

Planning and prospects for renewable power **NORTH AFRICA**



Unless otherwise stated, material in this publication may be freely used, shared, copied, reproduced, printed and/or stored, provided that appropriate acknowledgement is given of IRENA as the source and copyright holder. Material in this publication that is attributed to third parties may be subject to separate terms of use and restrictions, and appropriate permissions from these third parties may need to be secured before any use of such material.

REPORT CITATION

IRENA (2023), *Planning and prospects for renewable power: North Africa*, International Renewable Energy Agency, Abu Dhabi.

ISBN: 978-92-9260-485-1

ACKNOWLEDGEMENTS

This report was drafted by Sebastian Hendrik Sterl, Pablo Carvajal, Pauline Fulcheri and Mohamed A. Eltahir Elabbas under the guidance of Asami Miketa (IRENA) and Dolf Gielen (ex-IRENA), in close collaboration with Mohamed Bassam Ben Ticha (consultant), who conducted major development work with IRENA on the System Planning Test model for North Africa and provided modelling support. The report also received input from Bilal Hussain, Daniel Russo, Tommaso Tiozzo Bastianello and Farmata Diallo (IRENA).

Valuable review and consultation were provided by Chokri Zammali (Société Tunisienne de l'Électricité et du Gaz), Naima Chabouni (Mines ParisTech), Arman Aghahosseini (Lappeenranta University of Technology), Bob van der Zwaan (TNO), and IRENA colleagues Herib Blanco, Laura Al-Katiri, Ahmed Badr, Mirjam Reiner, Imen Gherboudj, Mohammed Sanusi Nababa, Rabia Ferroukhi, Binu Parthan, Gayathri Nair, Simon Benmarraze, Barbara Jinks, Paul Komor, Zoheir Hamed and Reem Korban.

For further information or to provide feedback: info@irena.org.

This report is available for download: www.irena.org/publications.

DISCLAIMER

This publication and the material herein are provided “as is”. All reasonable precautions have been taken by IRENA to verify the reliability of the material in this publication. However, neither IRENA nor any of its officials, agents or other third-party content providers provides a warranty of any kind, either expressed or implied, and accept no responsibility or liability for any consequence of use of the publication or material herein.

The information contained herein does not necessarily represent the views of all Members of IRENA. The mention of specific companies or certain projects or products does not imply that they are endorsed or recommended by IRENA in preference to others of a similar nature that are not mentioned. The designations employed and the presentation of material herein do not imply the expression of any opinion on the part of IRENA concerning the legal status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

CONTENTS

■	ABBREVIATIONS	8
■	ABOUT THIS REPORT	9
■	KEY TAKEAWAYS	11
1	REGIONAL OVERVIEW AND KEY DATA.....	13
1.1	Contribution of this report	13
1.2	North Africa's energy supply is highly dependent on fossil fuels	13
1.3	North African countries show diverging patterns of electricity in final energy demand	15
1.4	Electricity demand in North Africa is still growing strongly, requiring substantial power sector investments	16
1.5	Most North African countries have ambitious renewable electricity targets.....	19
1.6	Solar and wind power in North Africa are expanding and getting cheaper.....	22
1.7	Enhanced flexibility promotes integration of solar and wind into North African power systems.....	25
2	SCENARIOS FOR NORTH AFRICA'S ELECTRICITY SYSTEMS	31
2.1	SPLAT-N models capacity expansion in North Africa.....	31
2.2	Four scenarios for North Africa's power sector were modelled.....	36
2.3	The three Transition scenarios differ in their assumptions	41
2.4	If investment in fossil fuel projects is discontinued, least-cost capacity expansion is dominated by solar and wind power.....	45
2.5	Battery storage and hydrogen production are conducive to greater integration of solar PV, but they lower the need for CSP	51
2.6	Wind power is an attractive investment in all North African countries, especially in combination with hydrogen production.....	53
2.7	Battery storage and hydrogen production lower the need for additional cross-border interconnectivity	54
2.8	The need for battery storage increases with the share of variable renewables in the energy mix	65
2.9	Green hydrogen production, combined with variable renewables and storage, could become an integral part of an interconnected electricity system	69
2.10	CSP storage will be important to ensure system adequacy.....	75
2.11	Deployment of VRE with storage solutions can temper system costs if fossil fuel investments are halted	77
2.12	Holding down the levelised cost of electricity	79
2.13	The proposed transition towards VRE would substantially lower CO ₂ emissions from power generation.....	81
2.14	Additional studies could shed more light on the North African power system.....	83
2.15	Pathways to lower-cost electricity generation in North Africa	85
■	REFERENCES	86

FIGURES

Figure 1-1	Total primary energy supply structure in North Africa, 2019	14
Figure 1-2	Total final energy consumption in North Africa, 1990-2019	15
Figure 1-3	Electrification path of the energy sector in North Africa: electricity intensity and non-electricity energy intensity in North African countries, 1990-2019	16
Figure 1-4	Installed capacity and generation in North Africa in 2015 and 2019	17
Figure 1-5	Evolution of energy sector investments in North Africa, 2015-2020	18
Figure 1-6	Committed and planned power investments in North Africa, 2021-2025	18
Figure 1-7	Existing and committed capacity in North Africa by technology, compared with projected peak load, 2020-2040	19
Figure 1-8	Renewable energy capacity expansion by 2030 according to NDCs in North Africa	21
Figure 1-9	Share of energy sources in electricity generation in 2019 and most ambitious targets for renewable energy (including hydropower) in North Africa	22
Figure 1-10	Installed capacity of solar PV and CSP in North Africa, 2010-2020, and share in individual countries, 2020	23
Figure 1-11	Evolution of the average installation costs for solar PV projects in North Africa	24
Figure 1-12	Installed capacity of onshore wind in North Africa, 2010-2020, and share in individual countries, 2020	24
Figure 1-13	Evolution of average installation costs for onshore wind projects in North Africa	25
Figure 1-14	Existing and planned interconnection capacity in North Africa	26
Figure 2-1	Normalised load curves on an average day in each season in North Africa (applied for all years of the modelling period)	39
Figure 2-2	Examples of diurnal profiles of solar photovoltaic power generation for sites in Mauritania (UTC), Algeria (UTC+1) and Egypt (UTC+2)	44
Figure 2-3	Monthly average wind profile of different locations in Egypt and Morocco	44
Figure 2-4	Identified solar photovoltaic and wind model supply regions from resource screening in North Africa with 8% and 17% accounted losses, respectively	45
Figure 2-5	Capacity expansion in North Africa by technology in the four scenarios	47
Figure 2-6	Projection of generation in North Africa in the four scenarios, by technology	49
Figure 2-7	Share of energy sources in electricity generation in North Africa in the four scenarios, by technology	49
Figure 2-8	New installed solar photovoltaic capacity by country in the four scenarios	52
Figure 2-9	New installed concentrated solar power capacity by country in the four scenarios	52
Figure 2-10	New installed wind capacity by country in the four scenarios	53
Figure 2-11	Model assumptions (constraints) on exchange prices between North African countries and neighbouring regions	55
Figure 2-12	Total electricity trade flows in 2040 in the four scenarios	55
Figure 2-13	Gross exports and imports of electricity in North African countries in the four scenarios, 2018 and 2040	56
Figure 2-14	Morocco's imports from Spain in the Planned scenario, 2040	58

Figure 2-15	Morocco's imports from Algeria in the Planned scenario, 2040.....	58
Figure 2-16	Tunisia's imports from Algeria in the Planned scenario, 2040.....	59
Figure 2-17	Tunisia's imports from Libya in the Planned scenario, 2040	59
Figure 2-18	Tunisia's imports from Italy in the Planned scenario, 2040	60
Figure 2-19	Egypt's imports from Libya in the Planned scenario, 2040	60
Figure 2-20	Daily profiles of exports in the Transition scenario, 2040.....	61
Figure 2-21	Daily profiles of exchanges in the Transition + Batteries scenario, 2040.....	62
Figure 2-22	Daily profiles of exchanges in the Transition + Batteries + H ₂ scenario, 2040.....	63
Figure 2-23	Electricity exchanges in North Africa in the four scenarios, 2040 (GWh).....	64
Figure 2-24	Total installed battery capacity in the Transition + Batteries and the Transition + Batteries + H ₂ scenarios	66
Figure 2-25	Daily use profile of batteries by season and by country	67
Figure 2-26	Daily use of pumped hydropower in Morocco in all scenarios	68
Figure 2-27	Unit cost of hydrogen generated in screened wind and solar photovoltaic regions	71
Figure 2-28	Hydrogen supply curve in North Africa as determined by the model, 2030 and 2040... ..	71
Figure 2-29	Evolution of hydrogen production, electrolyser capacity and generation from variable renewable energy in North Africa in the Transition + Batteries + H ₂ scenario, 2025-2040.....	72
Figure 2-30	Seasonal hydrogen production in the Transition + Batteries + H ₂ scenario, by country and normalised (relative to maximum daily production in the year)	73
Figure 2-31	Daily hydrogen production rate in the Transition + Batteries + H ₂ scenario, by country	74
Figure 2-32	Daily hydrogen production in the Transition + Batteries + H ₂ scenario for each season, by country.....	74
Figure 2-33	Residual load duration curve in the Transition scenario, by country, 2040.....	76
Figure 2-34	Hourly capacity factor of concentrated solar power needed to meet demand in the Transition scenario, 2040.....	77
Figure 2-35	Evolution of system costs in the four scenarios.....	78
Figure 2-36	Total costs and total generation in North Africa in the four scenarios, 2020-2040.....	79
Figure 2-37	Evolution of total generation cost in North Africa in the four scenarios (annual system cost divided by annual generation).....	80
Figure 2-38	Average generation cost in the four scenarios, by country, 2040	80
Figure 2-39	Evolution of carbon dioxide emissions from the electricity sector in North Africa in the four scenarios.....	82
Figure 2-40	Cumulative carbon dioxide emissions and reductions in the four scenarios, 2020-2040.....	82
Figure 2-41	Average differences between the 1.5°C Scenario and Planned Energy Scenario for Africa, 2021-2050	84

TABLES

Table 1-1	Power-sector-related targets in North Africa as reflected in recent national plans and NDCs	20
Table 1-2	Hydrogen projects, partnerships, co-operation agreements and memoranda of understanding in North Africa	28
Table 2-1	Definition and modelling of power system inputs in SPLAT-N.....	32
Table 2-2	Planned and committed renewable energy projects in North Africa	35
Table 2-3	Assumptions behind the four modelled scenarios.....	37
Table 2-4	Summary of key results from the investigated scenarios.....	40
Table 2-5	Summary of the analysis of the steps needed to go from the Planned to the Transition scenario	42
Table 2-6	Country-level breakdown of the power generation mix by 2040, by scenario.....	50
Table 2-7	Sensitivity of scenario results to prices of exports from Egypt to outside North Africa	57
Table 2-8	Share of power exchanges in total electricity demand in North Africa	64
Table 2-9	Comparison of hydrogen production in the Transition + Batteries + H ₂ scenario with national, regional and global hydrogen demand projections, 2030 and 2040	72
Table 2-10	Comparison of electrolyser capacity in the Transition + Batteries + H ₂ scenario with national, regional and global hydrogen projections, 2030 and 2040.....	73



BOXES

Box 2-1	Characterisation of demand in the model.....	37
Box 2-2	Estimating variable renewable energy generation profiles.....	43
Box 2-3	Representation of storage in the model	47
Box 2-4	An example of IRENA's socio-economic analysis of energy transition roadmaps.....	83



ABBREVIATIONS

CAPEX	capital expenditure	LNG	liquefied natural gas
CCC	consolidated contractor's company	MSR	model supply region
CCPP	combined cycle power plant	Mt	megatonne
CF	capacity factor	MW	megawatt
CMP	Continental Master Plan	MWh	megawatt hour
CO₂	carbon dioxide	NDC	Nationally Determined Contributions
COMELEC	Maghreb Electricity Committee	O&M	operation and maintenance
CSP	concentrated solar power	ONEE	National Office of Electricity and Water (Morocco)
ct	cent	OPEX	operational expenditure
EEHC	Egyptian Electricity Holding Company	PJ	petajoule
EHB	European Hydrogen Backbone	PV	photovoltaic
EJ	exajoule	RE	renewable energy
ENTSO-E	European Network of Transmission System Operators for Electricity	ROR	run-of-river
EU	European Union	SPLAT-N	System Planning Test Model for North Africa
GDP	gross domestic product	TFEC	total final energy consumption
GHG	greenhouse gas	TWh	terawatt hour
GW	gigawatt	UNFCCC	United Nations Framework Convention for Climate Change
GWh	gigawatt hour	UNSD	United Nations Statistics Division
H₂	hydrogen (dihydrogen)	USD	United States dollar
HFO	heavy fuel oil	VRE	variable renewable electricity
IEA	International Energy Agency	WACC	weighted average cost of capital
IPP	independent power producers		
kW	kilowatt		

ABOUT THIS REPORT



This report is part of IRENA's series on planning and prospects for renewable energy, which focuses on renewable electricity generation in African power pools. Its context is the lack of a regional master plan for power system expansion in North Africa (Algeria, Egypt, Libya, Morocco, Mauritania and Tunisia) and IRENA's involvement in the search for energy transition pathways for the region. A recent example of that involvement is IRENA's participation as a modelling partner for the development of the African Continental Power Systems Master Plan (CMP), an initiative led by the African Union Development Agency's New Partnership for Africa's Development (AUDA-NEPAD) with the technical and financial support of the European Union.

This report presents various scenarios for power system expansion in North Africa through 2040, including the potentialities of hydrogen production and of interconnections within and outside the region (Southern Europe through Morocco and Tunisia; and Western Asia through Egypt). Feedback from national experts was collected during a workshop in March 2022, but this report does not necessarily reflect countries' official positions. Nor does it intend to prescribe a path for power sector development. The report is based on the System Planning Test Model for North Africa (SPLAT-North Africa), a model developed by IRENA and built on publicly available data. SPLAT-North Africa can be used in future capacity-building events and by the countries of the region to conduct their own analyses.

The report showcases possibilities for North African countries to diversify their electricity generation mixes and reduce their reliance on fossil fuel resources by 2040. The region stands to benefit from falling renewable energy costs and its ample endowments of wind and solar energy. Both can help the region decrease the cost of electricity generation by increasing the share of renewables in the electricity mix. Diversifying the sources of electricity generation would also allow the region to choose between using its fossil fuel resources locally or exporting them. The flexibility to make such choices is highly relevant in a context of high fossil fuel prices and the desire of Europe to increase imports of natural gas from North Africa.

Power generation in Algeria, Egypt, Libya and Tunisia is dominated by natural gas, while coal is the primary source in Morocco and oil in Mauritania. The vulnerability of fossil-fuel-based, non-diversified power generation is twofold. First, countries that rely heavily on imported fossil fuels (Tunisia, Morocco and Mauritania) are exposed to external price shocks in addition to the weight of imports on foreign currency reserves. Second, countries with fossil fuel reserves tend to subsidise the national fossil fuel industry so as to encourage cheaper generation from domestically produced fossil fuels, contorting countries' fiscal posture. Falling capital costs for solar photovoltaic and wind – accompanied by the global political and social pressures to achieve international climate objectives – will make it increasingly difficult to secure social acceptance of the higher costs of fossil-fuel-based generation. Continued investment in that fossil-fuel-based generation infrastructure may well leave countries with power plants that will be little used, both because of their higher fuel costs and in order to comply with targets for reduction of carbon dioxide emissions.

Based on the modelling studies presented here, this report finds that large-scale roll-out of variable renewable electricity generation from solar and wind power would be a cost-efficient way to avoid continued reliance on fossil fuels, while continuing to meet the rising demand for electricity in North Africa. Although solar and wind resources are weather dependent and thus variable, the report shows how the effects of variability can be mitigated using modern storage solutions (notably battery storage) and green hydrogen production for electricity export to the European market. The results show that such a transition path would lower the unit costs of power generation from those that would result from countries' current policies. Moreover, such transitions would help most countries reduce greenhouse gas emissions.

Chapter 1 of the report presents a regional overview of the region's energy and electricity situation. Chapter 2 describes the methods and assumptions used to compile four scenarios for the expansion of generating capacity in the region and discusses the aggregate results of those scenarios. The accompanying Data appendix (IRENA 2022b), presents the data used in the study and the country results obtained by processing those data using the model described in Chapter 2.



KEY TAKEAWAYS



North African countries are highly dependent on fossil fuels for electricity generation, rendering them vulnerable to price fluctuations of fossil fuel commodities on global markets and straining national budgets through subsidisation of fossil-fuel-based generation.



Diversifying away from a continued dependence on fossil fuels will allow North Africa to simultaneously lower the unit costs of power generation and allow the region to choose between using its fossil fuel resources locally or exporting them. Diversification can also lower the risks of disruption of energy supply in countries lacking local fossil fuel resources. A large-scale expansion of solar PV, concentrated solar power and wind power capacity, substantially beyond countries' current targets, could facilitate such a transition.



Power generation costs could be further reduced through utility-scale deployment of battery power plants, which would make it possible to integrate solar PV plants with the grid and reduce the need for additional interconnections between the countries of the region.



Even further benefits could be reaped from the production of green hydrogen for export to other markets, such as Europe. Under an ambitious hydrogen export scenario, a pronounced expansion of solar and wind power technologies to allow for large-scale hydrogen production could result in even lower unit costs of electricity, increasing earnings from hydrogen exports at competitive prices.



Such a scenario would require a quadrupling of power sector sizes and investments over current plans, but it would cut electricity generation costs in half.



Aside from reducing countries' dependencies on extractive resources, such a transition would have the additional benefit of substantially lowering greenhouse gas emissions from the power sector compared with present emissions and those that would be produced under current plans. The three transition scenarios presented in this report would bring a 75% reduction in emission levels by 2040 compared with 2020.



REGIONAL OVERVIEW AND KEY DATA



1.1 CONTRIBUTION OF THIS REPORT

IRENA's SPLAT-MESSAGE (System Planning Test model based on the Model for Energy Supply Strategy Alternatives and their General Environmental Impact) capacity expansion modelling framework, discussed in Section 2.1, was used to develop the SPLAT-North Africa model, covering six North African countries (Algeria, Egypt, Libya, Mauritania, Morocco and Tunisia) to chart possible pathways for North Africa's future electricity supply. In particular, the net benefits of storage (batteries and hydrogen, the latter for export to European markets) in an interconnected electricity system were investigated to illuminate the possibilities of reaching a much larger share of renewable electricity and a corresponding diversification away from fossil fuels by 2040.

A detailed description of the main assumptions – including the geographic and temporal characterisation of renewable resources (solar and wind), estimates of future electricity demand in the countries of the region, international fuel prices, and estimates of investment costs by technology type – is provided in Chapter 2. The accompanying Data appendix (IRENA, 2022b) presents the data used in the study and the country results obtained by processing those data using the model described in Chapter 2.

This first chapter summarises the energy and electricity sector context of North African countries. It presents a regional overview as well as country-specific data related to energy and electricity supply and demand, with a focus on (1) recent trends in the energy and electricity sectors; (2) current objectives for electricity supply; (3) the status of modern renewable energy technologies (in particular solar and wind power); and (4) options for their integration into North Africa's electricity systems.

1.2 NORTH AFRICA'S ENERGY SUPPLY IS HIGHLY DEPENDENT ON FOSSIL FUELS

While the countries in North Africa have increased the use of renewable sources in electricity production over the past decade, most of the region's primary energy supply still comes from fossil fuels, namely natural gas, oil and coal (in the case of Morocco). The primary energy supply structure of the countries is presented in Figure 1-1. For the whole region, fossil fuels accounted for 95% (8.5 exajoules [EJ]) of the total primary energy supply (9 EJ) in 2019. Gas and oil represented 49% (4.4 EJ) and 41% (3.7 EJ) of the total, respectively (UNSD, 2022).

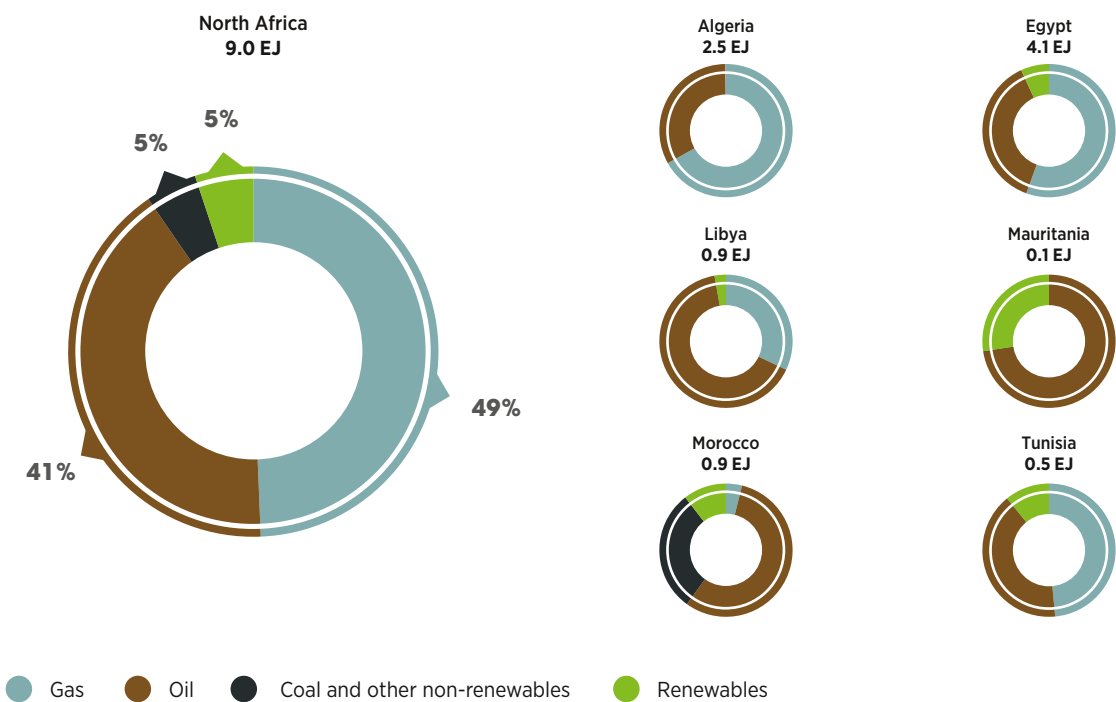
Libya and Algeria are the leading fossil fuel exporters in the region, with 80% and 59% of their oil and gas production being exported in 2019, respectively (UNSD, 2022). Both countries have historically been exporters of natural gas to Europe. Algeria exports natural gas as liquefied natural gas (LNG) and through three pipelines to Europe, the first reaching Italy through Tunisia (Enrico Mattei pipeline), the second leading to Spain through Morocco (Pedro Duran Farell pipeline)¹ and the third going directly from Algeria to Spain (Medgaz). As for Libya, the country exports natural gas through a direct pipeline to Italy (Greenstream pipeline).

¹ Exports from Algeria to Spain through this pipeline ceased in 2022.

In the past, Egypt was an oil and natural gas exporter, but declining resources and surging local demand have made it a net importer. Egypt was expected to again become a natural gas exporter thanks to recent discoveries in the Eastern Mediterranean and the development of national LNG projects (Bloomberg, 2021a, 2021b). Those natural gas reserves began to be extracted (Eni, 2020), but lower-than-expected production owing to technical issues (Stevenson, 2022) is limiting production from these fields and limiting exports from Egypt to the re-export of gas imported from neighbouring countries (Elgendy, 2022). Mauritania, a net energy importer, could also become a net exporter following offshore natural gas discoveries (S&P Global Platts, 2019). Tunisia, which was a net energy exporter until 2000, is now a net importer. The country imports natural gas from Algeria to make up for declining domestic resources. Morocco was importing natural gas from Algeria until the contract ended in 2021. Plans for a floating storage regasification unit terminal have been announced to import LNG. Except for Mauritania, all of the region’s countries possess oil-refining capacities. The uncertainties related to oil and gas resources illustrated by recent examples of lower-than-expected production in new fields strengthen the need for other energy sources.

Fossil-fuel-based electricity generation represents a major part of generation in the region. The fuels used in these power plants have different origins according to the country. Algeria and Egypt rely mainly on their domestic natural gas for electricity generation; Libya relies on domestic natural gas and oil products; and Tunisia relies partly on domestic natural gas and partly on imports from Algeria. Presently, Mauritania and Morocco rely totally on imported fuels (coal and oil products for Morocco and oil products for Mauritania).

Figure 1-1 Total primary energy supply structure in North Africa, 2019



Source: (UNSD, 2022).
 Note: EJ = exajoule.

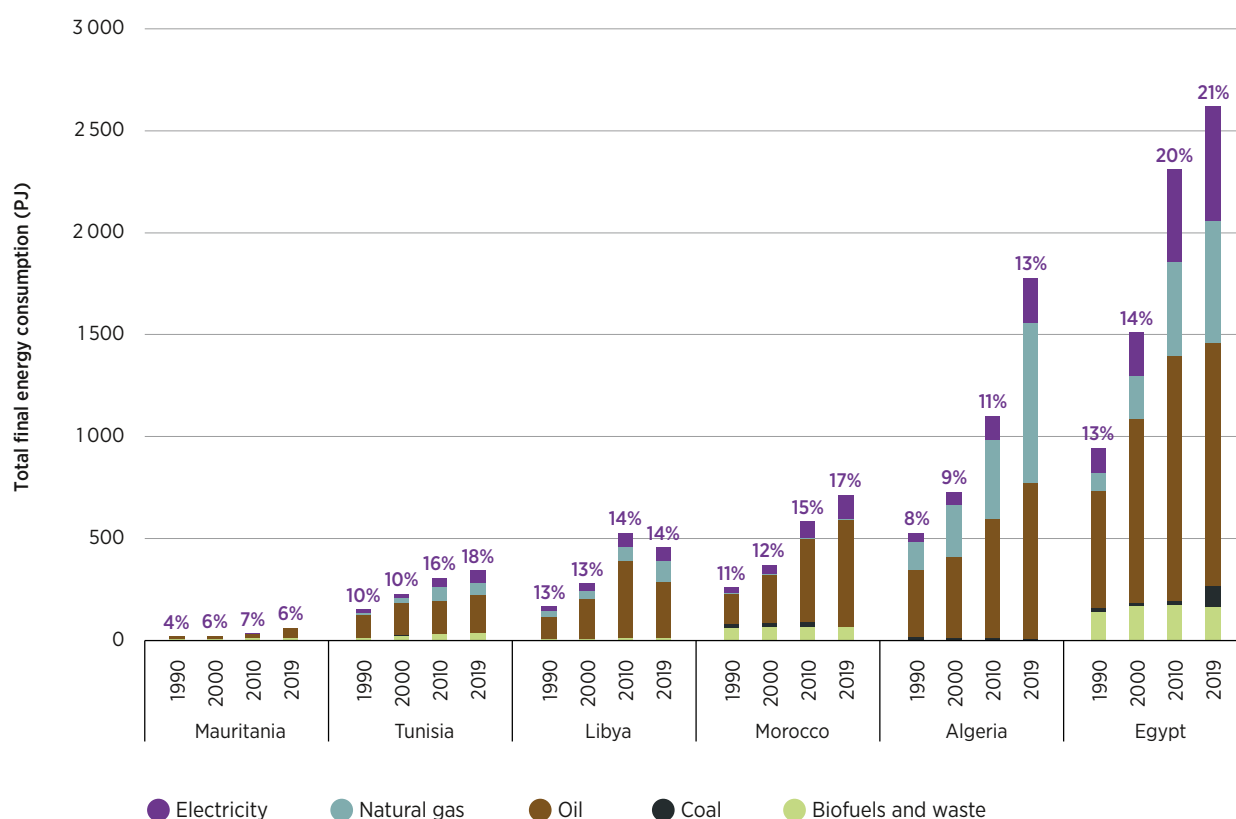
1.3 NORTH AFRICAN COUNTRIES SHOW DIVERGING PATTERNS OF ELECTRICITY IN FINAL ENERGY DEMAND

Generally, popular access to electricity in North Africa is very high (99%). Mauritania is an exception, but it recorded substantial progress in the last decade, with access rising to 47% in 2020 from 34% in 2010 (World Bank, 2019).

