considered [118]. It should be noted that these additional secondary costs are subject to uncertainties. Annual insurance costs for the PtX plant have been estimated at 1 % of the plants total investment costs [119].
For an estimation of labor costs the Wessel equation – a method of estimating the number of operating-hours required based on the plant capacity and the number of discrete operating steps [120]:

$$\frac{operating\ workhours}{tons\ of\ product} = T * \left(\frac{\#process\ steps}{capacity^{0.76}}\right)$$

with
T = 23, as rather pessimistic assumption, representing batch operations with maximum workload
$\#\mathrm{process\ steps}$ = number of central process steps; each PtX component assumed as one process step: gaseous hydrogen: 3; liquid hydrogen: 5; ammonia, methanol, FT, and jet fuel: 6
$\mathrm{capacity}$ = plant capacity in t/d
The cost of operating workhour has been assumed with 50 EUR/hr.

6 Results

This study analyzed the generation and export of five different PtX products (liquid and gaseous hydrogen, ammonia, methanol, jet fuel) in twelve countries. Both the PtX products and the country selection were predetermined by the H2Global Foundation. For each of the twelve countries, a GIS analysis was performed for the identification of up to four "RE regions" that could be suitable for the construction and operation of large-scale wind and PV parks, resulting in a total of 39 promising and globally distributed RE regions. At the same time, PtX generation sites with close proximity to suitable ports that could be used for PtX export were identified. The results were further differentiated by the local production cost (at gate) and the supply cost (including transport to Germany), both for the year 2030. In addition, sensitivity analyses and further sub-scenarios were conducted to provide a broader basis for the results, findings, and eventually the conclusions. Thus, the analyses performed produced a result set with more than 250 result series. On the one hand, a comprehensive discussion of each individual set of results would exceed the scope of this study. On the other hand, central statements for a large number of regions can be synthesized, summarized, and processed on the basis of example regions (see section 6.2 Discussion of selected regions).
The results chapter is therefore structured into an overview section, a discussion of selected regions, and the results for conducted sensitivity analyses and special sub-scenarios.
The complete range of results of the production and supply costs and GIS analyses for all of the 39 regions assessed can be found in the appendix to this study.

6.1 Results overview

This section aims to provide a general overview of the evaluated RE regions, their respective full load hours, and levelized cost of electricity (LCOE), as well as a comparison of the supply costs for all PtX products analyzed in this study.
Figure 6-1 and Figure 6-2 illustrate the Key Performance Indicators (KPI) for PV and onshore wind, respectively, in all countries evaluated. The two maps show that the lowest LCoE is achieved in countries where a combination of high full load hours and low capital costs is possible. At the same time, there can be very wide ranges in LCoE within a country. For example, the range for the levelized cost of onshore wind electricity in Colombia is 40–177 EUR/MWh$_{el}$ and for the regions analyzed for India, 56–84 EUR/MWh$_{el}$.
Generally worth highlighting based on the LCoE are countries like Brazil and Australia, which show very promising cost potentials for both PV (29–33 EUR/MWh$_{el}$) and onshore wind (41–50 EUR/MWh$_{el}$). Extremely favorable wind production costs can be reached in the La Guajira region in northern Colombia. The countries assessed for Northern Africa are also worth emphasizing as they show consistently favorable power generation cost potential below 36 EUR/MWh$_{el}$ for PV and 57 EUR/MWh$_{el}$ in the case of onshore wind.
Cost-effective production of green hydrogen and derivatives is potentially achieved at sites that have a favorable combination of solar and wind-based electricity production. However, if a region does not offer good hybrid sites, one option could be to consider separate PV and wind sites, each with advantageous conditions. A disadvantage here would be increased investment costs for the necessary power lines between RE production and the PtX site. However, these costs could be offset by increased full load hours and higher system utilization.

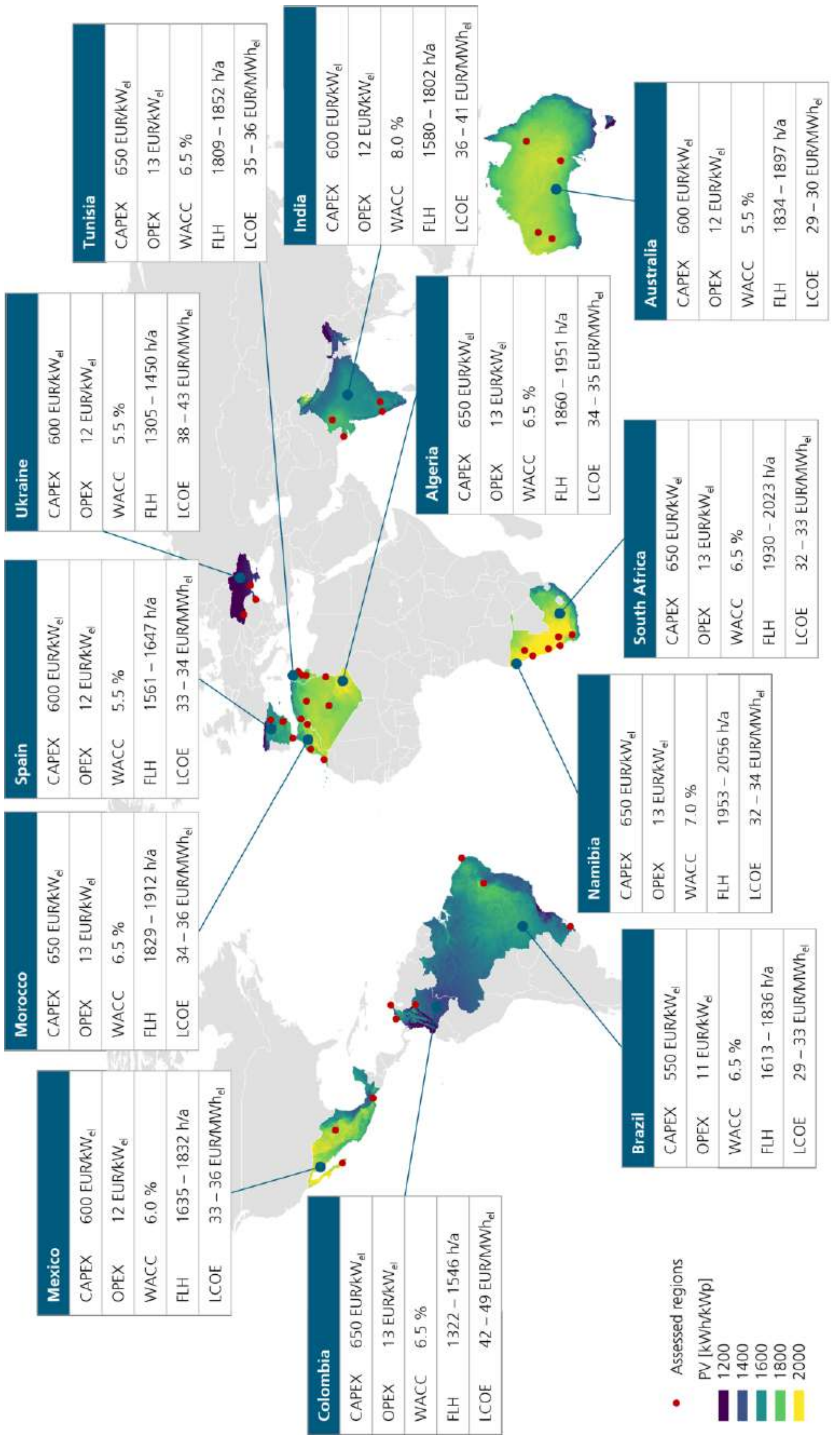

Figure 6-1: Key Performance Indicator map for electricity produced via PV in all countries and regions assessed (red markers) including cost assumptions, full load hours and the levelized cost of electricity.

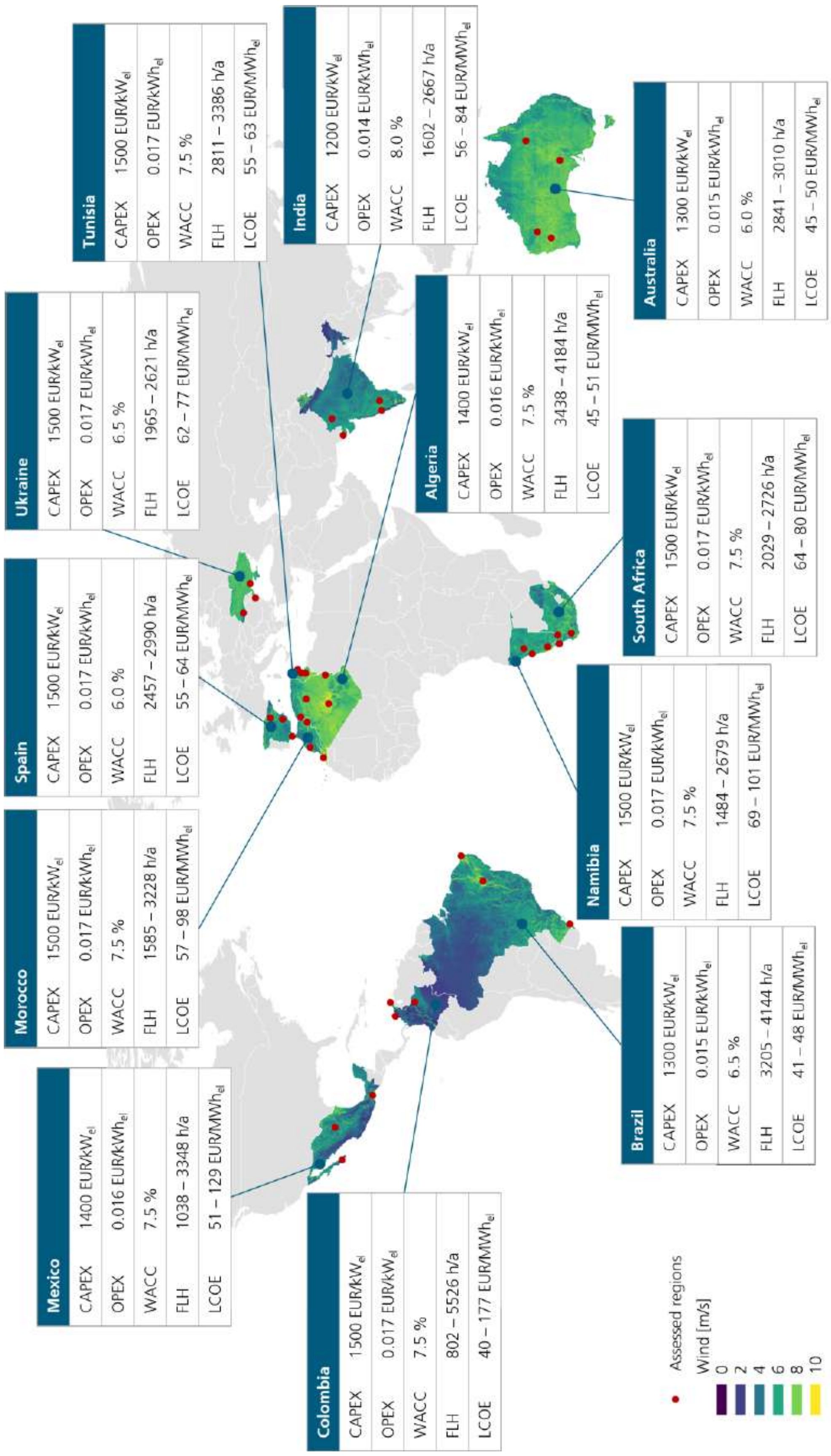

Figure 6-2: Key Performance Indicator map for electricity produced via onshore wind in all countries and regions assessed (red markers) including cost assumptions, full load hours and the levelized cost of electricity.

Figure 6-3 provides an overview for all assessed countries of the range of the levelized supply cost of PtX energy carriers including their transport to Germany.

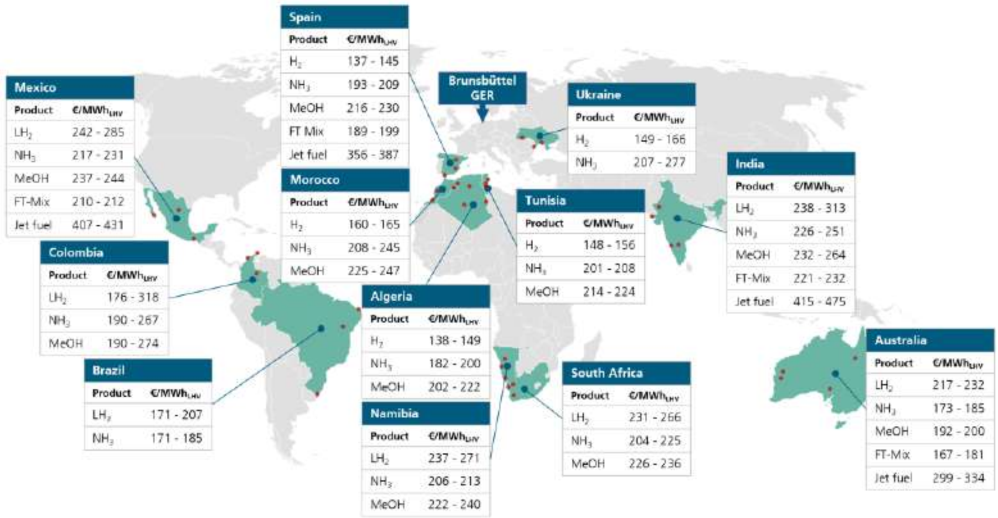

Figure 6-3: Range of levelized supply cost of PtX energy carriers including their transport to Germany for all assessed countries and regions (red markers). Liquid hydrogen, ammonia, methanol, jet fuel and FT mix are transported via ship. Gaseous hydrogen is based on transport via hydrogen pipelines as part of a European Hydrogen Backbone (see section 5.4.2).

In the following, the results for each of the analyzed PtX energy carriers are discussed, considering only the most promising region per country. The discussion will focus on the quantitative results. A discussion of the impacts and mechanisms that lead to the specific outcomes and performance of each PtX pathway is part of Section 6.2.

Liquid hydrogen: Liquid hydrogen production was analyzed for seven countries and a total of 23 regions (Figure 6-4). Within our parameter framework (chapter 5) the most promising regions for the production and supply of liquid green hydrogen are the Rio Grande do Norte region in Brazil (171 EUR/MWh; 5.71 EUR/kg LH_2) and the Colombian Northwestern region La Guajira (176 EUR/MWh; 5.86 EUR/kg LH_2). The best regions of the remaining countries for which a production and liquefaction of hydrogen was assessed are in the range of 217–256 EUR/MWh (7.24–8.52 EUR/kg LH_2). These supply costs include the total production and liquefaction cost as well as transport by ship to Germany. The regasification of liquid hydrogen is not included.
In comparison with the production costs of fossil-based hydrogen from natural gas steam reforming, the increased supply cost of green (liquid) hydrogen assessed here are put into perspective when the currently sharply increased market prices for natural gas are taken into account. Depending on the price of natural gas, the production costs for gray hydrogen have thus far been calculated at around 45–60 EUR/MWh H_2, but are likely to have risen sharply recently in the light of significantly higher natural gas market prices. In-house calculations show that, depending on the price of natural gas, the cost price for gray hydrogen could be in the range of 80 EUR/MWh fossil H_2 (2.76 EUR/kg fossil H_2; with NG at 50 EUR/MWh) up to temporary 210 EUR/ MWh fossil H_2 (7.00 EUR/kg fossil H_2; NG at 150 EUR/MWh) [121,122]. These costs are calculated without taking into account the costs for EU emissions allowances.
For all assessed regions the range of total annual amount of liquid hydrogen delivered to Germany ("total exported amount") is between 1.5–4.2 TWh. The considerable variance in production volumes, despite a uniform installed electrolysis capacity, is primarily explained by the site-dependent achievable RE full load hours and thus the utilization of the PtX plants. La Guajira (Colombia) and Rio Grande do Norte (Brazil) have exceptionally high electrolysis full load hours ranging from 6735 to 7187 hrs. per year, respectively, and therefore allow for the production of very high total amounts of PtX

energy carriers. Even within the evaluated countries, there are sometimes clear deviations. For example, the exported PtX volumes in Colombia's Hato Corazol are only 1.5 TWh, 61% less than the quantities produced in La Guajira. Further explanations of the plant full load hours and their effects on the other key performance indicators are given in section 6.2.

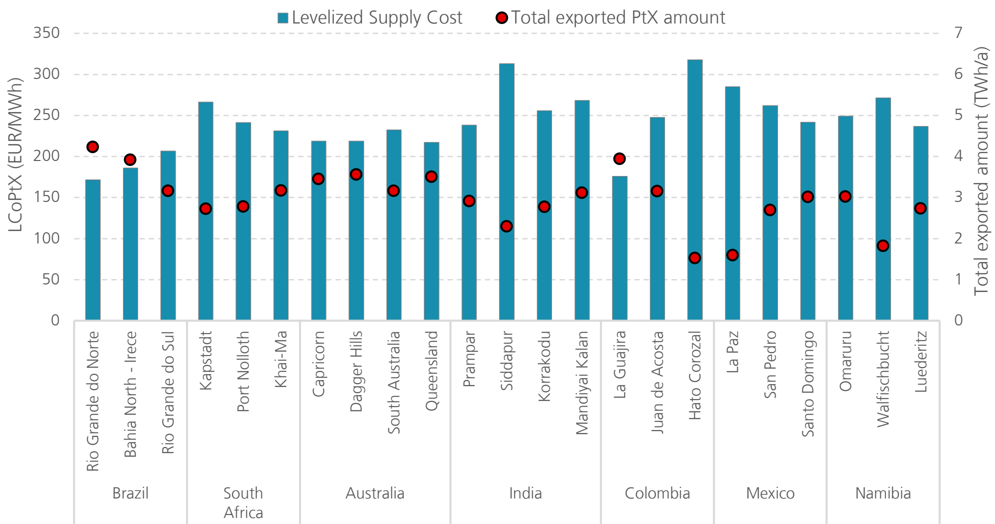

Figure 6-4: LH_2 – levelized supply cost and total exported amount of liquid green hydrogen at the target port in Germany for all assessed locations and for PtX plants with an electrolysis rated capacity of 1 GW_{el}.

It is obvious that with increasing distance, the PtX transport costs increase. At the same time, however, a long transport distance does not go hand in hand with high supply costs. Figure 6-5 illustrates this by showing the calculated liquid hydrogen production and shipping cost compared to the total transportation distance for selected regions. Although the export paths of regions from Australia have the highest transport costs, these regions benefit from very favorable production conditions and are thus significantly cheaper overall than, for example, exports from much closer Mexican regions.
As described in section 5.4.1, this assumes that liquid hydrogen is transported in large ships with transport capacities of 160,000 m^3 (~11kt H_2), which have not yet been built. If these future cryogenic transport concepts – which are being pursued not only by Kawasaki but also by others such as Hyundai Heavy Industries/KSOE – can be planned, approved by regulators, and built in sufficient numbers over the next decade, this will be a key piece in transporting hydrogen halfway around the globe [123,124]. Consideration of much smaller vessels, such as Moss Maritime's near-term concepts with a capacity of 500 tons of liquid hydrogen, will result in significantly higher transportation costs for long-distance scenarios [125].

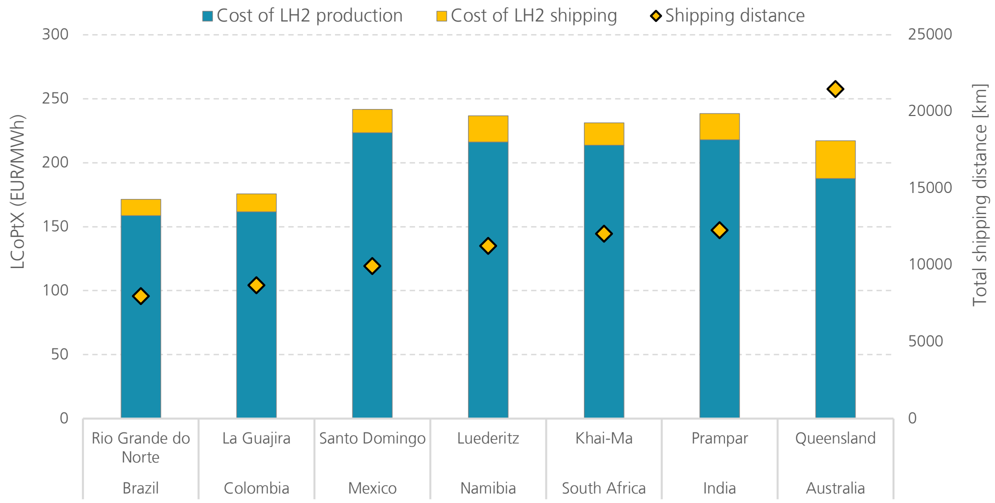

Figure 6-5: LH_2 – production and shipping cost compared to total ship transport distance; sorted in ascending order by transport distance.

Ammonia and methanol: For the production and supply of green ammonia to Germany (assessed for twelve countries and 39 regions) the total range within the regions assessed is from 171 EUR/MWh (886 EUR/ton NH_3) in Rio Grande do Norte in Brazil to 277 EUR/MWh (1435 EUR/ton NH_3) in Chernivtsi (Czernowitz) in Ukraine (Figure 6-6). The range for the best assessed regions within all countries assessed is from 171–226 EUR/MWh (886–1171 EUR/ton MeOH). As in the case of liquid hydrogen, the total volumes of ammonia produced and exported annually vary significantly, ranging from 1.6 to 4.2 TWh (low: Mandiyai Kalan (India)/Hato Corazol (Columbia); high: La Guajira (Colombia)).

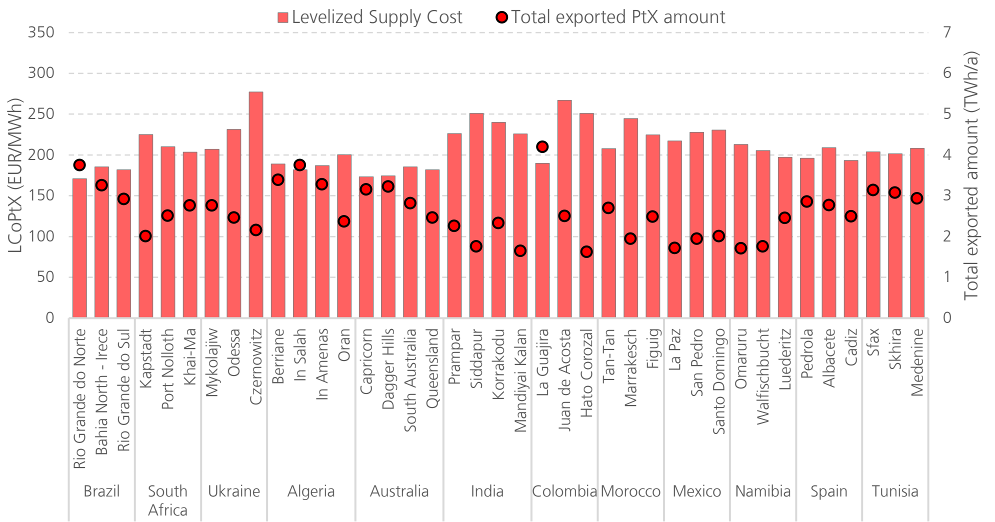

Figure 6-6: NH_3 – levelized supply cost and total exported amount of green ammonia at the target port in Germany for all assessed locations and for PtX plants with an electrolysis capacity of 1 GW_{el}.

In the case of the production and supply of green methanol based on carbon dioxide captured from the atmosphere (assessed for ten countries and 34 regions) the Colombian region La Guajira features the lowest supply cost (190 EUR/MWh; 1052 EUR/ton MeOH). The range for the best assessed regions within all countries assessed is from 190-237 EUR/MWh (1052-1313 EUR/ton MeOH), (Figure 6-7).
For both green ammonia and methanol, Australia needs to be highlighted. In all four Australian regions studied, levelized supply costs are only slightly higher than those of

the top regions, Rio Grande do Norte and La Guajira. With a range of 173-185 EUR/MWh in the case of green ammonia and a range of 192-200 EUR/MWh for green methanol, the Australian regions assessed show on the one hand low PtX production cost (see section 6.2.4) and on the other hand a cost-efficient large-scale and established ship transport to Germany of the liquid, high-energy end products.
As defined at the beginning of the project, the costs shown here refer to methanol production with carbon dioxide from large-scale DAC plants. In order to evaluate the high degree of uncertainty regarding the carbon dioxide supply costs from DAC and also to show an estimate for the use of carbon dioxide from point sources, chapters 6.3.1 and 6.3.4 go into more detail.

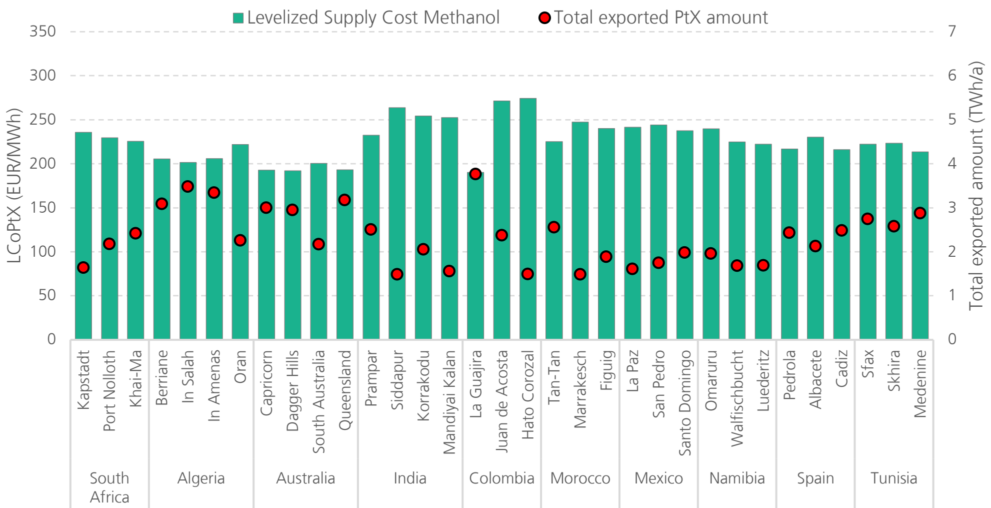

Figure 6-7: Methanol – Levelized Supply Cost and total exported amount of green methanol at the target port in Germany for all assessed locations and for PtX plants with an electrolysis capacity of 1 GW_{el}. Cost include the capturing of atmospheric carbon dioxide with low-temperature DAC. A sensitivity analysis for the DAC CAPEX is included in section 6.3.1.

Figure 6-8 shows the market price development for fossil (gray) methanol from November 2019 to November 2022. It becomes clear that the price of fossil methanol has almost doubled over the past two years with an increase of 77-86%. Nevertheless, the methanol supply costs determined in this study for 2030 are still significantly above current market prices. The red area on the right side of the diagram is therefore intended to estimate a market price development for the EU under the assumption that the prices for EU emission certificates increase by 10-30%/yr, which should also have an increasing effect on the market prices for fossil methanol. Although costs and prices cannot be directly compared, it is not unlikely under these limited assumptions that the costs of green methanol could converge strongly towards the EU market prices over the coming years and that substitution of imported green methanol could eventually no longer be necessary.

Figure 6-8: Fossil methanol market price development from Nov 2019 - Nov 2022 for the US and the EU market [126]. The red area represents fossil methanol price development under the assumption that the prices for EU emission allowances (EUA) [127,128] increase by 10-30%/year (starting at 30 EUR/t CO_2 in 2023). This results in EUA prices of 76-188 EUR/t CO_2, respectively, in 2030. The green area shows the supply costs for the green methanol analyzed in this study. Market prices for the European and the US market are based on historic prices published by the methanol institute. EUA prices and assumptions for future development are based on in-house studies of Fraunhofer ISE and projections by the European Central Bank. Greenhouse gas emissions of fossil methanol production of 0.84 t CO_{2eq}/t MeOH based on study by Mayer et al. 2010 [129].

Fischer-Tropsch products and jet fuel: The production of synthetic jet fuel has been assessed for four countries and a total of 14 regions (Figure 6-9). Since the production of jet fuel via the Fischer-Tropsch route is always associated with the production of other valuable synthetic products, the levelized supply costs are presented for the Fischer-Tropsch product mix and for jet fuel alone. In the latter case, it is assumed that the by-product diesel fuel is sold on the respective local market (see section 5.3). In the case of the Fischer-Tropsch product mix the global range of supply costs is 167-232 EUR/MWh (2040-2841 EUR/ton FT-mix) whereas in the case of jet fuel exports, the cost range is higher, at 299-475 EUR/MWh (3675-5828 EUR/ton FT-mix). Again, Australia performs well in the production and export of liquid PtX products, with comparatively large PtX production and export volumes and reasonable production and supply costs despite the long transportation distance.
The level of the supply costs in the jet fuel pathways clearly depends, among other things, on the prices and extent to which Fischer-Tropsch by-products (such as diesel, waxes) can be sold on the local markets. More detailed market studies on the producing countries are therefore required before any further investment decisions can be made, in order to be able to make more accurate cost forecasts.

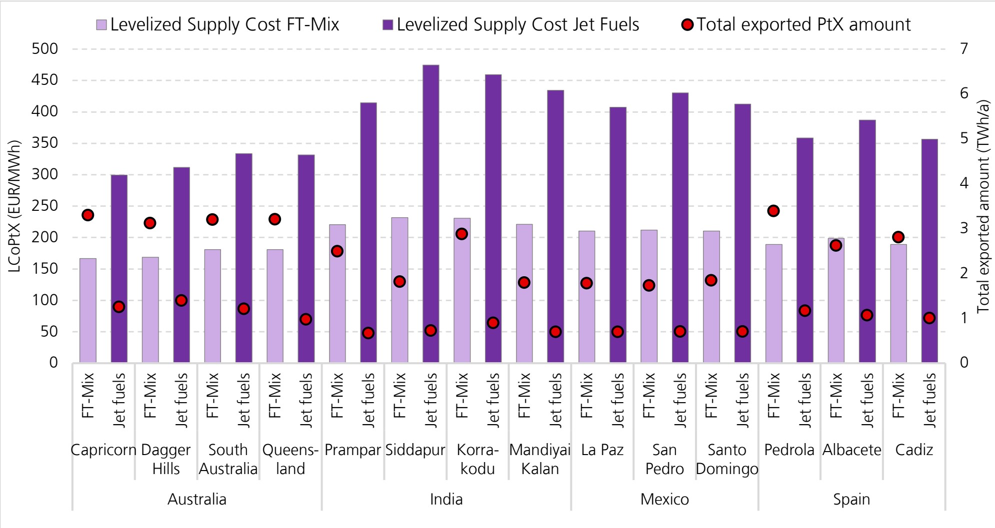

Figure 6-9: Jet fuel and Fischer-Tropsch product mix – levelized supply cost and total exported amount at the target port in Germany for all assessed locations and for PtX plants with an electrolysis capacity of 1 GW$_{el}$. Cost include the capturing of atmospheric carbon dioxide with low-temperature DAC. A sensitivity analysis for the DAC CAPEX is included in section 6.3.1.

Gaseous hydrogen via pipeline: The production and export of gaseous hydrogen in pipelines, assessed for five countries and 16 regions, shows a clear cost reduction potential compared to the ship transport of liquid PtX products (Figure 6-10). Assuming that a trans-European hydrogen pipeline network exists and that these pipelines are accessible for transport from the exporting region to Germany (see section 5.4.2), the supply costs for gaseous hydrogen range from 134-180 EUR/MWh (4.46-5.99 EUR/kg H_2). If dedicated hydrogen pipelines are assumed for transport from the exporting country to Germany the supply costs increase in some cases significantly and range from 158-279 EUR/MWh (5.25-7.76 EUR/kg H_2). For both pipeline scenarios the Spanish region Pedrola offers the lowest supply cost, but other regions, such as In Salah (Algeria) or Gibralter (Spain), also offer promising potential.
The total exported amounts vary from 1.9-4.1 TWh of gaseous hydrogen per year, with no clear trend in hydrogen export quantity between backbone and dedicated scenarios. Rather, the reason for the differing hydrogen product quantities lies in the investment costs required in each case. The investment costs for a dedicated hydrogen pipeline are significantly higher in all scenarios than the costs resulting from transport in a future hydrogen backbone. For this reason, a cost-optimal result in the dedicated scenarios requires significantly more renewables in order to be able to produce more hydrogen and thus better amortize the high investment costs.
A look at the Pareto fronts of the pipeline regions (e.g., Albacete, Spain; see Appendix section 9.10.2) also shows that in the backbone scenarios (orange dashed line) the hydrogen export quantities can be increased significantly if only slightly higher costs are accepted (e.g.,Albacete: from 2.58 TWh/yr to 3.5 TWh/yr with a supply cost increase from only 146 EUR/MWh to 151 EUR/MWh).

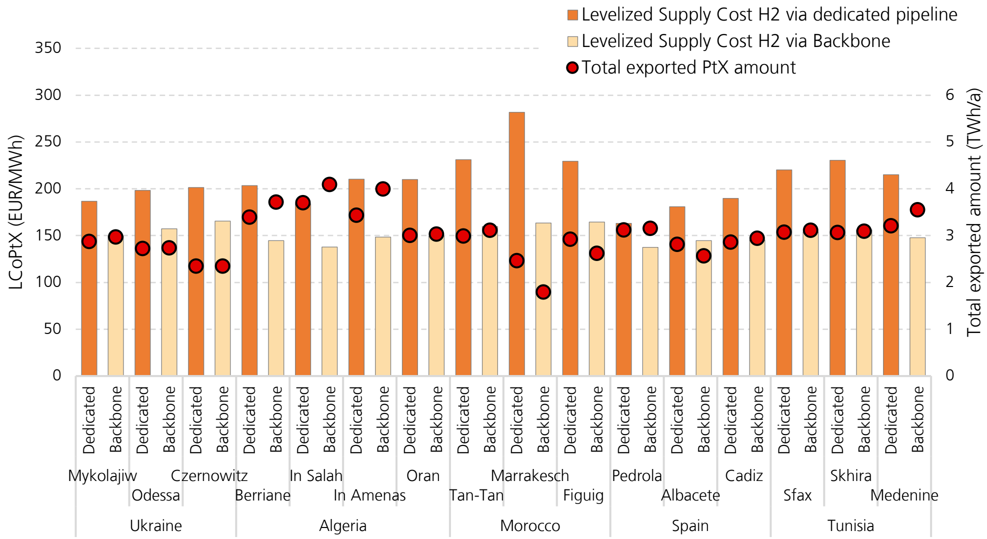

Figure 6-10: Gaseous Hydrogen via pipelines – levelized supply cost and total exported amount of gaseous hydrogen either transported via dedicated pipeline or via the European Hydrogen Backbone pipeline network. Transport considered at the target port in Germany for all assessed locations. Transport is considered until the transfer point at the German border.

Comparison of local cost and supply cost (including transport): For the PtX products ammonia, methanol, and jet fuel both the local production cost as well as the supply cost including the transport have been assessed. Figure 6-11 shows the difference in local and supply cost using the example of the green ammonia chain (left y-axis). The chart is ordered by the total shipping distance (right y-axis). The relative cost increase added by the ammonia shipping phase ranges from 0.4-3.9% of the total supply cost. The analysis shows that the amount of cost increase cannot be related to the total transport distance. Rather, the cost increase can be attributed to the total volume produced at the respective location and the optimal utilization of the available ships as well as their achievable capacity utilization. In the cases with significantly higher cost (e.g., Rio Grande do Norte), this is due, among other things, to a less than optimal utilization of the available transport vessels.

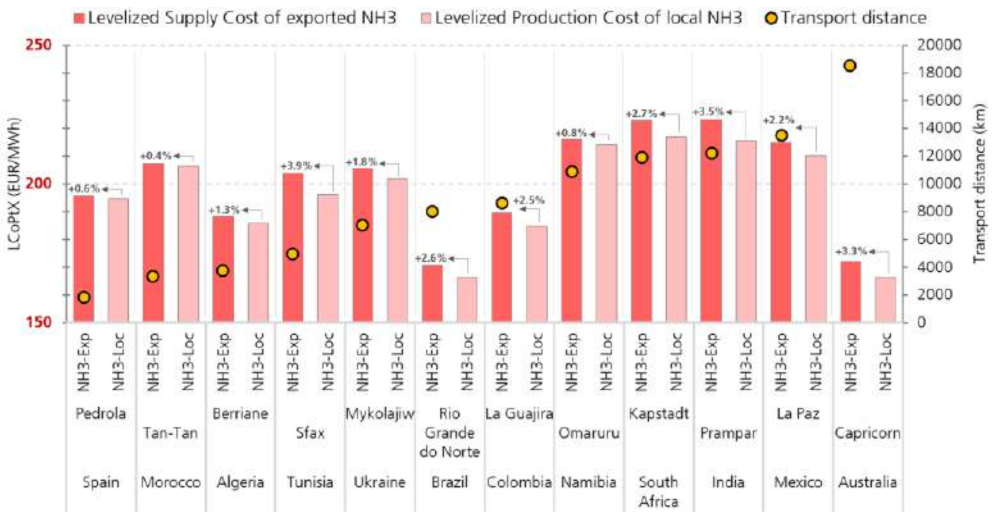

Figure 6-11: The difference in local and supply cost using the example of the green ammonia chain. The chart has been ordered by total shipping distance. For an improved representation the left y-axis is plotted with an offset.

6.2 Discussion of selected regions

The following sections highlight selected countries and focus regions in order to discuss the various facets of the techno-economic results. The focus regions were selected in coordination with the H2Global Foundation and covers different aspects of PtX production and export:

- Regions which show comparatively low PtX production and supply costs
  - Brazil – Rio Grande do Norte
  - Columbia – La Guajira
  - Australia – Dagger Hills
- Regions that have promising industrial policy significance through currently planned pilot projects and concrete roadmaps
  - Namibia – Lüderitz
  - Australia – Dagger Hills
- Region with long shipping routes:
  - Australia – Dagger Hills
- Region with gaseous hydrogen as target product and subsequent pipeline transport:
  - Morocco – Tan-Tan
- European location as comparison reference:
  - Spain – Pedrola

The selected focus regions are each discussed in the order of the applied methodology. First, the results for the GIS-analyses and RE potentials are presented. This is followed by the techno-economic results with the Pareto fronts, the production and supply costs and other site-specific key performance indicators.
The results for the other countries and regions assessed can be found in the results overview (section 6.1) and are presented in the Appendix chapter 9.

6.2.1 Brazil – Rio Grande do Norte

Brazil and its focus region Rio Grande do Norte were selected because the results obtained for wind and PV potential as well as PtX production and supply costs are very favorable. All three of the regions evaluated performed well in the overall cost comparison.

GIS and Renewable potential analysis

Brazil is the country with the largest area in South America. Although most parts of the country in the west are forested, the east has great potential for renewable energy. In addition, there is a great wealth of experience, especially with wind projects, but also with solar projects, which is noticeably reflected in the identified investment costs (Table 5-1).

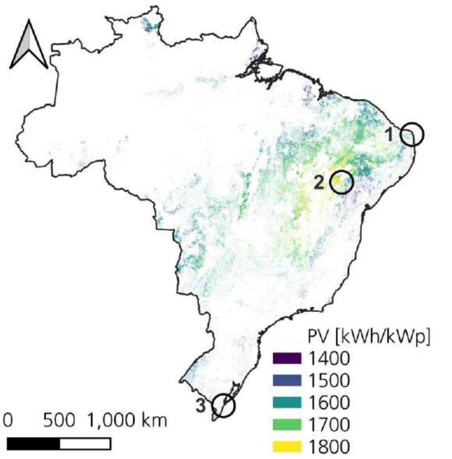

Figure 6-12: PV potential and selected regions in Brazil

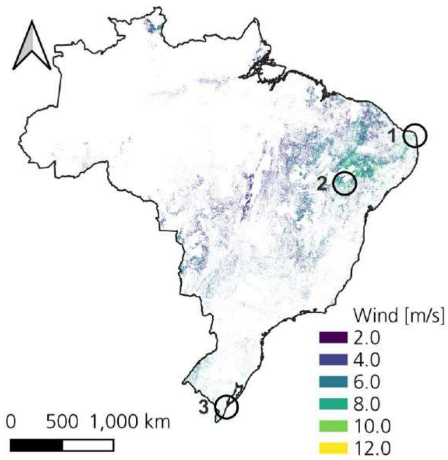

Figure 6-13: Wind potential and selected regions in Brazil

Rio Grande do Norte (Region 1) provides very good wind conditions due to its coastal location close to the northeast coast of the country (Figure 6-13). The average annual wind speed reaches up to 11 m/s, which leads to a high utilization of the wind turbines. The region also has good solar potential. The specific yield averages between 1,800–1,900 kWh/kWp (Figure 6-12).

Rio Grande do Norte is also characterized by a well-developed infrastructure. This is due to its proximity to Natal, a city with over a million inhabitants, but also to the high number of wind farms already built in the region. Consequently, not only are the power grid and road network well developed, but it can also be assumed that expertise for the planning and operation of renewable energy plants, as well as the necessary workforce for their construction, are locally available.

The distance from the location of renewable energy production to the PtX site and the Port of Natal is less than 50 km, resulting in low power transmission costs. The port is suitable for loading and unloading ships of the required size for exporting PtX products and can be used for the delivery of material during the production process. It is also well connected by rail and road to the RE region. Furthermore the Port of Natal is the closest port of the country to Europe, which results in a reduction of the shipping distance. However, a loading structure for chemicals or gas is not yet available, as the port is currently used only for shipping containerized cargo. Additionally, the port is situated inside the city of Natal. The availabilty of new, sufficiently large areas for the construction of PtX plants can therefore not be guaranteed for space-related reasons. It is probable that PtX production will need to be built at some distance from the port, which would entail additional costs [130,131].

Techno-economic results

This section first deals with production and supply costs, which are described and interpreted by including the respective key performance indicators. Subsequently, Pareto fronts are explained to provide insight into the range of possible results of the PtX pathway optimization process.

In Figure 6-14 the cost breakdowns[7] for the respective <u>cost-optimal system design</u> for the three scenarios – liquid hydrogen export (LH_2-Exp), ammonia export (NH3-Exp) and

[7] It is important to note that in the cost breakdowns, the respective *energy demands* of the individual components such as electrolysis or compressors are included in the cost shares of wind and PV (and not the

local ammonia (NH3-Loc) – are shown. The supply costs for liquid hydrogen and for ammonia including transport to Germany are comparable, at 171.4 EUR/MWh (5.71 EUR/kg LH_2) and 171 EUR/MWh (886 EUR/ton NH_3), respectively. In the case of a local ammonia use, the cost of 167 EUR/MWh (862 EUR/ton NH_3) is only 2.3% lower than that of exported ammonia.
In all three scenarios analyzed, renewable energy generation accounts for the highest share of costs, with wind energy dominating. Especially in the liquid hydrogen scenario, electricity generation consists almost entirely of wind power with installed capacities of 2.1 GW of wind and only 0.6 GW of PV. The reason for the different sizes of installed wind and PV capacities can be traced back to the underlying system simulation and optimization. In general, it can be stated on the basis of the results that a more dynamically operable path (such as the liquid hydrogen path) can rely on more wind energy than the less dynamic synthesis pathways. In contrast, the syntheses place a minimally greater emphasis on solar power, which is easier to dispatch, especially at regions close to the equator. This aspect is again highlighted in the case of the Namibian PtX scenarios (cf. 6.2.3).

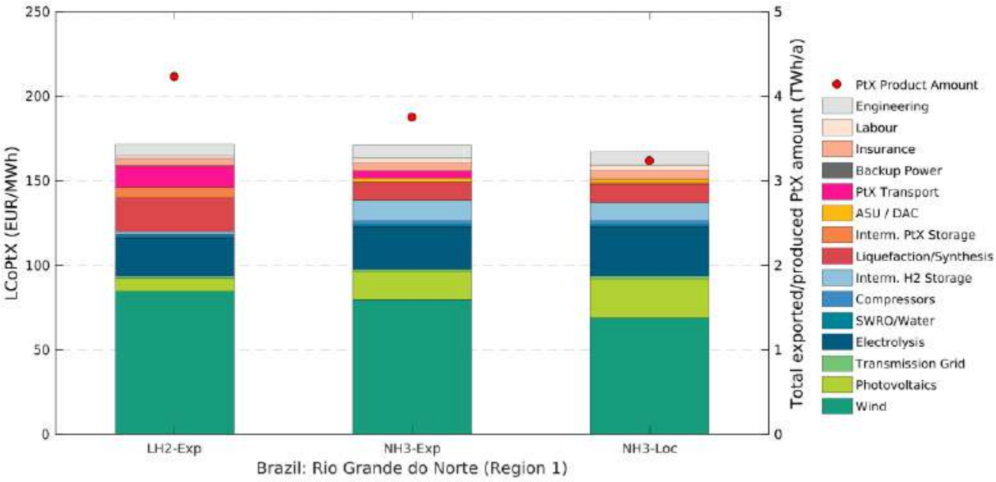

Figure 6-14: Cost breakdown and total PtX product amounts for the Brazilian location Rio Grande do Norte (Region 1) for three product scenarios – exported liquid hydrogen (LH2-Exp), exported and local distribution of ammonia (NH3-Exp, NH3-Loc, resp.). The costs shown here apply to the respective cost-optimal system layout.

For further interpretation of the cost breakdowns and techno-economic results, a selection of key performance indicators is listed in Table 6-1. With electrolysis full load hours of around 7,000 h/yr and more, this wind-PV hybrid site achieves extraordinarily high electrolysis utilization. This is also reflected in the production and supply costs, which are among the best of all analyzed sites.
Although the levelized cost of wind electricity is higher than that of PV electricity (in Rio Grande do Norte: 41 EUR/MWhel and 29 EUR/MWhel, respectively), the overall system benefits from a higher share of wind electricity in many of the scenarios assessed. This is due to the higher system utilization resulting from a larger wind share and thus reduced PtX production costs.
In the two assessed ammonia scenarios the wind-PV mix is more evenly balanced, with 1.3-1.8 GW of installed wind power and 1.2-1.4 GW of installed PV capacities. The reason that the liquid hydrogen pathway can benefit from even higher wind capacities is that, unlike ammonia synthesis, this technology can better follow a variable wind

cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the system energy demand directly affects the installed capacities of wind and PV. For example, the energy costs of electrolysis are not in the dark blue cost shares shown (with 22-29 EUR/MWh) but included in the cost shares for wind and PV.

profile and can therefore utilize a larger share of the wind energy generated. This fact is also reflected by a lower need for cost-intensive intermediate hydrogen storage in the liquid hydrogen pathway. Ammonia synthesis, in contrast, which allows part-load operation at only 80-100% of rated capacity, requires significantly larger intermediate hydrogen storage when run on variable renewables.
In turn, the high investment costs of hydrogen liquefaction compared to ammonia synthesis must be emphasized. This can be seen in Figure 6-14 by the substantial difference between these two central process steps.[8] (see section 5.3 for further reference).
The PtX product storage and ships required for subsequent export also cause significantly higher cost shares in the liquid hydrogen pathway than in the ammonia pathway.

Table 6-1: Key performance indicators for the cost-optimal system configuration for the Brazilian location Rio Grande do Norte (Region 1).

Brazil **Rio Grande do Norte**	**LH_2 Export**	**NH_3 Export**	**NH_3 Local**
Techno-economic KPI:			
Wind: Installed capacity (GW_{el})	2.1	1.8	1.3
Wind: LCoE (EUR/MWh_{el})		41	
PV: Installed capacity (GW_{el})	0.6	1.2	1.4
PV: LCoE (EUR/MWh_{el})		29	
Intermediate H_2 storage: Volume (1000*m³)	42	272	201
Electrolysis: Full load hours (h/yr)	7187	6716	5793
LCoPtX (EUR/MWh)	171	171	167
LCoPtX (EUR/ton)	5707	886	866
PtX Amount (GWh/yr)	4227	3747	3230
Selected investment cost (million EUR):			
Wind + PV	3097	2949	2493
PEM Electrolysis	750	750	750
Intermediate H_2 storage	88	572	423
Liquefaction/ synthesis	718	336	306
ASU	-	84	72
Total System	5862	5341	4540

Figure 6-15 shows the result range for the PtX pathway optimizations for liquid hydrogen, local and exported ammonia (see section 4.4.3 for Pareto methodology explanations).
The Pareto plot clearly illustrates how, at one site with constant renewable potential, varying product quantities result from differing pathway efficiencies and possible system dynamics. The theoretical chain efficiency from a liquid hydrogen pathway (η_{LHV} ~52-58%) is not far above that of a green ammonia pathway (η_{LHV} ~48-52%) and therefore can only explain the different product amounts to a limited extent [132]. Rather, the possible process dynamics are a central criterion when PtX chains are dynamically calculated and optimized. In the present case, the liquefaction step can have a significantly lower partial load (min. 25% of the nominal load) than ammonia synthesis (min. 80% of the nominal load). This, in particular, leads to the liquid hydrogen pathway

[8] Total CAPEX: Hydrogen Liquefaction unit: 718 million EUR; Ammonia synthesis: 338/306 million EUR (Exp-/Loc-Scenario)

being able to convert significantly more variable renewable energy to the final product than, for example, the ammonia or methanol pathway.
However, the Pareto front also shows that if slightly higher supply costs are accepted, significantly increased PtX product amounts are possible. For example, in the case of the ammonia local scenario (red dashed line), the PtX product volume in the cost optimum is 3.2 TWh/yr at a production cost of 167 EUR/MWh. In contrast, the PtX product quantity can be increased by 1 TWh to 4.2 TWh/yr, if slightly increased production costs of 172 EUR/MWh are accepted for the project.

