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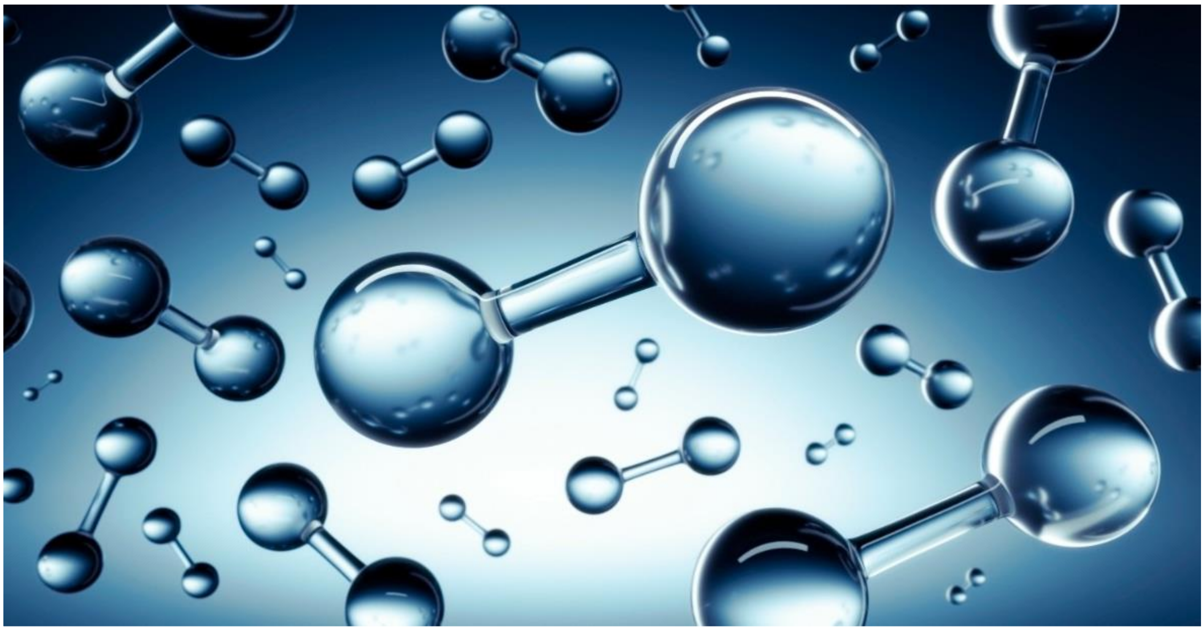

Assessment and analysis of the Power-to-X market and investment opportunities in Algeria

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List of abbreviations

AER	Ambitious Emission Reduction" scenario. AER+ represents the same scenario with hydrogen exports.
BAU	Business as Usual" scenario
BMZ	German Federal Ministry for Economic Cooperation and Development
CBAM	Carbon Border Adjustment Mechanism
WACC	Weighted average cost of capital
RE	Renewable energy
GHG	Greenhouse gases
HV	High voltage
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
MEM	Algerian Ministry of Energy and Mines
NZE	Net Zero Emissions" scenario. NZE+ represents the same scenario with hydrogen exports.
GDP	Gross domestic product
PIAT	In-Salah/Adrar/Timimoun Hub
PtX	Power to X (transformation of electrical energy into chemical products and energy carriers)
RED	Renewable Energy Directive
RIN	Interconnected Network North
GIS	Geographic information system
STEP	Water treatment plant
ZIP	Industrial port zone

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Summary

In addition to the main pillars of energy efficiency and renewable energy sources, global carbon neutrality targets call for the replacement of fossil fuels with synthetic fuels and energy carriers based on renewable energies (Power-to-X), particularly in sectors where the direct use of electricity is difficult or impossible. Over the coming decades, this will mean strong global demand for PtX products, such as green hydrogen and ammonia. Countries with limited resources and space for renewable energies, such as the Member States of the European Union and Germany in particular, will continue to depend on imports of these products to achieve their decarbonisation objectives.

Algeria, with its vast renewable energy potential and existing export infrastructure, could play a major role in the global PtX economy in the future and benefit from additional economic development opportunities through job creation and the effects of innovation.

During the intergovernmental negotiations in September 2021, the governments of Algeria and Germany decided to deepen and broaden their cooperation in the field of green hydrogen / renewable energies. In this context, this study examines the possibilities for Algeria to develop a local value chain for the PtX sector. The German development bank KfW has been mandated by the Federal Ministry for Economic Cooperation and Development (BMZ) to commission and support this study jointly with the Ministry of Energy and Mines (MEM). The results were worked out in three workshops using an interactive approach with key energy players in Algeria in the period from June 2022 to May 2023. The study was conducted by the Fraunhofer Society for Applied Research, represented by its two research institutes, the Fraunhofer Institute for Systems Research and Innovation ISI and the Fraunhofer Institute for Solar Energy Systems ISE.

The study first assesses renewable energy (RE) resources and develops market scenarios for PtX technology in the context of carbon dioxide emissions (CO_2)[1] scenarios for Algeria, taking into account Algeria's decarbonisation, its domestic demand for hydrogen and PtX products, as well as their exports.

Three main scenarios are defined for the analyses:

- The "**Business as Usual**" **(BAU)** scenario serves as a reference scenario, with no particular ambitions for decarbonisation. Emissions are almost doubled compared with today.
- In the "**Ambitious Emissions Reduction**" **(AER)** scenario, the use of fossil fuels and the associated CO2 emissions are considerably reduced by 2050. However, some fossil fuels remain in the energy system, both for final energy demand and for electricity generation. Emissions are reduced by 50% compared with today. This scenario presents the most realistic approach for Algeria regarding an ambitious approach to the decarbonisation of its economy. Another interpretation of this scenario is that zero net CO_2 emissions can only be achieved after 2050 in Algeria.
- The highly ambitious "**Net Zero Emissions**" **(NZE)** scenario aims to achieve zero net emissions of CO_2 by 2050, like the world as a whole. Such a scenario is particularly justified in the close economic context between Algeria and the European Union, with a Border Carbon Adjustment Mechanism (BCAM) being set up for countries that export their products to the European Union without reducing their own emissions.

The last two scenarios are combined with hydrogen exports, increasing to 15 TWh in 2035 and reaching 100 TWh in 2050. An analysis of the scenarios shows the following:

[1] This study only concerns CO_2 emission scenarios and not greenhouse gases (GHGs) in their entirety, which include CH_4, N_2O, etc.

- In the BAU scenario, final energy demand (FED) is expected to exceed 900 TWh by 2050. However, the other two scenarios forecast slower growth in FED. In the AER scenario, energy demand peaks around 2040, at just over 600 TWh, and remains at this level until 2050 (compared with 500 TWh today). In the NZE scenario, the FED peaks around 2040, then falls slightly to around 550 TWh in 2050.
- In the AER scenario, renewable fuels account for around 65% of the FED in 2050, of which 49% come from electricity and the remainder from biomass and renewable heat. Fossil fuels (in particular natural gas) still cover 35% of energy demand in 2050. Hydrogen makes a small contribution to domestic demand, as the level of decarbonisation does not yet require hydrogen in large quantities, which essentially contributes to exports.
- In the NZE scenario, fossil fuels are completely eliminated by 2050. Over 60% of the energy mix is electricity, supplemented by renewable heat sources such as solar, geothermal, biomass and hydrogen. Hydrogen contributes 100 TWh to domestic demand, and a similar amount to exports.
- Power generation capacity is increasing considerably, with photovoltaic and wind energy playing a key role in electricity production in all three cases.

The study then identifies and analyses in detail the sites and production configurations for hydrogen in Algeria.

The national roadmap for the development of hydrogen in Algeria provides for :
- an initial demonstration phase through short-term pilot projects (2023-2030; from 2 to 50 MW in size) (MEM 2023);
- a second phase of large-scale deployment and market creation (2030-2040);
- a third competitive market phase (2040-2050).

The choice of site for a PtX project depends on a multitude of geographical, social, political and regulatory variables. An in-depth spatial study is therefore the basis for any informed and justified decision to deploy such a project. Beyond the choice of site, a technical and economic study is used to detail the business model and ensure the project's profitability. This study provides the initial indicators that will then be refined in a feasibility study, including a request for specific quotes.

The renewable energy and PtX production sites were selected on the basis of a multi-criteria decision-making framework, taking into account technical-economic and other criteria (overlay analysis). During the workshop in December 2022 in Algiers, the stakeholders indicated the order for the weighting of the criteria for the selection of PtX sites.

The study initially analyses four sites, comparing their advantages and disadvantages. Following discussions during and after the workshop in December 2022, two sites were selected for detailed analysis:

- For an initial demonstration site and by 2030, a **50 MW electrolysis plant** has been set up in **Arzew** and 79-114 MW of renewable energy capacity has been installed to supply it. Despite the demonstration nature of the project, LCOHs of €4.5-5/kg can be achieved, assuming funding assistance. It should be borne in mind that this is a demonstration system, that investment costs for electrolysers are currently still high and that the subsequent construction of a larger system will unlock economies of scale. It is useful to recognise the construction of such a demonstration system primarily as an opportunity to accumulate knowledge for the construction, operation and maintenance of electrolysers and RE. As far as the use of the products is concerned, this study recommends using the hydrogen produced in industrial processes that already use hydrogen from fossil sources. One possibility would be ammonia synthesis.
- For a second site, and with a horizon of 2030 onwards, a **1,000 MW electrolysis plant is being** considered at **Hassi R'Mel**. We can see the effects of scale and the price reductions expected

in the years to come. The cost of hydrogen is significantly lower than for site 1 (LCOH of around €4/kg). Hydrogen costs are dominated by the cost of renewable energy. For the purposes of the study, it appeared more advantageous to transport electrons rather than molecules (i.e. to place the electrolysers close to the coast). In the case in point - 1,000 MW of electrolysis and a distance of around 500 km - the net difference between "coastal EL" and "near RE EL" LCOHs is fairly small. As the economic analysis shows, an increase in electrolysis capacity could tip the balance in favour of the "near-zero RE" concept.
- However, transport infrastructure costs account for less than 10% in all cases. For economic reasons, in particular the fact of being able to take advantage of economies of scale for large desalination plants on the coast, seawater has been favoured as a source in the modelling. For large RE projects far from the coast, other sources such as water downstream from wastewater treatment plants (WWTPs) will have to be studied.

The economic data chosen for the analysis can be considered conservative in several respects, particularly for the first installation at the Arzew site. Taken together, these factors can contribute in an optimistic case to reducing the costs of renewable electricity in 2025 by 20-25% compared to the values determined here. As the price of renewables represents a significant part of the cost of hydrogen, this also has an impact on the cost of hydrogen. A detailed study of the Arzew site and the financing conditions could provide more certainty about the optimal configuration and costs of the installation.

Finally, it should be emphasised that the installation of the electrolysers, the upstream hydrogen production chain (RE) and the downstream hydrogen production chain (production of PtX products) are accompanied by other monetary and non-monetary benefits (such as the creation of local jobs during construction and operation).

The third part of the study looked at the issue of **green hydrogen certification**. Certification is part of a wider reform of the laws and regulations governing the production, transport and use of hydrogen and its derivatives. In the context of hydrogen, certification is an instrument for guaranteeing that hydrogen complies with sustainability criteria and that it allows greenhouse gas (GHG) emissions to be reduced sufficiently. Certification is necessary because hydrogen is a homogeneous good that cannot be differentiated in terms of the greenhouse gas emissions of its supply chain or other environmental impacts. The hydrogen supply chain includes several life-cycle stages (production, packaging, transformation, transport) which can have an impact on the overall intensity of GHG emissions. Even "green" hydrogen, which is a common label referring to hydrogen produced from renewable electricity through electrolysis, can have a negative effect on decarbonisation efforts.

A number of definitions and criteria are important for the different cases of electricity distinguished by the European Renewable Energy Directive (RED II). These criteria must ensure that the production of renewable hydrogen encourages the production of new renewable energies and not the production of electricity from fossil fuels:

- **Additionality**: The additionality requirements ensure that the RE is newly installed for the purpose of using the electricity to produce hydrogen and that RE originally installed for a different purpose is not used to produce hydrogen and may defer its original use case. A renewable energy source is considered "new" if it was installed no more than 36 months before the installation of the electrolyser.
- **Temporal correlation**: The temporal requirement stipulates that the hydrogen is produced during the same hour as the electricity.
- **Spatial correlation**: Spatial correlation means that the RE and the electrolyser are located in the same tendering zone or that the RE is located in a neighbouring tendering zone where prices are equal to or higher than those in the hydrogen production zone.

The requirements for renewable hydrogen production will apply both **to domestic producers and to third-country producers who wish to export renewable hydrogen to the EU**. A certification system based on "voluntary schemes" will be set up to ensure that third-country producers comply with the same criteria.

To encourage the rapid expansion of electrolysers, and given the limited availability of unsubsidised renewable electricity generation in the near future, renewable hydrogen producers will have the option of signing long-term renewable electricity purchase agreements **with existing installations, provided that their electrolysers are commissioned before 2028**. The reason for this derogation is that the planning, authorisation procedures and installation of new additional renewable energy sources take time and could lead to delays in the deployment of electrolysers and limit the potential for creating economies of scale.

During a phasing-in period, renewable hydrogen producers are allowed to match renewable electricity production with its associated renewable hydrogen production **on a monthly basis**. In other words, renewable hydrogen producers can run their electrolysers at any time as long as the total amount of renewable electricity consumed matches the total amount of renewable hydrogen produced in that calendar month of the year. This will allow renewable hydrogen producers to provide a constant flow of renewable hydrogen to their customers, particularly in cases where no hydrogen storage infrastructure or options are yet available.

Auction zones may not be used in all countries. In this case, the delegated act provides that equivalent (most similar) concepts of a bidding zone are also allowed, provided that the objective of the delegated act is still respected. For example, similar market regulations or the physical characteristics of the network (level of interconnection) or the country itself are only allowed as a last resort.

The rules are designed to become stricter as the sector develops. From January 2030, all renewable hydrogen producers, including those with agreements with existing renewable power plants, will have to match the electricity they have purchased on an hourly basis. Member States wishing to do so may introduce hourly correlation from 1 July 2027, subject to notification to the Commission.

As there is not yet a global market for liquid hydrogen, a future certification system will need to be developed as the market grows. This will establish a framework for hydrogen exports. The study analyses the status quo of green hydrogen certification, the criteria relating to electricity to produce hydrogen, developments in certification processes, particularly in Europe, and discusses the implications for Algeria. The case most likely to apply to Algeria (mixed electricity grid) means that additionality, spatial and temporal criteria apply for Algerian hydrogen to be considered fully renewable in the EU. In addition, emissions from the supply chain must be kept low enough for the use of hydrogen to reduce greenhouse gas emissions by 70%.

The transitional provisions will enable Algeria to develop the hydrogen economy rapidly in cooperation with Germany and the European Union.

1 Introduction

Meeting global decarbonisation targets and achieving carbon neutrality will require increased efforts in energy efficiency and a global shift from fossil fuels to renewable energy sources. The global decarbonisation scenarios show that this also means replacing a proportion of fossil fuels with synthetic fuels and renewable energy carriers (Power-to-X), particularly in sectors where the direct use of electricity is not possible. This will create a strong global demand for PtX products, such as green hydrogen or ammonia, in the future. Countries with limited space and renewable energy resources, such as the member states of the European Union, will depend on imports of these products to meet their decarbonisation targets. Germany, for example, is likely to rely on imports to cover up to 70% of its hydrogen demand, which is expected to be between 90 and 110 TWh by 2030 (BMWK 2023).

Algeria, with its vast renewable energy resource potential, proximity to Europe and existing export infrastructure for fossil fuel-based energy carriers, could play a major role in the global PtX economy in the future, and could benefit from additional economic development opportunities through economic diversification, job creation and innovation effects. However, in addition to the techno-economic aspects, environmental aspects (i.e. water availability), the location of renewable energy sources and transport infrastructure, as well as regulatory conditions, are essential if feasible long-term strategies are to be devised for the development of the PtX market.

During the intergovernmental negotiations in September 2021, the governments of Algeria and Germany decided to deepen and broaden their cooperation in the field of green hydrogen / renewable energies. In this context, this study aims to support the development of environmentally and economically sustainable strategies for the development of the Algerian PtX market. The German development bank KfW has been commissioned by the Federal Ministry for Economic Cooperation and Development (BMZ) to commission and support this study in conjunction with the Ministry of Energy and Mines (MEM). It examines the possibilities for Algeria to develop a local value chain for PtX technologies. The study focuses on investment opportunities, particularly in the field of hydrogen economy plants, and examines the techno-economic potential of green hydrogen production and the potential role it could play in the national energy system on the basis of a scenario analysis **(Chapter 2)**. In addition, more detailed economic analyses are carried out for potential future project sites and the determination of the costs associated with hydrogen production **(Chapter 3)**. The third part of the study looks at the issue of green hydrogen certification, which ensures that hydrogen complies with sustainability criteria and makes it possible to reduce greenhouse gas (GHG) emissions sufficiently **(Chapter 4)**.

The study is being carried out by the Fraunhofer Society for Applied Research, represented by its two research institutes, the Fraunhofer Institute for Systems Research and Innovation ISI and the Fraunhofer Institute for Solar Energy Systems ISE.

2 Assessment of renewable energy resources and market development scenarios

This chapter assesses renewable energy resources and develops market scenarios for PtX technology in the context of greenhouse gas (GHG) emission scenarios for Algeria, taking into account Algeria's decarbonisation, its domestic demand for hydrogen and PtX products, as well as their export. Three main scenarios are defined for the analyses, which are combined with hydrogen exports. These scenarios take account of the national roadmap for the development of hydrogen in Algeria, which sets out:

- an initial demonstration phase through short-term pilot projects (2023-2030; from 2 to 50 MW in size) (MEM 2023);
- a second phase of large-scale deployment and market creation (2030-2040);
- a third competitive market phase (2040-2050).

2.1 Definition of scenarios

The scenario analysis includes the energy and carbon dioxide (CO2) balance of all sectors of final energy demand as well as the local electricity system. Future demand for hydrogen for the domestic market or for export is also taken into account, assuming additional demand for electricity for the production of hydrogen by electrolysis. The timeframe of the analysis extends from 2000 to 2050, using historical data from 2000 to 2019 as input. The year 2019 was chosen as the last historical year due to better data availability and to avoid the particular impact of the COVID crisis in 2020 and 2021 when projecting future energy demand. The LEAP energy system analysis model (LEAP 2023) is used as the modelling framework and NEMO (NEMO 2023) is used for electricity sector expansion planning, exploring pathways with minimum overall cost for the different scenarios.