Figure 1-2 shows the increase in final energy consumption in North African countries over the period 1990-2019. Egypt has achieved the highest electrification of end uses, with electricity's share in final energy consumption accounting for 21% in 2019 (563 petajoules [PJ]) (UNSD, 2022). In Morocco and Tunisia, electricity represents 18% and 17% of final energy consumption (120 PJ and 63 PJ, respectively), while it accounts for 13% in Algeria and 14% in Libya (224 PJ and 64 PJ, respectively) in 2019.

Figure 1-3 illustrates the electrification paths of the energy sector in the countries of the region. By comparing the evolution of electricity intensity (final electricity demand/gross domestic product [GDP]) with the evolution of energy intensity of other fuels (final demand of other fuels/GDP) for the period 1990-2019, the figure illustrates the divergent electrification pathways in North Africa. The direction of the arrows represents the evolution of the country's path over time. Countries can be classified into two main categories. On the one hand, those for which the slope of the arrow is negative, namely Egypt, Morocco and Tunisia, are characterised by a tendency towards greater use of electricity per unit of GDP while the use of other fuels drops. Electricity intensity in those countries has increased over time compared to other fuels. By contrast, the countries where the slope of the arrow is positive are characterised by an increasing intensity of both electricity and other fuels over time. This is the case for Algeria and Libya, which are both oil and gas producers, as well as Mauritania, which has benefitted from economic development and an increasing access to electricity.

Figure 1-2 Total final energy consumption in North Africa, 1990-2019

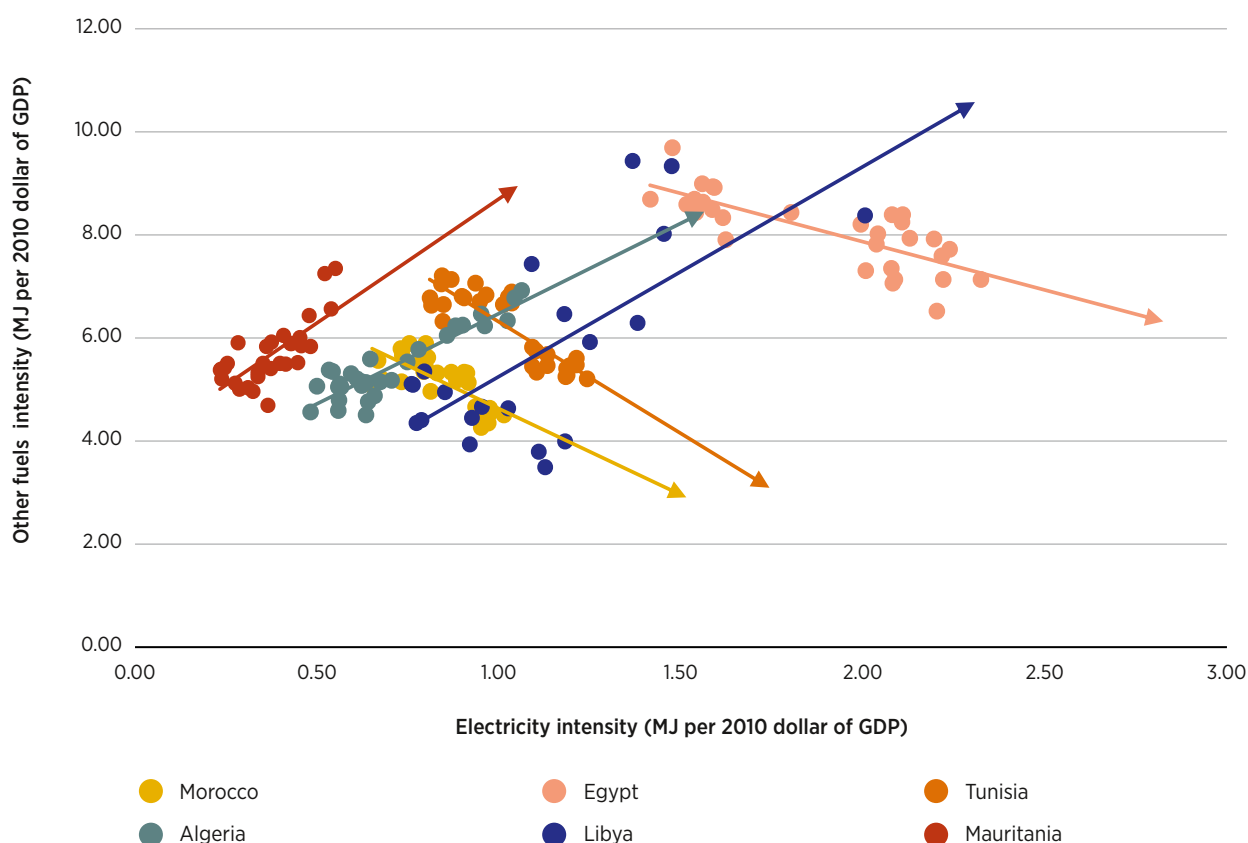


Source: (UNSD, 2022).

Note: PJ = petajoule.

Percentages indicate % share of electricity in total final energy consumption.

Figure 1-3 Electrification path of the energy sector in North Africa: electricity intensity and non-electricity energy intensity in North African countries, 1990-2019



Source: (UNSD, 2022; World Bank, 2021).

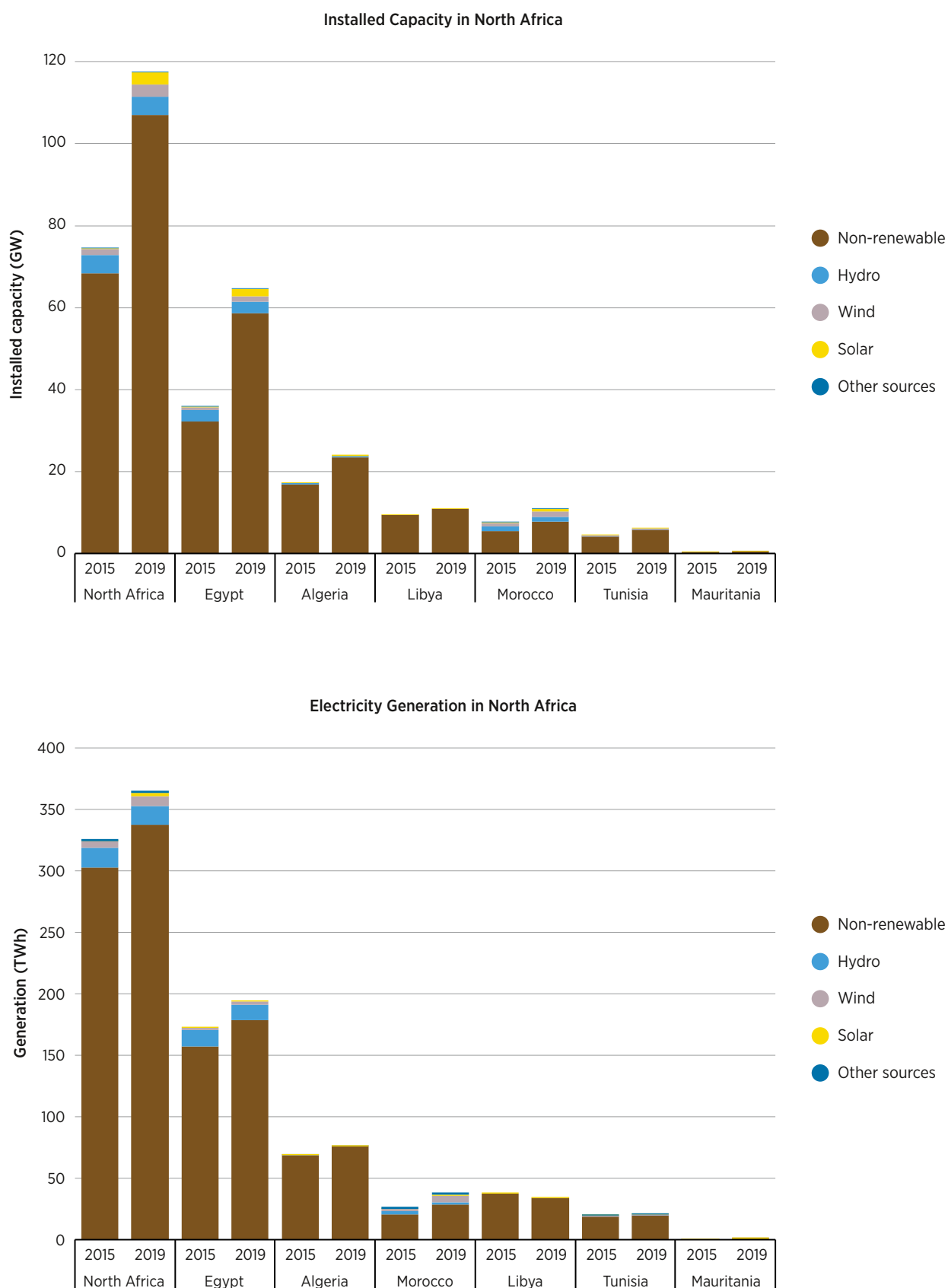
Note: GDP = gross domestic product; MJ = megajoule.

1.4 ELECTRICITY DEMAND IN NORTH AFRICA IS STILL GROWING STRONGLY, REQUIRING SUBSTANTIAL POWER SECTOR INVESTMENTS

To meet growing demand, electricity production in North Africa more than doubled from approximately 140 terawatt hours [TWh] to 367 TWh between 2000 and 2019 (UNSD, 2022). Installed power generation capacity in the region in 2020 is estimated at approximately 113 gigawatts [GW] (IRENA, 2020a). Natural gas has been the predominant fuel for power generation in the region, accounting for 76% (278 TWh) of total power generation (both simple and combined cycle gas plants). Regionally, the share of oil in power generation has steadily decreased. This is a result of the increase in natural gas generation, mainly in Algeria and Egypt.

Renewable energy has played a marginal role in generation, though its contribution has more or less doubled in the past five years. Hydropower has historically been the highest-producing renewable electricity technology in North Africa; however, it is concentrated in Egypt (on the Nile River) and Morocco (in the Atlas Mountains). The viability for future hydro generation in Egypt is low as most of the potential has already been exploited (Sterl *et al.*, 2021), while Morocco could still increase its capacity to 3100 megawatts [MW] (Azeroual *et al.*, 2018) from around 1300 MW today. Overall, hydropower's share in total power generation has gradually decreased, as non-hydro renewables have entered the market in the past decade. These non-hydro renewables (wind and solar) now make up 3% of total power generation, for a total of 10 TWh. Figure 1-4 provides a more detailed overview of the fuels used for electricity generation in the countries.

Figure 1-4 Installed capacity and generation in North Africa in 2015 and 2019



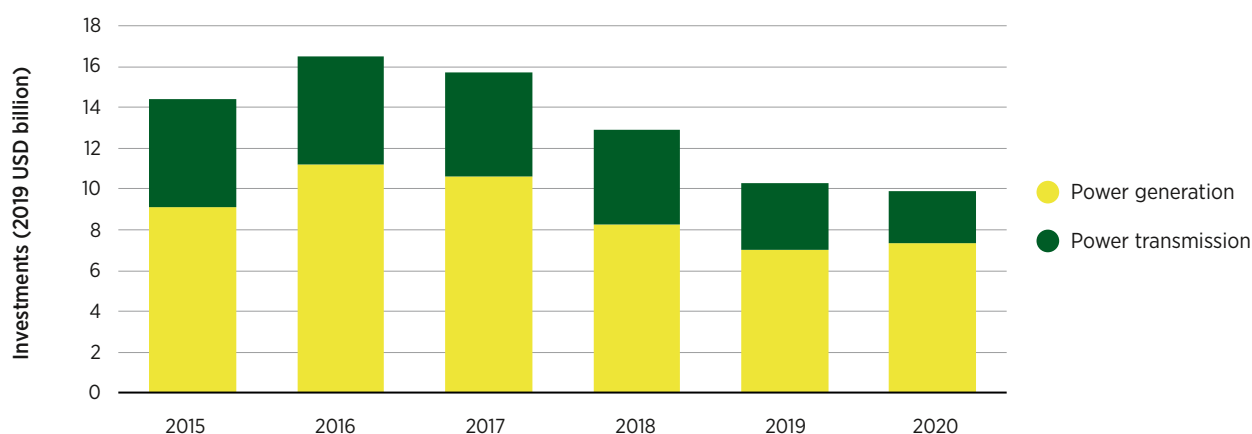
Source: (IRENA, 2020a).

Note: GW = gigawatt; TWh = terawatt hour.

Following the COVID-19 pandemic in 2020, power sector investments decreased in North Africa as in the rest of the world (IEA, 2020b). In the region, investments in power transmission were particularly affected, falling by 20% between 2019 and 2020, while investments in power generation remained roughly constant compared with 2019 (Figure 1-5). The chief reason for the drop in investment is that the power sector in North Africa is highly reliant on public funding, which was constrained because of the drop in world oil and gas prices and the increased cost of financing.

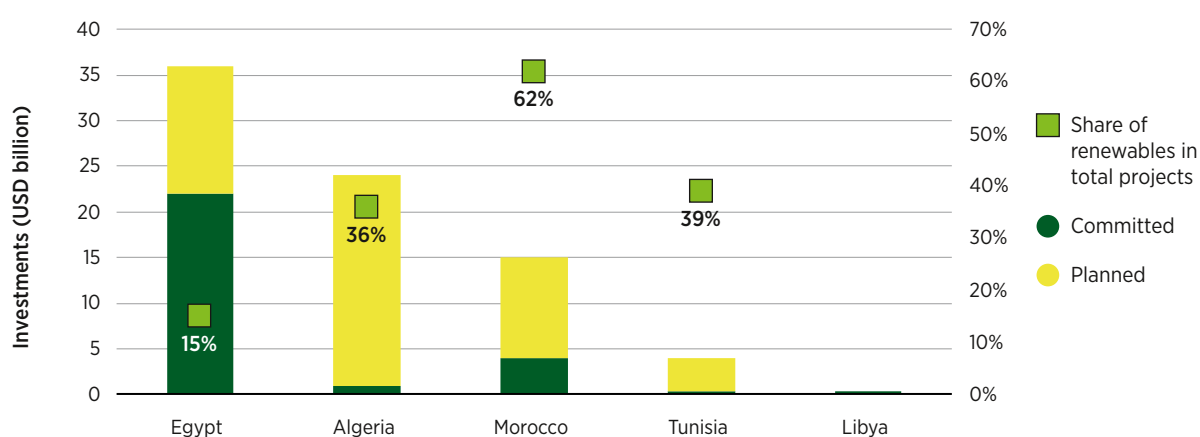
Committed power investments in North Africa for the period 2021-2025 are presented in Figure 1-6. The countries with the highest committed and planned power investments (including both generation and transmission) are Egypt (USD 36 billion), Algeria (USD 23 billion) and Morocco (USD 12 billion). In Tunisia and Libya, the corresponding figures are USD 3 billion and USD 0.3 billion, respectively (APICORP, 2021). Renewable energies represent a significant share of these investments: 62% for Morocco, 39% for Tunisia, 36% for Algeria and 15% for Egypt. Expressed as yearly averages, planned power investments in North Africa average around USD 15 billion per year during the period 2021-2025, of which about USD 5 billion would be dedicated to renewable energy.

Figure 1-5 Evolution of energy sector investments in North Africa, 2015-2020



Source: (IEA, 2020b).

Figure 1-6 Committed and planned power investments in North Africa, 2021-2025



Source: (APICORP, 2021).

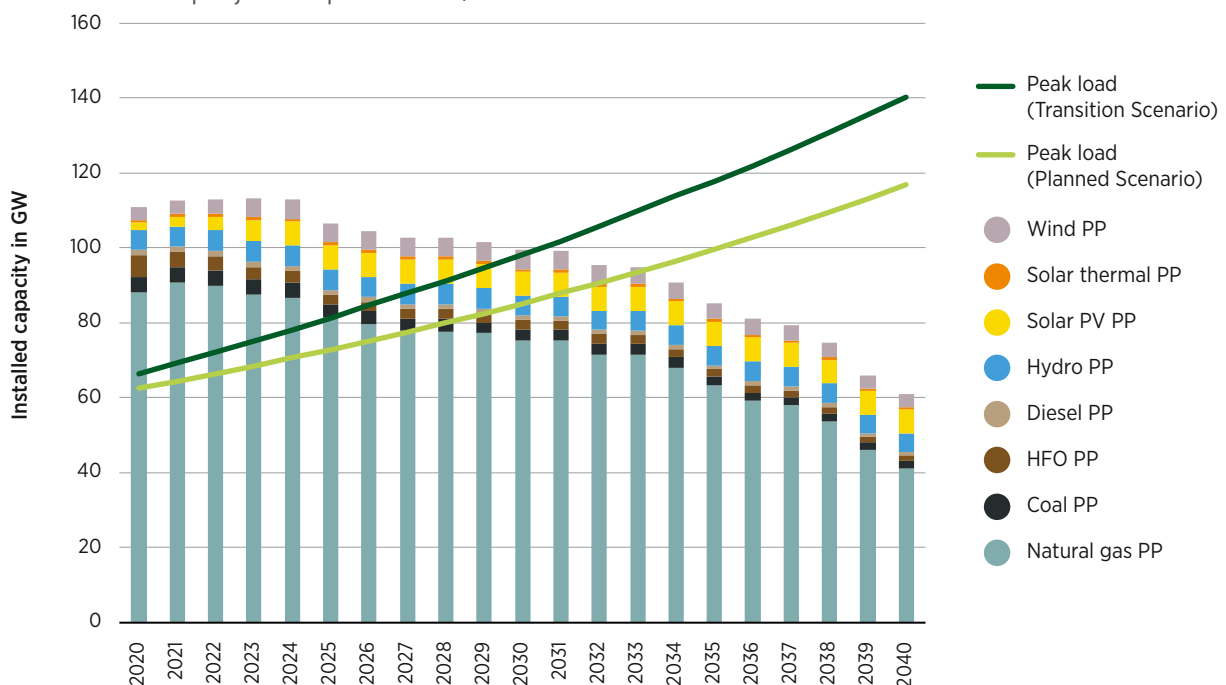
Note: Planned investments are pre-final investment decisions, made before the project owner/operator commences execution of the project. Committed investments are those made in projects that have entered the execution phase.

With respect to the projected retirement of existing power plants and the committed projects, Figure 1-7 presents the installed capacity remaining in the system that must be expanded to meet growth in demand. The projection of peak load in the region is shown under the two different scenarios used in this study: Planned and Transition. These are explained in depth in section 2.1.

Presently, excess generation capacity is available in the region. Although the existing capacity will remain sufficient in the short term (2020-2025), in the medium to long term (2025-2040) it is clear that it will not be enough to meet demand under either scenario. Thus, new power generation projects will have to be planned, and further investments will have to be committed for North Africa to keep meeting its electricity demand.

The principal goal of this study is to investigate the best ways to close the gap between existing and committed capacity on the one hand, and to meet projected demand, on the other. To put it bluntly, will the region continue to rely heavily on fossil fuels, or are there better alternatives?

Figure 1-7 Existing and committed capacity in North Africa by technology, compared with projected peak load, 2020-2040



Note: GW = gigawatt; HFO = heavy fuel oil; PP = power plant.

1.5 MOST NORTH AFRICAN COUNTRIES HAVE AMBITIOUS RENEWABLE ELECTRICITY TARGETS

In 2016, Morocco, Algeria, Tunisia, Libya, Egypt and Mauritania signed the Paris Agreement on Climate Change together with 191 other member states of the United Nations Framework Convention on Climate Change (UNFCCC). Within this context, they are required to submit Nationally Determined Contributions (NDCs) every five years, describing the mitigation and adaptation actions that they pledge to take to stay in line with the objectives of this agreement.² Libya has yet to ratify the Paris Agreement, but the other countries submitted their first NDCs between 2016 and 2017; Morocco, Tunisia and Mauritania submitted updated NDCs in 2021.

² In parallel, the UNFCCC has developed a mechanism for its parties to formulate and communicate long-term low-emission development strategies (LT-LEDS) to operationalise the carbon-neutral vision stipulated by the Paris Agreement. To date, many countries have submitted strategies to the UNFCCC (UNFCCC, 2021a), and the 26th United Nations Climate Change conference (COP26), set to take place in November 2021 in Glasgow, is expected to lead to further submissions. However, none of the North African countries have submitted an LT-LEDS so far.

NDCs tend to be reflective of countries' general policy targets concerning energy and climate, for example, through energy sector development plans, master plans, strategies or comparable documents. A summary of North African countries' policy objectives related to the electricity mix is provided in Table 1-1, drawn from NDCs and other strategic documents.

Table 1-1 Power-sector-related targets in North Africa as reflected in recent national plans and NDCs

COUNTRY	NATIONAL PLANS AND COMMITMENTS
Algeria	<ul style="list-style-type: none"> • Ratified the Paris Agreement on 20 October 2016. • The Nationally Determined Contribution (NDC) aims to reduce greenhouse gas (GHG) emissions by 7% (unconditional) to 22% (conditional) by 2030, compared with a business-as-usual scenario. • The Renewable Energy and Energy Efficiency Development Plan 2016-2030 and the NDC set a conditional target of 27% of electricity generation from renewables by 2030.
Egypt	<ul style="list-style-type: none"> • Ratified the Paris Agreement on 29 June 2017. • The NDC defines "increased use of renewable energy as an alternative to non-renewable energy sources" as one of the five pillars of mitigation policies. However, it provides no quantified renewable energy targets. • The Integrated Sustainable Energy Strategy 2035 calls for renewables to make up 42% of the electricity mix by 2035.
Libya	<ul style="list-style-type: none"> • Signed but has not ratified the Paris Agreement. The country has not submitted an NDC.
Mauritania	<ul style="list-style-type: none"> • Ratified the Paris Agreement on 27 February 2017. • The NDC, updated in October 2021, sets a target of reducing greenhouse gas (GHG) emissions by 11% (unconditional) to 92% (conditional) by 2030, compared with a business-as-usual scenario. • The renewable energy targets in Mauritania's NDC are unconditional and include reaching 13 gigawatts (GW) of renewable capacity by 2030 (including the capacity to produce hydrogen for export) and increasing the share of renewables in the energy mix to 50.34% by 2030.
Morocco	<ul style="list-style-type: none"> • Ratified the Paris Agreement on 21 September 2016. • The NDC, updated in June 2021, aims to reduce GHG emissions by 18.3% (unconditional) to 27.2% (conditional) by 2030, compared with a business-as-usual scenario. • The renewable energy targets in the NDC include reaching 52% of installed power capacity from renewable energy by 2030, of which 20% from solar, 20% from wind and 12% from hydropower. • The National Energy Efficiency Strategy aims to reduce energy consumption by 20% by 2030 compared with a business-as-usual scenario.
Tunisia	<ul style="list-style-type: none"> • Ratified the Paris Agreement on 10 February 2017. • The NDC, updated in October 2021, aims to reduce carbon intensity by 27% (unconditional) to 18% (conditional) by 2030, compared with 2010 as the base year. The NDC includes the target of 30% renewable electricity by 2030 (up from 2.6% in 2020). • The National Renewable Energy Action Plan 2018 targets a 3.8 GW capacity for renewables by 2030.

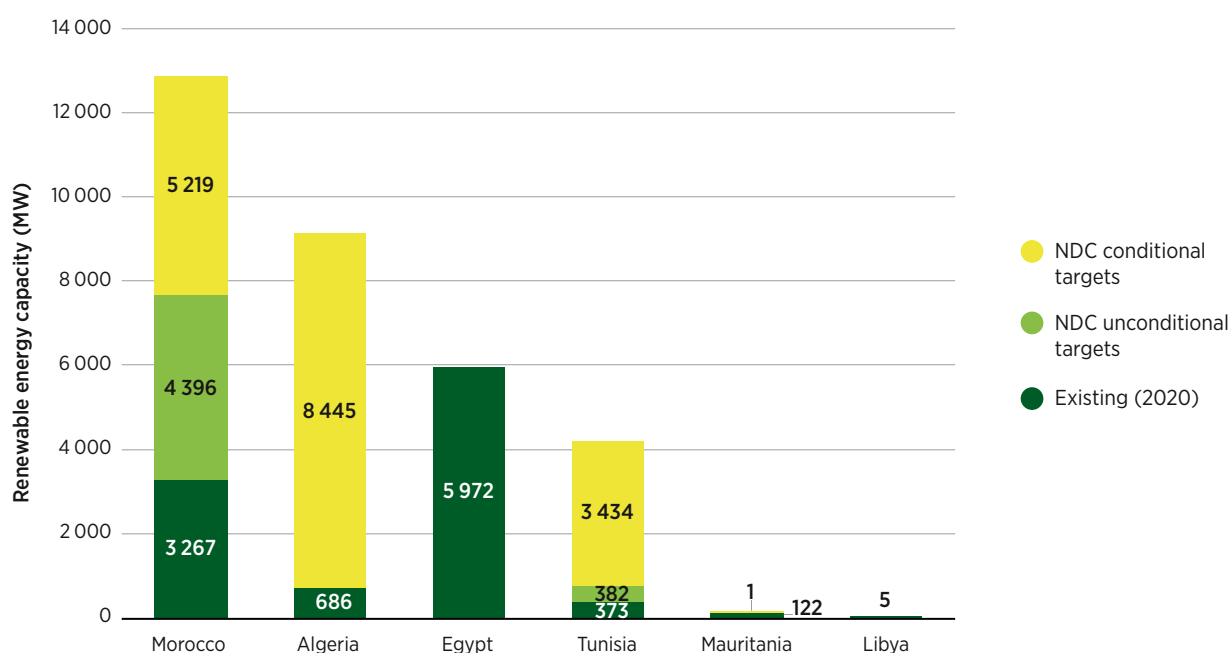
Source: (IEA, 2020b; UNFCCC, 2021b).