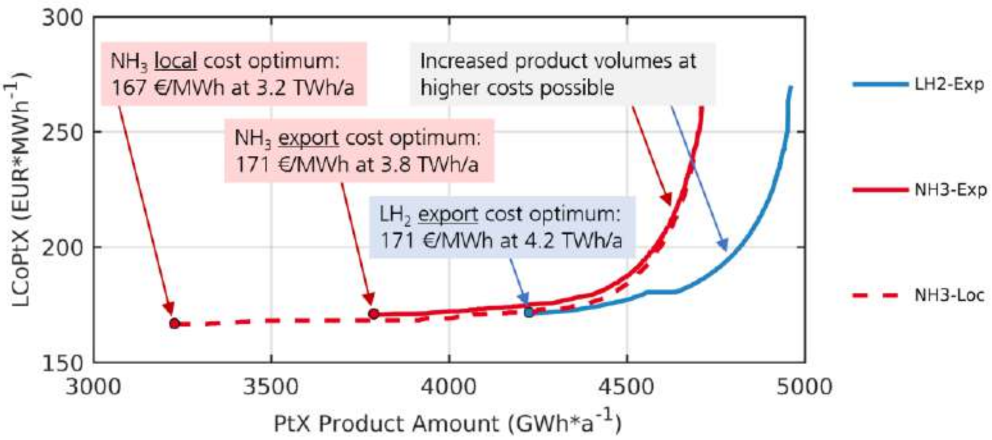

Figure 6-15: Pareto front for the Brazilian location Rio Grande do Norte (Region 1) for the three product scenarios exported liquid hydrogen (LH2-Exp), exported ammonia (NH3-Exp) and local distribution of ammonia (NH3-Loc).

In summary, the Rio Grande do Norte region benefits from excellent full load hours and comparatively low PtX production and supply costs, as well as from the proximity of the RE plants to the PtX site and the Port of Natal. In addition, the region meets important criteria with its large port and an international airport. Its proximity to the city of Natal provides the day-to-day infrastructure for the necessary skilled PtX and RE personnel. Aspects to be clarified would be the specific PtX plant location near the port site. As expected, the building density here is high. If the PtX plant were to be built outside the urban area, it would have to be clarified whether and how (local pipeline, rail) the PtX products would reach the port. In addition, the port of Natal would need to be expanded to include liquid products, as it is currently a large transshipment point for containers and bulk goods.
For long-term project planning, attention must also be paid to the cost of capital (calculated here with WACC=6.5%), which is dependent on the political situation in Brazil. A sensitivity analysis for the WACC is presented in Section 6.3.1.

6.2.2 Colombia – La Guajira/Uribia

Colombia has a rich potential for generating energy from renewable sources such as wind, solar, and hydro power, thanks to its diverse geography and favorable climate conditions. In recent years, the Colombian government has made significant investments in the development of its renewable energy sector, resulting in the growth of new projects and the expansion of existing ones. With the launch of the "Colombian Hydrogen Roadmap" in spring 2022 a focus was put on the production and export of PtX products and the way was paved for additional investments in this sector [133].

Renewable potential analysis

Due to its low production costs, the northern region La Guajira (Region 1) stands out when comparing the three regions identified for this country and in the overall results of the study. La Guajira will therefore be discussed here as a focus region.

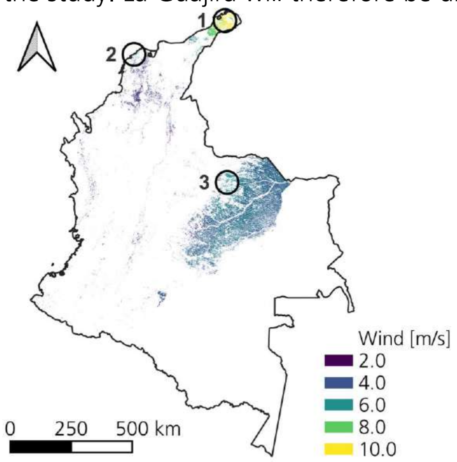

Figure 6-16: Wind potential and selected regions in Colombia

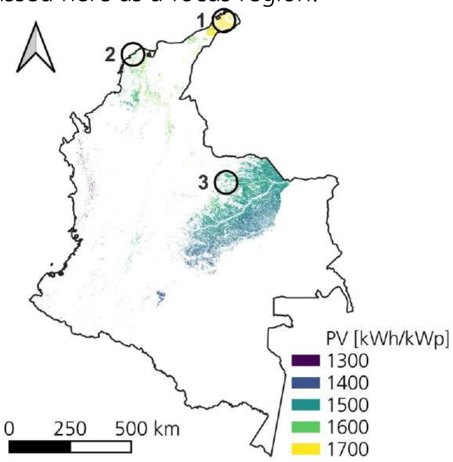

Figure 6-17: PV potential and selected regions in Colombia

It is located in the north of Colombia on a peninsula (Figure 6-16). The region is characterized by a high wind potential with annual average wind speeds of up to 12 m/s in certain areas. Due to its location close to the north, west, and east coasts, wind conditions are comparable to offshore sites. The region is therefore an ideal candidate for power generation by means of wind turbines. With a specific average yield between 1,700 and 1,900 kWh/kWp, the solar potential in the region is also to be considered favorable (Figure 6-17) [26,27].

A wind farm project has already been realized in the region on the northern coast of the peninsula. In addition, Piyohureka, a city with an airport and smaller industrial areas, especially in the mining sector, is located in the immediate vicinity. Thus, it can be assumed that the infrastructure of roads and rails is sufficient to realize further RE projects [19,22,23].

Moreover, the harbor Puerto Bolívar is located northeast of the city Piyohureka. It provides capacity for large cargo ships, as it is currently mainly used for shipping coal from the adjacent mines. It is therefore assumed to be sufficient for logistics during the RE construction process. For the export of PtX products additional expansions are necessary, as a terminal for the loading of liquid or cryogenic energy carriers is not yet available. The areas around the harbor that would be needed for this are generally available [131,134]. Due to the location of the harbor about 50 km from the RE production region, the transport distances from the energy production to the PtX site are comparatively short.

Uribia, a city of about 200,000 inhabitants, is located about 70 kilometers south-west of the selected RE region and 120 kilometers from the PtX production site. It can be assumed that part of the required workforce, also with the necessary expertise particularly for operation and maintenance of wind energy projects, can be sourced from the region. However, since the scale of the RE projects that have been realized in the region to date are comparatively small, the potential availability of skilled workers should be included in more in-depth analyses before further project implementation steps are taken [19].

Techno economic results

The cost breakdowns for the export of liquid hydrogen (LH_2-Exp), ammonia (NH3-Exp), and methanol (MeOH-Exp) as well as the local production cost of ammonia (NH3-Loc) for La Guahira/Uribia is depicted in Figure 6-18.

At this location, liquid hydrogen becomes most cost effective with export costs of 176 EUR/MWh (5852 EUR/ton LH_2) and an export amount of 3.9 TWh. This makes La Guajira, together with Rio Grande do Norte in Brazil, the most promising location for the export of liquid hydrogen. Australia (discussed in section 6.2.4) has equally favorable liquid hydrogen production costs but has a transport distance more than twice as long.
In the case of exported ammonia, this locations shows slightly higher costs than those for liquid hydrogen. However, with an ammonia supply cost of 190 EUR/MWh (987 EUR/ton NH_3) this region is still in the lower cost range of all the ammonia regions analyzed. Only Brazil and Australia have lower ammonia supply costs.
In the case of green methanol produced from captured atmospheric carbon dioxide, the supply costs (190 EUR/MWh (1053 EUR/ton MeOH)) are the same as for the ammonia pathway. This makes the region of La Guajira a special case. In all other regions evaluated in this study, ammonia always has some cost efficiency advantage over the methanol pathway. The reason for the comparatively good performance of the methanol pathway in La Guajira can be found in the high share of installed wind capacity compared to PV. At wind-dominated locations, the PtX pathways with a certain dynamic capability are the ones to benefit. Since methanol synthesis in this study has slightly higher dynamics than ammonia synthesis, it benefits from reduced intermediate hydrogen storage demand. The methanol supply costs in the La Guajira region, together with Australia, are the lowest of all the regions evaluated in this study.

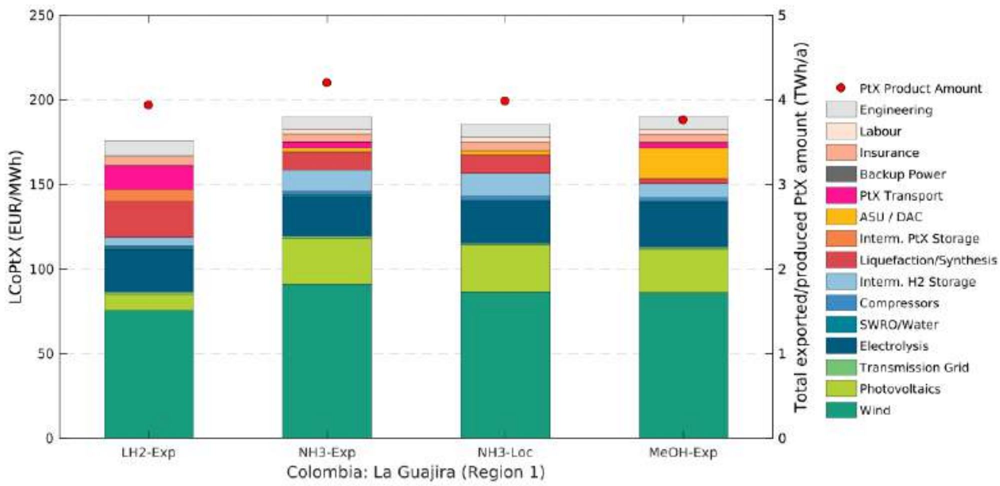

Figure 6-18: Cost breakdown and total PtX product amounts for the Colombian location Guajira/Uribia (Region 1) for four product scenarios exported liquid hydrogen (LH2-Exp), exported ammonia and methanol (NH3-Exp, MeOH-Exp) and the local distribution of ammonia (NH3-Loc). The costs shown here apply to the respective cost-optimal system layout.

As in the Brazilian case, the synthesis pathways require higher installed capacities of wind and PV for an optimal provision of electrolytic hydrogen. Again, this higher RE demand is caused by the slightly reduced chain efficiency and significantly more limited dynamics of ammonia and methanol synthesis compared to the liquid hydrogen pathway. In return, both synthesis pathways benefit from cost-efficient large-scale shipping, which is therefore hardly a factor in the cost shares.
In the case of the methanol scenario, the investment cost and fixed operational cost (w/o energy demand) of the necessary DAC system accounts for 9.5% of the total supply costs. The total investment for the DAC facility (DAC; CAPEX of 0.54 billion EUR) represents 10% of the total investment required (5.48 billion EUR) in the methanol scenario. In contrast to DAC, the ammonia pathway with an established nitrogen supply by means of an air separation unit (ASU; CAPEX of 0.09 billion EUR) offers a significantly more cost-effective technology to provide the necessary synthesis partner for the hydrogen.

Table 6-2: Key performance indicators for the cost-optimal system configuration for the Colombian location Guajira (Region 1)

Colombia **La Guajira**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Techno-economic KPI:				
Wind: Installed capacity (GW_{el})	1.3	1.7	1.5	1.5
Wind: LCoE (EUR/MWh_{el})	40			
PV: Installed capacity (GW_{el})	0.6	1.7	1.7	1.5
PV: LCoE (EUR/MWh_{el})	42			
Intermediate H_2 storage: Volume (1000*m³)	105	298	305	174
Electrolysis: Full load hours (h/yr)	6735	7528	7166	6929
LCoPtX (EUR/MWh)	176	190	186	190
LCoPtX (EUR/ton)	5852	984	962	1052
PtX Amount (GWh/yr)	3935	4196	3982	3759
Selected investment cost (million EUR):				
Wind + PV	2380	3705	3413	3137
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	220	625	640	365
Liquefaction/ synthesis	693	356	345	84
ASU/DAC	-	93	88	542
Total System	5280	6201	5796	5481

In conclusion, among the three regions identified in Colombia, only La Guajira stands out with very promising PtX production costs. Both hydrogen and its derivatives, ammonia and methanol, can be produced very cost-effectively in the La Guajira region compared to most of the other countries and regions assessed. The region also benefits from its direct access to the Atlantic Ocean, with a moderate transportation distance of less than 10,000 km. The region also has high land availability for both RE and PtX plants. Key infrastructure such as roads, medium voltage grids, a medium-sized airport, and the port of Piyohureka provide an important foundation for medium-term RE and PtX project implementation. For further refinements of the site assessment, the expansion possibilities of the port for handling larger quantities of liquid energy carriers would have to be reviewed.

6.2.3 Namibia – Lüderitz

Namibia is of great importance for the production of PtX products with renewable energy due to its abundance of solar and wind resources, as well as its strategic location for potential hydrogen exports to Europe. The country's vast desert areas receive some of the highest levels of solar irradiation in the world, making them an ideal location for solar energy production. In addition, Namibia's coastal region benefits from strong and consistent winds, which can be harnessed for wind energy production.
Moreover, the location on the southwestern coast of Africa positions the country as a key player in the global and especially European hydrogen market. Namibia has already begun to pursue this potential with private as well as governmental investors, as in the

"Hyphen" project [21].[9] A continuation of this development together with an increase in the number of RE projects is therefore extremely likely.

Renewable potential analysis
Namibia is considered to have great potential for both wind and solar energy. In addition, the country's willingness to implement renewable energy projects has led to a high level of interest in the African country in recent years.

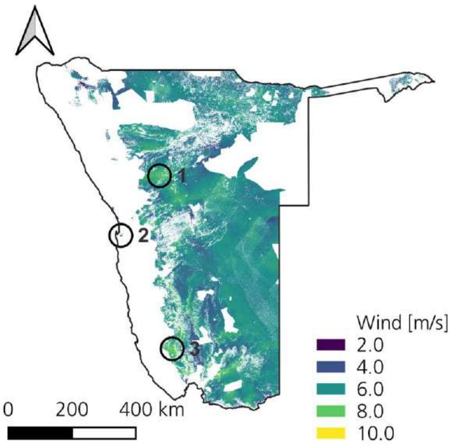

Figure 6-19: Wind potential and selected regions in Namibia

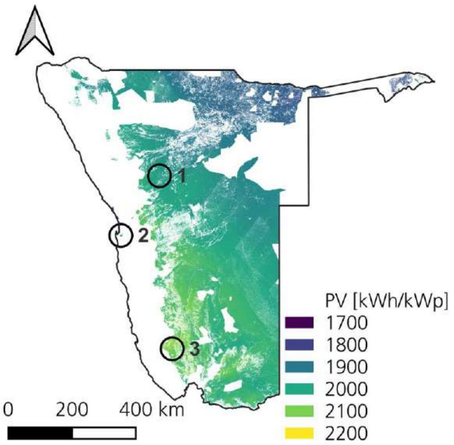

Figure 6-20: PV potential and selected regions in Namibia

The region west of Lüderitz (hereinafter referred to as "Lüderitz"; region 3) is characterized by excellent potential for renewable energy. The annual average wind speeds are in places over 10 m/s, which leads to a high utilization of wind turbines. In addition, the region has some of the greatest PV potential worldwide. The specific yield ranges between 2,000 and 2,200 kWh/kWp (Figure 6-20) [26,27].
The localized region is situated about 150 km east of the city of Lüderitz and its port and hence in acceptable proximity to one of the two possible export harbors for Namibian PtX products. This comparatively short distance not only reduces power transmission costs, but also allows the use of the well-developed road and railway network infrastructure. In addition, due to a low level of land use in the selected region, a very high availability of land can generally be assumed. In Namibia, large parts of the country are excluded because they are in national parks (Figure 4-1). Some of the areas excluded in this process are among the world's best locations for hybrid PV and wind power generation, and thus have enormous potential for the production of PtX products. National parks were generally excluded in the context of this study for the reasons mentioned in chapter 4.1.1. However, for the country of Namibia, this exclusion is worthy of further analysis and evaluation, as the Namibian government appears to be willing to discuss the realization of renewable energy projects in certain national parks [21,23].
The potential of Namibia with regard to the production of renewable, synthetic products has already been discovered by other ventures, such as the "Hyphen" project. In the coming years, the realization of the first PtX projects in Namibia is to be expected. It can therefore be assumed that the existing infrastructure, especially for renewable energy generation in the region around Lüderitz, will be further developed in a timely manner

[9] The ~EUR8.7 billion "Hyphen" project is planned to be developed in two phases, with the construction of renewables with a capacity of up to 5 GW and electrolysis capacities of 3 GW at full development. The location for this project is in the Tsau Khaeb National Park, which was declared a national restricted area in 2008 and therefore was not considered as a location for this project due to the selection criteria (section 4.1) [21,135].

and on a large scale. Thus, it can be anticipated that the required workforce with the appropriate expertise can soon be provided in the region. Most likely, this will also include the establishment of locally-based manufacturers and suppliers. Additionally it is reasonable to assume an expansion of the harbor for the large-scale export of PtX products, since the region and country are aiming to become a relevant player in the field of green hydrogen and derivatives production [21].

Techno economic results

In terms of PtX production and supply costs (Figure 6-21), Lüderitz ranks in the middle compared to all regions analyzed. The liquid hydrogen path results in a supply cost of 237 EUR/MWh (7884 EUR/ton LH_2) for exported liquid hydrogen, which is slightly above the average of all regions. In the case of the production and supply cost of ammonia (export: 197 EUR/MWh or 1022 EUR/ton; local: 193 EUR/MWh or 1001 EUR/ton) and methanol (export: 222 EUR/MWh or 1229 EUR/ton), Lüderitz ranks slightly below the overall average but has significantly lower production and export volumes of 1.7-2.7 TWh (Table 6-3).

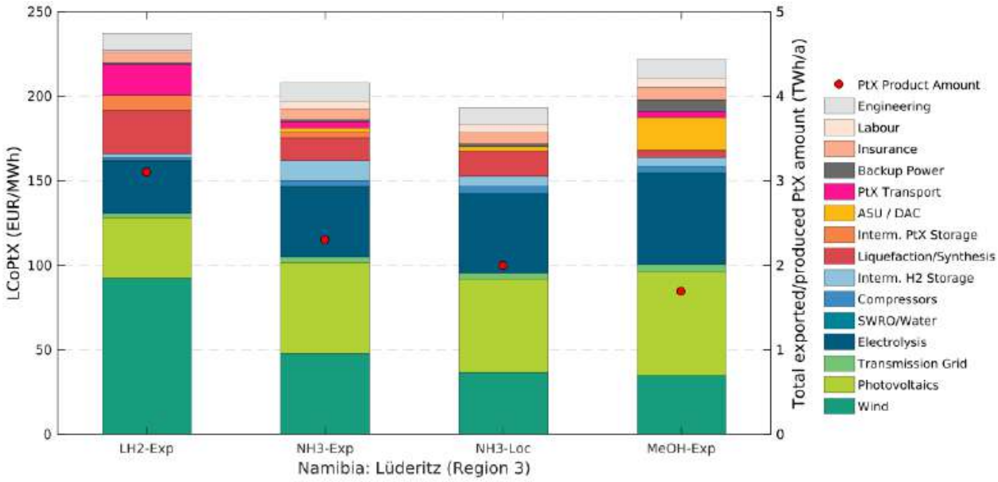

Figure 6-21: Cost breakdown and total PtX product amounts for the Namibian location Lüderitz (Region 3) for four product scenarios - exported liquid hydrogen (LH_2-Exp), exported ammonia (NH_3-Exp), local distribution of ammonia (NH_3-Loc), and exported methanol based on DAC (MeOH-Exp). The costs shown here apply to the respective cost-optimal system layout.

One of the main reasons for the lower ammonia and methanol export volumes is the comparatively lower number of full-load hours of electrolysis at this PV-dominated location. Other regions such as La Guajira, which have very high annual wind speeds and thus favorable levelized cost of wind electricity, also have a significantly higher wind installation factor. Lüderitz, in contrast, ranks in the upper-middle range with its levelized cost of wind electricity, which is why the share of PV capacities at this location is also more pronounced. In the case of the methanol path, for example, this is also reflected in the purchase of backup power (dark gray band), which is necessary to be able to continue operating the DAC plant during the night or on cloudy days with low wind speeds. An exception in terms of installed PV capacity is the liquid hydrogen pathway, which considers much larger wind farms compared to ammonia and methanol. One reason for these increased wind capacities is the high initial investment costs for the liquefaction process and the transport of liquid hydrogen. These high investment costs can best be compensated by the highest possible production rate, on which the high investment is amortized. Wind power, even though it has slightly higher electricity production costs, is suitable for this because it allows high capacity factors. Solar power reaches its limits at some point due to the day-night cycle.

Table 6-3: Key performance indicators for the cost-optimal system configuration for the Namibian region Lüderitz (Region 3)

Namibia **Luederitz**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.2	0.9	0.4	0.3
Wind: LCoE (EUR/MWh_{el})	69			
PV: Installed capacity (GW_{el})	1.7	1.6	1.7	1.5
PV: LCoE (EUR/MWh_{el})	32			
Intermediate H_2 storage: Volume (1000*m³)	28	43	66	47
Electrolysis: Full load hours (h/yr)	4829	4395	3574	3112
LCoPtX (EUR/MWh)	237	197	193	222
LCoPtX (EUR/ton)	7884	1022	1001	1229
PtX Amount (GWh/yr)	2730	2454	1993	1690
Selected investment cost (million EUR):				
Wind + PV	2859	2333	1702	1514
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	58	90	138	99
Liquefaction/Synthesis	644	253	234	53
ASU/DAC	-	66	46	250
Total System	5491	4106	3300	3129

In summary, it should be said that the region east of Lüderitz analyzed here is one of the more average among the regions analyzed. Production and supply costs, as well as the produced quantities, are in the middle range. A very large number of areas in Namibia were excluded from the present analysis because they are designated as nature reserves. This applies in particular to the areas around Lüderitz and along the coast (compare Figure 4-1), thus excluding landscapes with high wind and solar potential, although they are the site of the currently much-discussed Hyphen pilot project. For the analysis here, this means that potentially promising PtX areas were excluded and not discussed in order to take into account the important protection of sensitive habitats. Decisions as to whether RE and PtX sites can also be realized in such regions must be examined in each individual case.

There is currently significant momentum in the development of Power-to-X projects in Namibia. On the one hand, a very small and indebted country faces enormous foreign interest from investors and private financiers who see this country as a very important player for the large-scale generation of hydrogen and derivatives. These interests need to come together in a coordinated way for this to happen. The Namibian government is currently doing a lot to take big steps here. For example, international congresses are being organized, international partnerships are being expanded, and several local research and pilot projects are intended to put the country on a hydrogen course.

6.2.4 Australia – Dagger Hills

Australia generally has huge land potential and excellent conditions for renewable energy, despite its extremely long transport distance from Europe. For this and other reasons, Australia has been investigated and evaluated in several studies regarding its PtX production and export potential. In addition, publicly funded research projects are focused on the production and export of green hydrogen and derivatives and the first hydrogen partnerships have been established [136–138].

Renewable potential analysis

The suitable areas for renewable energy sites cover only a comparatively small part of the total area of the Australian landscape. This is due to the low population density and the large unused areas in the interior of the country, resulting in a lack of infrastructure in the form of roads and railways. Since the distance to the power and road network is defined as an exclusion criterion, major parts of the country are not considered as potential locations. However, the low population density also results in a generally high availability of land and thus low land use costs. This also applies to areas that are located within the required distance of 100 km from power and road networks and thus serve as potential sites [19,28].

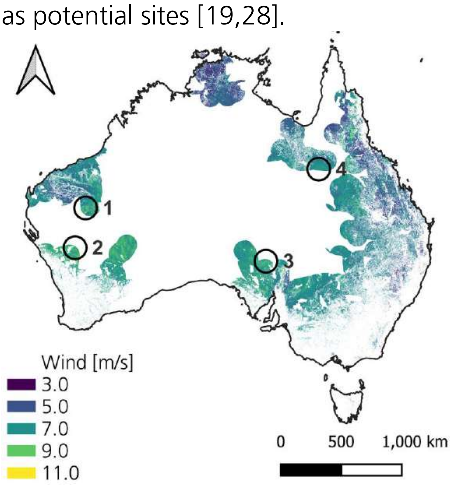

Figure 6-22: Wind potential and selected regions in Australia

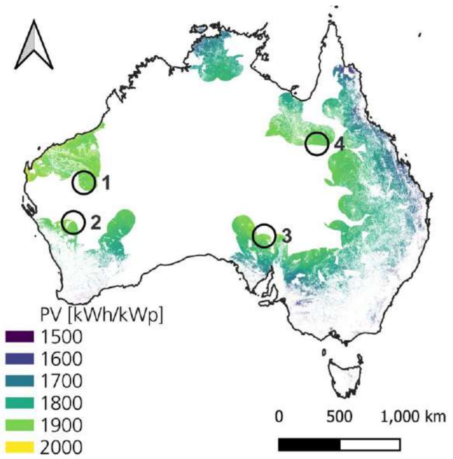

Figure 6-23: PV potential and selected regions in Australia

In Dagger Hills (Region 2) in the south of Western Australia, average annual wind speeds of up to 9 m/s can be measured (Figure 6-22). In addition, there is a high quantity of solar irradiance, resulting in a specific solar yield in the region of between 1,800 and 2,000 kWh/kWp (Figure 6-23) [26,27].

Due to a high number of mining operations in the selected region, the road network is sufficiently well developed for the implementation of the RE project. In turn, the required workforce is not located directly on site [19,28].

About 500 kilometers away from Dagger Hills is the nearest major city, Perth, which is the capital of Western Australia and features the largest port of the state, the Fremantle Port. It already provides the necessary infrastructure for loading various energy carriers such as petroleum and natural gas into large vessels and thus can serve as a PtX production site as well as the gateway for the export of PtX products. However, due to the location of the port directly adjacent to the city, high land availability for the PtX facility cannot be assumed. This fact may be associated with additional costs which cannot be considered in this analysis [131,139].

Furthermore, it can be assumed that the necessary industry and expertise for the implementation of RE projects is available in Australia due to the country's many years of experience, especially in the field of solar technology [19,28].

Techno economic results

Figure 6-24 shows the cost breakdowns and total PtX product amounts for the Western Australian region Dagger Hills. The subsequent Table 6-4 lists the related key performance indicators for the cost-optimal system configuration.

In terms of local PtX production costs, Dagger Hills ranks among the best of the sites analyzed in this study. A hybrid design that places an emphasis on wind energy leads to above-average electrolysis full load hours and thus to comparatively high total PtX quantities produced in all PtX pathways investigated. Even in the export scenarios, the liquid energy carriers that are transported over the long distance (18,600 km) still perform very well due to cost-efficient ship transport. In the case of liquid hydrogen, however, the long transport route adds significant transport costs to the favorable local production costs. Nevertheless, the supply costs for liquid hydrogen from Dagger Hills to Germany are still in the upper midfield of all analyzed regions.

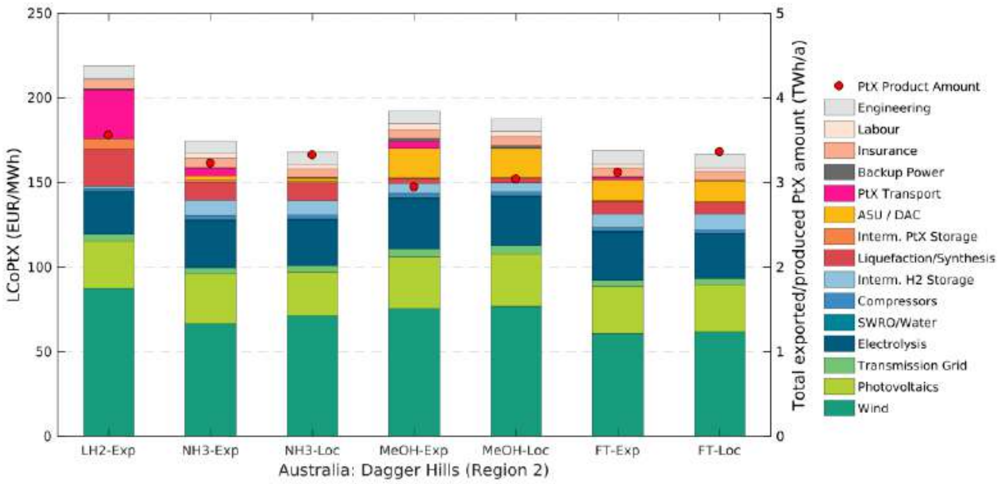

Figure 6-24: Cost breakdown and total PtX product amounts for the Western Australian region Dagger Hills (Region 2) for the seven product scenarios - exported liquid hydrogen (LH_2-Exp), as well as the exported and local scenarios for ammonia, methanol and Fischer-Tropsch products (NH_3-Exp, MeOH-Exp, FT-Exp and NH3-Loc, MeOH-Loc, FT-Loc, respectively). The costs shown here apply to the respective cost-optimal system layout.

Australia was one of the countries for which Fischer-Tropsch products and derived jet fuel were also analyzed. If the complete Fischer-Tropsch product mix is taken as the usable product, this pathway performs comparatively well from a cost perspective and is on par with the ammonia pathway and thus lower than the methanol pathway. On the one hand, the Fischer-Tropsch pathway requires a clearly larger intermediate hydrogen storage than methanol due to the limited synthesis dynamics[10], but on the other hand the Fischer-Tropsch pathway benefits from a significant heat extraction potential from the synthesis for the DAC plant (compare section 5.3). As a consequence, within the assumptions made, the entire thermal demand of the low-temperature DAC units can be covered by the synthesis excess heat and requires no additional electrical heating from RE. In the case of methanol, whose reaction takes place at much lower temperatures, less excess heat can be recovered for operation of the DAC units. This, in turn, increases the demand for RE energy in the methanol pathway to meet the thermal demand of the DAC plant.

Table 6-4: Key performance indicators for the cost-optimal system configuration for the Australian location Dagger Hills (Region 2). The table only shows the results for the export scenarios. The complete KPI table including the local scenarios is included in the appendix.

Australia **Dagger Hills**	LH_2 Export	NH_3 Export	MeOH Export	FT-Mix Export	Jet Fuel Export
Techno-economic KPI:					
Wind: Installed capacity (GW_{el})	2.1	1.5	1.5	1.3	1.7
Wind: LCoE (EUR/MWh_{el})	46				

[10] The main reason here is the more limited dynamics assumed for the Fischer-Tropsch pathway (90-100%) compared to the methanol pathway (60-100%); see section 5.3 for details.

PV: Installed capacity (GW_{el})	1.8	1.7	1.7	1.6	1.6
PV: LCoE (EUR/MWh_{el})	30				
Intermediate H_2 storage: Volume (1000*m³)	34	187	110	165	241
Electrolysis: Full load hours (h/yr)	6604	5799	5436	5126	6020
LCoPtX Export (EUR/MWh)	219	175	192	169	311
LCoPtX Export (EUR/ton)	7288	905	1062	2064	3824
PtX Amount (GWh/yr)	3555	3224	2944	3115	1395
Selected investment cost (million EUR):					
Wind + PV	3828	2925	2945	2611	3191
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	70	392	232	346	505
Liquefaction/ synthesis	709	310	75	204	224
ASU/DAC	-	73	446	327	384
Total System	7089	5243	5151	4886	5767

The export of the Fischer-Tropsch product mix represents one possibility. However, if the aim is to obtain jet fuel as the end product, direct distillation and processing of the Fischer-Tropsch product mix at the synthesis site makes sense. As described in section 5.3, this study considers 38 wt% jet fuel and 62 wt% diesel fuel, obtained as products after distillation of the Fischer-Tropsch product mixture. The diesel fuel is assumed to be sold to the local market[11] at 0.80 EUR/L. The revenue is credited to the Fischer-Tropsch jet fuel production. Figure 6-25 shows the levelized supply cost in the case of the Fischer-Tropsch product mixture in comparison with the cost of jet fuel. The revenues from the sale of the diesel by-product are shown here as light blue and the resulting jet fuel costs of 311 EUR/MWh (3824 EUR/t) are marked as red. For all four of the assessed Australian regions the resulting green jet fuel production and supply costs range from 299-331 EUR/MWh (2.71-3.03 EUR/L; incl. transport to GER) and are therefore clearly above the current market prices[12] for conventional, fossil jet fuel. This more differentiated presentation of the production costs for products from the Fischer-Tropsch synthesis makes it clear that, in case of this PtX pathway, it is indeed necessary to analyze the

[11] Basically, a sales price of 0.80EUR/L was assumed for the FT diesel side-product to calculate the isolated cost for jet fuel. In the case of Australia, this reflects the market situation well: 2022 average selling price for diesel fuel in Australia: 2.05 AUD/L; excl. GST (10%) and excise tax (0.442 AUD/L) resulting in 1.40 AUD/L = ~0.90EUR/L (equaling ~1.75 EUR diesel value per kg jet fuel). However, the diesel market price will be highly variable and dependent on the country under study.

[12] Current market prices for jet fuel are highly variable and, depending on the source, fluctuated by +118-249% in the crisis year 2022 alone (relative to the base year 2015). Depending on the source, the net market price for jet fuel has recently been around 0.70-1.40 EUR/L (excluding taxes and fees)

composition of the product mixture in more detail. A simplified communication of 'only' the FT product mixture costs, on the other hand, gives an incomplete picture.

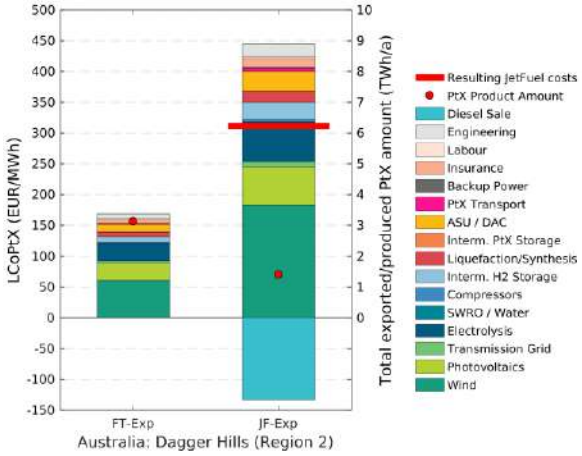

Figure 6-25: A comparison of the levelized supply costs for the Fischer-Tropsch product mixture and the cost of Fischer-Tropsch jet fuel. The revenues from the sale of the diesel by-product are shown as light blue, the resulting jet fuel costs as red marker.

Overall, it can be stated that Australia generally has huge land potential and excellent conditions for renewable energy, the country is politically stable, and the average financing costs are among the lowest. The (energy) infrastructures are excellently developed along the main population centers, the necessary workforce is available and education standards are high [140]. The infrastructure conditions relevant for PtX production and export (power grids, streets, airports, and harbors) are of a high standard in the regions analyzed. The fact of the very long transport distance, which was previously seen as a shortcoming in the case of Australia, did not prove to be a pitfall in the analyzed paths. Especially for green ammonia and methanol, the regions analyzed for Australia result in favorable supply costs due to their excellent RE potential over other regions analyzed in e.g., Spain, Algeria, and Tunisia (compare Figure 6-6 and Figure 6-7). However, in the case of liquid hydrogen, the transport conditions currently assumed for 2030 in the first large liquid hydrogen carriers result in substantial costs. A key question here will be how quickly the cryogenic transport systems and peripheral safety equipment for such ships can pass through the certification process, whether the ships can be built in significant numbers in a timely manner, and how quickly significant economies of scale can be achieved.

6.2.5 Morocco – Tan-Tan

Morocco is of great importance for the export of PtX products. This is partly due to the country's high potential for wind and PV generation. Moreover, the short distance to Europe and the existing pipeline infrastructure, as well as the ambitious expansion targets of the government, give reason to anticipate lower transport costs for the energy sources and thus lower overall costs [141]. For example, in the HYPAT project[13], Morocco is seen as a focus country among all analyzed PtX exporting countries when thinking in the long term.

Renewable potential analysis

Especially on the coasts and in the south of the country a high wind potential can be found. The PV potential is mainly constant throughout the country with slightly higher

[13] HYPAT: "Global hydrogen potential atlas for the sustainable hydrogen economy of tomorrow"; Duration: 2021–2024, Funding: Federal Ministry of Education and Research BMBF.

full load hours in the interior of the country. Despite the well-developed infrastructure in the form of the electricity and transport network, large parts of the interior of the country are not available as potential areas for renewable energies, due to the Atlas Mountains, which extend right across Morocco.

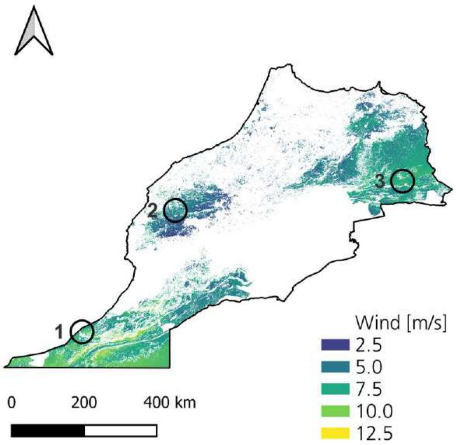

Figure 6-26: Wind potential and selected regions in Morocco

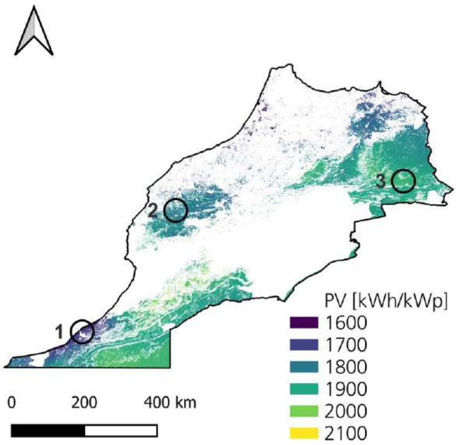

Figure 6-27: PV potential and selected regions in Morocco

Tan-Tan (region 1) on the west coast in the south of Morocco is characterized by its great wind potential, with average annual wind speeds of up to 10 m/s (Figure 6-27 In addition, there is good solar potential with a specific yield of 1,700 to 1,800 kWh/kWp (Figure 6-27), making it a promising location for hybrid RE production [26,27].
Due to the low population density and land use, a high availability of land can generally be assumed in the region [19,23]. The city of Tan-Tan itself has about 70,000 inhabitants and consists of a well-developed infrastructure in terms of rails, roads, and an airport. However, it cannot be expected that the workforce or the housing will be fully sufficient to fulfill the demand of a project of the expected scale [19,28].
In addition, the moderate distance of about 250 km to the coast and thus the harbor of Agadir as the PtX-production and export site are major benefits of the selected region. The harbor of Agadir is one of the main export harbors of Morocco. Although the port can serve large container vessels, infrastructure for the transport of chemicals and gases has yet to be built. Nonetheless, land availability can be considered high, as there are many open spaces inland in close proximity to the port [131].
Due to the comparatively short distance to Europe, transport via pipelines can be considered as an alternative to shipping. Together with Nigeria, the Moroccan government is planning a natural gas pipeline along the African Atlantic coast. This is intended primarily to supply the African continent, but it will also deliver to Europe. Although there are no current plans to use the pipeline to transport hydrogen, it is generally conceivable that it could be rededicated for hydrogen admixtures if demand grows [142].

Techno economic results

Figure 6-28 shows the cost breakdowns and total PtX product amounts for the Moroccan location Tan-Tan. Green ammonia, methanol, and gaseous hydrogen were the focus of the assessments. Ammonia and methanol are assumed to be transported by ship from the identified ports, while gaseous hydrogen is fed into hydrogen pipelines. For the latter, a distinction was made between transport in dedicated hydrogen pipelines and transport in an expanded European Hydrogen Backbone (see section 5.4.2).
With a focus on green ammonia and methanol production cost, Tan-Tan ranks in the middle of all analyzed regions in this study. The other two Moroccan regions analyzed,

near Marrakech and Figuig (not shown below), have slightly higher production costs than Tan-Tan.

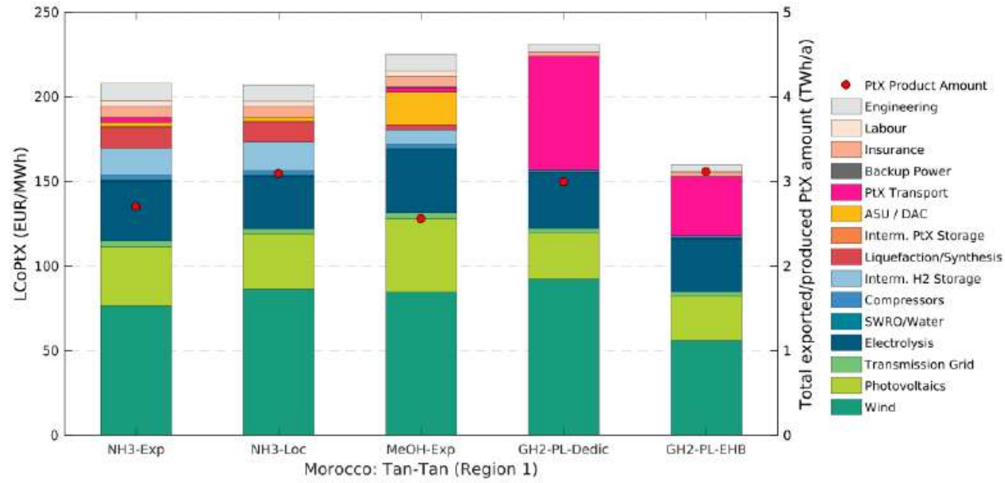

Figure 6-28: Cost breakdown and total product amounts for the Moroccan location Tan-Tan (Region 1) for five product scenarios exported ammonia and methanol (NH_3-Exp, MeOH-Exp), local distribution of ammonia (NH_3-Loc), and gaseous hydrogen either transported in dedicated hydrogen pipelines (GH_2-PL-Dedic) or transported in an expanded European Hydrogen Backbone (GH_2-PL-EHB). The costs shown here apply to the respective cost-optimal system layout.

Both wind and PV power generation costs in Tan-Tan are in the middle range (Wind: 57 EUR/MWh$_{el}$, PV: 34 EUR/MWh$_{el}$, Table 6-5). In terms of installed RE capacities, the cost-optimal system design shows a slight focus on low-cost PV power (1.4-1.7 GW$_{el}$). However, significant wind energy capacities (1.1-1.4 GW$_{el}$) are also considered in order to keep the intermediate hydrogen storage as small as possible and the utilization of the PtX system high. In the scenarios for ammonia and methanol export, the electrolysis utilization reaches about 4800 h/yr which is slightly above the average of all sites.
In the case of gaseous hydrogen transported via a dedicated pipeline or a European pipeline network, significant differences in supply costs can be identified. While a dedicated pipeline from Tan-Tan to Germany results in a supply cost of 231 EUR/MWh (7700 EUR/ton H_2) a transport in an expanded European Hydrogen Backbone enables a supply cost of 160 EUR/MWh (5321 EUR/ton H_2). It becomes clear that a dedicated hydrogen pipeline over transport distances of several hundred or even thousand kilometers would be disadvantageous from an economic point of view. Utilization would be too low and the investment costs (Tan-Tan: 2214 million EUR, 3335 km total pipeline length) for such a project-specific pipeline would be out of proportion to the amount of hydrogen transported. If, on the other hand, the plans for a European Hydrogen Backbone (EHB) were pursued further, hydrogen transport over such distances would certainly be a more attractive option. The strengths of an EHB would be, besides the achievable hydrogen throughputs and the possible transport distances, the fact that in addition to newly built hydrogen pipelines also a retrofit of existing natural gas pipelines would be considered, which could limit the necessary investment costs.

Table 6-5: Key performance indicators for the cost-optimal system configuration for the Moroccan region Tan-Tan (Region 1).

Morocco **Tan-Tan**	**NH_3 Export**	**NH_3 Local**	**MeOH Export**	**GH_2 PL Dedic.**	**GH_2 PL EHB**
Techno-economic KPI:					
Wind: Installed capacity (GW$_{el}$)	1.1	1.5	1.2	1.5	1.0
Wind: LCoE (EUR/MWh$_{el}$)			57		

PV: Installed capacity (GW_{el})	1.4	1.5	1.7	1.2	1.2
PV: LCoE (EUR/MWh_{el})			34		
Intermediate H_2 storage: Volume (1000*m³)	236	289	117	-	-
Electrolysis: Full load hr (h/yr)	4833	5536	4698	5929	4837
LCoPtX Export (EUR/MWh)	208	207	225	231	160
LCoPtX Export (EUR/ton)	1077	1073	1246	7700	5321
PtX Amount (GWh/yr)	2696	3088	2552	2992	3110
Selected investment cost (million EUR):					
Wind + PV	2616	3179	2860	3061	2231
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	496	606	246	-	-
Liquefaction/synthesis	275	302	68	-	-
ASU/DAC	60	70	386	-	-
Total System	4815	5502	4865	6241	3298

In summary, it can be stated that Morocco is not at the front range of all analyzed regions, as possibly expected, but instead has production and supply costs in the middle range. However, infrastructure, political agenda, and proximity to the European continent speak for a medium-term partner for the production and export of hydrogen and its derivatives. In particular, the prospect of a connection to a future European Hydrogen Backbone for the large-scale transport of gaseous green hydrogen is an important aspect in this context.

6.2.6 Spain – Pedrola

Spain is of great importance when it comes to the inner-European production of hydrogen and PtX products. This is due in particular to the fact that this European country, in addition to good RE potential, also has good connections to the EU's logistics, energy and electricity networks, and also a short transport distance.
Moreover, multiple transport options are feasible. Not only the provision of large amounts of PtX products to a single hub, but also the direct distribution to different processing and consuming sectors is possible. Especially to further expand Europe’s energy independence, it is a major benefit to establish European PtX production capacities.

Renewable potential analysis
Under the basic requirement to keep the transport distances for PtX energy carriers low and thus provide the products at low cost, Spain has special advantages in comparison to other countries due to its location within Europe. Compared to other European countries it has one of the highest wind and solar potentials within Europe and is therefore an excellent country for the European production of PtX products.