Three main scenarios are defined for the analyses:

- The Net Zero Emissions (NZE) scenario aims to achieve zero net CO_2 emissions by 2050. It is based on a combination of energy efficiency measures and fuel switching. By 2050, no fossil fuels are used, either for final energy supply or for electricity generation. An important justification for this scenario is that the European Union has decided to introduce the Carbon Border Adjustment Mechanism (CBAM), which targets countries outside the European Union that export their products to Europe, as is the case with Algeria. To avoid Algerian products being heavily taxed on export, the economy also needs to be decarbonised. To achieve this, in addition to electricity, biomass and renewable heat, hydrogen is used for energy storage and, to a limited extent, as a fuel in certain end-use sectors, mainly industry and domestic transport, as well as a raw material for non-energy purposes.
- In the Ambitious Emission Reductions (AER) scenario, fossil fuel use and associated CO_2 emissions are significantly reduced by 2050. However, some fossil fuels remain in the energy system, both for final energy demand and for electricity generation. This scenario includes significant energy efficiency measures, but to a lesser extent than the NZE scenario, as the implied efficiency gains from fuel switching to direct electrification are smaller. Unlike the NZE scenario, hydrogen is not used in the final energy demand sectors, but it can be used for seasonal energy storage in the electricity sector. Another interpretation of this scenario is that zero net CO_2 emissions can only be achieved after 2050 in Algeria.
- The "Business as Usual" (BAU) scenario serves as a pure comparison scenario with no decarbonisation ambitions. It is assumed here that the energy intensities and fuel shares of the various sectors remain constant at 2019 levels.

Two other sub-scenarios are based on the AER and NZE and take account of hydroelectricity exports. In these scenarios, called AER+/NZE+, the green hydrogen export target varies in two phases. In the first phase, hydrogen exports increase linearly from 0 TWh in 2025 to 15 TWh in 2035. Thereafter, assuming faster expansion due to learning effects, they increase to reach 100 TWh in 2050.

Planning the expansion of the electricity sector is done endogenously (with respect to the composition of the power mix) by minimising the overall cost of the system for given scenarios. Table 1 summarises the three scenarios and their main differences.

Table 1 The three scenarios for Algeria and their main differences

Scenario	Status quo (BAU)	Ambitious emissions reductions (AER) / (AER+)	Net zero emissions in 2050 (NZE) / (NZE+)
Final energy demand	Energy intensities and fuel shares are kept constant	Increase energy efficiency + switch to **65% renewable** fuels by 2050	Increased energy efficiency + switch to **100% renewable** fuels until 2050
Electrical sector	Least-cost optimization **without emissions targets** for capacity expansion beyond announced national plans	Least-cost optimization with a target of around **85% renewable electricity** by 2050 for capacity additions beyond national plans announced.	Least-cost optimization with a target of **zero net emissions in 2050** for capacity additions beyond the announced national plans.
Hydrogen export	No	No / Yes (2025: 0 TWh, 2035: 15 TWh, 2050: 100 TWh)	No / Yes (2025: 0 TWh, 2035: 15 TWh, 2050: 100 TWh)

2.2 Data and methods

2.2.1 Final energy demand

Population and gross domestic product (GDP) are two important factors influencing local energy demand. A combination of national (ONS 2023) and international (UN 2022, World Bank 2023) sources is used as the basis for the population data. For the evolution of the national population up to 2050, the average variant of the UN World Population Prospects is taken into account, which gives 50.3 million inhabitants in 2030 and 60.9 million inhabitants in 2050. GDP per capita is estimated on the basis of historical trends, rising from constant 2015 US$ 4115 in 2019 to constant 2015 US$ 4500 in 2030 and constant 2015 US$ 5100 in 2050. To take account of sectoral trends, total GDP is decomposed into sectoral value added for industry, services and agriculture, using shares from the World Bank's World Development Indicators. Figures for the resulting trends in population, GDP and sectoral value added are provided in the appendix.

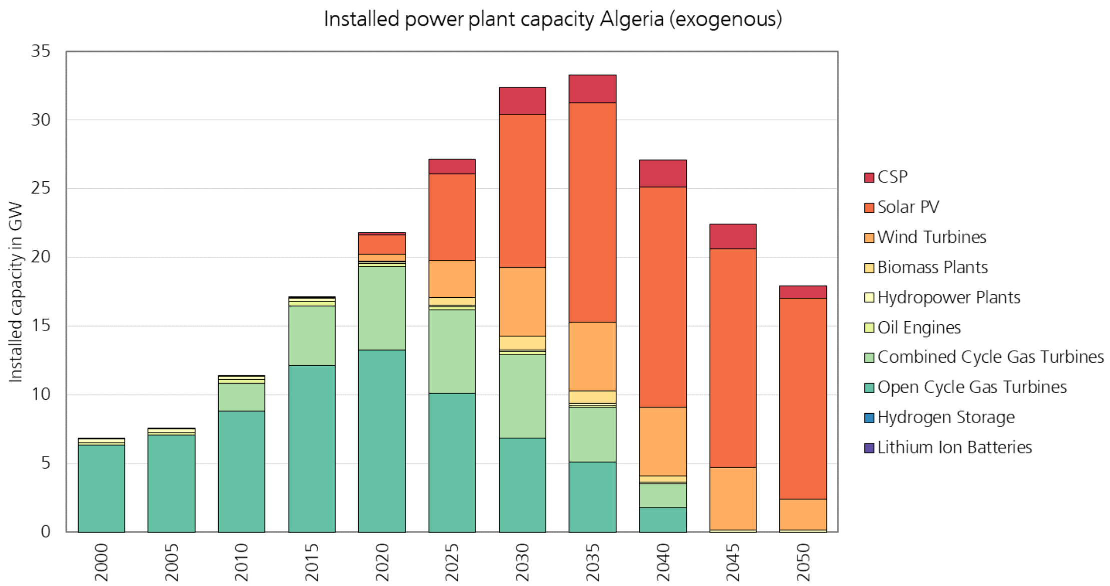
For final energy demand by sector and by fuel, national data from the Office National des Statistiques (ONS 2023) and historical energy balances from the Ministry of Energy and Mines and the commercial database Global Energy & CO_2 Data (Enerdata 2023) are used. In combination with data on GDP and sectoral value added, the final energy intensity of the various sectors and their fuel shares can be deduced. The main driver of energy demand, the level of activity, depends on the different sectors. For industry, services and agriculture, it is the corresponding sectoral value added. For the other sectors, it is total GDP. Final energy demand in the various sectors is assumed to decrease linearly by 30% by 2050 for all sectors and all scenarios. Additional efficiency gains resulting from fuel switching are taken into account. In the transport sector, the direct use of electricity results in an energy intensity 50% lower than that of fossil fuels. For hydrogen, the intensity is 30% lower than for fossil fuels. For all other sectors, the use of electricity and renewable heat is assumed to be 10% more efficient than the use of fossil fuels, biomass and hydrogen. The fuel shares for the different sectors and scenarios are shown in the appendix.

2.2.2 Electricity sector

Planning for the expansion of the electricity sector is carried out with the aim of minimising the total system cost of the respective scenarios. To account for daily and seasonal fluctuations in electricity demand and supply, the model has a temporal resolution of 288 time slices per year, corresponding to one 24-hour reference day per month. For each of these time slices and each year, electricity demand must be met by building, dispatching and shutting down various production and storage technologies on the supply side. The electricity demand for hydrogen production, including electrolysis efficiency losses, is calculated and added to the direct electricity demand of the final energy demand sectors. Electrolysis efficiency is increased from 60% in 2020 to 75% in 2050.

Historical data from the statistical bulletins of the Arab Electricity Union (AUE 2023), the CREG and future national renewable energy expansion plans, as well as indicative programmes for electricity and gas production facilities up to 2030 (MEM 2023) are taken into account in the model. Existing and planned power plant capacities are assumed to be retired at the end of their technical life. For future development, only the increases in RE capacity defined in the national plans are taken into account, but not fossil technologies. The resulting change in the specified minimum capacity of power plants is shown in Figure 1. As can be seen, natural gas turbines dominate the current electricity system, and their installed capacity has risen sharply in recent years. Based on the resulting age structure and assuming that no new capacity is built in the future, the last existing fossil fuel power plants in the system would be phased out between 2040 and 2045. However, expansion planning still allows for the modelled installation of new oil engines or gas turbines if all boundary conditions are met, thereby reducing overall system costs.

Figure 1: Input data for the exogenous model for the assumed evolution of the minimum installed capacity of power plants in Algeria by technology up to 2050



Source: Own representation based on historical data from the Arab Electricity Union's statistical bulletins (AUE 2023) and on future national renewable energy expansion plans up to 2030 (MEM 2023).

In total, there are ten different options for electricity generation and storage. The default emission factors for fossil power plants are taken from LEAP's internal technology and environmental database. A summary table of the main techno-economic parameters for the different power plant and storage technologies is provided in the appendix. The two energy storage options are lithium-ion batteries for short-term storage and a hydrogen storage module for seasonal storage, which combines the three stages of electrolysis, physical hydrogen storage and reconversion in hydrogen turbines. In a detailed study, the possibility of storage by pumping water (STEP, pumped water transfer station) is also envisaged, but requires a detailed analysis of possible storage sites.

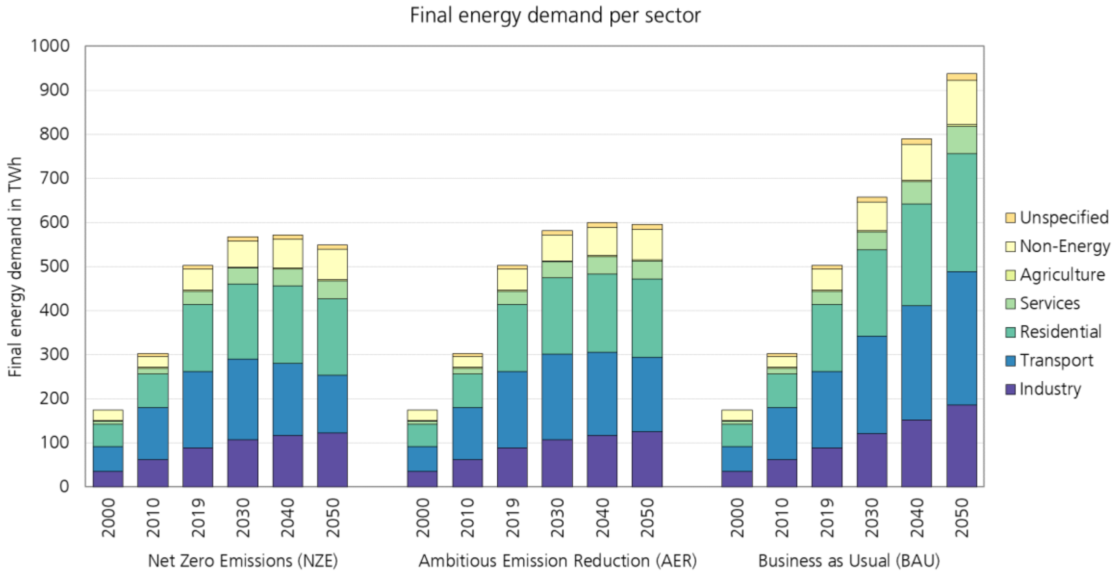
The weighted average cost of capital (WACC) is assumed to be 7.5% per annum. Fuel costs for natural gas (US$65.0/toe constant 2015) and oil (US$223.1/toe constant 2015) were taken from Enerdata (Enerdata 2023). For biomass, a price of US$2.5/GJ constant 2015 is assumed based on price ranges provided by IRENA (IRENA 2012, IRENA 2018). The solar PV and wind time series are based on 2020 weather data downloaded from renewables.ninja (Pfenninger & Staffel 2023) and aggregated in 288 time-slice format. The resulting availability curves are presented in the appendix. As hydroelectric resources in Algeria are limited, the maximum capacity of hydroelectric plants is exogenously limited to 500 MW.

2.3 Results

2.3.1 Final energy demand

Historical and projected trends in final energy demand by sector and by fuel for the three scenarios are shown in Figure 2 and Figure 3. From 2000 to 2019, Algeria experienced a sharp increase in final energy demand, which almost tripled from 174 TWh to 503 TWh. This growth is mainly due to the industrial, residential and transport sectors, which together account for more than 80% of national electricity consumption. While all the scenarios assume continued growth, the rates differ considerably. In the BAU scenario, without efficiency measures or fuel switching, energy demand is expected to exceed 900 TWh by 2050. However, the other two scenarios forecast slower growth. In the AER scenario, energy demand peaks around 2040 at just over 600 TWh, and remains at this level until 2050. In the NZE scenario, FED peaks around 2040, then declines slightly to around 550 TWh in 2050.

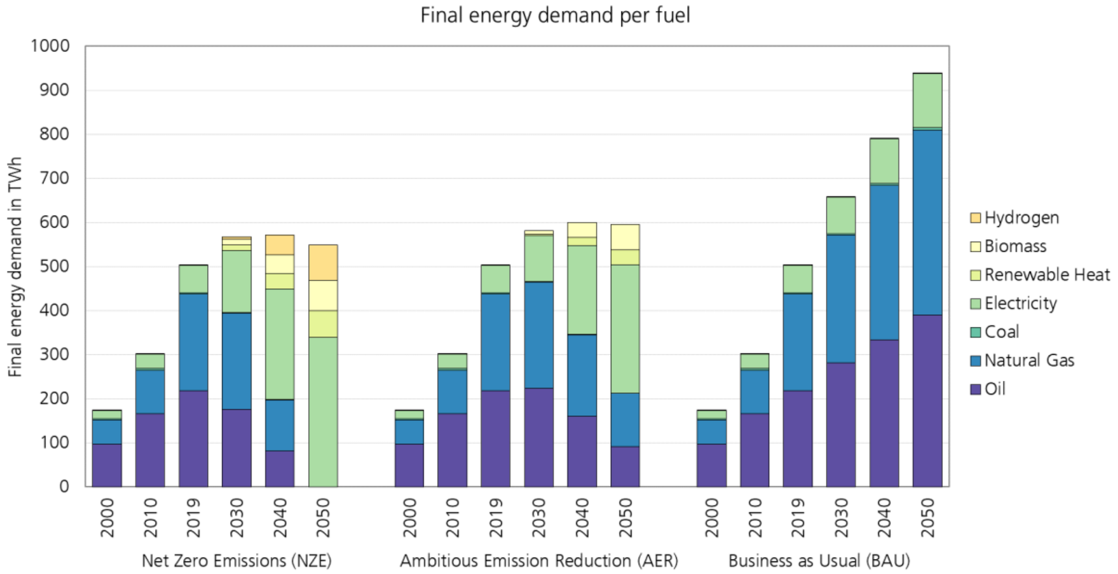
Figure 2: Algeria's final energy demand by sector and by scenario up to 2050



Source: Own representation with historical data based on ONS (ONS 2023), MEM (MEM 2023) and Enerdata (Enerdata 2023), as well as own projections for future scenarios.

The most significant differences between the two decarbonisation scenarios are observed in the transport sector, due to the higher share of battery electric vehicles. A higher share of direct electrification, particularly in the national transport sector, contributes to higher implicit efficiency gains. In 2000, the energy mix was dominated by oil (56%), but the share of electricity and natural gas increases by 2019. In the NZE scenario, fossil fuels are completely eliminated by 2050. Over 60% of the energy mix is electricity, supplemented by renewable heat sources such as solar, ambient, biomass and hydrogen. In the AER scenario, renewable fuels account for around 64.5% of the FED in 2050, of which 49% comes from electricity and the remainder from biomass and renewable heat. Nevertheless, fossil fuels still cover 35.5% of energy demand in 2050. In contrast, the BAU scenario, which serves as a reference without any decarbonisation ambitions, keeps the share of fuels unchanged, leading to a sharp increase in demand for oil and gas.

Figure 3: Algeria's final energy demand by fuel and scenario to 2050



Source: Own representation with historical data based on ONS (ONS 2023), MEM (MEM 2023) and Enerdata (Enerdata 2023), as well as own projections for future scenarios.

2.3.2 Electricity sector without hydrogen exports

The power sector expansion paths with the lowest total system costs differ for the three scenarios, both in terms of technology mix and total installed capacity (see Figure 4). In the BAU scenario, with relatively low electricity demand and no CO_2 constraint, total capacity in 2050 is 66 GW, composed mainly of gas turbines and solar photovoltaic panels combined with battery storage. In the REA, this value rises to 178 GW due to the increase in electricity demand and the given decarbonisation trajectory. Solar photovoltaic and wind power account for the largest share of electricity generation. For short-term storage, batteries are increasingly used after 2030, while seasonal hydrogen storage plays a minor role. On the other hand, a certain proportion of gas turbines will still be in service in 2050. The situation is different in the NZE scenario. To meet electricity demand in 2050 in a completely CO_2-neutral way, the highest installed capacity of the three scenarios is required, with a total of 318 GW. As intermittent generation technologies such as solar photovoltaics and wind power dominate the energy mix, short-term storage in the form of batteries and seasonal hydrogen storage will be needed. The latter will be added mainly after 2040, replacing gas turbines. As a result of the cap on CO_2 emissions, the gas turbines remaining in the system in 2050 will no longer be distributed.

Figure 4: Increase in installed capacity of power plants in Algeria as a function of optimal costs, by technology, for the different scenarios up to 2050

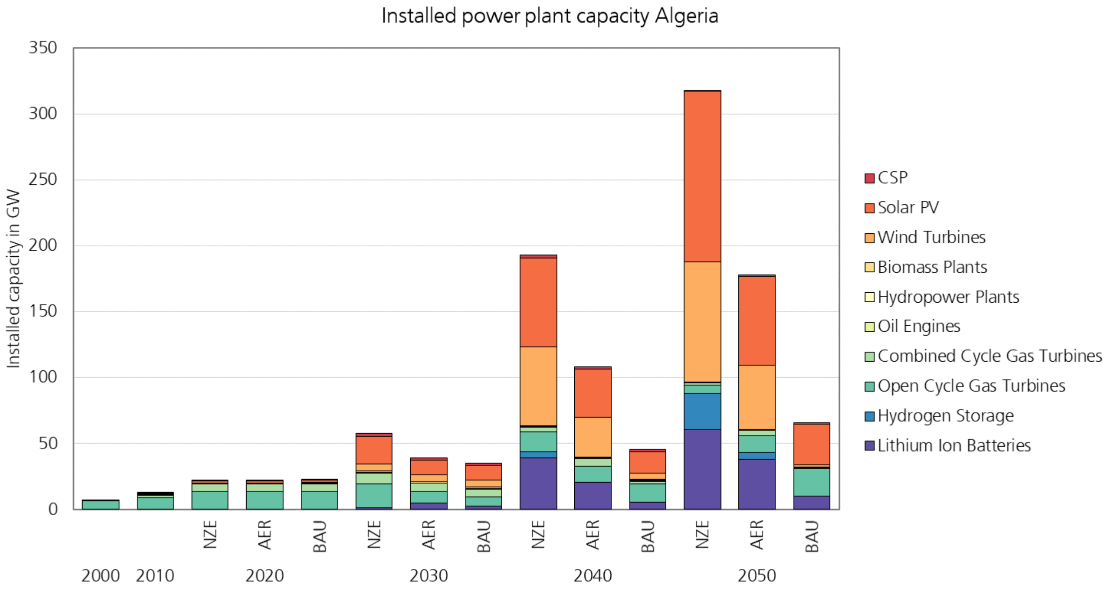
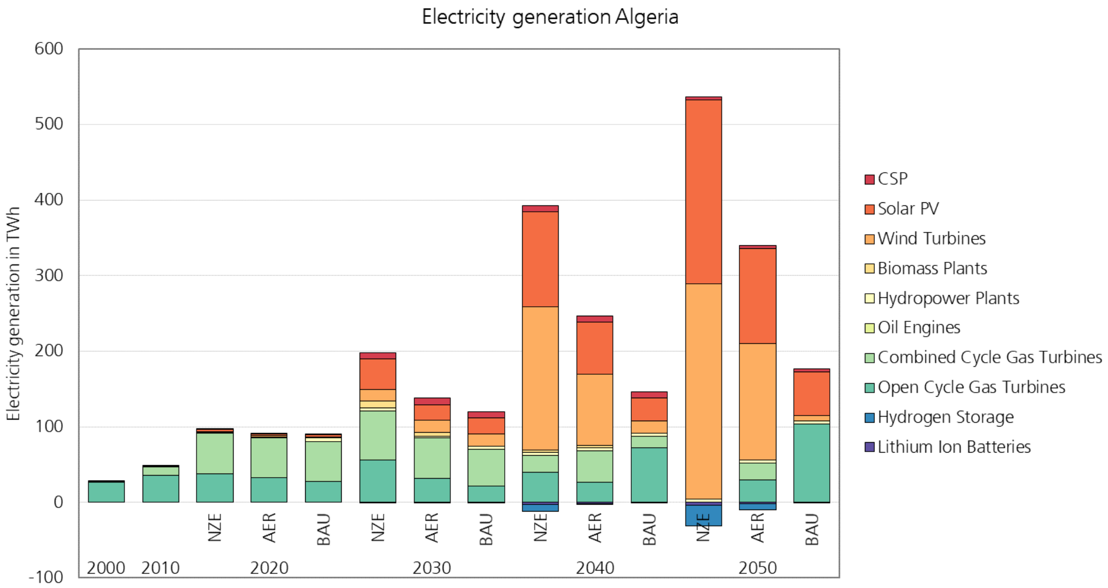


Figure 5: Optimal evolution of electricity generation costs in Algeria by technology for the different scenarios up to 2050



With regard to electricity generation in TWh presented in Figure 5 the situation is similar to that for generation capacity. The highest electricity production in 2050 is in the NZE scenario with 536 TWh, followed by the AER scenario with 340 TWh and the BAU scenario with 176 TWh. Production in the NZE scenario, which includes both the electricity needed to meet local hydrogen demand and storage losses (represented by negative values in the diagram), is therefore three times higher than in the BAU scenario, and in the AER scenario it is a factor of 1.9. Whereas in the NZE scenario, 100% of electricity in 2050 is generated from renewable energy sources, mainly solar photovoltaic and wind power, in the AER scenario, around 15% of electricity is still generated from natural gas. In the

BAU scenario with no emission limits, an even greater proportion is covered by natural gas. However, the amount of electricity generated from natural gas decreases between 2045 and 2050 and is replaced by solar photovoltaic electricity, as this is the most cost-effective solution according to the assumptions made in this scenario too.