The countries' policy ambitions reveal an overall desire to reach a higher share of renewables in electricity generation. All of the NDCs include renewable energy capacity expansion targets for 2030, both unconditional and conditional, as presented in Table 1-1 and Figure 1-8. The most ambitious and detailed NDC in the region is Morocco's, which calls for renewable power plants to make up 52% of installed capacity by 2030. This target, set in the country's first NDC, remains at the same level in the updated version; it is reiterated in Morocco's "Stratégie Bas Carbone à Long Terme – Maroc 2050" (Long-Term Low Emission Development Strategy or LT-LEDS). Almost half of Morocco's renewable energy targets are unconditional, while the remaining half is conditioned on external financial and policy support. If all conditions were met, the country would triple the installed capacity of renewables during the decade.

Ambitious renewable energy targets were also set in Algeria's and Tunisia's NDCs, which aim to reach 27% and 30% electricity generation from renewables by 2030, up from 1% and 4% at present. However, almost all the renewable energy targets of these two countries are conditional, and their aim to multiply the national renewable power generation capacity by more than ten will depend on external conditions. As for Mauritania, while its first NDC did not contain any quantified renewable energy objectives, the updated version includes ambitious unconditional targets, such as reaching 50.34% of renewables in its energy mix by 2030. In contrast, Libya has not yet submitted an NDC, and Egypt has not provided any quantified renewable energy targets. Figure 1-9 shows the most ambitious targets for the share of renewable resources in power generation to which North African governments have committed themselves through NDCs or other strategy documents.

Most countries are achieving far below the targets set and they currently rely heavily on fossil fuels for their electricity production. However, given these targets, it is to be expected that non-hydro renewable resources will increase in importance in the years to come. The next section looks at recent trends in these resources in the North African context.

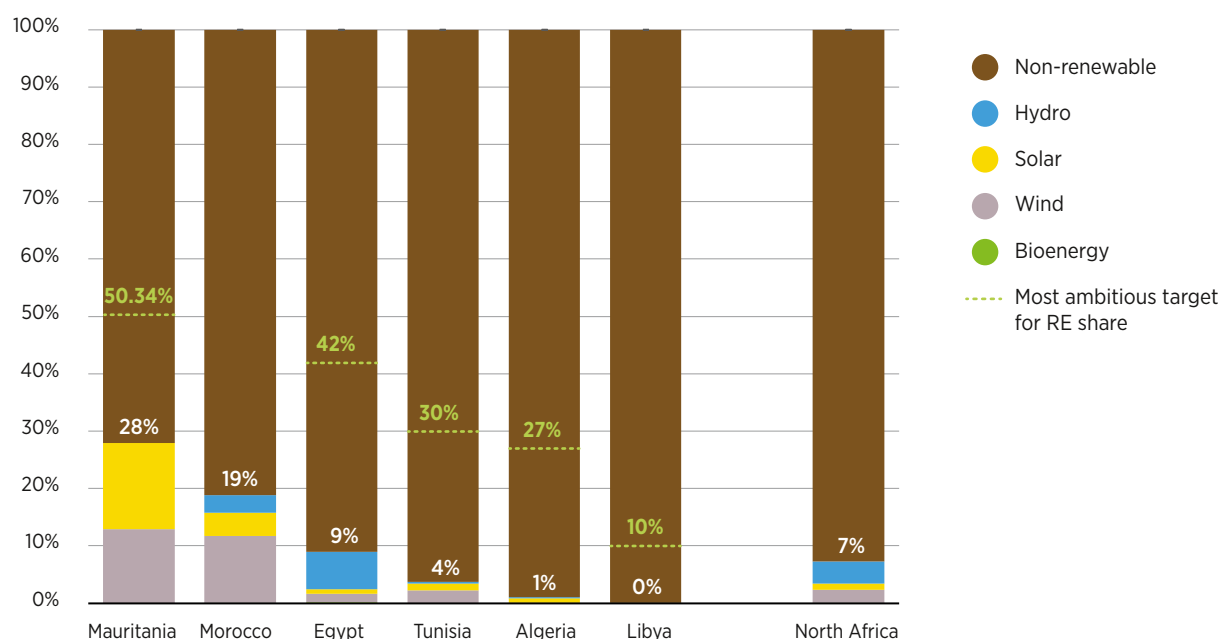
Figure 1-8 Renewable energy capacity expansion by 2030 according to NDCs in North Africa



Source: (UNFCCC, 2021b).

Note: MW = megawatt; NDC = Nationally Determined Contribution.

Figure 1-9 Share of energy sources in electricity generation in 2019 and most ambitious targets for renewable energy (including hydropower) in North Africa



Source: (IRENA, 2020a; Ministry of Electricity and Renewable Energy of Libya, 2013; Ministry of Energy and Mining of Algeria, 2015; Ministry of Environment and Sustainable Development of Tunisia, 2015; Reuters, 2021a).

Note: Morocco has a target for installed renewable energy capacity, not for the share of renewable energy in the electricity mix. RE = renewable energy.

1.6 SOLAR AND WIND POWER IN NORTH AFRICA ARE EXPANDING AND GETTING CHEAPER

In the last decade, the growth rates of worldwide use of fossil fuels have slowed down, partly owing to the increased use of renewable energy sources such as wind and solar as a consequence of their shrinking costs.

Installed solar capacity, both photovoltaic (PV) and thermal, in North Africa has increased strongly in the past five years, reaching more than 3 000 MW in 2020. However, that capacity still corresponds to just 2.7% of the region's total installed electricity generation capacity of roughly 116 GW (IRENA, 2020a) (Figure 1-10a). Regional differences are stark, with the share of solar in installed capacity ranging from less than 0.1% (Libya) to more than 15% (Mauritania) (see also Table A-1 in the Data appendix [IRENA, 2022b]).

Egypt and Algeria have played a critical role in installing solar PV power plants; together they represent 84% of the total solar PV installed capacity in North Africa in 2020 (Figure 1-10b). Most installed solar power capacity is connected to the grid; off-grid capacity is mostly found on Algeria's isolated southern grids. Regarding concentrated solar power (CSP), Morocco had over 90% of the region's capacity in 2020, mainly from the 510 MW Noor-Ouarzazate plant – the world's largest CSP plant (Masen, 2016). Algeria and Egypt have installed smaller CSP plants: in 2011, they inaugurated the ISCC Hassi R'mel (SolarPACES, 2011a) and the ISCC Kuraymat (SolarPACES, 2011b) power plants, respectively, with capacities of 20 MW each. The Algerian government, in its 2015 Renewable Energy Roadmap (Ministère de l'Énergie et des Mines, Algérie, 2015), set a target of reaching 2 GW of CSP by 2030.

As shown in Figure 1-11, the average total installed cost for solar PV in the North African region dropped from USD 2 000/kilowatt (kW) in 2015 to USD 1 306/kW in 2019 (GlobalData, 2020). These data cover 38 projects in North Africa, of which 34 are in Egypt, mainly in the Benban Solar Park area. On a global scale,

the installation cost fell from USD 1800/kW to USD 995/kW during the same period (IRENA, 2020b). Recent tariffs reported in Tunisia for independent power producer projects between 50 MW and 200 MW averaged USD 30/megawatt hour (MWh) (Tunisian Ministry of Industry, Energy and Mines, 2019). The lowest tariff was proposed for the 200 MW solar plant in Tataouine; at TND 71.783/MWh (approx. USD 24/MWh), this was the lowest solar bid recorded in Africa at the award date.

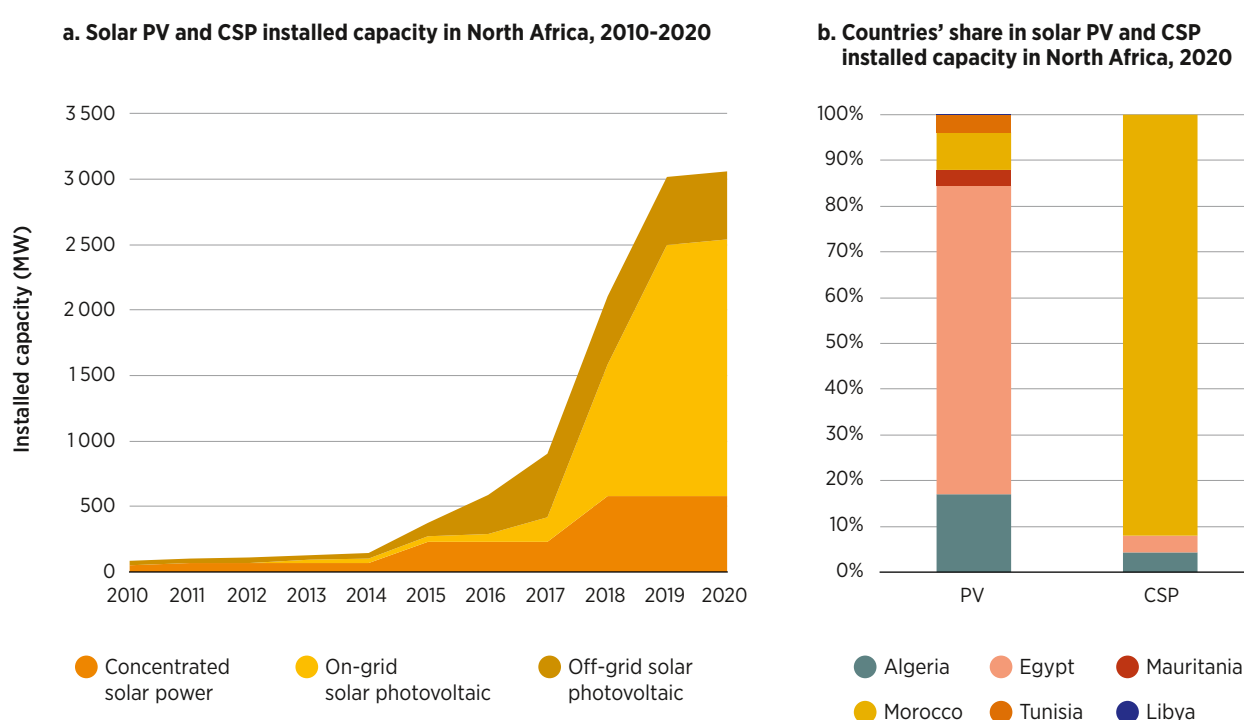
Solar CSP plants remain more costly than solar PV plants, despite declining cost trends; for comparison, NOOR III, one of the CSP power plants of the Noor-Ouarzazate complex, had a total installed cost of USD 5 367/kW (MAZARS, 2016).

A similar increase in wind energy's installed capacity can be discerned from data over the past decade. The total installed wind capacity in the region, all of it onshore (see Figure 1-12) was slightly more than 3 000 MW at the end of 2020, representing 2.7% of North Africa's total power generation capacity (IRENA, 2020a). Again, regional differences are pronounced: from zero in Libya to nearly 6% in Mauritania. Egypt and Morocco are the main players in wind power, with a 45% and 46% share of total installed wind capacity in all of North Africa, respectively.

The average total installed cost of wind energy projects in the region has also fallen significantly (see Figure 1-13), from USD 1795/kW in 2015 to USD 1448/kW in 2019 (GlobalData, 2020). The data cover seven projects installed in North Africa between 2015 and 2019, four in Egypt and three in Morocco. In the same period, the installation cost declined globally from USD 1642/kW to USD 1549/kW (IRENA, 2020b).

In summary, although the contribution of solar and wind power to North Africa's electricity mix remains relatively small, the data show that renewable energy sources have grown in importance. Their economic and environmental competitiveness also makes them, in the short and medium term, one of the best alternatives to replace electricity generation based on fossil fuels.

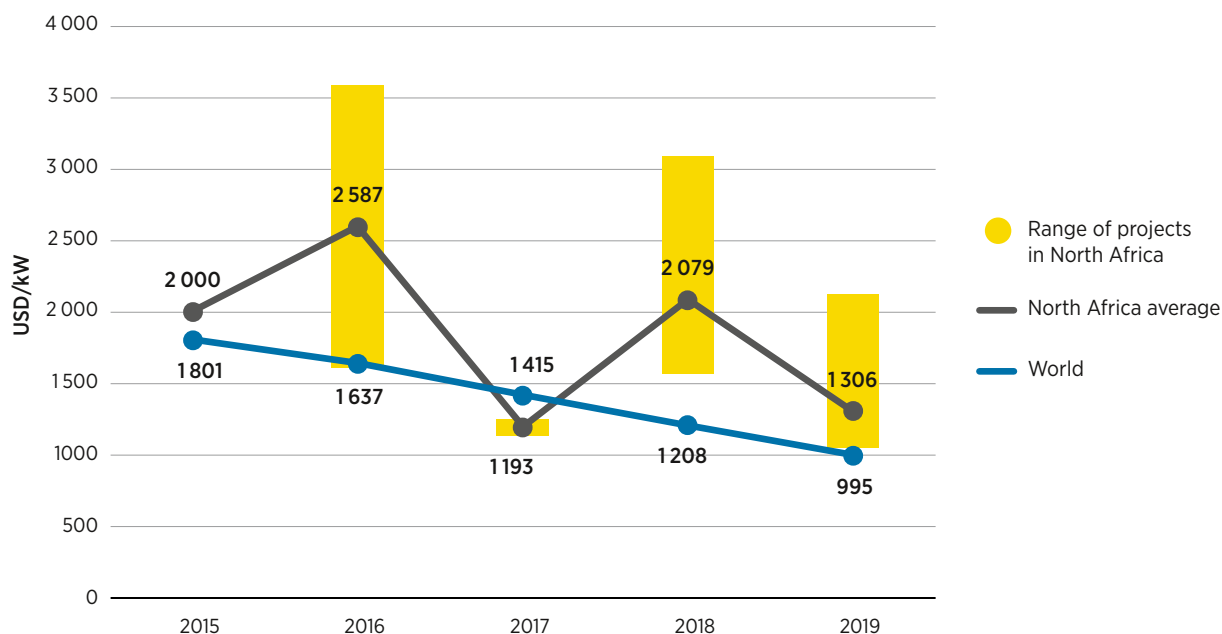
Figure 1-10 Installed capacity of solar PV and CSP in North Africa, 2010-2020, and share in individual countries, 2020



Source: (IRENA, 2020a).

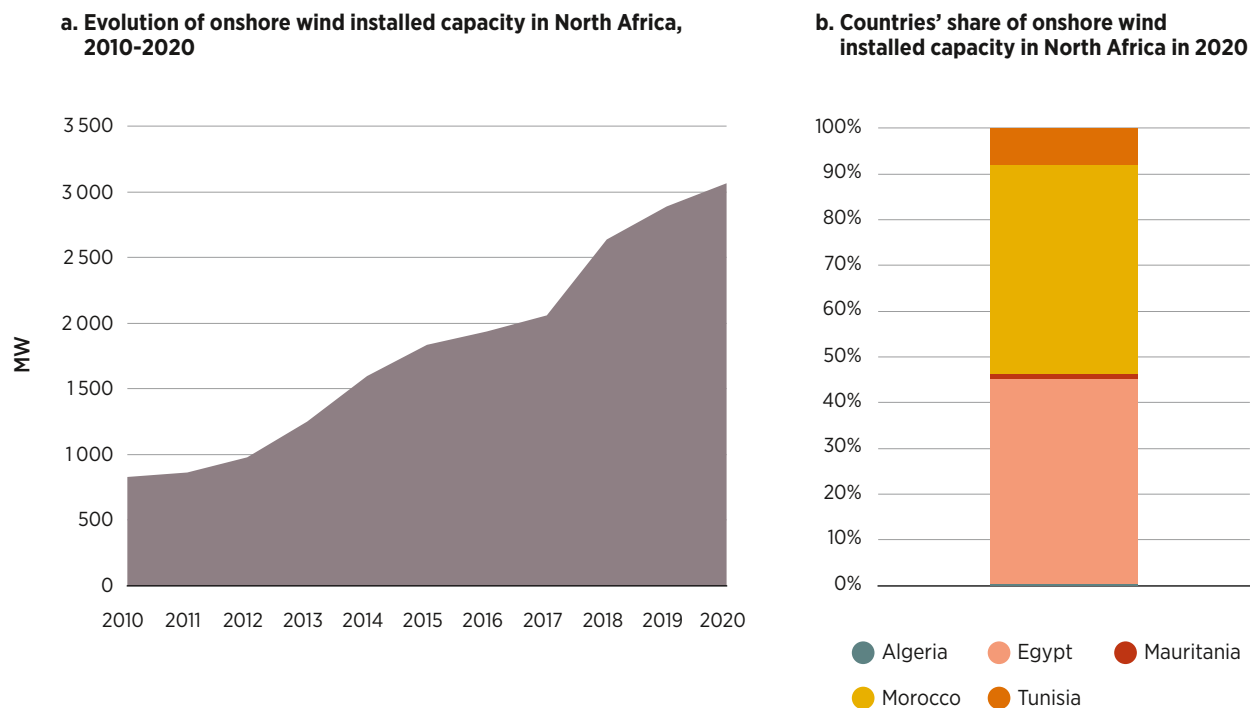
Note: CSP = concentrated solar power; MW = megawatt; PV = photovoltaic.

Figure 1-11 Evolution of the average installation costs for solar PV projects in North Africa



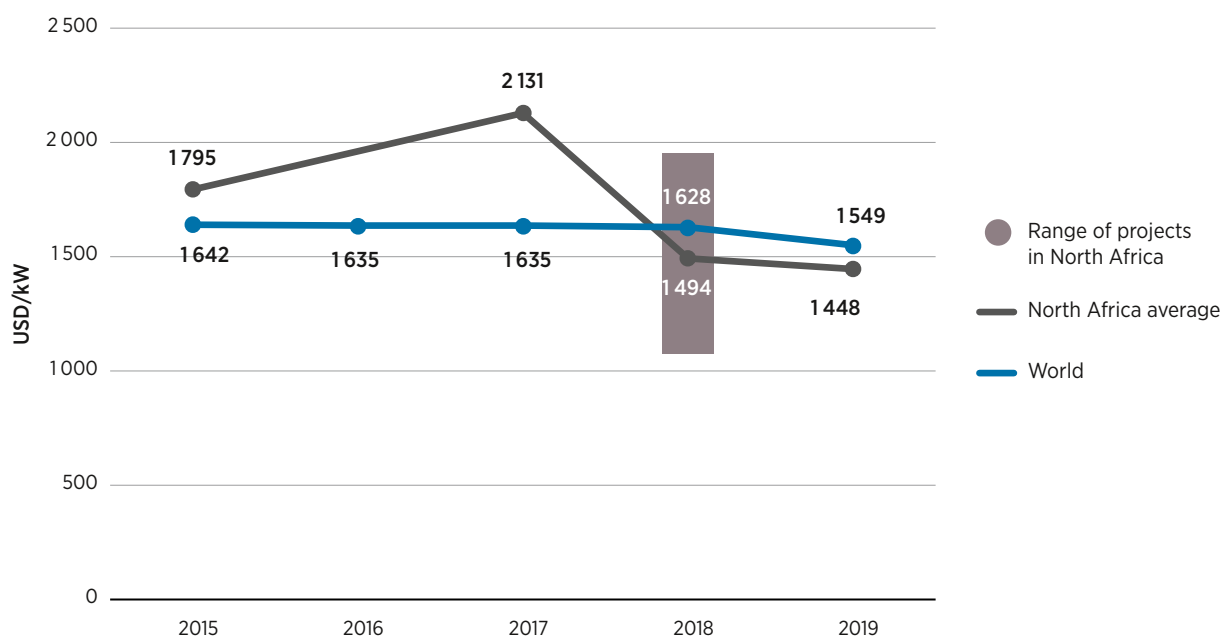
Source: (GlobalData, 2020; IRENA, 2020b).
Note: kW = kilowatt.

Figure 1-12 Installed capacity of onshore wind in North Africa, 2010-2020, and share in individual countries, 2020



Source: (IRENA, 2020a).
Note: MW = megawatt.

Figure 1.13 Evolution of average installation costs for onshore wind projects in North Africa



Source: (GlobalData, 2020; IRENA, 2020b).
Note: kW = kilowatt.

1.7 ENHANCED FLEXIBILITY PROMOTES INTEGRATION OF SOLAR AND WIND INTO NORTH AFRICAN POWER SYSTEMS

Realising the potential of variable renewable sources, mainly solar PV and wind power, to generate electricity for North African power systems will depend on flexibility – that is, on measures to enhance the integration of variable renewable energy into the grid. Operationally, these measures can be generation-based (e.g. flexible dispatch from thermal or hydropower plants, as well as increased interconnections), storage-based (e.g. battery storage or hydrogen production) or demand-based (e.g. demand response and sectoral coupling) (Sterl, 2021).

This report focuses mainly on the potential benefit of storage to enhance system flexibility and its effects on the need for system interconnectivity. An overview of the current state of interconnectivity, battery storage and hydrogen production follows.

1.7.1 Interconnections

This section summarises the existing topology and possible expansion of interconnections through transmission upgrades. For each country, three types of internal connections were identified: existing transmission lines (operational), planned projects (under construction or with an estimated start date in the period 2025-2030) and candidate projects (including existing projects that, in new generation scenarios, present opportunities for expansion). The data on transmission lines and planned projects for the whole region were collected from the *Comité Maghrébin de l'Electricité* (COMELEC, a supranational committee between Morocco, Algeria, Tunisia, Libya and Mauritania to coordinate energy policy and liberalization efforts, especially regarding the transmission networks of the member states) and the Egyptian Electricity Holding Company. The maps in Figure 1-14 summarise the existing and planned interconnection capacity between North African countries, as well as those connecting North African countries with other regions.

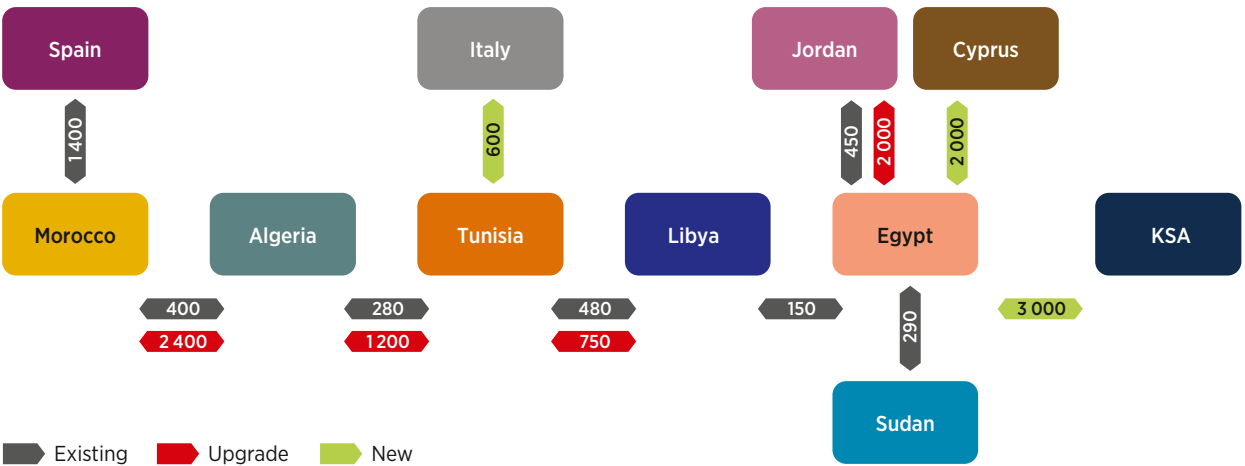
All North African countries are interconnected, except Mauritania.³ However, the interconnection between Tunisia and Libya has been facing technical issues and has been used mainly at times when Libya's eastern and western grids were disconnected. Moreover, a stability problem appears when trying to synchronously connect Libya-Egypt-Jordan-Syria with Tunisia-Algeria-Morocco and the European Network of Transmission System Operators (ENTSO-E). The drop in frequency, owing to insufficient generation in the southeastern Mediterranean, triggers protections on the lines, which are then automatically disconnected. The last test of the interconnection took place in 2010. The test demonstrated that the Tunisia-Libya interconnection was possible only when Libya and Egypt were disconnected.

Despite this, the interconnections between North African countries are intended to improve the system's reliability. Within COMELEC, Algeria, Morocco and Tunisia share the reserve margin required to stabilise the system. Yet, some of the existing interconnection lines are not currently operating at the designed capacity. Among the factors contributing to this situation are delays in connecting projects, upgrades to national power systems and regulatory frameworks that have not advanced adequately. The existing interconnection capacity for intra-regional exchanges between North African countries is presently limited to 1310 MW, even though the physical capacity of the interconnection lines is 4 500 MW.

Another aspect considered in this study is interconnection with countries from other regions. North Africa is presently interconnected to Europe through lines between Morocco and Spain, and will be further joined through planned interconnections between Tunisia and Italy. In addition, Egypt is already interconnected with Jordan and Sudan (Med-TSO, 2020) and will soon be interconnected with Saudi Arabia (Farag, 2022).

Presently no market mechanism governs these interconnections. The National Office of Electricity and Drinking Water (Office National de l'Electricité et de l'Eau Potable, ONEE), the Moroccan power utility, is an actor in the Spanish electricity market and thus can purchase and sell electricity through the interconnection between Morocco and Spain. In some cases, contracts are established between countries for imports and exports of electricity at fixed prices (Redouane *et al.*, 2018).

Figure 1-14 Existing and planned interconnection capacity in North Africa



Source: Figure adapted from CEJA (Centre d'Études Juridiques Africaines), www.ceja.ch/en/north-africa/.

³ Mauritania is interconnected with several West African Power Pool (WAPP) countries. In this study, we do not model the interactions between Mauritania and WAPP countries. A separate report on WAPP appeared in this series in 2018 (IRENA, 2018a).

1.7.2 Battery storage

Battery storage is expected to become a critical enabler for the integration of large shares of variable renewable electricity, such as solar PV and wind, into power systems (IRENA, 2021a). Batteries can enhance system flexibility by storing surplus energy for later release, for example, when the sun is not shining or the wind not blowing strongly enough to generate electricity, particularly on day-night time scales (IRENA, 2017). Batteries can also provide ancillary services, such as absorbing surplus power or compensating for shortfalls on a scale of milliseconds (mimicking the behaviour of large rotating masses in thermal and hydropower plants), thus contributing to grid stability. This capability is known as “synthetic inertia” (IRENA, 2019a). Similarly, batteries can help manage grid congestion, thus allowing transmission system upgrades to be deferred, among other advanced applications.