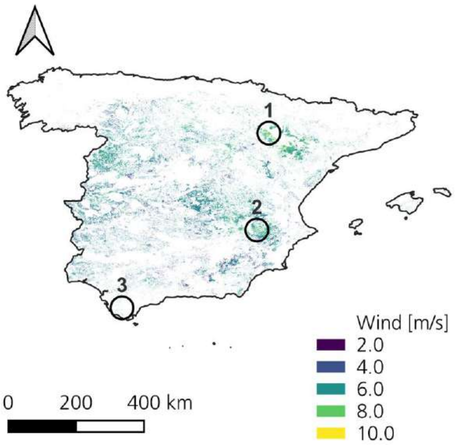

Figure 6-29: Wind potential and selected regions in Spain

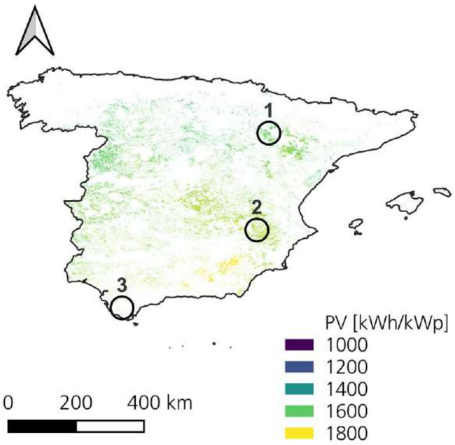

Figure 6-30: PV potential and selected regions in Spain

In Pedrola (region 1), in the west of the province of Aragon, average wind speeds of 8 to 9 m/s can be observed ((Figure 6-29). This high wind potential has already been partially tapped, which is reflected in a significant number of wind farms in the region around Pedrola [19,27]. Likewise, a moderate solar potential can be found here with a specific yield of 1,600 to 1,700 kWh/kWp (Figure 6-30) [26].
Furthermore, Spain in general has a very well-developed infrastructure in the selected region. In addition to the expansive power and road network, the availability of fresh water is an attractive aspect [19]. This reduces the costs of water supply and treatment for electrolysis. The high diversity in the transport possibilities of the energy carriers is an additional benefit. A direct feed-in of hydrogen into the existing and widely developed European gas grid is possible, as well as the transport of synthesis products such as ammonia, liquid hydrogen, and methanol by ship, rail, or road. Depending on the region, the needs of local industrial consumers such as the steel or cement industry can also be covered at the same time [19,28]. The use of industrial carbon dioxide point sources is analyzed in a special scenario (section 6.3.4).
Around Pedrola, the closest harbor as a possible PtX site is the port of Bilbao, located about 200 km from the RE site on the northern coast of Spain. The port is currently used in particular for shipping containers as well as solid raw materials such as steel and coal. This means that ships transporting PtX products could generally call at the port, although the loading and unloading infrastructure required for this has yet to be built. Due to the port's proximity to the city, it can be assumed that the general availability of land is low [131].
The proximity to larger cities to provide the required workforce and the existing expertise in the field of renewables energies in that region provide additional advantages for Pedrola as a conceivable region and Bilbao as a possible PtX site.

Techno economic results

Figure 6-31 shows the cost breakdowns and total PtX product amounts for the analyzed region located northwest of Pedrola. Green ammonia, methanol, Fischer-Tropsch products and derived jet fuel were analyzed to be used locally or transported via ship to Germany. Gaseous hydrogen is either fed into a dedicated hydrogen pipeline or injected into the European Hydrogen Backbone (see section 5.4.2). The key performance indicators related to the system's cost-optimal configuration are included in Table 6-6.

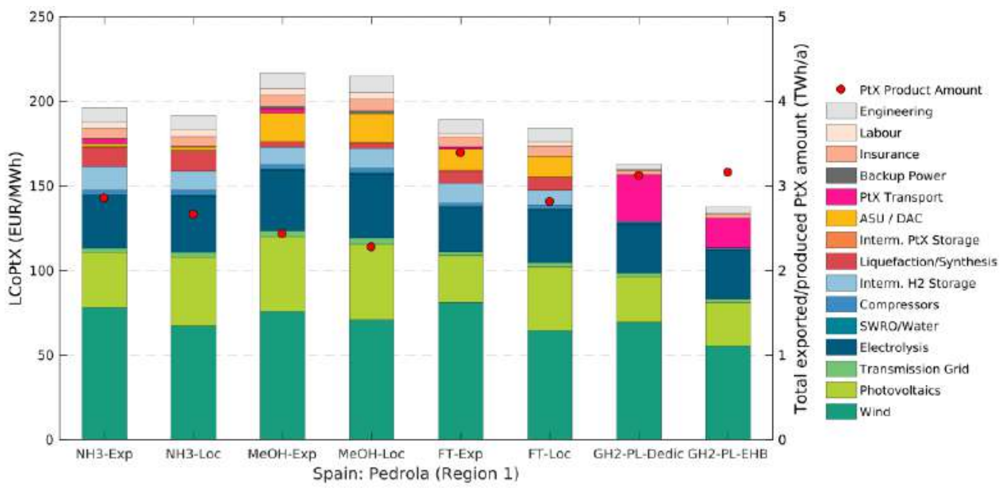

Figure 6-31: Cost breakdown and total product amounts for the Spanish location Pedrola (Region 1) for the eight product scenarios - exported ammonia, methanol and Fischer-Tropsch products (NH_3-Exp, MeOH-Exp, FT-Exp), their local distribution (NH_3-Loc, MeOH-Loc, FT-Loc), as well as gaseous hydrogen either transported in dedicated hydrogen pipelines (GH_2-PL-Dedic) or transported in an expanded European Hydrogen Backbone (GH_2-PL-EHB). The costs shown here apply to the respective cost-optimal system layout.

The Spanish region of Pedrola performs better than the study average in both production and supply costs. While this region cannot compete with prime locations such as Rio Grande do Norte (BRA), La Guajira (COL), or Dagger Hills (AUS) in terms of production cost, it benefits from favorable PV generation costs and low capital costs, as well as proximity to other European consumer countries. Both ammonia and methanol (with carbon dioxide from DAC), with supply costs of 196 EUR/MWh (1016 EUR/t) and 217 EUR/MWh (1198 EUR/t) respectively, are still well above fossil parity, but allow green energy production within the EU at comparably low cost.

Particularly notable are the results for gaseous hydrogen, which is transported to Germany by pipeline. Although Spain has higher hydrogen production costs than other countries discussed for the import of gaseous hydrogen by pipeline, it benefits from the short pipeline distances. This leads to the fact that, for the present analyses, this region in northern Spain has significantly lower hydrogen supply costs than, for example, very good wind and PV sites in Morocco (compare section 6.2.5). Even though the detailed routing for a pipeline connecting the Iberian Peninsula with France and the rest of Europe is currently shifting from onshore to offshore, it can be assumed that a production of green hydrogen in Spain makes economic sense. The results shown here, at least, support this assumption.

Table 6-6: Key performance indicators for the cost-optimal system configuration for the Spanish region Pedrola (Region 1). The table only shows the results for the export scenarios. The complete KPI table including the local scenarios is included in the appendix.

Spain Pedrola	NH_3 Export	MeOH Export	FT Export	Jet Fuel Export	GH_2 PL Dedic	GH_2 PL EHB
Techno-economic KPI:						
Wind: Installed capacity (GW_{el})	1.4	1.1	1.7	1.3	1.3	1.1
Wind: LCoE (EUR/MWh_{el})	55					
PV: Installed capacity (GW_{el})	1.7	1.9	1.7	1.6	1.5	1.5
PV: LCoE (EUR/MWh_{el})	35					
Intermediate H_2 storage: Volume (1000*m^3)	257	163	258	273	-	-
Electrolysis: Full load hours (h/yr)	5116	4473	5564	5018	5437	4908

LCoPtX Export (EUR/MWh)	196	217	189	358	163	137
LCoPtX Export (EUR/ton)	1016	1198	2313	4400	5430	4574
PtX Amount (GWh/yr)	2854	2430	3387	1166	3120	3156
Selected investment cost (million EUR):						
Wind + PV	3043	2507	3528	2981	2889	2482
PEM Electrolysis	750	750	750	750	750	750
Intermediate H_2 storage	539	343	542	574	-	-
Liquefaction/ synthesis	285	66	214	201	-	-
ASU / DAC	64	360	356	319	-	-
Total System	5299	4935	6030	5430	4968	3544

A comparison of the levelized supply cost in case of the Fischer-Tropsch product mixture and the cost of Fischer-Tropsch jet fuel is shown in Figure 6-32. Again, it becomes clear that a differentiated consideration of the Fischer-Tropsch production cost is important. While the supply cost for the Fischer-Tropsch product mixture of 189 EUR/MWh (2313 EUR/ton) can easily keep up with the other liquid PtX products, the cost for the jet fuel, at 358 EUR/MWh (4400 EUR/t), appears to be significantly higher.

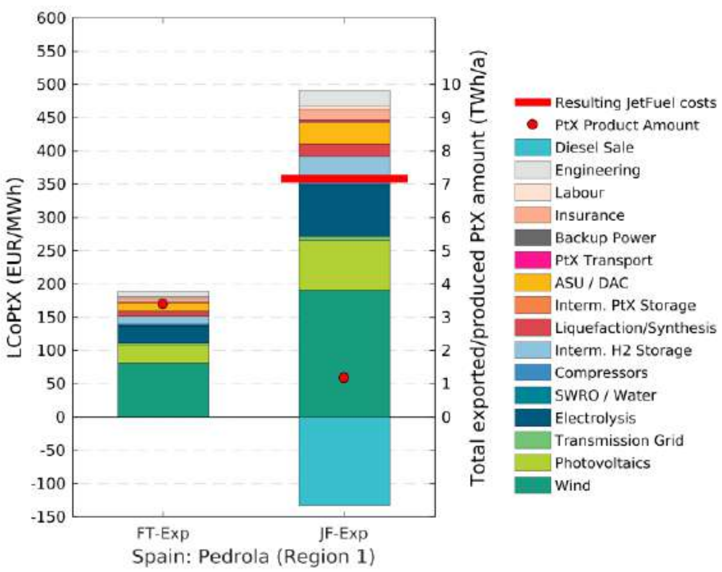

Figure 6-32: A comparison of the levelized supply cost in the case of the Fischer-Tropsch product mixture and the cost of Fischer-Tropsch jet fuel. The revenues from the sale of the diesel by-product are shown as light blue, the resulting jet fuel costs as red marker.

In summary, it can be stated that Spain in general offers a high land availability for renewable energy generation and that Pedrola in particular is a potential top location within Europe. Further advantages here are good wind and PV conditions, which can lead to above-average system utilization. In addition to low capital costs, the necessary infrastructure - such as power grids, roads and workforce - is comparatively good and the supply of spare parts should not prove to be a challenge. In the case of "Pedrola", the land availability at the potential PtX site, the port of Bilbao, should be analyzed in more detail in further detailed planning.

6.3 Sensitivity analyses and special scenarios

In the previous section, overall results for the twelve countries and a total of 39 regions were presented and discussed. These results are based on a clearly defined set of technological background assumptions which are described in chapter 5. However, even these values, which attempt to look into the future of hydrogen technologies, are subject to uncertainties. For this reason, sensitivity analyses of central parameters are carried out in this section. In addition, special scenarios were developed in consultation with H2Global Stiftung to broaden the scope of the results of the analyzed pathways:

- Sensitivity analyses: Dependency of the PtX supply cost on a variation of the
  - Selected investment cost (PV, wind, electrolysis, DAC, transport vessels)
  - Weighted average cost of capital (WACC)
  - Part load limit of liquefaction and syntheses
- Special scenarios:
  - Assessment of the local green hydrogen production cost, without any further conversion and supply
  - 100% off-grid scenario, without any grid connection
  - carbon dioxide supply: Utilization of concentrated carbon dioxide source instead of DAC

6.3.1 Sensitivity analyses of central parameters

The central objective of the subsequent sensitivity analyses is to show how strongly the PtX production and supply costs depend on individual key techno-economic parameters. Therefore, the sensitivity analyses have been performed using **Lüderitz in Namibia** as a sample region. The PtX pathways analyzed are liquid hydrogen, ammonia, and methanol. The techno-economic parameters considered and their respective ranges of change during the sensitivity analysis[14] are shown in Table 6-7.

Table 6-7: Analyzed parameter sensitivity

<table>
<tr><th>Parameter</th><th>Base Value</th><th>Variation</th><th>Unit</th></tr>
<tr><td>CAPEX: PV</td><td>650 EUR/kW_p</td><td rowspan="4">-50% to +50%</td><td rowspan="4">%</td></tr>
<tr><td>CAPEX: Wind</td><td>1500 EUR/kW_p</td></tr>
<tr><td>CAPEX: Electrolysis</td><td>750 EUR/kW_p</td></tr>
<tr><td>CAPEX: Transport vessels</td><td>Table 5-11</td></tr>
<tr><td>CAPEX: DAC</td><td>500</td><td>500 - 1500</td><td>EUR/(ton/yr)</td></tr>
<tr><td>WACC</td><td>7.25</td><td>2.5 - 10</td><td>%</td></tr>
<tr><td>H_2 conversion:
Part load limit</td><td>LH_2: 25
NH_3: 80
MeOH: 60</td><td>25 - 100</td><td>%</td></tr>
</table>

[14] The sensitivity analyses were performed in an isolated manner. This means that the specific variable (e.g., CAPEX PV) is changed, while the original baseline value is maintained for all other variables. Each parameter change has an influence on the overall system layout. Therefore, the optimization process was performed again for each separate parameter change. For example, if the cost of wind power is lower, the optimization algorithm would potentially install more wind power capacity. Also, varying the partial load limit of the liquefaction or syntheses results in a completely different system design.

The investment costs for the key supply chain components PV, wind, electrolysis and the transport vessels were varied between -50% and +50% of the specific baseline value. In the case of the DAC units, the investment costs were only varied upwards to reflect the significant uncertainties arising from the currently still young and not highly scaled technology. Variation in the direction of lower investment costs was omitted in the case of the DAC. The WACCs were varied in a range that roughly reflects the complete global range for possible country-specific WACCs (cf. 5.1.1).
For each of the isolated variations of a key performance indicator, the result diagrams are shown and explained below. Here, each data point corresponds to a separate system optimization and reflects the respective cost optimum of the specific PtX path.

Variation of renewables and electrolysis CAPEX: Figure 6-33 shows the dependence of the PtX supply cost on a CAPEX variation for renewables, electrolysis and transport vessels. The sensitivity analysis clearly shows that the components with the highest shares in the total investment costs along the specific PtX value chain (Electrolysis, liquid hydrogen transport vessel, wind power plants for the liquid hydrogen case) also represent the greatest levers for a significant reduction in PtX generation costs.
For example, an increase in the cost of PV components has a clear cost-increasing effect on the obtained PtX products. On the other hand, further PV cost reduction, e.g., through technological developments in PV module production or economy of scale effects, is beneficial for PtX costs.
In the case of the expensive liquid hydrogen ship, varying ship investment costs have a noticeable impact on the supply cost of liquid hydrogen. In contrast, in the case of the large-scale and simultaneously low-cost ammonia and methanol vessels, a variation of the initial ship investment costs has no relevant impact on the PtX supply cost. However, these statements are only valid in the context of the methodology adopted here, in which the ship investment costs are directly allocated to the PtX products. It is very likely that in the future long-term purchase agreements will be concluded between producers and purchasers of green PtX products. Here, fluctuations in the ship investment costs would have no direct impact on the PtX supply cost.

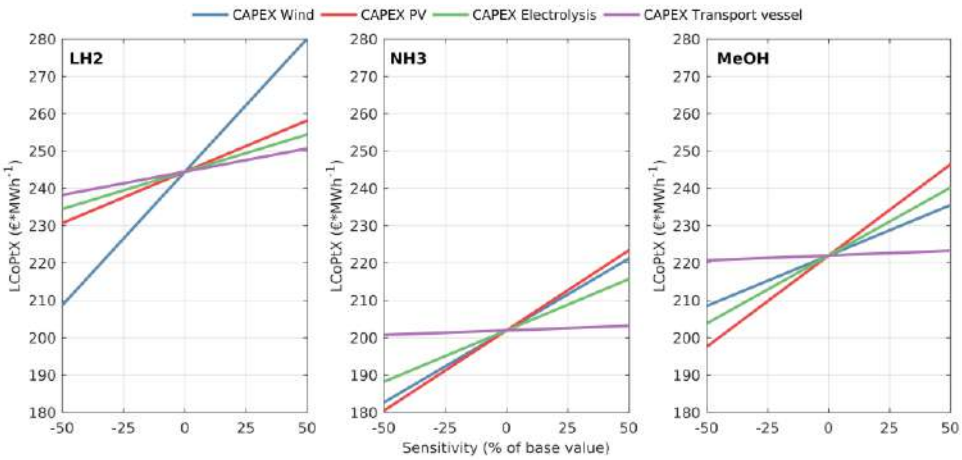

Figure 6-33: Sensitivity analyses results for a variation of key components investment costs.

Variation of DAC CAPEX: In the case of green methanol production with atmospheric carbon dioxide, the DAC modules contribute to a significant investment demand. In the case of the methanol pathway in Lüderitz and an annual carbon dioxide demand of 440kt, investments of EUR 0.25 billion need to be raised. This corresponds to 8% of the total investment (EUR 3.15 billion) for the methanol pathway. If only the foreground PtX components such as electrolysis, desalination, storage, synthesis and the direct periphery, are considered in the total investment (EUR 1.23 billion), the DAC plant accounts for 20% of the total investment.

In addition, the investment costs for this still young technology are subject to high uncertainties. Currently realized pilot plants for low-temperature DAC (e.g., Climeworks, Global Thermostat) achieve capture capacities of 2-4kt carbon dioxide per year and are aiming for 36 kt carbon dioxide within the next two years. Carbon Engineering, a leader in high-temperature DAC technology, is currently building a pilot plant in Texas (Ector County DAC plant) that promises to annually capture up to 1 Mt of atmospheric carbon dioxide at its final scale-up stage. The plant is scheduled to come on line in 2024.
Either way, it is still a long way to go for this still nascent technology to reach the capture cost targets of well below 100 EUR per ton of carbon dioxide captured. The predictions and estimates of the necessary investment costs of these technologies are correspondingly diffuse, and in some cases vary widely. The specific investment of 500 EUR per ton of annual capture capacity considered in this study is based on published and reviewed values. But due to a lack of data from real pilot plants at significant scale, these literature values are subject to large uncertainties and may well be discussed controversially and viewed critically. For this reason, the DAC CAPEX was also subjected to a sensitivity analysis and varied significantly upwards.
The resulting influence of the DAC CAPEX on the methanol supply cost is shown in Figure 6-34. In the case of a doubling of DAC CAPEX, methanol supply costs would increase by 11%; in the case of a tripling of DAC CAPEX, by as much as 24%. These are cost increases that certainly require detailed planning for specific PtX projects that are dependent on atmospheric carbon, especially since there is no guarantee that the necessary LT DAC capacities can be provided by the target year 2030 at the latest.

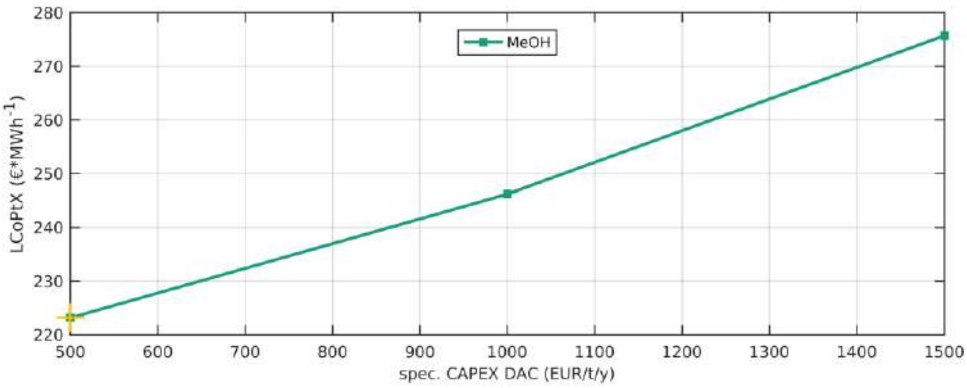

Figure 6-34: Variation of specific DAC investment costs and their impact on the methanol supply cost (incl. transport). Sensitivity conducted for the Lüderitz region, Namibia. The pathway's base value is indicated with yellow marker.

Variation of WACC: A major influence on PtX costs is also the weighted average cost of capital (WACC). The WACC considers country-level aspects such as economic and political stability as well as the technological risk and return expectations (compare section 5.1.1). Both factors may vary over time, as new technologies become mature. [143]
Figure 6-35 shows the supply costs for liquid hydrogen, ammonia and methanol in relation to the WACC considered for the overall system cost. The analysis shows that more investment-intensive technologies such as the LH_2 pathway are more dependent on the respective financing costs in a production country.
For example, lowering the WACC from 7.25% to 5% reduces the supply cost for the ammonia pathway (3.89 bn EUR total investment) by 7.4%, while the supply cost for LH_2 pathway (6.46 bn EUR total investment) can be reduced by 16%.
The coordination of the framework conditions of a specific PtX project with investors and lenders as well as the involved political departments is therefore a central step for establishing a coordinated basis that offers a corresponding level of security for investors and helps to keep the WACC low.

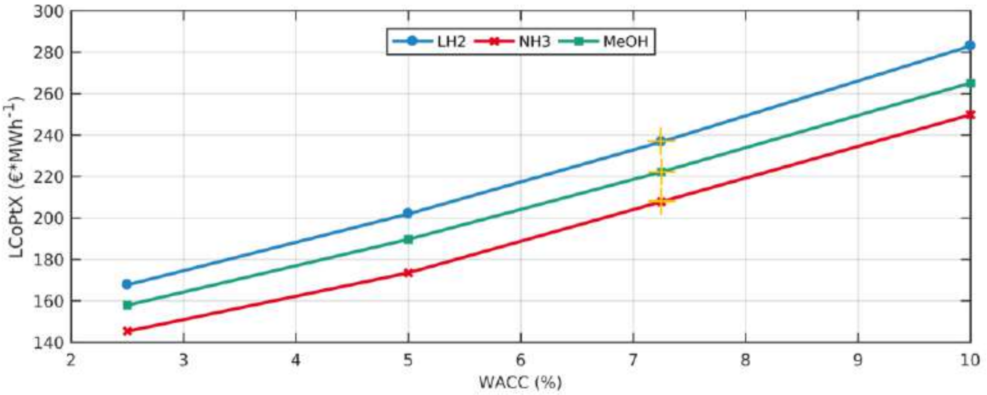

Figure 6-35: Variation of the Weighted Average Cost of Capital (WACC) and its impact on the PtX supply cost (incl. transport). Sensitivity conducted for the Lüderitz region, Namibia. The pathway's base value is indicated with yellow marker.

Variation of part load limit of liquefaction/syntheses: Synthesis processes and their periphery, such as heat exchangers and compressors, require an almost constant hydrogen feed to operate efficiently in the intended operating window. Whereas conventional feedstocks such as fossil natural gas or coal can be provided in constant quantities without any problems, the supply of green hydrogen may vary due to fluctuations in RE production, entailing the need for an intermediate hydrogen storage. The storage acts as a buffer between flexible electrolysis and the steady-state hydrogen conversion step and must be designed to be particularly large in order to have sufficient hydrogen stored at all times. The criterion of a dynamic operation of synthesis processes is increasingly becoming the focus of science and industrial research. There are currently several projects dealing with the operation and optimization of dynamically operated methanol and ammonia reactors, which are making significant progress in this area. Also in the present study, a limited dynamic operation of synthesis and hydrogen liquefaction was assumed (see section 5.3). In order to show the influence of the dynamics on the PtX supply cost, the operating window was subjected to a sensitivity analysis in which the part load limit was varied between 25-100%. The following figure illustrates the impact of a variation of the specific part load limit on the respective supply cost for liquid hydrogen, ammonia and methanol.

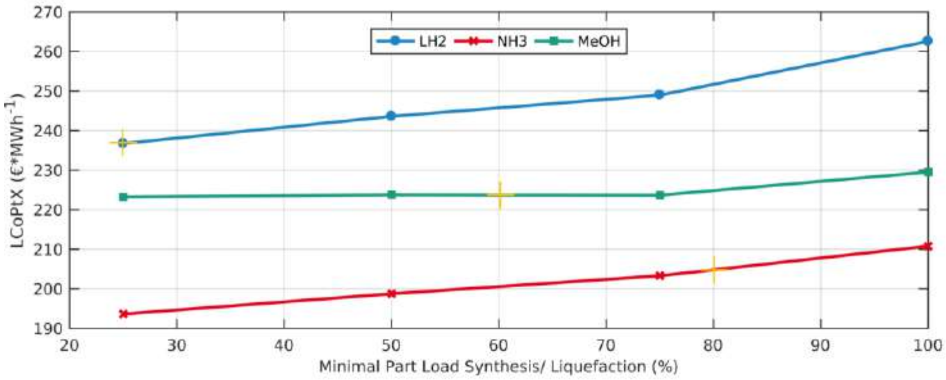

Figure 6-36: Variation of part load limit of liquefaction/syntheses and its impact on the PtX supply cost (incl. transport). "Part load limit" here refers to the lower limit of the operating window (e.g., a limit of 25% allows operation of the liquefaction/synthesis between 25-100% of the nominal load). Sensitivity conducted for the Lüderitz region, Namibia. The pathway's base value is indicated with yellow marker.

The analysis shows that a certain dynamic capability of liquefaction and synthesis has a clear cost-reducing potential. In particular, the "first ~25% dynamics" (75-100% part load limit) can significantly reduce the supply cost. The reason is that the size of the cost-intensive intermediate hydrogen storage can be significantly reduced by a certain dynamic capability. In the context of the present analysis, this is particularly true for the methanol pathway. Here, a limited flexibility window of ~75-100% of the nominal load can be sufficient to almost fully exploit the cost reduction potential. In the case of ammonia synthesis and hydrogen liquefaction, on the other hand, which have higher specific investment costs (c.f. section 5.3), even larger flexibility windows can offer further cost reduction potential.

6.3.2 Assessment of "at-gate hydrogen" generation cost

The present study has focused on the cost of the generation and, in selected scenarios, the export of synthetic energy carriers. The production costs of gaseous hydrogen on site at the plant ("at-gate"), on the other hand, were not considered. However, many current studies refer to these at-gate costs of green gaseous hydrogen and use them as reference values for the global comparison of potential PtX sites. To discuss the production costs of gaseous hydrogen without further liquefaction, conversion to synthetic fuels, or transportation, all regions in this study were analyzed again in terms of their local hydrogen production potential. For this purpose, dedicated optimizations were carried out for each region and the best system design was determined in each case.
Figure 6-37 shows the levelized cost of gaseous hydrogen produced in 1 GW_{el} electrolysis with dedicated wind and PV power generation without intermediate storage, further liquefaction, conversion to synfuels or any transport. For the most promising regions in Brazil, Colombia and Australia, local hydrogen production costs in the year 2030 are in the range of 96-108 EUR/MWh (3.21-3.61 EUR/kg H_2). The total cost for all regions studied range between 96-160 EUR/MWh (3.21-5.33 EUR/kg H_2).

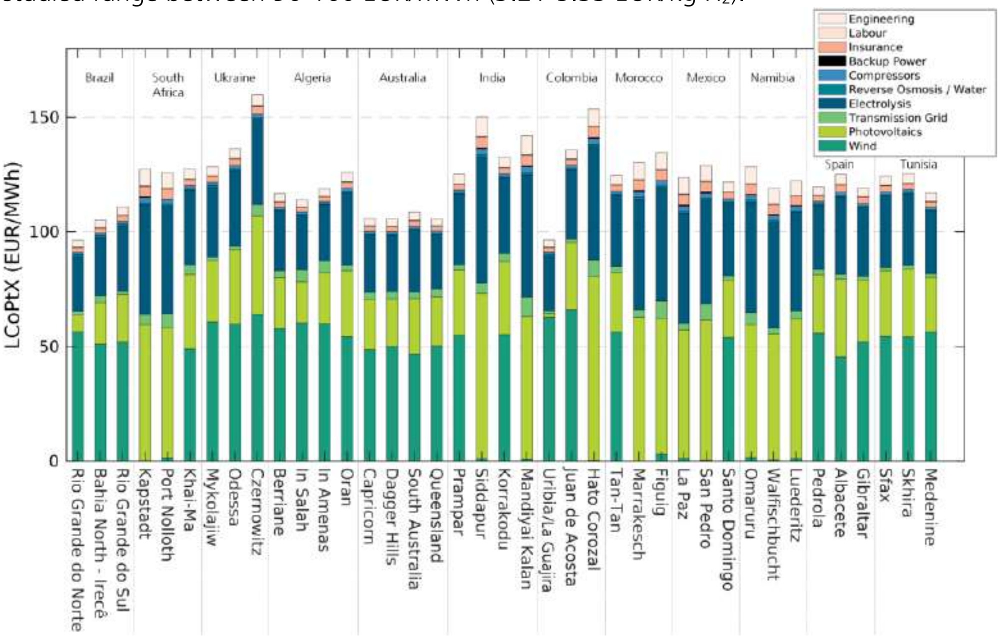

Figure 6-37: The levelized cost of producing gaseous hydrogen in 1 GW_{el} electrolysis with dedicated wind and PV power generation examined for the year 2030 and for all regions studied. The costs shown indicate the "at-gate" cost for gaseous hydrogen without intermediate storage, further liquefaction, conversion to synfuels, or any transport.

If these values are compared with the published target values of national roadmaps and international price projections and scenarios for 2030, it becomes clear how ambitious these target values are in part (Table 6-8; based on [144]). At this point, it should be emphasized that in the present study, costs and not prices were calculated. Prices, in turn, are derived by taking into account marginal costs such as manufacturing, including transport plus surcharges such as for profits, risk, distribution, warranties, or R&D costs [145]. In order to enable a profitable operation of PtX plants, the total costs of their products should either be directly below the attainable market prices or else instruments such as those of the H2Global Foundation must be applied.
However, it should be recalled at this point that the significantly increased market prices of natural gas have an equally cost-increasing effect on the production costs of gray

hydrogen, with a production cost above 2.50 EUR/kg H_2 (cf. NG price effect discussion in section 6.1).

Table 6-8: Published target values of national roadmaps and international price projections and scenarios for hydrogen in 2030.

Communicator	Type of assessment	Price range per kg H_2	Reference
This study	Scenarios	3.21-5.33 EUR *(costs)*	*Power-to-X country analyses, 2023*
Hydrogen Council	Projection	1.40-2.30 USD	*Hydrogen insights, 2021; [6]*
European Council	Target	1.10-2.40 EUR	*Hydrogen strategy, 2020; [146]*
IEA	Scenarios	1.50-3.50 USD	*Net Zero by 2050, 2021; [147]*
IRENA	Scenarios	1.40-2.00 USD	*Low RE cost scenarios in Green H2 cost reduction, 2020; [148]*

6.3.3 Off-grid scenario

The main scenarios of the present study all considered hydrogen generation from 100% variable renewables. The other units of the PtX chains, such as compressors and heat pumps, were also supplied with renewable electricity if available. Only at times when local wind and PV capacities were not sufficient, it is assumed that these auxiliary units could be supplied with grid electricity. However, sufficient grid connectivity for capacities of a few megawatts electrical power supply is not inherently available in all potential PtX regions. At such locations, the dependence on the variable generation profile of local RE capacities and on existing storage potentials is intensified. In order to take into account situations in which network coverage in off-grid regions does not appear to be readily possible, a selected PtX region in India was simulated and optimized as a remote scenario.

The selected region of Siddapur in western India stood out in the base case analyses for its focus on PV power. At the optimal system design, wind power generation is virtually non-existent at this rather low-wind location, resulting in a high demand for backup power from the grid in particular during night hours. External electricity supply from grid at this location totaled up to 5.8% of the total annual electricity demand for this PtX site (study average: 0.8%). Under these conditions of a power supply from almost exclusively PV, a remote scenario appears to be an even greater technical challenge. For the remote scenario a backup power supply by a stationary fuel cell system has been assumed. The fuel cell utilizes the hydrogen from the intermediate storage to provide electricity for the must-run capacities during periods of low renewable energy generation. The installed power of the fuel cell is determined in the system simulation process. Investment costs of 1,000 EUR/kW and an efficiency of 50% have been assumed for the stationary fuel cell system [149].

Figure 6-38 illustrates the difference in supply costs for PtX systems that draw their backup power either from the grid or from a local stationary fuel cell. The analysis shows that in the case of a 100% remote scenario without any utilization of grid electricity, total costs increase moderately, by 4.5% for the liquid hydrogen and ammonia pathways and by 12% for the methanol pathway. The latter relies more on a small but constant supply of baseload power due to the energy requirements of the DAC plant and the limited dynamics of methanol synthesis compared to hydrogen liquefaction.

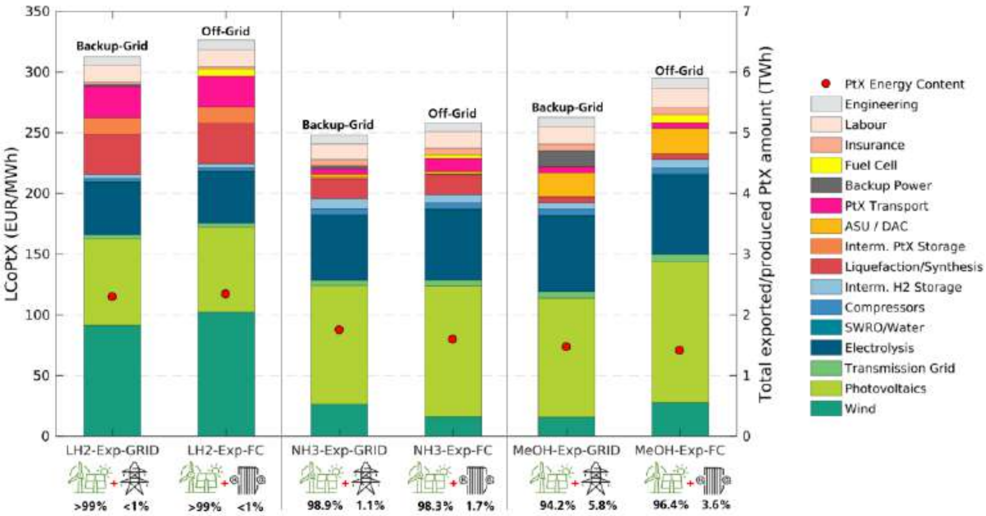

Figure 6-38: Impact of backup power supply via grid (GRID) or local stationary fuel-cell (FC) on supply cost of liquid hydrogen, ammonia, and methanol. In the FC scenario the PtX system is designed for a 100% remote off-grid operation without any utilization of external grid electricity.

Based on this analysis, it can be stated that PtX generation without the use of any grid electricity should not be ruled out from the beginning. The search for the best PtX sites should not consider the availability of grid power as a primary criterion, but rather focus on wind and solar potential, as well as the availability of water and other infrastructure such as roads and ports. Indeed, such grid-free PtX production has the charm of a 100% green PtX generation without the use of any fossil electricity. However, a disadvantage for a PtX system without any grid connection would be that surplus renewable electricity could not be fed into the grid and thus made available to other consumers.

6.3.4 Carbon supply via concentrated carbon dioxide point source

The carbon source considered in this study for the methanol and Fischer-Tropsch pathways is a carbon dioxide supply using DAC. The advantages of atmospherically sequestered carbon are its location independence and the fact that the carbon dioxide sequestered in the synfuel has a net zero climate impact if emitted later. Clear disadvantages for DAC technology so far are the significantly higher carbon dioxide capture costs and energy demands as well as the limited DAC capacities which are considered possible for both LT and HT DAC over the coming years. Carbon point sources have the advantage that the carbon dioxide can be captured much more energy and cost efficiently due to the higher concentration in the source stream.

In order to compare the methanol supply cost based on a carbon dioxide point source with the supply cost based on DAC, a system optimization was performed for the region of Pedrola in Spain (Region 1). In Spain, industrial point sources with significant carbon dioxide amounts are highly dispersed throughout the country (Figure 6-39). The carbon dioxide demand in the methanol scenario in Pedrola, Spain (611 kt CO_2/yr), could be covered by a refinery (Refinería Petronor in Muskiz) with sufficiently high direct carbon dioxide emissions located near the selected PtX hub.

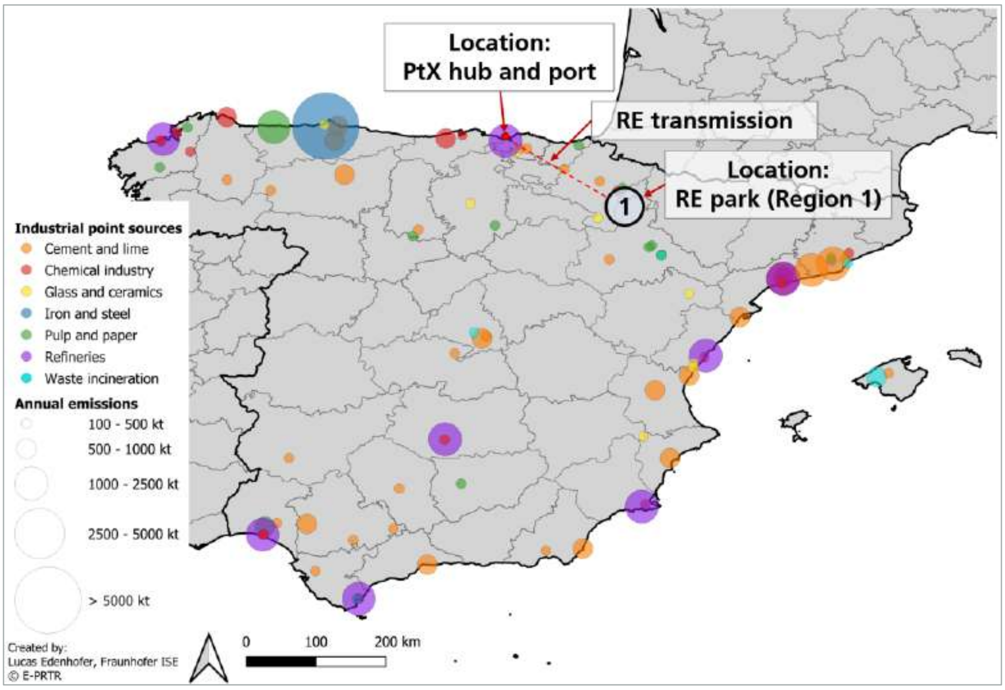

Figure 6-39: Location and amount of annual direct carbon dioxide emissions for various industrial carbon dioxide point sources in Spain. Pedrola (Region 1) as the selected location for the sensitivity analysis is indicated with a black circle. Graph based on in-house GIS-Analysis for data from the reference year 2017.

Figure 6-40 shows the results for the methanol pathway supplied either with atmospheric carbon dioxide via DAC or with carbon dioxide captured from an industrial point source for which the supply costs varied over a range from 40-120 EUR/t CO_2.

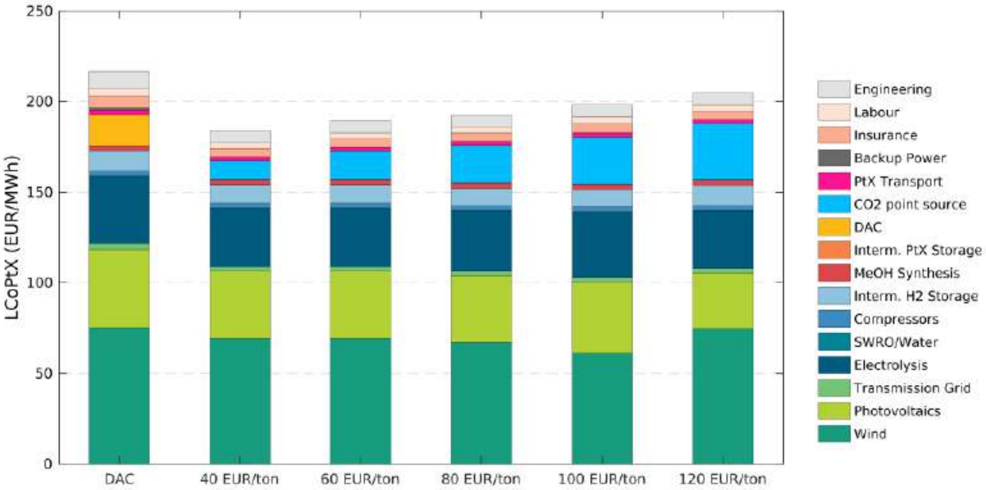

Figure 6-40: Comparison of supply cost for methanol produced either by carbon dioxide from DAC (left bar) or from a concentrated point source with varying carbon dioxide supply costs.

The analysis shows that the use of carbon dioxide point sources, if available at the point of PtX generation, can make sense from an economic point of view. Methanol supply cost in the Pedrola case can be reduced from 217 EUR/MWh (with DAC; 1212 EUR/ton) to 179 EUR/MWh (999 EUR/ton) at best with carbon dioxide point source at 40 EUR/ton CO_2. Capture costs of 40 EUR/ton CO_2 can be seen as representative for processes in the chemical sector and to some extent in the refinery sector [150,151]. In addition to the lower carbon dioxide capture costs, the reduced total system energy demand had a positive effect on the PtX supply cost. This was due to the fact that less wind and PV capacity was required, as the energy-intensive operation of the DAC units was no longer necessary.

7
Conclusions and recommendations

This chapter summarizes the findings from the country analyses and also aims to highlight the remaining technological challenges for a large-scale ramp-up of PtX import pathways.

This study investigated the production and supply costs of key PtX products for a total of 12 pre-selected countries and 39 regions. The comprehensive results presented are based on extensive country analyses regarding the RE generation potential, identification of promising regions, and holistic simulations and optimization of PtX production and supply pathways for each of the identified locations. In addition, extensive sensitivities and special scenarios were calculated to evaluate particular aspects of the techno-economy of large-scale PtX chains.
Overall, the following key elements for beneficial PtX generation can be identified from the present study:

- Site-specific analyses of regions promising for Power-to-X production are essential for reliable cost estimates. The complex interaction of wind and photovoltaic production profiles, topographical and infrastructural conditions, and also administrative conditions make site-specific analyses indispensable. General assessments for future Power-to-X regions based only on isolated wind or photovoltaic potentials and costs neglect these aspects.
- Total product transport distance can have a decisive influence but is not necessarily a knock-out criterion (cf. the evaluated Australian regions).
- Low levelized cost of renewable electricity generation and associated high full load hours significantly affect electrolysis capacity utilization and total Power-to-X product output.
- Favorable *combined* conditions for wind and PV power generation can be more advantageous in numerous cases than locations with extremely good conditions for only wind or PV at a time. Decent hybrid RE locations lead to higher utilization and lower need for intermediate hydrogen storage.
- Low weighted average cost of capital has a high overall impact on final production and supply costs.

Country-specific findings: In the overall comparison of all the countries analyzed and the PtX supply costs achievable, Brazil, Australia and Spain in particular stand out (sections 6.2.1, 6.2.4 and 6.2.6, respectively). In the case of **Brazil**, the Rio Grande do Norte region stands out with excellent combined wind and PV potentials and resultant PtX production costs. In addition, the transport distance to be covered for import to Europe is reasonable compared to other potential global PtX locations. In particular, for the PtX pathways for liquid hydrogen and ammonia and the corresponding supply costs of 171 EUR/MWh (5.71 EUR/kg LH_2, 885 EUR/ton NH_3), this region outperforms all other regions evaluated. The other two regions evaluated, Irece and Rio Grande do Sul, show slightly elevated costs but also offer above-average PtX potential. The four regions evaluated in **Australia** consistently score above average and offer low supply costs despite the exceptionally long transport distance. Advantages here include optimal combined wind and PV conditions, low WACC, and high land availability as well as available labor and education. In addition, important decisions are already being made by the Australian government, research organizations, and industrial sectors with regard to becoming a powerhouse PtX exporter. **Spain**, which has been included as a European reference country was also extensively analyzed with regard to its renewables and PtX potential, scores above average among the countries evaluated. In particular, the two regions of Pedrola and Gibraltar show promising PtX cost potentials for the production of green ammonia, methanol, and Fischer-Tropsch products (section 6.2.6). In the case of gaseous hydrogen production and a subsequent transport via pipeline, Pedrola in the northeast of the Iberian Peninsula is particularly convincing, with low production and supply costs (sections 6.2.6 and 6.3.2). Whether a sufficient pipeline connection between Germany and Spain via France is feasible from 2030 also depends on the implementation of the current European Hydrogen Backbone plans (section 5.4.2). The decision to design the "H2Med" axis, now planned as a subsea pipeline, as a dedicated hydrogen pipeline was an important step in this regard. In addition to the low cost of capital, Spain also benefits from the good availability of the necessary infrastructure, such as power grids, roads, and workforce, as well as the potential on-time delivery of spare parts.

Further regions with advantageous production and supply costs for green energy carriers were also identified: The countries under consideration for the MENA region - **Morocco, Algeria, Tunisia** - are not only in close proximity to the EU but are able to offer above-average conditions for PtX production. In particular, the seven regions considered for Algeria and Tunisia consistently show favorable green ammonia and methanol production and supply costs in the range of 190-250 EUR/MWh. In Morocco, the southwestern region of Tan-Tan performed with average electricity and PtX production costs while the other two assessed regions, near Marrakech and Figuig, showed elevated costs (section 6.2.5).

In addition to these countries, the La Guajira region in **northern Colombia** is noticeable. The region of La Guajira offers extraordinarily high wind and PV full load hours and therefore very low PtX production costs. Further advantages are the proximity between the RE generation and PtX hub as well as the manageable transport distance. However, based on our analyses, the remaining regions in Colombia promise very limited RE and PtX potential.

Namibia, assessed for ammonia, methanol, and liquid hydrogen, performs well on average in terms of production and supply costs, with the Lüderitz region offering the best potential among the regions assessed (section 6.2.3). For Namibia, however, it should be emphasized that here, too, the land potential is huge and first-mover consortia are already active in the region to realize PtX production and export chains with the involvement of local authorities and the population. In this study, vast areas of Namibia were excluded from the outset because they are defined as national parks or restricted military areas. These regions show in part even higher wind speeds and thus potential for even lower PtX production costs.

For the regions in the remaining countries – **South Africa, India, Mexico and Ukraine** – the evaluated PtX energy carriers show higher costs, although there are also individual regions which show quite an average cost performance. The main drawbacks for these regions are the moderate potential for wind energy and, in the case of PtX export, longer transport distances. In the case of these regions, an additional factor is that they were valued at a comparatively high WACC of 6.8-8.0%, taking into account the overall WACC range in this study of 5.8-8.0%.

In the case of "at-gate" **production costs of gaseous hydrogen**, the Brazilian and Australian regions, as well as La Guajira in Colombia, also show excellent results ranging from 3.21-3.61 EUR/kg H_2 (section 6.3.2). These costs are well within or even below the current production cost of fossil hydrogen, considering the increased price of natural gas (cf. NG price effect discussion in section 6.1).

In general, it cannot be stated that a specific region performs equally well or poorly across all PtX end products. Rather, efficiency shifts in terms of production costs from one PtX end product to another can be observed within a region. The central cause for these shifts is the interplay between installed wind-PV ratio, the potential dynamics of the respective PtX system, and the total transport distance. One example is the Mexican region of La Paz on the peninsula off the mainland. While this region has the highest production costs for liquid hydrogen among the three Mexican regions evaluated, it has the lowest costs for green ammonia production. In the case of the PV-dominated region of La Paz which borders the East Pacific, for example, there is a high demand for backup power as well as a significantly longer shipping route compared to the other two locations. This leads to significantly higher supply costs for liquid hydrogen compared to ammonia and methanol, which can be transported very cost-efficiently. In the case of

the other two Mexican regions, San Pedro and Santo Domingo, which border the western Atlantic, the costs of liquid hydrogen, ammonia, and methanol, are more comparable.
The results presented always refer to the PtX cost optimum in the respective region. For many regions, however, it can be stated that if slightly increased PtX production costs are accepted (~5-15% cost increase), significantly increased total produced PtX amounts are possible (~30-50% product amount increase; e.g., Figure 6-15).

