Electrons or molecules

Comparing electricity and hydrogen imports from the MENA region to Europe

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TABLE OF CONTENTS

Handlungsempfehlungen Für das BMWi – Schlussfolgerungen für EP/ED in der Golfregion 1

Executive Summary 2

1. Introduction: International Trade of renewable energy 3

2. Costs of long-distance electrictiy or hydrogen transport in 2030 4

2.1 Scenario 1: End use electricity 4
2.2 Scenario 2: End use hydrogen 5
2.3 Using existing infrastructure 5
2.4 Methods and assumptions 6

3. Feasibility of long-distance renewables trade 8

3.1 Geographic considerations 8
3.2 Geostrategic considerations: energy supply 9
3.3 Geostrategic considerations: route selection 9
3.4 Exporting country energy systems 10

4. Cost of blue hydrogen 11

Appendix A: Model Assumptions 12

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[1] On October 11, 2019, Guidehouse LLP completed its previously announced acquisition of Navigant Consulting Inc. In the months ahead, we will be working to integrate the Guidehouse and Navigant businesses. In furtherance of that effort, we recently renamed Navigant Consulting Inc. as Guidehouse Inc.

HANDLUNGSEMPFEHLUNGEN FÜR DAS BMWI – SCHLUSSFOLGERUNGEN FÜR EP/ED IN DER GOLFREGION

Der in DEU verbreitete Konsens, **dass auch in einem vollständig erneuerbaren Energiesystem Energieimporte nach Europa notwendig sein werden, ist auch auf der Arabischen Halbinsel bekannt und wird mit Interesse verfolgt**. Während in DEU diesbezüglich jedoch primär über den Import molekularer Energieträger wie Wasserstoff diskutiert wird, ist am Golf die Idee vom Export erneuerbarer Elektrizität über ein interkontinentales Stromnetz ebenfalls Teil der Überlegungen. **Die vorliegende Studie vergleicht den Transport von erneuerbarer Energie in Form von Wasserstoff (H_2) durch Pipelines mit dem Transport als Strom über eine Übertragungsleitung**:

- **Kosten**: Je weiter die Distanz ist und je günstiger der erneuerbare Strom, desto eher lohnt sich Übertragung als H_2 mit anschließender Re-Elektrifizierung. Also könnten für Importe von der Arabischen Halbinsel H_2-Pipelines und für Nordafrika Stromleitungen billiger sein.

- **Wert im Stromsystem**: In der Strom-Route können DEU Abnehmer nur bei zeitgleicher Erzeugung im Lieferland Strom erhalten. H_2-Re-Elektrifizierung kann jederzeit erfolgen, sodass Mehrkosten der H_2-Route durch höheren Systemnutzen kompensiert werden könnten.

- **Versorgungssicherheit:** H_2 lässt sich deutlich einfacher in großen Mengen speichern als Strom, sodass Versorgungsrisiken bei H_2 besser eingedämmt werden können als bei Strom.

- **H_2 als Endprodukt**: wenn Endverbraucher in DEU nicht Strom, sondern H_2 benötigen (z.B. industrielle Verbraucher), ist eine H_2-Pipeline in jedem Szenario günstiger.

Gaspipelines und Stromleitungen bestehen aktuell zwischen Europa und Nordafrika, nicht aber der Arabischen Halbinsel. **Kurzfristig sind Exporte aus Nordafrika also einfacher umzusetzen**. Mittel- und langfristig wird jedoch auch die **Arabische Halbinsel** benötigt, um eine **Diversität der Lieferländer** und **hinreichende Volumina** zu erreichen. Hierzu wäre die Verschiffung von H_2-Derivaten (z.B. Kohlenwasserstoffen) und perspektivisch Pipelines (z.B. via Ägypten) denkbar.

Blauer H_2 auf Basis fossiler Rohstoffe ist in Golfländern von Interesse, insbesondere bei Ölfirmen wie ADNOC oder Saudi Aramco. DEU sollte hier jedoch darauf hinweisen, dass **grüner H_2 mittelfristig wettbewerbsfähiger** erwartet wird und Investitionen in „blaue“ Produktion daher risikobehafteter sind. Außerdem besteht die Gefahr, dass ein Fokus auf blauem H_2 den generellen Dialog über die Transformation zu einem erneuerbaren Energiesystem untergräbt.

Die Energiezusammenarbeit des BMWi im Rahmen der Energiepartnerschaft/-dialoge behandelt das Thema Wasserstoff bereits sehr intensiv; zusätzliche Aktivitäten sind anzustreben:

- In den **VAE** fanden 2020 bereits zwei Workshops in diesem Bereich statt, eine Studienreise wurde von März auf Juni 2020 verschoben. Eine gemeinsame Studie ist ebenfalls in Planung.