Currently, the deployment of battery storage is not included in national energy plans in North African countries, and there are no large-scale stationary battery storage projects in the region. The paucity of economically viable projects in the region is traceable to the high present cost of batteries (Killer, Farrokhseresht and Paterakis, 2020). However, this technology is expected to offer enormous global potential in the longer term as costs fall (IRENA, 2017). With substantial growth in production capacity, technology improvements and falling manufacturing costs, the price of lithium-ion batteries, the technology that currently dominates the market, has fallen by around 90% in the past decade (BNEF, 2020). In 2020, for the first time, battery pack prices of less than USD 100/kilowatt hour (kWh) were reported for transport applications, according to Bloomberg New Energy Finance, which forecasts that this figure will become the average market price by 2023. While costs for utility-scale storage are higher than for transport applications, decreasing trends are expected there, too (NREL, 2021).

At the regional level, recent research focusing on the integration of high shares of renewable energies in North Africa energy systems have identified substantial potential for the deployment of battery storage in the region to compensate for the variability of renewable sources of energy (Aghahosseini, Bogdanov and Breyer, 2020; Killer, Farrokhseresht and Paterakis, 2020).

1.7.3 Hydrogen

Over the last few years, North African countries have signed several agreements with partner countries and private companies to explore green hydrogen production and launch pilot projects. The final objective is to export hydrogen produced in North Africa to other regions for the purpose of decarbonising hard-to-abate sectors, such as certain industrial sub-sectors. Projects that have been announced or that are under development are presented in Table 1-2.

Many of these projects are export oriented. Morocco and Tunisia signed co-operation agreements with Germany in 2020 (Federal Ministry for Economic Affairs and Energy, 2020) to forge partnerships and alliances in green hydrogen. The existing natural gas transport infrastructure between North Africa and Europe could be used for these exports (Timmerberg and Kaltschmitt, 2019). Another option is seaborne transportation of liquified hydrogen or ammonia (IRENA, 2022a). In a move that demonstrates the viability of using existing infrastructure to transport hydrogen, SNAM and ENI launched a partnership on gas pipelines between Algeria and Italy in November 2021 (Jewkes, 2021).

Some countries in North Africa have included hydrogen in their national energy strategies. Morocco published a national strategy on green hydrogen in August 2021, after the creation of a national hydrogen commission in 2019 (Ministère de l’Energie, des Mines et de l’Environnement du Maroc, 2021a, 2021b). In the founding document, the Moroccan Ministry of Energy, Mines and Sustainable Development estimates that the country could capture up to 4% of the global green hydrogen demand by 2030 (Ministère de l’Energie, des Mines et de l’Environnement du Maroc, 2021c). In July 2021, Egypt also announced the preparation of

an integrated strategy for hydrogen production; its Energy Strategy 2030 now includes green hydrogen (Ahram Online, 2021). In March 2022, the Egyptian Ministry of Electricity and Renewable Energy, the Ministry of Petroleum and Mineral Resources and the European Bank for Reconstruction and Development signed a memorandum of understanding to establish a framework for assessing the potential of low-carbon hydrogen supply chains; the purpose of the framework is to produce guidelines for the national low-carbon hydrogen strategy (Zgheib, 2022).

Europe's REPower EU Plan (European Commission, 2022a) estimates a renewable hydrogen demand of 20 megatonnes (Mt) in 2030, of which 10 Mt would be imported. To facilitate the imports, the European Commission will support the development of three major hydrogen import corridors via the Mediterranean, the North Sea and Ukraine. The European Commission's EU External Energy Strategy (European Commission, 2022b), published in May 2022, announced that the Commission is working on a Mediterranean Green Hydrogen Partnership between the European Union and countries in the southern Mediterranean. The partnership will start with an EU-Egypt Hydrogen Partnership and an EU-Morocco Green Partnership. The target to import 10 Mt of hydrogen represents a slight increase from what was previously considered in the Global Ambition Scenario published in the ten-year network development plan of ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSO-G), released in October 2021, which envisioned imports of 9 Mt in 2030, 2.5 Mt of which would be imported from North Africa (ENTSO-G and ENTSO-E, 2021). In the same scenario, hydrogen imports from North Africa were expected to increase to 7.8 Mt by 2040.

Table 1-2 Hydrogen projects, partnerships, co-operation agreements and memoranda of understanding in North Africa

COUNTRY	PROJECT/AGREEMENTS	DATE OF AGREEMENT	CHARACTERISTICS AND TARGETS	SOURCE
Morocco	Agreement for the development of an ammonia and green hydrogen project (HEVO Ammoniac Maroc) between the Ministry of Energy and Mines, Fusion Fuel Green and CCC (Consolidated Contractors Group S.A.L.)	July 2020	Green ammonia: 3 650 tonnes (t) in 2022; 60 000 t in 2025 and 2026. Hydrogen: 616 t in 2022, 3 472 t in 2023, 6 940 t in 2024, 10 411 t in 2025 and 2026. Investment: EUR 865 million.	(Fusion Fuel Green PLC, 2021)
	Partnership agreement on green hydrogen between the Moroccan and German governments	June 2020	100-megawatt (MW) renewable energy plant to produce green hydrogen in Morocco.	(Afrik 21, 2020)
	Agreement between Morocco and Portugal for the development of green hydrogen	February 2021	No details provided	(Masen, 2021)
	The Moroccan Agency for Solar Energy (Masen) plans to develop a hybrid photovoltaic/wind power plant to supply a green hydrogen plant	November 2020	Electrolysis capacity 100 MW 2022: finalisation of the feasibility study and tendering process. 2024-2025: commercial launch of the site.	(Masen, 2020)

COUNTRY	PROJECT/AGREEMENTS	DATE OF AGREEMENT	CHARACTERISTICS AND TARGETS	SOURCE
Egypt	Memorandum of understanding (MoU) between the Egyptian Ministry of Electricity and Renewable Energy and Siemens	January 2021	Assessment of production of green hydrogen in Egypt and implementation of a pilot project.	(Egypt Today, 2021)
	Co-operation agreement between Egypt's Ministries of Electricity, Petroleum and the Navy and DEME (Belgium)	March 2021	Studies on producing green hydrogen in Egypt and exporting it.	(Daily News Egypt, 2021)
	Agreement between Eni, the Egyptian Electricity Holding Company and the Egyptian Natural Gas Holding Company	July 2021	Study to assess the feasibility of projects to produce green and blue hydrogen in Egypt.	(Eni, 2021a)
	MoU between Siemens and the Egyptian Electricity Holding Company (EEHC)	August 2021	Launch of a green hydrogen pilot project with an electrolysis capacity of 100-200 MW.	(Siemens, 2021)
	Partnership between Scatec (Norway), the ammonia company Fertiglabe and the Sovereign Wealth Fund of Egypt	October 2021	Development of a 100 MW green hydrogen plant for ammonia in Egypt.	(S&P Global Platts, 2021)
	MoU between the Egyptian Ministry of Electricity and Renewable Energy, the Ministry of Petroleum and Mineral Resources and the European Bank for Reconstruction and Development to assesses low-carbon hydrogen in Egypt	March 2022	Assessment to produce guidelines for the national low-carbon hydrogen strategy.	(Zgheib, 2022)
Tunisia	MoU between Tunisia and Germany	December 2020	Establishment of a Tunisian-German alliance on green hydrogen.	(Tunisian Ministry of Industry, Energy and Mines, 2020)
Algeria	MoU between the state-owned oil company Sonatrach and Eni	March 2020	Development of a pilot project to produce green hydrogen in Algeria.	(Eni, 2021b; Reuters, 2021b)
Mauritania	MoU between the Mauritanian Ministry of Oil and the Australian company CWP Global	May 2021	Development of a 30-gigawatt (GW) power-to-X plant in Mauritania to produce and export green hydrogen ("AMAN" project). Total cost: USD 40 billion.	(CWP, 2021)
	MoU between the Mauritanian Ministry of Petroleum, Mines and Energy and the Africa-based energy group, Chariot	September 2021	Feasibility study for "Project Nour", a 10 GW green hydrogen plant. In April 2022, Chariot signed a MoU with the Port of Rotterdam to import renewable hydrogen.	(Chariot Transitional Energy, 2021, 2022)



SCENARIOS FOR NORTH AFRICA'S ELECTRICITY SYSTEMS



The modelled results presented in this chapter confirm that North Africa's electricity mixes could be diversified away from fossil fuel dependency while decreasing the unit costs of electricity generation. This result could be obtained by integrating much higher shares of renewable electricity, well beyond 50%, than current targets foresee. Such a high share of renewables could be absorbed through better interconnections between the countries of the region, as well as with neighbouring regions, and through large-scale deployment of battery storage and hydrogen production. The suggested renewable power portfolio would include solar photovoltaic (PV), concentrated solar power (CSP) and wind power.

Expanded use of storage technologies makes it possible to achieve greater and more efficient levels of renewable energy in an interconnected electricity system while also reducing the unit cost of electricity supply. Exploitation of the region's hydrogen production potential could meet a significant share of Europe's projected hydrogen demand in 2040, thus helping to decarbonise Europe's energy sector.

2.1 SPLAT-N MODELS CAPACITY EXPANSION IN NORTH AFRICA

This section summarises the planning methodology used in this study and its application to the development of scenarios for the expansion of electricity capacity in North Africa.

Expanding capacity optimally requires identifying the best way to combine new construction of generation and transmission assets with retirements of old assets so as to minimise the net present value of total system costs in North Africa over a given planning horizon and under a given set of assumptions. This determination is derived from the solution of a least-cost optimisation model: IRENA's System Planning Test Model for North Africa (SPLAT-N)⁴ (IRENA, 2018a).

SPLAT-N was developed using a model generator known as the Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE). MESSAGE is a flexible, dynamic, bottom-up, multi-year energy system model that applies linear and mixed-integer optimisation techniques. It was initially developed by the International Institute of Applied System Analysis but has been further enhanced by the International Atomic Energy Agency.

The MESSAGE platform requires as input a set of demand projections, a database of transmission infrastructure, economic and technical parameters of power supply technologies, and information on existing capital stock and its remaining life span.

From the starting point of existing power infrastructure in the region, the model calculates an evolution of technically feasible technology mixes that achieve a least-cost objective over the planning period. In other words, the model generates minimal total discounted system costs, including investment, operation and maintenance, fuel and any other user-defined costs, while meeting various system requirements (e.g. sufficient supply to match demand at a given time or sufficient resources and capacity to achieve the desired production) and user-defined constraints (e.g. reserve margin, speed of technology deployment, emission limits, policy targets).

⁴ <https://www.irena.org/energytransition/Energy-System-Models-and-Data/System-Planning-Test-Model>.

The model inputs described above can be varied by the user to explore various system evolution scenarios under specific sets of assumptions. The model's "solution" includes, among other things, required investment in new technologies, projected electricity production, fuel consumption and trade patterns. The economic and environmental implications associated with particular least-cost energy systems can be easily calculated with the model. The SPLAT-N model contains more than 450 generating plants in the region and six cross-border transmission lines; it covers a 20-year horizon (2020-2040). Its temporal resolution is defined by five seasons, each having ten distinct daily time slices, and it considers each country as a separate node (using the copper-plate assumption within each country, *i.e.* perfect transmission is assumed within a country's borders).

2.1.1 Power system inputs and modelling

The first step in optimising capacity expansion in North Africa is to build a robust database of power generation assets. Intensive data collection was carried out for each of the six countries of the region. This process consisted of replicating each existing power system's operation, comparing the model outputs with recorded historical generation and adjusting certain variables (*e.g.* power generation and capacity expansion, power exchange, operational constraints and maximum allowable yearly capacity expansion). The result was a reliable base case for each country operating in isolation (or with international electricity exchange restrictions). Finally, the individual databases were merged into a single consolidated database for the six North African countries.

Devising a long-term capacity expansion plan also requires configuring the most relevant inputs to the system. The main elements are the supply of electricity (power producers) and the transmission network. These inputs to the model are divided into three categories, as defined in Table 2-1.

Annual electricity consumption and peak load projections for each of the six countries over the 2020-2040 planning horizon are among the inputs required by the model. The model was configured to optimise supply to meet demand on the level of the transmission grid (*i.e.* before distribution losses). Electricity injected by auto-producers, such as Sonatrach in Algeria, is considered as part of the demand, but off-grid self-generation (*e.g.* that is used by mines in Mauritania) is not. Details of the model's handling of demand are provided in Box 2-1.

Table 2-1 Definition and modelling of power system inputs in SPLAT-N

CATEGORY	DEFINITION AND MODELLING
Existing power system	This category represents the power systems in place as of 2020 (the start of the modelling horizon).
Committed generation and transmission	This category includes the generation and transmission elements currently under construction, as well as projects whose implementation has been approved. The deployment of these elements may be considered guaranteed in the model results.
Candidates for generation and cross-border transmission expansion	<p>These are the elements of the system that may or may not be retained in the long term and may thus be part of the optimisation process. The characteristics of these projects (size, location, technology, etc.) must be consistent with existing infrastructure, price trends and energy resource potential. The model will select them if they show a net benefit to the modelled power system, which implies that building, operating and maintaining them should minimise the total cost of power system expansion.</p> <p>Candidate wind and solar power plants considered in this study are site specific, with different load curves associated to each location. Fossil-fuel-based power plants are generic candidates not dependent on location.</p>

Table 2-1 Definition and modelling of power system inputs in SPLAT-N (continued)

CATEGORY	DEFINITION AND MODELLING
Candidates for generation and cross-border transmission expansion	<p>For “candidate” generation projects, the investment cost (also called construction or capital cost) must be defined in order to compute annualised capital costs. Investment cost payments can be determined from the project start date or from several years before (lead time). Capital costs are different depending on the technology, size and location. The model will build candidates if doing so minimises the total cost, namely the net present value of the investment cost, the cost of operation and maintenance, and fuel costs (see section 2.1.5).</p> <p>Expansion of transmission capacity refers to adding lines to the system, changing the existing transmission topology and reinforcing existing transmission corridors (represented by nodes). This model considers only transmission lines between countries. Each individual country is represented as a single node. Thus, the costs of grid extension within each country are not fully captured. Whereas the Planned scenario considers only installed and committed lines, the expansion of interconnection capacity is allowed in the three Transition scenarios. When the model considers it economically beneficial to export or import power, it will expand transmission capacity to develop electricity trade. Inter-connections are considered both within North Africa and between North Africa and Europe (the existing interconnections between Spain and Morocco, Egypt and Jordan, and Egypt and Sudan, and the planned interconnection between Tunisia and Italy). Hourly export prices are considered to vary according to historical prices in Italy and Spain for interconnections between Italy and Tunisia and between Spain and Morocco, and according to historical annual prices for interconnections between Jordan and Egypt.</p>

Note: SPLAT-N = System Planning Test Model for North Africa.

2.1.2 Modelling of safety and operational constraints

Additional safety and operational constraints are included in the model, as summarised below.

Reserve margin requirements (spinning and non-spinning). We consider a reserve margin of 10% of available capacity over the peak load. Technologies contributing to this reserve margin are fossil fuel power plants, biomass, hydropower, CSP with thermal storage and batteries. The reason for allowing the last two to contribute to the reserve margin is that these technologies can be considered to be part of the reserve capacity, provided that storage levels are typically high enough to provide peak power for limited periods of time. (The implications of this need for the design of CSP plants are explored in section 2.10.) Variable renewable energy (VRE) technologies, on the other hand, are not given a capacity credit and are deemed not to contribute to the reserve margin.

Dispatch limits. The maximum instantaneous penetration of solar PV and wind power is limited to 70% of demand country by country. CSP is not considered in this limit. However, when hydrogen (H₂) is introduced in the model (in the Transition + Batteries + H₂ scenario),⁵ the 70% limit is also not applied to the electricity used to produce hydrogen, as it is produced entirely using renewable electricity.

Minimum generation constraints/non-economic group dispatch. A minimum generation level is considered for fossil-fuel-based power plants (5% for gas turbine, 15% for combined cycles, 20% for coal power plants); a minimum dispatch of 70% is considered for nuclear power plants.

⁵ The three Transition scenarios are introduced in section 2.2.

2.1.3 Electricity generation technologies considered as options during the modelling period

The following list of technologies are considered as options for closing the gap between installed assets, on the one hand, and projected electricity demand on the other.

- **Wind power.** The potential in each country is described in Box 2-2 and in the accompanying Data Appendix.
- **Solar PV.** The potential in each country is described in in Box 2-2 and in the accompanying Data Appendix.
- **Solar thermal.** CSP is considered as an option in combination with three-hour storage and with a fixed-generation profile. In section 2.10, we explore whether this assumption about storage associated with CSP is appropriate.
- **Natural gas.** Open and combined cycles are considered as candidates. In the Transition scenarios, no fossil fuel generation can be installed after 2025. During the period 2020-2025, 9.1 gigawatts (GW) have been committed or are under construction in the region.
- **Nuclear power.** The Dhabaa nuclear power project in Egypt is considered committed; construction begins in 2025.
- **Biomass.** Biomass power plants are considered as candidates according to the national plans (e.g. the 960 megawatts (MW) potential presented in Morocco's national biomass roadmap).
- **Hydropower.** No new hydropower projects are considered in the countries of the region as the potential is almost entirely exhausted.

2.1.4 Capacity expansion planning

Table 2-2 summarises targeted and committed renewable energy projects, as well as the most recent official planning documents in North African countries. Targeted capacity includes the targets set by governments in their latest national planning documents. These target capacities correspond to the additional capacity needed, as estimated in the respective planning documents, to reach national renewable energy targets. The model does not consider these targeted capacities as fixed (*i.e.* as a certain part of the future power system) in order to allow for optimisation. Committed projects are those that are considered to have a high probability of being built in the short or medium term, and whose main characteristics (capacity, energy, location, investment cost) are known, as explained in section 2.1.5. The committed power plants are included in the model as certain parts of the future power system – that is, the model considers that they will be built and operated in all scenarios. During the modelling period (2020-2040) the committed fossil fuel power plants in the region represent 9.1 GW (natural gas combined cycle and open cycle plants) to be installed and enter into service by the end of 2021, primarily in Algeria.

In the Data appendix (IRENA, 2022b), Section 1.1 contains country-level detail on current installed capacity (Table A-1, Table A-2 and Table A-3); Section 1.5 contains the capacity expansion results for modelling years 2025, 2030, 2035 and 2040 (Table A-21 through Table A-25).

Table 2-2 Planned and committed renewable energy projects in North Africa

RECENT PLANNING DOCUMENT		PROJECTS (PLANNED AND COMMITTED)
Algeria	National Renewable Energy Development Strategy 2015-2030 (METRE, 2015)	Planned: <ul style="list-style-type: none"> Renewable Energy Strategy: 22 GW from solar and wind by 2030, including 13.5 GW solar PV, 5 GW wind, 2 GW CSP Committed: <ul style="list-style-type: none"> 2021 tender: 1000 MW solar PV by 2023 (Radio Algérienne, 2021) 100 MW solar PV by 2022 (Afrik 21, 2019; Sonelgaz, 2019) Difel Solar PV (Commission de régulation de l'Electricité et du Gaz d'Algérie, 2019) and Hybridisation of OCGT
Egypt	2035 Integrated Sustainable Energy Strategy (Ministry of Electricity and Renewable Energy, 2016) Egyptian Solar Plan (Ministry of Electricity and Renewable Energy, 2012)	Planned <ul style="list-style-type: none"> Energy Strategy: 42% renewables in the installed capacity mix by 2035 (22% PV, 14% wind, 3% CSP, 2% hydropower) Solar Plan: add 3.5 GW of renewables power plants by 2027, comprised of 2.8 GW CSP and 700 MW PV Committed: <ul style="list-style-type: none"> Solar PV project in the Kom Ombo: 200 MW; wind power project in the Ras Ghareb: 500 MW by 2022-2023 (AMEA Power, 2019) Solar PV power station in Kom Ombo: 50 MW (Arab Fund for Economic & Social Development, 2017) Hurghada PV Power Plant Project: 20 MW (ZAWYA, 2019) Zaafarana Wind Power Plant: 50 MW (EQ International, 2021)
Morocco	National Energy Strategy (Masen, 2015) Investment Plan 2019-2023 (ONEE, 2019)	Planned: <ul style="list-style-type: none"> Energy Strategy: 52% of the installed power capacity from renewables in 2030. Add 10 GW of renewable energy capacities between 2018 and 2030 (4.5 GW solar, 4.2 GW wind, 1.3 GW hydropower) Investment Plan: 1.6 GW wind power, 2 GW solar, a new pumped hydro project of 350 MW (Abdelmoumen project), 220 MW new hydro generation in the period 2020-2030
Tunisia	Tunisian Solar Plan (Ministry of Industry, Energy and Mines of Tunisia, 2015)	Planned: <ul style="list-style-type: none"> Solar Plan: Add 3 815 MW renewable power by 2030, including 1510 MW solar PV, 1 755 MW of wind and 450 MW CSP Committed (Ministry of Industry, Energy and Mines of Tunisia, 2015): <ul style="list-style-type: none"> 1 084 MW solar PV and 200 MW wind by 2021-2024

Note: The table does not include Mauritania as the country does not have an official publicly available master plan. CSP = concentrated solar power; GW = gigawatt; MW = megawatt; OCGT = open cycle gas turbine; PV = photovoltaic.

2.1.5 Evolution of capital expenditure, operating expenditure and fuel costs for power generation

The capital expenditure of building new generating plants is an essential parameter for expanding the economic capacity of the system. For each technology, the same capital costs were considered for all regions in North Africa. The estimated evolution of these capital costs to 2040 can be found in section 1.4 (Table A-14 and Table A-16) in the accompanying Data appendix (IRENA, 2022b). A 10% discount rate was assumed for all costs.

For committed projects, announced project costs are used. For other generic fossil-fuel-based generation options (open and combined cycle gas turbines, coal power plants), the investment costs cited in internationally recognised sources (Timilsina and Deluque Curiel, 2020) and listed in section 1.4 (Table A-14) of the accompanying Data appendix (IRENA, 2022b), are used in all countries; the yearly fixed operating expenditure is assumed to be 3% of the capital expenditure. These costs are taken to be constant throughout the study period as the technologies in question are assumed to have reached maturity.

For non-conventional generation technologies, namely solar PV, wind and CSP, there is a significant trend towards lower capital costs. In general, these technologies show a relatively steep decline in the early years of the study, followed by a less pronounced decline at some later point. This aspect mainly represents the gradual

maturation of these technologies over the study horizon. Between 2020 and 2040, IRENA's costing analysis projects wind investment costs to fall from USD 1 458/kilowatt (kW) to USD 842/kW; for solar PV they are expected to fall from USD 950/kW to USD 280/kW. In the same period, CSP (with three-hour storage) capital costs are projected to decline from USD 4 058/kW to USD 2 562/kW. Overall, solar PV is expected to be the power generation technology with the lowest capital costs by 2024. The operation and maintenance costs of wind, solar PV and solar thermal power plants are presented in Table A-16 of the accompanying Data appendix (IRENA, 2022b).

Electricity production in North Africa is based chiefly on natural gas and heavy fuel oil in Egypt, Libya, Algeria and Tunisia, and on coal in Morocco (IEA, 2020c; see also section 1.2). Fuel price projections were based on price projections from internationally recognised benchmarks (Timilsina and Deluque Curiel, 2020), and no differentiation was made between country-level fuel prices and those between producers and importers. The rationale for this is that subsidies are the main reason for inter-country differences in fuel prices; this approach thus avoided skewing results on the basis of such subsidies. In other words, using global fuel prices allows us to take into account the real cost of electricity generation and the real potential for exporting those fuels from oil and gas producing countries.

As shown in section 1.4 in Table A-14 in the accompanying Data appendix (IRENA, 2022b), an increase in fossil fuel prices is expected in the short term, through 2025. After that date, a stabilisation is projected as demand for these fuels is expected to decrease owing to higher penetration of renewables.

2.2 FOUR SCENARIOS FOR NORTH AFRICA'S POWER SECTOR WERE MODELLED

Using the SPLAT-N model described previously, four scenarios were developed for North Africa's power sectors. These are described below and in Table 2-3.

The Planned scenario represents the achievement of planned policy goals through 2040, with countries reaching (but not surpassing) their renewable targets in power generation. Electricity demand is deemed to follow historical trends and with electricity's role in meeting final demand at current levels. For power exchanges between countries in the region and outside it, only the existing and committed interconnections are used. It is also assumed that North African countries will reach their national targets for the share of renewables in electricity generation. Once these targets are met, the same share is maintained for the remainder of the modelling period.

The Transition scenario considers that electrification expands in North Africa and that power interconnections are developed to enable higher exchanges of electricity between countries. Higher power demand is assumed for the region given the higher penetration of electricity in final energy consumption. (Box 2-1 provides details about the model's characterisation of demand.) Expansion of interconnection capacities is permitted to complement the existing and committed lines within the region and with countries outside North Africa. No investment in fossil-fuel-based power plants is made after 2025. An overview of the differences between the Planned and Transition scenarios (surpassing national renewable energy targets, disallowing new fossil fuel investments, higher electrification rates and increased interconnections) is given in section 2.3.

The Transition + Batteries scenario introduces the possibility of battery storage to provide flexibility to better integrate VRE, while maintaining the same parameters as the Transition scenario. The model allows for the deployment of battery storage technology to balance supply and demand on sub-daily timescales.

The Transition + Batteries + H₂ scenario assumes that, in addition to battery storage, hydrogen production is possible in North Africa using electrolyzers powered only by renewable electricity. The model allows for the construction of electrolysing facilities to produce green hydrogen in all North African countries where

hydrogen projects have been announced (see Table 1-2). Hydrogen production is considered for export only, namely to the European market, resulting in revenues for the producing countries. To ensure the production of green hydrogen, carbon dioxide (CO₂) emissions are capped at the level of the Transition scenario. The model will determine the quantity of hydrogen that can be produced at a cost that is less than or equal to the defined hydrogen export cost.

Table 2-3 Assumptions behind the four modelled scenarios

PLANNED	TRANSITION	TRANSITION + BATTERIES	TRANSITION + BATTERIES + H ₂
Historic demand growth and electrification levels Current interconnection capacity Countries' renewable energy targets are met but not surpassed	Higher demand growth with higher electrification of end uses Possibility to increase interconnection capacity No fossil-fuel-based generation investment after 2025 Renewable energy targets can be surpassed	Higher demand growth with higher electrification of end uses Possibility of increasing interconnection capacity No fossil-fuel-based generation investment after 2025 Renewable energy targets can be surpassed	Higher demand growth with higher electrification of end uses Possibility of increasing interconnection capacity No fossil-fuel-based generation investment after 2025 Renewable energy targets can be surpassed
		Battery storage	Battery storage
			Hydrogen production

Note: H₂ = hydrogen.