Technology-specific findings: The **electrolysis** capacity was set at 1 GW_{el} in the present study. Basically, a high dynamic capability of the electrolysis process is an important aspect for 100% renewables-based PtX systems in order to follow the variable renewables supply and to keep the electrical system well balanced. PEM electrolysis as well as (pressurized) alkaline systems are the relevant electrolysis technologies here. The topic of **intermediate hydrogen storage** is still underestimated, if not neglected, in many current techno-economic efficiency and feasibility studies. However, in light of the need for at least hourly resolved simulation and optimization of PtX systems, the relevance of an intermediate hydrogen storage prior to synthesis or liquefaction becomes obvious. In particular, syntheses which currently have limited dynamics may require intermediate hydrogen storage capacities with total volumes of several thousand cubic meters. The aboveground pressurized steel tanks considered in this study can thus contribute significant cost shares of up to 15% to the total supply cost. Hydrogen storage in underground salt caverns or depleted natural gas reservoirs, a significantly less expensive option than aboveground pressurized tanks, was excluded from this study, as it severely limits site selection and requires detailed geological knowledge of the PtX region concerned. For specific implementations, however, such concepts can offer further cost-saving potential if technically feasible. In any case, **flexible synthesis processes** are a key to cost-efficient PtX pathways. However, our sensitivity analyses have also shown that in the case of the methanol pathway, a limited flexibility window of ~70-100% of the nominal load can be sufficient to fully exploit the cost reduction potential. In the case of ammonia synthesis and hydrogen liquefaction, on the other hand, which have higher investment costs, larger flexibility windows are advantageous (section 6.3.1). In this study, the **liquid hydrogen** pathways have higher supply costs than green ammonia or methanol for many of the regions evaluated under the technology assumptions made. The main reason here is the higher capital costs for liquefiers and cryogenic ship transport. However, for sites that are strongly wind-dominated (e.g., La Guajira, Colombia, section 6.2.2) and thus exhibit high variability in electricity and hydrogen supply, liquefaction benefits from its higher dynamic capability compared to synthesis. Liquid hydrogen can be produced more cost-effectively at such sites. For hydrogen liquefaction, it should be emphasized that the individual liquefier capacities resulting for the present scenarios of up to 160 kt hydrogen per year represent more than the current globally installed hydrogen liquefier capacities [73]. This means that although the technology has a high degree of maturity, there could be bottlenecks in technology supply for large projects. The same aspect applies to a carbon supply via **DAC technologies** for **methanol** and Fischer-Tropsch syntheses. In particular, for low-temperature DAC (considered in the present study), in addition to ambitious carbon dioxide cost targets, the technology must be made available at the kiloton scale. High-temperature DAC systems seem to be a step ahead and are aiming at the realization of the first plants in the megaton range. However, it is necessary to develop concepts that allow the significantly higher thermal energy demand to be covered by renewable energy sources and not by natural gas. Carbon point sources, if available at appropriate capture cost, can provide a corresponding cost reduction potential for the C-dependent pathways (Figure 6-40). In the case of the CO_2-based **Fischer-Tropsch** pathway, the reverse water gas shift reactor represents a technological bottleneck and is currently not yet available at sufficient technological maturity. The analyses of green jet fuel via the FT pathway show that it may be economically disadvantageous to sell the by-products of the FT synthesis locally at possibly low market prices. It may make more sense to export the entire FT mix and offer the by-products and their green attributes for sale at potentially higher market prices at the destination. The **ammonia** pathway emerged as the most cost-efficient pathway for almost all of the regions analyzed. However, if green ammonia is not discussed for use as a green fertilizer or chemical but as a hydrogen carrier, it is relevant to consider the energy-intensive and not yet advanced reforming of ammonia in the cost analyses. With regard to the **GIS-based infrastructure analyses** for the regions analyzed, it can be noted that in some cases huge areas of land were excluded from the analyses because they did not have the necessary roads and network capacities (Namibia, Australia). In some cases, these areas have high solar irradiation and wind speeds. Some of the **ports** considered for export are thus far only oriented towards bulk cargo and require expansion before the green energy carriers can be exported. These costs could not be considered in the assessments. An alternative solution for larger PtX projects could also be floating offshore terminals, which can enable ship loading with limited intervention in the local port infrastructure.

Key challenges and geopolitical dependencies in PtX chains: In the context of the extensive wind and PV capacity required for GW-scale PtX projects such as those investigated in this study, a construction period of several years is to be expected. Fluctuating commodity costs during construction can have a significant impact on the overall investment costs not only for renewables and central components, but also for other peripheral technologies such as transmission cables or transformer stations. Delays due to long supply chains are to be expected, and the impact of these on the overall cost of the project is difficult to predict. In addition, changing political conditions and regulatory requirements for international construction projects can have a direct impact on the implementation of projects of this magnitude.

With regard to RE technologies, it should be emphasized that these entail a central dependence on the Asian market. While this has been true for PV components almost consistently for a decade, it is also important to emphasize that in the wind power sector (partial) aspects of the production chain are being transferred to Asia as well [152–154]. With regard to water electrolysis, and also because of the ambitious electrolysis capacity targets of the EU, the study makes it clear that it is imperative to avoid a relocation of the electrolysis manufacturing industries to the Asian market. Now is the time to promote the development of a 89anufacturingg industry for water electrolysis and to move away from small-scale hardware to GW manufacturing. The aspect of dependency also applies to the purchase of rare earths, more than half of which are sourced from the Asian continent [155]. Regarding the ship-based transportation of PtX products, it should be emphasized that many of the major shipyards are located in China and South Korea. In the case of the liquid hydrogen import pathway, there must also be a sufficient number of large-scale vessels available by 2030 to serve green hydrogen projects.

Considering the infrastructural bottlenecks, it is also important to not only keep an eye on the PtX generation side, but also to build up the process chains downstream of the import. The import ports must have appropriate unloading and local storage infrastructure for PtX products. If there is a pipeline connection for the national transport of hydrogen, energy-efficient conversion facilities (regasifiers, reformers) must be planned. Domestic transport of PtX products requires national transport chains (pipelines, barges, trains) on the one hand, and downstream transport and storage chains on the macro level (trucks for gaseous hydrogen, Power-to-Liquid products, liquid organic hydrogen carriers (LOHC), seasonal storage) on the other. In addition, the application side must be converted to the use of green energy sources and chemicals, and planning security and investment incentives must be created along the entire value chain.

Even if, from a German perspective, PtX imports will not reach the same magnitudes as current fossil imports, it should be emphasized that green hydrogen is a no-regret option in the energy system, whose supply routes must now be established. Over the next few years, therefore, bilateral agreements will still form the first tender roots of a global hydrogen trade. In the years thereafter, from 2030 onwards, trade in hydrogen and its derivatives will then become more diversified, with certain security of supply. These import vectors will be complemented by a local production of green hydrogen and

derivatives in Germany. In combination with the German energy transformation and greatly increased local RE production, this will make it possible to phase out fossil energies entirely [156]. The necessary legal framework and specifications for the production of green hydrogen and derivatives must be developed further, but important steps are currently being taken (e.g., the EU Delegated Act on criteria for the production of green hydrogen and its greenhouse gas intensity, from February 2023) [157].
One of the most important aspects related to building a hydrogen and PtX import economy is avoiding a new energy colonialism with unidirectional energy and value vectors. PtX import strategies should therefore be embedded in sustainable development partnerships that support socioeconomic development and decarbonization of the economy in partner countries [158]. Although it seems certain that especially large companies with sufficient risk capital, possibly from the oil and gas business, will invest in large-scale PtX, it should be ensured that cooperation and involvement of local actors in the exporting country is a fundamental requirement. This will support a sustainable and timely implementation of import strategies. The infrastructures necessary for PtX should also help the exporting countries to achieve their climate goals and to generate social added value through, for example, the creation of jobs and the supply of electricity and drinking water.

In conclusion, this study has shown that even in the medium term, green hydrogen and its derivatives can be produced and supplied at costs that may well be attractive considering the tense market situation for fossil fuels and rising market prices (cf. section 6.1). When analyzing the costs of green energy carriers, one should refrain from comparing them with the expired price tags of fossil references. Instead, such cost comparisons should take into account the current price developments of fossil fuels and additionally internalize the environmental costs caused, for example, by direct carbon dioxide emissions as well as other environmental hazards unavoidably linked to a fossil economy.
Numerous regions analyzed in this study for the year 2030 offer PtX production costs clearly below 200 EUR/MWh with production volumes of up to 4 TWh/yr per project. For gaseous hydrogen, local production costs of 110 EUR/MWh (3.67 EUR/kg H_2) and below were identified. The analyses also showed that transport is not the decisive criterion for a cost-efficient supply of green PtX products. Rather, in addition to good locations for renewable power production and a high utilization of the currently still capital-intensive PtX components, low capital costs and a favorable and secure long-term environment for investors are required. Instruments such as H2Global can be helpful in this context in shaping long-term contracts and reducing risks for investors and producers.

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9 Appendix

9.1 Algeria

9.1.1 Renewable potential analysis

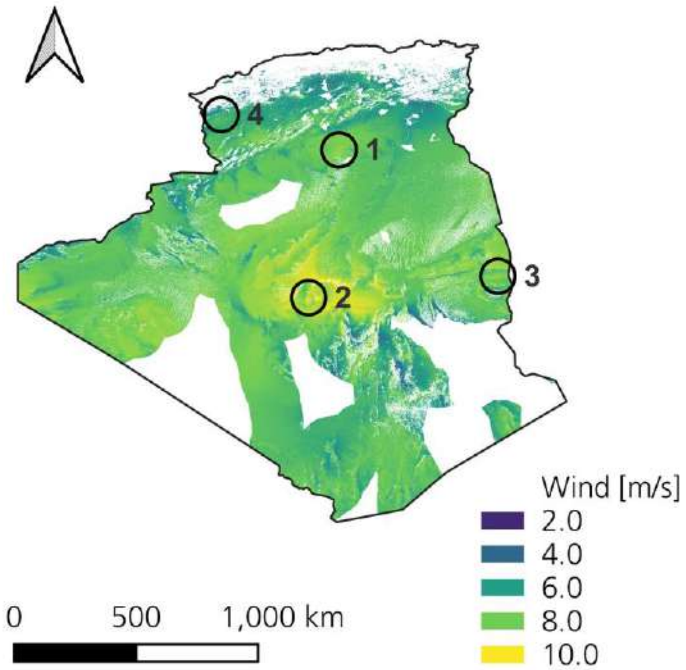

Figure 9-1: Selected regions and wind potential in Algeria

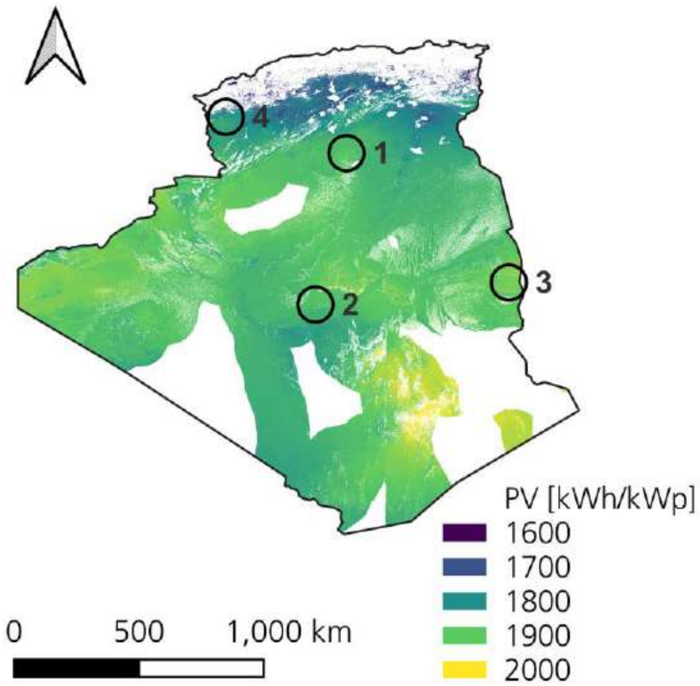

Figure 9-2: Selected regions and PV potential in Algeria

9.1.2 Techno-economic results – Berriane (Region 1)

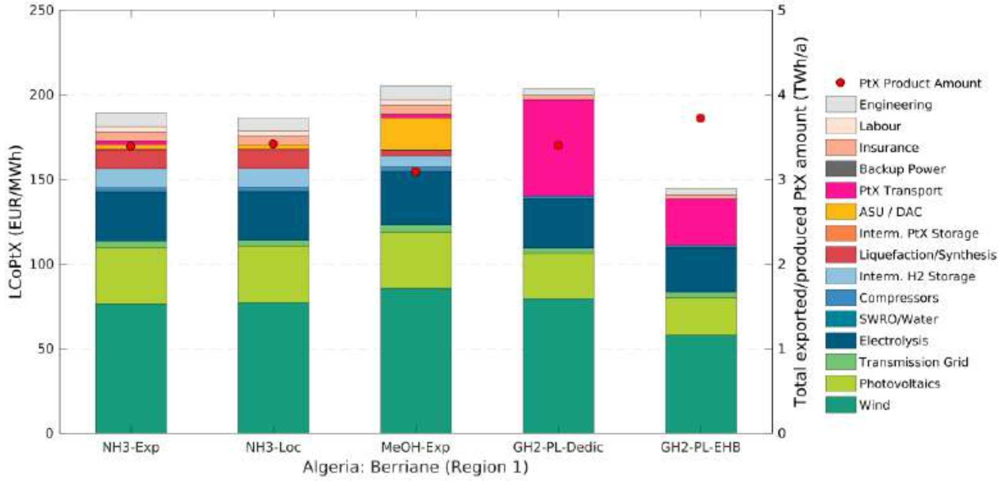

Figure 9-3: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Algerian site "Berriane" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-1: Key performance indicators for the cost-optimal system configuration for the Algerian site "Berriane" (Region 1) for NH_3, MeOH, and gaseous H_2.

Algeria **Berriane**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.5	1.5	1.5	1.5	1.2
Wind: LcoE (EUR/MWh_{el})			51		
PV: Installed capacity (GW_{el})	1.7	1.7	1.6	1.4	1.3
PV: LcoE (EUR/MWh_{el})			35		
Intermediate H_2 storage: Volume (1000*m³)	207	204	114	-	-
Liquefaction/ synthesis: Capacity (tpd)	1921	1935	1812	463	463
Electrolysis: Full load hours (h/yr)	6068	6119	5679	6501	5779
Unused RE power (%)	15	15	10	12	7
Grid electricity used (%)	0.06	0.06	0.32	-	-
LcoPtX (EUR/MWh)	189	186	205	203	145
LcoPtX (EUR/ton)	980	966	1136	6770	4813
PtX Amount (GWh/yr)	3384	3412	3084	3393	3716
Total electr. Demand (GWh_{el}/yr)	6570	6628	6851	6498	5730
Selected investment cost (million EUR):					
Wind + PV	3189	3231	3130	3050	2537
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	435	428	239	-	-
Liquefaction/Synthesis	316	318	77	-	-
ASU/DAC	76	76	472	-	-
Total System	5446	5413	5293	6188	3644

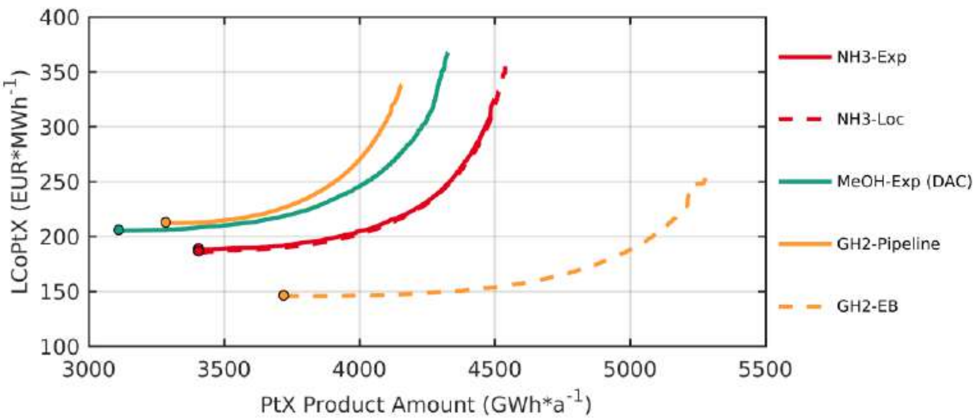

Figure 9-4: The Pareto fronts for the Algerian site "Berriane" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.1.3 Techno-economic results – In Salah (Region 2)

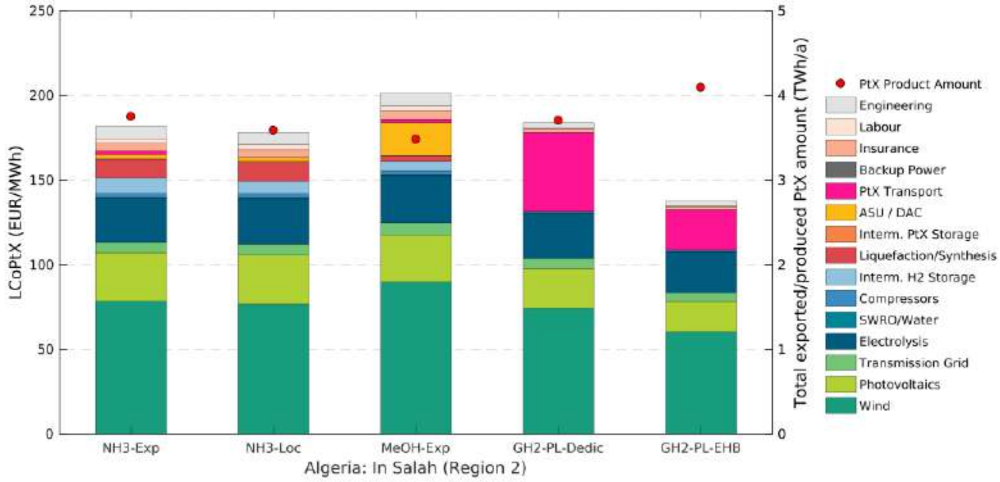

Figure 9-5: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Algerian site "In Salah" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-2: Key performance indicators for the cost-optimal system configuration for the Algerian site "In Salah" (Region 2) for NH_3, MeOH, and gaseous H_2.

Algeria In Salah	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.6	1.5	1.7	1.5	1.3
Wind: LcoE (EUR/MWh_{el})			45		
PV: Installed capacity (GW_{el})	1.7	1.6	1.5	1.3	1.1
PV: LcoE (EUR/MWh_{el})			34		
Intermediate H_2 storage: Volume (1000*m³)	188	145	113	-	-
Liquefaction/ synthesis: Capacity (tpd)	2156	2070	2087	463	463
Electrolysis: Full load hours (h/yr)	6716	6428	6405	6864	6364
Unused RE power (%)	13	12	10	9	5
Grid electricity used (%)	0.06	0.06	0.27	-	-
LcoPtX (EUR/MWh)	182	178	202	184	138
LcoPtX (EUR/ton)	942	922	1114	6125	4587
PtX Amount (GWh/yr)	3746	3586	3478	3701	4091
Total electr. Demand (GWh_{el}/yr)	7302	6972	7754	6878	6335
Selected investment cost (million EUR):					
Wind + PV	3269	3087	3299	2922	2573
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	395	305	238	-	-
Liquefaction/Synthesis	339	331	84	-	-
ASU/DAC	85	82	544	-	-
Total System	5651	5284	5716	5963	3808

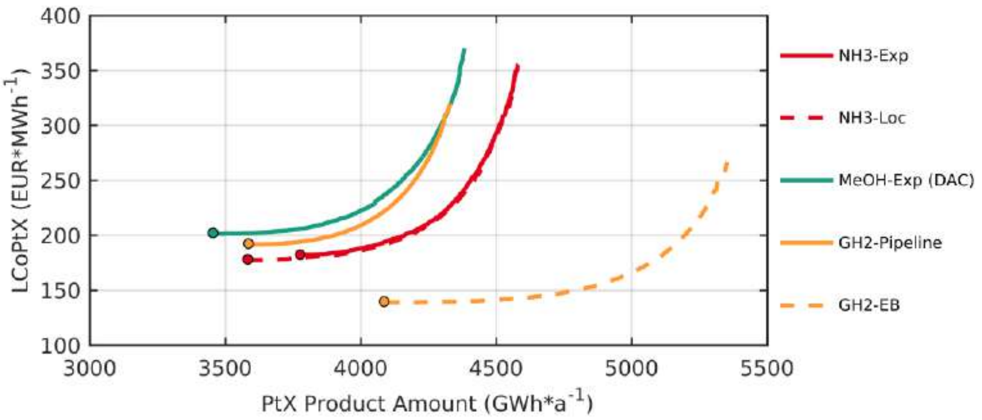

Figure 9-6: The Pareto fronts for the Algerian site "In Salah" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.1.4 Techno-economic results – In Amenas (Region 3)

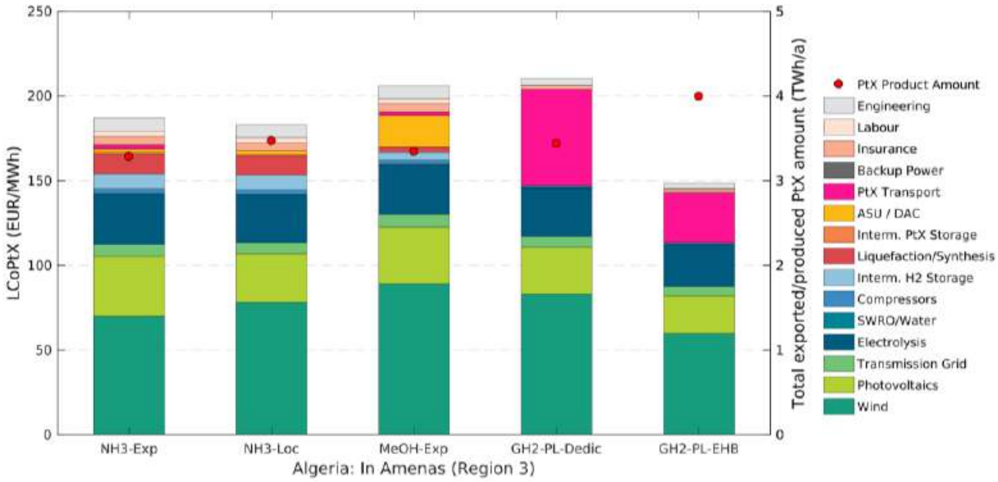

Figure 9-7: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Algerian site "In Amenas" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-3: Key performance indicators for the cost-optimal system configuration for the Algerian site "In Amenas" (Region 3) for NH_3, MeOH, and gaseous H_2.

Algeria **In Amenas**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.3	1.5	1.7	1.6	1.3
Wind: LcoE (EUR/MWh_{el})			49		
PV: Installed capacity (GW_{el})	1.8	1.5	1.7	1.4	1.3
PV: LcoE (EUR/MWh_{el})			34		
Intermediate H_2 storage: Volume (1000*m³)	164	170	91	-	-
Liquefaction/ synthesis: Capacity (tpd)	1856	1952	1910	463	463
Electrolysis: Full load hours (h/yr)	5880	6214	6147	6807	6208
Unused RE power (%)	10	9	10	9	6
Grid electricity used (%)	0.04	0.04	0.19	-	-
LcoPtX (EUR/MWh)	187	183	206	210	149
LcoPtX (EUR/ton)	968	947	1139	7000	4947
PtX Amount (GWh/yr)	3279	3466	3338	3434	3991
Total electr. Demand (GWh_{el}/yr)	6332	6711	7415	6809	6165
Selected investment cost (million EUR):					
Wind + PV	2958	3119	3450	3185	2756
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	344	357	191	-	-
Liquefaction/Synthesis	310	320	80	-	-
ASU/DAC	73	77	498	-	-
Total System	5225	5357	5743	6468	3993

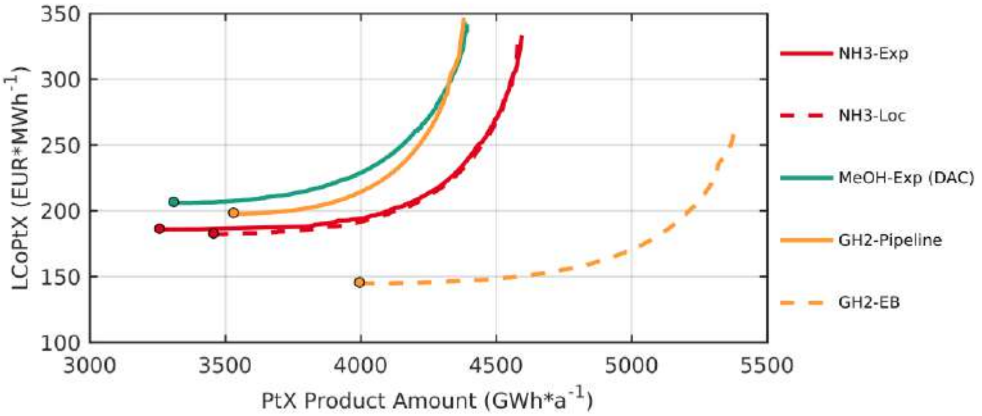

Figure 9-8: The Pareto fronts for the Algerian site "In Amenas" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.1.5 Techno-economic results – Oran (Region 4)

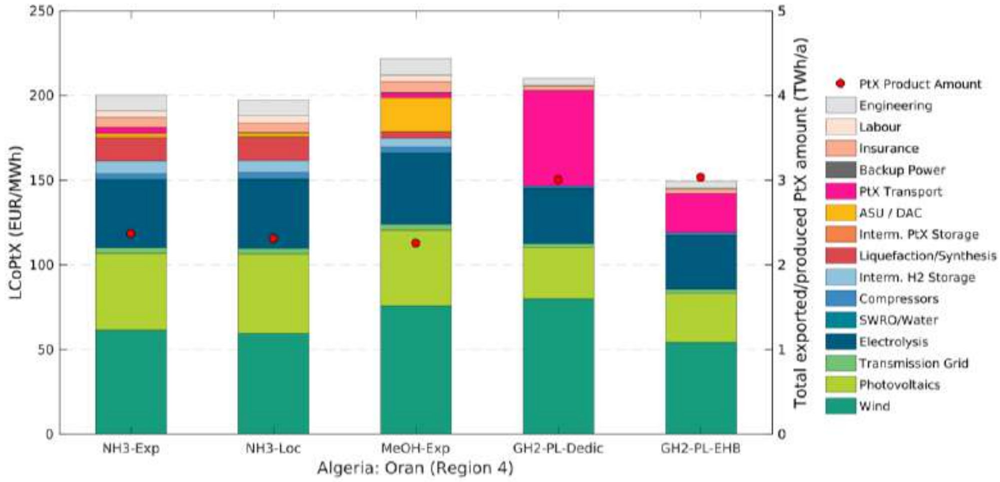

Figure 9-9: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Algerian site "Oran" (Region 4) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-4: Key performance indicators for the cost-optimal system configuration for the Algerian site "Oran" (Region 4) for NH_3, MeOH, and gaseous H_2.

Algeria **Oran**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	0.9	0.8	1.0	1.5	1.0
Wind: LcoE (EUR/MWh_{el})			59		
PV: Installed capacity (GW_{el})	1.6	1.6	1.5	1.4	1.3
PV: LcoE (EUR/MWh_{el})			35		
Intermediate H_2 storage: Volume (1000*m³)	99	94	69	-	-
Liquefaction/ synthesis: Capacity (tpd)	1356	1313	1389	463	463
Electrolysis: Full load hours (h/yr)	4240	4137	4150	5564	4716
Unused RE power (%)	14	14	11	14	9
Grid electricity used (%)	0.16	0.16	0.69	-	-
LcoPtX (EUR/MWh)	200	197	222	210	149
LcoPtX (EUR/ton)	1038	1023	1227	6995	4976
PtX Amount (GWh/yr)	2365	2307	2253	3000	3032
Total electr. Demand (GWh_{el}/yr)	4590	4479	5028	5549	4678
Selected investment cost (million EUR):					
Wind + PV	2305	2244	2456	2943	2273
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	208	197	145	-	-
Liquefaction/Synthesis	257	252	66	-	-
ASU/DAC	54	52	362	-	-
Total System	4105	3954	4282	5758	3320

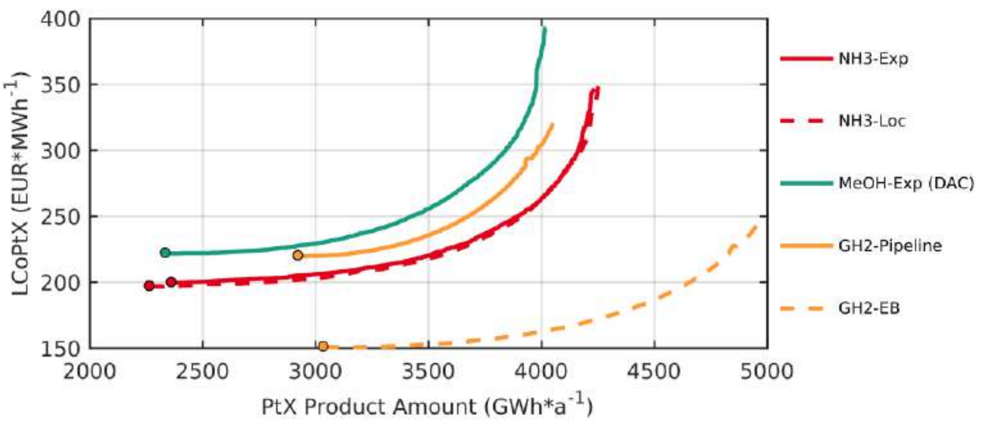

Figure 9-10: The Pareto fronts for the Algerian site "Oran" (region 4) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.2 Australia

9.2.1 Renewable potential analysis

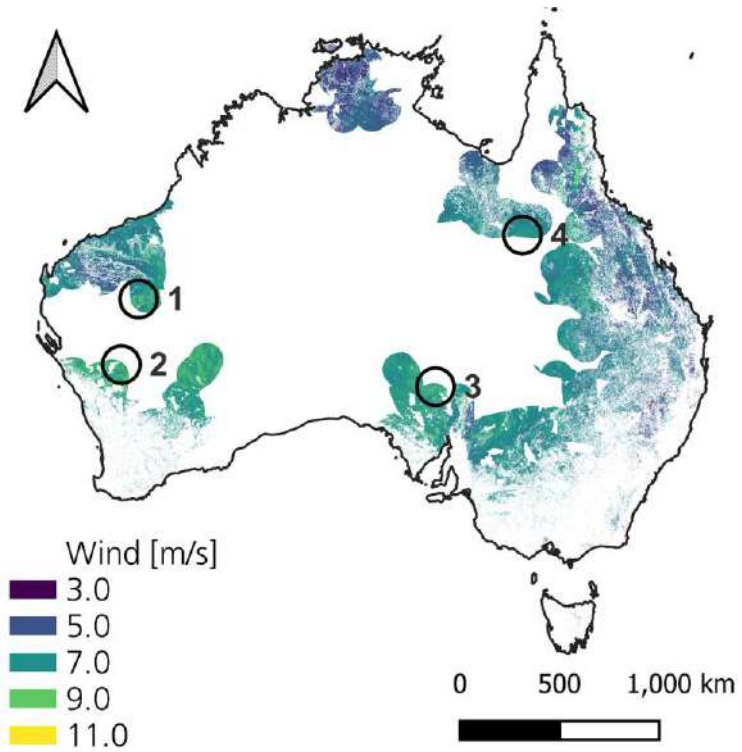

Figure 9-11: Selected regions and wind potential in Australia.

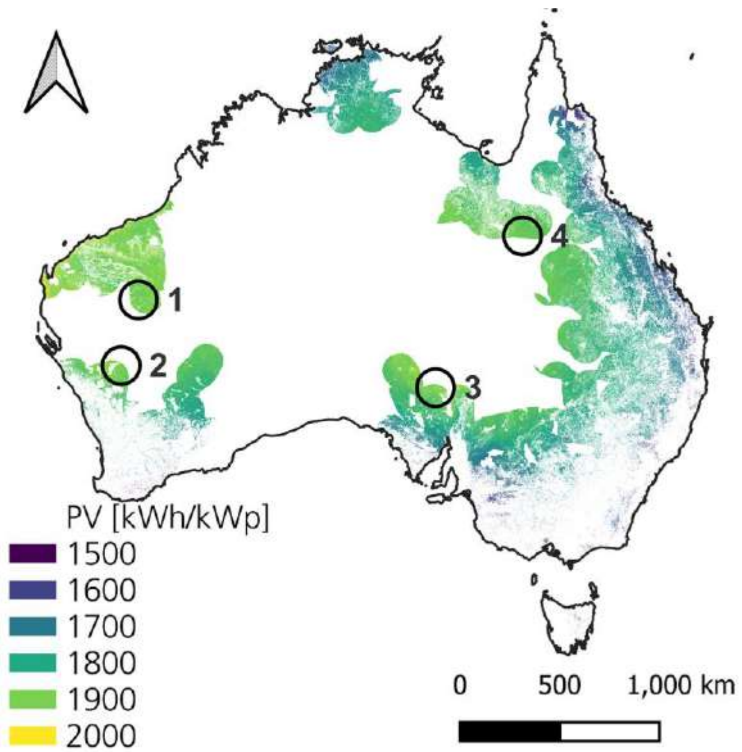

Figure 9-12: Selected regions and PV potential in Australia.

9.2.2 Techno-economic results – Capricorn (Region 1)

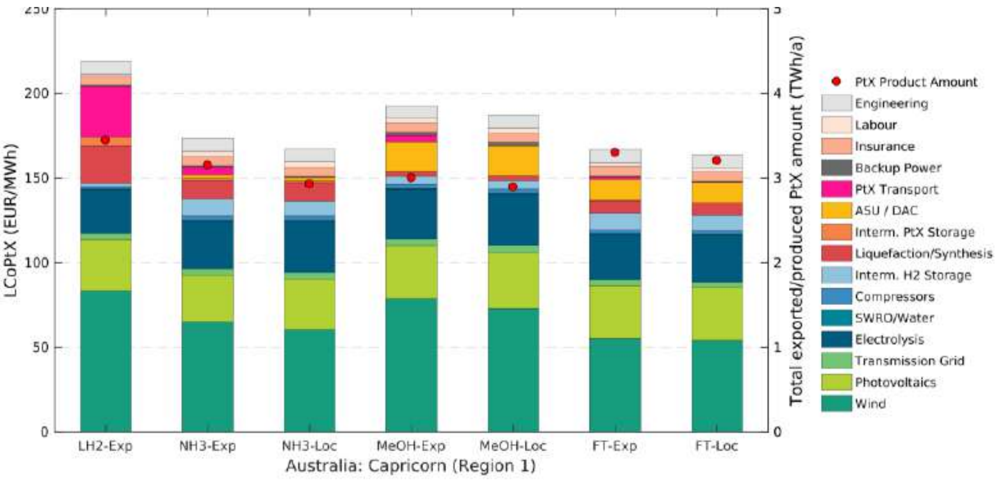

Figure 9-13: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Australian site "Capricorn" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-5: Key performance indicators for the cost-optimal system configuration for the Australian site Capricorn (Region 1) for LH_2, NH_3, and MeOH.

Australia **Capricorn**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	2.0	1.4	1.2	1.6	1.5
Wind: LcoE (EUR/MWh_{el})			48		
PV: Installed capacity (GW_{el})	1.9	1.6	1.6	1.7	1.7
PV: LcoE (EUR/MWh_{el})			29		
Intermediate H_2 storage: Volume (1000*m³)	38	200	164	89	91
Liquefaction/ synthesis: Capacity (tpd)	423	1826	1691	1719	1677
Electrolysis: Full load hours (h/yr)	6402	5654	5247	5555	5323
Unused RE power (%)	18	11	10	13	11
Grid electricity used (%)	0.20	0.17	0.18	0.49	0.52
LcoPtX (EUR/MWh)	219	173	167	193	187
LcoPtX (EUR/ton)	7280	898	866	1066	1034
PtX Amount (GWh/yr)	3444	3149	2926	2999	2890
Total electr. Demand (GWh_{el}/yr)	7314	6107	5651	6720	6429
Selected investment cost (million EUR):					
Wind + PV	3740	2805	2554	3158	2946
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	80	419	345	187	191
Liquefaction/Synthesis	683	307	293	75	74
ASU/DAC	-	72	67	448	437
Total System	6930	5119	4593	5288	4961

Table 9-6: Key performance indicators for the cost-optimal system configuration for the Australian site Capricorn (Region 1) for jet fuel and FT-mix.

Australia **Capricorn**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.3	1.3	1.3	1.2
Wind: LcoE (EUR/MWh_{el})		48		
PV: Installed capacity (GW_{el})	1.7	1.9	1.9	1.8
PV: LcoE (EUR/MWh_{el})		29		
Intermediate H_2 storage: Volume (1000*m³)	211	193	215	190
Liquefaction/ synthesis: Capacity (tpd)	291	292	776	751
Electrolysis: Full load hours (h/yr)	5396	5402	5439	5260
Unused RE power (%)	13	15	15	14
Grid electricity used (%)	0.17	0.17	0.18	0.18
LcoPtX (EUR/MWh)	299	295	167	164
LcoPtX (EUR/ton)	3675	3625	2040	2000
PtX Amount (GWh/yr)	1251	1252	3297	3203
Total electr. Demand (GWh_{el}/yr)	5814	5824	5865	5666
Selected investment cost (million EUR):				
Wind + PV	2715	2762	2775	2655
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	442	406	451	398
Liquefaction/Synthesis	211	211	212	208
ASU/DAC	345	346	350	338
Total System	5100	5067	5195	4938

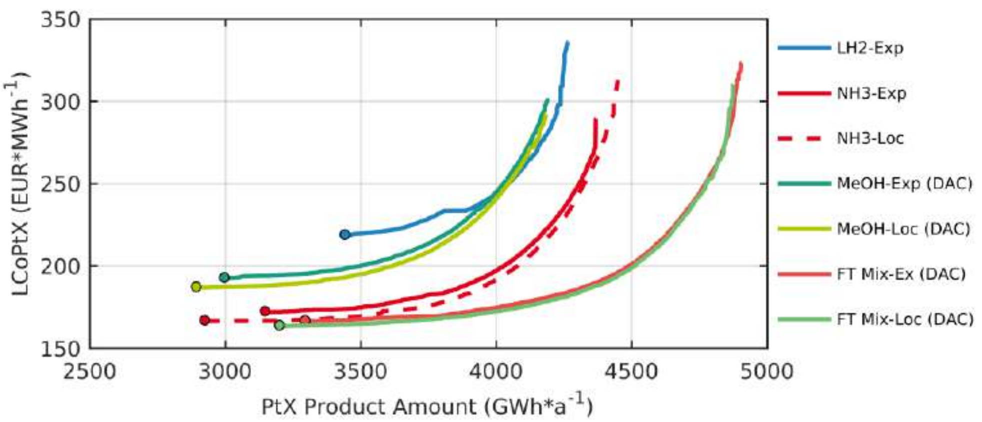

Figure 9-14: The Pareto fronts for the Australian site "Capricorn" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.2.3 Techno-economic results – Dagger Hills (Region 2)

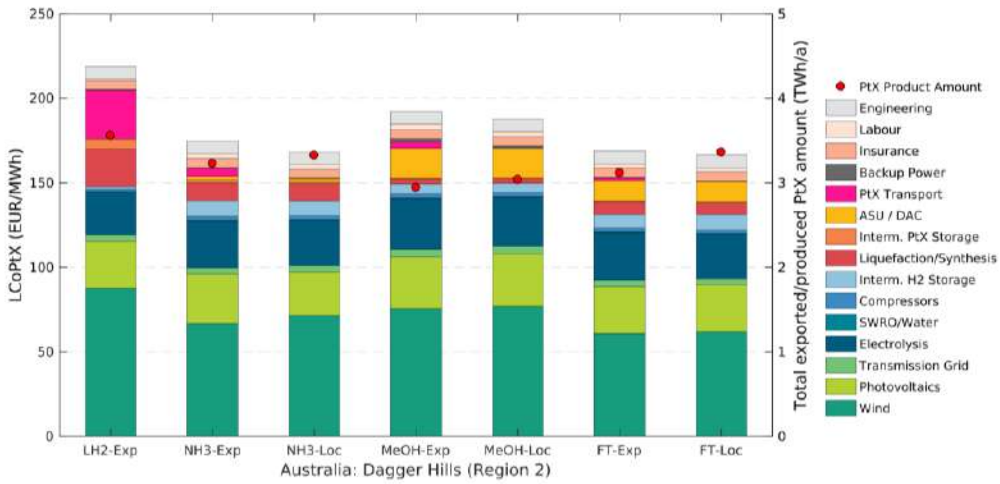

Figure 9-15: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Australian site "Dagger Hills" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-7: Key performance indicators for the cost-optimal system configuration for the Australian region Dagger Hills (Region 2) for LH_2, NH_3, and MeOH.

Australia **Dagger Hills**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	2.1	1.5	1.6	1.5	1.6
Wind: LcoE (EUR/MWh_{el})			46		
PV: Installed capacity (GW_{el})	1.8	1.7	1.6	1.7	1.7
PV: LcoE (EUR/MWh_{el})			30		
Intermediate H_2 storage: Volume (1000*m³)	34	187	181	110	106
Liquefaction/ synthesis: Capacity (tpd)	444	1853	1899	1710	1755
Electrolysis: Full load hours (h/yr)	6604	5799	5960	5436	5590
Unused RE power (%)	19	14	14	11	13
Grid electricity used (%)	0.12	0.13	0.13	0.44	0.42
LcoPtX (EUR/MWh)	219	175	168	192	188
LcoPtX (EUR/ton)	7288	905	870	1062	1037
PtX Amount (GWh/yr)	3555	3224	3320	2944	3037
Total electr. Demand (GWh_{el}/yr)	7546	6274	6456	6563	6760
Selected investment cost (million EUR):					
Wind + PV	3828	2925	3024	2945	3094
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	70	392	381	232	222
Liquefaction/Synthesis	709	310	314	75	76
ASU/DAC	-	73	75	446	458
Total System	7089	5243	5167	5151	5193

Table 9-8: Key performance indicators for the cost-optimal system configuration for the Australian region Dagger Hills (Region 2) for jet fuel and FT-mix.

Australia **Dagger Hills**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.7	1.6	1.3	1.4
Wind: LcoE (EUR/MWh_{el})	46			
PV: Installed capacity (GW_{el})	1.6	1.7	1.6	1.7
PV: LcoE (EUR/MWh_{el})	30			
Intermediate H_2 storage: Volume (1000*m³)	241	235	165	202
Liquefaction/ synthesis: Capacity (tpd)	324	321	726	785
Electrolysis: Full load hours (h/yr)	6020	5961	5126	5523
Unused RE power (%)	17	17	15	16
Grid electricity used (%)	0.12	0.12	0.13	0.13
LcoPtX (EUR/MWh)	311	304	169	166
LcoPtX (EUR/ton)	3824	3736	2064	2034
PtX Amount (GWh/yr)	1395	1379	3115	3358
Total electr. Demand (GWh_{el}/yr)	6523	6456	5519	5964
Selected investment cost (million EUR):				
Wind + PV	3191	3149	2611	2854
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	505	493	346	424
Liquefaction/Synthesis	224	223	204	213
ASU/DAC	384	380	327	354
Total System	5767	5633	4886	5213

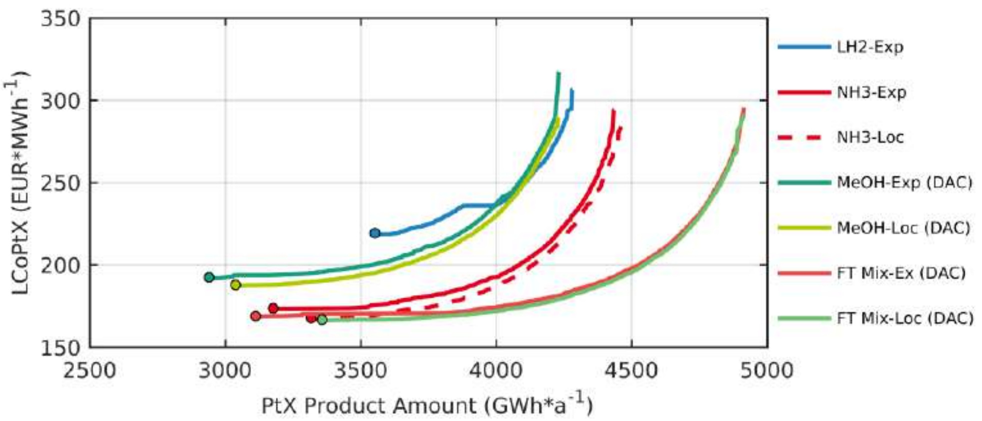

Figure 9-16: The Pareto fronts for the Australian site "Dagger Hills" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.2.4 Techno-economic results – South Australia (Region 3)

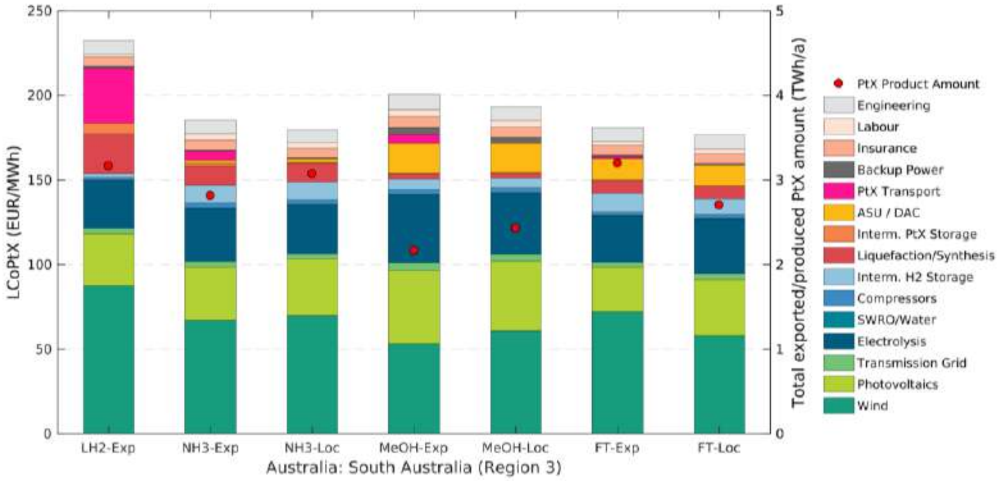

Figure 9-17: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Australian site "South Australia" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

9-9: Key performance indicators for the cost-optimal system configuration for the Australian region South Australia (Region 3) for LH_2, NH_3, and MeOH.

Australia **South Australia**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	2.0	1.3	1.5	0.8	1.0
Wind: LcoE (EUR/MWh_{el})			50		
PV: Installed capacity (GW_{el})	1.8	1.6	1.9	1.7	1.8
PV: LcoE (EUR/MWh_{el})			29		
Intermediate H_2 storage: Volume (1000*m³)	48	191	209	84	93
Liquefaction/ synthesis: Capacity (tpd)	402	1575	1726	1245	1391
Electrolysis: Full load hours (h/yr)	5973	5043	5523	3987	4472
Unused RE power (%)	19	16	19	9	12
Grid electricity used (%)	0.32	0.25	0.24	1.04	0.93
LcoPtX (EUR/MWh)	232	185	180	200	193
LcoPtX (EUR/ton)	7734	960	930	1109	1070
PtX Amount (GWh/yr)	3161	2813	3070	2164	2428
Total electr. Demand (GWh_{el}/yr)	6833	5457	5994	4840	5423
Selected investment cost (million EUR):					
Wind + PV	3607	2703	3100	2085	2456
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	101	401	438	177	195
Liquefaction/Synthesis	659	281	297	62	66
ASU/DAC	-	62	68	325	363
Total System	6789	4922	5236	4003	4343

Table 9-10: Key performance indicators for the cost-optimal system configuration for the Australian region South Australia (Region 3) for jet fuel and FT-mix.

Australia **South Australia**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.5	1.6	1.6	1.1
Wind: LcoE (EUR/MWh_{el})	50			
PV: Installed capacity (GW_{el})	1.8	1.9	1.5	1.6
PV: LcoE (EUR/MWh_{el})	29			
Intermediate H_2 storage: Volume (1000*m³)	197	257	227	162
Liquefaction/ synthesis: Capacity (tpd)	278	292	740	624
Electrolysis: Full load hours (h/yr)	5205	5446	5252	4444
Unused RE power (%)	22	21	20	19
Grid electricity used (%)	0.25	0.24	0.24	0.28
LcoPtX (EUR/MWh)	334	333	181	177
LcoPtX (EUR/ton)	4095	4085	2212	2160
PtX Amount (GWh/yr)	1207	1263	3194	2702
Total electr. Demand (GWh_{el}/yr)	5641	5907	5690	4793
Selected investment cost (million EUR):				
Wind + PV	3036	3160	3036	2423
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	413	540	476	340
Liquefaction/Synthesis	205	211	206	186
ASU/DAC	330	346	333	281
Total System	5337	5602	5454	4515

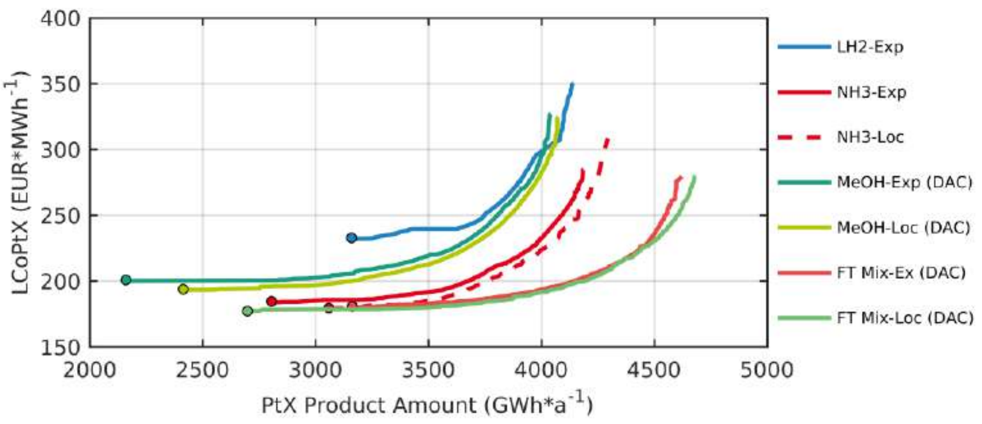

Figure 9-18: The Pareto fronts for the Australian site "South Australia" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.2.5 Techno-economic results – Queensland (Region 4)

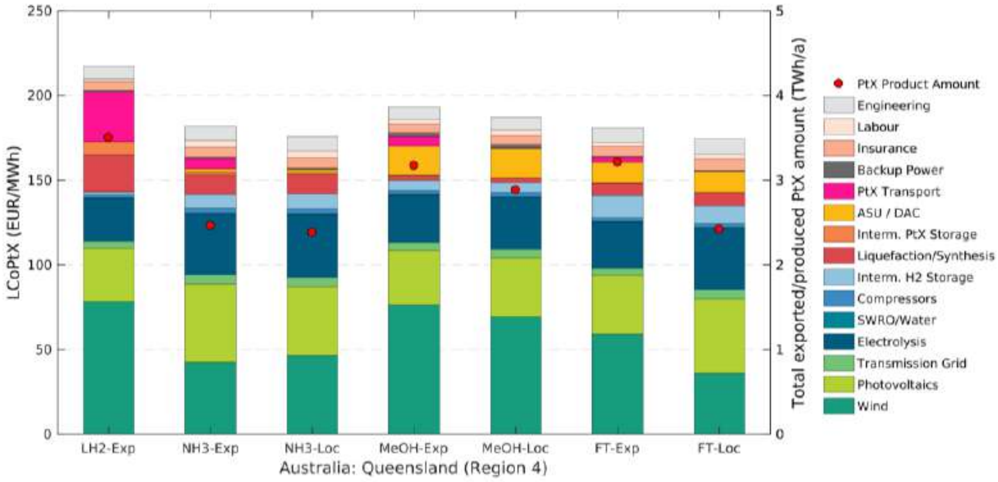

Figure 9-19: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Australian site “Queensland” (Region 4) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-11: Key performance indicators for the cost-optimal system configuration for the Australian region Queensland (Region 4) for LH_2, NH_3, and MeOH.