- In **Saudi-Arabien** ist der ED in Kontakt mit relevanten Stakeholdern (z.B. Peter Terium, Leiter Energie bei Neom), im Juni 2020 soll ein Wasserstoff-Workshop in Riad stattfinden.

- In **Oman** engagiert sich der Energiedialog zusammen mit Firma „Hydrogen Rise“ aus München in der Debatte vor Ort, u.a. bei einem Symposion im Oktober 2019.

- Als Ergänzung zu bilateralen Plattformen sollten auch **regionale Ansätze** verfolgt werden, z.B. im Rahmen einer möglichen MENA-Regionalkonferenz 2021.

Für den Dialog zum **Aufbau internationaler H_2-Märkte sollten die EP/ED die zentrale Anlaufstelle** sein. Ein Aufbau paralleler Initiativen mit Fokus auf H_2 sollte auf EP/ED zurückgreifen, da die Einbettung in die Systemtransformation und den Ausbau erneuerbarer Energien unabdingbar ist.

EXECUTIVE SUMMARY

With a current energy trade deficit of around 11,000 TWh, imports are indispensable for covering European energy demand – and the question arises of how future CO_2 neutral energy imports will look like. One possibility is to import electricity or hydrogen (H_2) from the Middle East & North Africa (MENA)-region, where both can be produced cheaply at scale due to abundant renewable energy potential. The analysis in chapter 2 compares the import of either H_2 or electricity in the year 2030. The results depend on the end use of the product:

- Figure 1 shows that if the end use in Europe is electricity, it is cheaper to use electricity transmission for shorter distances (e.g. from Morocco). For longer distances (e.g. from the United Arab Emirates), H_2 transmission is cheaper, even if this H_2 needs to be converted back into electricity.

- If the end-use is H_2 (e.g. in industry) and not electricity, it is always cheaper to import H_2 rather than electricity which would be converted to H_2 in Europe.

Using existing electricity transmission assets makes the electricity option cheaper in all scenarios. However, existing trans-Mediterranean electricity lines are very limited and will in any case not be able to sufficiently supply projected long-term import demand.

Beyond costs, there are also other considerations to be made as discussed in chapter 3:

- Geographic conditions can hinder the construction of transmission assets – between Europe and the MENA region though, several feasible routes exist (chapter 3.1)

- Energy imports create considerable dependencies for importing countries. Resilience against possible supply disruptions is typically achieved by storing strategic reserves – this is an advantage for H_2, which can be stored more easily from today's view (chapter 3.2). Also, transmission assets are by nature at risk when crossing conflict areas – hence, shipping of H_2 or its derivatives could be a reasonable addition to pipelines or electricity lines, even though shipping is pricier (chapter 3.3).

Finally, chapter 4 compares costs of "blue" H_2 that is produced from natural gas with carbon capture and storage and "green" H_2 produced from renewable energy. While blue H_2 is cheaper today in some regions, costs for green H_2 are expected to fall, making long-term investments in blue H_2 production appear risky.

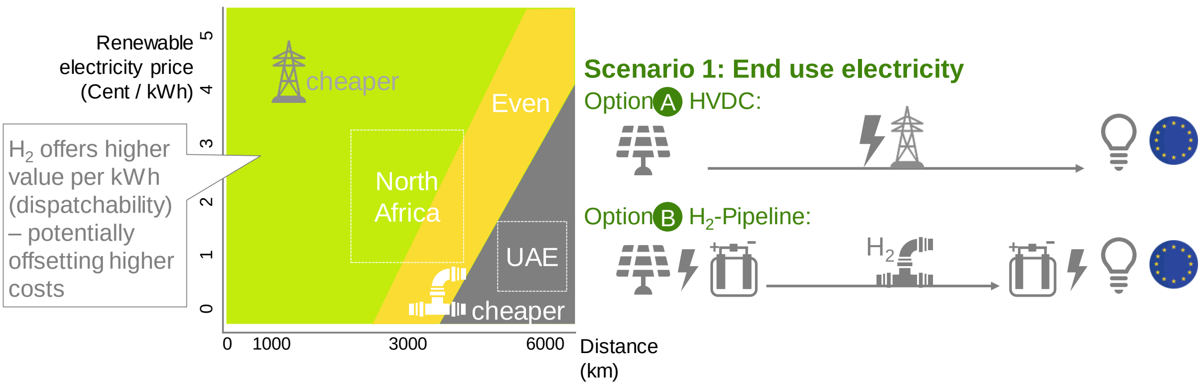

Figure 1 Costs of importing electricity or hydrogen in 2030 from the MENA region if the final consumption is electricity

1. INTRODUCTION: INTERNATIONAL TRADE OF RENEWABLE ENERGY

To achieve the European Union (EU) climate target of carbon neutrality by 2050, electricity will need to supply close to 60% of the final energy consumption according to estimates. The production of hydrogen and its derivatives will require additional electricity in the range of 600 – 1200 TWh, bringing the total electricity demand in Europe up to 4800 – 6000 TWh by 2050.[2] The net electricity generation in 2017 was 3100 TWh.[3] The EU will therefore need to nearly double its electricity generation by 2050, while switching from fossil to renewable generation at the same time. This begs the question of how to supply that amount of electricity and what role imports will play in this supply.