Box 2-1 Characterisation of demand in the model

Two electricity demand scenarios were considered in this report: Planned demand and Transition demand. These are described below.

Planned demand scenario. The demand projections and underlying assumptions were derived from historical trends and assume no drastic electrification of end-use sectors. The historical growth of final electricity demand shows different trends in the countries of the region. The rate of growth of final electricity demand is increasingly uncoupled from the GDP growth rate owing to energy efficiency measures. In this scenario, we assume a continuation of this trend with an average growth rate of 2.8% per year (decreasing from 5.9% in the period 2005-2010 and 4.0% in 2010-2015 but increasing from 0.3% in 2015-2019).

- In Egypt, the growth rate of final demand has continuously decreased over the past two decades owing to better energy efficiency (lower electricity intensity, expressed as kilowatt hours/unit of GDP).
- Algeria shows a sustained growth rate over the past two decades, which is projected to continue at the same level during 2019-2040 (average yearly growth rate of 5.6%).
- In Libya, in this scenario, a growth rate of 2.6% is assumed for the period 2019-2040. The trend in the decade since 2010 cannot be taken as a reference because of the major decrease of final electricity demand during 2010-2015 and only modest growth during 2015-2019. Final electricity demand was stagnant prior to 2010 and very moderate in 2005-2010.
- In Mauritania, efforts to reach electricity access for all will keep the rate of growth in final electricity demand at a high level during the period 2019-2040. Average yearly growth of 7.3% is assumed in the model.
- In Morocco, annual growth in final electricity demand has been declining for two decades owing to better energy efficiency. This scenario assumes this trend will continue, with an average annual rate of increase in demand of 2.2% (compared to 4.8% during 2010-2015 and 2.8% during 2015-2019).
- In Tunisia, a similar pattern can be seen, with a decrease in the annual rate of growth in final demand from 6% in 2005-2010 to 2.6% in 2010-2015 and 3% in 2015-2019. In this scenario, we anticipate an average yearly growth rate of 2.3% during the period 2019-2040.

Box 2-1 Characterisation of demand in the model (continued)

Total final electricity demand in the region is projected to roughly double from around 288 TWh in 2019 to approximately 590 TWh in 2040 (Table A-4 of the accompanying Data appendix [IRENA, 2022b]). The average annual rates of growth in electricity demand and peak demand are estimated at 3.5% (Table A-5 and Table A-6); and the share of electricity in total final energy consumption (TFEC) is assumed to be 20% by 2040 (Table A-7). By 2040, Egypt is expected to have the largest final demand for electricity (277 TWh) in the region, followed by Algeria (197 TWh) and Morocco (53 TWh). It is noteworthy that two of the areas of highest consumption (Egypt and Morocco) show GDP growth rates below the North Africa average.

In reality, daily demand profiles change over the years owing to changing consumption habits and sectoral patterns of electricity use. For example, the mounting use of air conditioning altered the load curve of most North African countries by shifting the peak load from the winter season to summer. Historical data show that this shift occurred at different moments in the different countries. The first occurrences of peak load during the summer were 2007 in Morocco, 2008 in Libya and 2009 in Algeria. Climate change may push peak loads in summer even higher.

In the model, the shape of the normalised profile is assumed to be invariable to 2040 owing to the lack of detailed data on electricity use patterns in the coming decades. The profile is thus exogenous and does not account for the dynamics of new technological innovations such as demand-side response strategies.

Transition demand. The demand projection in this scenario assumes a continuous increase in the share of electricity in final energy consumption representing a growing electrification of end uses. The assumed electrification trend (higher share of electricity in TFEC) is based on past growth in energy intensity (TFEC/GDP) and specific electricity intensity (final electricity consumption/GDP) (see Figure 1-3). In all countries, the share of electricity in TFEC is assumed to reach higher levels than in the Planned scenario. The average yearly demand and peak demand growth rate for North Africa is estimated at 4.4% (see Tables A-4, A-5 and A-6 of the Data appendix [IRENA, 2022b]); the share of electricity in TFEC reaches 27% by 2040. Total electricity demand for North Africa is projected to increase from 288 TWh in 2019 to around 708 TWh in 2040, representing a 20% increase in electricity demand over the Planned demand. By 2040, Egypt is expected to have the largest electricity demand (352 TWh) in the region, followed by Algeria (205 TWh) and Morocco (64 TWh). For Mauritania, the demand projection is the same in the Planned and Transition scenarios; this is because demand growth in Mauritania is driven principally by increasing access to electricity, which is reflected in the Planned scenario.

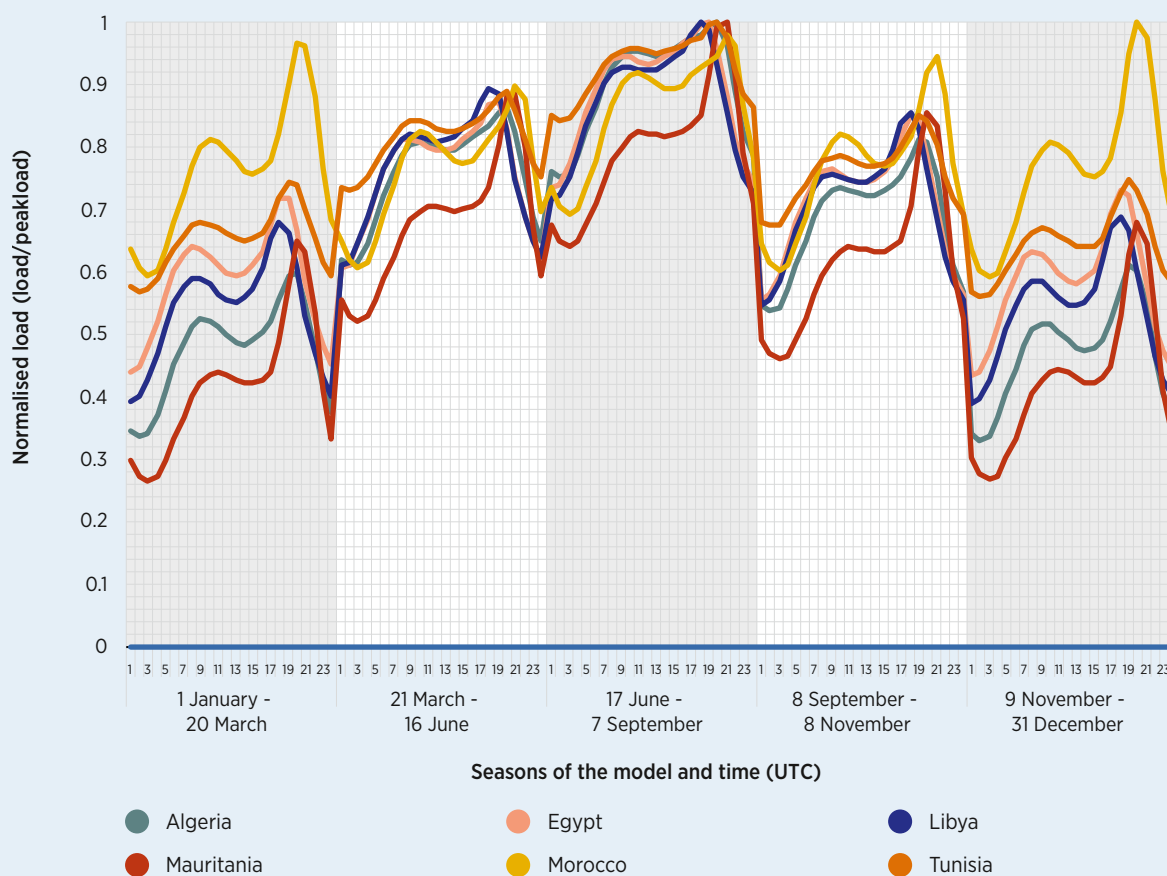
Projections to assess future load profiles were made following the methodology of Toktarova *et al.* (2019), since real load curve data were not publicly available for all of the six countries as of the writing of this study. The method used generates a load curve reflecting seasonal variation and various factors (such as temperature and air conditioning use). Electricity demand is projected at hourly resolution within a single framework for all countries by decomposing historical data into a set of sine functions to analyse the cyclical pattern of the data. The method provides important information for electricity network planning and is flexible enough to be applied to various socio-economic scenarios based on alternative assumptions about long- and short-term trends and projections. The generated load curves are used for the whole modelling period and scaled by the electricity dispatched each year.

Load profiles are aggregated by time slice. The System Planning Test Model for North Africa (SPLAT-N) was set up using five seasons and ten daily time slices. Season 1 begins on 1 January and ends on 20 March; Season 2 begins on 21 March and ends on 16 June; Season 3 begins on 17 June and ends on 7 September; Season 4 begins on 8 September and ends on 8 November; Season 5 begins on 9 November and ends on 31 December. The ten daily time slices consist of a six-hour night slice and nine two-hour slices for the remainder of the day, resulting in 50 time slices over the course of the year.

Box 2-1 Characterisation of demand in the model (continued)

Figure 2-1 shows for each country the model's normalised load curves on an average day in each of the five seasons. The main characteristic of the region's load curves is an annual peak in Season 3 due to the use of air conditioning. The extent of the peak differs from country to country owing to the disparity in the penetration of air conditioning. The peak in the summer load curve is nearly the same in the daytime and in the evening, which would likely affect how solar is used: directly during the daytime peak and via storage in the evening. Unlike the summer and spring load curves, which are relatively similar for most countries, the winter and autumn curves differ, displaying a slight duck curve with different magnitudes. Unlike the spring and summer load curves, the evening loads in autumn and winter show a higher peak owing to demand for lighting and household appliances.

Figure 2-1 Normalised load curves on an average day in each season in North Africa (applied for all years of the modelling period)



Note: UTC = Coordinated Universal Time.

Key results for the four scenarios related to the development of renewable energy sources, CO₂ emissions, investments, costs, battery storage and hydrogen development are summarised in Table 2-4. The sections that follow discuss each of these results in more detail.

Table 2-4 Summary of key results from the investigated scenarios

PARAMETER	PLANNED	TRANSITION	TRANSITION + BATTERIES (costs related to batteries)	TRANSITION + BATTERIES + H ₂
Installed capacity in 2040 (GW)	180	286	270	597
– of which RE capacity (GW)	76	235	220	546
– of which VRE capacity (GW)	72	229	214	541
Total generation in 2040 (TWh)	647	822	812	1878
– of which RE generation (TWh)	236	713	701	1770
– of which VRE generation (TWh)	223	701	689	1753
RE share in generation in 2040 (%)	36	87	86	94
VRE share in generation in 2040 (%)	35	85	85	93
CO ₂ emissions from electricity generation in 2040 (MtCO ₂ /year)	146	35	34	33
Cumulative investment in generation capacity, 2020-2040 (USD billions)	152	379	343 + (13)	573 + (19)
Total system cost, 2020-2040 (USD billions)	863	898	881 + (5)	1063 + (4)
Revenue from hydrogen production, 2020-2040 (USD billions)	-	-	-	358
New PV capacity, 2020-2040 (GW)	34	23	29	149
New CSP capacity, 2020-2040 (GW)	0.4	74	61	55
New wind capacity, 2020-2040 (GW)	34	129	121	333
Batteries in 2040 (capacity in GW/ storage volume in GWh)	-	-	13.0/78	19.2/115.2
Hydrogen production in 2040 (MtH ₂ /year)	-	-	-	24
Electrolyser capacity (GWe)	-	-	-	156
Investment in electrolyzers, 2020-2040 (USD billion)	-	-	-	77.4
Net unit cost of power generation in 2040 (UScents/kWh)	8.7	7.5	7.1	4.7
VRE curtailment in 2040 (%) relative to generation potential of VRE	3	25	16	5

Note: CO₂ = carbon dioxide; CSP = concentrated solar power; GW = gigawatt; GWe = gigawatt electrical; GWh = gigawatt hour; H₂ = hydrogen; kWh = kilowatt hour; MtCO₂ = megatonnes of carbon dioxide; MtH₂ = megatonnes of hydrogen; PV = photovoltaic; RE = renewable energy; TWh = terawatt hour; VRE = variable renewable energy.

2.3 THE THREE TRANSITION SCENARIOS DIFFER IN THEIR ASSUMPTIONS

The basic assumptions of the model change in three ways when moving from the Planned to the Transition scenarios. These concern (1) national renewable energy targets, which are met exactly in the Planned scenario but can be surpassed in the Transition scenarios; (2) electricity demand, which is higher under the Transition scenarios, because end-use electrification is assumed to be more extensive; and (3) cross-border interconnections, the capacity of which can be strengthened under the Transition scenarios.

A brief investigation of these steps using the SPLAT-N model for sensitivity analysis reveals which of these steps has the strongest impact on the observed changes in the power mix between the Planned and the Transition scenarios (see Table 2-5). The investigation involves three test scenarios that progressively close the gap between the Planned and the Transition scenarios:

- **Test A:** Same as Planned, but allowing countries' renewable energy targets to be exceeded
- **Test B:** Same as Test A, but disallowing fossil fuel investments after 2025
- **Test C:** Same as Test B, but with increased electrification leading to a higher electricity demand

The Transition scenario (Table 2-4) thus becomes equal to Test C, plus the possibility for additional interconnections between countries.

The results of these test scenarios as compared to the Planned and Transition scenarios are shown in Table 2-5. It is clear that the largest change between the Planned and Transition scenarios is exhibited by Test A: if countries' renewable energy targets are allowed to be surpassed, the model finds solutions at substantially lower cost by deploying more renewables (doubling the installed capacity of renewable energy by 2040, *i.e.* from 37% to 72% in the power mix), mostly solar PV and wind power. This indicates that increased ambition in countries' renewable energy deployment targets today could pave the way for more cost-effective systems in the future.

The constraint of prohibiting new fossil fuel investments after 2025 (Test B) results in a smaller jump in renewable energy capacity (22%), and the composition of the renewable energy portfolio changes. The model now prefers deploying CSP with thermal storage instead of solar PV, as CSP's higher capacity credit (the fraction of the installed capacity which could be relied upon to be available at any given time) makes CSP plants a better investment than solar PV, given the halt after 2025 on new thermal power plants that could have provided firm capacity.

The effect of higher demand due to electrification (Test C) is that nearly all the new demand is met by new VRE plants, with the share of renewables in the power mix remaining essentially unchanged.

Lastly, the effect of allowing additional interconnection capacity between neighbouring countries is seen to have marginal effects on overall installed renewable energy capacity, but it reduces overall system costs and the unit costs of electricity. This is because interconnections allow better exploitation of the spatio-temporal synergies between demand and countries' VRE profiles (see Box 2-2).

The different assumptions related to the modelling of interconnections between the North African countries and between these countries and other regions are shown in Table A-17 of the accompanying Data appendix (IRENA, 2022b). In the Planned scenario, no expansion of the existing interconnection capacity is considered. In the three Transition scenarios the expansion of interconnection capacity within North Africa is possible and subject to optimisation.

The average yearly prices of exchanging electricity with countries outside the region are based on 2019 actual prices, drawn from the annual report of the Jordanian National Electric Power Company, market data for Sicily (Italy), and market data for Spain (see Figure 2-11). The prices of the Jordan-Egypt interconnection are used for the Sudan-Egypt interconnection because specific price data for the latter link are lacking.

Table 2-5 Summary of the analysis of the steps needed to go from the Planned to the Transition scenario

	PLANNED	TEST A (same as Planned, except that renewable energy targets may be exceeded)	TEST B (Test A + no fossil fuel investments after 2025)	TEST C (Test B + higher demand)	TRANSITION (Test C + more interconnections)
Installed capacity in 2040 (GW)	180	236	233	289	286
– of which RE capacity (GW)	76	150	183	238	235
– of which VRE capacity (GW)	72	144	177	232	229
Total generation in 2040 (TWh)	647	676	685	822	822
– of which RE generation (TWh)	236	501	573	708	713
– of which VRE generation (TWh)	223	484	558	694	701
RE share in generation in 2040 (%)	36	74	84	86	87
VRE share in generation in 2040 (%)	34	72	81	85	85
CO ₂ emissions from electricity generation in 2040 (MtCO ₂ /year)	146	61	35	38	35
Cumulative investment in generation capacity, 2020-2040 (USD billion)	152	227	298	382	379
Total system cost, 2020-2040 (USD, billions)	863	799	794	905	898
New PV capacity, 2020-2040 (GW)	34	33	17	23	23
New CSP capacity, 2020-2040 (GW)	0.4	17	52	74	74
New wind capacity, 2020-2040 (GW)	34	92	104	131	129
Net unit cost of power generation in 2040 (UScents/kWh)	8.7	7.3	7.6	7.7	7.5

Note: CO₂ = carbon dioxide; CSP = concentrated solar power; GW = gigawatt; kWh = kilowatt hour; MtCO₂ = megatonnes of carbon dioxide; PV = photovoltaic; RE = renewable energy; TWh = terawatt hour; VRE = variable renewable energy.

Box 2-2 Estimating variable renewable energy generation profiles

Renewable energy's potential in North Africa is spread widely, with excellent solar resources in all countries and good wind resources, especially along Morocco's western coast and in Egypt. The region's hydropower potential has already been mostly exploited, and biomass resources are limited.

Falling costs have already made variable renewable energy (VRE) sources viable alternatives to fossil fuels. Yet their variability (daily and seasonal, in the case of wind and solar) still limits their use. The solution is to exploit the spatial and temporal complementarity present in the region. For example, tapping the region's widespread solar power potential will require measures to mitigate day-night variability. Fortunately, various sites in Egypt show a marked potential for wind power generation during the night, when solar power is not available. Furthermore, thanks to the wide range of longitudes in the region, the daily temporal complementarity between the solar profiles of countries such as Egypt, Algeria and Mauritania is also pronounced (Figure 2-2). Another potential complementarity between countries' renewable resources is observed at the seasonal level. Figure 2-3 shows how the wind profiles of Egypt and Morocco could complement each other during the year.

The complementarity of the region's geographical and climatic circumstances presents an excellent opportunity to integrate electricity markets, yielding significant economic, environmental and energy security benefits. To measure the extent of that opportunity, we identified "model supply regions" (MSRs) using a methodology developed in IRENA and LBNL (2015). The exercise involved screening high-potential locations as candidate sites for wind and solar power plant development and deployment. Each MSR is characterised by different resource availability and infrastructure costs (linked to the expansion of roads and transmission infrastructure). The model selects the distribution of new installed capacity that offers the least-cost solution in light of the cost parameters and the fit between VRE load curves and the demand load curve.

For each country, the MSRs selected for wind and solar power plant deployment had to satisfy the following criterion: that a full exploitation of their potential would suffice, on average, to cover future electricity demand. For each country, 50 MSRs were selected for wind and 50 for solar photovoltaic (PV). MSR coordinates, maximum capacity and capacity factor are summarised in the accompanying Data appendix (IRENA, 2022b) in Table A-8 (wind) and Table A-11 (solar PV). Country-level illustrations are provided in section 1.7 of the Data appendix.

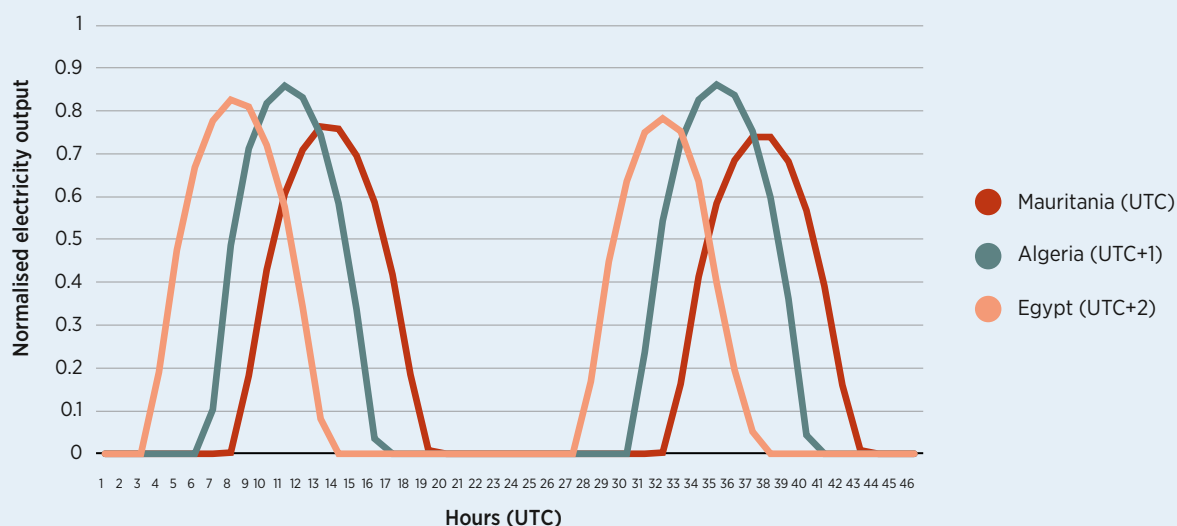
To reduce model runtime, instead of using each MSR as a separate technology in the System Planning Test Model for North Africa (SPLAT-N), MSRs were clustered into ten distinct clusters by country based on *k*-means clustering, thus grouping together MSRs with highly similar temporal profiles. The allocation of MSRs across each country's ten clusters is provided in Table A-8 and Table A-11. The deployment of VRE capacity across the different clusters for each scenario is shown in Table A-9 and Table A-12 (IRENA, 2022b). These tables demonstrate the added value of considering distinct clusters of MSRs for each country instead of representing VRE as a single, generic technology: the model deploys capacity in clearly different sets of clusters across the four scenarios, depending on which specific combination of resource profiles results in a cost-optimal overall system. The clustering method yielded a set of distinct VRE-generation profiles (with distinct possibilities to contribute to a balanced electricity mix and distinct synergies with other VRE plants and with demand) to be considered for the optimisation exercise.

The MSRs' capacity factor profiles for the SPLAT-N model were derived by averaging across time slices for each of the five modelled seasons, thereby smoothing out intra-seasonal and intra-day variability, especially for wind. To validate the results, additional simulations at full hourly resolution were performed based on the proposed cost-optimal capacity expansion scenarios. That exercise corroborated the pertinence of the SPLAT-N model results (see section 2.9).

Figure 2-4 shows the total solar and wind potential for each country across all screened MSRs and the range of their capacity factors. The capacity factors calculated for solar PV include 4% outage losses and 4% inverter and alternating current losses for solar PV. For wind, outage losses account for 2% and array and collection losses are 15% (IRENA and LBNL, 2015). The identified total deployment potential (in megawatts) and the ranges of capacity factors (post-losses) across MSRs by country are found in Table A-10 and Table A-13 (IRENA, 2022b).

Box 2-2 Estimating variable renewable energy generation profiles (continued)

Figure 2-2 Examples of diurnal profiles of solar photovoltaic power generation for sites in Mauritania (UTC), Algeria (UTC+1) and Egypt (UTC+2)



Note: UTC = coordinated universal time.

Figure 2-3 Monthly average wind profile of different locations in Egypt and Morocco

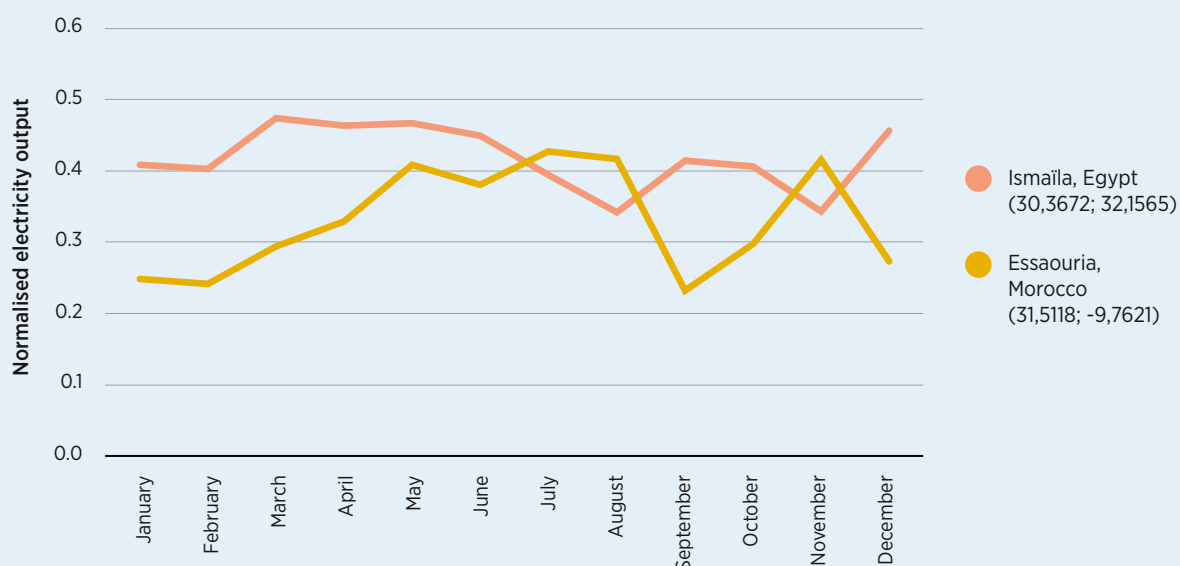
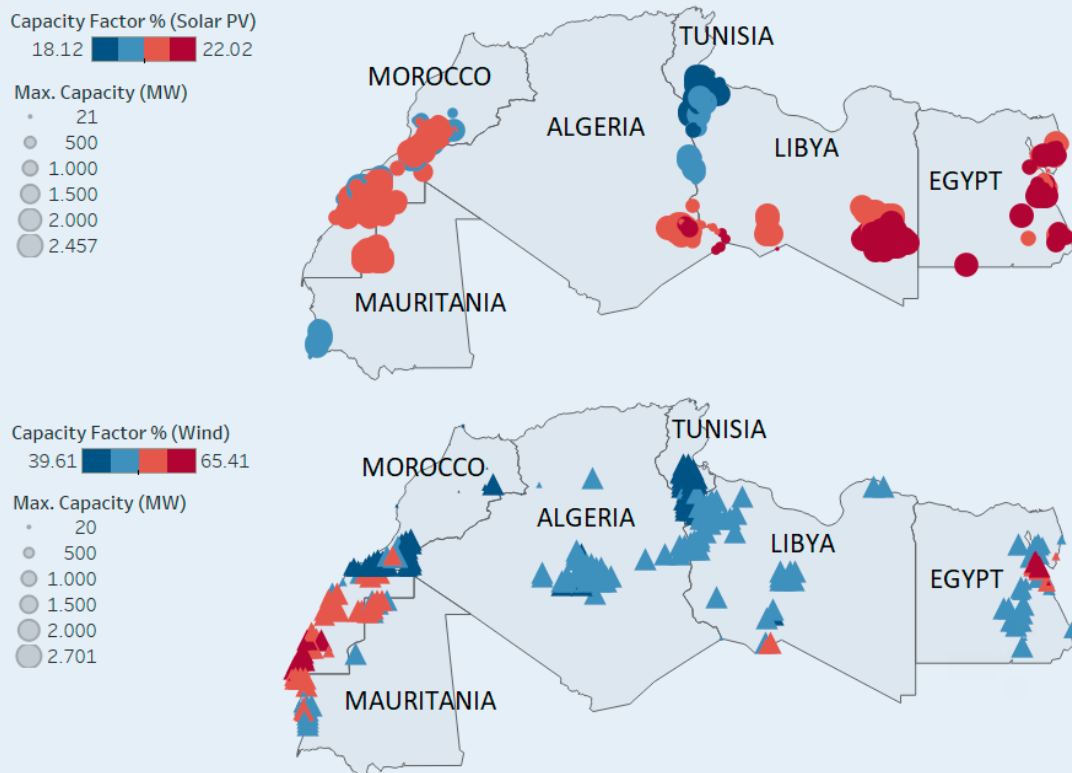


Figure 2-4 Identified solar photovoltaic and wind model supply regions from resource screening in North Africa with 8% and 17% accounted losses, respectively



Note: A country-tailored technical analysis for planning project development can be conducted using zoning analysis developed under the IRENA Global Atlas for Renewable Energy.