Figure 6 and Figure 7 show the hourly generation load in 2050 for the REA and NZE scenarios. Both scenarios show the expected patterns of peak PV generation in the middle of the day, although the peaks are significantly more pronounced in the NZE scenario. In both scenarios, some of the solar energy produced is stored for later use during periods when PV and wind sources are unable to meet demand. However, the use of hydrogen storage differs considerably between the two scenarios. In the NZE scenario, hydrogen storage plays a crucial role in seasonal storage, whereas its use remains limited in the AER scenario. On the other hand, in the AER scenario, gas turbines are commissioned during periods of limited availability of wind and solar resources to meet energy demand.

As solar and wind energy cannot be distributed due to meteorological fluctuations, the issue of load flexibility is becoming increasingly important, particularly with high proportions of renewable energy in the electricity system. The use of electrolysers, which is beneficial to the electricity system, can play an important role in this respect. Other flexibility options could include charging battery electric vehicles and shifting demand in industrial processes. The interaction between the different options and their impact on the capacities and costs of the electricity system should be analysed in greater detail in future studies.

Figure 6: Breakdown of electricity generation and storage technologies for the Ambitious Emissions Reductions (AER) scenario in 2050

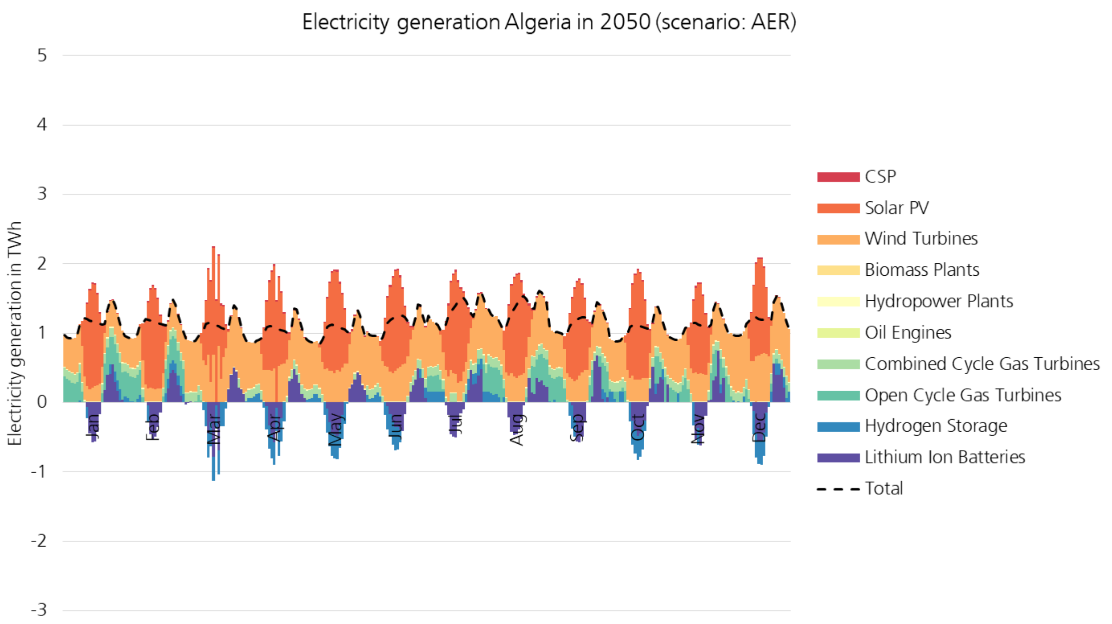
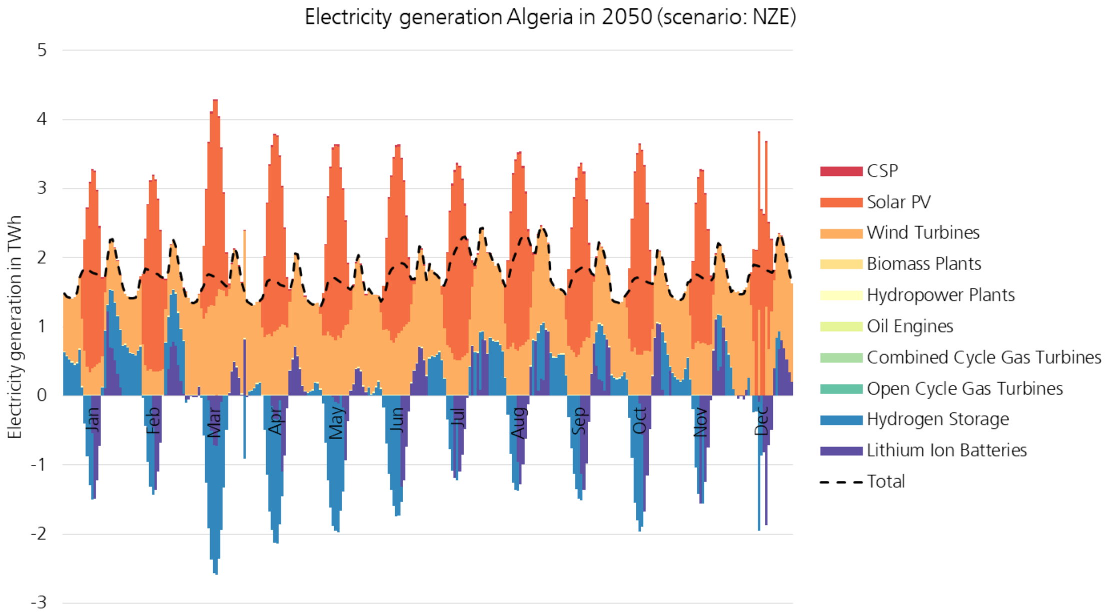
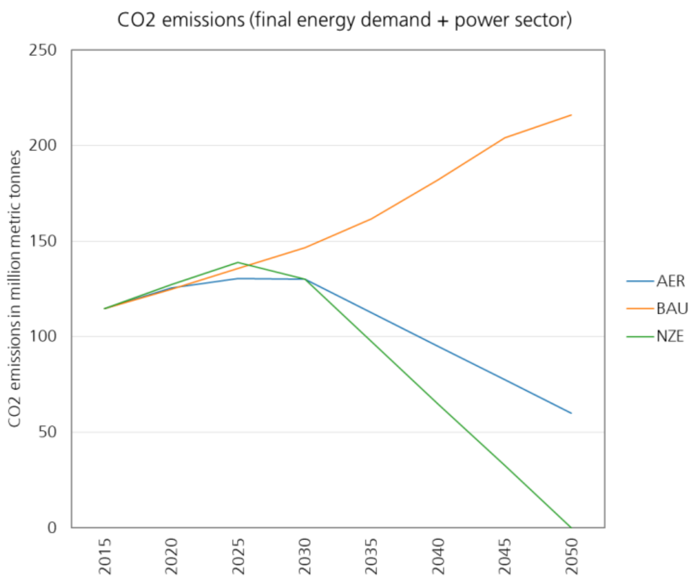


Figure 7: Distribution of electricity generation and storage technologies for the net zero emissions (NZE) scenario in 2050



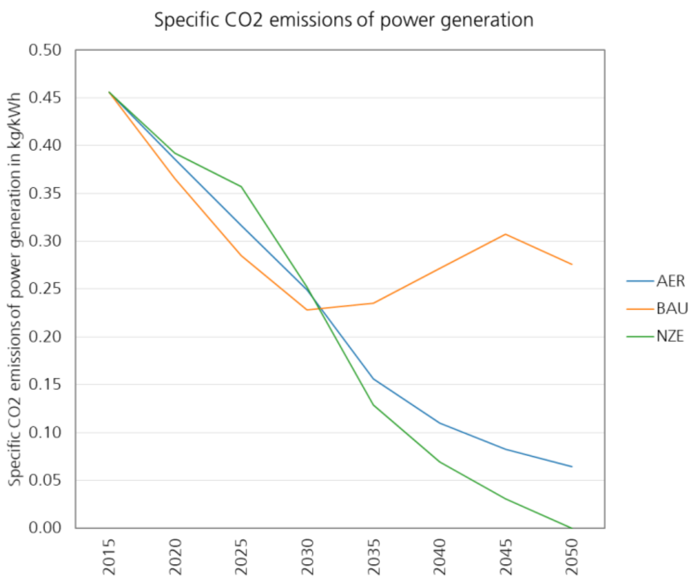
After 2025, total emissions from the final energy demand and electricity generation sectors show significant differences between the three scenarios. While emissions, as shown in Figure 8 for the two decarbonisation scenarios NZE and AER respect the specified emission limits after 2030 and reach values of 0 Mt and 60 Mt, respectively, in 2050, the BAU scenario without emission limits shows a significantly higher value of 216 Mt of CO_2 .

Figure 8: Total CO2 emissions from final energy demand and electricity generation by scenario up to 2050



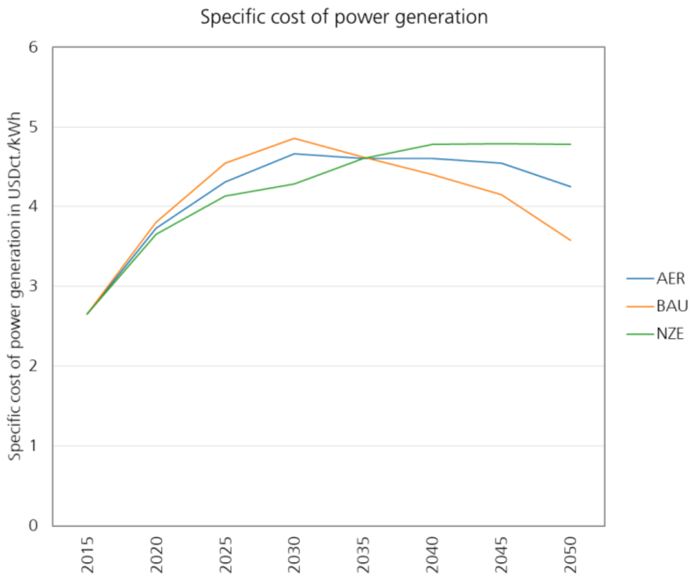
The specific CO_2 emissions from electricity generation, shown in Figure 9 decrease in all scenarios from a value of around 0.5 kg/kWh. Initially, the BAU scenario even has the lowest specific emissions, due to the ambitious targets for integrating renewable energies and the moderate growth in electricity demand. However, between 2030 and 2035, this trend reverses to around 0.28 kg/kWh and the NZE scenario then has the lowest specific emissions, followed by the AER scenario. The emission factors for electricity generation in 2050 are 0 kg/kWh (NZE), around 0.12 kg/kWh (AER) and around 0.33 kg/kWh (BAU).

Figure 9: Specific CO_2 emissions from electricity generation by scenario up to 2050



As shown in Figure 10 specific electricity costs increase slightly in all scenarios, more strongly in the initial phase of the BAU scenario due to the high renewable energy expansion targets mentioned above. In the long term, costs are slightly higher in the NZE scenario than in the AER and BAU scenarios. In 2050, the resulting specific production costs are between 3.5 and 4.9 USDct/kWh. However, it is important to note that these cost estimates do not take into account CO_2 pricing mechanisms or other externalities.

Figure 10: Trend in the specific cost of electricity generation by scenario up to 2050

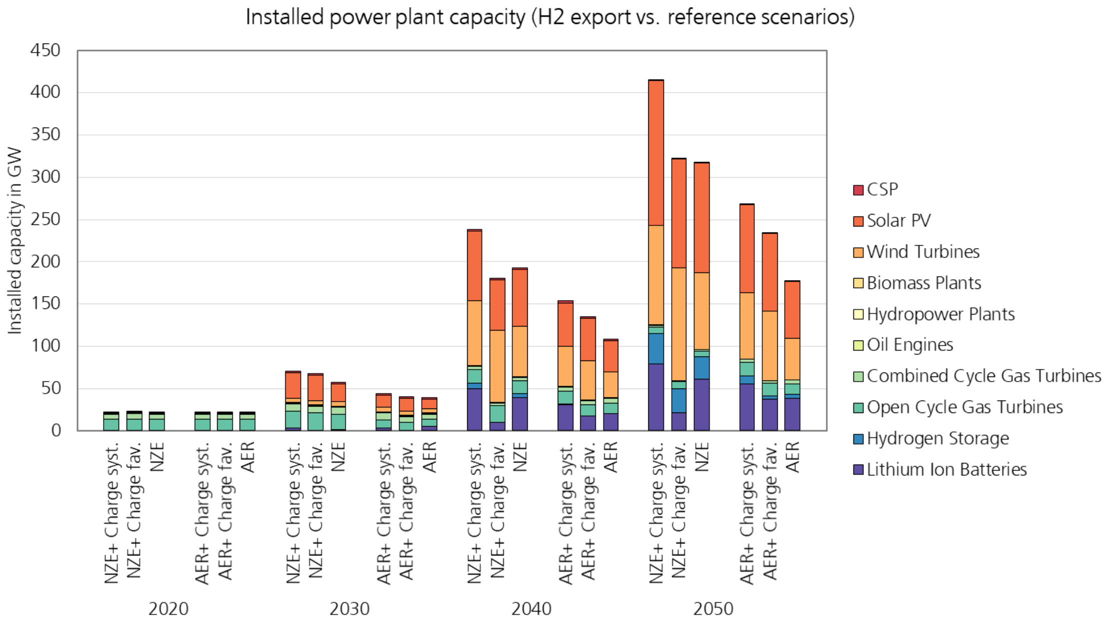


2.3.3 Electricity sector with hydrogen exports

The AER+ and NZE+ hydrogen export scenarios examine the impact of two different electrolyser load curves on overall power system expansion. The first is the "system load" curve, where hydrogen production is exactly equal to the other total electrical system load. This corresponds to a capacity factor of 71%, or 6220 hours of full load. The second load curve is the "favourable load" curve, which takes into account the availability of photovoltaic and wind resources, and is highest when the availability of renewable energies exceeds the demand for electricity. In order to achieve a total electrolyser capacity factor of 40%, which corresponds to 3,505 hours of full load, the distribution peaks are partially reduced. Hydrogen exports are increased in two stages, starting with 0 TWh in 2025 and 15 TWh in 2035, followed by a further increase to 100 TWh in 2050. Assuming an efficiency of 75%, the electrolysis capacity required for 2050 would be 21.1 GW for the system load curve and 38.0 GW for the favourable load curve. These capacity estimates reflect the need to meet hydrogen production requirements associated with established export targets, while taking into account the operating characteristics and availability of renewable energy sources.

The evolution of the resulting installed capacities for the hydrogen export scenarios and the corresponding reference scenarios is shown in Figure 11. Compared to the scenarios without hydrogen exports, the overall capacity of the electricity sector in 2050 increases for the AER scenario by 51% (system load) and 32% (favourable load). The flexible allocation of electrolysis can therefore help to reduce the demand for storage in the system. For the NZE+ scenarios, this effect is even stronger, here the overall capacity in 2050 increases by 31% for the allocation of the system load but only by 1% with the favourable load curve, the battery storage capacity even decreases by 64% compared to the NZE+ scenario. The favourable electrolysis load leads to a change in the overall system load curve (demand flexibility and peak shifting), which results in a lower overall storage demand, both seasonally (hydrogen) and in the short term (batteries). In 2040, this even results in a lower total installed capacity with hydrogen exports under a favourable distribution of electrolysers compared to the NZE reference scenario without hydrogen exports, as the higher production capacity is more than offset by the lower storage capacity. The effect is less pronounced in the AER+ scenarios than in the NZE+ scenario because the remaining gas turbines in the system provide flexibility and therefore less storage is required throughout the system.

Figure 11: Cost-optimal increase in power plant capacity by technology for different hydrogen export scenarios compared with reference scenarios up to 2050



3 Identification of project sites and investment opportunities

The choice of site for a PtX project depends on a multitude of geographical, social, political and regulatory variables. An in-depth spatial study is therefore the basis for any informed and justified decision to deploy such a project.