The EU is already a net importer of energy with imports exceeding exports by around 11000 TWh in 2017.[4] In the light of such a pronounced import dependency, it is likely that the EU will continue to be an energy importer in a decarbonized future – which is not necessarily to be seen negatively. There are several benefits in trading renewable energy internationally:

- Cost advantage – Production characteristics of renewable energy differ significantly between regions, as the example of solar irradiation shows: While central and northern Europe usually experience around 1250 kWh per m^2 per year, the value for countries in the MENA region in contrast is around 2500 kWh per m^2 per year.[5]

- Volume advantage – Technically, Europe could generate the amounts of renewable electricity mentioned above domestically: For Germany alone, the technical potential for renewable electricity is estimated at 7800 TWh per year. However, the actual potential is much lower mainly due to land use competition with agriculture and settlements, reducing the realistic renewable electricity potential to around 800 TWh.[6]

- Seasonal advantage – There are structural differences between regions in electricity supply and demand over the year: Central and northern Europe experience the highest demand in winter due to heating, while countries in the MENA region typically have peak demand in summer when cooling consumes large amounts of energy. International trade of renewable energy could match these complementary patterns, leading to better resource utilization and thus lower system costs.

The conclusion that international trade of renewable energy in the future is likely both required and desirable leads to the question which energy carrier is best suited to realize the corresponding long-distance transport. Chapter 2 assesses this in detail.

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[2] Eurelectric (2018) "Decarbonisation Pathways". Accessed via: https://cdn.eurelectric.org/media/3457/decarbonisation-pathways-h-5A25D8D1.pdf

[3] Eurostat (2020), "Electricity Production, Consumption and Market Overview". Accessed via: https://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_production,_consumption_and_market_overview

[4] Eurostat (2020), "Energy Production and Imports". Accessed via: https://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_production_and_imports#The_EU_and_its_Member_States_are_all_net_importers_of_energy

[5] Wirth (2020) "Levelized Cost of Electricity Renewable Energy Technologies". Fraunhofer ISE Accessed via: https://www.ise.fraunhofer.de/content/dam/ise/en/documents/publications/studies/EN2018_Fraunhofer-ISE_LCOE_Renewable_Energy_Technologies.pdf

[6] The Boston Consulting Group (2018): Klimapfade für Deutschland. Available online: https://bdi.eu/publikation/news/klimapfade-fuer-deutschland/

2. COSTS OF LONG-DISTANCE ELECTRICTIY OR HYDROGEN TRANSPORT IN 2030

The MENA region, with its abundant potential of solar energy offers the opportunity to cheaply produce renewable energy in large volumes. We analyze two potential options that could be employed to transport this renewable energy from the MENA region to Europe:

A. electricity through high-voltage (direct current) transmission lines

B. hydrogen from electrolysis through pipelines

Also, we regard two end-use scenarios in our analysis. For each scenario the two options mentioned above for importing either electricity (option A) or hydrogen (option B) are compared:

1. Direct electricity consumption in Europe

2. Direct hydrogen consumption in Europe (e.g. a chemical plant)

2.1 Scenario 1: End use electricity

The left-hand side of Figure 2 shows an indicative cost comparison of options A and B in the case that the end user in Europe requires electricity. For electricity transmission, a newly constructed high-voltage direct current (HVDC) line is assumed, for the transportation of hydrogen a newly constructed hydrogen pipeline. The green shading in Figure 2 indicates a costs advantage of electricity transmission, yellow a parity between the costs of electricity or hydrogen transmission and grey a cost advantage of hydrogen transmission.

Figure 2 displays these cost differentials as functions of the main variable cost drivers:

- Distance of energy transmission – longer distances are a cost advantage for hydrogen because one km pipeline is cheaper per unit of energy than one km HVDC

- Renewable electricity price – lower prices are a cost advantage for hydrogen because conversion losses become less of an economic issue

This means that for higher renewable generation prices (>1 Cent / kWh) and shorter distances (<3000km), it is cheaper to import electricity directly. From a distance of around 3000 km, hydrogen becomes competitive, albeit only for electricity prices between zero and four cents per kWh. Starting from a distance of around 4000 km and electricity prices between zero and three cents per kWh, the import of hydrogen and reconversion to electricity becomes cheaper than importing electricity directly.