MW = megawatt; PV = photovoltaic.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

2.4 IF INVESTMENT IN FOSSIL FUEL PROJECTS IS DISCONTINUED, LEAST-COST CAPACITY EXPANSION IS DOMINATED BY SOLAR AND WIND POWER

The results of our capacity expansion modelling for the Planned, Transition, Transition + Batteries and Transition + Batteries + H₂ scenarios are illustrated in Figure 2-5. A more comprehensive table can be found in section 1.5 of the Data appendix (IRENA, 2022b).

In the Planned scenario, which meets countries' current renewable electricity targets, a gradual increase in natural gas-fired generation, in absolute terms, is suggested. While the share of natural gas in total installed capacity decreases (from 63% in 2025 to 52% in 2040) as countries meet their renewable electricity targets, it still remains the primary contributor to electricity generation capacity in 2040 (95 GW) in North Africa.

Compared with the Planned scenario, the Transition scenario constrains investment in fossil-fuel-based generation from 2025 onward. The result of this constraint is a higher share of intermittent wind generation entering the system (at an annual growth rate of 10%). Additionally, large shares of CSP are also deployed

to balance the system without natural gas generation (a 35% increase each year between 2025 and 2040). Without utility-scale battery storage, however, solar PV deployment proceeds more slowly than in the Planned scenario, given the lack of flexibility to balance its diurnal variability (a flexibility provided by natural gas in the Planned scenario). At the end of the modelling horizon, renewables represent 82% of the total installed capacity in North Africa in this scenario, while VRE represents 80% of the total. Natural gas installed capacity falls by 49% between 2025 and 2040.

The introduction of batteries (see Box 2-3) in the Transition + Batteries scenario allows a higher penetration of solar PV that partly replaces CSP, as batteries are highly suited to reduce the day-night variability of solar PV output. In 2040, 31 GW of solar PV are installed in North Africa, 26% above the 24 GW deployed in the Transition scenario without batteries. Wind power capacity does not change as much as solar PV, as wind power generation benefits less from battery storage than solar PV because its variabilities are typically exhibited on time scales other than day-night. Overall, the Transition + Batteries scenario is characterised by a lower total installed capacity in 2040 (270 GW compared with 286 GW in the Transition scenario) since batteries permit a more optimal use of the installed technologies with lower curtailment (the curtailment rate falls to 16% from 25% in the Transition scenario). VRE comes to represent 79% of the total installed capacity in 2040.

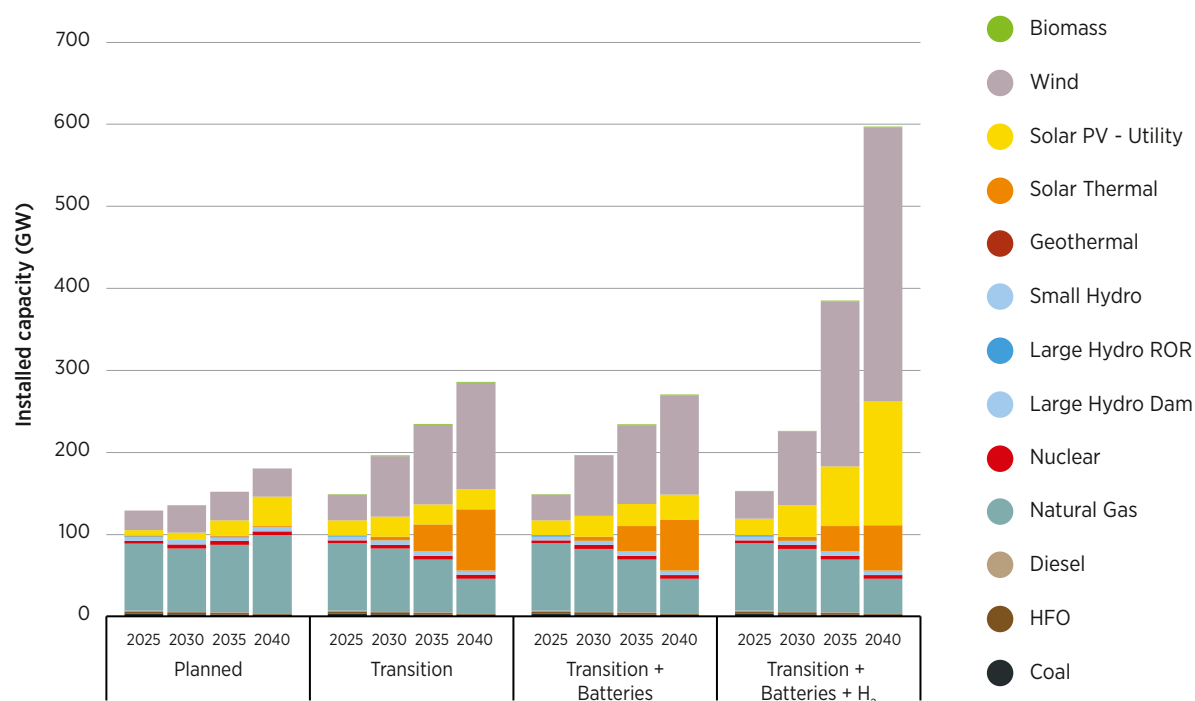
The Transition + Batteries + H₂ scenario contains the same assumptions as the Transition + Batteries scenario but allows for the development of electrolyser capacity to produce green hydrogen from renewable electricity. This new feature leads to a surge of the total installed capacity over the modelling horizon, reaching 597 GW in 2040, twice as much as in the Transition + Batteries scenario (270 GW). This is a consequence of the significant growth of renewable power capacity installed by 2040 expressly to produce hydrogen. The additional capacity is 212 GW for wind and 120 GW for solar PV over the Transition + Batteries scenario. On the other hand, the installed capacity of CSP is reduced in this scenario compared with the Transition + Batteries scenario (by 6 GW) because hydrogen production provides the flexibility needed to integrate more wind and solar PV into the energy mix. In total, VRE represents 91% of total installed capacity in 2040 in the Transition + Batteries + H₂ scenario.

In all three Transition scenarios, biomass is used to its maximum potential in Morocco as defined in the Morocco National Plan (960 MW) (Ministère de l'Énergie, des Mines et de l'Environnement du Maroc, 2021d). The estimated potential for other countries is very small.

The option to invest in additional cross-border transmission capacity in the Transition scenarios allows for a more optimal deployment of solar and wind power plants, favouring their preferential buildout in locations with the highest capacity factors and the greatest synergies within the region, not just within individual countries. The generated electricity is then more easily distributed through greater interconnection capacity, making it possible to meet the same renewable objectives with less installed capacity.



Figure 2-5 Capacity expansion in North Africa by technology in the four scenarios



Note: GW = gigawatt; H₂ = hydrogen; HFO = heavy fuel oil; PV = photovoltaic; ROR = run-of-river.

Box 2-3 Representation of storage in the model

Presently, pumped hydro is the only storage option used in the region. One 350-MW pumped hydro power plant is in service in Morocco; a second 415-MW plant is under construction. Both plants are considered in the model. Due to a lack of data, no future possibilities for additional pumped hydro power plants were considered. However, further possibilities for (closed-loop) pumped hydropower are likely to exist, particularly in Morocco's Atlas Mountains.

Three other storage options are considered in the technologies modelled for North Africa: solar thermal storage, batteries and hydrogen production for export.

Solar thermal is assigned a fixed generation profile in the model. It generates while solar radiation is available during the day and continues to generate after sunset to supply electricity during the evening peak. In this model, we assume a three-hour storage capacity for concentrated solar power plants.

Batteries are considered an option in all countries starting from 2025. We assume six-hour storage batteries. The National Renewable Energy Laboratory's mid-scenario cost projections and technical parameters are used, assuming a 15-year lifetime and an 85% efficiency of the charging/discharging cycle (NREL, 2021). Batteries are considered to operate for day-night balancing – that is, the model does not allow them to operate for seasonal storage. Assumed capital expenditure and operational expenditure trajectories of battery storage are given in Table A-18 in the Data appendix (IRENA, 2022b).

In the model, all *hydrogen production* is assumed to be from renewable electricity. That assumption is operationalised by imposing a constraint that hydrogen must be produced without any increase in carbon dioxide emissions over scenarios in which hydrogen does not figure. Hydrogen production is considered an option from 2025 in the countries where projects or partnerships have been announced (*i.e.* Algeria, Egypt, Mauritania, Morocco and Tunisia). Plants are considered by three vintage years (2025, 2030 and 2035), with investment costs decreasing and efficiency increasing over time. Electrolyser cost assumptions are presented in Table A-19. All hydrogen produced is assumed to be allocated for export at a price that is assumed exogenously (see Table A-20 in IRENA, 2022b).

Box 2-3 Representation of storage in the model (continued)

The model optimises the quantity of hydrogen to be produced, using export prices as the optimisation mechanism. Export prices are given in Table A-20 (IRENA, 2022b) and are based on IRENA's projections (IRENA, 2020b). In addition, we estimate the hydrogen quantity that could be produced at different export prices. The model also optimises the dispatch of electricity to meet either electricity demand or to produce hydrogen for export according to the opportunity cost of the latter. In this study, hydrogen must be produced at a cost less than or equal to USD 2/kilogramme (kg), as this is considered to be the cost at which hydrogen can become a viable alternative to conventional fuels (Edwardes-Evans, 2020). This cost does not include transport by pipeline, estimated at EUR 0.11-0.21/kg (EHB, 2021). Pipeline transport is possible between North Africa and Europe, where hydrogen demand is projected to reach around 10 megatonnes (Mt) in 2030, 40 Mt in 2040 and 70 Mt in 2050 (EHB, 2021). These transport costs are not considered in this study.

The results in terms of electricity generation are presented in Figure 2-6 and Figure 2-7. More detailed data can be found in Table 2-3 (country-level breakdown) as well as section 1.5 of the Data appendix (IRENA, 2022b).

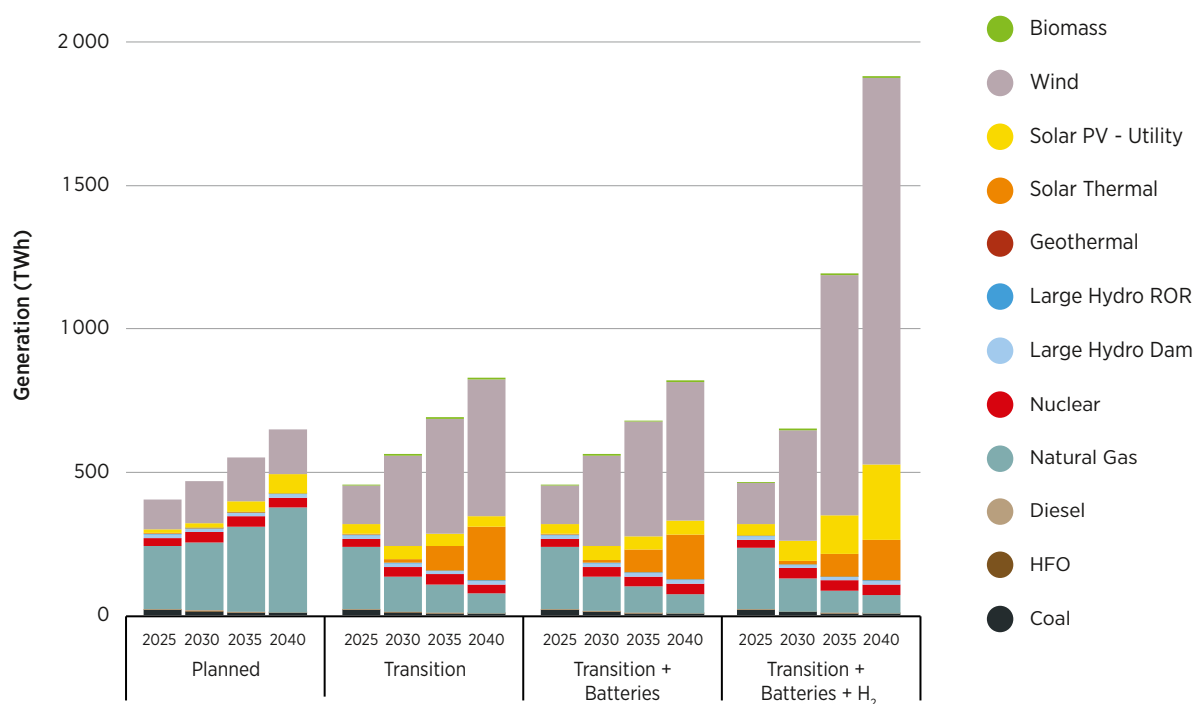
In the Planned scenario, the share of renewable energy remains at roughly the same level over the modelling period (from 33% in 2025 to 37% in 2040, corresponding to 135 terawatt hours (TWh) and 236 TWh, respectively). The proportion of VRE increases from 30% to 34% of total generation over the 20-year planning horizon, rising from 120 TWh to 223 TWh. The small increase in the share of renewables is due to increased demand and the model constraint of keeping the renewables target at the same level in the post-2030 period.

In contrast, the share of renewables in total generation increases sharply in the Transition scenario, from 41% in 2025 to 87% in 2040. In this scenario, in which fossil fuel investments are disallowed after 2025, thermal generation decreases both in absolute terms and in proportion to total generation, with a net reduction of 68% between 2025 and 2040 (falling from 218 TWh in 2025 to 69 TWh in 2040). This reduction is offset by renewable generation (chiefly wind), which grows from 30% to 58% of total generation (134 TWh to 479 TWh).

When adding battery storage to the Transition scenario, electricity generation from solar PV becomes more relevant and replaces some generation from wind and CSP, while generation from other energy sources remains similar. In 2040, solar PV generation is indeed 35% higher in the Transition + Batteries scenario (47 TWh), where it represents 6% of total power generation, than in the Transition scenario (35 TWh), where it accounts for only 4% of the total.

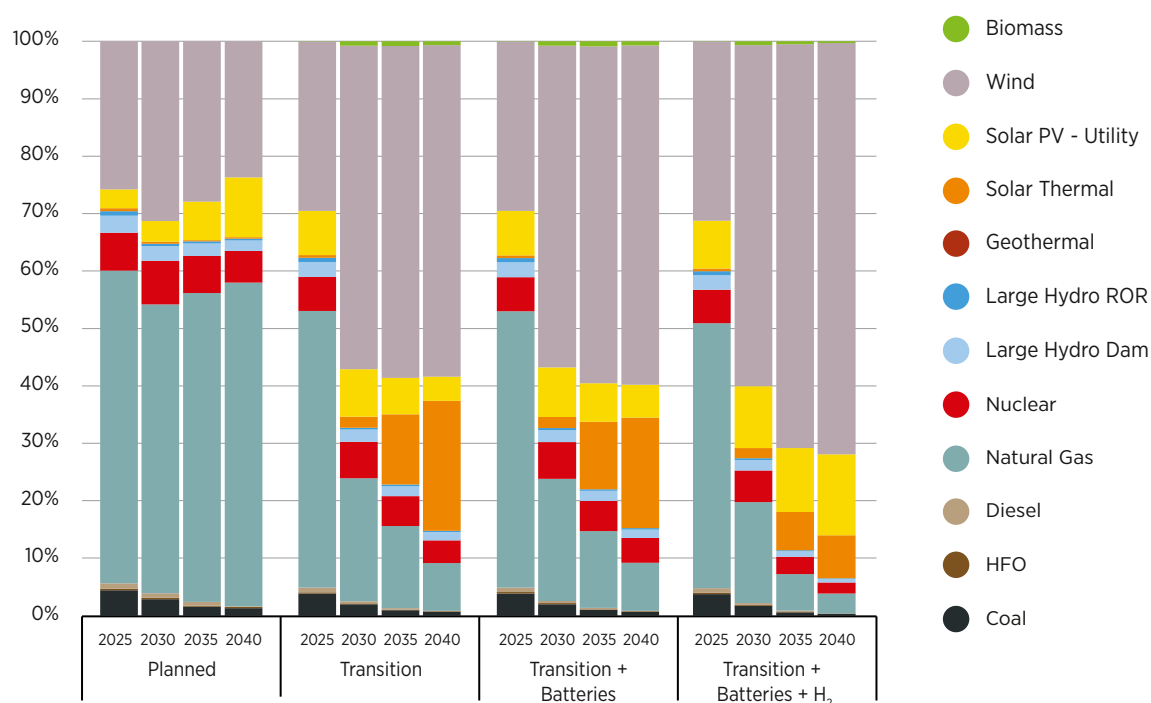
Enabling hydrogen production in North Africa leads to a surge in renewable generation, which reaches 1773 TWh in 2040 (compared with around 700 TWh in both the Transition and Transition + Batteries scenarios). This additional generation (more than 1000 TWh) is used to produce renewable hydrogen for export (since electricity demand in North Africa does not change across the three Transition scenarios). In this scenario, the share of renewables in total generation reaches 94% at the end of the modelling horizon, the highest level of all scenarios. The greater power demand created by the production of hydrogen for export allows for more integration of renewable energy, with hydrogen serving as a system flexibility option. Solar thermal also helps to deal with a part of the variability.

Figure 2-6 Projection of generation in North Africa in the four scenarios, by technology



Note: H₂ = hydrogen; PV = photovoltaic; ROR = run-of-river; TWh = terawatt hour.

Figure 2-7 Share of energy sources in electricity generation in North Africa in the four scenarios, by technology



Note: H₂ = hydrogen; HFO = heavy fuel oil; PV = photovoltaic; ROR = run-of-river.

Table 2-6 Country-level breakdown of the power generation mix by 2040, by scenario

GENERATION MIX IN 2040 (%)	COAL	HFO	DIESEL	NATURAL GAS	NUCLEAR	HYDRO RESERVOIR	HYDRO ROR	GEOTHERMAL	SOLAR PV	CSP	WIND	BIOMASS
Planned scenario												
Algeria	0%	0%	0%	74%	0%	0%	0%	0%	15%	0%	11%	0%
Egypt	0%	0%	0%	45%	11%	3%	1%	0%	8%	0%	32%	0%
Libya	0%	4%	1%	86%	0%	0%	0%	0%	4%	0%	6%	0%
Mauritania	0%	0%	0%	53%	0%	0%	0%	0%	11%	0%	35%	0%
Morocco	20%	0%	0%	15%	0%	4%	0%	0%	13%	4%	44%	0%
Tunisia	0%	0%	0%	72%	0%	0%	0%	0%	14%	0%	15%	0%
Transition scenario												
Algeria	0%	0%	0%	9%	0%	0%	0%	0%	2%	29%	59%	0%
Egypt	0%	0%	0%	10%	8%	2%	0%	0%	5%	18%	58%	0%
Libya	0%	1%	1%	1%	0%	0%	0%	0%	6%	34%	56%	0%
Mauritania	0%	0%	0%	4%	0%	0%	0%	0%	1%	31%	64%	0%
Morocco	9%	0%	0%	0%	0%	3%	0%	0%	6%	22%	51%	9%
Tunisia	0%	0%	0%	10%	0%	0%	0%	0%	6%	23%	61%	0%
Transition + Batteries scenario												
Algeria	0%	0%	0%	9%	0%	0%	0%	0%	4%	25%	62%	0%
Egypt	0%	0%	0%	10%	9%	2%	0%	0%	6%	14%	58%	0%
Libya	0%	1%	1%	2%	0%	0%	0%	0%	9%	28%	59%	0%
Mauritania	0%	0%	0%	4%	0%	0%	0%	0%	7%	31%	57%	0%
Morocco	8%	0%	0%	0%	0%	2%	0%	0%	6%	20%	56%	8%
Tunisia	0%	0%	0%	10%	0%	0%	0%	0%	6%	22%	62%	0%
Transition + Batteries + H₂ scenario												
Algeria	0%	0%	0%	5%	0%	0%	0%	0%	17%	10%	67%	0%
Egypt	0%	0%	0%	7%	6%	1%	0%	0%	10%	9%	67%	0%
Libya	0%	1%	1%	1%	0%	0%	0%	0%	9%	28%	60%	0%
Mauritania	0%	0%	0%	0%	0%	0%	0%	0%	20%	1%	78%	0%
Morocco	1%	0%	0%	0%	0%	0%	0%	0%	13%	4%	80%	2%
Tunisia	0%	0%	0%	1%	0%	0%	0%	0%	18%	3%	77%	0%

Note: CSP = concentrated solar power; H₂ = hydrogen; HFO = heavy fuel oil; PV = photovoltaic; ROR = run-of-river.

2.5 BATTERY STORAGE AND HYDROGEN PRODUCTION ARE CONDUCTIVE TO GREATER INTEGRATION OF SOLAR PV, BUT THEY LOWER THE NEED FOR CSP

New solar capacity (solar PV and CSP) installed in North Africa between 2020 and 2040 increases under all scenarios (Figure 2-8 and Figure 2-9). In all cases, Algeria and Egypt, which have the largest power systems in the region, are the countries that install the most new solar PV and CSP capacity. In the Transition + Batteries + H₂ scenario, however, Mauritania, Tunisia and Morocco also deploy substantial solar PV capacity to produce green hydrogen. In this case, total solar PV installed capacity reaches 151 GW in 2040 in North Africa.

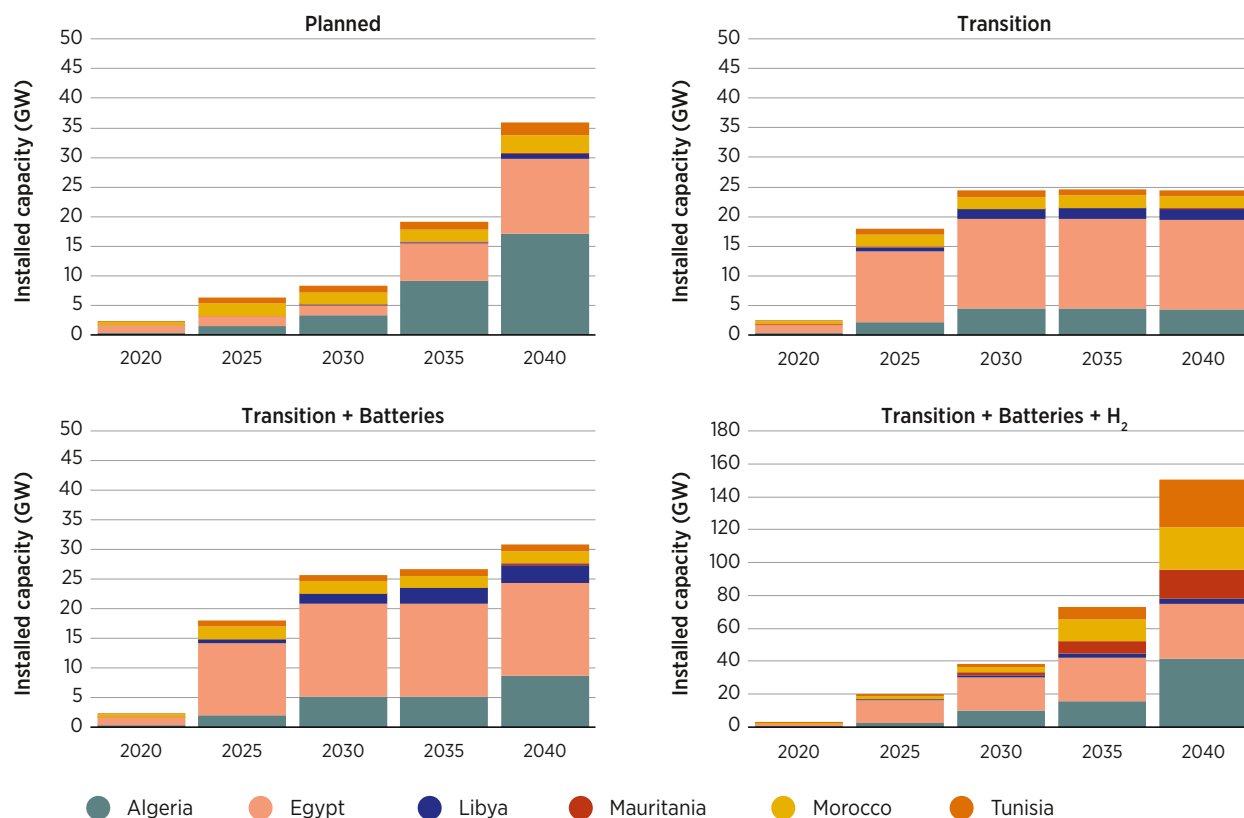
As mentioned in the previous section, the introduction of battery storage enables greater development of solar PV (Figure 2-8), compared with the Transition scenario. In 2040, 31 GW of solar PV capacity is installed in North Africa in the Transition + Batteries scenario, compared with 36 GW and 24 GW in the Planned and Transition scenarios, respectively, neither of which include the option of battery storage. The slightly higher total installed capacity of solar PV in the Planned scenario compared with the Transition scenario is due to the presence of CSP in the Transition scenarios, with CSP's storage capability providing a part of the needed reserve margin. In the Transition scenario, solar PV capacity stagnates after 2030, leaving room for CSP. The Transition + Batteries + H₂ scenario is by far the one that implies the greatest development of solar PV, with 151 GW installed by 2040. This means that hydrogen production allows a better integration of solar PV, since power not used to meet demand is converted into hydrogen.