Australia **Queensland**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.9	0.7	0.8	1.7	1.4
Wind: LcoE (EUR/MWh_{el})			48		
PV: Installed capacity (GW_{el})	2.0	2.1	1.8	1.9	1.8
PV: LcoE (EUR/MWh_{el})			29		
Intermediate H_2 storage: Volume (1000*m³)	38	126	132	122	105
Liquefaction/ synthesis: Capacity (tpd)	429	1372	1317	1798	1635
Electrolysis: Full load hours (h/yr)	6486	4413	4270	5835	5310
Unused RE power (%)	15	15	12	11	10
Grid electricity used (%)	0.20	0.24	0.23	0.54	0.58
LcoPtX (EUR/MWh)	217	182	176	193	187
LcoPtX (EUR/ton)	7230	942	911	1069	1035
PtX Amount (GWh/yr)	3499	2459	2381	3169	2884
Total electr. Demand (GWh_{el}/yr)	7405	4766	4595	7065	6406
Selected investment cost (million EUR):					
Wind + PV	3683	2192	2060	3308	2910
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	81	264	277	257	221
Liquefaction/Synthesis	690	259	252	77	73
ASU/DAC	-	54	52	469	426
Total System	7036	4255	3977	5642	4987

Table 9-12: Key performance indicators for the cost-optimal system configuration for the Australian region Queensland (Region 4) for jet fuel and FT-mix.

Australia **Queensland**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.8	0.8	1.3	0.6
Wind: LcoE (EUR/MWh_{el})	48			
PV: Installed capacity (GW_{el})	1.7	1.9	2.0	1.9
PV: LcoE (EUR/MWh_{el})	29			
Intermediate H_2 storage: Volume (1000*m³)	216	194	274	159
Liquefaction/ synthesis: Capacity (tpd)	223	233	743	559
Electrolysis: Full load hours (h/yr)	4177	4367	5265	3973
Unused RE power (%)	12	16	20	15
Grid electricity used (%)	0.23	0.22	0.17	0.26
LcoPtX (EUR/MWh)	331	323	181	174
LcoPtX (EUR/ton)	4070	3971	2211	2132
PtX Amount (GWh/yr)	970	1014	3206	2419
Total electr. Demand (GWh_{el}/yr)	4488	4695	5682	4293
Selected investment cost (million EUR):				
Wind + PV	2027	2218	2928	1953
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	453	408	576	335
Liquefaction/Synthesis	179	184	207	174
ASU/DAC	265	277	335	252
Total System	4329	4444	5541	4048

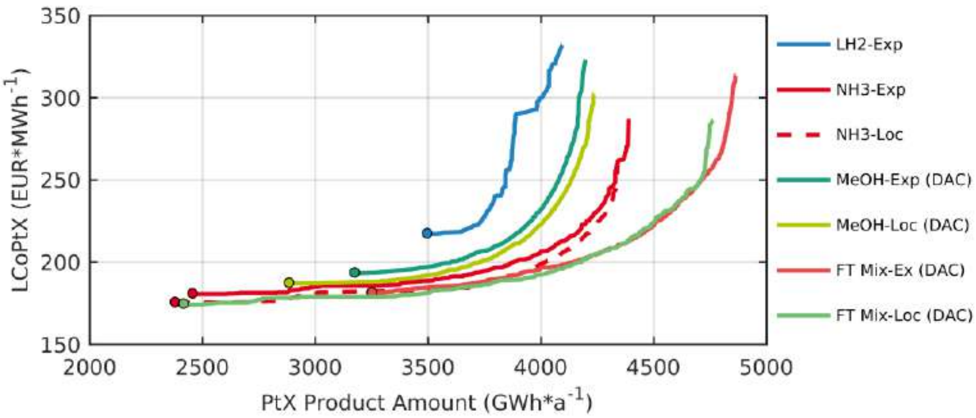

Figure 9-20: The Pareto fronts for the Australian site "Queensland" (region 4) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.3 Brazil

9.3.1 Renewable potential analysis

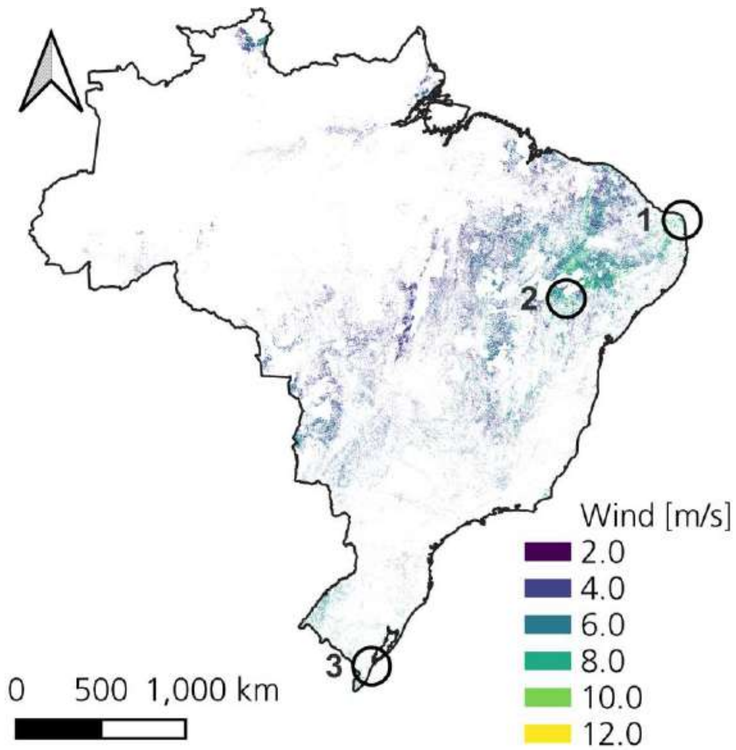

Figure 9-21: Selected regions and wind potential in Brazil.

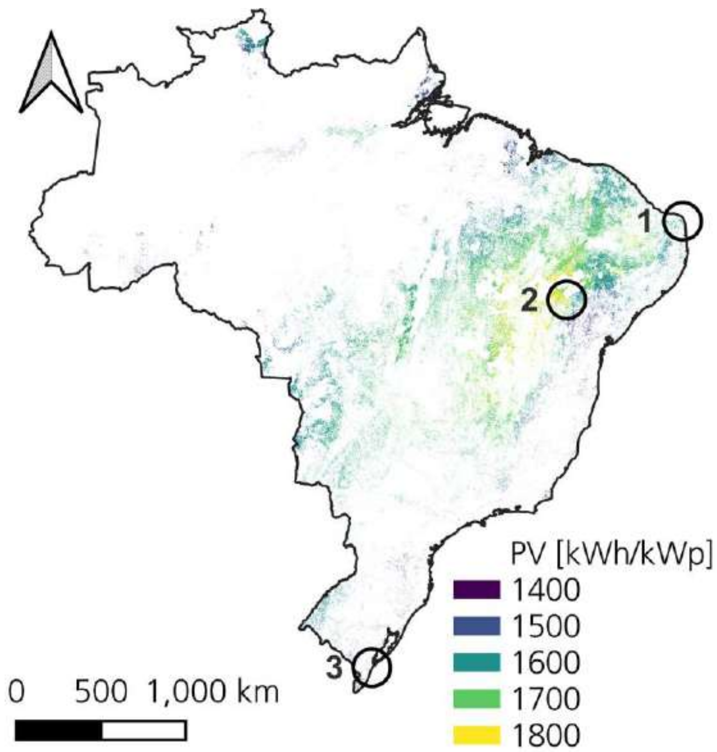

Figure 9-22: Selected regions and PV potential in Brazil.

9.3.2 Techno-economic results – Rio Grande do Norte (Region 1)

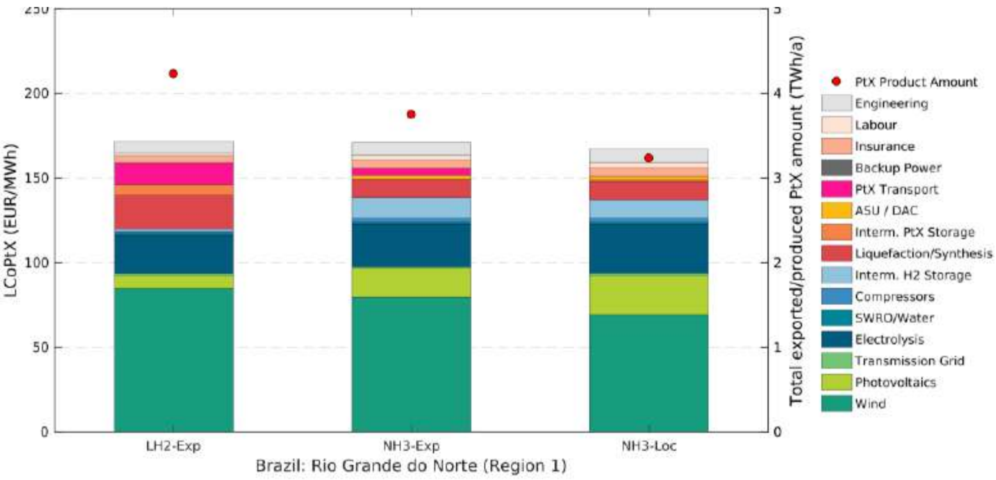

Figure 9-23: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Brazilian site "Rio Grande do Norte" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-13: Key performance indicators for the cost-optimal system configuration for the Brazilian region Rio Grande do Norte (Region 1) for LH_2 and NH_3.

Brazil **Rio Grande do Norte**	**LH_2 Export**	**NH_3 Export**	**NH_3 Local**
Technoeconomic KPI:			
Wind: Installed capacity (GW_{el})	2.1	1.8	1.3
Wind: LcoE (EUR/MWh_{el})		41	
PV: Installed capacity (GW_{el})	0.6	1.2	1.4
PV: LcoE (EUR/MWh_{el})		29	
Intermediate H_2 storage: Volume (1000*m³)	42	272	201
Liquefaction/ synthesis: Capacity (tpd)	452	2119	1813
Electrolysis: Full load hours (h/yr)	7187	6716	5793
Unused RE power (%)	16	22	21
Grid electricity used (%)	-	-	-
LcoPtX (EUR/MWh)	171	171	167
LcoPtX (EUR/ton)	5707	886	866
PtX Amount (GWh/yr)	4227	3747	3230
Total electr. Demand (GWh_{el}/yr)	8158	7279	6235
Selected investment cost (million EUR):			
Wind + PV	3097	2949	2493
PEM Electrolysis	750	750	750
Intermediate H_2 storage	88	572	423
Liquefaction/Synthesis	718	336	306
ASU/DAC	-	84	72
Total System	5862	5341	4540

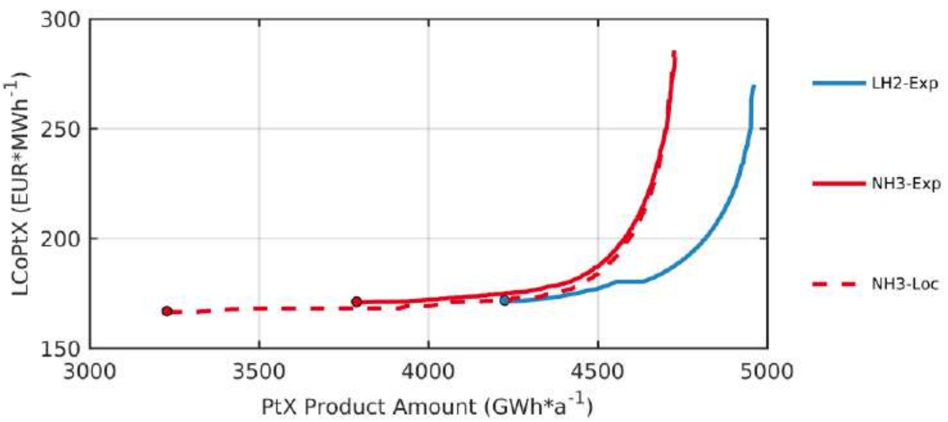

Figure 9-24: The Pareto fronts for the Brazilian site "Rio Grande do Norte" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.3.3 Techno-economic results – Bahia North – Irecê (Region 2)

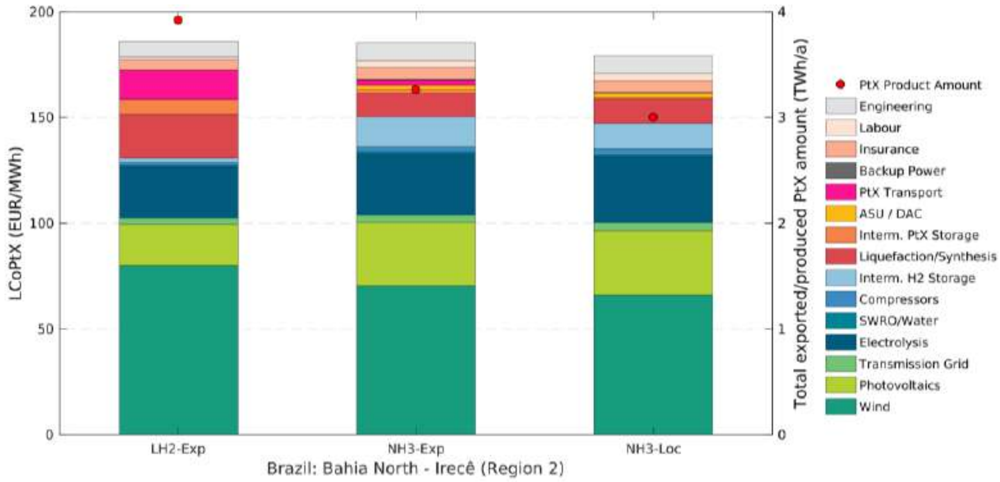

Figure 9-25: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Brazilian site "Bahia North – Irecê" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-14: Key performance indicators for the cost-optimal system configuration for the Brazilian region Bahia North – Irece (Region 2) for LH_2 and NH_3.

Brazil **Bahia North – Irece**	LH_2 Export	NH_3 Export	NH_3 Local
Technoeconomic KPI:			
Wind: Installed capacity (GW_{el})	2.0	1.4	1.2
Wind: LcoE (EUR/MWh_{el})		46	
PV: Installed capacity (GW_{el})	1.4	1.8	1.7
PV: LcoE (EUR/MWh_{el})		28	
Intermediate H_2 storage: Volume (1000*m³)	46	272	215
Liquefaction/ synthesis: Capacity (tpd)	429	1858	1691
Electrolysis: Full load hours (h/yr)	6698	5851	5384
Unused RE power (%)	15	20	18
Grid electricity used (%)	0.08	0.11	0.10
LcoPtX (EUR/MWh)	186	185	179
LcoPtX (EUR/ton)	6192	961	929
PtX Amount (GWh/yr)	3917	3258	2997
Total electr. Demand (GWh_{el}/yr)	7610	6317	5792
Selected investment cost (million EUR):			
Wind + PV	3354	2891	2567
PEM Electrolysis	750	750	750
Intermediate H_2 storage	97	571	451
Liquefaction/Synthesis	691	310	293
ASU/DAC	-	73	67
Total System	6208	5312	4710

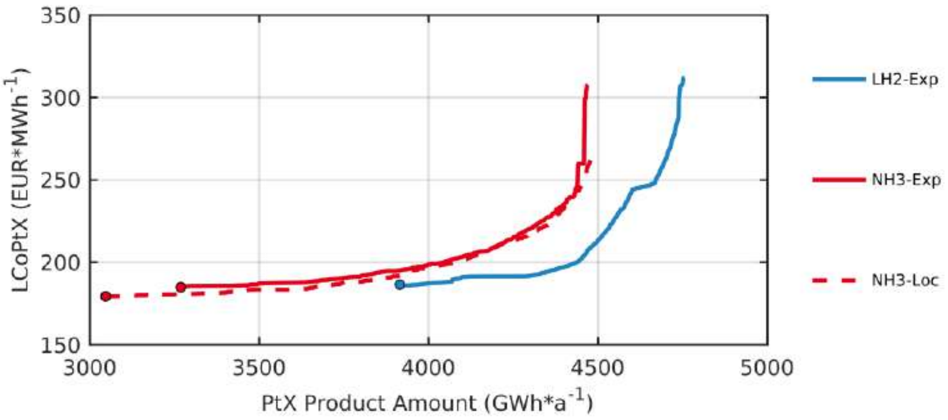

Figure 9-26: The Pareto fronts for the Brazilian site "Bahia North – Irecê" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.3.4 Techno-economic results – Rio Grande do Sul (Region 3)

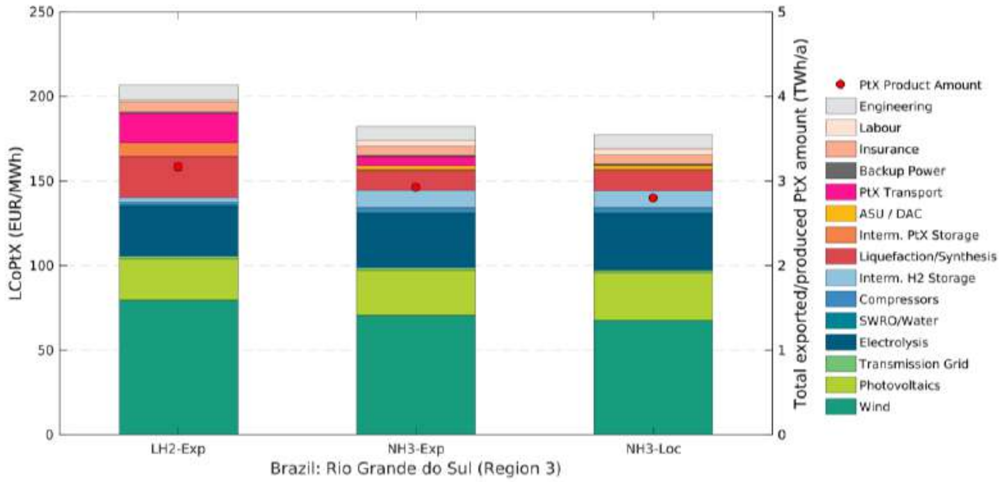

Figure 9-27: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Brazilian site "Rio Grande do Sul" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-15: Key performance indicators for the cost-optimal system configuration for the Brazilian region Rio Grande do Sul (Region 3) for LH_2 and NH_3.

Brazil **Rio Grande do Sul**	**LH_2 Export**	**NH_3 Export**	**NH_3 Local**
Technoeconomic KPI:			
Wind: Installed capacity (GW_{el})	1.6	1.3	1.2
Wind: LcoE (EUR/MWh_{el})		48	
PV: Installed capacity (GW_{el})	1.5	1.5	1.5
PV: LcoE (EUR/MWh_{el})		33	
Intermediate H_2 storage: Volume (1000*m³)	56	177	164
Liquefaction/ synthesis: Capacity (tpd)	395	1700	1614
Electrolysis: Full load hours (h/yr)	5500	5237	5014
Unused RE power (%)	16	14	13
Grid electricity used (%)	0.35	0.26	0.27
LcoPtX (EUR/MWh)	207	182	177
LcoPtX (EUR/ton)	6887	943	919
PtX Amount (GWh/yr)	3161	2919	2795
Total electr. Demand (GWh_{el}/yr)	6297	5674	5424
Selected investment cost (million EUR):			
Wind + PV	2915	2537	2402
PEM Electrolysis	750	750	750
Intermediate H_2 storage	117	372	344
Liquefaction/Synthesis	650	294	285
ASU/DAC	-	67	64
Total System	5622	4610	4311

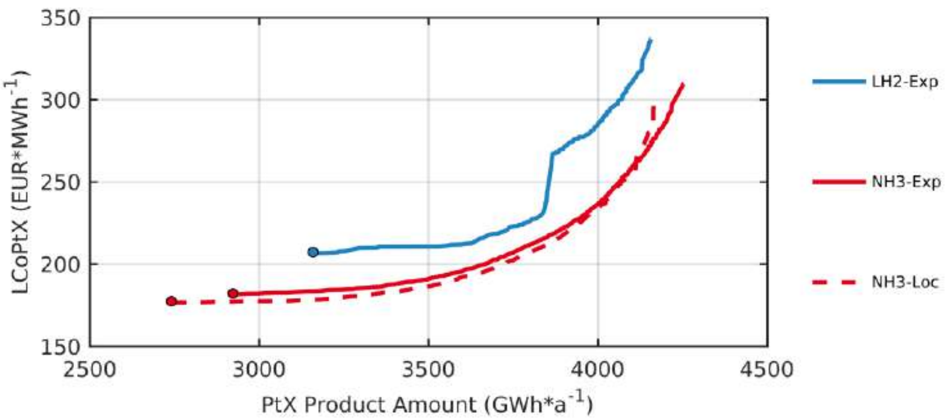

Figure 9-28: The Pareto fronts for the Brazilian site "Rio Grande do Sul" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.4 Colombia

9.4.1 Renewable potential analysis

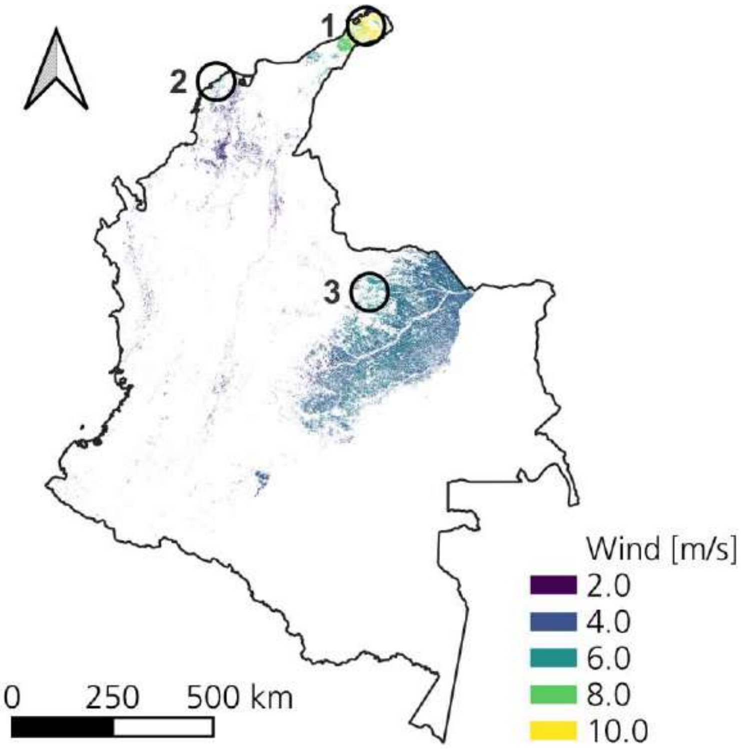

Figure 9-29: Selected regions and wind potential in Colombia.

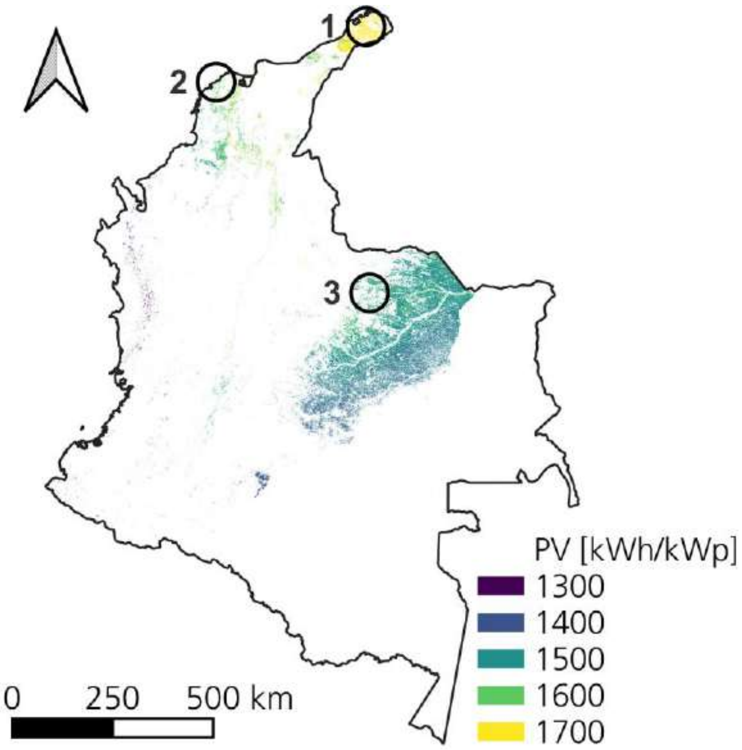

Figure 9-30: Selected regions and PV potential in Colombia.

9.4.2 Techno-economic results – La Guajira (Region 1)

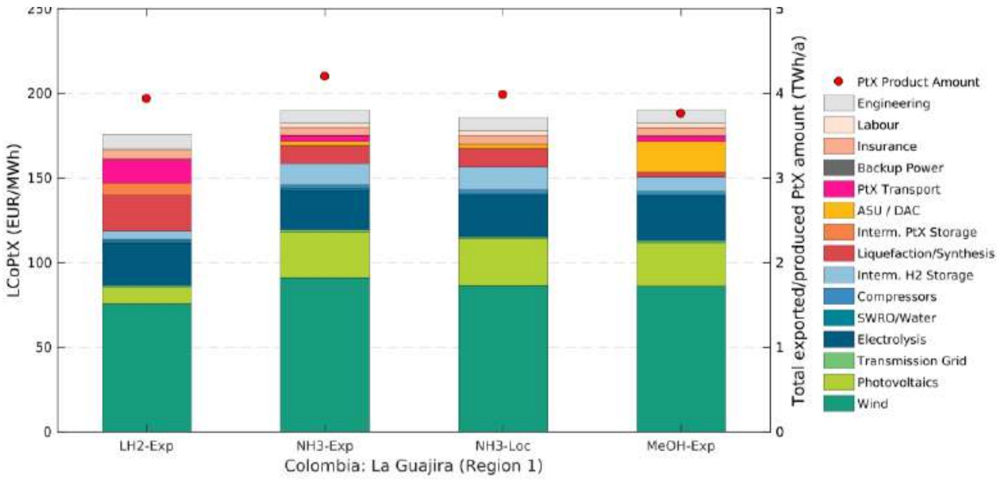

Figure 9-31: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Colombian site "La Guajira" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-16: Key performance indicators for the cost-optimal system configuration for the Colombian region La Guajira (Region 1) for LH_2, NH_3 and MeOH.

Colombia **La Guajira**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.3	1.7	1.5	1.5
Wind: LcoE (EUR/MWh_{el})			40	
PV: Installed capacity (GW_{el})	0.6	1.7	1.7	1.5
PV: LcoE (EUR/MWh_{el})			42	
Intermediate H_2 storage: Volume (1000*m³)	105	298	305	174
Liquefaction/ synthesis: Capacity (tpd)	431	2343	2219	2079
Electrolysis: Full load hours (h/yr)	6735	7528	7166	6929
Unused RE power (%)	7	31	29	17
Grid electricity used (%)	0.01	0.02	0.02	0.05
LcoPtX (EUR/MWh)	176	190	186	190
LcoPtX (EUR/ton)	5852	984	962	1052
PtX Amount (GWh/yr)	3935	4196	3982	3759
Total electr. Demand (GWh_{el}/yr)	7629	8217	7812	8378
Selected investment cost (million EUR):				
Wind + PV	2380	3705	3413	3137
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	220	625	640	365
Liquefaction/Synthesis	693	356	345	84
ASU/DAC	-	93	88	542
Total System	5280	6201	5796	5481

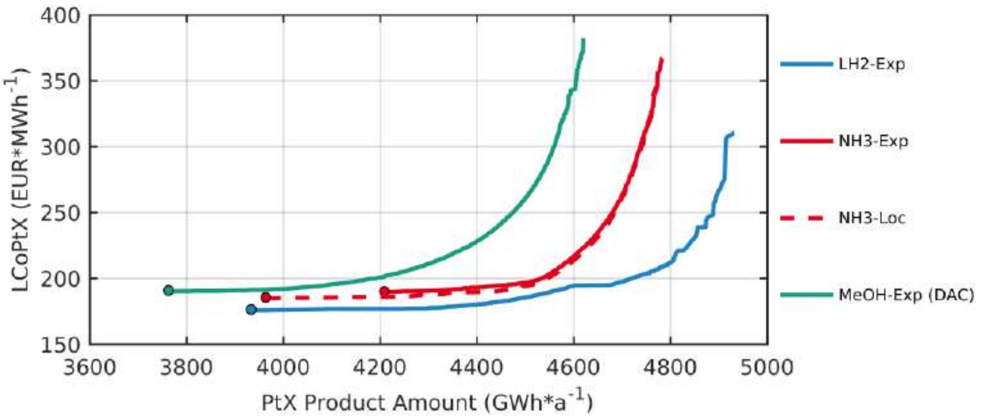

Figure 9-32: The Pareto fronts for the Colombian site "La Guajira" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.4.3 Techno-economic results – Juan de Acosta (Region 2)

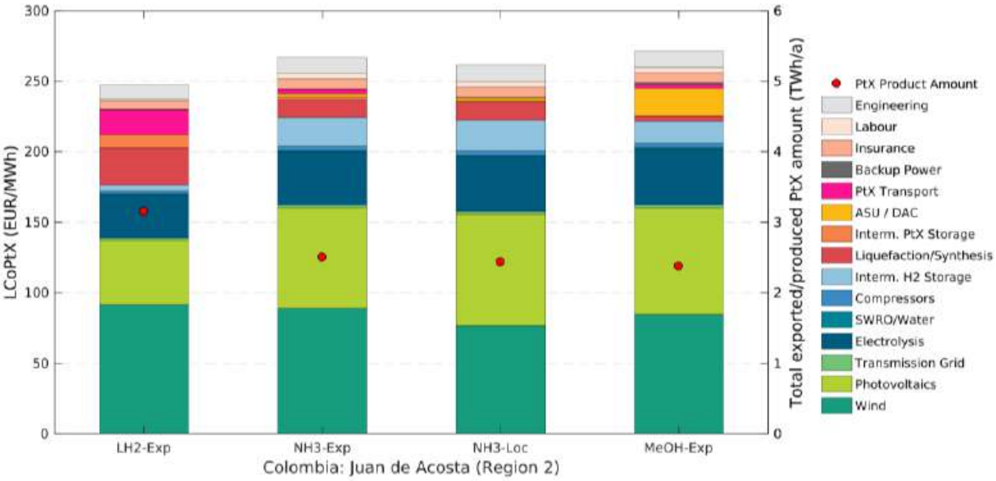

Figure 9-33: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Colombian site "Juan de Acosta" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-17: Key performance indicators for the cost-optimal system configuration for the Colombian region Juan de Acosta (Region 2) for LH_2, NH_3 and MeOH.

Colombia **Juan de Acosta**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.6	1.3	1.0	1.1
Wind: LcoE (EUR/MWh_{el})			62	
PV: Installed capacity (GW_{el})	2.2	2.7	2.9	2.7
PV: LcoE (EUR/MWh_{el})			49	
Intermediate H_2 storage: Volume (1000*m³)	80	283	295	208
Liquefaction/ synthesis: Capacity (tpd)	423	1414	1385	1423
Electrolysis: Full load hours (h/yr)	5519	4490	4371	4379
Unused RE power (%)	16	32	31	23
Grid electricity used (%)	0.11	0.11	0.13	0.42
LcoPtX (EUR/MWh)	247	267	262	271
LcoPtX (EUR/ton)	8238	1383	1355	1500
PtX Amount (GWh/yr)	3153	2500	2435	2374
Total electr. Demand (GWh_{el}/yr)	6302	4857	4722	5281
Selected investment cost (million EUR):				
Wind + PV	3865	3652	3487	3478
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	169	593	619	437
Liquefaction/Synthesis	683	263	260	67
ASU/DAC	0	56	55	371
Total System	6702	5911	5679	5629

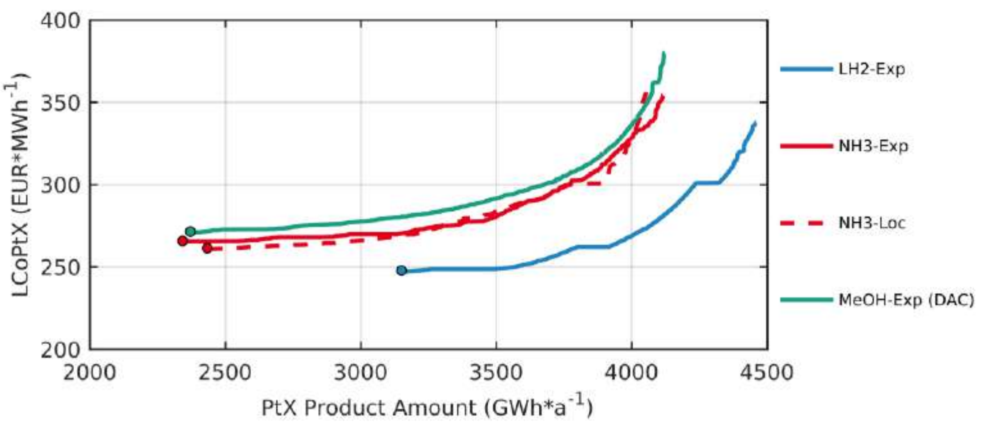

Figure 9-34: The Pareto fronts for the Colombian site "Juan de Acosta" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.4.4 Techno-economic results – Hato Corazol (Region 3)

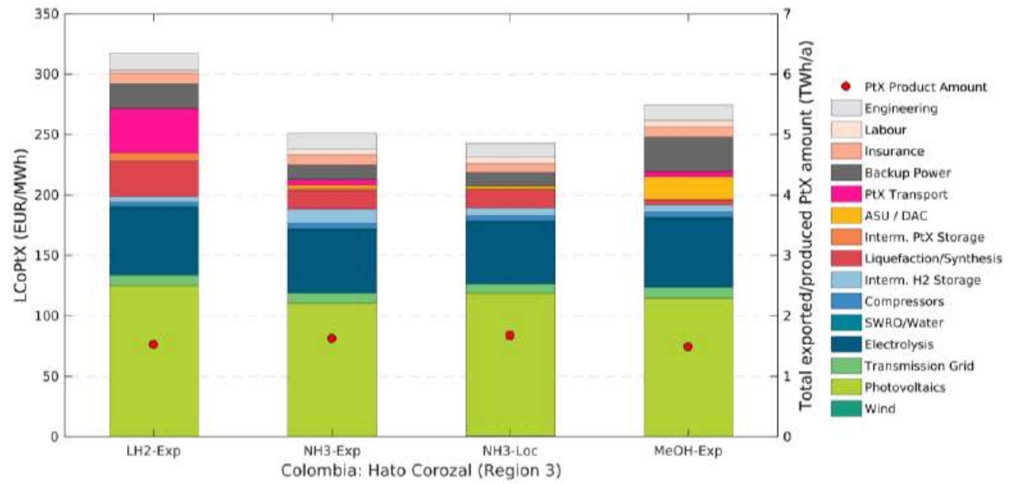

Figure 9-35: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Colombian site "Hato Corazol" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-18: Key performance indicators for the cost-optimal system configuration for the Colombian region Hato Corozal (Region 3) for LH_2, NH_3 and MeOH.

Colombia **Hato Corozal**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	-	-	-	-
Wind: LcoE (EUR/MWh_{el})	177			
PV: Installed capacity (GW_{el})	2.9	2.6	3.0	2.6
PV: LcoE (EUR/MWh_{el})	44			
Intermediate H_2 storage: Volume (1000*m³)	41	105	59	49
Liquefaction/ synthesis: Capacity (tpd)	184	979	950	860
Electrolysis: Full load hours (h/yr)	2905	2918	2993	2746
Unused RE power (%)	21	18	23	15
Grid electricity used (%)	7.08	4.56	4.44	9.54
LcoPtX (EUR/MWh)	318	251	243	274
LcoPtX (EUR/ton)	10577	1301	1259	1517
PtX Amount (GWh/yr)	1522	1623	1669	1488
Total electr. Demand (GWh_{el}/yr)	3604	3360	3446	3686
Selected investment cost (million EUR):				
Wind + PV	1891	1787	1971	1696
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	87	220	124	103
Liquefaction/Synthesis	368	211	207	49
ASU/DAC	-	39	38	224
Total System	4130	3591	3573	3349

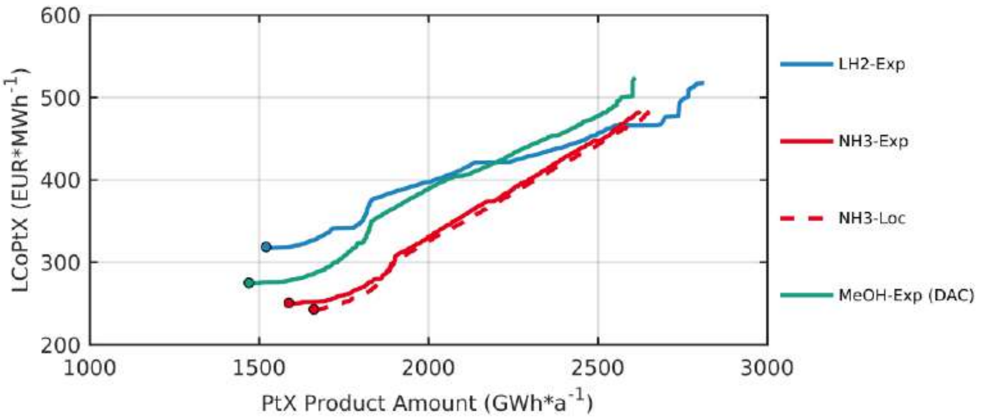

Figure 9-36: The Pareto fronts for the Colombian site "Hato Corazol" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.5 India

9.5.1 Renewable potential analysis

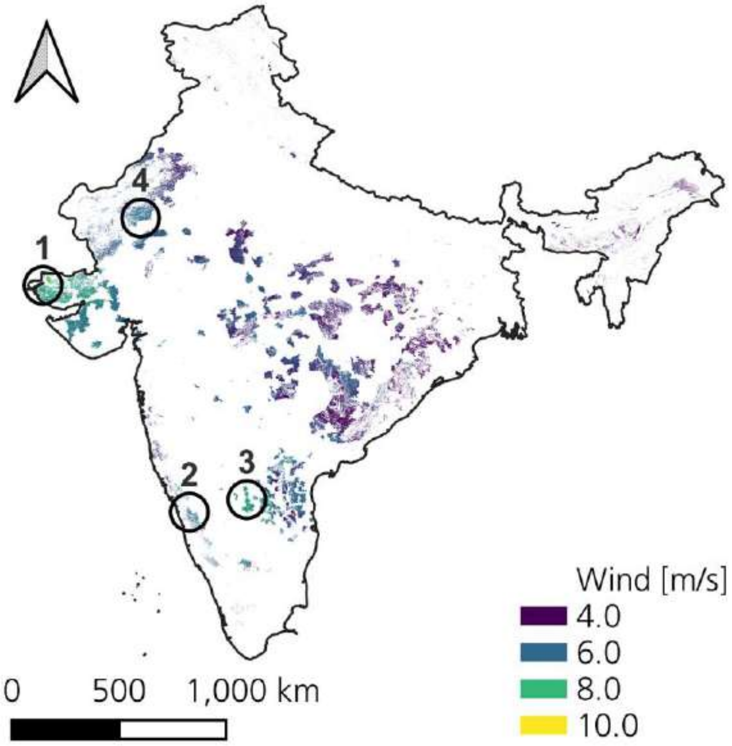

Figure 9-37: Selected regions and wind potential in India.

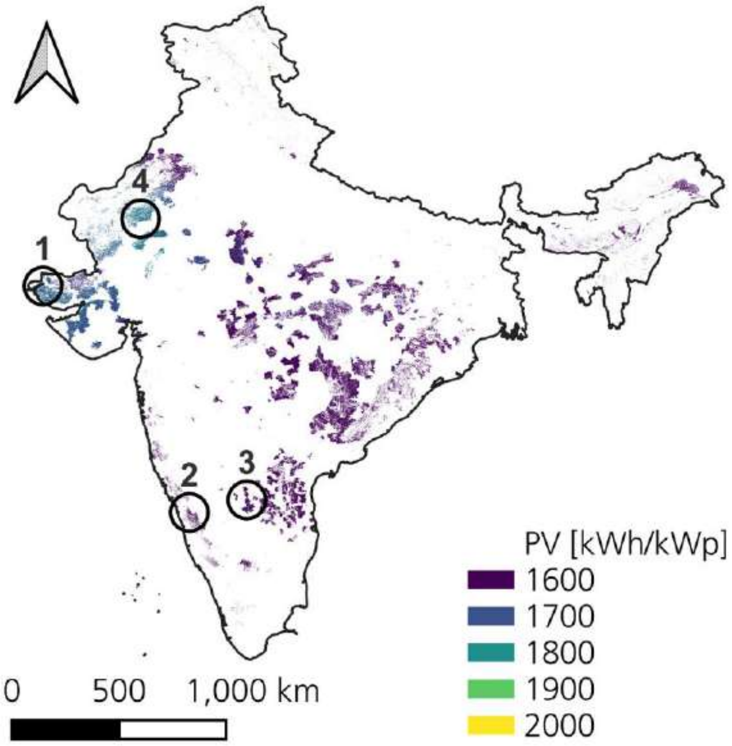

Figure 9-38: Selected regions and PV potential in India.

9.5.2 Techno-economic results – Prampar (Region 1)

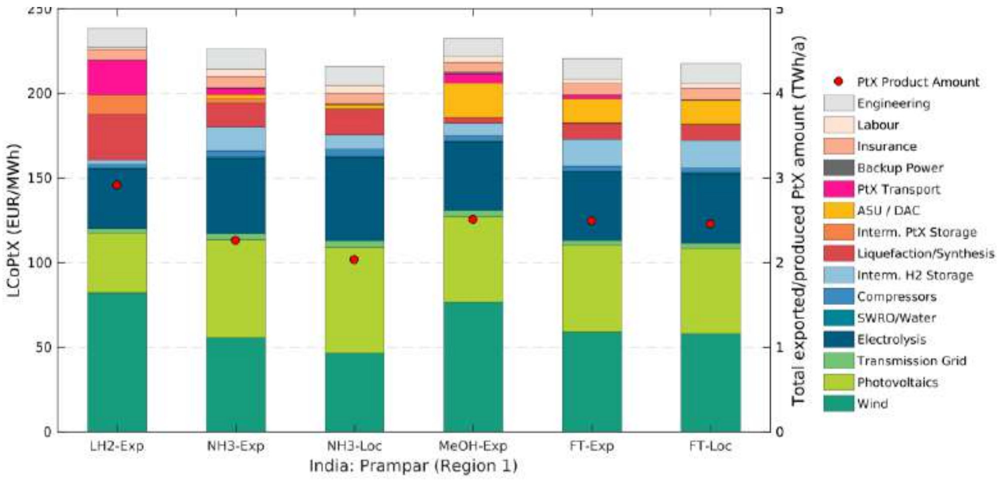

Figure 9-39: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Indian site "Prampar" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-19: Key performance indicators for the cost-optimal system configuration for the Indian region Prampar (Region 1) for LH_2, NH_3 and MeOH.

India **Prampar**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.6	0.8	0.6	1.3
Wind: LcoE (EUR/MWh_{el})	56			
PV: Installed capacity (GW_{el})	1.6	2.0	2.0	1.9
PV: LcoE (EUR/MWh_{el})	37			
Intermediate H_2 storage: Volume (1000*m³)	40	159	87	91
Liquefaction/ synthesis: Capacity (tpd)	360	1271	1138	1466
Electrolysis: Full load hours (h/yr)	5196	4049	3642	4609
Unused RE power (%)	13	21	20	16
Grid electricity used (%)	0.14	0.15	0.18	0.40
LcoPtX (EUR/MWh)	238	226	216	232
LcoPtX (EUR/ton)	7938	1171	1120	1285
PtX Amount (GWh/yr)	2910	2258	2031	2503
Total electr. Demand (GWh_{el}/yr)	5891	4379	3955	5559
Selected investment cost (million EUR):				
Wind + PV	2855	2209	1925	2703
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	85	334	182	192
Liquefaction/Synthesis	606	247	231	68
ASU/DAC	-	50	45	382
Total System	5560	4179	3577	4661

Table 9-20: Key performance indicators for the cost-optimal system configuration for the Indian region Prampar (Region 1) for jet fuels and FT-mix.

India **Prampar**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.1	-	1.0	0.9
Wind: LcoE (EUR/MWh_{el})	56			
PV: Installed capacity (GW_{el})	2.1	2.2	1.9	1.9
PV: LcoE (EUR/MWh_{el})	37			
Intermediate H_2 storage: Volume (1000*m³)	66	103	200	203
Liquefaction/ synthesis: Capacity (tpd)	154	153	581	574
Electrolysis: Full load hours (h/yr)	2877	2862	4087	4027
Unused RE power (%)	17	19	24	23
Grid electricity used (%)	1.34	3.21	0.14	0.14
LcoPtX (EUR/MWh)	415	423	221	218
LcoPtX (EUR/ton)	5092	5191	2699	2664
PtX Amount (GWh/yr)	663	665	2488	2452
Total electr. Demand (GWh_{el}/yr)	3218	3266	4405	4340
Selected investment cost (million EUR):				
Wind + PV	1367	1344	2343	2274
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	139	216	420	427
Liquefaction/Synthesis	144	143	178	177
ASU/DAC	183	181	262	258
Total System	3028	3056	4499	4381

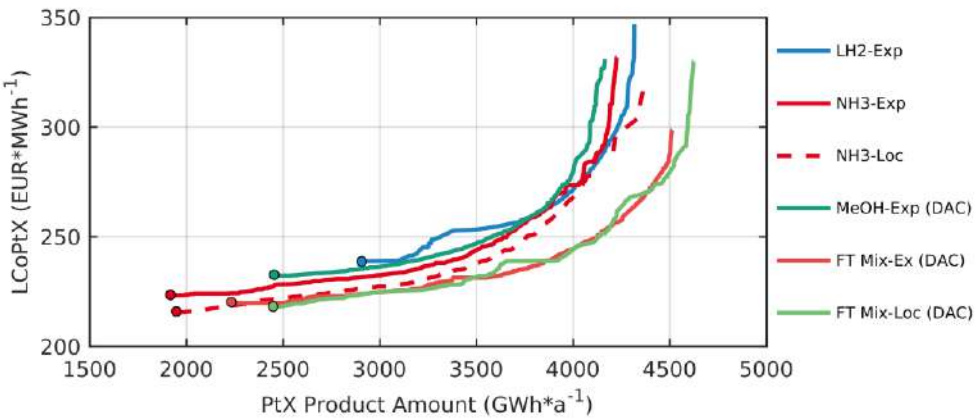

Figure 9-40: The Pareto fronts for the Indian site "Prampar" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.5.3 Techno-economic results – Siddapur (Region 2)

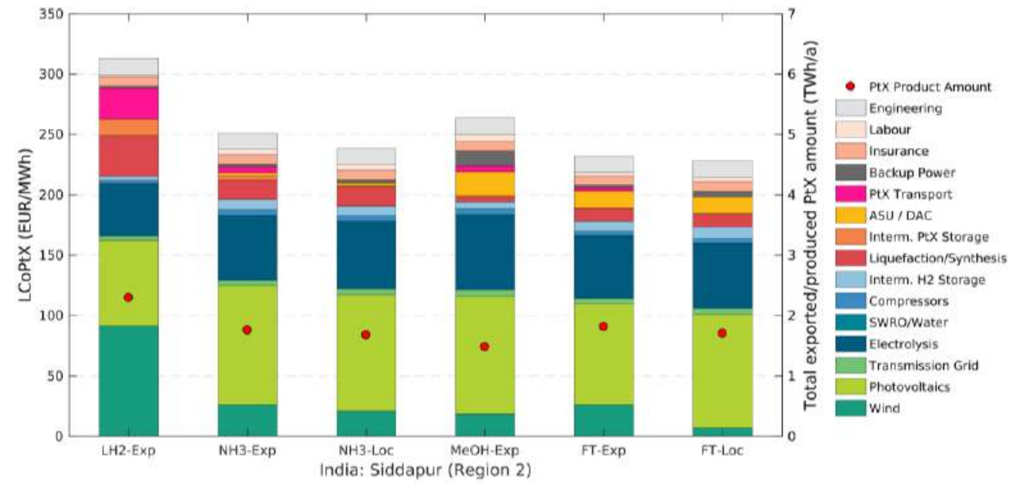

Figure 9-41: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Indian site "Siddapur" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-21: Key performance indicators for the cost-optimal system configuration for the Indian region Siddapur (Region 2) for LH_2, NH_3 and MeOH.