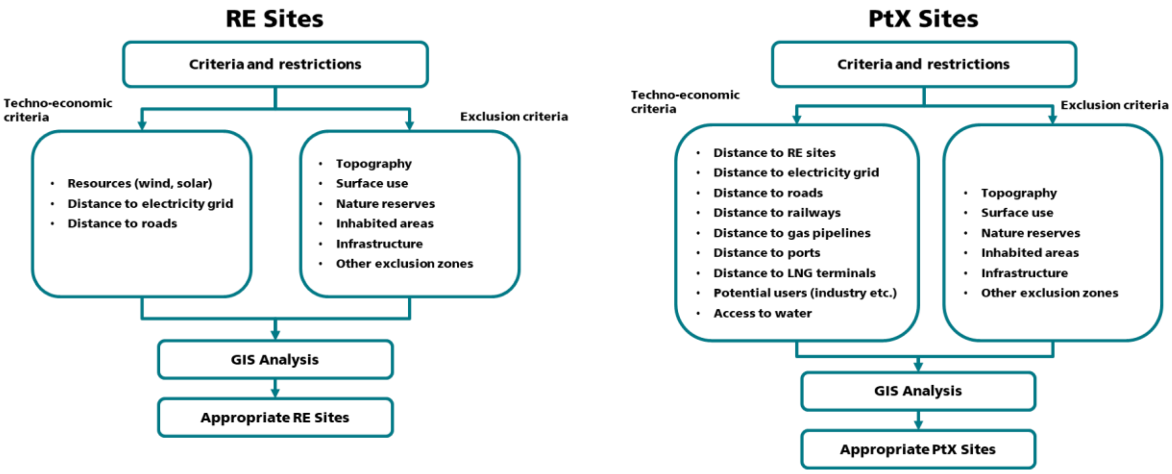
As well as choosing the site, a technical and economic study is used to detail the business model and ensure that the project is profitable. This study provides the initial indicators that will then be refined in a feasibility study, including a request for specific quotes.

The costs of a PtX project are characterised above all by a high level of investment: design costs, renewable energy, electrolysers, electricity transmission network, hydrogen pipeline, aqueduct, seawater desalination unit. Compared with a conventional process such as the synthesis of "grey" ammonia, there are virtually no ongoing costs such as "fuel" or "raw materials". On the other hand, this means that a project such as "green" ammonia synthesis requires stable and reliable investment conditions. Investment support (grants, bonuses or low-interest loans) can make the project more profitable.

3.1 Methodology for selecting sites

The renewable energy and PtX production sites were selected on the basis of a multi-criteria decision framework, taking into account technical, economic and other criteria (see Figure 12).

Figure 12: Logic diagram for applying the criteria



Source: Fraunhofer ISE inter nes works

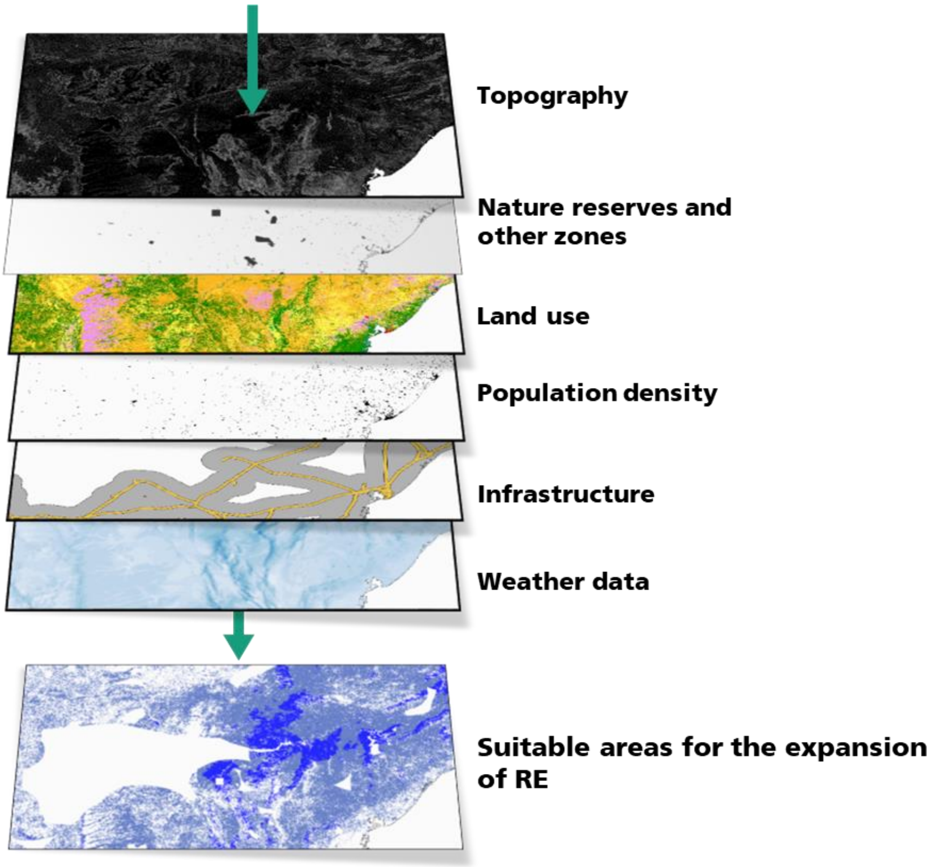
3.1.1 Methodology for selecting renewable energy sites

The methodology used to select RE sites is called **overlay analysis**. It involves visualising the area to be analysed on a map in a geographic information system (GIS) software package[2] . By using various layers and assigning them inclusion or exclusion cut-off values, it is possible to analyse a multitude of geographical properties at the same time and to proceed through a principle of exclusion to arrive at areas eligible for RE projects. As part of this project, a number of geographical

[2] The Fraunhofer ISE uses ArcGIS (commercial) and QGIS (free) software, depending on the application and the user. This rating does not represent a recommendation or paid advertisement from the software distributors.

and technical restrictions and limitations for the construction of onshore wind turbines and ground-mounted photovoltaic power plants have been determined.

Figure 13: Overlay analysis



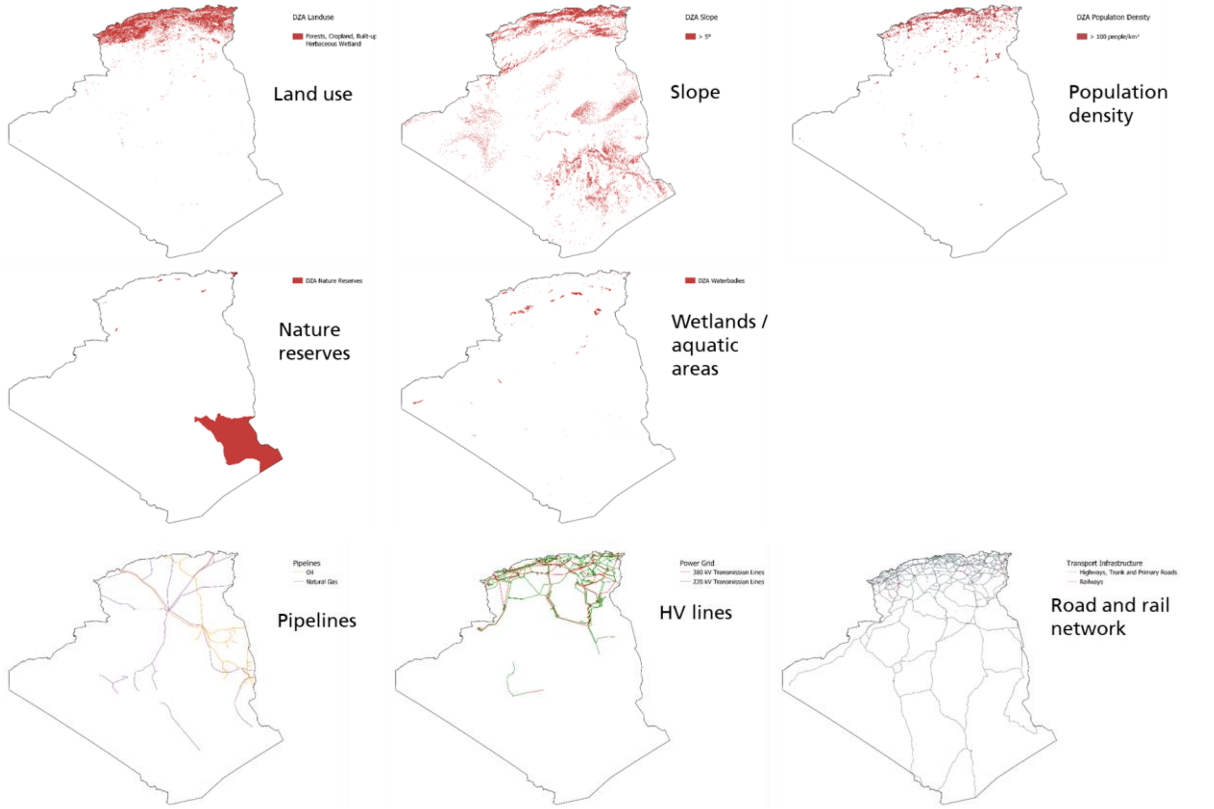
Source: Fraunhofer ISE internal work

In hierarchical order, the criteria taken into account are: general topography (excluding slopes > 5°), nature reserves and other exclusion zones, land use (aquatic, snow and ice areas, forests, agricultural land[3] , urban areas, wetlands), population density, availability of infrastructure: high-voltage lines, pipelines in the broadest sense, road and rail networks, ports, airports, waterways. By passing the geographical data through this "sieve", we obtain a map that shows sites with no major exclusion criteria and that shows infrastructures that are critical for the deployment of PtX projects.

The result is a set of miniature cards showing the exclusion zones in red, as shown in Figure 14.

[3] There are initial demonstration projects for "Agri-PV" photovoltaic power plants on top of agricultural fields, enabling better use to be made of the land in a context of severe spatial constraints. Certain plants benefit from the partial shade created by the installation of PV panels.

Figure 14: Thumbnail maps from GIS analysis

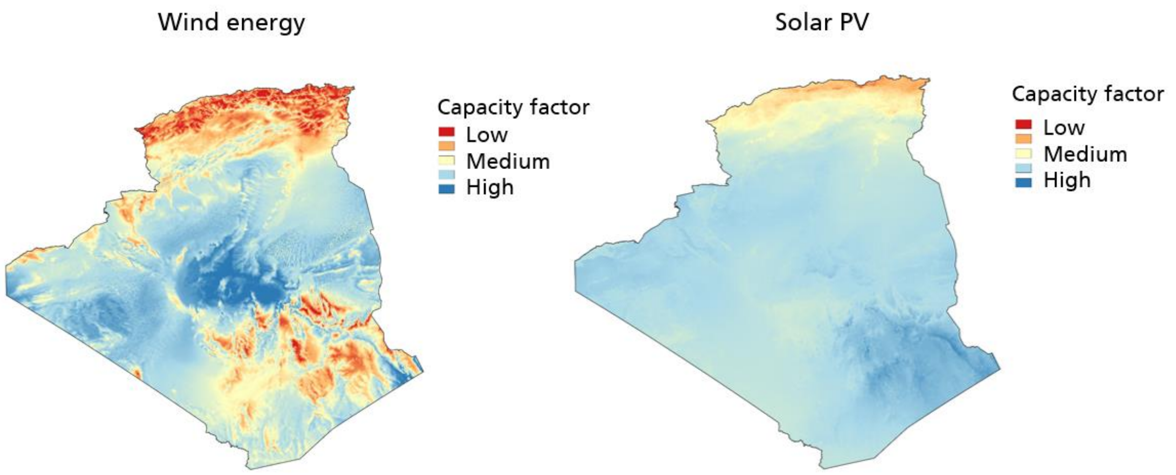


Source: Fraunhofer ISE internal work; Geofabrik https://download.geofabrik.de/africa/algeria.html; Copernicus Global Land Cover https://lcviewer.vito.be/download; WorldPop https://www.worldpop.org/; ENTSOE https://www.entsoe.eu/data/map/; Sonatrach https://sonatrach.com/

The next step is to highlight the specific geographical parameters for RE, i.e. average wind speed and average solar irradiation. Normally, load factor maps choose a colour palette that shows high factors in red and low factors in blue. For this analysis, the palette has been reversed so as not to confuse zones with high load factors with exclusion zones (see above). In this way, the "red = to be avoided for major projects" logic is retained and is consistent. The result is shown in Figure 15.

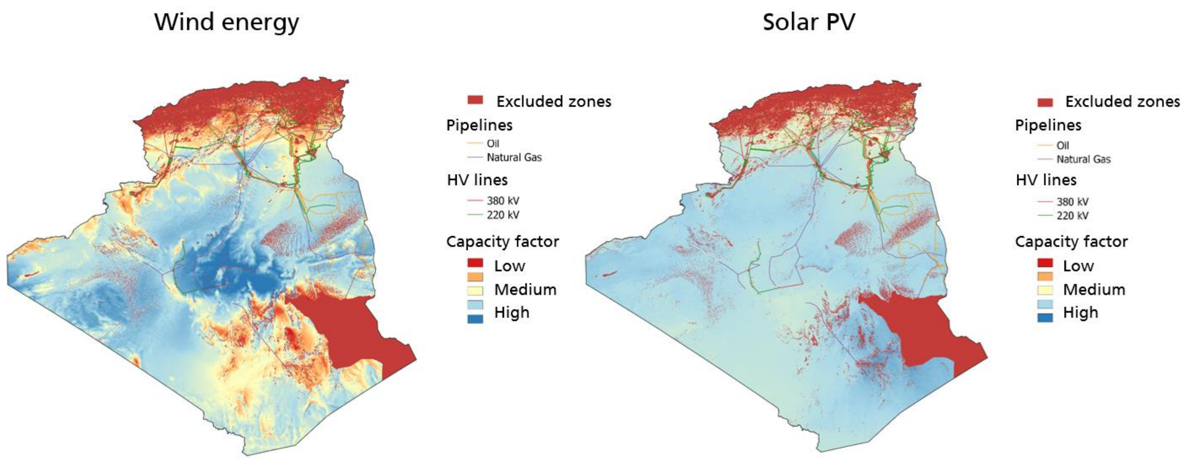
By superimposing all the zones determined by the analysis, we obtain the thumbnails shown in Figure 16.

Figure 15: RE capacity factors



Source: Global Solar Atlas https://globalsolaratlas.info Global Wind Atlas https://globalwindatlas.info/ Renewables Ninja https://www.renewables.ninja/

Figure 16: Overlay of exclusion zones and RE capacity factors



Source: see above

Several analytical remarks are now possible:

1. The greatest potential for renewable energy lies to the south of the Tell. At the same time, the Tell is home to more than two-thirds of the population and most of the fertile land - the Tell is therefore subject to numerous constraints, which explains why almost all of its area is included in the excluded zones.
2. On the other hand, industrial and household consumption is also concentrated on the Tell. There is therefore a clear need for energy transmission infrastructure, whether HV lines or pipelines.
3. The Tell remains an area with very good wind and PV potential. The installation of demonstration sites (subject to the availability of land) or PV panels on public, commercial and private buildings is still entirely feasible and would benefit from the excellent industrial infrastructure.
4. The west, south, east and centre of the country offer some of the best renewable energy potential in the world. The major challenges hampering their exploitation are the industrial infrastructure that needs to be developed, and the weather conditions. These include the

extreme heat on the PIAT, which means that wind turbines and PV panels will have to be adapted or relocated to a less restrictive area, but at the expense of the load factor.

The influence of an RE project on the chosen site is an additional criterion. The start-up and proliferation of renewable energy projects creates potential for growth and the development of know-how for the companies involved. Despite the fact that wind turbines and PV panels do not require a great deal of technical maintenance, there is still an industrial sector for verification, monitoring and technical control (especially electrical engineering) that needs to develop at the same time as an RE project. This means that local jobs can be created and there is an opportunity for a network of specialised SMEs to accompany an RE project. What's more, RE projects with their infrastructure requirements can be part of a policy of regionalisation and industrial development. For example, a major RE site located between the two electricity grids RIN and PIAT could offer the prospect of their interconnection, which may not have been profitable before. Such an interconnection would increase access to the interconnected electricity network for a greater number of industries and individuals who would today be dependent on an isolated system.

3.1.2 Methodology for selecting PtX sites

Water electrolysis is the preferred method of converting electrical energy into hydrogen in this study. With an efficiency of around 70% (or more for large installations), most of the electrical energy is transformed into chemical energy, which has the advantage of being storable and more easily transportable. Hydrogen can be transported as a gas in a lorry or in a hydrogen pipeline, or in liquid form. It is advantageous to transform the hydrogen into another product such as ammonia, methanol or synthetic methane because their volumetric energy density is much higher than that of the hydrogen leaving the electrolyser.

Water is a critical resource for any PtX project. Algeria is a country with a predominantly hot and dry climate, so access to water is limited without technological means. Seawater desalination is a relatively inexpensive way of meeting the drinking water needs of the population and industry. Nevertheless, capacities are limited, household consumption is increasing and access to the sea is a *sine qua non* condition for taking advantage of desalination. Algeria has a desalination capacity of over three million cubic metres per day. The ecological impact of discharged brine needs to be considered, particularly in view of the development of the technology throughout the Mediterranean.

Purified water from wastewater treatment plants (WWTPs) is another possibility for electrolysis, which is gaining in importance[4] . The advantage would be access to sources that are more spatially distributed than desalination plants. According to the Tractebel/Engie study for the GIZ and the Algeria-Germany Energy Partnership, STEPs provide a flow of around 1.5 million m^3/day.

Groundwater remains another available source for electrolysis. However, ecological and sustainability impact studies are recommended before starting an electrolysis programme, particularly in an arid country.

Algeria has a special case of a water source: the Albian aquifer, the largest underground water table in the world, extends under the territory of Algeria, Tunisia and Libya. It contains brackish water, which is dangerous in terms of salinising the soil when it rises accidentally or naturally. It could represent a resource that could be exploited for electrolysis by building a desalination unit. On the other hand, the question of waste management, and therefore of brine, would once again arise, and with even greater sensitivity than in the case of seaside sites. In addition, for reasons of water

[4] https://www.businessfrance.fr/algerie-projets-d-assainissement-une-enveloppe-de-84-mds-dzd-degagee#:~:text=Alg%C3%A9rie%20currently%20171,10%20stations%20only%20in%202000

and food safety, the use of water from the Albien aquifer must be ruled out, in accordance with the guidelines issued by the country's highest authorities.

The logic behind the siting of electrolysers and hydrogen by-product synthesis units is somewhat different from that of RE sites. Firstly, they require much less surface area and the potential for solar or wind irradiation does not play a major role. This type of site benefits from and enables synergies with industrial zones such as Mediterranean ports. The point sources of CO_2 present there (steelworks, cement works) offer the possibility of methanol synthesis.[5] The ammonia and fertiliser industries are already highly developed and can absorb large quantities of hydrogen. Existing LNG terminals and gas pipelines are key infrastructures for evacuating PtX products to Europe or elsewhere. With their strong added value, PtX sites can stimulate sustainable economic growth, which translates into demand, but also into the creation of suppliers, maintenance and infrastructure. On the other hand, PtX sites require more manpower and the presence of an already more developed industrial fabric than RE sites.

The selection criteria for a PtX site may seem more qualitative than for RE sites. However, over and above the economic fabric described above, there is a real economic choice which influences the choice of site. The energy transported between the RE site and the PtX site may be in the form of electrons (HV line) or molecules (lorries, hydrogen pipeline, pipeline). There are therefore a number of economic factors to be taken into account, which also depend on the size of the planned installation. The question that practically all PtX projects come back to is: how far is it more advantageous to place the electrolysis/synthesis close to the RE (to transport the molecules) and how far is it advantageous to transport the electrons?