With regard to new CSP installed capacity, only 1 GW is expected to be developed under the Planned scenario in North Africa by 2040 (Figure 2-9). In contrast to the Planned scenario, the absence of new fossil fuel power plants after 2025 in the Transition scenario produces a need for more dispatchable power generation, which can be provided by CSP with thermal storage, since this technology can provide electricity during the evening peak load. The result is the installation of 75 GW of CSP capacity by 2040, well above the 24 GW solar PV capacity. When battery storage is enabled, CSP capacities are still installed but at a slower pace, resulting in 62 GW and 55 GW of CSP capacity in the Transition + Batteries and Transition + Batteries + H₂ scenarios, respectively. In the three transition scenarios, Algeria and Egypt represent more than 80% of the region's CSP installed capacity in 2040.

In the Planned scenario, firm capacity is provided by fossil fuel power plants. In the Transition scenario, it is provided by CSP, and therefore CSP takes the place of some PV. When batteries are considered as an option, they contribute to firm capacity by “firming up” solar PV, thus obviating some of the need for dispatchable CSP capacity.

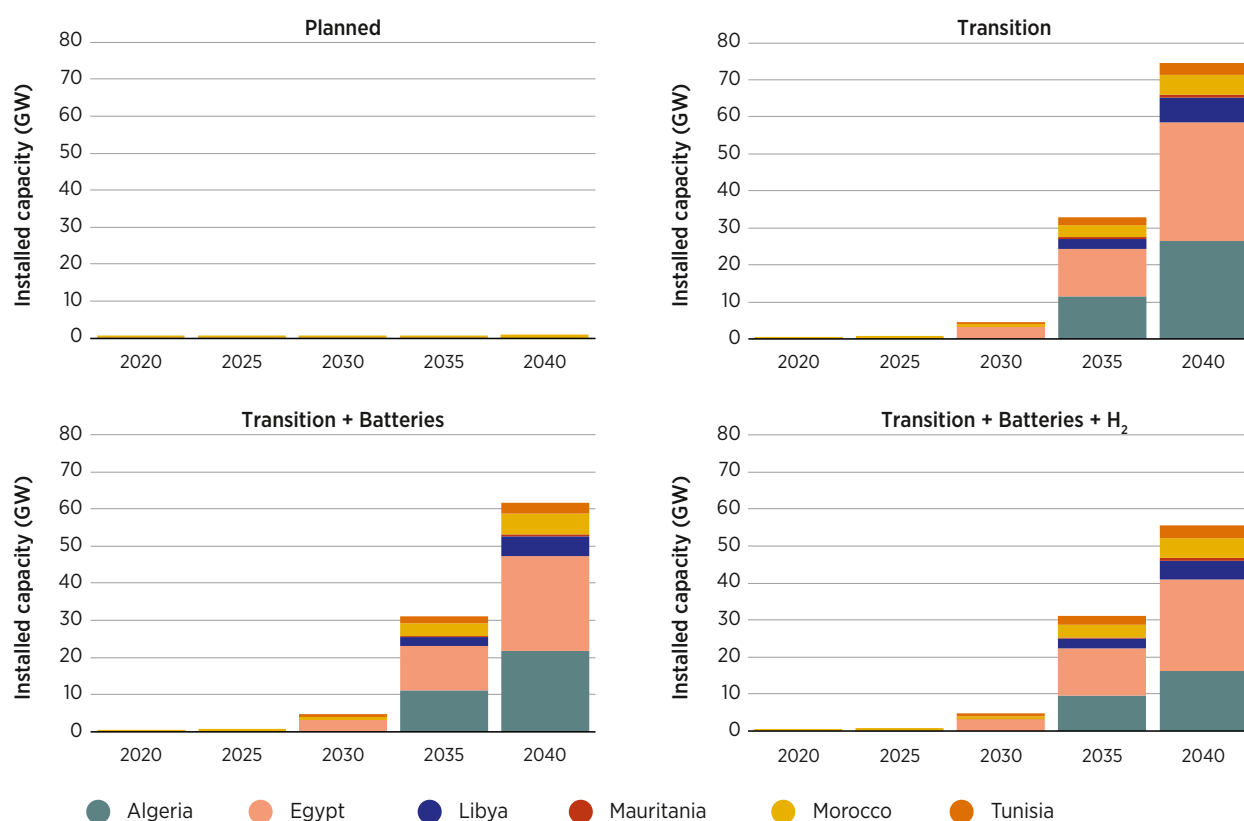


Figure 2-8 New installed solar photovoltaic capacity by country in the four scenarios



Note: GW = gigawatt; H₂ = hydrogen.

Figure 2-9 New installed concentrated solar power capacity by country in the four scenarios



Note: GW = gigawatt; H₂ = hydrogen.

2.6 WIND POWER IS AN ATTRACTIVE INVESTMENT IN ALL NORTH AFRICAN COUNTRIES, ESPECIALLY IN COMBINATION WITH HYDROGEN PRODUCTION

The new wind capacity installed by each North African country between 2020 and 2040 is presented in Figure 2-10. Detailed numbers can be found in section 3.7.

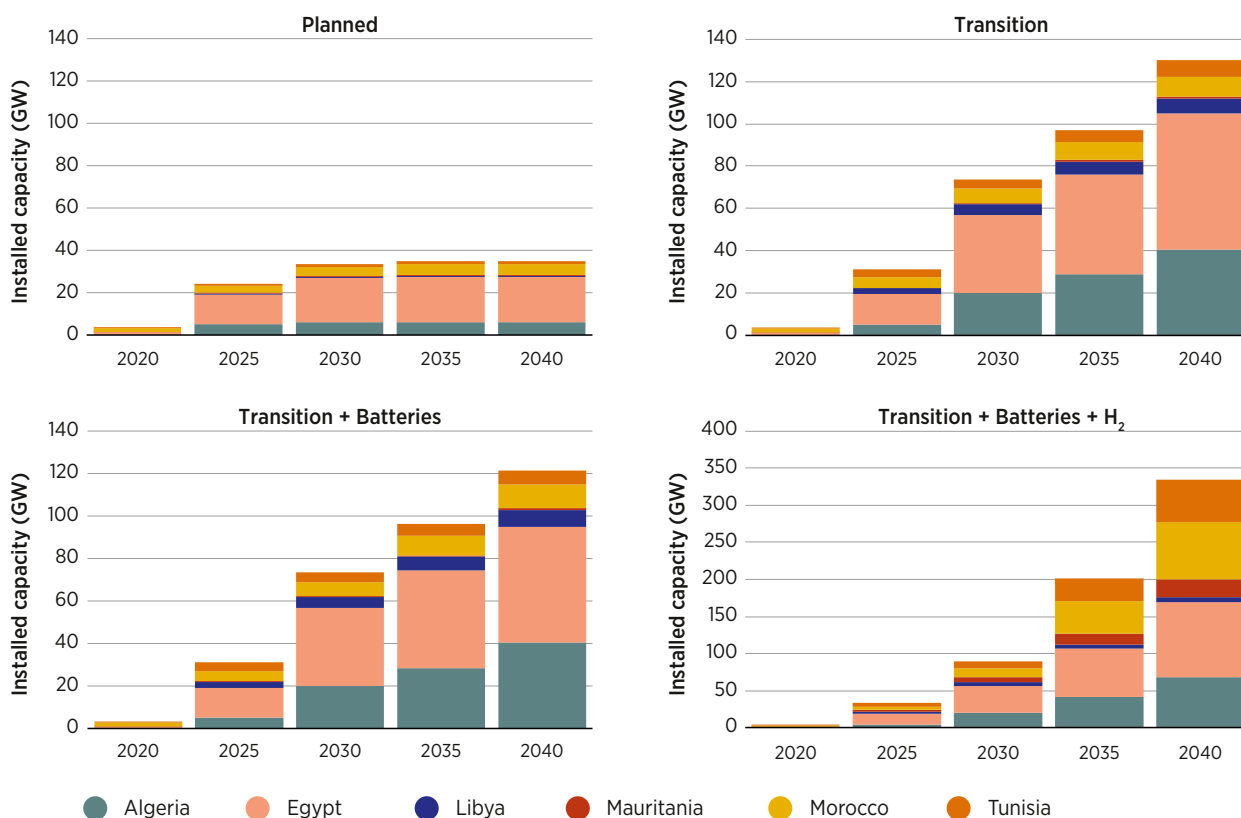
The Planned scenario leads to the lowest development of wind capacity. By 2040, under that scenario, a total of just 35 GW wind capacity is installed in the region, more than half of it in Egypt (21 GW).

Wind capacity is significantly increased in the Transition scenario, reaching 130 GW wind by 2040. As in the Planned scenario, half of this capacity is installed in Egypt (65 GW). In this scenario, curtailment of wind energy is observed at different times of the year. The effective capacity factor of wind power plants in the region in 2040 – that is, the energy produced and sent out to the grid – falls from 50.5% in the Planned scenario to 42% in the Transition scenario.

The Transition + Batteries scenario is characterised by a slightly lower installed wind capacity than in the Transition scenario (121 GW, or 9 GW less than the Transition scenario). This is explained by the higher development of solar PV installed capacity as well as the introduction of batteries, which reduce curtailment by storing electricity. The effective capacity factor of wind power plants in the region in 2040 rises in this scenario compared with the Transition scenario (where batteries are not available) from 42% to 45.5%.

As mentioned previously, the introduction of hydrogen production for export leads to a boom in renewable energy capacity, including wind energy. By 2040, 334 GW of wind capacity is installed in the region, almost three times more than in the Transition + Batteries scenario. The country leading this deployment is still

Figure 2-10 New installed wind capacity by country in the four scenarios



Note: GW = gigawatt; H₂ = hydrogen.

Egypt, with a wind capacity of 100 GW in 2040, but its share in total wind capacity is lower than in the other scenarios, because Morocco, Algeria and Tunisia also boost their wind capacity to produce renewable hydrogen (reaching 77 GW, 69 GW and 58 GW, respectively). In this scenario, less wind is curtailed than the Transition + Batteries scenario; the effective capacity factor of wind reaches 46%, compared with 45.5% in the Transition + Batteries scenario.

The pace at which wind capacity is deployed in North Africa differs across the scenarios. While additions to wind capacity stagnate in the Planned scenario after 2030, once national targets are reached, the Transition + Batteries + H₂ scenario maintains a steady pace, with additional capacity expanding until the end of the modelling period. The average annual growth rate of wind capacity during the period 2030-2040 is close to zero in the Planned scenario, 5.5% in the Transition scenario, 4.3% in the Transition + Batteries scenario and 14.1% in the Transition + Batteries + H₂ scenario.

2.7 BATTERY STORAGE AND HYDROGEN PRODUCTION LOWER THE NEED FOR ADDITIONAL CROSS-BORDER INTERCONNECTIVITY

Under all scenarios, the power exchanges of North African countries (within the region as well as with countries outside the region) are significantly greater in 2040 than in 2018, when two-thirds of the 5.5 TWh of gross exchanges took place through the Morocco-Spain interconnection. As shown in Table 2-8, the 2040 volume of power trade between the countries of the region and outside the region swells from 23.6 TWh in the Planned scenario (of which 7.1 TWh is within the region) to 69.5 TWh in the Transition scenario (of which 32.3 TWh within the region), 55.5 TWh in the Transition + Batteries scenario (of which 25.5 TWh within the region) and 42.6 TWh in the Transition + Batteries + H₂ Scenario in 2040 (of which 21.3 TWh within the region).

The exchange price assumptions within the region and with the neighbouring regions, shown in Figure 2-11, are based on the historical hourly prices in Spain and Italy as published (GME, 2021; OMIE, 2021). Hourly prices are not available on interconnections between Egypt and Jordan, or between Egypt/Sudan and Egypt/Saudi Arabia. For those interconnections we assign a constant price for the year based on the 2019 price on the Egypt-Jordan interconnection (NEPCO, 2019).

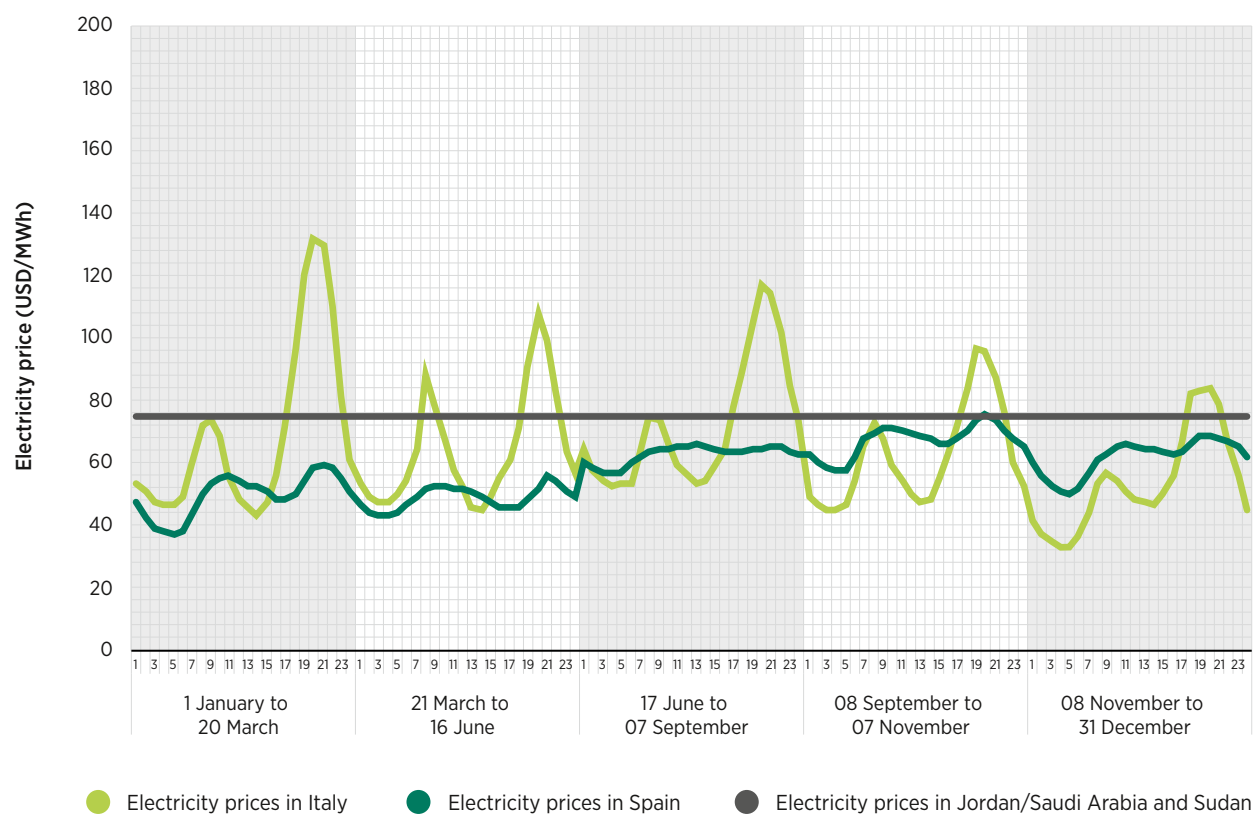
The volume of electricity traded by North African countries in 2040 is lowest in the Planned scenario, with a total of 23.7 TWh exchanged, most of it traded with countries outside North Africa (Spain and Italy). This still corresponds to a fivefold increase in trade between 2018 and 2040. The present constraint on exchange between the countries of the region is the lack of trade mechanisms and the settings put on these lines, even though the physical capacities of the interconnection lines are sufficient to allow more exchange.

Interconnections play a significantly higher role in the Transition scenario. The total trade flow is three times that in the Planned scenario (69.5 TWh), and half of this being intra-regional power trade. Clearly, it is cost-effective for countries to exploit the spatio-temporal complementarities of VRE by expanding cross-border transmission capacity rather than allowing each country to relying solely on the VRE resources within its own borders. These complementarities play out at multiple scales (across the day-night cycle, across seasons, and across time zones); details are provided in section 3.3.

When introducing batteries to this Transition scenario, the need for power exchanges is reduced (to 55.5 TWh), as batteries provide an alternative flexibility measure. If the region begins to produce hydrogen, the total traded volume decreases further (to 42.6 TWh). The opportunity of using electricity to produce hydrogen and export it at an assumed price of USD 2/kilogramme of hydrogen (kgH₂) (see Box 2-3) becomes more cost-effective in this scenario than exporting electricity. The total trade flows of electricity between countries under the four scenarios are represented in Figure 2-12.

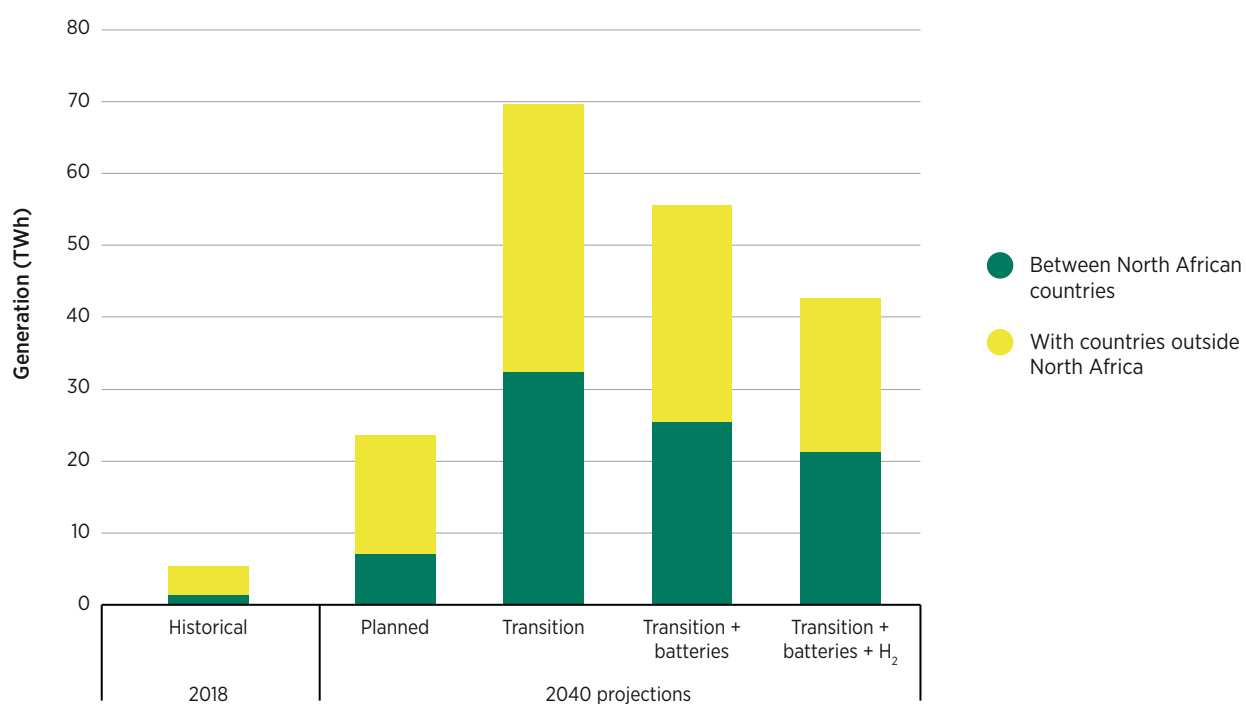
Figure 2-13 shows the gross exports and imports for each country in the results of the four scenarios.

Figure 2-11 Model assumptions (constraints) on exchange prices between North African countries and neighbouring regions



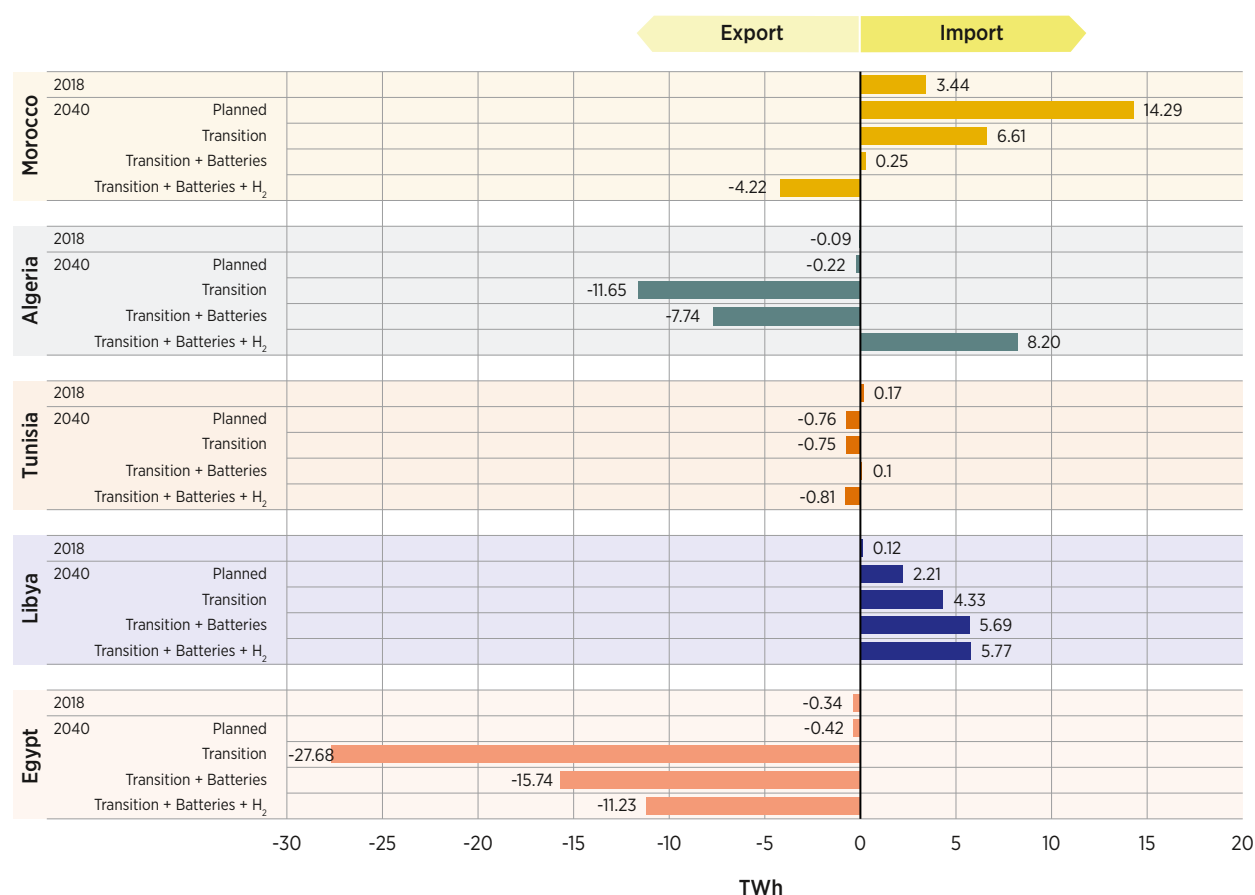
Note: MWh = megawatt hour; NAPP = North African Power Pool.

Figure 2-12 Total electricity trade flows in 2040 in the four scenarios



Note: TWh = terawatt hour.

Figure 2-13 Gross exports and imports of electricity in North African countries in the four scenarios, 2018 and 2040



Note: H₂ = hydrogen; GWh = gigawatt hour.

To assess the impact of export prices on the results, we run a sensitivity test considering various prices of exports from Egypt to Jordan, Saudi Arabia and Sudan. Table 2-7 shows the results. Lower export prices do not lead to a decrease in exports in the Transition scenario owing to the availability of electricity generation that would otherwise be curtailed. When batteries are considered as an option (the Transition + Batteries scenario), lower export prices lead to more batteries being installed in Egypt and less electricity being exported outside the region; at the same time, slightly more electricity is exported within the region (to Libya). When hydrogen is added (the Transition + Batteries + H₂ scenario), lower prices of exports outside the region lead to a further reduction of exports and slightly more batteries being installed.



Table 2-7 Sensitivity of scenario results to prices of exports from Egypt to outside North Africa

PRICE OF EXPORTS FROM EGYPT TO COUNTRIES OUTSIDE THE REGION IN USD/MWH	75	67.5	60	37.5	15
Exports from Egypt to outside the region in 2040 (GWh)					
Planned scenario	0	0	0	0	0
Transition scenario	23 739	23 672	23 128	22 634	21 527
Transition + Batteries scenario	14 832	12 544	9 097	2 169	1 099
Transition + Batteries + H ₂ scenario	8 156	5 355	5 106	0	0
Battery storage capacity in Egypt by 2040 (MW)					
Planned scenario	0	0	0	0	0
Transition scenario	0	0	0	0	0
Transition + Batteries scenario	6 681	7 339	8 428	10 634	10 471
Transition + Batteries + H ₂ scenario	7 696	7 867	8 040	9 714	10 122
Exports from Egypt to Libya in 2040 (GWh)					
Planned scenario	415	415	415	415	415
Transition scenario	6 598	6 796	8 600	8 481	8 795
Transition + Batteries scenario	4 539	5 057	5 851	6 861	8 286
Transition + Batteries + H ₂ scenario	3 972	3 991	3 873	4 012	3 945

Note: GWh = gigawatt hour; MW = megawatt; MWh = megawatt hour.

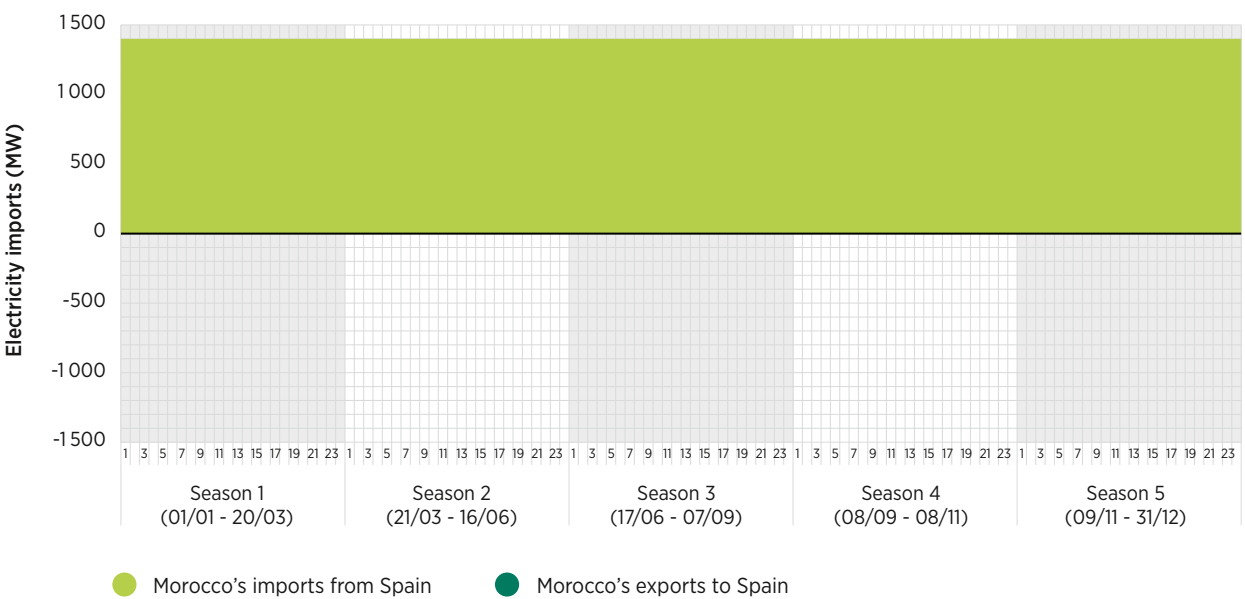
Looking at the daily and seasonal profiles of exports and imports between the countries provides a better understanding of the observed trade flows. In the results of the Planned scenario, Morocco imports at a nearly constant capacity from Spain and Algeria (Figure 2-14 and Figure 2-15). Algeria imports from Tunisia during all seasons and all hours of the day, except during the evening peak load in Tunisia, when Tunisia is importing from Algeria (Figure 2-16). Tunisia exports to Libya as well, especially during the summer season (Figure 2-17). Furthermore, the flow on the interconnection line between Tunisia and Italy is used more intensely from Italy to Tunisia than in the other direction. This is due to the low electricity prices during the offload periods in Italy (during the night) and low prices during Italy's solar power availability (Figure 2-18). In this scenario, the electricity exchange between Libya and Egypt turns out to be characterised by a flow from the latter to the former in summer and equilibrium in other seasons (Figure 2-19). Finally, in this scenario, there is no electricity trade between Egypt and Jordan/Sudan because of the price assumptions considered.