This comparison is only concerned with costs and makes no assumption on the value of a kWh of electricity under either option A or B. As electricity production from hydrogen would be dispatchable, it could be the case that importing hydrogen is economical even if importing electricity is cheaper, as hydrogen-based electricity could be sold in times of higher prices in European electricity markets.

Latest auction results in the United Arab Emirates (UAE) and Saudi Arabia already feature generation prices for solar PV installations of around 2 EUR-Cents / kWh, which would be in the lower half of each graph of Figure 2.[7] In North Africa, there are less examples for auctions, but prices so far range from 6,4 EUR-Cents / kWh (concentrated solar power in Morocco) to 2,4 EUR-Cents / kWh (PV in Egypt) and can be expected to fall further until 2030.[8]

2.2 Scenario 2: End use hydrogen

Scenario 2 on the right-hand side of Figure 2 goes through the same steps but for the end use of hydrogen and not electricity. Correspondingly, imported electricity needs to be converted to hydrogen, and imported hydrogen does not need to be reconverted to electricity.

In this scenario, it is always cheaper to import hydrogen directly (option B), than electricity and convert it to hydrogen in Europe. This is because the conversion losses of electrolysis are inevitable in both options and the only differentiator that remains are the higher CAPEX costs of a HVDC transmission line compared to a pipeline.

The comparison is for made for the year 2030, which means that a range of assumptions were made, which are further explained in chapter 2.4.

2.3 Using existing infrastructure

The previous analysis was based on the new construction of both the HVDC and the hydrogen pipeline. However, up to a certain distance, i.e. mainly between North Africa and Europe, it is also possible to rely on existing infrastructure. Existing gas pipelines would need be retrofitted to be able to transport hydrogen. Morocco and Spain are already connected by two 380 – 400 kV electricity transmission lines.

Assuming such a use of existing infrastructure would reduce the CAPEX of the electricity transmission to zero, while existing natural gas pipelines would still need to be retrofitted. This results in electricity imports being cheaper for all scenarios. The cost advantage is significant, at least 5 EUR-Cents / kWh, when the final use is electricity. If the final use is hydrogen, the cost advantage shrinks to 0,5 – 1,4 EUR-Cents / kWh for shorter distances between 500 km and 3000 km. The comparison for longer distances is meaningless as no infrastructure exists to transport electricity from the Arabian Peninsula to Europe.

The absolute potential of this HVDC cost advantage is small though: The existing transmission capacity for electricity is limited to the transmission lines between Morocco and Spain. This connection is already in use, which means its capacity for additional transmission is limited – especially in light of the scale of the energy import demand discussed in chapter 1. The use of existing gas infrastructure would however enable much larger quantities of energy to be transmitted due to the well-developed pipeline infrastructure primarily for gas imports from Algeria.

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[7] Publicover, Brian (2020) “Solar is gaining traction in MENA region – but plenty of obstacles remain”, PV Magazine. Accessed via: https://www.pv-magazine.com/2020/01/17/mesia-outlines-past-progress-future-promise-in-sweeping-look-at-solar-across-middle-east-and-north-africa/

[8] Kraemer (2019) “Morocco Breaks New Record with 800 MW Midelt 1 CSP-PV at 7 Cents”, SolarPACES. Accessed via: https://www.solarpaces.org/morocco-breaks-new-record-with-800-mw-midelt-1-csp-pv-at-7-cents/

PV Magazine (2018) „Egypt wants cheaper solar bids, lowers bar to $0.025/kWh”, Accessed via: https://www.pv-magazine.com/2018/09/11/egypt-wants-cheaper-solar-bids-lowers-bar-to-0-025-kwh/

2.4 Methods and assumptions

The basic assumption underlying this modelling is that a new renewable electricity generation asset in the MENA region is connected to an energy consumer in Europe with a new-built HVDC line or hydrogen pipeline. Either transmission system is built without major geographical restrictions.

The model makes assumptions about four different technologies, i) costs for hydrogen electrolysis, ii) costs for the reconversion of hydrogen into electricity by fuel cell and iii) transportation cost of electricity via a HVDC transmission line and iv) transportation cost of hydrogen via a newly constructed hydrogen pipeline. Input parameters including their value and source are listed in Appendix A: Model Assumptions, Table 1.

The costs of hydrogen electrolysis are based on available technology in 2020 with an annual cost reduction until 2030 derived from IEA.[9] Cost assumptions for the fuel cell are based on JRC estimates for 2030 directly.[10] The costs for HVDC transmission line are based on estimates by Dii for 2050 and were adapted for 2030.[11] The model assumes an unweighted average of marine and land MENA and EU HVDC transmission cost for the entire distance.

Weighted average costs of capital were assumed to be 8% for all technologies. New assets – both pipelines and HVDC – could however be (co-)financed with concessional loans e.g. by the European Investment Bank or the World Bank. That would lead to a slight cost advantage of the more capital-intensive HVDC option, but would probably not fundamentally change the relative economics of the two options.