India **Siddapur**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.6	0.3	0.3	0.2
Wind: LcoE (EUR/MWh_{el})	84			
PV: Installed capacity (GW_{el})	2.5	2.6	2.5	2.2
PV: LcoE (EUR/MWh_{el})	41			
Intermediate H_2 storage: Volume (1000*m³)	40	77	67	42
Liquefaction/ synthesis: Capacity (tpd)	348	1045	955	847
Electrolysis: Full load hours (h/yr)	4150	3153	3002	2733
Unused RE power (%)	23	25	22	14
Grid electricity used (%)	0.79	1.13	1.37	5.31
LcoPtX (EUR/MWh)	313	251	238	264
LcoPtX (EUR/ton)	10420	1300	1235	1459
PtX Amount (GWh/yr)	2291	1757	1674	1482
Total electr. Demand (GWh_{el}/yr)	4830	3519	3360	3532
Selected investment cost (million EUR):				
Wind + PV	3357	2000	1794	1570
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	84	162	141	89
Liquefaction/Synthesis	591	220	208	49
ASU/DAC	-	41	38	221
Total System	6015	3715	3352	3138

Table 9-22: Key performance indicators for the cost-optimal system configuration for the Indian region Siddapur (Region 2) for jet fuel and FT-mix.

India **Siddapur**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.4	0.3	0.4	0.1
Wind: LcoE (EUR/MWh_{el})		84		
PV: Installed capacity (GW_{el})	2.6	2.2	2.3	2.4
PV: LcoE (EUR/MWh_{el})		41		
Intermediate H_2 storage: Volume (1000*m³)	78	89	76	84
Liquefaction/ synthesis: Capacity (tpd)	169	162	424	396
Electrolysis: Full load hours (h/yr)	3103	2955	2980	2801
Unused RE power (%)	24	18	20	22
Grid electricity used (%)	1.09	1.13	1.07	2.53
LcoPtX (EUR/MWh)	475	462	232	228
LcoPtX (EUR/ton)	5828	5668	2836	2789
PtX Amount (GWh/yr)	720	686	1811	1702
Total electr. Demand (GWh_{el}/yr)	3457	3289	3315	3175
Selected investment cost (million EUR):				
Wind + PV	1964	1745	1814	1577
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	163	186	160	177
Liquefaction/Synthesis	152	148	148	142
ASU/DAC	201	192	191	178
Total System	3694	3441	3528	3238

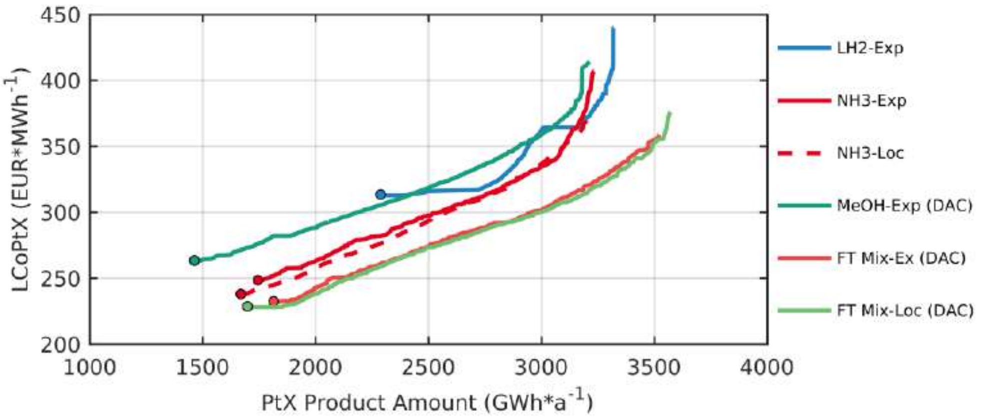

Figure 9-42: The Pareto fronts for the Indian site "Siddapur" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.5.4 Techno-economic results – Korrakodu (Region 3)

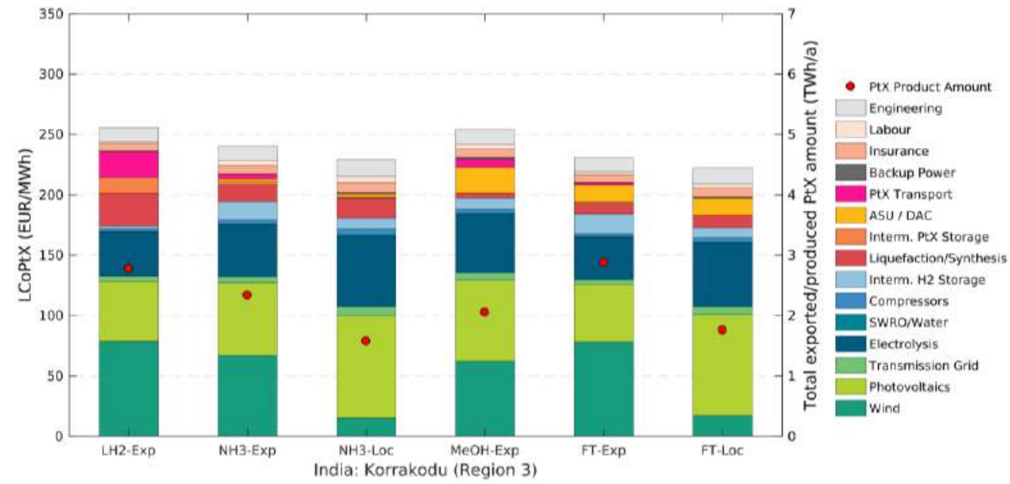

Figure 9-43: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Indian site "Korrakodu" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

able 9-23: Key performance indicators for the cost-optimal system configuration for the Indian region Korrakodu (Region 3) for LH_2, NH_3 and MeOH.

India **Korrakodu**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.5	1.0	0.2	0.9
Wind: LcoE (EUR/MWh_{el})	57			
PV: Installed capacity (GW_{el})	2.1	2.1	2.0	2.1
PV: LcoE (EUR/MWh_{el})	39			
Intermediate H_2 storage: Volume (1000*m³)	35	177	74	96
Liquefaction/ synthesis: Capacity (tpd)	342	1310	903	1252
Electrolysis: Full load hours (h/yr)	4905	4185	2826	3773
Unused RE power (%)	19	24	14	16
Grid electricity used (%)	0.21	0.16	0.73	0.71
LcoPtX (EUR/MWh)	256	240	229	254
LcoPtX (EUR/ton)	8515	1244	1188	1406
PtX Amount (GWh/yr)	2772	2331	1575	2049
Total electr. Demand (GWh_{el}/yr)	5597	4534	3136	4594
Selected investment cost (million EUR):				
Wind + PV	3011	2542	1418	2289
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	74	371	155	202
Liquefaction/Synthesis	584	252	201	62
ASU/DAC	-	52	36	326
Total System	5751	4614	3028	4231

Table 9-24: Key performance indicators for the cost-optimal system configuration for the Indian region Korrakodu (Region 3) for jet fuel and FT-mix.

India **Korrakodu**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.8	0.1	1.5	0.2
Wind: LcoE (EUR/MWh_{el})	57			
PV: Installed capacity (GW_{el})	2.2	2.5	2.1	2.2
PV: LcoE (EUR/MWh_{el})	39			
Intermediate H_2 storage: Volume (1000*m³)	178	102	239	72
Liquefaction/ synthesis: Capacity (tpd)	209	164	671	409
Electrolysis: Full load hours (h/yr)	3863	2986	4728	2888
Unused RE power (%)	22	21	26	21
Grid electricity used (%)	0.19	1.18	0.13	0.58
LcoPtX (EUR/MWh)	459	445	231	222
LcoPtX (EUR/ton)	5637	5462	2819	2720
PtX Amount (GWh/yr)	897	694	2875	1759
Total electr. Demand (GWh_{el}/yr)	4189	3335	5118	3203
Selected investment cost (million EUR):				
Wind + PV	2282	1608	3061	1593
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	374	215	503	151
Liquefaction/Synthesis	173	149	194	144
ASU/DAC	248	194	302	184
Total System	4399	3390	5455	3281

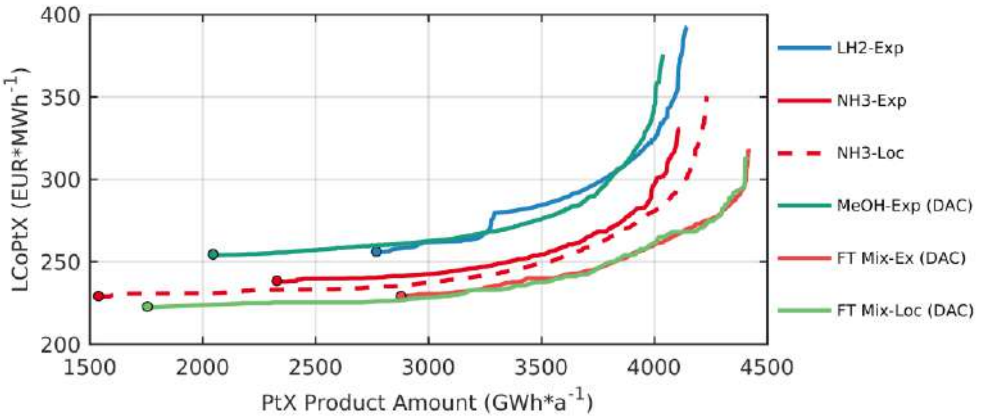

Figure 9-44: The Pareto fronts for the Indian site "Korrakodu" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.5.1 Techno-economic results – Mandiyai Kalan (Region 4)

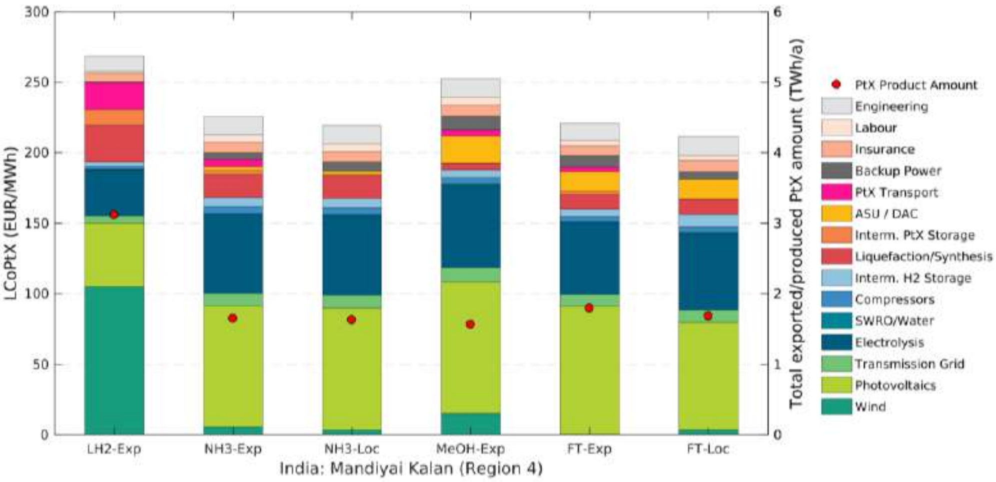

Figure 9-45: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Indian site "Mandiyai Kalan" (Region 4) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-25: Key performance indicators for the cost-optimal system configuration for the Indian region Mandiyai Kalan (Region 4) for LH_2, NH_3 and MeOH.

India **Mandiyai Kalan**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	2.4	0.1	-	0.2
Wind: LcoE (EUR/MWh_{el})			78	
PV: Installed capacity (GW_{el})	2.2	2.2	2.1	2.2
PV: LcoE (EUR/MWh_{el})			36	
Intermediate H_2 storage: Volume (1000*m³)	49	55	54	44
Liquefaction/ synthesis: Capacity (tpd)	377	960	917	860
Electrolysis: Full load hours (h/yr)	5429	2951	2911	2898
Unused RE power (%)	17	14	15	15
Grid electricity used (%)	0.38	2.39	3.16	4.30
LcoPtX (EUR/MWh)	268	226	219	253
LcoPtX (EUR/ton)	8937	1170	1136	1397
PtX Amount (GWh/yr)	3115	1645	1624	1559
Total electr. Demand (GWh_{el}/yr)	6221	3334	3314	3709
Selected investment cost (million EUR):				
Wind + PV	4160	1377	1337	1544
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	102	116	114	92
Liquefaction/Synthesis	627	209	203	49
ASU/DAC	-	38	36	224
Total System	7016	3082	2936	3198

Table 9-26: Key performance indicators for the cost-optimal system configuration for the Indian region Mandiyai Kalan (Region 4) for jet fuel and FT-mix.

India **Mandiyai Kalan**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.1	-	-	-
Wind: LcoE (EUR/MWh_{el})	78			
PV: Installed capacity (GW_{el})	2.5	2.0	2.5	1.9
PV: LcoE (EUR/MWh_{el})	36			
Intermediate H_2 storage: Volume (1000*m³)	55	79	47	75
Liquefaction/ synthesis: Capacity (tpd)	161	152	416	393
Electrolysis: Full load hours (h/yr)	2984	2806	2943	2757
Unused RE power (%)	23	13	24	11
Grid electricity used (%)	2.16	4.17	4.34	2.89
LcoPtX (EUR/MWh)	434	419	221	212
LcoPtX (EUR/ton)	5334	5146	2703	2587
PtX Amount (GWh/yr)	693	652	1789	1678
Total electr. Demand (GWh_{el}/yr)	3371	3221	3398	3124
Selected investment cost (million EUR):				
Wind + PV	1562	1225	1498	1224
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	115	165	98	157
Liquefaction/Synthesis	147	143	146	141
ASU/DAC	191	180	187	177
Total System	3294	2958	3243	2941

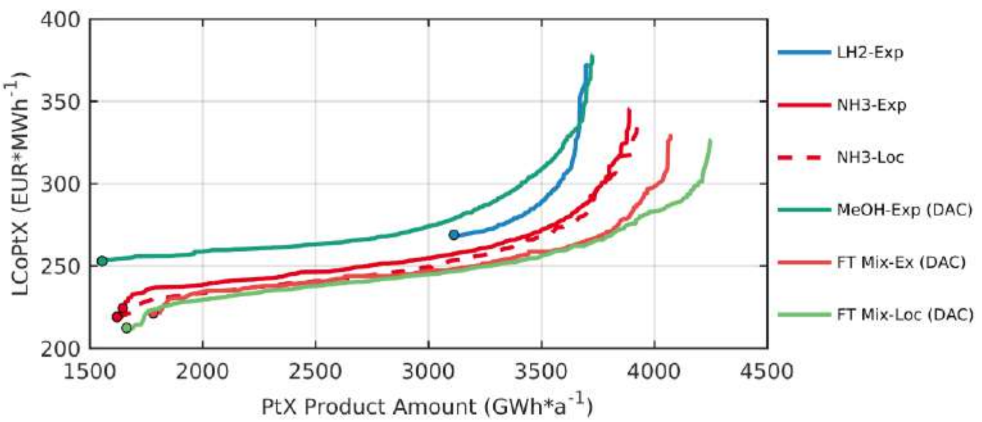

Figure 9-46: The Pareto fronts for the Indian site "Mandiyai Kalan" (region 4) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.6 Mexico

9.6.1 Renewable potential analysis

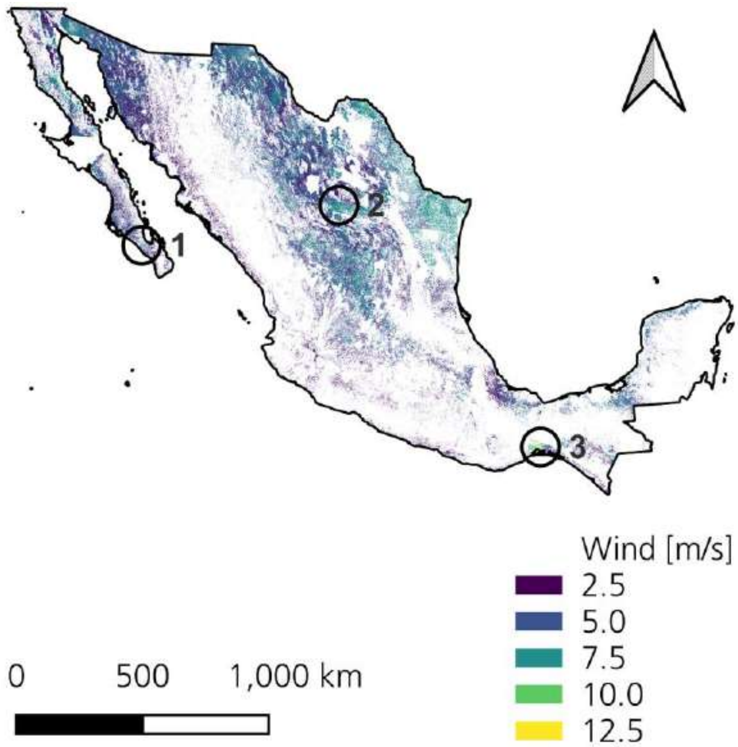

Figure 9-47: Selected regions and wind potential in Mexico.

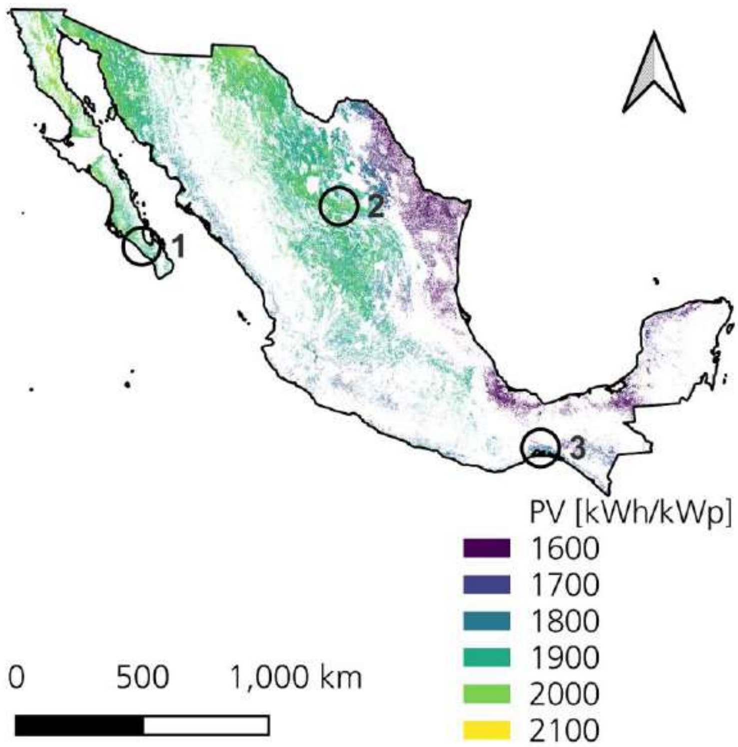

Figure 9-48: Selected regions and PV potential in Mexico.

9.6.2 Techno-economic results – La Paz (Region 1)

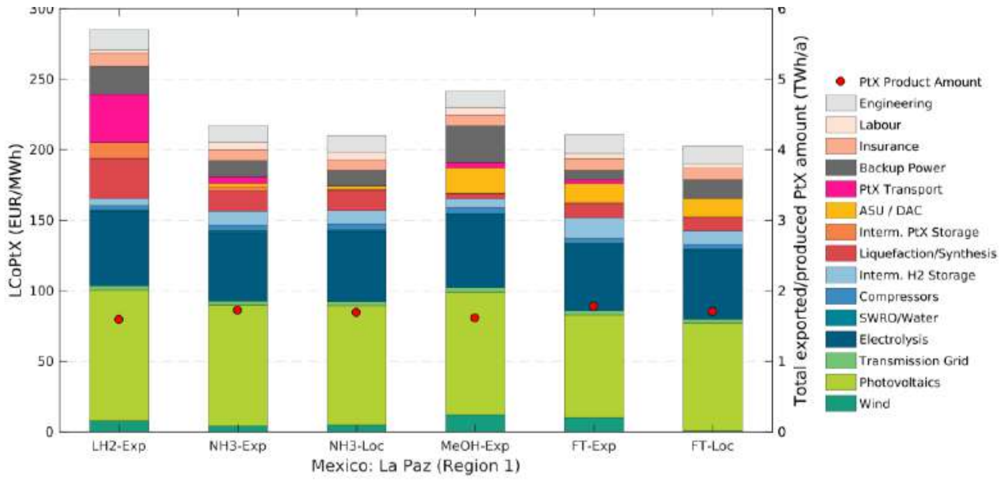

Figure 9-49: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Mexican site "La Paz" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-27: Key performance indicators for the cost-optimal system configuration for the Mexican region La Paz (Region 1) for LH_2, NH_3 and MeOH.

Mexico **La Paz**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.1	0.1	0.1	0.1
Wind: LcoE (EUR/MWh_{el})	129			
PV: Installed capacity (GW_{el})	2.5	2.5	2.4	2.4
PV: LcoE (EUR/MWh_{el})	33			
Intermediate H_2 storage: Volume (1000*m³)	45	94	90	58
Liquefaction/ synthesis: Capacity (tpd)	192	993	967	892
Electrolysis: Full load hours (h/yr)	3040	3081	3032	2966
Unused RE power (%)	25	25	24	21
Grid electricity used (%)	5.16	3.43	3.25	6.70
LcoPtX (EUR/MWh)	285	217	210	242
LcoPtX (EUR/ton)	9496	1125	1088	1337
PtX Amount (GWh/yr)	1588	1718	1688	1610
Total electr. Demand (GWh_{el}/yr)	3716	3525	3462	3891
Selected investment cost (million EUR):				
Wind + PV	1623	1569	1537	1620
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	95	198	188	121
Liquefaction/Synthesis	381	213	210	51
ASU/DAC	-	39	38	232
Total System	3882	3284	3130	3210

Table 9-28: Key performance indicators for the cost-optimal system configuration for the Mexican region La Paz (Region 1) for jet fuel and FT-mix.

Mexico La Paz	**Jet Fuel Export**	**Jet Fuel Local**	**FT-Mix Export**	**FT-Mix Local**
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	-	0.1	0.1	-
Wind: LcoE (EUR/MWh_{el})	129			
PV: Installed capacity (GW_{el})	2.5	2.4	2.2	2.2
PV: LcoE (EUR/MWh_{el})	33			
Intermediate H_2 storage: Volume (1000*m³)	107	89	151	91
Liquefaction/ synthesis: Capacity (tpd)	163	159	420	397
Electrolysis: Full load hours (h/yr)	2991	2938	2918	2798
Unused RE power (%)	28	28	20	23
Grid electricity used (%)	3.72	3.01	2.15	4.31
LcoPtX (EUR/MWh)	407	399	210	203
LcoPtX (EUR/ton)	5000	4904	2574	2477
PtX Amount (GWh/yr)	695	682	1775	1700
Total electr. Demand (GWh_{el}/yr)	3432	3347	3291	3225
Selected investment cost (million EUR):				
Wind + PV	1553	1573	1497	1326
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	224	187	316	192
Liquefaction/Synthesis	148	146	147	142
ASU/DAC	193	188	189	179
Total System	3311	3239	3386	2982

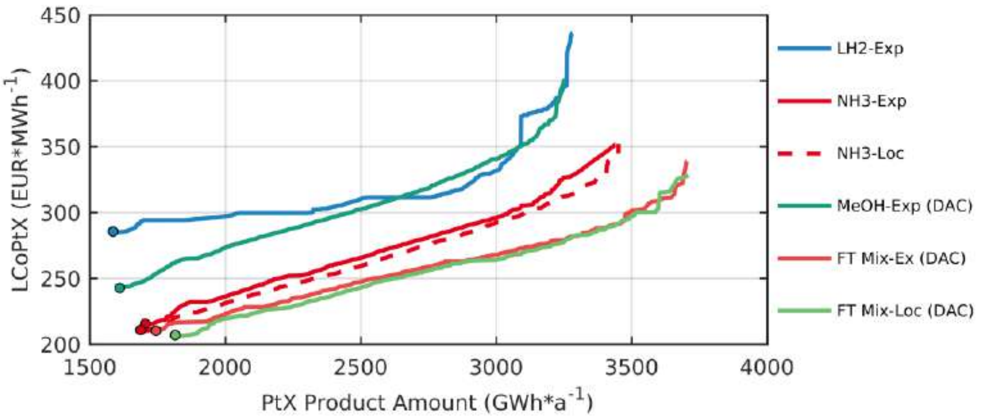

Figure 9-50: The Pareto fronts for the Mexican site "La Paz" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.6.3 Techno-economic results – San Pedro (Region 2)

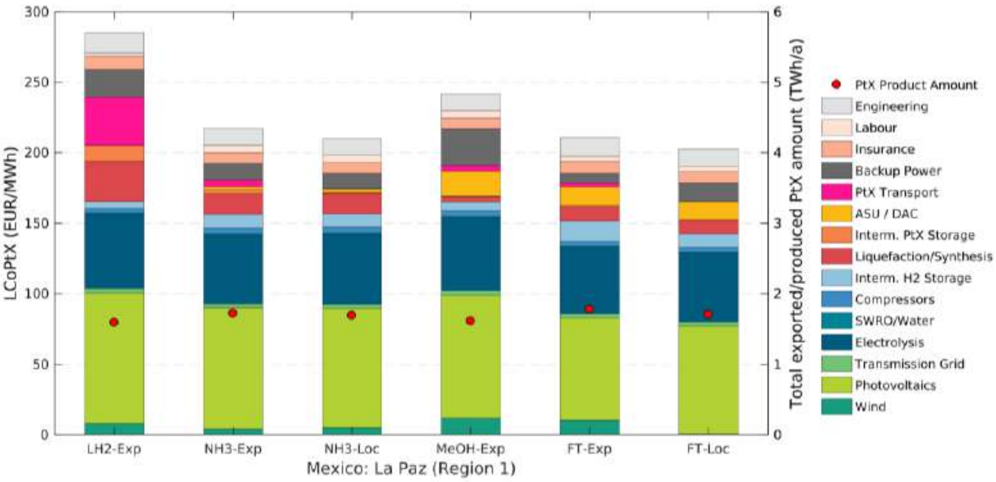

Figure 9-51: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Mexican site "San Pedro" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-29: Key performance indicators for the cost-optimal system configuration for the Mexican region San Pedro (Region 2) for LH_2, NH_3 and MeOH.

Mexico San Pedro	**LH_2 Export**	**NH_3 Export**	**NH_3 Local**	**MeOH Export**
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.7	0.6	0.1	0.5
Wind: LcoE (EUR/MWh_{el})	86			
PV: Installed capacity (GW_{el})	2.2	2.2	2.0	2.2
PV: LcoE (EUR/MWh_{el})	32			
Intermediate H_2 storage: Volume (1000*m³)	31	138	87	64
Liquefaction/ synthesis: Capacity (tpd)	345	1117	897	1022
Electrolysis: Full load hours (h/yr)	4771	3485	2790	3226
Unused RE power (%)	16	18	13	14
Grid electricity used (%)	0.46	0.61	2.25	2.22
LcoPtX (EUR/MWh)	262	228	212	244
LcoPtX (EUR/ton)	8729	1180	1099	1350
PtX Amount (GWh/yr)	2694	1943	1554	1747
Total electr. Demand (GWh_{el}/yr)	5487	3838	3146	4025
Selected investment cost (million EUR):				
Wind + PV	3750	2122	1290	2029
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	66	290	183	134
Liquefaction/Synthesis	587	229	200	55
ASU/DAC	-	44	35	267
Total System	6480	4088	2969	3801

Table 9-30: Key performance indicators for the cost-optimal system configuration for the Mexican region San Pedro (Region 2) for jet fuel and FT-mix.

Mexico **San Pedro**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.3	0.1	0.1	0.1
Wind: LcoE (EUR/MWh_{el})	86			
PV: Installed capacity (GW_{el})	2.3	2.0	2.3	2.2
PV: LcoE (EUR/MWh_{el})	32			
Intermediate H_2 storage: Volume (1000*m³)	83	110	88	87
Liquefaction/ synthesis: Capacity (tpd)	162	147	403	396
Electrolysis: Full load hours (h/yr)	3011	2723	2847	2794
Unused RE power (%)	23	16	24	21
Grid electricity used (%)	0.83	2.25	2.53	2.16
LcoPtX (EUR/MWh)	431	407	212	207
LcoPtX (EUR/ton)	5286	4996	2590	2535
PtX Amount (GWh/yr)	699	632	1730	1698
Total electr. Demand (GWh_{el}/yr)	3345	3071	3231	3156
Selected investment cost (million EUR):				
Wind + PV	1829	1299	1493	1441
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	174	231	184	184
Liquefaction/Synthesis	148	140	143	142
ASU/DAC	192	174	182	178
Total System	3637	3102	3307	3196

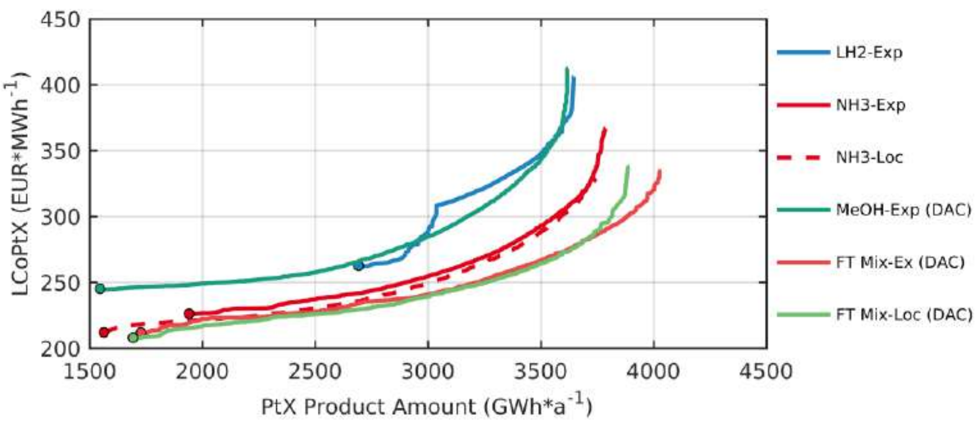

Figure 9-52: The Pareto fronts for the Mexican site "San Pedro" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.6.4 Techno-economic results – Santo Domingo (Region 3)

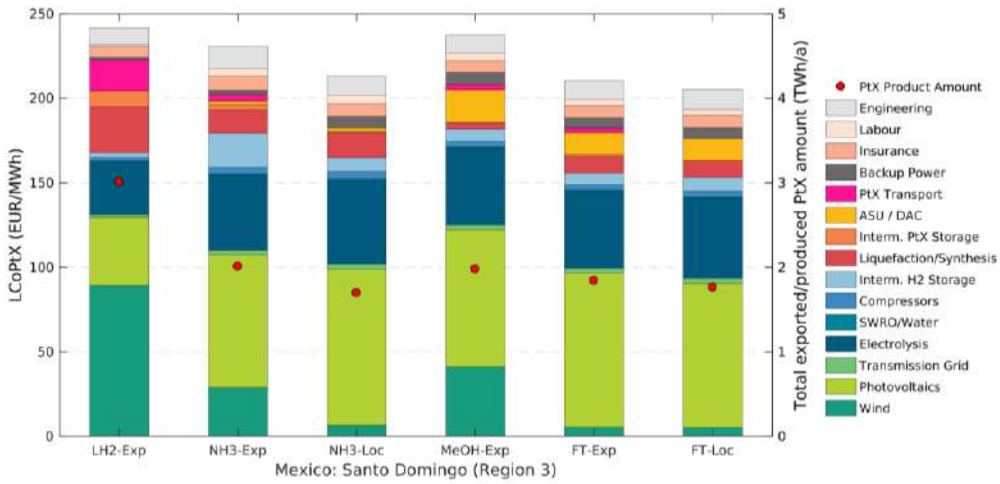

Figure 9-53: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Mexican site “Santo Domingo” (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-31: Key performance indicators for the cost-optimal system configuration for the Mexican region Santo Domingo (Region 3) for LH_2, NH_3 and MeOH.

Mexico **Santo Domingo**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.6	0.3	0.1	0.5
Wind: LcoE (EUR/MWh_{el})	51			
PV: Installed capacity (GW_{el})	2.0	2.7	2.6	2.7
PV: LcoE (EUR/MWh_{el})	36			
Intermediate H_2 storage: Volume (1000*m³)	52	234	77	82
Liquefaction/ synthesis: Capacity (tpd)	432	1159	992	1179
Electrolysis: Full load hours (h/yr)	5447	3609	3048	3648
Unused RE power (%)	26	27	25	26
Grid electricity used (%)	0.44	0.78	1.94	1.91
LcoPtX (EUR/MWh)	242	231	213	237
LcoPtX (EUR/ton)	8048	1195	1105	1313
PtX Amount (GWh/yr)	3007	2008	1696	1977
Total electr. Demand (GWh_{el}/yr)	6279	3981	3438	4522
Selected investment cost (million EUR):				
Wind + PV	3425	2072	1678	2294
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	109	492	162	172
Liquefaction/Synthesis	694	234	213	60
ASU/DAC	-	46	39	307
Total System	6215	4192	3249	4055

Table 9-32: Key performance indicators for the cost-optimal system configuration for the Mexican region Santo Domingo (Region 3) for jet fuel and FT-mix.

Mexico **Santo Domingo**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.1	0.1	0.1	0.1
Wind: LcoE (EUR/MWh_{el})	51			
PV: Installed capacity (GW_{el})	2.7	2.7	2.8	2.5
PV: LcoE (EUR/MWh_{el})	36			
Intermediate H_2 storage: Volume ($1000*m^3$)	89	86	71	81
Liquefaction/ synthesis: Capacity (tpd)	164	163	431	410
Electrolysis: Full load hours (h/yr)	3011	2995	3031	2892
Unused RE power (%)	28	28	30	26
Grid electricity used (%)	1.91	2.11	1.98	2.04
LcoPtX (EUR/MWh)	413	404	210	205
LcoPtX (EUR/ton)	5066	4961	2573	2509
PtX Amount (GWh/yr)	698	695	1841	1760
Total electr. Demand (GWh_{el}/yr)	3396	3385	3423	3264
Selected investment cost (million EUR):				
Wind + PV	1717	1698	1786	1597
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	187	180	149	171
Liquefaction/Synthesis	149	149	149	145
ASU/DAC	194	193	194	185
Total System	3442	3369	3488	3243

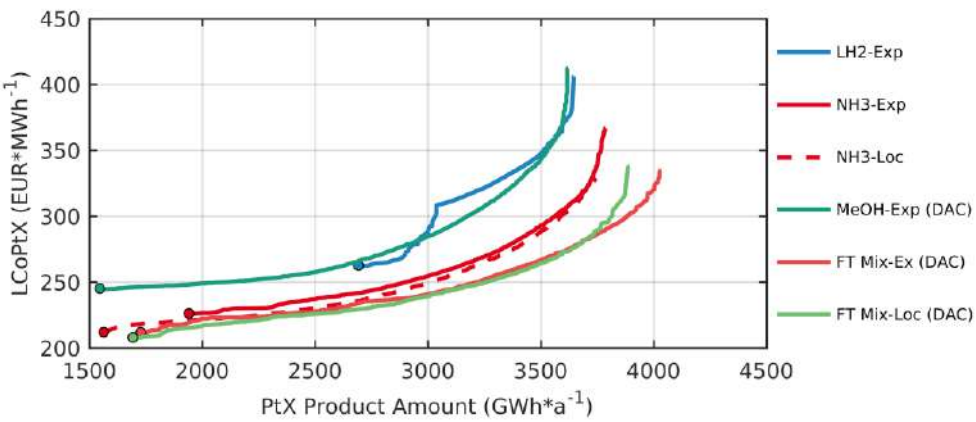

Figure 9-54: The Pareto fronts for the Mexican site "Santo Domingo" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.7 Morocco

9.7.1 Renewable potential analysis

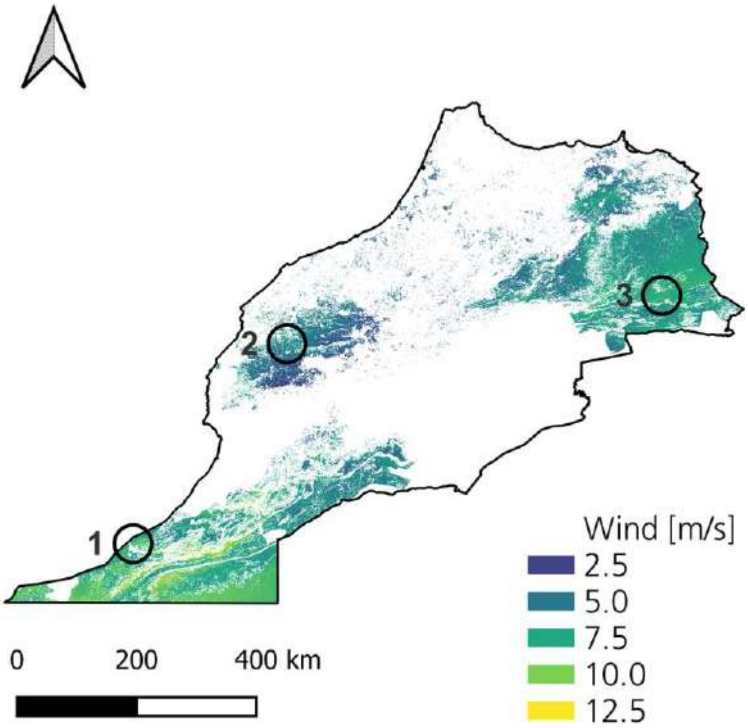

Figure 9-55: Selected regions and wind potential in Morocco.

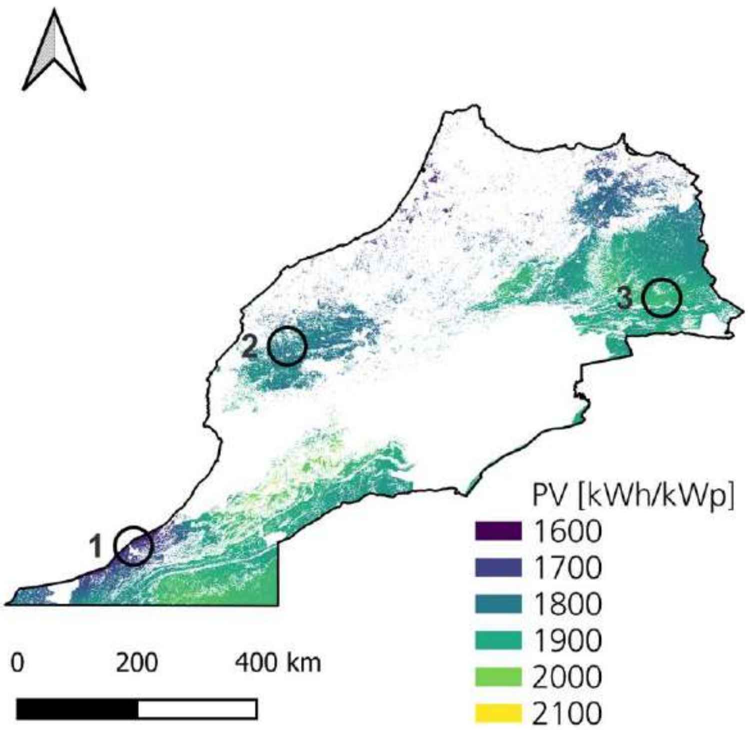

Figure 9-56: Selected regions and PV potential in Morocco.

9.7.2 Techno-economic results – Tan-Tan (Region 1)

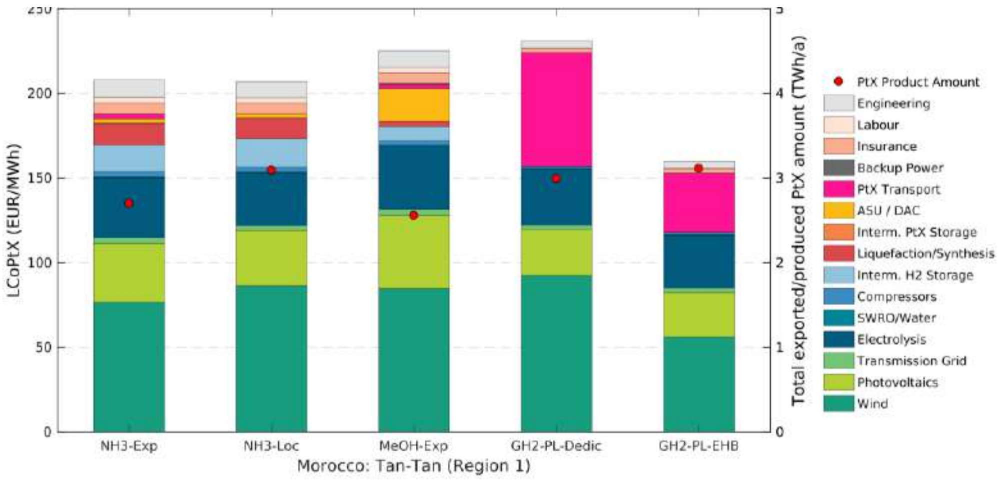

Figure 9-57: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Moroccan site "Tan-Tan" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-33: Key performance indicators for the cost-optimal system configuration for the Moroccan region Tan-Tan (Region 1) for NH_3, MeOH and gaseous H_2.

Morocco **Tan-Tan**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.1	1.5	1.2	1.5	1.0
Wind: LcoE (EUR/MWh_{el})			57		
PV: Installed capacity (GW_{el})	1.4	1.5	1.7	1.2	1.2
PV: LcoE (EUR/MWh_{el})			34		
Intermediate H_2 storage: Volume (1000*m³)	236	289	117	-	-
Liquefaction/ synthesis: Capacity (tpd)	1523	1775	1481	463	463
Electrolysis: Full load hours (h/yr)	4833	5536	4698	5929	4837
Unused RE power (%)	14	18	16	14	8
Grid electricity used (%)	0.08	0.06	0.39	-	-
LcoPtX (EUR/MWh)	208	207	225	231	160
LcoPtX (EUR/ton)	1077	1073	1246	7700	5321
PtX Amount (GWh/yr)	2696	3088	2552	2992	3110
Total electr. Demand (GWh_{el}/yr)	5215	5993	5679	5910	4789
Selected investment cost (million EUR):					
Wind + PV	2616	3179	2860	3061	2231
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	496	606	246	-	-
Liquefaction/Synthesis	275	302	68	-	-
ASU/DAC	60	70	386	-	-
Total System	4815	5502	4865	6241	3298

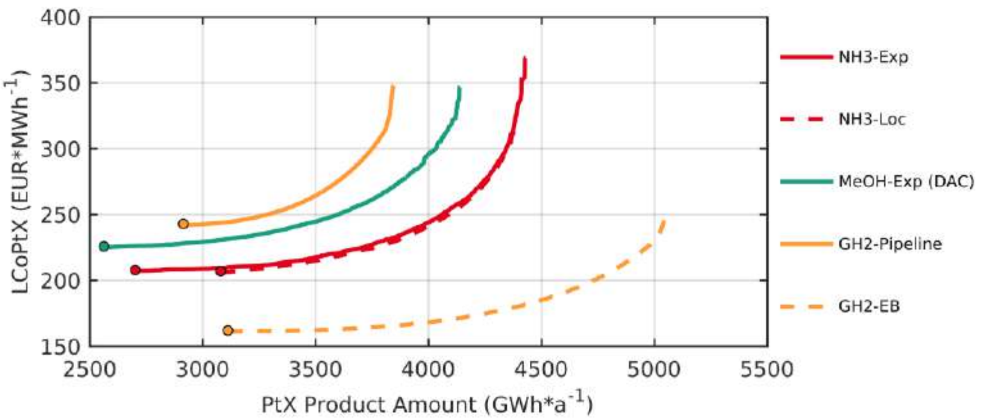

Figure 9-58: The Pareto fronts for the Moroccan site "Tan-Tan" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.7.3 Techno-economic results – Marrakech (Region 2)

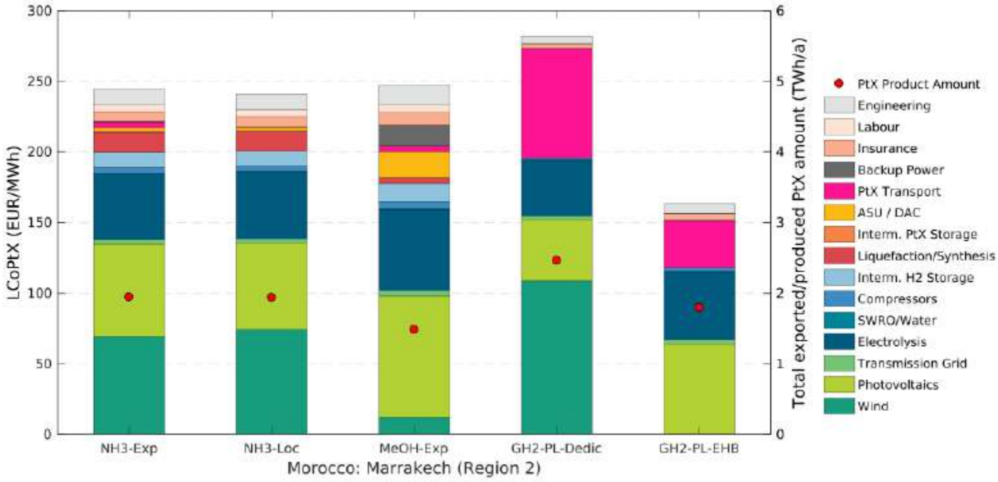

Figure 9-59: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Moroccan site "Marrakech" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-34: Key performance indicators for the cost-optimal system configuration for the Moroccan region Marrakech (Region 2) for NH_3, MeOH and gaseous H_2.