During the workshop in December 2022 in Algiers, the stakeholders indicated the following order for the weighting of the above-mentioned elements concerning the choice of PtX sites:

1. Fundamental choice: Target capacity of the project and quantity of renewable energy to be built
2. Fundamental choice: whether or not to connect the RE site to the grid (for cost or regulatory reasons)
3. Water availability
4. Renewable energy production costs
5. Optimising the costs associated with transporting
    a. Electricity
    b. Water
    c. CO_2 (for methanol synthesis)
    d. PtX products (hydrogen and derivatives)
6. National and international regulatory conditions
7. The electrolysis technology chosen
8. The type of discharge for PtX

In what follows, this report will attempt to provide some food for thought by providing models and taking into account the weighting of elements.

It should be borne in mind that this is an initial estimate of hydrogen production costs based solely on the economic models developed by Fraunhofer ISE. A concrete feasibility study (with measurements of PV and wind potential, concrete quotes for RE, electrolysers and all the equipment to be

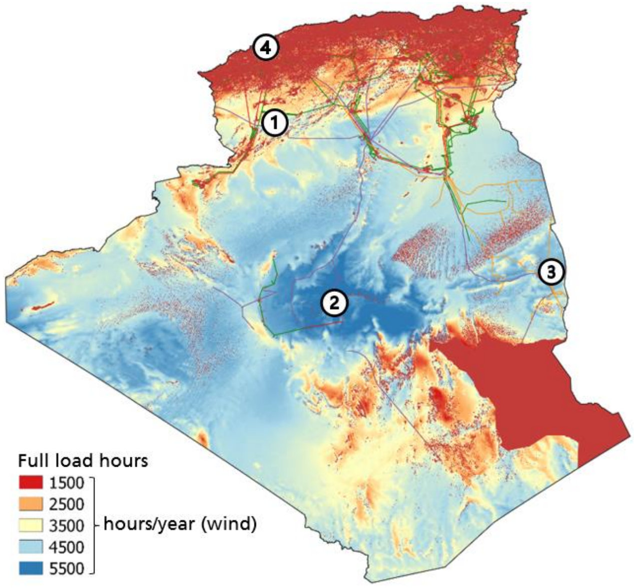
[5] The EU's regulatory requirements regarding the origin of CO_2 for "green" PtX products need to be considered. Under current legislation, CO_2 from a cement plant can be used to synthesise a fuel such as methanol until 2041. It is not clear what will happen after that. There will certainly be permits for "hard to kill" sectors and for cement plants using biogenic secondary fuels.

considered, as well as more developed financing plans) will provide a much more accurate estimate of LCOH, and probably lower than the values in this report.

3.2 Description of selected sites

According to the analysis described in chapter 0the study initially proposes four sites, in order to compare their advantages and disadvantages, the main elements of which are described in Figure 17. The sites are located in El Bayadh (1), In Salah (2), In Amenas (3) and Oran (4). Two sites are located in the north, including site (4) directly on the coast and site (1) in the Djebel Amour. Site (2) is in the heart of the Sahara. Site (3) is in the east, in the wilaya of Illizi.

Figure 17: Sites selected after the initial GIS analysis



① **El Bayadh**
- High wind and PV potential
- Close to pipelines and HV lines
- Moderate distance from the coast (< 300km)

② **In Salah**
- Very high wind potential, high PV potential
- Close to pipelines and local HV lines
- Far from the coast

③ **In Amenas**
- High wind potential, very high PV potential
- Close to pipelines
- Far from coast and HV lines

④ **Oran**
- Moderate wind potential, good PV potential
- Close to pipelines and HV lines
- By the sea

Source: see above

The following table shows the results of the spatial analysis:

Table 2: Details of data from GIS analysis

Scale: very favourable (++), favourable (+), neutral (o), unfavourable (-), very unfavourable (--)

	(1) El Bayadh	(2) In Salah	(3) In Amenas	(4) Oran
Latitude	33.365	27.432	28.222	35.756
Longitude	0.582	2.302	9.384	-0.319
Wind energy potential	+ (3.500 h)	++ (4.100 h)	+ (3.600 h)	o (2,700 h)
PV potential	++ (1.900 h)	++ (1.900 h)	++ (1.900 h)	o (1,700 h)
Distance to roads	++ (10 km)	++ (20 km)	++ (< 10 km)	++ (< 10 km)
Distance to rail	+ (80 km)	-- (610 km)	-- (630 km)	++ (< 10 km)
Distance to coast	o (280 km)	-- (950 km)	-- (980 km)	++ (< 10 km)
Distance to HV lines	++ (< 10 km)	+ (20 km*) (*PIAAT network)	- (300 km)	++ (< 10 km)

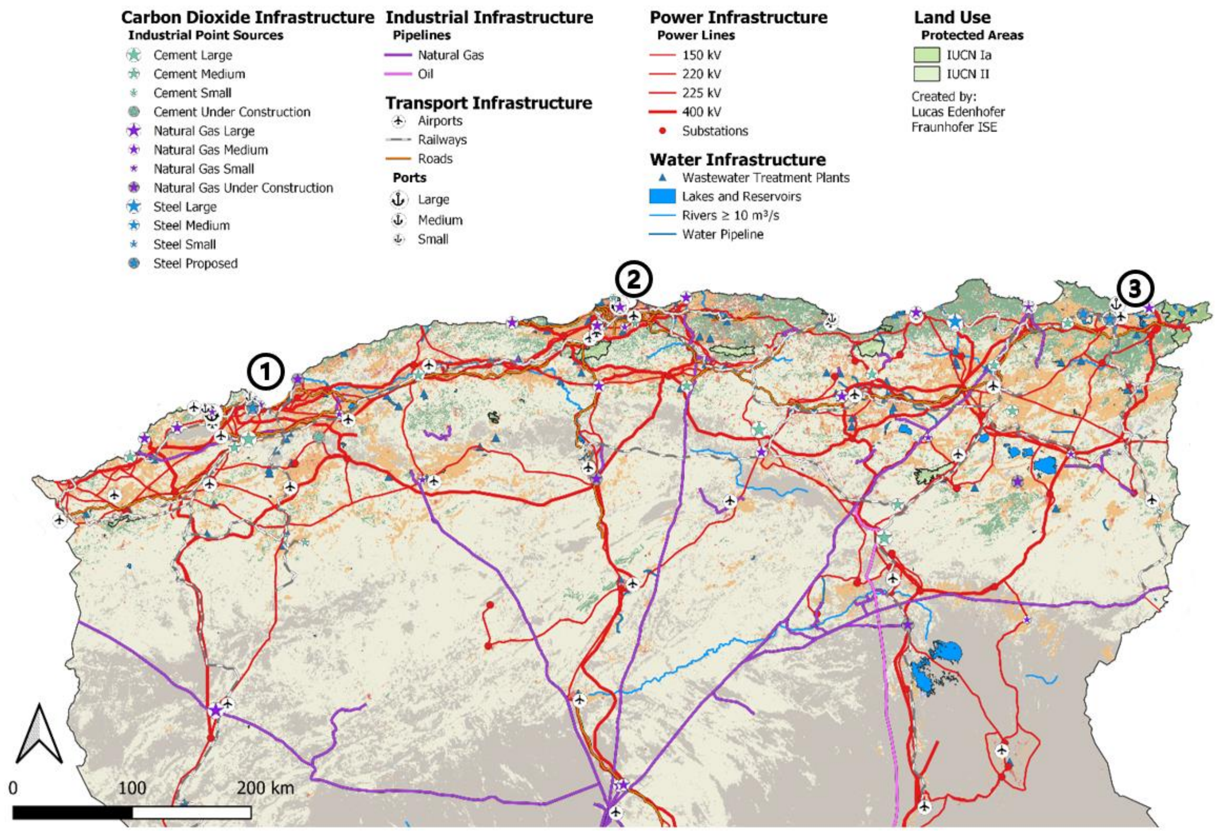
	(1) El Bayadh	(2) In Salah	(3) In Amenas	(4) Oran
Distance to gas pipelines	+ (40 km)	++ (< 10 km)	+ (20 km)	++ (< 10 km)
Surface availability	+	++	++	--
Distance to customers H_2	+	--	--	++
Distance for suppliers	o	-	--	++

Source: see above

The best site in terms of renewable energy potential is In Salah (2). However, it is not currently connected to the RIN, but only to the PIAT network. Its distance from the coast means the risk of additional logistical costs for the construction phase. The best infrastructure is in Oran, but the disadvantages are the lack of available space and the low load factor.

Based on analyses of the industrial fabric of the North, the study proposed - in advance of the December 2022 workshop - three sites that are particularly suitable for use as demonstration or even large-scale PtX sites. The industrial port zones (ZIP) of Arzew (1), Algiers (2) and Skikda (3) are marked in the Figure 18.

Figure 18: Industrial fabric in northern Algeria



Source: Fraunhofer ISE, based on various data collections

All three sites have large-scale seawater desalination facilities. All three sites are connected to major gas pipelines, and Arzew is close to the Medgaz pipeline linking Beni Saf to Almeria in Spain. The ports of Arzew and Skikda have LNG terminals, so there is an efficient infrastructure for evacuating large quantities of energy for export. Some of this infrastructure can be reused to export PtX products. Retrofit studies of this kind are under way, notably for the floating LNG terminals in Northern

Germany, which are supposed to be built "H_2 ready". The ports of Arzew and Skikda also have ammonia syntheses that can absorb large quantities of hydrogen.

3.3 Results - Detailed analysis of sites

Following discussions during and after the workshop in December 2022, two sites have been selected for detailed analysis. The first is Arzew. For the second site, the aim was to find a location between El Bayadh and Ghardaïa. As the study progressed, Hassi R'Mel emerged as the optimum site 2 because of its renewable energy potential and its industrial base. The site is also already connected to the electricity grid.

The following tables provide an overview of the economic parameters that form the basis of the LCOE calculations (electricity costs), on which the LCOH costs of hydrogen are based.

Table 3: Economic data for the PV energy system

PV	Site 1: Arzew/Oran	Site 2: Hassi R'Mel	Unit
Year	2022	2030	-
CAPEX	900	650	€/kW
OPEX	1,8	1,9	of CAPEX
WACC	7	7	% (cost of capital)
Service life	30	30	Years
Load factor	1.761	1.861	h/a
LCOE	3,99	2,95	€ct/kWh

Source: Fraunhofer ISE calculations based on common assumptions in this project

Table 4 Economic data for the wind energy system

Wind	Site 1: Arzew/Oran	Site 2: Hassi R'Mel	Unit
Year	2022	2030	-
CAPEX	1.600	1.450	€/kW
OPEX	4,8	3,0	of CAPEX
WACC	7	7	% (cost of capital)
Service life	25	25	Years
Load factor	2.713	3.421	h/a
LCOE	4,61	3,93	€ct/kWh

Source: Fraunhofer ISE calculations based on common assumptions in this project

Projected electricity costs for 2030 are around €30/MWh for solar and €40/MWh for wind power at Hassi R'Mel. These are very competitive prices, which mean that hydrogen can be produced at low cost. It is entirely possible to find even more competitive locations in Algeria, but we also have to take into account the cost of infrastructure and the fact that the Saharan climate - first and foremost the high temperatures - does not necessarily make it easy to exploit the enormous potential for renewable energy.

Nevertheless, it should be noted that the economic data in the tables above can be considered conservative in several respects, particularly for the first installation on the Arzew site:

(1) CAPEX values are given for the year 2022. An installation at Arzew could start up in 2025/2026, which would allow the cost of renewables to fall until then (by around 11% for photovoltaics and 3.5% for wind power). In the short term, however, it should be borne in mind that the price of materials and installations may also rise as a result of the impact of energy prices and inflation.

(2) CAPEX values have been chosen relatively conservatively at 900 Euro per kWh installed for photovoltaics and 1600 Euro per kW installed for wind. Optimistic limits given by IRENA for 2021 are 600 Euro and 1400 Euro per kW respectively for photovoltaics and wind. Unfortunately, data for the MENA region is scarce.

(3) The 7% WACC values are certainly realistic for the region, but can fall to 3% in certain cases of subsidised loans. The same applies to the financing of electolyzers.

Taken together, these factors can contribute in an optimistic case to reducing the costs of renewable electricity in 2025 by 20-25% compared to the values determined here. As the price of renewables is a significant part of the cost of hydrogen, this also has an impact on the cost of hydrogen. A detailed study of the Arzew site and the financing conditions could provide more certainty about the optimal configuration and costs of the installation. This also implies consideration of connecting a hydrogen production facility to the electricity grid.

3.3.1 Site 1: Arzew, 50 MW electrolysis unit

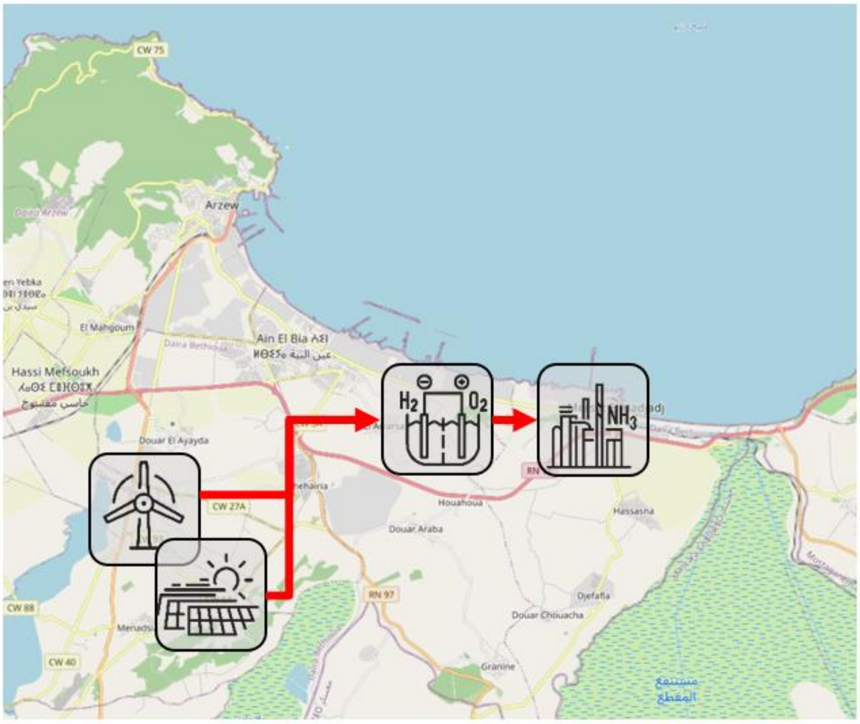
Introduction

The Arzew site is an excellent starting point for a demonstration project as part of the first phase of the roadmap for the development of hydrogen in Algeria. Its strengths lie in its excellent industrial infrastructure (access to water, hydrogen consumers, ports, manpower and equipment). Its renewable energy potential is limited compared with other sites in Algeria, but is still perfectly adequate.

The analysis provides for a 50 MW electrolyser with an operating rate of 60%. For this demonstration project, the electrolyser should be connected to the electricity grid. In order to be able to illustrate the supply of renewable energy during visits or conferences, it makes sense to install a few PV panels in the vicinity of the electrolyser. Otherwise, the necessary wind turbines and PV panels do not need to be installed directly on site. A display could show the instantaneous power of the panels on site, the power of the other panels and wind turbines and the power of the electrolyser.

The subject of the study is the cost of the hydrogen produced and an analysis of possible uses for the products. The project is scheduled for completion in 2030.

Figure 19: Schematic diagram for site 1: Arzew / Oran



Source: Fraunhofer ISE / Openstreetmap contributors

Analysis

As shown schematically in Figure 19 the RE would be connected to an electrolyser whose products are hydrogen and oxygen. The hydrogen would be used to manufacture ammonia and the oxygen would be used for medical or industrial purposes.

Arzew's solar potential is 1,761 hours per year and its wind potential is 2,713 hours per year. In order to operate a 50 MW electrolyser and not regularly exceed this threshold downwards, it is necessary to oversize the solar and wind installations, so that it is possible to achieve a load factor for the electrolyser greater than that of the solar and wind potential, even without using electricity from the grid.

The economic parameters for this site, for which construction would begin in the next few years, are given in Table 5 next table.

Table 5: Economic parameters for site 1

	CAPEX (EURO/kW)	OPEX ($\%_{CAPEX}$ /a)	Useful life (a)
PV	**900**	**1,8**	**30**
Wind	**1.600**	**4,8**	**25**
Electrolysis	**1.000**	**2**	**25**

Source: Fraunhofer ISE on the basis of the assumptions used in this project

Cost optimisation using the "PtXProSIM" toolbox, developed by Fraunhofer ISE, is carried out in "least cost" mode. In other words, for a given configuration and the constraints of a 50 MW electrolyser, the algorithm looks for the distribution that results in the lowest hydrogen production costs (LCOH - levelised cost of hydrogen). There are therefore no constraints on the minimum operation of the electrolyser for a certain number of hours.

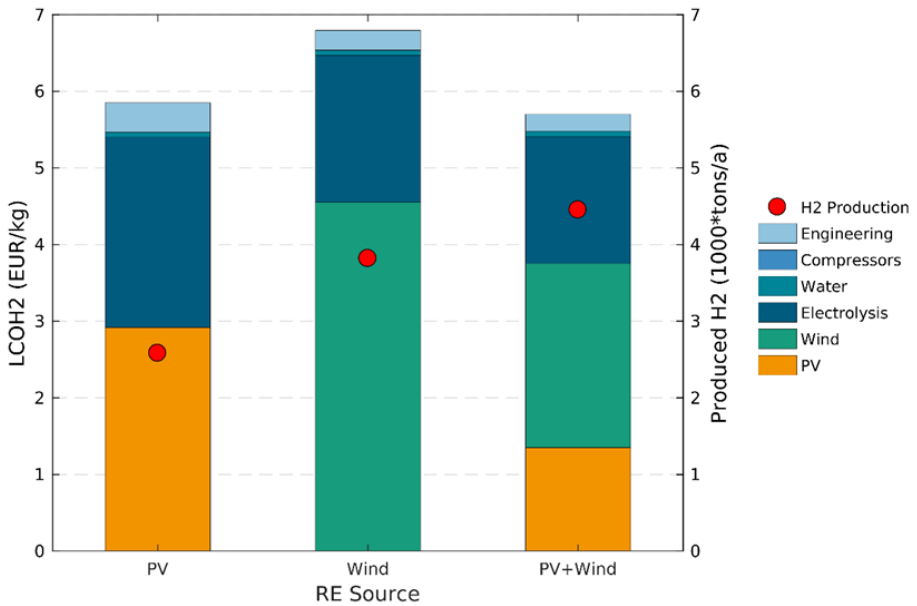
Three cases were determined independently of each other. A configuration with only solar panels, a configuration with only wind turbines and a "mixed" configuration. Table 6 lists the economic results.