[9] IEA (2019) "The Future of Hydrogen". Accessed via https://www.iea.org/reports/the-future-of-hydrogen

[10] JRC (2019) "Global deployment of large capacity stationary fuel cells", JRC Technical Reports. Accessed via https://publications.jrc.ec.europa.eu/repository/bitstream/JRC115923/jrc115923_stationary_fuel_cells_16042019_final_pubsy_online.pdf

[11] Dii (2012) "Perspectives on a Sustainable Power System for EUMENA" 2050 Desert Power. Accessed via https://dii-desertenergy.org/publications/desert-power-2050/

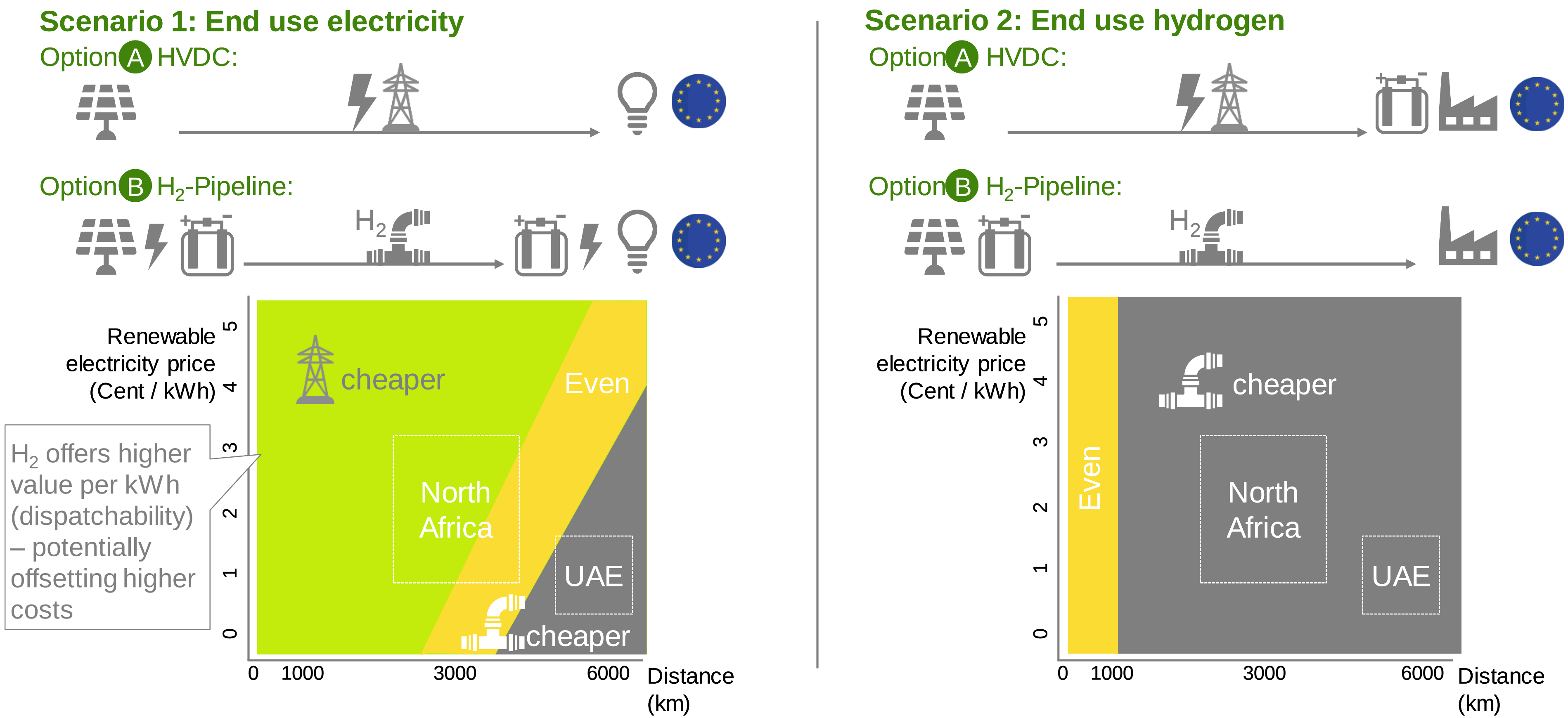


Figure 2 Costs of importing electricity or hydrogen in 2030 from the MENA region to Germany (own illustration)