Morocco **Marrakech**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	0.9	0.9	0.1	1.7	-
Wind: LcoE (EUR/MWh_{el})			98		
PV: Installed capacity (GW_{el})	1.9	1.8	1.9	1.6	1.8
PV: LcoE (EUR/MWh_{el})			36		
Intermediate H_2 storage: Volume (1000*m³)	117	111	109	-	-
Liquefaction/ synthesis: Capacity (tpd)	1090	1085	828	463	463
Electrolysis: Full load hours (h/yr)	3486	3473	2731	4875	2789
Unused RE power (%)	21	19	14	13	10
Grid electricity used (%)	0.28	0.26	6.46	-	0.32
LcoPtX (EUR/MWh)	245	241	247	282	163
LcoPtX (EUR/ton)	1268	1247	1369	9386	5440
PtX Amount (GWh/yr)	1944	1937	1482	2460	1793
Total electr. Demand (GWh_{el}/yr)	3817	3796	3570	4864	2841
Selected investment cost (million EUR):					
Wind + PV	2560	2564	1437	3641	1144
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	246	233	229	-	-
Liquefaction/Synthesis	225	225	48	-	-
ASU/DAC	43	43	216	-	-
Total System	4332	4249	3139	6670	2174

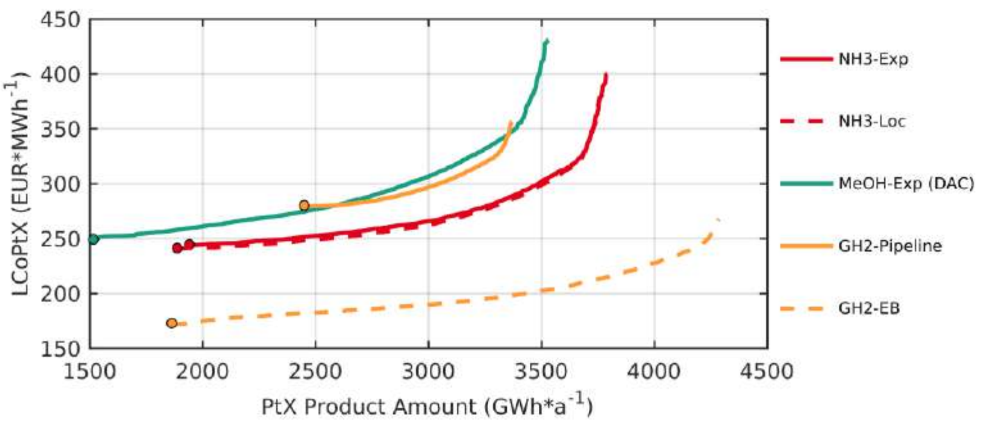

Figure 9-60: The Pareto fronts for the Moroccan site "Marrakech" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.7.4 Techno-economic results – Figuig (Region 3)

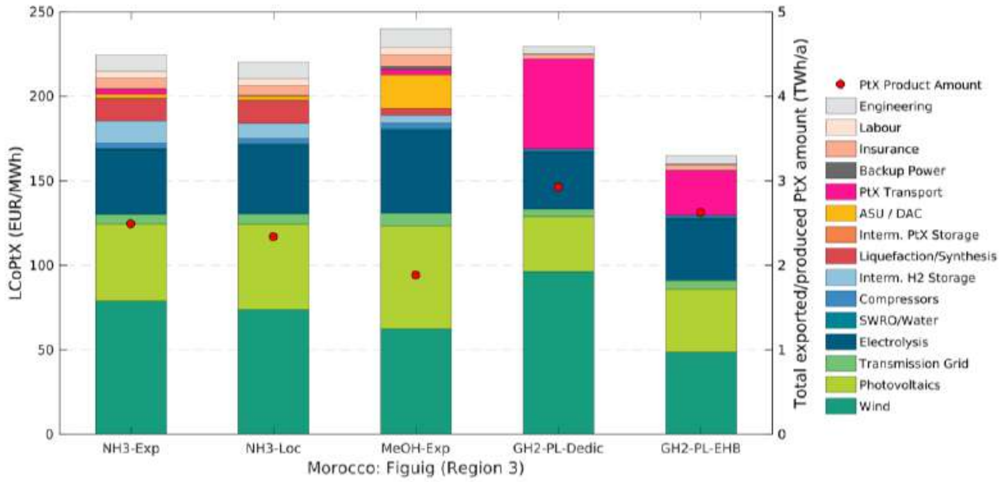

Figure 9-61: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Moroccan site "Figuig" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-35: Key performance indicators for the cost-optimal system configuration for the Moroccan region Figuig (Region 3) for NH_3, MeOH and gaseous H_2.

Morocco **Figuig**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.1	1.0	0.7	1.6	0.7
Wind: LcoE (EUR/MWh_{el})			68		
PV: Installed capacity (GW_{el})	1.7	1.8	1.8	1.5	1.5
PV: LcoE (EUR/MWh_{el})			34		
Intermediate H_2 storage: Volume (1000*m³)	182	119	50	-	-
Liquefaction/ synthesis: Capacity (tpd)	1429	1319	1136	463	463
Electrolysis: Full load hours (h/yr)	4461	4182	3461	5598	4076
Unused RE power (%)	16	18	12	13	8
Grid electricity used (%)	0.10	0.12	0.83	-	-
LcoPtX (EUR/MWh)	225	220	240	230	165
LcoPtX (EUR/ton)	1164	1141	1327	7642	5480
PtX Amount (GWh/yr)	2487	2333	1880	2921	2620
Total electr. Demand (GWh_{el}/yr)	4815	4519	4227	5567	4045
Selected investment cost (million EUR):					
Wind + PV	2845	2682	2164	3409	2088
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	382	249	105	-	-
Liquefaction/Synthesis	265	253	58	-	-
ASU/DAC	56	52	296	-	-
Total System	4941	4538	3936	6173	3213

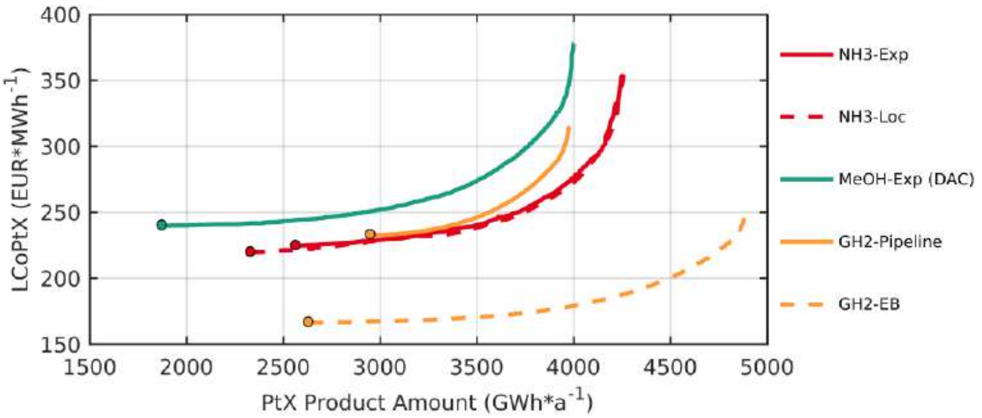

Figure 9-62: The Pareto fronts for the Moroccan site "Figuig" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.8 Namibia

9.8.1 Renewable potential analysis

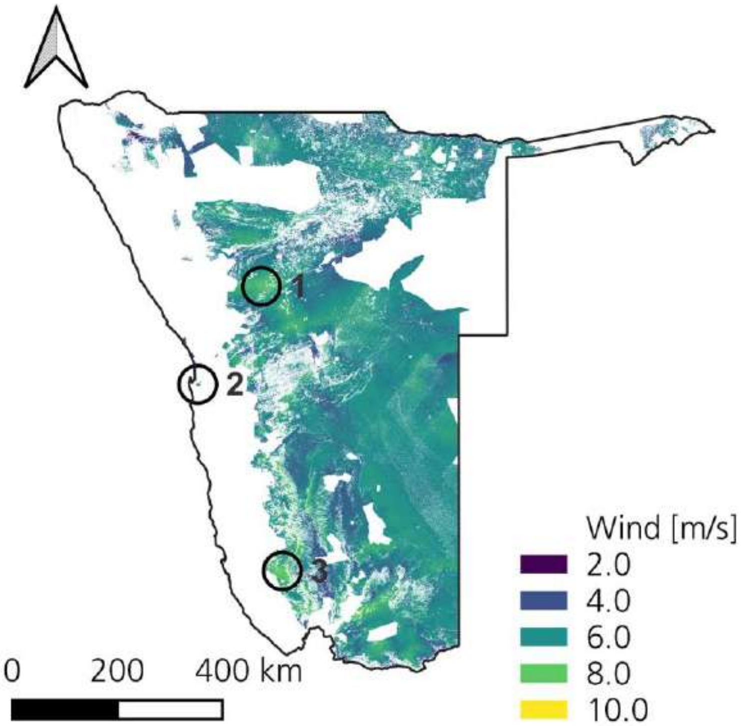

Figure 9-63: Selected regions and wind potential in Namibia.

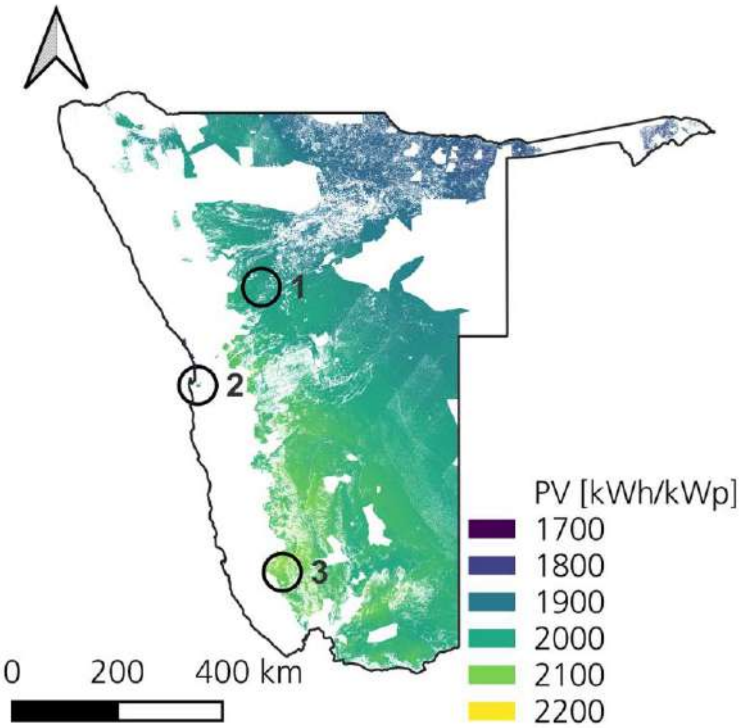

Figure 9-64: Selected regions and PV potential in Namibia.

9.8.2 Techno-economic results – Omaruru (Region 1)

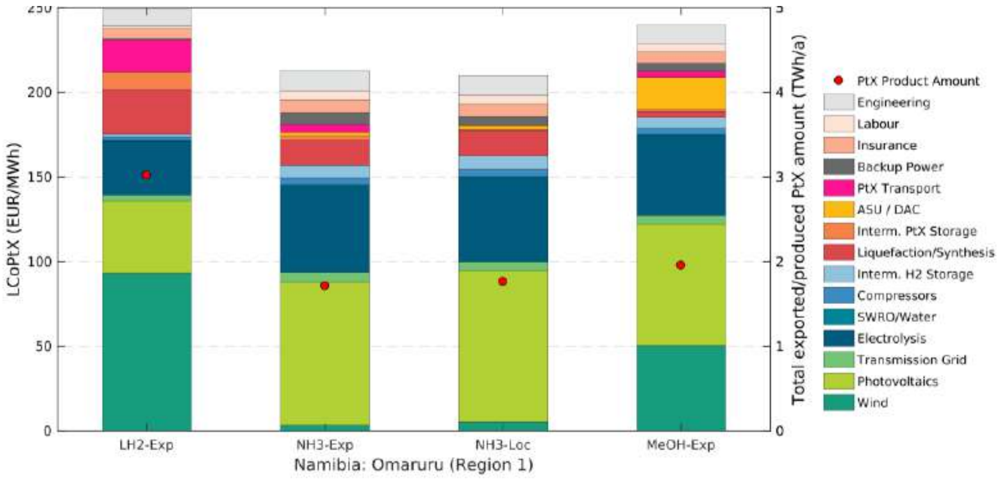

Figure 9-65: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Namibian site "Omaruru" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-36: Key performance indicators for the cost-optimal system configuration for the Namibian region Omaruru (Region 1) for LH_2, NH_3, and MeOH.

Namibia **Omaruru**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.7	-	0.1	0.6
Wind: LcoE (EUR/MWh_{el})		77		
PV: Installed capacity (GW_{el})	1.9	2.2	2.4	2.1
PV: LcoE (EUR/MWh_{el})		34		
Intermediate H_2 storage: Volume (1000*m³)	28	68	76	67
Liquefaction/ synthesis: Capacity (tpd)	396	954	990	1120
Electrolysis: Full load hours (h/yr)	5288	3069	3163	3599
Unused RE power (%)	15	20	24	17
Grid electricity used (%)	0.41	3.16	2.49	1.89
LcoPtX (EUR/MWh)	249	213	210	240
LcoPtX (EUR/ton)	8294	1103	1087	1325
PtX Amount (GWh/yr)	3020	1711	1762	1953
Total electr. Demand (GWh_{el}/yr)	6080	3504	3591	4453
Selected investment cost (million EUR):				
Wind + PV	3755	1464	1617	2241
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	59	144	159	141
Liquefaction/Synthesis	651	208	213	58
ASU/DAC	-	38	39	292
Total System	6510	3144	3233	4013

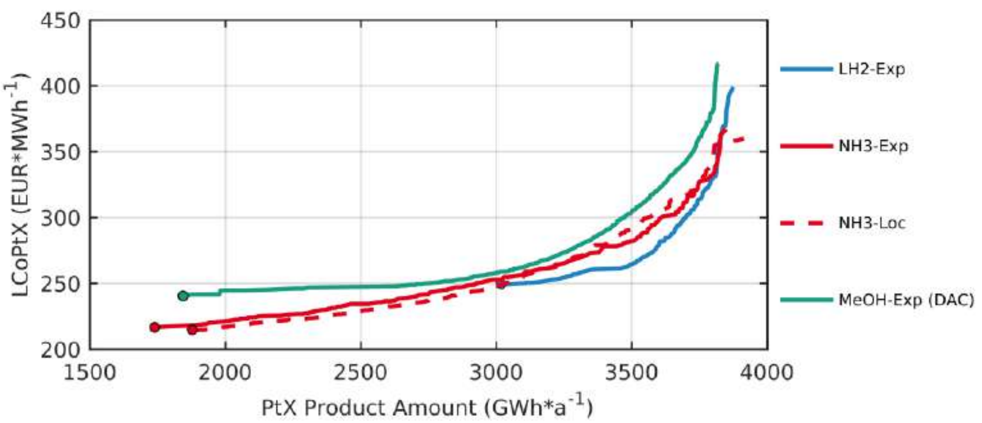

Figure 9-66: The Pareto fronts for the Namibian site "Omaruru" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.8.3 Techno-economic results – Walvis Bay (Region 2)

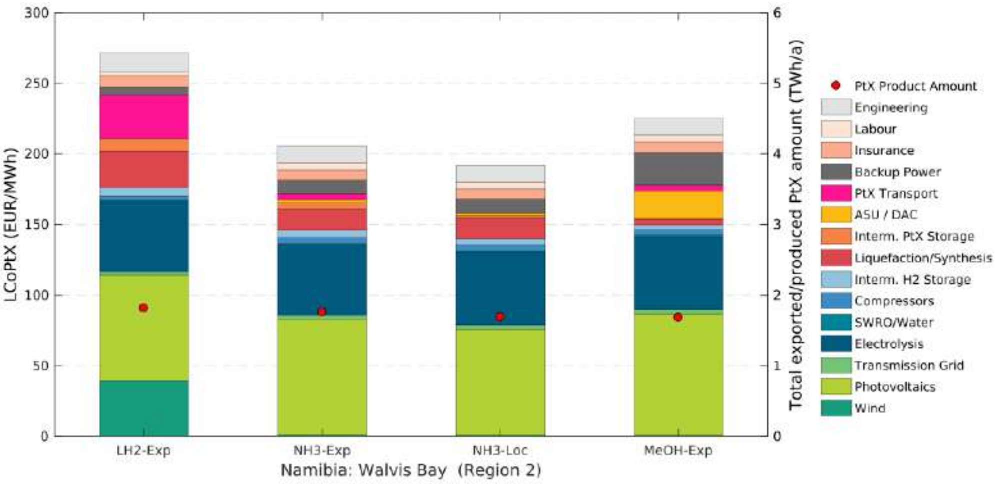

Figure 9-67: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Namibian site "Walvis Bay" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-37: Key performance indicators for the cost-optimal system configuration for the Namibian region "Walvis Bay" (Region 2) for LH_2, NH_3, and MeOH.

Namibia **Walvis Bay**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	0.5	-	-	-
Wind: LcoE (EUR/MWh_{el})			101	
PV: Installed capacity (GW_{el})	2.0	2.2	1.9	2.2
PV: LcoE (EUR/MWh_{el})			32	
Intermediate H_2 storage: Volume (1000*m³)	62	50	39	31
Liquefaction/ synthesis: Capacity (tpd)	193	1013	979	1003
Electrolysis: Full load hours (h/yr)	3391	3157	3028	3096
Unused RE power (%)	21	24	17	21
Grid electricity used (%)	2.33	4.22	4.34	9.14
LcoPtX (EUR/MWh)	271	206	192	225
LcoPtX (EUR/ton)	9037	1065	992	1244
PtX Amount (GWh/yr)	1815	1759	1689	1681
Total electr. Demand (GWh_{el}/yr)	3995	3644	3492	4159
Selected investment cost (million EUR):				
Wind + PV	2002	1426	1250	1424
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	130	106	82	65
Liquefaction/Synthesis	382	215	211	54
ASU/DAC	-	40	39	262
Total System	4268	3055	2710	2977

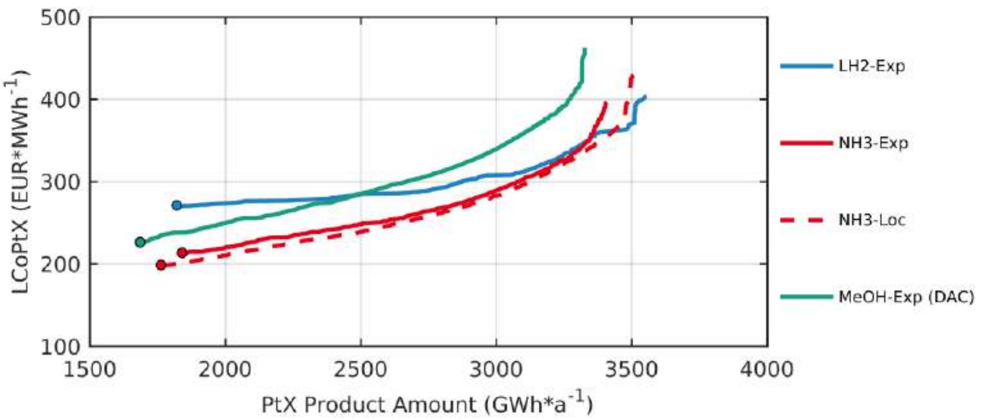

Figure 9-68: The Pareto fronts for the Namibian site "Walvis Bay" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.8.4 Techno-economic results – Lüderitz (Region 3)

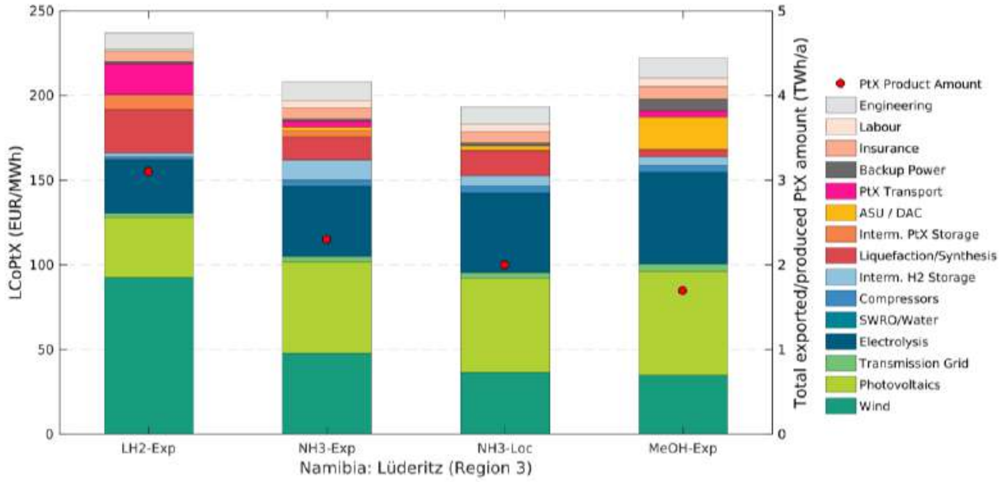

Figure 9-69: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Namibian site “Lüderitz” (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-38: Key performance indicators for the cost-optimal system configuration for the Namibian region Lüderitz (Region 3) for LH_2, NH_3, and MeOH.

Namibia **Lüderitz**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.2	0.9	0.4	0.3
Wind: LcoE (EUR/MWh_{el})			69	
PV: Installed capacity (GW_{el})	1.7	1.6	1.7	1.5
PV: LcoE (EUR/MWh_{el})			32	
Intermediate H_2 storage: Volume (1000*m³)	28	43	66	47
Liquefaction/ synthesis: Capacity (tpd)	371	1672	1160	959
Electrolysis: Full load hours (h/yr)	4829	4395	3574	3112
Unused RE power (%)	13	11	12	7
Grid electricity used (%)	0.63	0.53	0.78	2.71
LcoPtX (EUR/MWh)	237	197	193	222
LcoPtX (EUR/ton)	7884	1022	1001	1229
PtX Amount (GWh/yr)	2730	2454	1993	1690
Total electr. Demand (GWh_{el}/yr)	5559	4784	3926	3886
Selected investment cost (million EUR):				
Wind + PV	2859	2333	1702	1514
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	58	90	138	99
Liquefaction/Synthesis	644	253	234	53
ASU/DAC	-	66	46	250
Total System	5491	4106	3300	3129

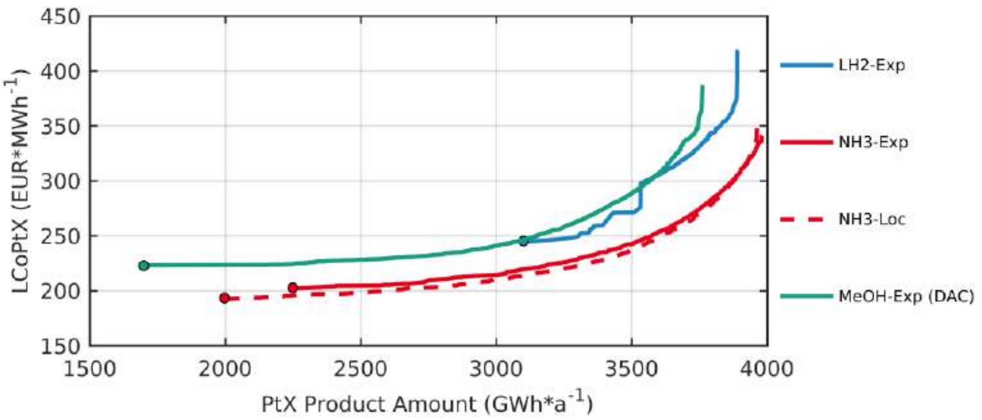

Figure 9-70: The Pareto fronts for the Namibian site "Lüderitz" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.9 South Africa

9.9.1 Renewable potential analysis

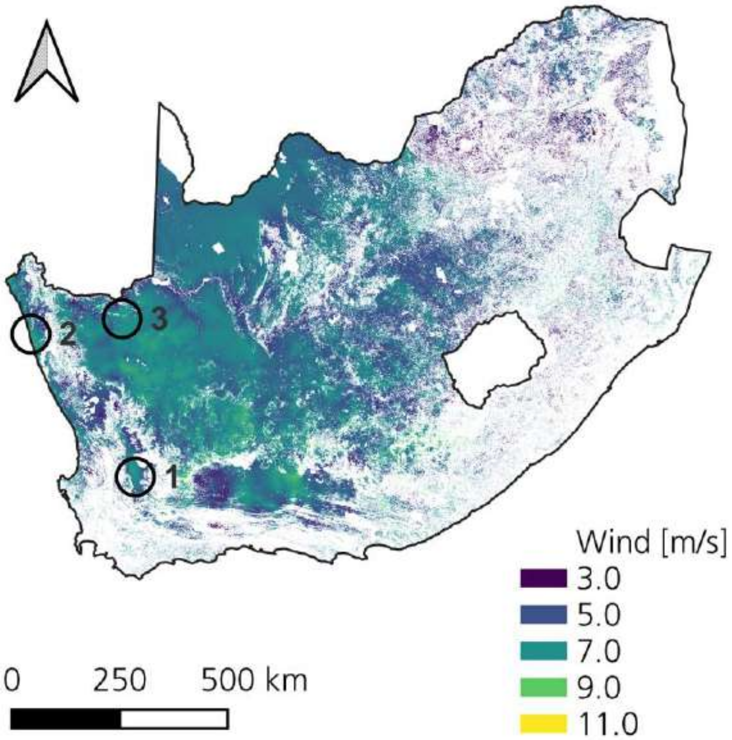

Figure 9-71: Selected regions and wind potential in South Africa.

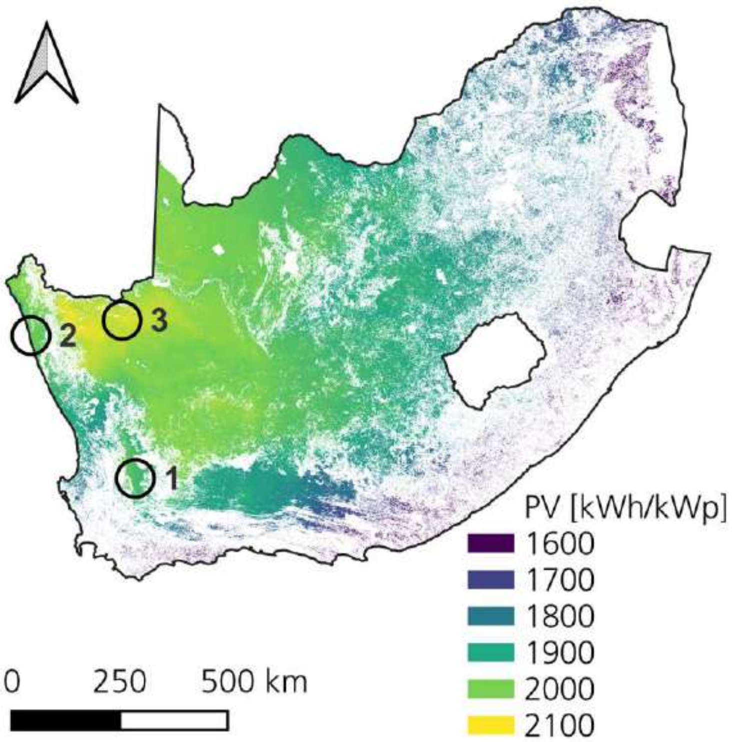

Figure 9-72: Selected regions and PV potential in South Africa.

9.9.2 Techno-economic results – Cape Town (Region 1)

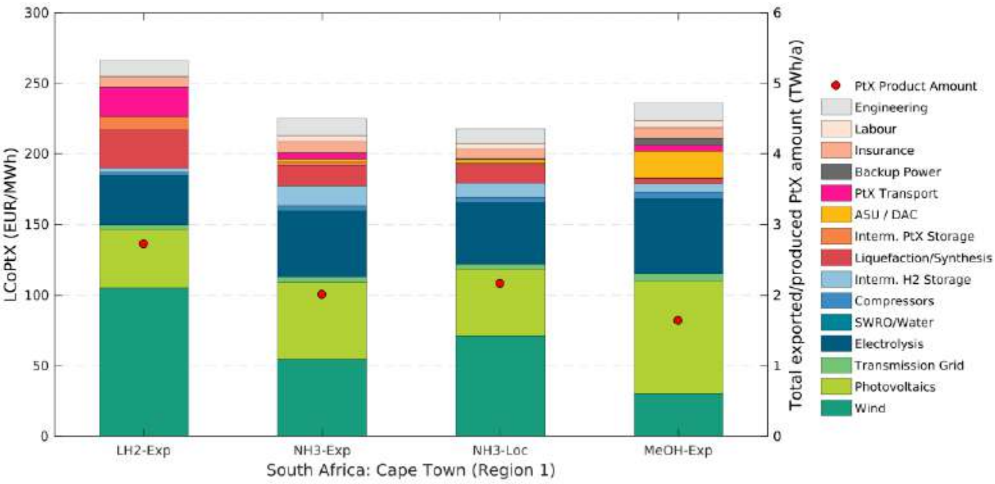

Figure 9-73: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the South African site "Cape Town" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-39: Key performance indicators for the cost-optimal system configuration for the South African region Cape Town (Region 1) for LH_2, NH_3, and MeOH.

South Africa **Cape Town**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.8	0.7	0.9	0.3
Wind: LcoE (EUR/MWh_{el})			80	
PV: Installed capacity (GW_{el})	1.7	1.7	1.6	2.0
PV: LcoE (EUR/MWh_{el})			34	
Intermediate H_2 storage: Volume (1000*m³)	43	158	122	57
Liquefaction/ synthesis: Capacity (tpd)	366	1183	1243	946
Electrolysis: Full load hours (h/yr)	4810	3599	3878	3018
Unused RE power (%)	17	12	12	17
Grid electricity used (%)	0.49	0.58	0.46	3.35
LcoPtX (EUR/MWh)	266	225	218	236
LcoPtX (EUR/ton)	8862	1166	1129	1304
PtX Amount (GWh/yr)	2720	2007	2163	1637
Total electr. Demand (GWh_{el}/yr)	5541	3941	4220	3826
Selected investment cost (million EUR):				
Wind + PV	3751	2093	2430	1751
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	91	332	257	119
Liquefaction/Synthesis	613	237	244	52
ASU/DAC	-	47	49	247
Total System	6424	4048	4207	3398

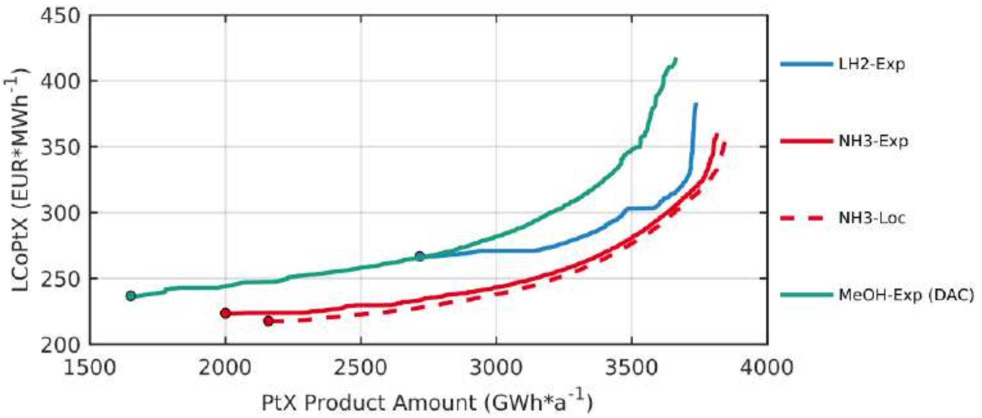

Figure 9-74: The Pareto fronts for the South African site "Cape Town" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.9.3 Techno-economic results – Port Nolloth (Region 2)

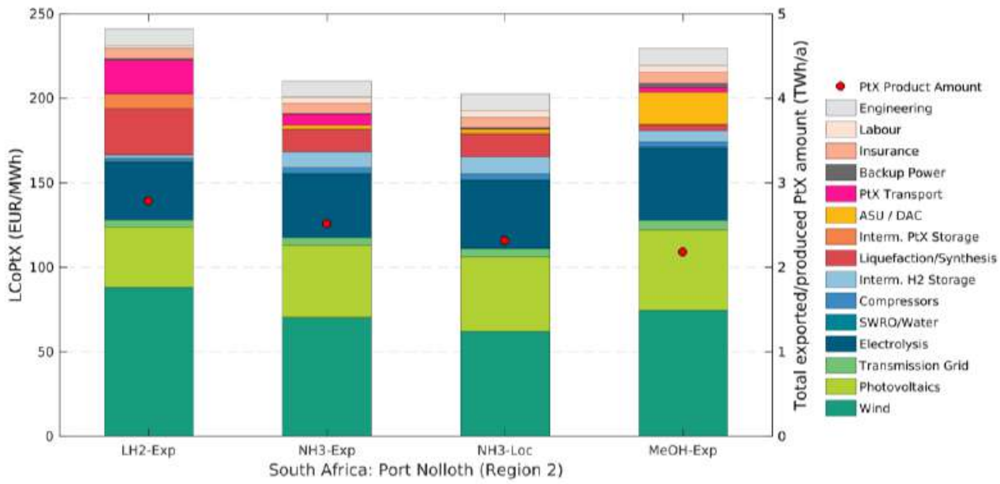

Figure 9-75: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the South African site "Port Nolloth" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-40: Key performance indicators for the cost-optimal system configuration for the South African region Port Nolloth (Region 2) for LH_2, NH_3, and MeOH.

South Africa **Port Nolloth**	**LH_2 Export**	**NH_3 Export**	**NH_3 Local**	**MeOH Export**
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.4	1.0	0.8	0.9
Wind: LcoE (EUR/MWh_{el})			65	
PV: Installed capacity (GW_{el})	1.5	1.6	1.6	1.6
PV: LcoE (EUR/MWh_{el})			32	
Intermediate H_2 storage: Volume (1000*m³)	33	133	127	80
Liquefaction/ synthesis: Capacity (tpd)	376	1456	1349	1264
Electrolysis: Full load hours (h/yr)	4910	4507	4147	4013
Unused RE power (%)	13	15	12	11
Grid electricity used (%)	0.49	0.49	0.54	1.60
LcoPtX (EUR/MWh)	241	210	203	230
LcoPtX (EUR/ton)	8031	1088	1049	1270
PtX Amount (GWh/yr)	2779	2511	2313	2176
Total electr. Demand (GWh_{el}/yr)	5642	4904	4512	4916
Selected investment cost (million EUR):				
Wind + PV	3085	2587	2247	2425
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	69	280	266	169
Liquefaction/Synthesis	626	268	256	62
ASU/DAC	-	58	53	330
Total System	5781	4600	4101	4295

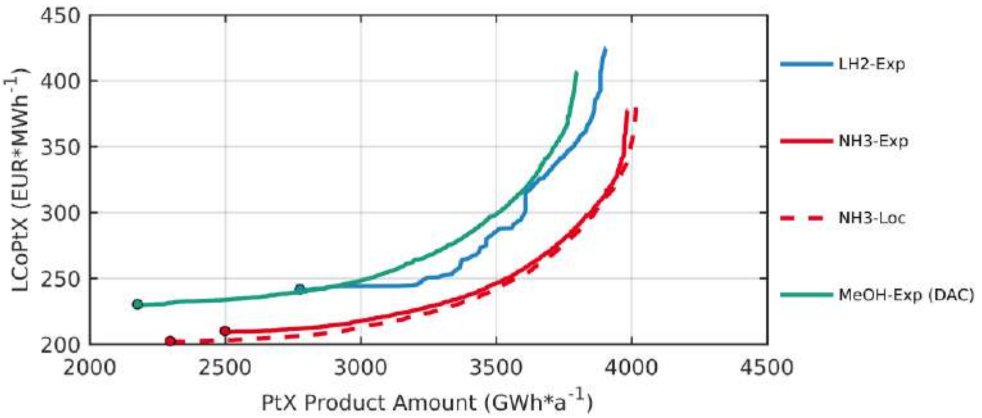

Figure 9-76: The Pareto fronts for the South African site "Port Nolloth" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.9.4 Techno-economic results – Khai-Ma (Region 3)

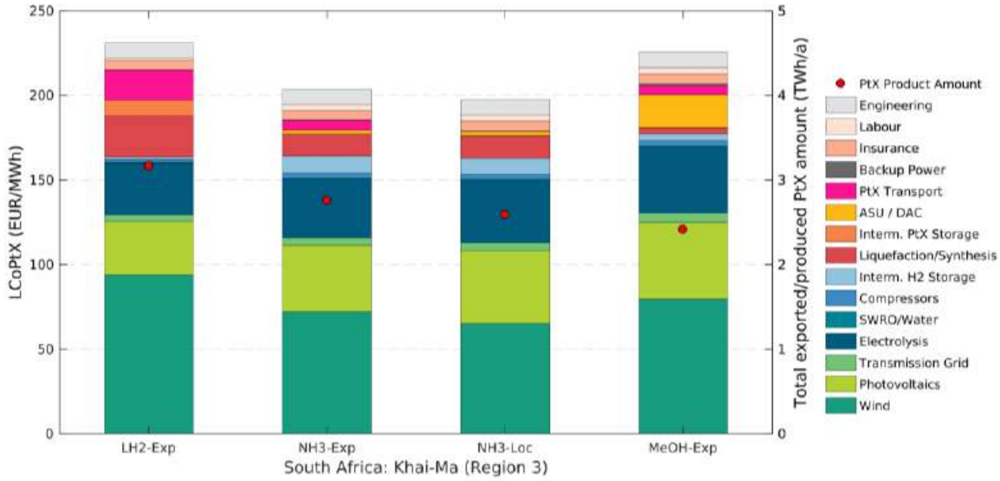

Figure 9-77: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the South African site “Khai-Ma” (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-41: Key performance indicators for the cost-optimal system configuration for the South African region Khai-Ma (Region 3) for LH_2, NH_3, and MeOH.

South Africa **Khai-Ma**	LH_2 Export	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.7	1.1	1.0	1.1
Wind: LcoE (EUR/MWh_{el})			64	
PV: Installed capacity (GW_{el})	1.5	1.7	1.7	1.7
PV: LcoE (EUR/MWh_{el})			32	
Intermediate H_2 storage: Volume (1000*m³)	26	153	132	56
Liquefaction/ synthesis: Capacity (tpd)	385	1613	1513	1442
Electrolysis: Full load hours (h/yr)	5495	4943	4640	4441
Unused RE power (%)	13	12	12	11
Grid electricity used (%)	0.26	0.24	0.26	0.81
LcoPtX (EUR/MWh)	231	204	198	226
LcoPtX (EUR/ton)	7703	1054	1023	1247
PtX Amount (GWh/yr)	3163	2757	2588	2412
Total electr. Demand (GWh_{el}/yr)	6271	5345	5017	5383
Selected investment cost (million EUR):				
Wind + PV	3536	2780	2552	2732
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	55	321	277	118
Liquefaction/Synthesis	638	285	274	67
ASU/DAC	-	64	60	376
Total System	6296	4886	4468	4667

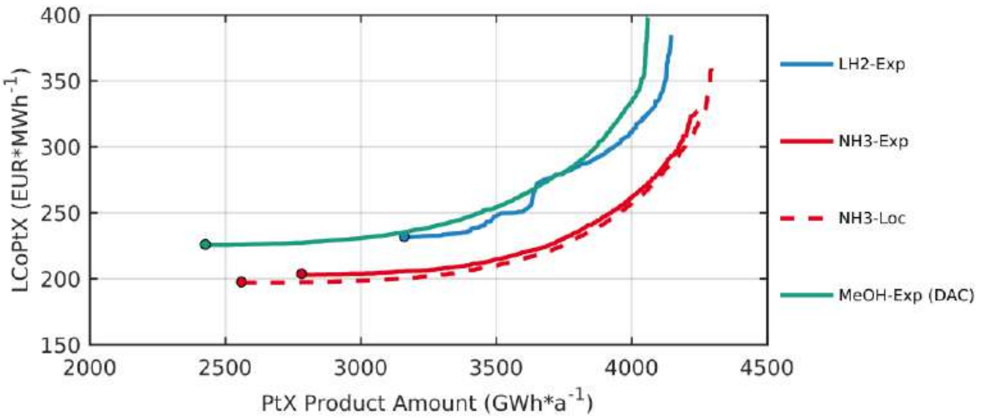

Figure 9-78: The Pareto fronts for the South African site "Khai-Ma" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.10 Spain

9.10.1 Renewable potential analysis

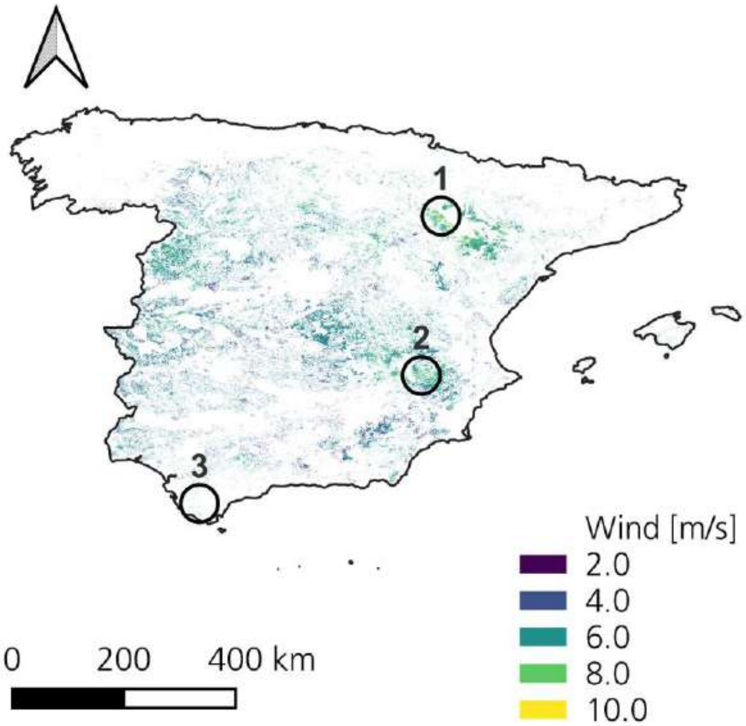

Figure 9-79: Selected regions and wind potential in Spain.

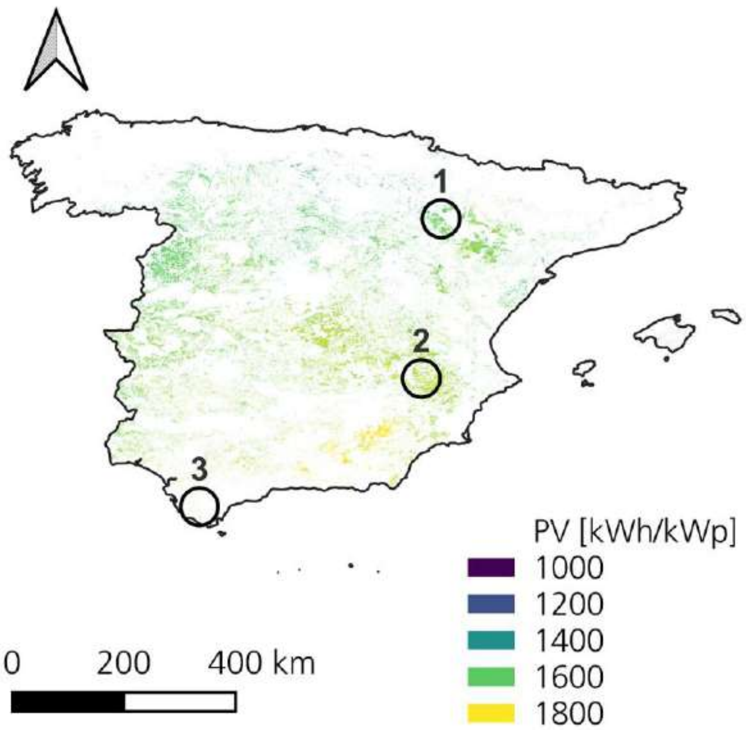

Figure 9-80: Selected regions and PV potential in Spain.

9.10.2 Techno-economic results – Pedrola (Region 1)

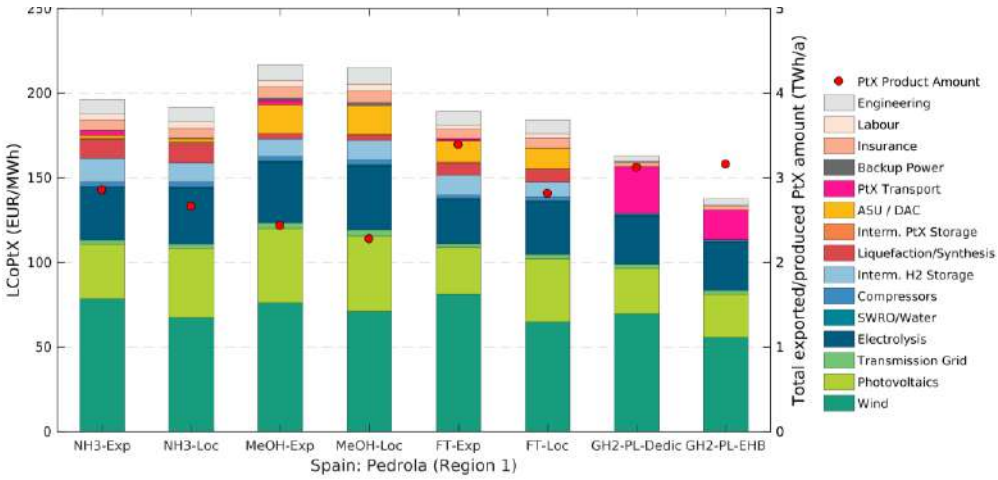

Figure 9-81: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Spanish site "Pedrola" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-42: Key performance indicators for the cost-optimal system configuration for the Spanish region "Pedrola" (Region 1) for NH_3 and MeOH.

Spain **Pedrola**	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.4	1.1	1.1	1.0
Wind: LcoE (EUR/MWh_{el})	55			
PV: Installed capacity (GW_{el})	1.7	2.0	2.0	1.9
PV: LcoE (EUR/MWh_{el})	35			
Intermediate H_2 storage: Volume (1000*m³)	257	193	163	169
Liquefaction/ synthesis: Capacity (tpd)	1615	1518	1382	1301
Electrolysis: Full load hours (h/yr)	5116	4767	4473	4187
Unused RE power (%)	14	15	13	11
Grid electricity used (%)	0.08	0.10	0.56	0.63
LcoPtX (EUR/MWh)	196	191	217	215
LcoPtX (EUR/ton)	1016	992	1198	1189
PtX Amount (GWh/yr)	2854	2659	2430	2274
Total electr. Demand (GWh_{el}/yr)	5522	5147	5409	5062
Selected investment cost (million EUR):				
Wind + PV	3043	2819	2857	2582
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	539	406	343	356
Liquefaction/Synthesis	285	275	66	63
ASU/DAC	64	60	360	339
Total System	5299	4841	4935	4596

Table 9-43: Key performance indicators for the cost-optimal system configuration for the Spanish region "Pedrola" (Region 1) for jet fuel, FT-mix and gaseous H_2.

Spain **Pedrola**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:						
Wind: Installed capacity (GW_{el})	1.3	1.4	1.7	1.1	1.3	1.1
Wind: LcoE (EUR/MWh_{el})	55					
PV: Installed capacity (GW_{el})	1.6	1.8	1.7	1.9	1.5	1.5
PV: LcoE (EUR/MWh_{el})	35					
Intermediate H_2 storage: Volume (1000*m^3)	273	303	258	160	-	-
Liquefaction/ synthesis: Capacity (tpd)	270	284	790	656	463	463
Electrolysis: Full load hours (h/yr)	5018	5270	5564	4617	5437	4908
Unused RE power (%)	14	16	18	18	11	8
Grid electricity used (%)	0.08	0.08	0.06	0.10	-	-
LcoPtX (EUR/MWh)	358	356	189	184	163	137
LcoPtX (EUR/ton)	4400	4376	2313	2252	5430	4574
PtX Amount (GWh/yr)	1166	1224	3387	2810	3120	3156
Total electr. Demand (GWh_{el}/yr)	5406	5688	6015	4978	5402	4858
Selected investment cost (million EUR):						
Wind + PV	2981	3196	3528	2808	2889	2482
PEM Electrolysis	750	750	750	750	750	750
Intermediate H_2 storage	574	636	542	337	-	-
Liquefaction/Synthesis	201	207	214	192	-	-
ASU/DAC	319	336	356	295	-	-
Total System	5430	5705	6030	4890	4968	3544

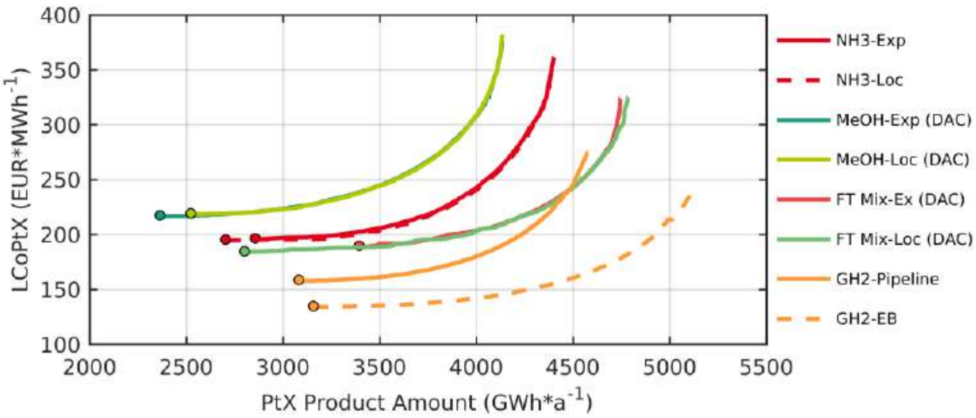

Figure 9-82: The Pareto fronts for the Spanish site "Pedrola" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.10.3 Techno-economic results – Albacete (Region 2)

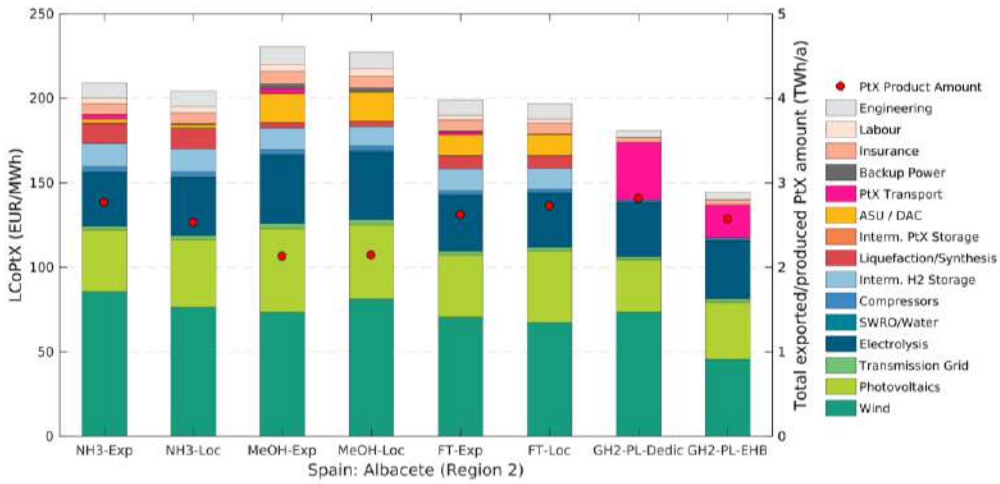

Figure 9-83: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Spanish site "Albacete" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-44: Key performance indicators for the cost-optimal system configuration for the Spanish region Albacete (Region 2) for NH_3 and MeOH.