Table 6: Economic results for site 1

	PV	Wind	PV+Wind
PV [in MW]	82	-	65
Wind power[in MW]	-	79	49
$LCOH_2$ [EURO/kg]	5,85	6,8	5,7
Load factor of electromill [in h]	2.670	3.950	4.610
Capital expenditure [in M€]	133	186	196

Source: Fraunhofer ISE calculations based on common assumptions in this project

Figure 20: Economic results for site 1



Source: Fraunhofer ISE

The results of this simulation allow the following analytical remarks:

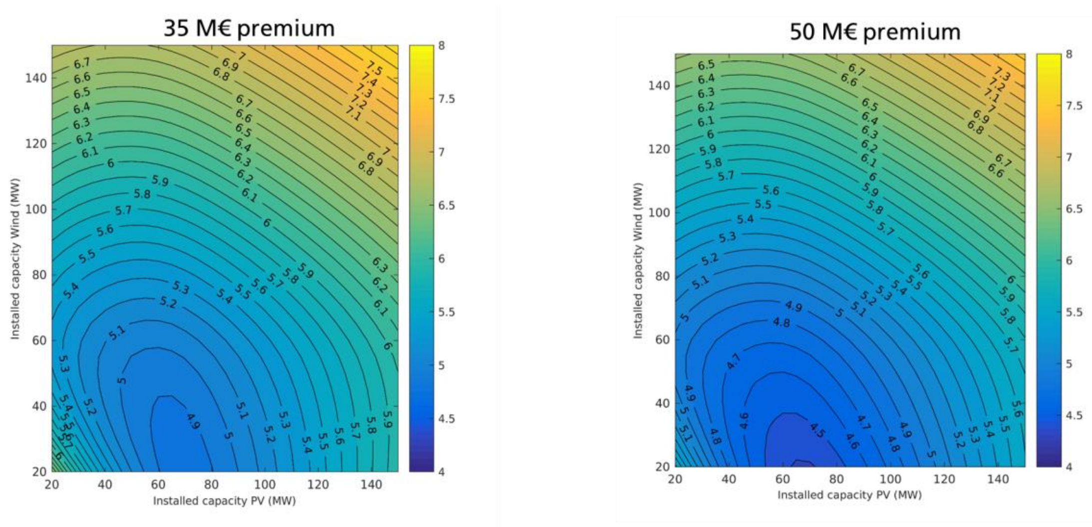
- A system based solely on 82 MW of solar energy would represent the lowest investment costs (€133 million). The cost of producing hydrogen would be €5.85/kg. However, the electrolyser could only operate for 2,670 hours a year, producing around 2,600 tonnes of hydrogen.
- A system based solely on 79 MW of wind turbines would represent the highest investment costs (€186 million). The cost of producing hydrogen would be €6.8/kg. However, the electrolyser could operate for 3,950 hours a year, producing around 3,850 tonnes of hydrogen.

- A mixed system costs the most (€196 million), but it allows the electrolyser to operate for 4,610 hours, which corresponds to a rate of 58% compared with an industrial year of 8,000 hours[6] . The system produces hydrogen at a cost of €5.7/kg, and is expected to produce around 4,500 tonnes a year.
- Hydrogen costs are dominated by the cost of renewable energy.
- The presence of wind power increases hydrogen production considerably due to the higher peak hours of this energy. On the other hand, the high investment costs of wind turbines increase the unit cost per kilo of hydrogen from a certain point onwards.

In the context of a possible investment premium from the KfW, this study offers insights into the effect of such a premium on the profitability of an electrolysis plant. It should be noted that - depending on the amount of the premium - the optimisations determine different least-cost points. We cannot simply transpose the hypotheses from one case to another without redoing the optimisation calculations.

Assuming an investment premium of between €35 and €50 million, and based on a mixed PV + wind system to maximise the number of peak hours, we obtain a three-dimensional diagram showing the maximum power of the wind turbines on the vertical axis and the maximum power of the PV panels on the horizontal axis. The third dimension, the LCOH cost, is shown in colour and with isometric lines.

Figure 21: Effect of investment premiums



Source: Fraunhofer ISE

With a premium of €35 million, it is therefore possible to reduce the LCOH to below €4.9/kg (a reduction of 16.3% compared with €5.7/kg without a premium, see above).

With a premium of €50 million, it is therefore possible to reduce the LCOH to below €4.5/kg (a reduction of 26.6% compared with €5.7/kg without a premium, see above).

It should not be forgotten that this is a demonstration system, that the investment costs of electrolysers are currently still high and that the subsequent construction of a larger system will unlock economies of scale. We would also remind you of the conservative price approach to renewable costs. For example, the LCOH of this system should not be compared with the LCOH of a steam

[6] The difference between the 8,760 hours in a year and the 8,000 hours in an "industrial year" is explained by the planned maintenance and shutdown intervals.

reformer in the chemical industry. It is useful to recognise the construction of such a demonstration system primarily as an opportunity to accumulate knowledge for the construction, operation and maintenance of electrolysers and RE.

In terms of product use, the study recommends using the hydrogen produced in industrial processes that already use fossil hydrogen.

One possibility would be ammonia synthesis. The demonstrator should be built close to one of the Haber-Bosch syntheses at Arzew to avoid transporting the hydrogen over too great a distance. The gas used in the Haber-Bosch synthesis is a gas containing nitrogen and hydrogen in a ratio of 1:3. This ratio is achieved by optimising the two methane steam reforming trains. The additional quantities of hydrogen to be ingested in this scenario are relatively small compared with the amount of hydrogen consumed by the large Haber-Bosch syntheses at Arzew: The AOA synthesis with a maximum capacity of 2.4 million tonnes of ammonia per year consumes up to 54 tonnes of pure hydrogen per hour. The Fertial and Sorfert syntheses (around one million tonnes of ammonia) consume around 20 tonnes of pure hydrogen per hour. A minor adjustment to the reformers could modify the N_2:H_2 ratio and allow the use of hydrogen from electrolysis. The production cost per kilo of ammonia can be estimated by dividing the cost of hydrogen by 5.55. This is a very rough calculation, which does not take into account the CAPEX for an ammonia synthesis unit. However, as the plant has already been built, this shortened calculation can be used in this case.

With a premium of €35 million, and an LCOH below €4.9/kg, we can estimate an ammonia production cost of €883/t.

With a premium of €50 million, and an LCOH below €4.5/kg, we can estimate an ammonia production cost of €811/t.

These production costs are higher than those for fossil ammonia. We mustn't forget the small size of the installation and a higher selling price than would be expected for green ammonia.

Another possibility would be to use it in the hydrocracking process at an oil refinery site. According to available data[7] , the Arzew refinery processes up to 81,000 barrels of crude oil per day. So there is a demand for hydrogen in a hydrocracker that could be met by hydrogen from electrolysis.

The oxygen also produced during electrolysis can be used for medical purposes or in industries that require it, such as metallurgy, steelmaking, glassmaking or water treatment. At the output of an electrolyser, there is always a little hydrogen left in the oxygen and vice versa. A purification unit is strictly necessary in most cases, but the technology is well known and mastered.

[7] https://www.eia.gov/international/content/analysis/countries_long/Algeria/algeria.PDF

3.3.2 Site 2: Hassi R'Mel, electrolysis 1 GW

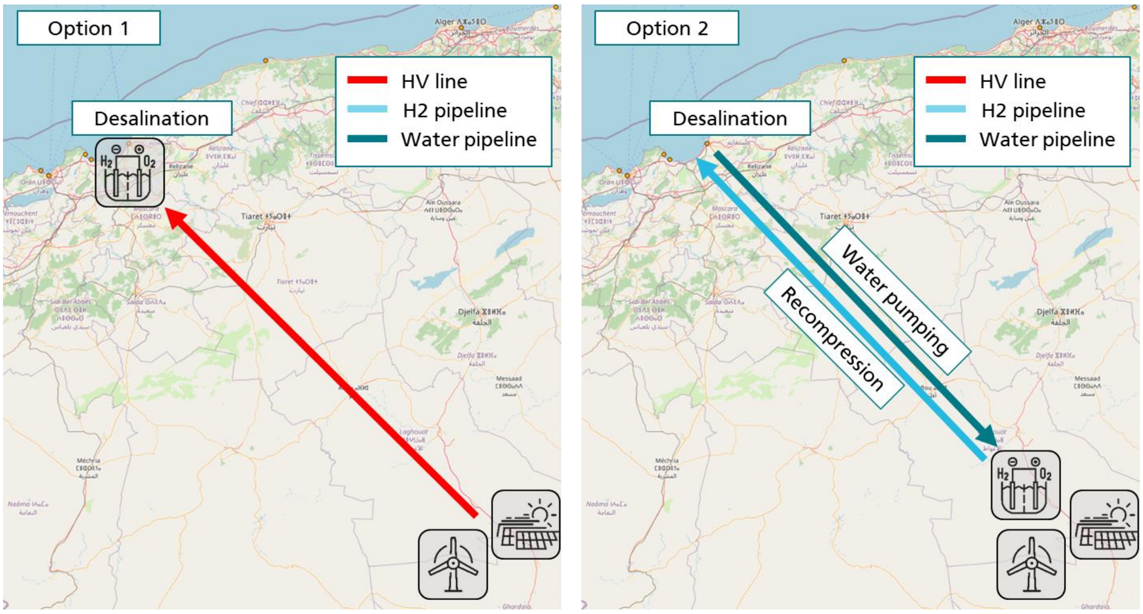
Introduction

The Hassi R'Mel site is an excellent location for a large-scale project as part of the second or third phase of the roadmap for the development of hydrogen in Algeria. The strong points are the good industrial infrastructure (proximity and synergies with the largest natural gas deposit in Algeria, with the required manpower and equipment). Its renewable energy potential is excellent, and climatic conditions are less restrictive than further south in the Sahara. On the other hand, there are no hydrogen consumers nearby, the evacuation of electricity or hydrogen poses technical difficulties, and access to water is more complicated.

The analysis calls for a 1,000 MW electrolyser.

The purpose of the study is to determine the cost of the hydrogen produced and to optimise this cost in terms of the HV lines to be built or extended and the pipelines to be laid. The project's completion horizon is beyond 2030.

Figure 22: Schematic diagram for site 2: Hassi R'Mel



Source: Fraunhofer ISE / Openstreetmap contributors

Analysis

This study distinguishes between two options. In the first case ("Coastal electrolysis"), the renewable energies are built at Hassi R'Mel and the electricity is transmitted via a new HV line. The electrolysis plant would be located on the coast, in this case at Arzew - for the reasons already described above. In the second case ("Electrolysis close to RE"), the RE and the electrolysis are built in Hassi R'Mel. The water is transported from the coast in an aqueduct and the hydrogen is evacuated to Arzew in a hydrogen pipeline. Recompression is required after around 200 km, and will be supplied by consuming some of the hydrogen transported.

Hassi R'Mel's solar potential is 1,861 hours per year and its wind potential is 3,421 hours per year. In order to operate a 1,000 MW electrolyser and not regularly exceed this threshold, it is necessary to oversize the solar and wind installations, so that it is possible to achieve a load factor for the electrolyser greater than that of the solar and wind potential, even without using electricity from the grid.

The economic parameters for this site, for which construction would begin after 2030, are given in Table 7.

Table 7: Economic parameters for site 2

	CAPEX (EUR/kW)	OPEX ($\%_{CAPEX}$ /a)	Useful life (a)
PV	650	1,9	30
Wind	1.450	3	25
Electrolysis	750	2	25

Source: Fraunhofer ISE on the basis of the assumptions used in this project

Cost optimisation using the "PtXProSIM" toolbox developed by Fraunhofer ISE is carried out in "least cost" mode. In other words, for a given configuration and the constraints of a 1,000 MW electrolyser, the algorithm looks for the distribution that results in the lowest hydrogen production costs (LCOH - levelised cost of hydrogen). There is therefore no constraint on the minimum operation of the electrolyser for a certain number of hours.

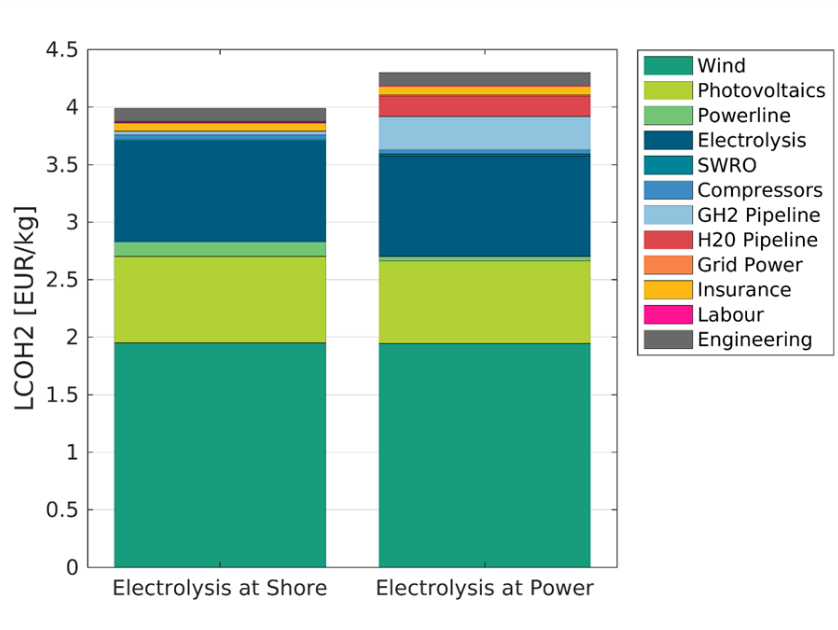
Two scenarios have been described above. There is no distinction between RE sources in this case, only an analysis of a mixed PV + wind farm.

Table 8: Economic results for site 2

	EL coastal	EL near EnR
PV [in MW]	1.287	1.240
Wind power[in MW]	1.290	1.295
$LCOH_2$ [EURO/kg]	4,0	4,3
EL load factor [in h]	5.908	6.120
Hydrogen produced [in t/a]	110.997	111.815
Total CAPEX [in €M]	3.882	4.262

Source: Fraunhofer ISE calculations based on common assumptions in this project

Figure 23: Economic results for site 2



Source: Fraunhofer ISE

The results of this simulation allow the following analytical remarks:

- LCOH prices fall to €4/kg for this larger plant.
- The estimate of ammonia production costs explained above indicates a value of around €720/t.
- Hydrogen costs are dominated by the cost of renewable energies
- Transport (HV network or hydro/water pipeline) appears, but does not exceed 5-10% of LCOH
- For the concrete case in point - 1,000 MW of electrolysis and a distance of around 500 km - the difference between the "coastal EL" and "near-zero RE" LCOHs is fairly small. As the economic analysis below will show, an increase in electrolysis capacity could tip the balance in favour of the "near-zero RE" concept.
- We can see the effects of scale as well as the price reductions expected over the coming years. The cost of hydrogen is significantly lower than for site 1.

To optimise the implementation of electrolysis, the study modelled the costs of electricity transmission on a HV line, as well as the costs of an aqueduct and a hydrogene pipeline.

The following assumptions are made for all three systems:

HV line :

- Line carrying 1 GW of electrical power
- Transport losses: 1.1%/1,000 km
- Investment: €190,000/GW/km plus power electronics[8]

Aqueduct :

- Cost modelling based on a power law, determined on the basis of empirical data (literature)
- 20% margin for obstacle avoidance

Hydrogen pipeline :

- Injection pressure after electrolysis: 80 bar, inlet pressure: 30 bar
- Recompression after approx. 200 km, using some of the hydrogen

[8] Wang et al, Analysing future demand, supply, and transport of hydrogen, 2021.

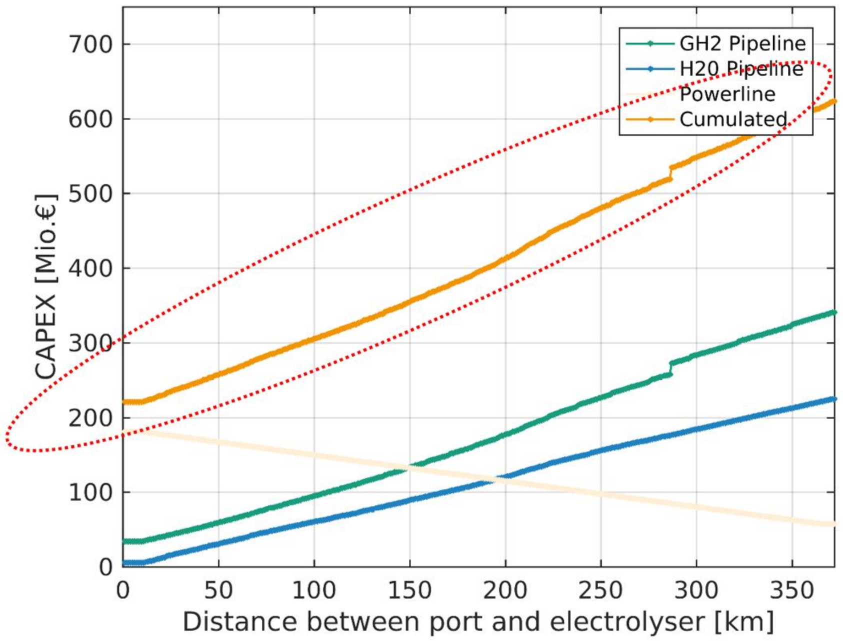
- Cost modelling based on a power law, determined on the basis of empirical data (literature)
- Note: There is a decrease in specific costs as a function of diameter, i.e. a larger diameter pipeline will cost more per metre, but the increase in flow rate is a square function of diameter. The hydro-pipeline will therefore be able to carry a much higher flow rate, which will lower the specific costs of the hydro-pipeline.

The study looked for the point of economic equilibrium, i.e. the ideal location for electrolysis. In fact, the results of the modelling recommend the "coastal EL" case. The cost of an HV line is high (around €200 million), but it is still cheaper than any other scenario where the electrolysis would be located elsewhere. Figure 24 shows the cumulative costs, which increase strictly with the distance between the port and the electrolyser. It should be noted that a "base" of around €25 million is planned for a hydrogen pipeline. There will always be a need for a certain number of pipes to transport and distribute the water and to collect and evacuate the hydrogen.

In this case, the model calculates a water pipeline with a diameter of 201 mm. This is rather small for a pipeline - bearing in mind the explanations on water pipelines above, it is therefore important to point out that when laying a water pipeline, it is advisable to oversize it, provided that you are able and willing to increase the flow afterwards.

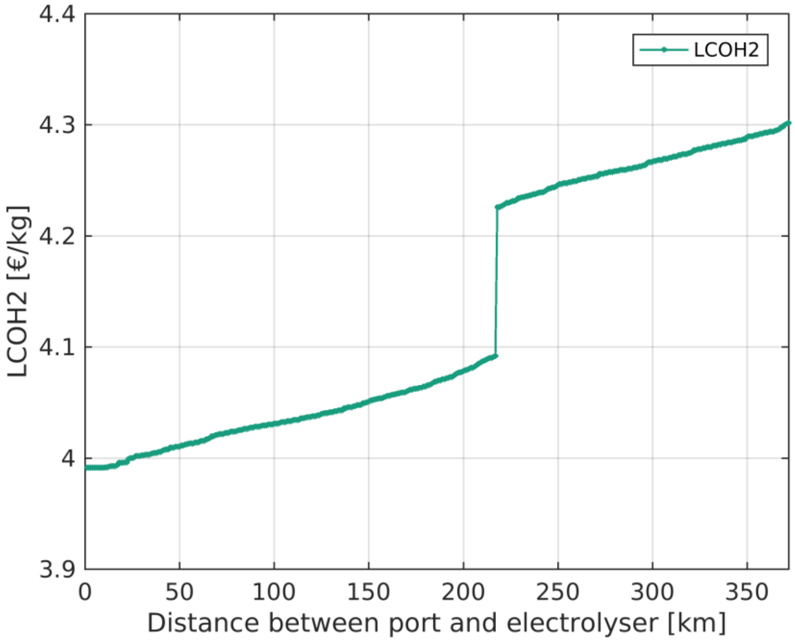
LCOH growth as a function of distance, Figure 25 also shows a discontinuity corresponding to the recompression of the hydrogen, resulting in a loss and therefore an additional cost.