3. FEASIBILITY OF LONG-DISTANCE RENEWABLES TRADE

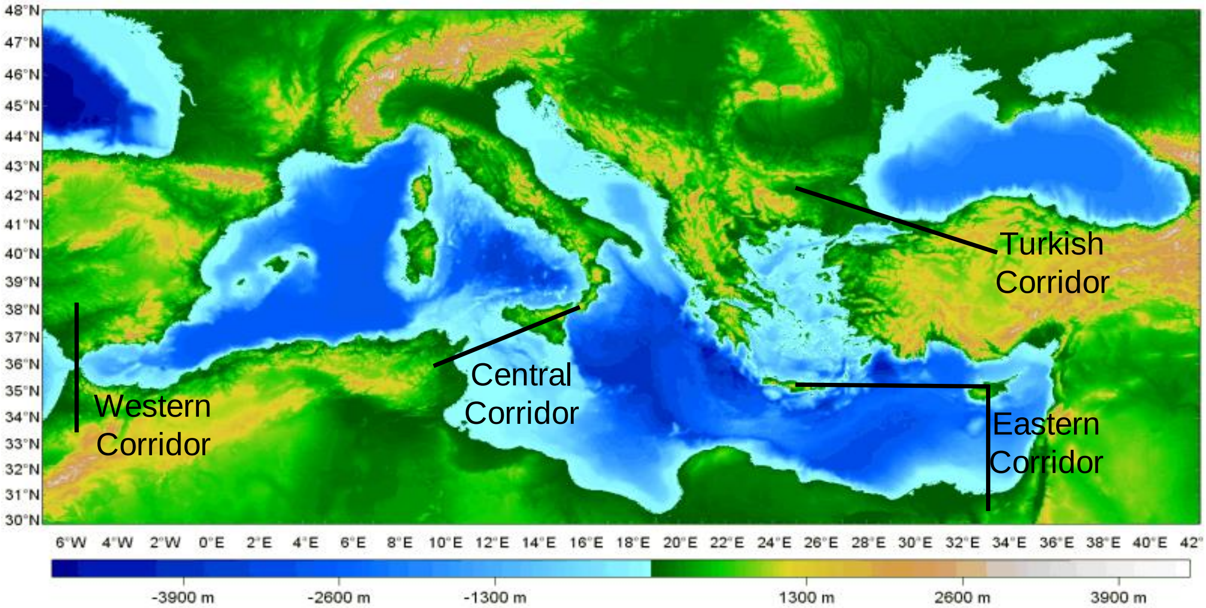
Chapter 2 and Figure 2 assess the economics of different modes of long-distance transport of renewables assuming no geographic or geostrategic obstacles. This chapter therefore analyses how intercontinental electricity or hydrogen infrastructure is affected by such factors.

3.1 Geographic considerations

Importing renewable energy via electric power transmission cables or through a hydrogen pipeline raises challenges for engineers to bridge the natural barriers between the MENA region and Europe. Broadly speaking, there are three possible routes: the Western corridor (Strait of Gibraltar), the Central corridor (Sicily Strait), and the Eastern corridor (Aegean Sea) (see Figure 3). [12] Another possible corridor could cut through the Black Sea. The Taurus Mountains alongside the Turkish–Syrian border provide another geographic obstacle for electricity lines and hydrogen pipelines.

Several gas pipelines already connect North Africa and Europe: Maghreb-Europe (Morocco-Spain), Medgaz (Algeria-Spain), Transmed (Tunisia-Sicily), Greenstream (Libya-Sicily), and Galsi (Tunisia-Sardinia). Only two electricity interconnections link the African continent and Europe. The two subsea cables bridge Morocco and Spain. The Spanish electricity grid operator REE and the Moroccan counterpart L'Office National de l'Électricité et de l'Eau Potable have signed a MoU for a third interconnection in 2019.[13]

Figure 3 Topographical map of the Mediterranean Sea[12]



[12] CIBRA, Università degli Studi di Pavia (2015). Accessed via: http://www-3.unipv.it/webcib/edu_Mediterraneo_uk.html

[13] Tsagas, Ilias (2019) „Spain's third interconnection with Morocco could be Europe's chance for African PV – or a boost for coal", PV Magazine. Accessed via: https://www.pv-magazine.com/2019/02/20/spains-third-interconnection-with-morocco-could-be-europes-chance-for-african-pv-or-a-boost-for-coal/

3.2 Geostrategic considerations: energy supply

Trading renewable energy between the MENA region and Europe raises concerns over potential geostrategic ramifications. European economies are heavily reliant on a steady energy supply which is to a large extent based on imports (mostly oil and gas, see chapter 1). To warrant security of supply, EU law for instance requires the Member States to hold strategic petroleum reserves lasting for 90 days of average consumption.[14]

If electricity was to become an energy commodity imported from third countries at large scale, similar precautionary storage measures would need to be taken. Storing electricity however is a technological challenge from today's view, as the German example shows: Amongst electricity storage solutions in Germany, pumped hydroelectric energy storage holds the largest share with a capacity of about 40 GWh[15] followed by compressed air reservoirs with 0.64 GWh. For an annual net electricity consumption of 527 TWh[16], this corresponds to the average electricity consumption of only 40 minutes.