Spain **Albacete**	NH_3 Export	NH_3 Local	MeOH Export	MeOH Local
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.5	1.2	1.0	1.1
Wind: LcoE (EUR/MWh_{el})	64			
PV: Installed capacity (GW_{el})	1.9	1.9	1.9	1.7
PV: LcoE (EUR/MWh_{el})	33			
Intermediate H_2 storage: Volume ($1000*m^3$)	245	217	175	157
Liquefaction/ synthesis: Capacity (tpd)	1634	1453	1202	1211
Electrolysis: Full load hours (h/yr)	4957	4532	3915	3941
Unused RE power (%)	18	17	15	13
Grid electricity used (%)	0.11	0.14	0.97	0.84
LcoPtX (EUR/MWh)	209	204	230	228
LcoPtX (EUR/ton)	1083	1058	1274	1258
PtX Amount (GWh/yr)	2765	2528	2127	2141
Total electr. Demand (GWh_{el}/yr)	5377	4907	4766	4783
Selected investment cost (million EUR):				
Wind + PV	3388	2964	2660	2707
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	514	455	368	331
Liquefaction/Synthesis	287	268	60	61
ASU/DAC	65	57	313	316
Total System	5603	5009	4679	4634

Table 9-45: Key performance indicators for the cost-optimal system configuration for the Spanish region Albacete (Region 2) for jet fuel, FT-mix and gaseous H_2.

Spain Albacete	**Jet Fuel Export**	**Jet Fuel Local**	**FT-Mix Export**	**FT-Mix Local**	**GH_2 PL Dedic.**	**GH_2 PL EHB**
Technoeconomic KPI:						
Wind: Installed capacity (GW_{el})	1.3	1.2	1.2	1.2	1.3	0.7
Wind: LcoE (EUR/MWh_{el})			64			
PV: Installed capacity (GW_{el})	1.9	1.8	1.8	2.1	1.6	1.6
PV: LcoE (EUR/MWh_{el})			33			
Intermediate H_2 storage: Volume (1000*m³)	226	228	215	211	-	-
Liquefaction/ synthesis: Capacity (tpd)	249	239	610	641	463	463
Electrolysis: Full load hours (h/yr)	4585	4390	4305	4475	5051	3992
Unused RE power (%)	20	17	18	22	12	8
Grid electricity used (%)	0.13	0.14	0.14	0.15	-	-
LcoPtX (EUR/MWh)	387	381	199	197	181	145
LcoPtX (EUR/ton)	4755	4676	2433	2405	6022	4815
PtX Amount (GWh/yr)	1065	1020	2621	2724	2811	2567
Total electr. Demand (GWh_{el}/yr)	4961	4746	4652	4846	5028	3962
Selected investment cost (million EUR):						
Wind + PV	3113	2883	2834	3029	2940	2075
PEM Electrolysis	750	750	750	750	750	750
Intermediate H_2 storage	474	478	451	442	-	-
Liquefaction/Synthesis	192	187	183	189	-	-
ASU/DAC	295	283	275	289	-	-
Total System	5373	5088	5041	5203	5105	3115

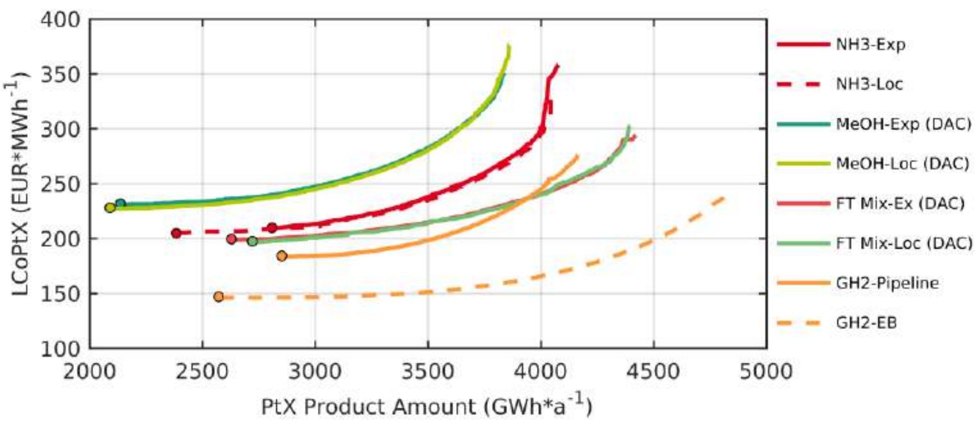

Figure 9-84: The Pareto fronts for the Spanish site "Albacete" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.10.4 Techno-economic results – Gibraltar/Cádiz (Region 3)

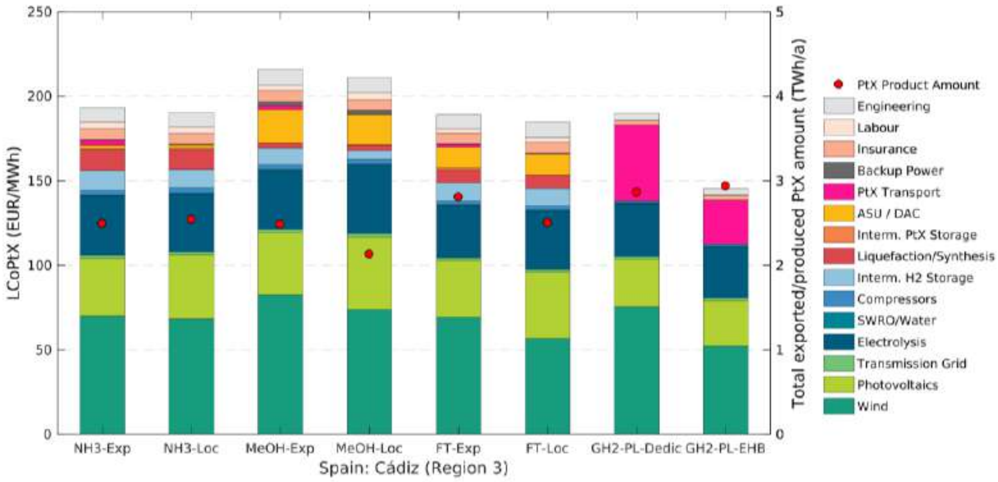

Figure 9-85: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Spanish site "Gibraltar/Cádiz" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-46: Key performance indicators for the cost-optimal system configuration for the Spanish region "Gibraltar/Cádiz" (Region 3) for NH_3 and MeOH.

Spain **Gibraltar/Cádiz**	NH_3 Export	NH_3 Local	MeOH Export
Technoeconomic KPI:			
Wind: Installed capacity (GW_{el})	1.1	1.1	1.3
Wind: LcoE (EUR/MWh_{el})		57	
PV: Installed capacity (GW_{el})	1.6	1.8	1.7
PV: LcoE (EUR/MWh_{el})		34	
Intermediate H_2 storage: Volume (1000*m³)	186	177	153
Liquefaction/ synthesis: Capacity (tpd)	1438	1467	1605
Electrolysis: Full load hours (h/yr)	4465	4555	4571
Unused RE power (%)	12	15	12
Grid electricity used (%)	0.16	0.17	0.74
LcoPtX (EUR/MWh)	193	190	216
LcoPtX (EUR/ton)	1002	986	1194
PtX Amount (GWh/yr)	2491	2541	2483
Total electr. Demand (GWh_{el}/yr)	4826	4931	5548
Selected investment cost (million EUR):			
Wind + PV	2539	2655	2889
PEM Electrolysis	750	750	750
Intermediate H_2 storage	390	371	322
Liquefaction/Synthesis	266	269	72
ASU/DAC	57	58	418
Total System	4546	4581	4975

Table 9-47: Key performance indicators for the cost-optimal system configuration for the Spanish region "Gibraltar/Cádiz" (Region 3) for jet fuel, FT-mix and gaseous H_2.

Spain **Gibraltar/Cádiz**	Jet Fuel Export	Jet Fuel Local	FT-Mix Export	FT-Mix Local	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:						
Wind: Installed capacity (GW_{el})	1.0	0.8	1.2	0.9	1.3	0.9
Wind: LcoE (EUR/MWh_{el})	57					
PV: Installed capacity (GW_{el})	1.6	1.7	1.7	1.8	1.5	1.5
PV: LcoE (EUR/MWh_{el})	34					
Intermediate H_2 storage: Volume (1000*m³)	188	198	191	167	-	-
Liquefaction/ synthesis: Capacity (tpd)	232	216	654	583	463	463
Electrolysis: Full load hours (h/yr)	4305	3980	4619	4116	5309	4569
Unused RE power (%)	15	13	18	16	13	9
Grid electricity used (%)	0.16	0.21	0.15	0.19	-	-
LcoPtX (EUR/MWh)	356	351	189	185	190	145
LcoPtX (EUR/ton)	4374	4307	2314	2256	6322	4844
PtX Amount (GWh/yr)	1000	924	2806	2500	2862	2938
Total electr. Demand (GWh_{el}/yr)	4647	4299	4995	4449	5288	4533
Selected investment cost (million EUR):						
Wind + PV	2518	2207	2825	2382	2873	2282
PEM Electrolysis	750	750	750	750	750	750
Intermediate H_2 storage	395	416	401	351	-	-
Liquefaction/Synthesis	183	176	191	179	-	-
ASU/DAC	275	256	295	262	-	-
Total System	4632	4268	5019	4379	5407	3302

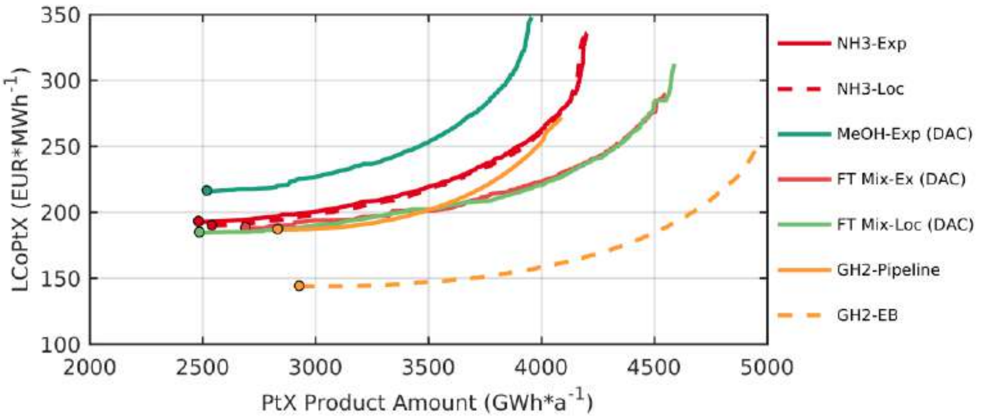

Figure 9-86: The Pareto fronts for the Spanish site "Gibraltar/Cádiz" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.11 Tunisia

9.11.1 Renewable potential analysis

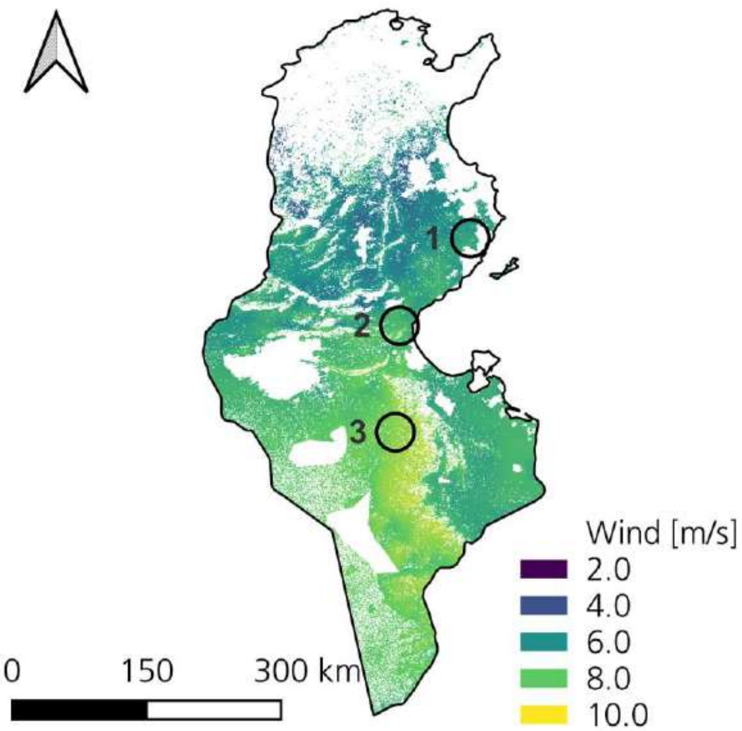

Figure 9-87: Selected regions and wind potential in Tunisia.

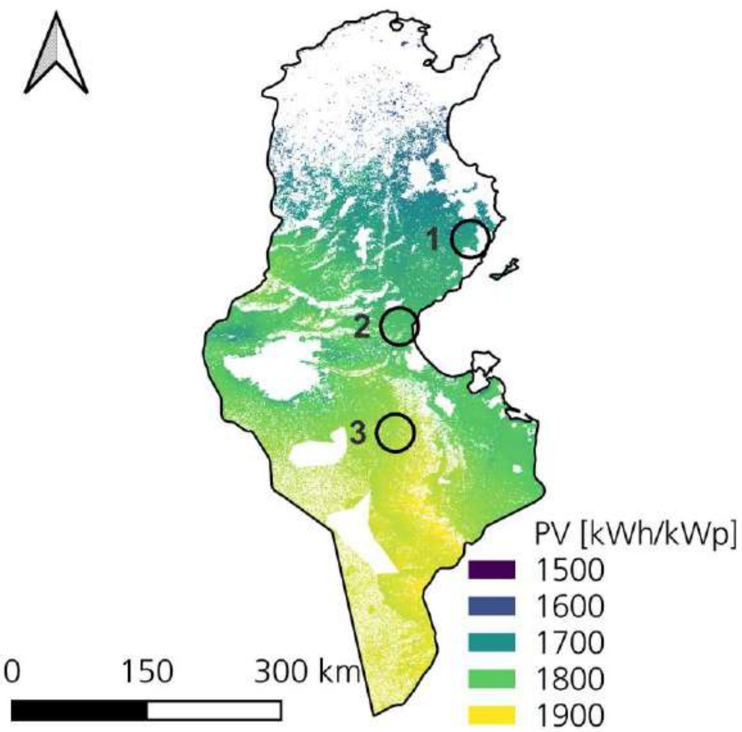

Figure 9-88: Selected regions and PV potential in Tunisia.

9.11.2 Techno-economic results – Sfax (Region 1)

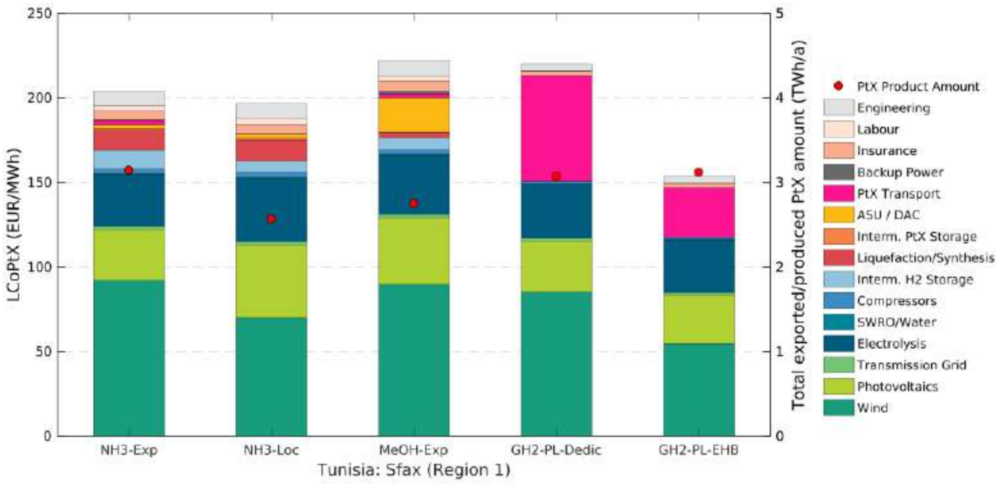

Figure 9-89: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Tunisian site "Sfax" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-48: Key performance indicators for the cost-optimal system configuration for the Tunisian region Sfax (Region 1) for NH_3, MeOH, and gaseous H_2.

Tunisia **Sfax**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.6	1.0	1.4	1.5	0.9
Wind: LcoE (EUR/MWh_{el})			60		
PV: Installed capacity (GW_{el})	1.5	1.7	1.7	1.4	1.4
PV: LcoE (EUR/MWh_{el})			36		
Intermediate H_2 storage: Volume ($1000*m^3$)	196	94	109	-	-
Liquefaction/ synthesis: Capacity (tpd)	1824	1467	1698	463	463
Electrolysis: Full load hours (h/yr)	5626	4589	5050	5879	4843
Unused RE power (%)	17	17	13	14	8
Grid electricity used (%)	0.10	0.14	0.54	-	-
LcoPtX (EUR/MWh)	204	197	222	220	154
LcoPtX (EUR/ton)	1057	1019	1229	7333	5123
PtX Amount (GWh/yr)	3138	2559	2743	3068	3113
Total electr. Demand (GWh_{el}/yr)	6094	4953	6113	5863	4792
Selected investment cost (million EUR):					
Wind + PV	3360	2594	3137	3108	2308
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	412	198	229	-	-
Liquefaction/Synthesis	307	269	74	-	-
ASU/DAC	72	58	443	-	-
Total System	5476	4308	5144	6147	3325

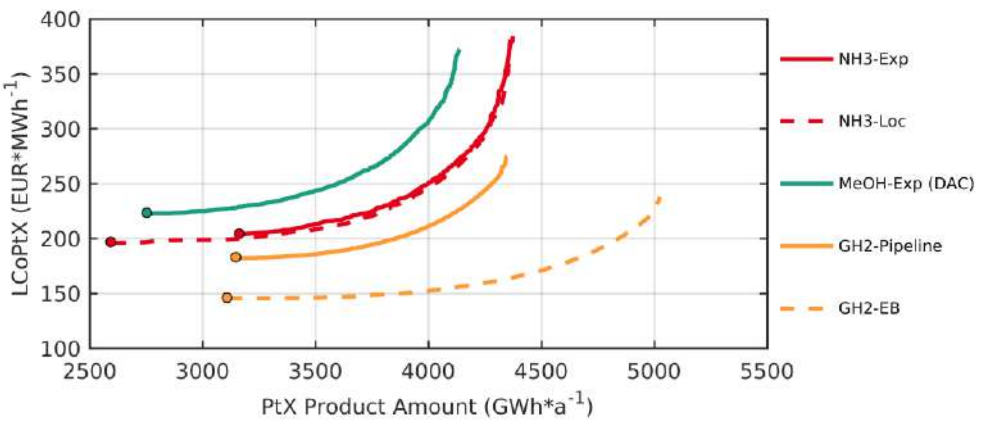

Figure 9-90: The Pareto fronts for the Tunisian site "Sfax" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.11.3 Techno-economic results – Shkira (Region 2)

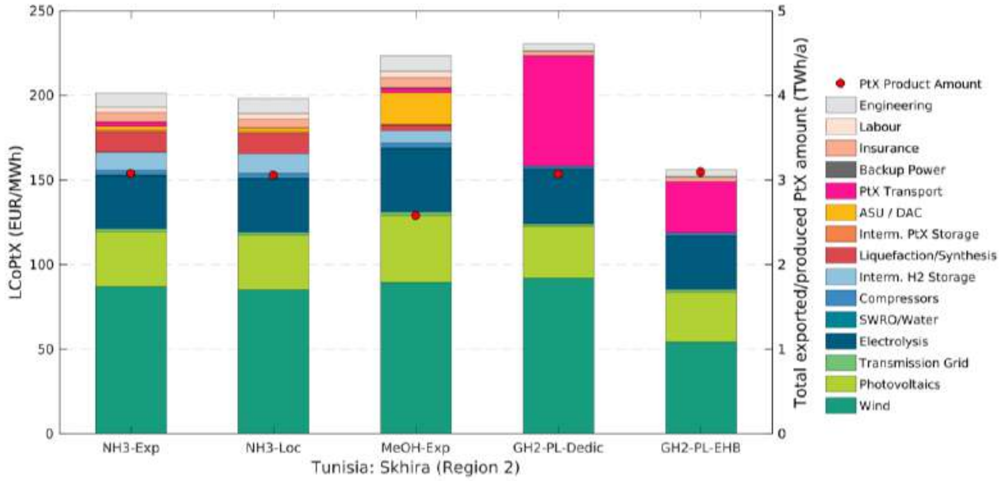

Figure 9-91: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Tunisian site "Shkira" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-49: Key performance indicators for the cost-optimal system configuration for the Tunisian region Skhira (Region 2) for NH_3, MeOH, and gaseous H_2.

Tunisia **Skhira**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.5	1.5	1.3	1.6	1.0
Wind: LcoE (EUR/MWh_{el})			63		
PV: Installed capacity (GW_{el})	1.5	1.5	1.6	1.4	1.4
PV: LcoE (EUR/MWh_{el})			36		
Intermediate H_2 storage: Volume (1000*m³)	178	194	107	-	-
Liquefaction/ synthesis: Capacity (tpd)	1797	1796	1485	463	463
Electrolysis: Full load hours (h/yr)	5510	5472	4745	6079	4806
Unused RE power (%)	14	13	12	13	7
Grid electricity used (%)	0.04	0.04	0.34	-	-
LcoPtX (EUR/MWh)	201	198	224	230	156
LcoPtX (EUR/ton)	1043	1026	1236	7673	5202
PtX Amount (GWh/yr)	3073	3052	2577	3067	3090
Total electr. Demand (GWh_{el}/yr)	5948	5905	5713	6060	4750
Selected investment cost (million EUR):					
Wind + PV	3265	3187	2978	3333	2331
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	374	407	226	-	-
Liquefaction/Synthesis	304	304	69	-	-
ASU/DAC	71	71	387	-	-
Total System	5337	5222	4909	6460	3350

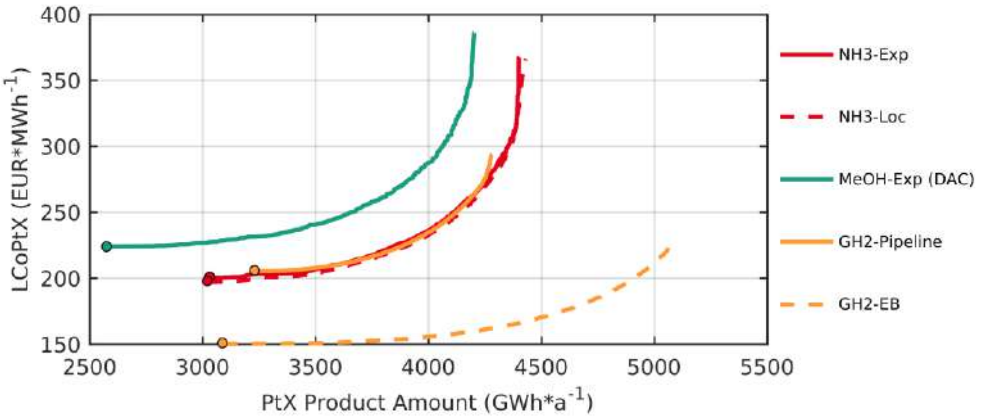

Figure 9-92: The Pareto fronts for the Tunisian site "Shkira" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.11.4 Techno-economic results – Medenine (Region 3)

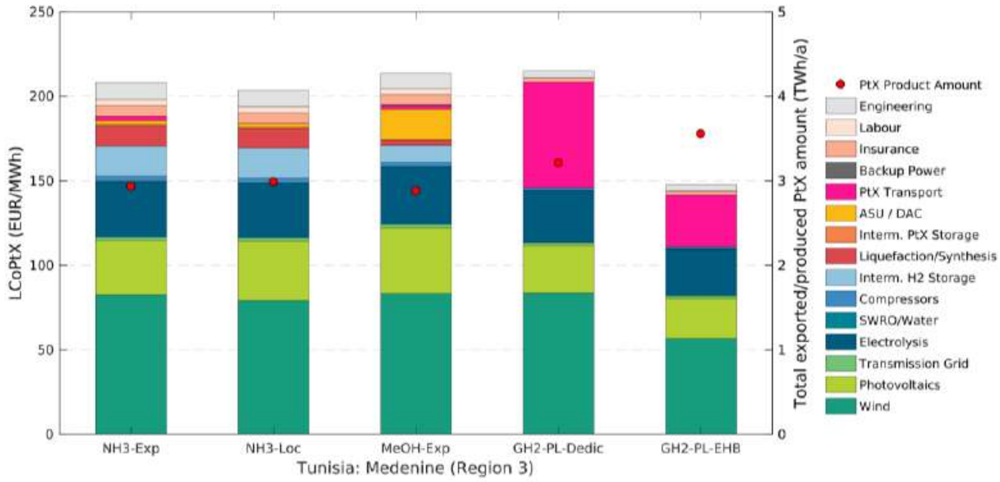

Figure 9-93: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Tunisian site "Medenine" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-50: Key performance indicators for the cost-optimal system configuration for the Tunisian region Medenine (Region 3) for NH_3, MeOH, and gaseous H_2.

Tunisia **Medenine**	NH_3 Export	NH_3 Local	MeOH Export	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:					
Wind: Installed capacity (GW_{el})	1.3	1.3	1.3	1.4	1.1
Wind: LcoE (EUR/MWh_{el})			55		
PV: Installed capacity (GW_{el})	1.4	1.6	1.7	1.4	1.3
PV: LcoE (EUR/MWh_{el})			35		
Intermediate H_2 storage: Volume (1000*m³)	292	293	161	-	-
Liquefaction/ synthesis: Capacity (tpd)	1615	1645	1582	463	463
Electrolysis: Full load hours (h/yr)	5274	5355	5297	6353	5523
Unused RE power (%)	17	18	14	12	7
Grid electricity used (%)	0.06	0.06	0.37	-	-
LcoPtX (EUR/MWh)	208	203	214	215	148
LcoPtX (EUR/ton)	1078	1054	1181	7163	4919
PtX Amount (GWh/yr)	2932	2985	2877	3205	3551
Total electr. Demand (GWh_{el}/yr)	5690	5783	6392	6341	5468
Selected investment cost (million EUR):					
Wind + PV	2884	2943	3045	3052	2453
PEM Electrolysis	750	750	750	750	750
Intermediate H_2 storage	614	615	339	-	-
Liquefaction/Synthesis	285	288	71	-	-
ASU/DAC	64	65	412	-	-
Total System	5216	5211	5163	6192	3485

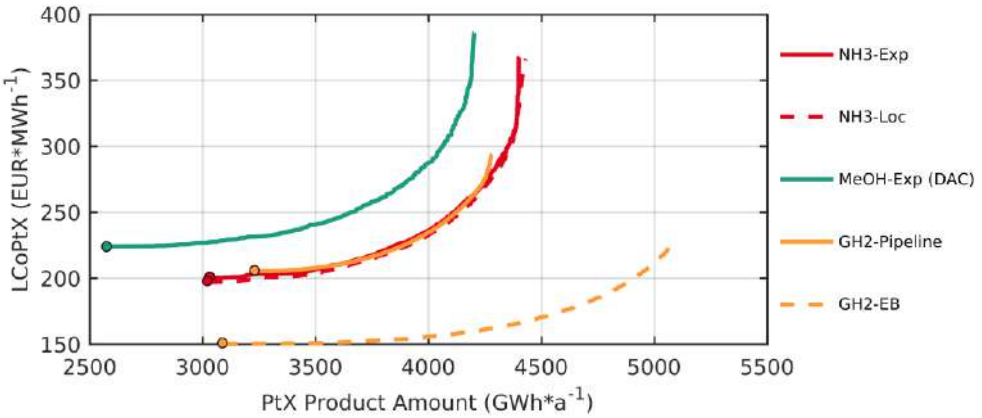

Figure 9-94: The Pareto fronts for the Tunisian site "Medenine" (region 3) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.12 Ukraine

9.12.1 Renewable potential analysis

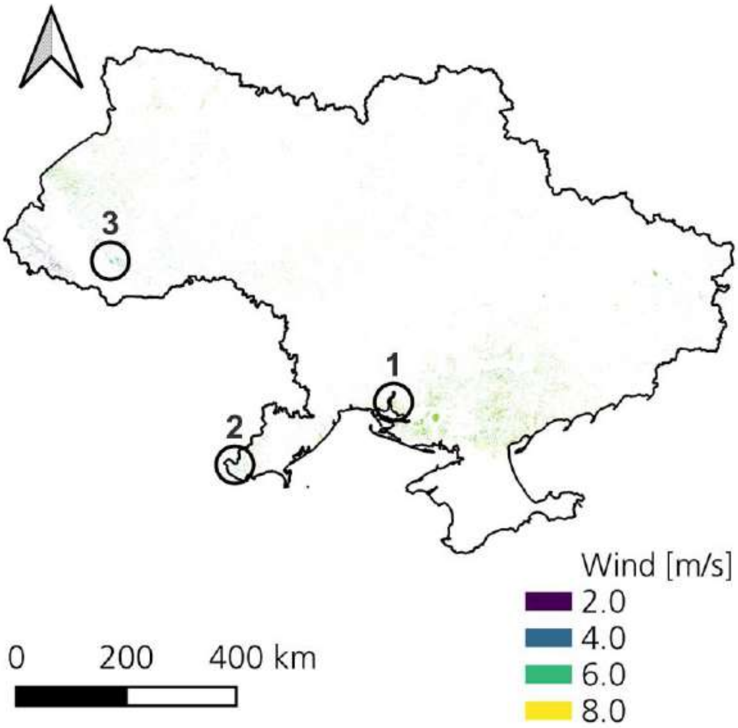

Figure 9-95: Selected regions and wind potential in the Ukraine.

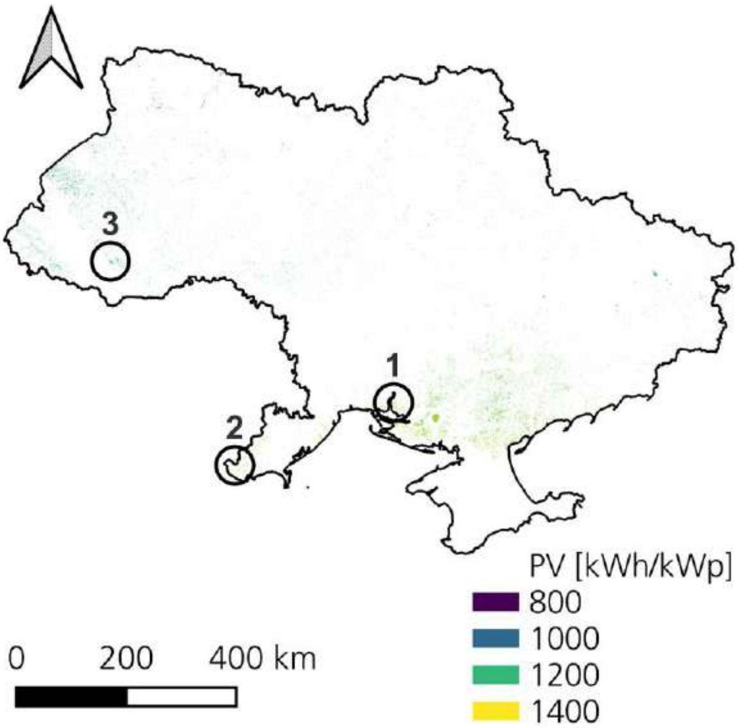

Figure 9-96: Selected regions and PV potential in the Ukraine.

9.12.2 Techno-economic results – Mykolaiv (Region 1)

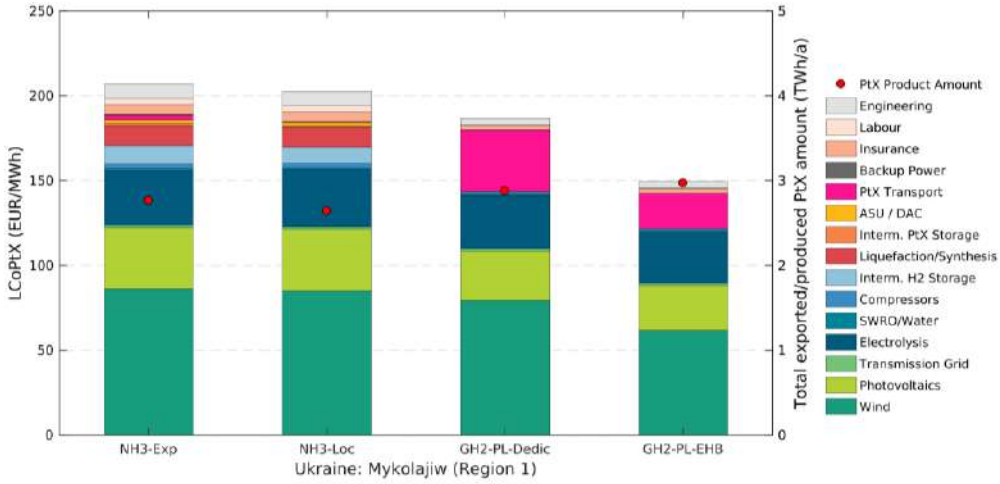

Figure 9-97: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Ukrainian site "Mykolaiv" (Region 1) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-51: Key performance indicators for the cost-optimal system configuration for the Ukrainian region Mykolaiv (Region 1) for NH_3 and gaseous H_2.

Ukraine **Mykolaiv**	**NH_3 Export**	**NH_3 Local**	**GH_2 PL Dedic.**	**GH_2 PL EHB**
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.5	1.4	1.4	1.1
Wind: LcoE (EUR/MWh_{el})	62			
PV: Installed capacity (GW_{el})	1.8	1.7	1.5	1.4
PV: LcoE (EUR/MWh_{el})	38			
Intermediate H_2 storage: Volume (1000*m³)	187	156	-	-
Liquefaction/ synthesis: Capacity (tpd)	1611	1520	463	463
Electrolysis: Full load hours (h/yr)	4954	4737	5167	4619
Unused RE power (%)	16	16	11	8
Grid electricity used (%)	0.28	0.28	-	-
LcoPtX (EUR/MWh)	207	203	187	149
LcoPtX (EUR/ton)	1072	1049	6219	4976
PtX Amount (GWh/yr)	2763	2641	2875	2970
Total electr. Demand (GWh_{el}/yr)	5365	5124	5133	4570
Selected investment cost (million EUR):				
Wind + PV	3281	3112	3014	2544
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	392	328	-	-
Liquefaction/Synthesis	285	275	-	-
ASU/DAC	64	60	-	-
Total System	5329	4977	5220	3544

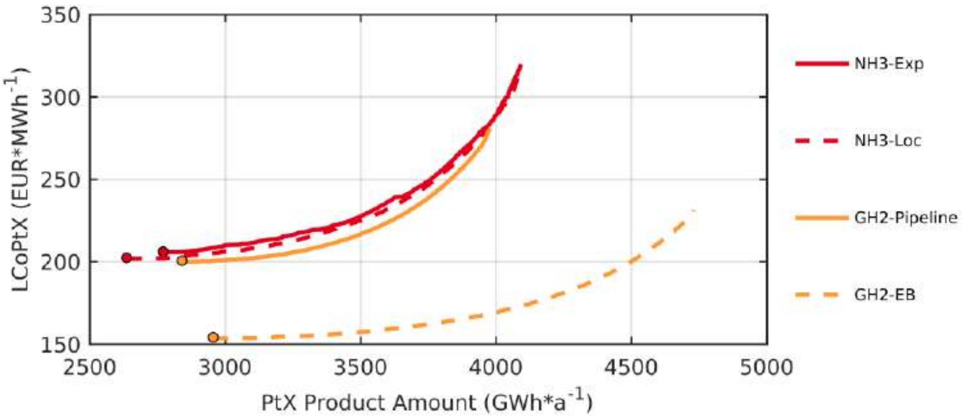

Figure 9-98: The Pareto fronts for the Tunisian site "Mykolaiv" (region 1) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.12.3 Techno-economic results – Odessa (Region 2)

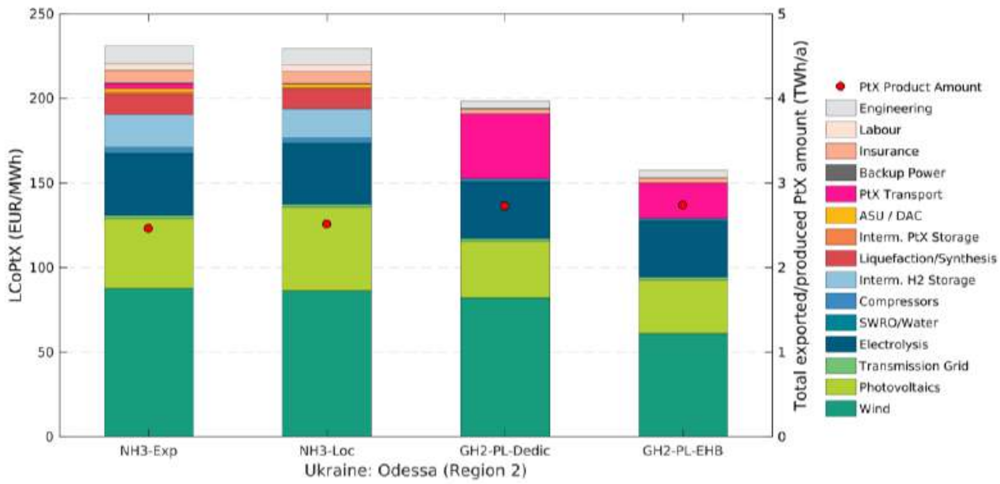

Figure 9-99: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Ukrainian site "Odessa" (Region 2) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-52: Key performance indicators for the cost-optimal system configuration for the Ukrainian region Odessa (Region 2) for NH_3 and gaseous H_2.

Ukraine **Odessa**	NH_3 Export	NH_3 Local	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.4	1.4	1.4	1.1
Wind: LcoE (EUR/MWh_{el})			69	
PV: Installed capacity (GW_{el})	1.8	2.2	1.6	1.6
PV: LcoE (EUR/MWh_{el})			38	
Intermediate H_2 storage: Volume (1000*m³)	1375	1398	463	463
Liquefaction/ synthesis: Capacity (tpd)	4408	4503	4897	4257
Electrolysis: Full load hours (h/yr)	17	23	12	9
Unused RE power (%)	0.35	0.35	-	-
Grid electricity used (%)	231	230	198	157
LcoPtX (EUR/MWh)	1198	1190	6601	5239
LcoPtX (EUR/ton)	2459	2509	2725	2737
PtX Amount (GWh/yr)	4771	4883	4864	4212
Total electr. Demand (GWh_{el}/yr)				
Selected investment cost (million EUR):	3172	3420	3138	2542
Wind + PV	750	750	750	750
PEM Electrolysis	631	566	-	-
Intermediate H_2 storage	259	262	-	-
Liquefaction/Synthesis	54	55	-	-
ASU/DAC	5457	5550	5350	3549
Total System	1375	1398	463	463

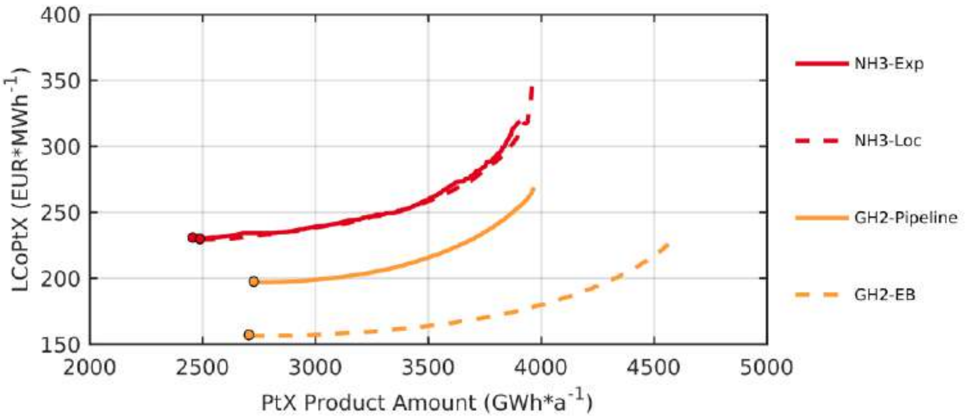

Figure 9-100: The Pareto fronts for the Ukrainian site "Odessa" (region 2) show the respective PtX supply costs (LcoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

9.12.4 Techno-economic results – Chernivtsi (Czernowitz, Region 3)

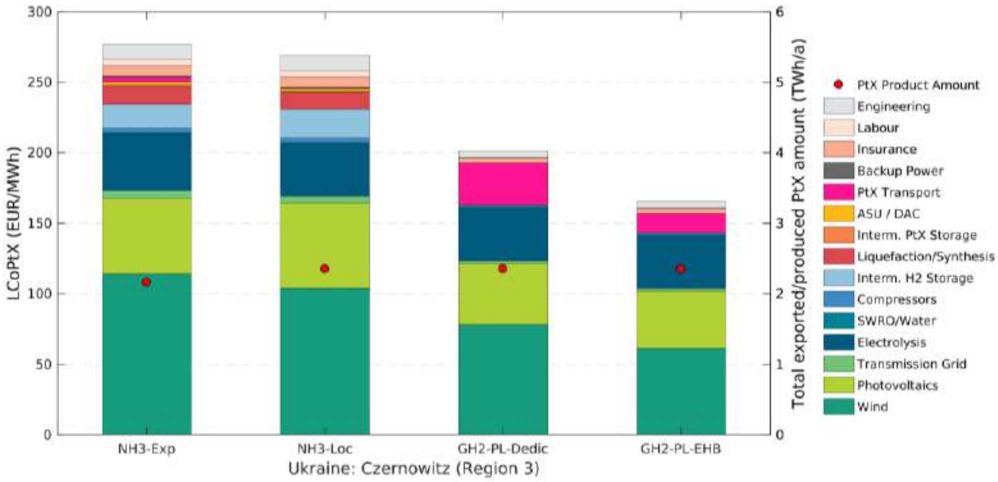

Figure 9-101: Cost breakdowns (left y-axis) and total PtX product amounts (right y-axis) for the Ukrainian site "Chernivtsi" (Region 3) and the assessed PtX energy carriers and their local production (-Loc) or supply cost (-Exp) including transport to Germany. The costs shown here apply to the respective cost-optimal system layout. The respective energy demands of individual components (such as electrolysis or compressors) are included in the cost shares of wind and PV (and not in the cost share of the electrolysis or compressors). The reason is that the systems are almost exclusively supplied by the local dedicated wind and PV plants. Therefore, the energy demand of a specific component directly affects the installed capacities of wind and PV.

Table 9-53: Key performance indicators for the cost-optimal system configuration for the Ukrainian region Chernivtsi (Region 3) for NH_3 and gaseous H_2.

Ukraine **Chernivtsi**	NH_3 Export	NH_3 Local	GH_2 PL Dedic.	GH_2 PL EHB
Technoeconomic KPI:				
Wind: Installed capacity (GW_{el})	1.6	1.6	1.2	1.0
Wind: LCoE (EUR/MWh_{el})	77			
PV: Installed capacity (GW_{el})	2.1	2.5	1.8	1.7
PV: LCoE (EUR/MWh_{el})	43			
Intermediate H_2 storage: Volume (1000*m³)	228	298	-	-
Liquefaction/ synthesis: Capacity (tpd)	1196	1316	463	463
Electrolysis: Full load hours (h/yr)	3899	4264	4095	3647
Unused RE power (%)	27	28	13	10
Grid electricity used (%)	0.46	0.49	0.01	0.01
LCoPtX (EUR/MWh)	272	263	201	166
LCoPtX (EUR/ton)	1409	1363	6703	5516
PtX Amount (GWh/yr)	2171	2374	2350	2344
Total electr. demand (GWh_{el}/yr)	4243	4648	4073	3617
Selected investment cost (million EUR):				
Wind + PV	3700	3957	2922	2456
PEM Electrolysis	750	750	750	750
Intermediate H_2 storage	480	626	-	-
Liquefaction/Synthesis	238	252	-	-
ASU/DAC	47	52	-	-
Total System	5760	6143	4736	3464

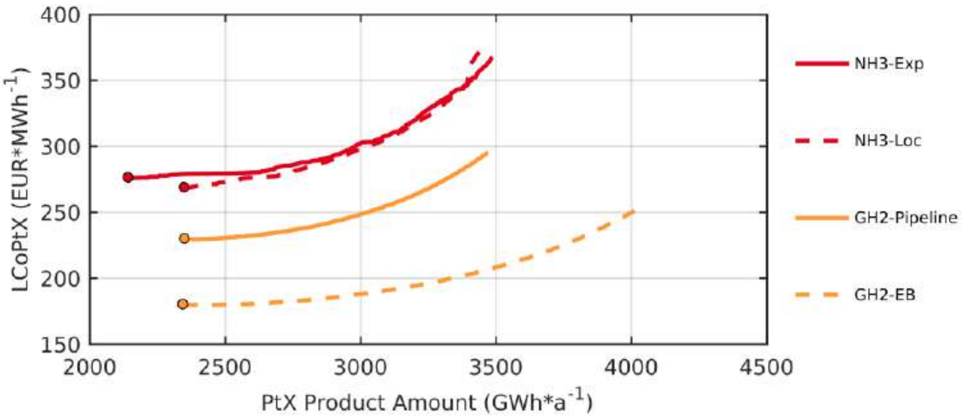

Figure 9-102: The Pareto fronts for the Ukrainian site "Chernivtsi" (region 3) show the respective PtX supply costs (LCoPtX; incl. transport) identified in the optimization process as a function of the total PtX product amount. The PtX system designs and costs presented and discussed in this study always refer to the absolute cost optimum at the left end of the Pareto fronts. If a higher product amount (at a constant installed electrolysis capacity of 1 GW_{el}) is targeted at a site, this can be significantly increased in some cases with only a slight increase in PtX supply costs.

Fraunhofer Institute for Solar Energy Systems ISE
Heidenhofstraße 2
79110 Freiburg im Breisgau
Germany
www.ise.fraunhofer.de

Contact:

Dr.-Ing. Christoph Hank
Hydrogen Technologies
Sustainable Synthesis Products
christoph.hank@ise.fraunhofer.de

Fraunhofer Institute for Solar Energy Systems ISE
Heidenhofstraße 2
79110 Freiburg im Breisgau
Germany
www.ise.fraunhofer.de