Figure 24: Individual and cumulative costs of transport lines



Source: Fraunhofer ISE based on models

Figure 25: Effect of distance between port and electrolyser on hydrogen costs



3.4 Discussion and conclusions for the analysis of the two sites

This study analysed two sites for the implementation of PtX projects.

For an initial demonstration site and by 2030, a 50 MW electrolysis plant has been set up in Arzew and 79-114 MW of renewable energy capacity has been installed to supply it. Despite the demonstration nature of the project, LCOHs of €4.5-5/kg can be achieved, assuming financial support.

For a second site, and with a horizon starting in 2030, a 1,000 MW electrolysis plant is being considered. The following question has been analysed: should the electrolysis be located close to renewable energy sources or close to centres of consumption? How should the energy be evacuated? In the form of electricity or in the form of molecules?

In the calculations presented above, it is more advantageous to transport electrons rather than molecules. However, the cost of the transport infrastructure represents less than 10% in all cases.

It is possible to achieve LCOHs of €4/kg with a gigawatt electrolyser.

A corollary to the question of energy transport is that of water transport. For economic reasons, and in particular to take advantage of economies of scale for large desalination plants on the coast, seawater has been favoured as a source in the modelling. For large-scale renewable energy projects far from the coast, other sources such as water downstream of WWTPs will have to be studied.

There are several ways of exporting green energy. HV lines (e.g. direct current) already cross the world's seas. However, their capacity remains limited. The gas pipelines that currently link Algeria to Europe represent a possibility for exporting hydrogen. The resistance of steels to hydrogen will need to be studied to determine whether retrofitting is feasible. If not, new hydrogen pipelines under the sea are entirely conceivable. The transport of molecules with added value for the local economy, such as methane, ammonia, methanol or synthetic fuels, represents the third aspect. Algeria has been exporting large quantities of LNG, ammonia and other petrochemical products for decades. It is entirely conceivable that fossil raw materials could gradually be replaced by renewable energies. Investment is needed to convert port infrastructures. The European Union (EU) is currently developing a certification system for green hydrogen and its derivatives, the most important points of which are detailed in the next chapter. Their knowledge and application will make it possible to sell PtX products in Europe and contribute to the decarbonisation of industry that is necessary to comply with the 2015 Paris Agreement.

In addition to the purely hydrogen production and derivatives aspects, there are other monetary and non-monetary benefits to consider (summarised in Table 9).

A hydrogen production site will need a seawater desalination unit and will be able to supply drinking water to the communities and industries surrounding the project. Electrolysis also produces oxygen, a gas with many medical and industrial uses. The development of renewable energies in general promotes urban development and infrastructure in the project regions.

During the construction and operation of a PtX project, local jobs are created and the value chain is strengthened. For this type of project, it is possible to mobilise the domestic economy for a considerable proportion of the work. Hydrogen or PtX production, even on a small scale, serves as a test bed for a multitude of training courses (operators, administrators, certification, regulations, science and technology). The hydrogen produced can be used in local green mobility projects, for example in fuel cell buses.

Table 9: Other monetary and non-monetary benefits associated with the construction of electrolysers

Monetary	Non-monetary
Drinking water supply for municipalities bordering the project	Local employment during construction and operation
Production of oxygen for medical and industrial purposes	Potential for green mobility projects in the region (hydrogen buses)
Surplus energy can be used for urban development in the project area	Motivation for establishing a green energy certification mechanism
	A test bed for all administrative and regulatory challenges
	Supporting the development of academic and operational staff in the field of green hydrogen

4 Certification of green hydrogen

4.1 Relevance of hydrogen certification

In the context of hydrogen, certification is an instrument that can be used to guarantee that hydrogen complies with sustainability criteria and that it allows greenhouse gas (GHG) emissions to be reduced sufficiently. Certification is necessary because hydrogen is a homogeneous good that cannot be differentiated in terms of the greenhouse gas emissions of its supply chain or other environmental impacts. The hydrogen supply chain includes several life-cycle stages (production, packaging, transformation, transport) which can have an impact on the overall intensity of GHG emissions. Even "green" hydrogen, which is a common label referring to hydrogen produced from renewable electricity through electrolysis, can have a negative effect on decarbonisation efforts:

- If existing renewable energy (RE) systems are used to produce hydrogen that would otherwise have been used in direct electrification devices, hydrogen production can have a negative effect on decarbonisation efforts. To compensate for this renewable electricity, fossil electricity production increases, which indirectly leads to an increase in greenhouse gas emissions.
- The installation of new RE for hydrogen exports slows down the country's general decarbonisation efforts, because the resources for building new RE for direct electrification are blocked or the potential of RE is generally limited.
- Hydrogen production can also have an impact on land use: RE (e.g. photovoltaic solar energy) requires large areas of land. Care must be taken to ensure that the area used for hydrogen production does not prevent it from being used for other purposes (e.g. other renewable energy projects, agriculture, etc.).
- Hydrogen is produced from fresh water (or desalinated seawater), which can lead to potential competition with drinking water needs. In addition, the electricity required for additional desalination must be taken into account (and must also be renewable).

4.2 Status quo on green hydrogen certification

There is currently no coherent hydrogen certification system worldwide, and the development process is still in its early stages. Several international projects, initial schemes and governance are under development, notably in the European Union, the United Kingdom, China, the United States and Australia (WEC 2022). These include the European Renewable Energy Directive (RED) and the European CertifHy project, the Californian Low Carbon Fuel Standard, the Chinese Hydrogen Alliance Standard and Australia's industry-led zero-carbon certification scheme (smartenergy 2022).

In addition, several standardisation activities are being developed, such as the European Clean Hydrogen Alliance's hydrogen standardisation roadmap or the CEN/CENELEC hydrogen safety standards. Certification is also an important element for support instruments in which hydrogen is involved, such as carbon contracts for difference or the border adjustment mechanism for carbon.

In a study carried out by the World Energy Council and the German energy agency DENA (WEC 2022), the various certification systems and standards were examined and compared. It was found that it was difficult to harmonise existing international systems and regulations due to variations in sustainability criteria and the scope of the benchmark. However, harmonised approaches are necessary for a global liquid market (White et al 2021). At present, it is impossible to know whether regional certification schemes will prevail or whether a harmonised global approach will be aimed for at some point. Regional schemes with large differences in sustainability criteria risk fragmenting the market.

As there is not yet a global market for liquid hydrogen, a future certification system will need to be developed as the market grows.

4.3 Renewable Energy Directive II

For the European market, the certification of hydrogen from renewable sources will be governed by the Renewable Energy Directive (RED), which is currently (from May 2022) in force in its 2018 version (RED II Directive (EU) 2018/2001)). A revised version of RED III is currently in preparation. The RED contains the regulations under which bio-based renewable fuels and non-bio-based renewable fuels (RNBO) as well as recycled carbon fuels can be taken into account to meet the EU's renewable energy targets. Renewable hydrogen and other hydrogen-based renewable derivatives such as ammonia, methanol or other synthetic hydrocarbons are considered non-biobased renewable fuels.

Articles 25 to 30 of RED II contain important elements for certification, such as the definition of sustainability criteria or how to take into account emissions from fuels throughout their life cycle. In addition, two delegated acts were published in 2023, in accordance with Article 27 (3) of RED II.

The first delegated act[9] defines when hydrogen can be considered a renewable energy source, allowing it to be taken into account in the EU's renewable energy targets. For renewable energy sources such as hydropower, the characteristics of the electricity needed to produce hydrogen by electrolysis are of particular importance. This is why the delegated act contains details on the electricity production criteria (see section 4.3.1).

Another important element is the reduction in greenhouse gas emissions that can be achieved through hydrogenation and other renewable energy sources. This is why the second delegated act[10] specifies the method for calculating these reductions in greenhouse gas emissions (see section 4.3.2).

The delegated acts were published in the Official Journal of the European Union in June 2023 and the criteria described have therefore come into force. The two acts are linked and necessary for fuels to be taken into account in EU countries' renewable energy targets. They will provide regulatory certainty for investors, as the EU aims to achieve domestic renewable hydrogen production of 10 million tonnes and renewable hydrogen imports of 10 million tonnes by 2030, in line with the REPowerEU plan. The new rules will apply to both domestic producers and international producers exporting renewable hydrogen to the EU.

4.3.1 Criteria for electricity to produce hydrogen

The first delegated act specifies the cases in which the production of hydrogen can be considered entirely renewable, even if it is produced via connection to the network of a network that is not entirely decarbonised. If hydrogen is considered entirely renewable, it can be counted towards the EU's renewable energy targets.

A number of definitions and criteria are important for the different cases of electricity distinguished by RED II. These criteria must ensure that the production of renewable hydrogen encourages the production of new renewable energies and not the production of electricity from fossil fuels.

- Additionality: Additionality requirements ensure that RE is newly installed for the purpose of using electricity to produce hydrogen. This rule ensures that renewable energies originally installed for a different purpose are not used to produce hydrogen, and that they may not be

[9] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0011.01.ENG&toc=OJ%3AL%3A2023%3A157%3AFULL
[10] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0020.01.ENG&toc=OJ%3AL%3A2023%3A157%3AFULL

used for their original purpose. A renewable energy source is considered "new" if it was installed no more than 36 months before the installation of the electrolyser. The European Commission is planning a transition period for this criterion: for installations built before 2028, the additionality criteria will only apply after 2038.

- Temporal correlation: The temporal requirement stipulates that hydrogen is produced during the same hour as electricity. The European Commission provides for a transition period for this criterion: until 31.12.2029, the temporal correlation between RE production and electrolysis must only be on a monthly basis. The temporal criterion can also be met by using stored renewable electricity or renewable electricity whose prices are low enough to make it uneconomical to ramp up electricity produced from fossil fuels.
- Spatial correlation: Spatial correlation means that the RE and the electrolyser are located in the same tendering zone, or that the RE is located in a neighbouring tendering zone where prices are equal to or higher than those in the hydrogen production zone. For hydrogen produced by the electricity grid, tendering zones are a central element, which are defined by the EU regulator ACER as the largest geographical area in which market players can exchange energy without capacity allocation and where a single electricity market price applies. The spatial requirements are designed to prevent grid congestion between RE and electrolysers.

Bidding zones may not be used in all countries. In this case, the delegated act provides that equivalent (most similar) concepts of a bidding zone are also allowed, provided that the objective of the delegated act is still respected. For example, similar market regulations or the physical characteristics of the network (level of interconnection) or the country itself are only allowed as a last resort.

The cases can be divided into several categories. The first distinction is made according to whether the hydrogen is produced from a direct line between the RE (for example, photovoltaic solar panels or wind turbines) and the electrolyser, or whether the electrolyser is fed by electricity from the grid.

The simplest case is that of a direct line between the RE and the electrolyser. In this case, the "additionality" criterion must be met. If the electrolyser has a direct line to the RE and a connection to the grid, it must be proven, using a smart meter, that no electricity from the grid has been used for a hydrogen production load.

In the case of network generation, there are four different sub-cases.

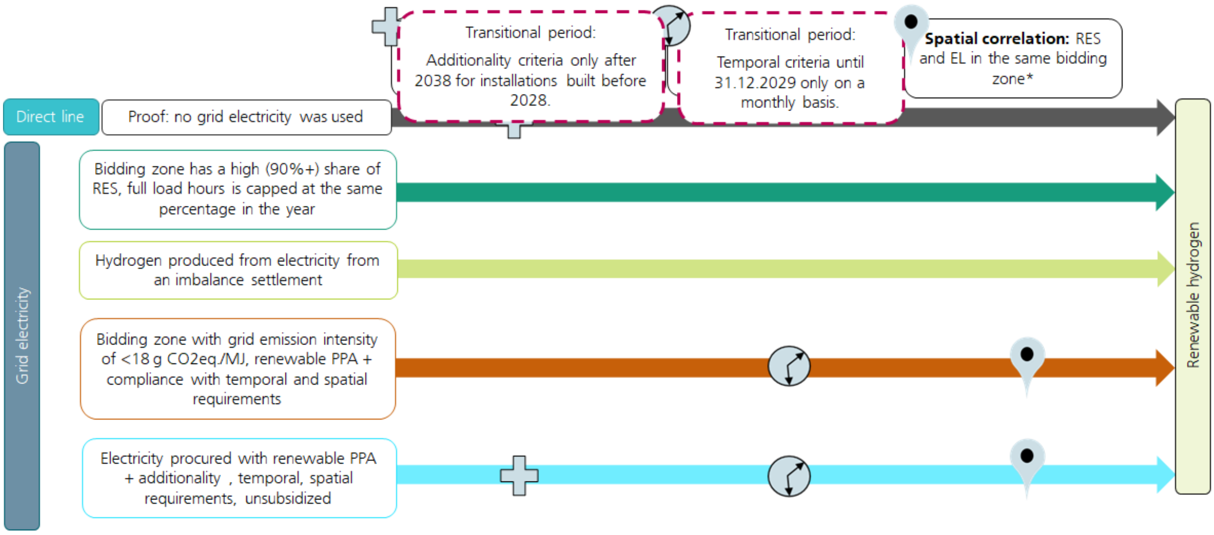
1. The hydrogen is produced in a tendering zone that has a high share (90%+) of RE in the previous calendar year. The full-load hours of hydrogen production are capped at the same percentage of the year (for example, if the RE share in the network is 95%, only 95% of the full-load hours of hydrogen production are considered renewable). In such a bidding zone, it is considered that the 70% GHG emission reduction criterion of Article 25(2) of the RED II for renewable fuels would already be met, and that additional RE installations could potentially have an impact on grid operation.
2. The tender area has a grid emission intensity <18 g CO_2eq/MJ. In this case too, additional RE installations are not required in the tender area to meet the 70% GHG emission reduction threshold required for renewable hydrogen (see next section). This case again requires a renewable electricity purchase contract certifying that the electricity is renewable, as well as compliance with temporal and spatial requirements.
3. Hydrogen produced from electricity from an imbalance settlement. In this case, hydrogen production could prevent redispatching and thus lead to greater use of the renewable electricity produced.

4. The last case describes the situation in which none of the above criteria apply to the network. In this case, a number of additional criteria must be met to produce renewable hydrogen. The electricity used in the electrolysis must be purchased under a renewable PPA. This PPA must ensure that the renewable energy production units meet the additionality criteria (i.e. they were installed no more than 36 months before the electrolyser). In addition, hydrogen production must comply with the above-mentioned temporal and spatial requirements, and no other subsidies have been received.

In addition to the above criteria, no double funding is possible (see Art. 5b: as renewable hydrogen can already be counted towards the EU's renewable energy targets, RE used to produce hydrogen cannot have received funding)[11] . Article 5b is subject to the transition period of Article 11 for capacity commissioned before 1 January 2028.

The five cases described above are summarised in Figure 26.

Figure 26: Electricity criteria for hydrogen to be considered fully renewable



Source: Own compilation, based on ((EC 2023), (EC 2023-2), (Stiftung Umweltenergierecht 2023))

4.3.2 Calculating greenhouse gas emission savings thanks to hydrogen

In addition to the criteria relating to electricity, there are also criteria relating to the reduction in greenhouse gas emissions through the use of hydrogen and other renewable fuels compared to fossil fuel. Article 25(2) of RED II stipulates that the greenhouse gas emission reductions achieved by RFNBOs must be at least 70%.

The second delegated act specifies the method for calculating the greenhouse gas emission reductions resulting from the use of RFNBO in transport and of fuels based on recycled carbon. It also sets the minimum threshold for reducing greenhouse gas emissions from fuels based on recycled carbon at 70%.

[11] . Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023Art. 5b (...provided that the following criteria are met: .... b) The installation producing renewable electricity has not received support in the form of operating aid or investment aid, excluding support received by installations prior to their retrofitting, financial support for land or for connection to the grid system, support that does not constitute net support, such as fully reimbursed support, and support for renewable electricity production facilities that supply facilities producing renewable liquid and gaseous transport fuel of non-biological origin used for research, testing and demonstration purposes.

The 70% reduction in GHG emissions must be achieved compared with a reference fossil fuel of 94 g CO2eq/MJ, which is equivalent to the requirements applicable to biofuels (EC 2023). GHG emissions must be calculated over the entire life cycle (upstream emissions from input supply, production and processing, transport and distribution, fuel combustion) of the fuel supply chain. Production emissions from the manufacture of the EnR or the electrolyser are not taken into account in the calculation of the fuel's life cycle emissions.

To determine the GHG emissions intensity of electricity used to produce hydrogen, several cases must be distinguished. If the criteria for renewable electricity in the first delegated act, described in section 4.3.1, are met, the electricity can be considered as not emitting g CO2eq/MJ.

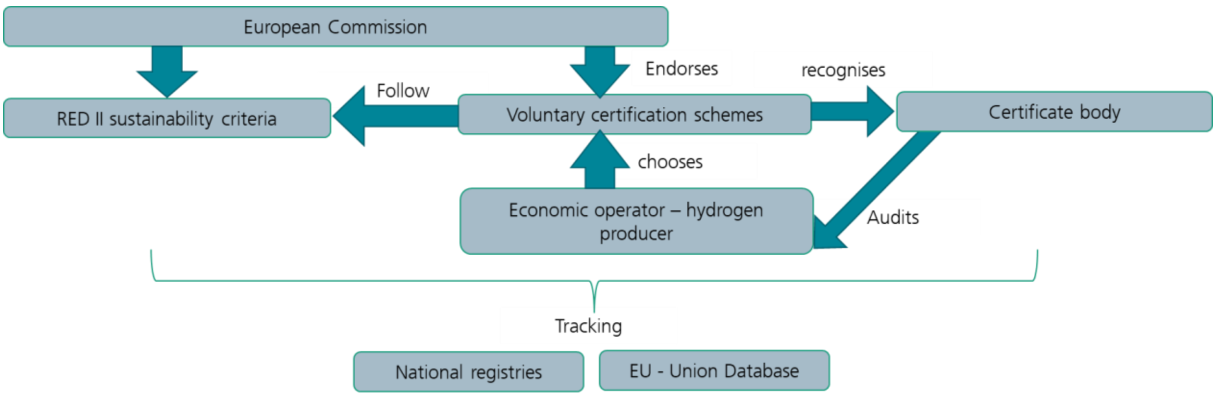
4.4 EU certification process

The European Commission will approve certification systems that meet the sustainability criteria defined in RED II. As these certification systems can be private, the process of exercising regulation through private systems is called hybrid certification. The approved system can be chosen by the economic operator (for example, the hydrogen producer). For example, for biofuels, several systems comply with the RED II criteria and can be chosen by producers. As a minimum, the systems must comply with the RED II criteria, but they may add more stringent criteria or other types of sustainability considerations, such as social criteria.

The (voluntary) certification systems recognise a third-party certification body, which will monitor the economic operator (EC 2023). For biofuels, 15 voluntary and national certification schemes are currently recognised by the European Commission (EC 2023-3).