One advantage of hydrogen in contrast is its storage capability, which is quite similar to that of natural gas. Large volumes of hydrogen could for example be stored in salt caverns at low cost. German gas utilities already today voluntarily maintain a strategic gas reserve with a capacity of 24.6 billion m^3 which would last for about 80 days of average consumption.[17]

Geostrategically, hydrogen imports therefore appear the more viable option compared to electricity imports in terms of secure energy supply.

3.3 Geostrategic considerations: route selection

When discussing renewable energy imports from the MENA region, risks of transport corridor disruptions are to be examined closely. Some of the regions that would be crossed in case of a transmission asset from the Arabian Peninsula to Europe are or were conflict zones, such as the Sinai, Lebanon or Syria. In the case of Morocco, many of the most attractive sites for generating renewable energy are in Western Sahara which is a territory disputed under international law.

A scenario of instability along import routes is a major drawback both for pipelines and electricity lines. Due to this uncertainty, shipping of hydrogen or its derivatives might become a relevant addition for long-distance renewable energy transport, even if it is more expensive from today's view.[18]

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[14] Directive 2009/119/EG imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products.
Accessed via: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0119&from=DE

[15] Deutscher Bundestag (2017). Sachstand zur Entwicklung der Stromspeicherkapazitäten in Deutschland von 2010 bis 2016. Aktenzeichen: WD 8 - 3000 - 083/16.
Accessed via: https://www.bundestag.de/resource/blob/496062/759f6162c9fb845aa0ba7d51ce1264f1/wd-8-083-16-pdf-data.pdf

[16] Statista (2020) Nettostromverbrauch in Deutschland. Accessed via: https://de.statista.com/statistik/daten/studie/164149/umfrage/netto-stromverbrauch-in-deutschland-seit-1999/

[17] BMWi (2020) Instrumente zur Sicherung der Gasversorgung. Accessed via: https://www.bmwi.de/Redaktion/DE/Artikel/Energie/gas-instrumente-zur-sicherung-der-versorgung.html

[18] IEA (2019): The Future of Hydrogen. Accessed via: https://www.iea.org/publications/reports/thefutureofhydrogen/

3.4 Exporting country energy systems

The state of the energy markets in the MENA region also needs to be discussed in this context. While virtually the entire MENA region offers excellent conditions for the deployment of renewable energy sources, the energy systems today are very much dependent on fossil fuels. Most MENA countries however have ambitious plans to build new renewable energy resources, develop and improve the energy infrastructure.

Regarding energy trade balances, the picture is more heterogeneous: Morocco and Tunisia are net importers of energy, mainly fossil fuels, while Algeria, Saudi Arabia and the UAE are net exporters of energy, mainly of oil and gas.

While the creation of vast export capabilities might be of interest to these countries in the medium- and long-term, many countries might need to focus on securing the local demand first and foster a deeper integration within local energy markets, before large quantities of renewables can be exported. A partial solution could be the leveraging of internationally co-financed projects to create the know-how and local expertise in renewables, where it is not already available, to advance the local energy markets in tandem. This is however subject to thorough feasibility studies including environmental and social impact assessments.

4. COST OF BLUE HYDROGEN

Hydrogen is currently mainly produced from natural gas and coal, generating significant carbon emissions (“grey hydrogen”).[19] One option to decarbonize this is to still use fossil feedstock but capture and store the carbon emissions (“blue hydrogen”). This compares to “green hydrogen” which is produced from renewable energy sources and therefore generates no carbon emissions in production.

Figure 4 compares the costs of production for green and blue hydrogen depending on the largest respective cost drivers – the price of natural gas and renewable electricity:

- Green hydrogen is competitive at renewable electricity prices below 20 €/MWh even if natural gas prices are very low – this is a price level already seen in the UAE.[20]
- Blue hydrogen is competitive only at a renewable energy price above 25 €/MWh and up to a natural gas price of around 80 €/MWh. This would be the case in Germany with onshore wind auctions, for instance, yielding 47 to 63 €/MWh in 2018/19.[21]

The picture presented here will very likely shift in favor of green hydrogen in the future as the cost of renewable electricity and electrolyzers will most likely continue to decrease.[22] For blue hydrogen in contrast, natural gas prices are forecasted to increase[23] and steam methane reforming is a mature technology, leaving little room for significant CAPEX reductions.

Using blue hydrogen just as a bridging technology due to lower costs in the short-term can also be problematic since it requires to install infrastructure along the production chain to capture and store carbon emissions. Once green hydrogen is more economic, these assets are at risk to be stranded.