The entire certification process must be tracked throughout the value chain. The European Commission plans to implement an EU database that collects all the data and can transmit it from one agent to another in the supply chain. In addition, there should be a link between the EU database and the national registers. The certification process is summarised in Figure 27.

Figure 27: Certification process



Source: Compiled by Fraunhofer ISI.

4.5 Discussion - Relevance for Algeria

EU regulatory requirements apply to EU producers and to non-EU producers wishing to export to the EU. Exporting countries will select a voluntary certification scheme approved by the European Commission. These voluntary certification schemes must be accepted by EU Member States as sufficient proof that the imported hydrogen complies with the EU's mandatory sustainability criteria. This reduces the administrative burden for exporting countries, as they do not have to distinguish between different national schemes, but can use a single EU-wide scheme recognised by the European Commission (EC 2023).

As long as the Algerian electricity system does not comply with the high decarbonisation targets defined in cases 1 and 2 discussed in section 4.3.1, the case most likely to apply to Algeria is case 4. This means that the additionality, spatial and temporal criteria apply for Algerian hydrogen to be considered fully renewable in the EU. In addition, supply chain emissions (e.g. additional electricity consumption for compression and transport) must be kept at sufficiently low levels for the use of hydrogen to achieve a 70% reduction in carbon dioxide emissions. This also includes the transitional provisions described above, which will enable Algeria to develop the hydrogen economy rapidly in cooperation with Germany and the European Union.

5 List of figures

6 List of tables

7 References

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A.1 Annex

Figure A 1: Population trends in Algeria and projections to 2050 based on the UN World Population Prospects 2022 (UN 2022)

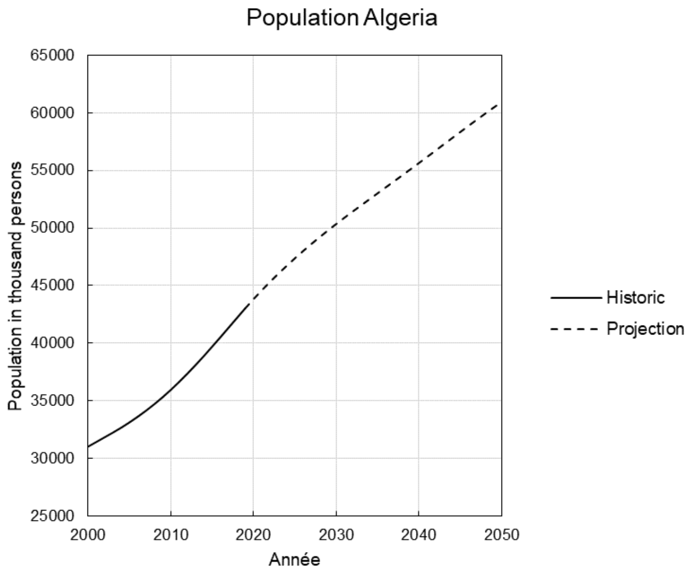

Figure A 2: Evolution of Algerian GDP (historical data from the World Bank (World Bank 2023) and own projections for future evolution)

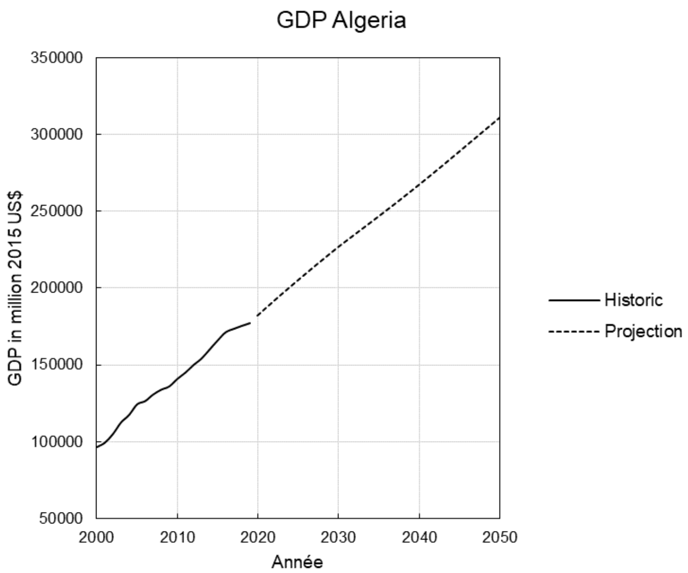

Figure A 3: Evolution of Algerian sectoral value added (World Bank historical data (World Bank 2023) and own projections for future evolution)

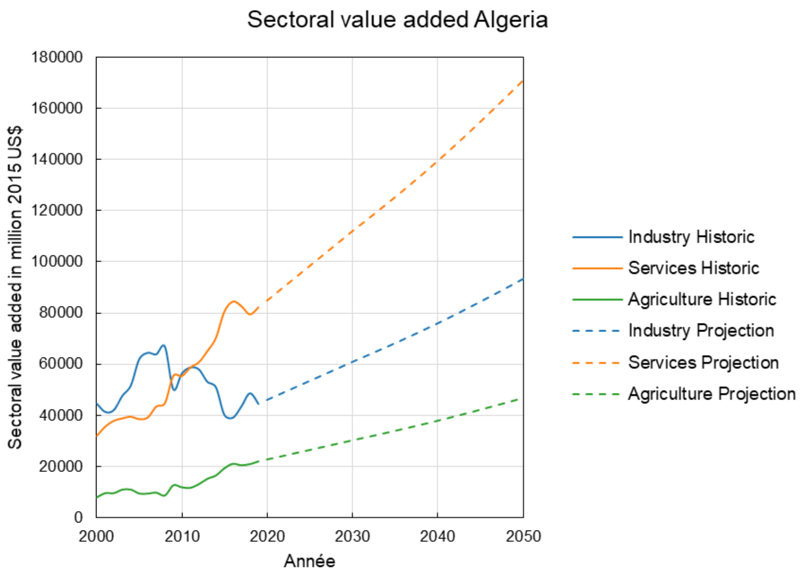

Figure A 4: Time series of onshore wind availability in Algeria (own calculation based on (Pfenninger & Staffel 2023))

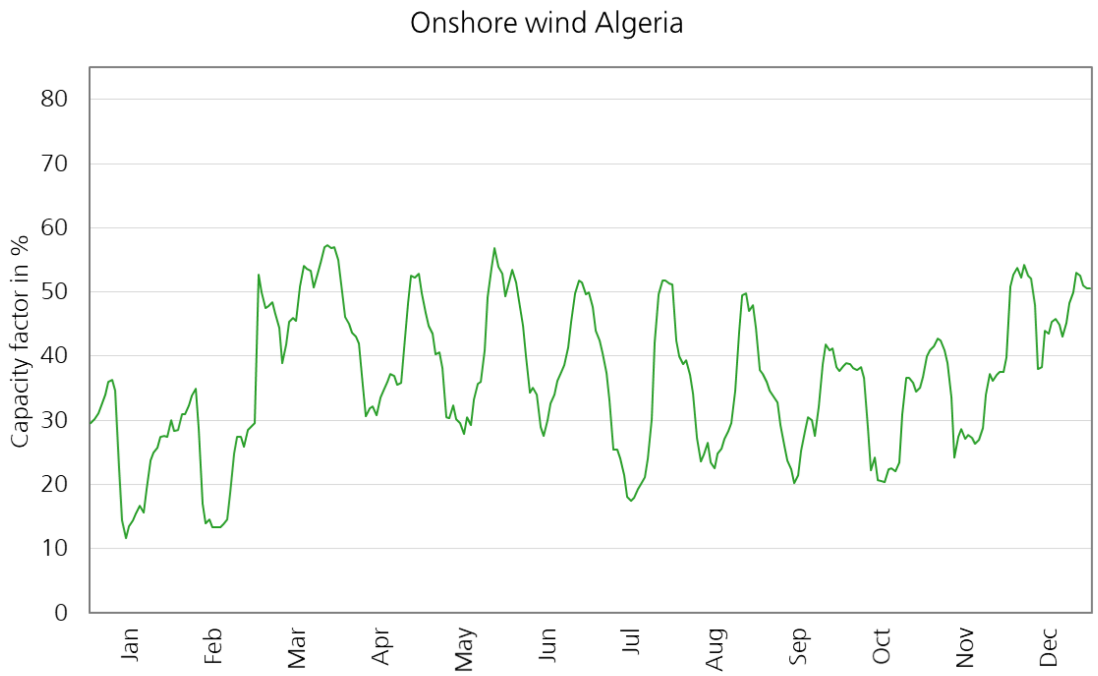

Figure A 5: Time series of solar photovoltaic energy availability in Algeria (own calculation based on (Pfenninger & Staffel 2023))

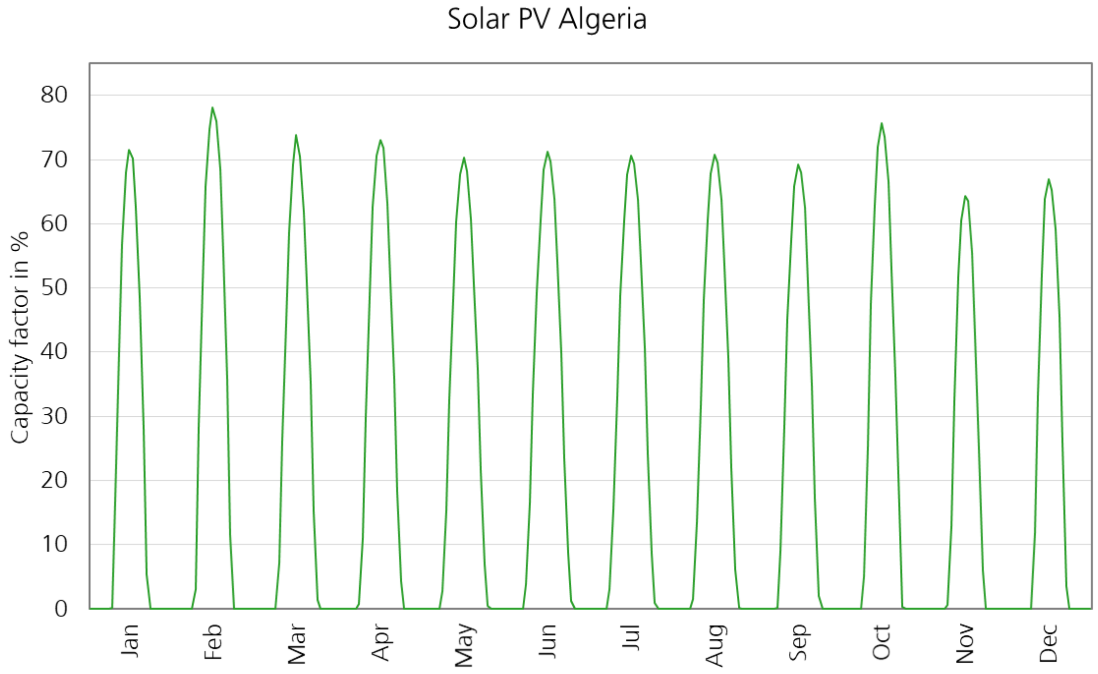

Figure A 6: Time series of the two forms of electrolyser load for the hydrogen export scenarios

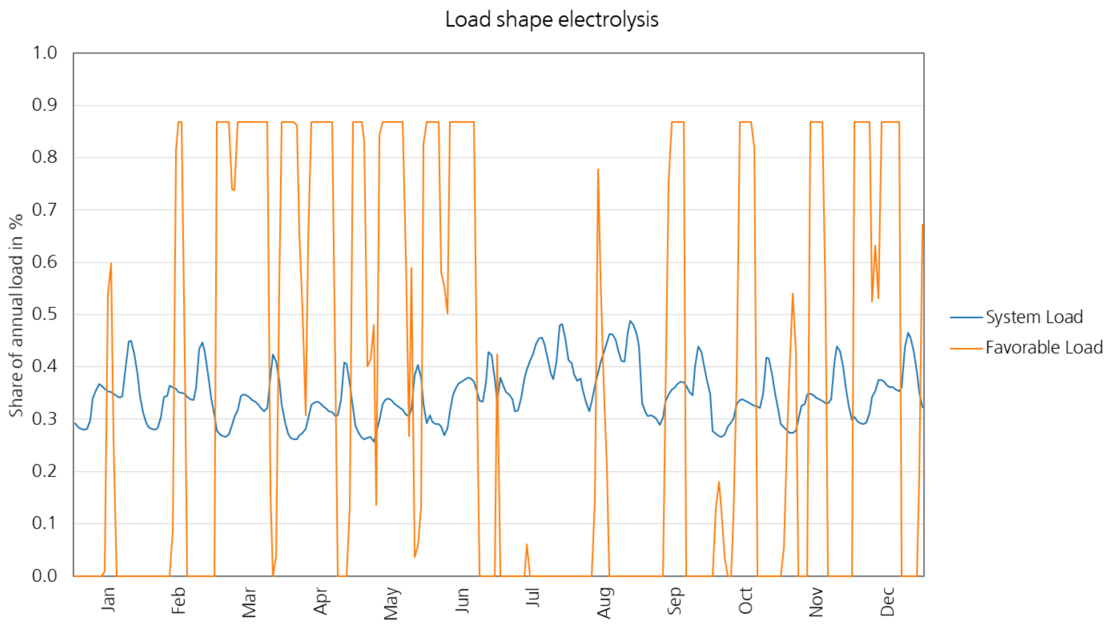

Table 10: Table of historical and future fuel shares for the different sectors of final energy demand and the different scenarios

Fuel Share in %	2000	2010	2019	2030 NZE	2030 AER	2030 BAU	2050 NZE	2050 AER	2050 BAU
Industry									
Oil	24.3	17.7	8.3	4.5	4.5	8.3	0.0	0.0	8.3
Natural Gas	45.1	56.2	64.1	54.0	60.0	64.1	0.0	30.0	64.1
Coal	9.6	5.0	2.8	1.0	1.0	2.8	0.0	0.0	2.8
Electricity	19.7	20.5	24.8	35.0	32.0	24.8	65.0	55.0	24.8
Renewable Heat	0.0	0.0	0.0	3.0	1.0	0.0	15.0	10.0	0.0
Biomass	1.2	0.6	0.1	1.5	1.5	0.1	5.0	5.0	0.1
Hydrogen	0.0	0.0	0.0	1.0	0.0	0.0	15.0	0.0	0.0
Transport									
Oil	99.5	99.5	99.3	82.0	95.0	99.3	0.0	50.0	99.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	0.5	0.5	0.7	15.0	4.0	0.7	65.0	40.0	0.7
Renewable Heat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	2.0	1.0	0.0	15.0	10.0	0.0
Hydrogen	0.0	0.0	0.0	1.0	0.0	0.0	20.0	0.0	0.0
Residential									
Oil	40.5	29.0	14.9	5.0	10.0	14.9	0.0	0.0	14.9
Natural Gas	46.5	56.4	70.9	60.0	66.0	70.9	0.0	20.0	70.9
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	12.6	14.4	14.2	30.0	22.0	14.2	75.0	65.0	14.2
Renewable Heat	0.0	0.0	0.0	4.0	1.0	0.0	20.0	10.0	0.0
Biomass	0.4	0.3	0.0	1.0	1.0	0.0	5.0	5.0	0.0
Hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Services									
Oil	31.6	37.9	33.7	27.0	29.0	33.7	0.0	5.0	33.7
Natural Gas	0.0	0.4	12.3	10.0	10.0	12.3	0.0	5.0	12.3
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	68.4	61.7	54.0	60.0	60.0	54.0	85.0	80.0	54.0
Renewable Heat	0.0	0.0	0.0	3.0	1.0	0.0	15.0	10.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Agriculture									
Oil	30.9	21.9	21.2	18.0	19.0	21.2	0.0	10.0	21.2
Natural Gas	0.0	18.9	18.1	13.0	14.0	18.1	0.0	5.0	18.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	69.1	59.2	60.6	65.0	65.0	60.6	80.0	75.0	60.6
Renewable Heat	0.0	0.0	0.0	2.0	1.0	0.0	10.0	5.0	0.0
Biomass	0.0	0.0	0.0	1.0	1.0	0.0	5.0	5.0	0.0
Hydrogen	0.0	0.0	0.0	1.0	0.0	0.0	5.0	0.0	0.0
Non Energy									

Oil	40.2	39.9	12.0	5.0	10.0	12.0	0.0	5.0	12.0
Natural Gas	59.8	60.1	88.0	80.0	85.0	88.0	0.0	60.0	88.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Heat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	10.0	5.0	0.0	50.0	35.0	0.0
Hydrogen	0.0	0.0	0.0	5.0	0.0	0.0	50.0	0.0	0.0
Unspecified									
Oil	7.0	7.0	6.9	1.0	5.0	6.9	0.0	0.0	6.9
Natural Gas	93.0	93.0	93.1	75.0	83.0	93.1	0.0	40.0	93.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	0.0	0.0	0.0	20.0	10.0	0.0	75.0	50.0	0.0
Renewable Heat	0.0	0.0	0.0	2.0	1.0	0.0	10.0	5.0	0.0
Biomass	0.0	0.0	0.0	1.0	1.0	0.0	5.0	5.0	0.0
Hydrogen	0.0	0.0	0.0	1.0	0.0	0.0	10.0	0.0	0.0

Source: Based on Enerdata historical values (Enerdata 2023) and our own estimates for future developments.

Table 11: Overview of the technical and economic assumptions for the various power plants and storage technologies

Technology	CAPEX [2015 US$/kW]			OPEX (variable) [2015 US$/MWh]			OPEX (fix) [2015 US$/kW/year]			Efficiency [%]			Lifetime [years]		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
Lithium Ion Batteries	845	528	349	2.30	2.07	1.84	0.31	0.16	0.08	91.0	92.0	92.0	20.0	25.0	30.0
Hydrogen Storage	1866	1403	855	0.00	0.00	0.00	55.09	41.12	27.33	26.4	34.3	45.0	20.0	20.0	20.0
Open Cycle Gas Turbines	545	522	494	5.40	5.40	5.40	9.68	9.29	8.91	40.0	41.0	43.0	25.0	25.0	25.0
Combined Cycle Gas Turbines	1056	996	960	5.28	5.04	4.80	35.16	33.36	31.20	56.0	58.0	60.0	25.0	25.0	25.0
Oil Engines	412	412	403	7.20	7.20	7.20	10.56	10.14	9.72	35.0	35.0	35.0	25.0	25.0	25.0
Hydropower Plants	3072	3072	3072	6.00	6.00	6.00	92.16	92.16	92.16	100.0	100.0	100.0	50.0	50.0	50.0
Biomass Plants	2200	2200	2200	6.00	6.00	6.00	66.00	66.00	66.00	40.0	40.0	40.0	25.0	25.0	25.0
Wind Turbines	1800	1300	1000	0.00	0.00	0.00	86.40	39.00	25.00	100.0	100.0	100.0	25.0	27.5	27.5
Solar PV	1200	550	300	0.00	0.00	0.00	18.27	9.62	6.60	100.0	100.0	100.0	30.0	35.0	35.0
CSP	5500	4000	2500	0.00	0.00	0.00	82.50	60.00	37.50	100.0	100.0	100.0	25.0	25.0	25.0

Source: Own compilation based on literature values (DEA 2016, Ram et al 2020, IEA 2021, Frontier Economics 2018, Agora 2021, ENS 2021) and consultations with local experts.