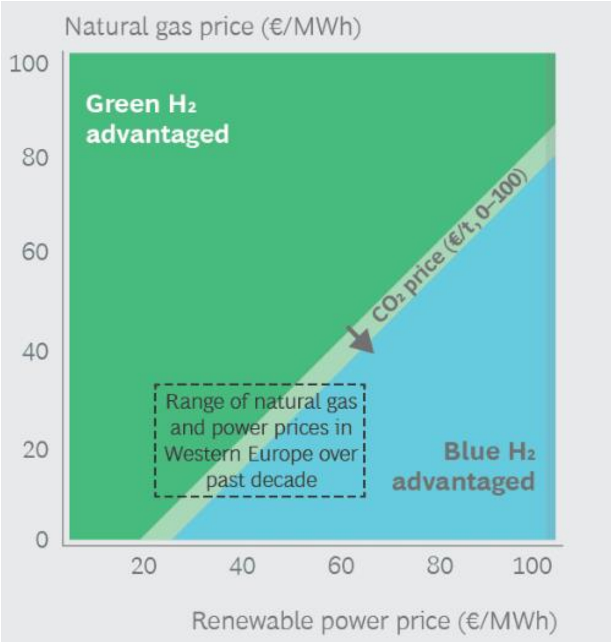

Figure 4 Price comparison of blue vs. green hydrogen[24]

[19] IRENA (2019) “Hydrogen: A Renewable Energy Perspective”. Accessed via: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf

[20] PV Magazine (2019) “Dubai’s 900 MW solar tender sees lowest bid of $0.0169/kWh”. Accessed via: https://www.pv-magazine.com/2019/10/10/dubais-900-mw-solar-tender-sees-lowest-bid-of-0-0169-kwh/

[21] Source: Bundesnetzagentur.

[22] Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): The Future Cost of Electricity-Based Synthetic Fuels. Available online: https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf

[23] Deloitte (2019) “Price forecast Oil, Gas & Chemicals”, Accessed via: https://www2.deloitte.com/ca/en/pages/resource-evaluation-and-advisory/articles/deloitte-canadian-price-forecast.html

[24] Boston Consulting Group (2019) “The Real Promise of Hydrogen”, Accessed via: https://www.bcg.com/publications/2019/real-promise-of-hydrogen.aspx.

APPENDIX A: MODEL ASSUMPTIONS

Table 1 Model Input Assumptions

Input	Value	Source	Comment
General Assumptions			
WACC	8 %	-	Typically assumed value for global analyses
Full-Load Hours	4380	-	Equal FLH are assumed for all technologies. The value represents a 50% load factor, which could be achieved by combining PV with wind or CSP.
Electrolysis			
CAPEX 2030	330 Euro /kW	Kuehn (2020), Scaling up green hydrogen electrolysis in the Middle East, Presentation by Siemens	Cost reductions based on (IEA, 2019) assumed for 2030.
Years of usage	15	-	Typically assumed value for global analyses
Efficiency	80 %	Kuehn (2020), Scaling up green hydrogen electrolysis in the Middle East, Presentation by Siemens	
Fuel Cell			
CAPEX 2030	1500 Euro /kW	Weidner, Ortiz Cebolla, & Davies, (2019) „Global deployment of large capacity stationary fuel cells“, Accessed via: jrc115923_stationary_fuel_cells_16042019_final_pubsy_online.pdf	
Years of usage	15	-	Typically assumed value for global analyses
Efficiency	75 %	ET, (2019) „Von Strom in Wasserstoff und zurück“, Accessed via: https://www.energie.de/et/news-detailansicht/nsctrl/detail/News/von-strom-in-wasserstoff-und-zurueck-in-einer-anlage-2019470/	

HVDC Power Line			
CAPEX 2030	0,995 Euro / kW * km	Zickfeld & Wieland, (2012) „2050 Desert Power Perspectives on a Sustainable Power System from EUMENA“	Average value based on estimates for Europe, MENA and Submarine values. Provided values for 2050 were calculated back with an assumed cost degression of 1,5% p.a. between 2030 and 2050.
OPEX	0,0001 Cent / kWh * km	Zickfeld & Wieland, (2012) „2050 Desert Power Perspectives on a Sustainable Power System from EUMENA“	
Years of usage	40	-	Typically assumed value for global analyses
Efficiency	98,4 % per 1000km	Zickfeld & Wieland, (2012) „2050 Desert Power Perspectives on a Sustainable Power System from EUMENA“	
Converter Pair	180 Euro / kW	Zickfeld & Wieland, (2012) „2050 Desert Power Perspectives on a Sustainable Power System from EUMENA“	One converter pair, i.e. two converters were assumed per transmission line
Hydrogen Pipeline			
All-in cost	0,75 Cent / (kWh * 1000km)	Navigant analysis for Gas for Climate	Assuming a new pipeline construction
All-in cost	0,6 Cent / (kWh * 1000km)	Navigant analysis for Gas for Climate	Assuming a retrofit of existing pipeline infrastructure