The flow patterns in 2040 are different in the Transition scenario, where a higher level of renewable energy is deployed. Exports from Spain to Morocco remain important, balanced by exports from Morocco to Spain during periods of excess solar power generation. Additionally, Morocco simultaneously imports electricity from Algeria that is added to exports to Spain (Morocco becoming the transit country). This is shown in Figure 2-20, which illustrates the average daily profile of exports from Algeria to Morocco and from Morocco to Spain. A similar pattern is seen in all interconnected countries of the region, with interconnection balancing the surplus of generation of solar energy. This leads to balanced exchanges of electricity in both directions on most interconnection lines (bidirectional, rather than unidirectional, trade patterns). The patterns of flows in the Transition + Batteries scenario are similar to those seen in the Transition scenario.

All trade flows in 2040 are presented in the diagrams in Figure 2-23.

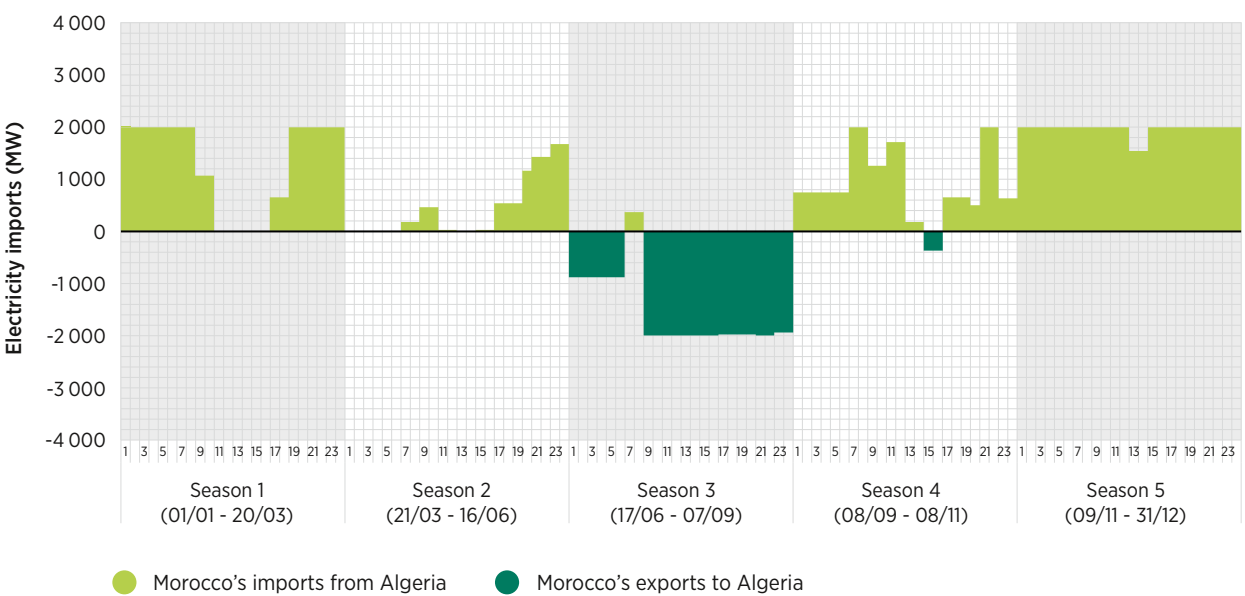
The general presence of bidirectionality may mitigate the danger of countries becoming overly dependent on their neighbours’ electricity generation. Further, the introduction of utility-scale storage and of hydrogen production technology reduces the overall recourse to exchanges (Table 2-8), further reducing potential worries about high dependency on electricity imports.

Figure 2-14 Morocco’s imports from Spain in the Planned scenario, 2040



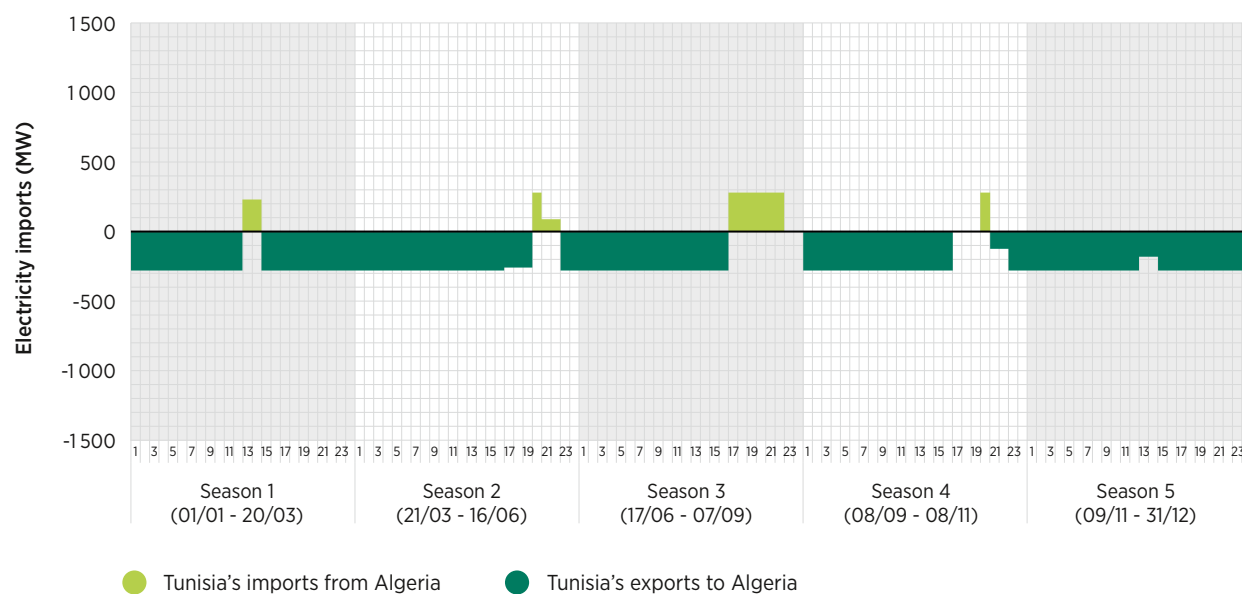
Note: MW = megawatt.

Figure 2-15 Morocco’s imports from Algeria in the Planned scenario, 2040



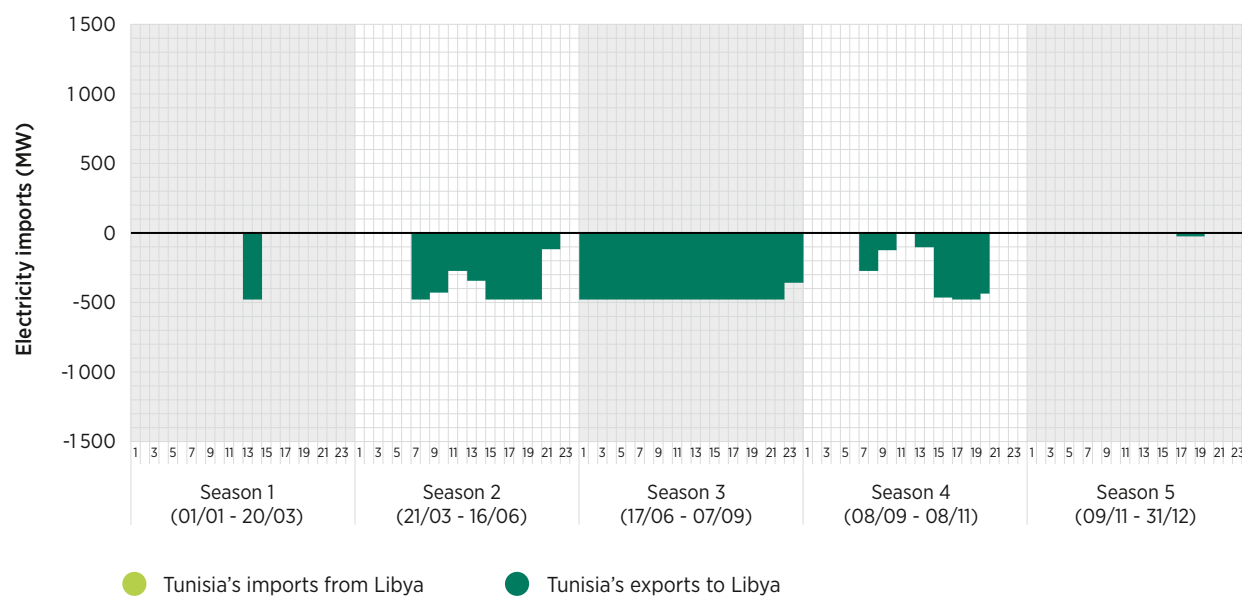
Note: MW = megawatt.

Figure 2-16 Tunisia's imports from Algeria in the Planned scenario, 2040



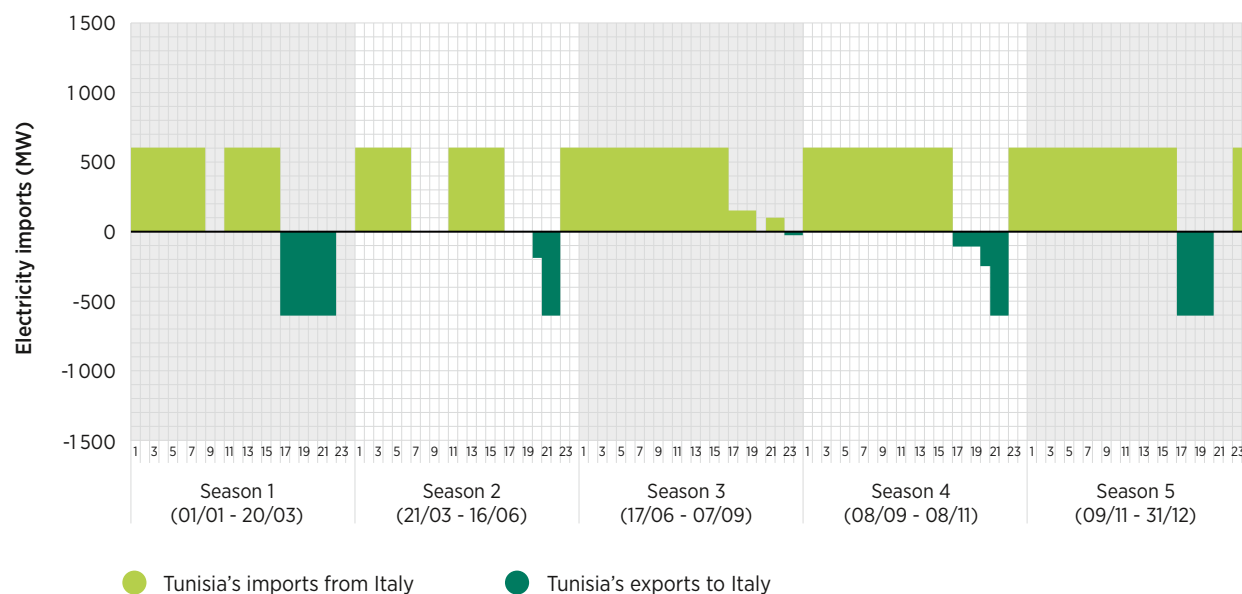
Note: MW = megawatt.

Figure 2-17 Tunisia's imports from Libya in the Planned scenario, 2040



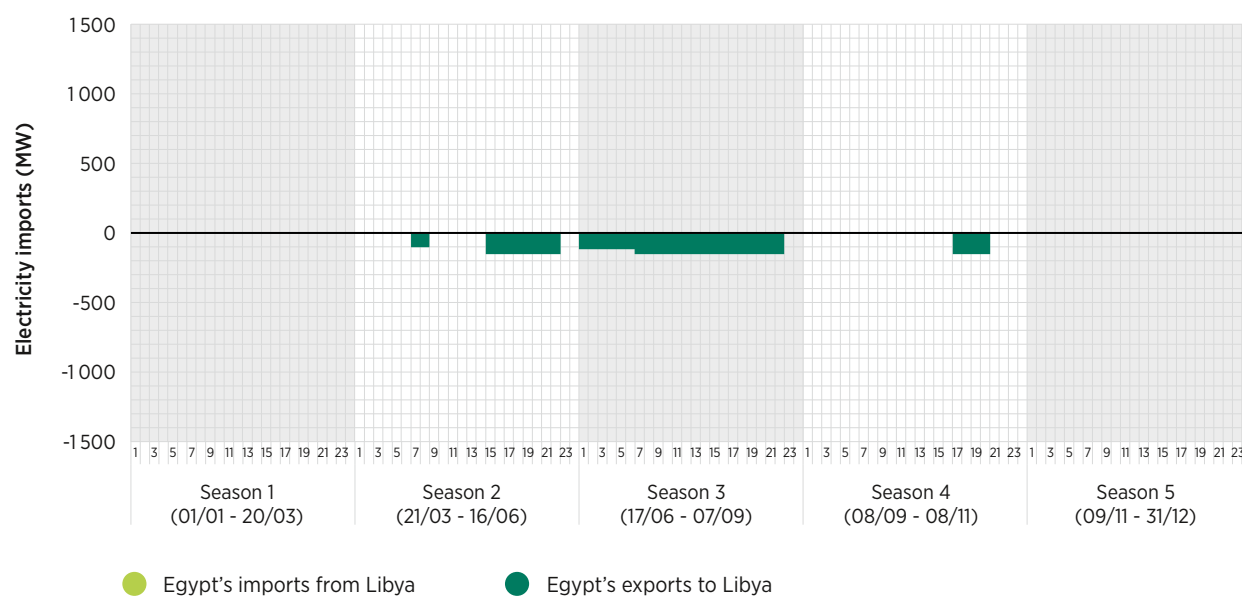
Note: MW = megawatt.

Figure 2-18 Tunisia's imports from Italy in the Planned scenario, 2040



Note: MW = megawatt.

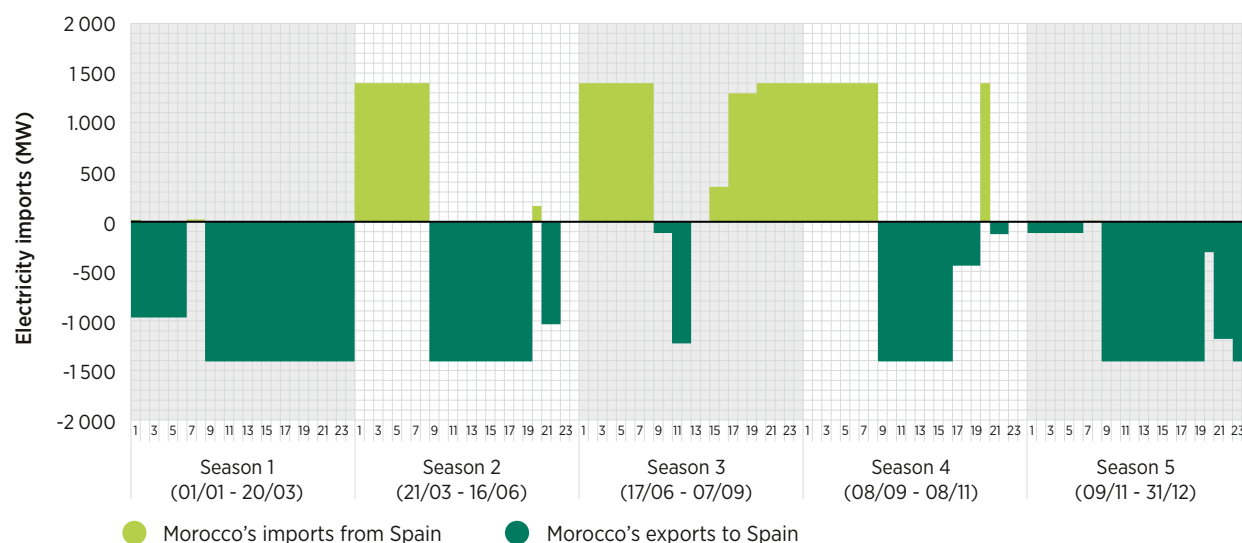
Figure 2-19 Egypt's imports from Libya in the Planned scenario, 2040



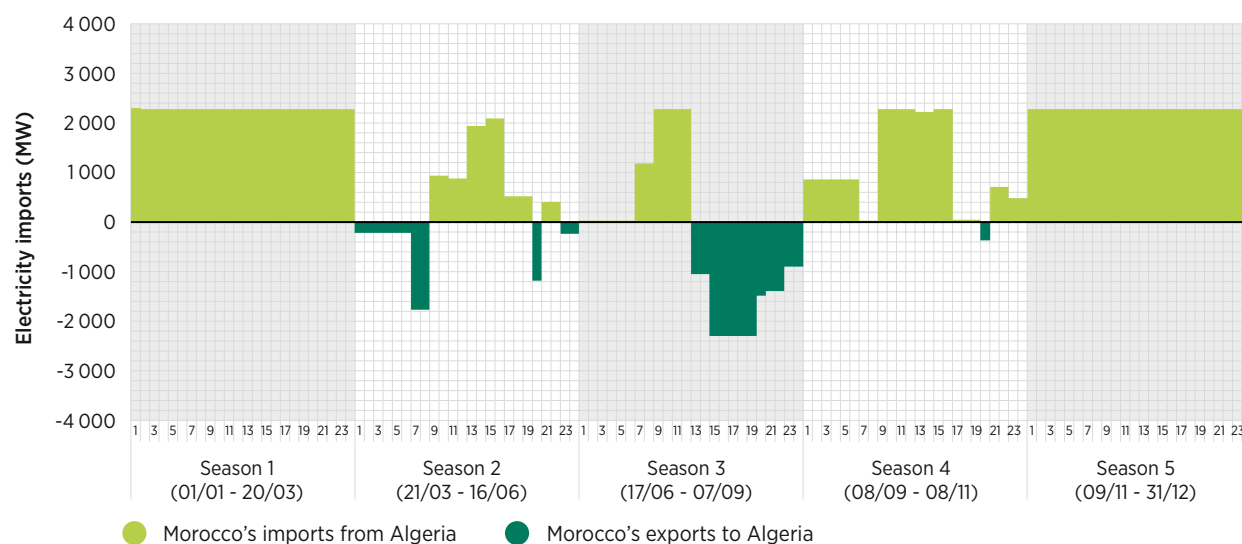
Note: MW = megawatt.

Figure 2-20 Daily profiles of exports in the Transition scenario, 2040

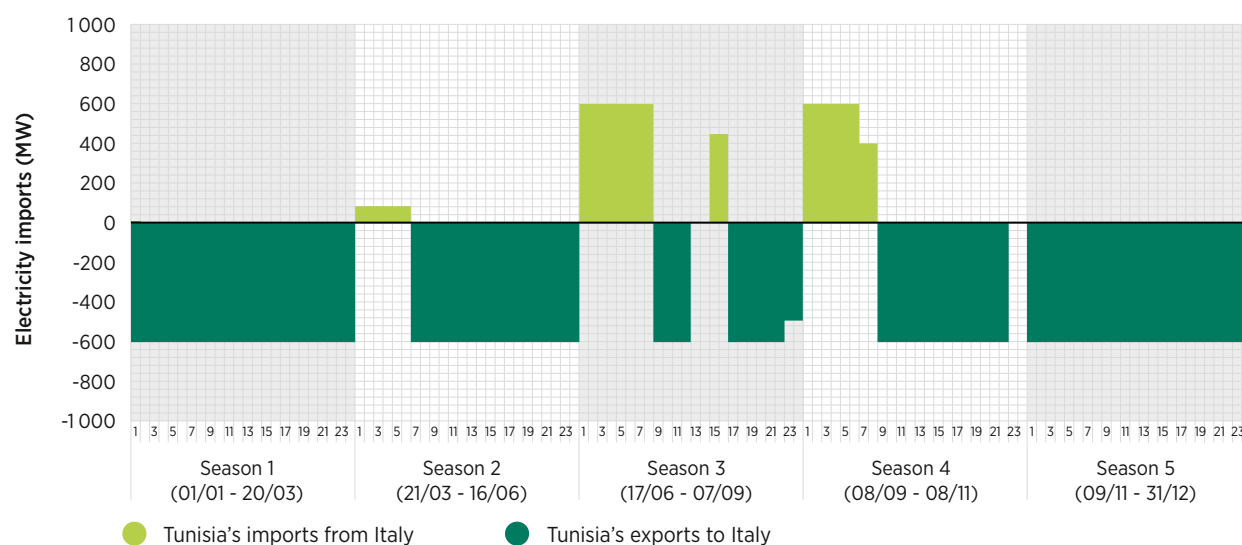
Morocco's imports from Spain - Transition Scenario



Morocco's imports from Algeria - Transition Scenario



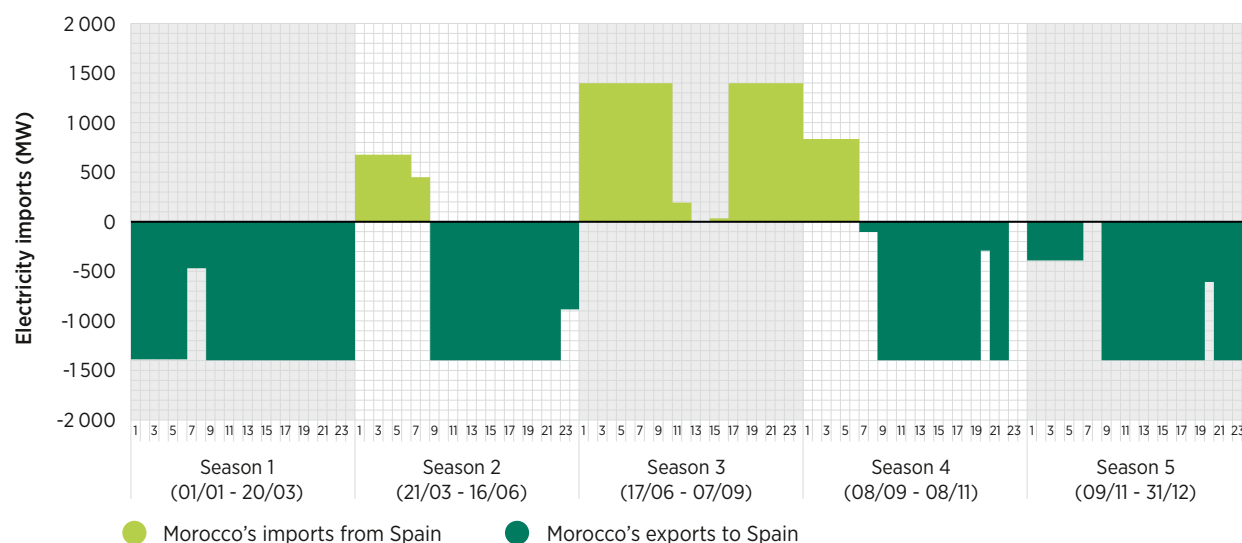
Tunisia's imports from Italy - Transition Scenario



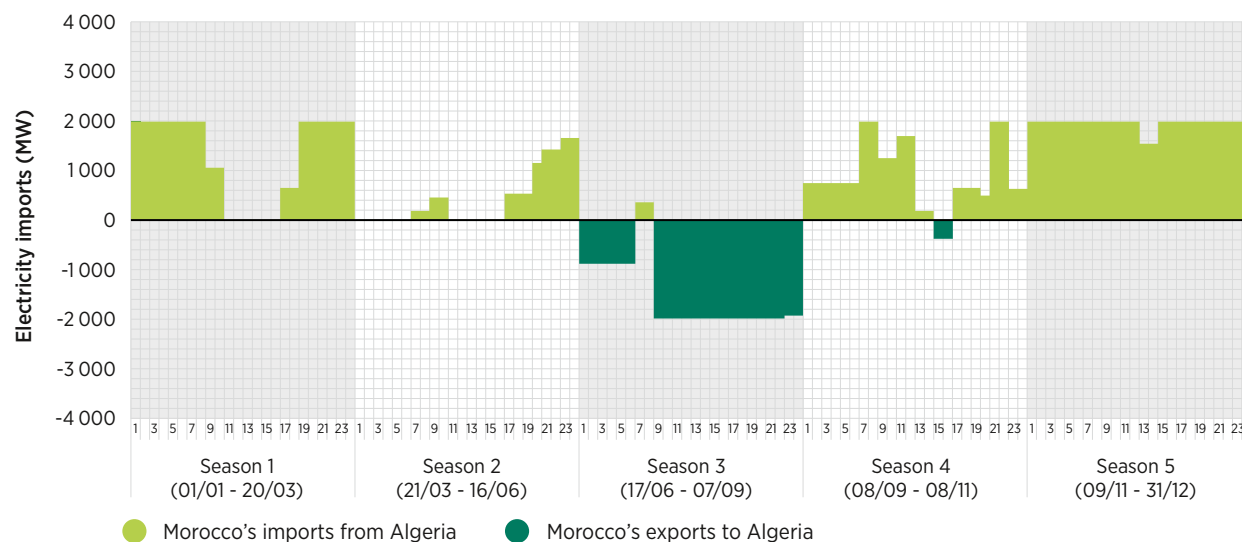
Note: MW = megawatt.

Figure 2-21 Daily profiles of exchanges in the Transition + Batteries scenario, 2040

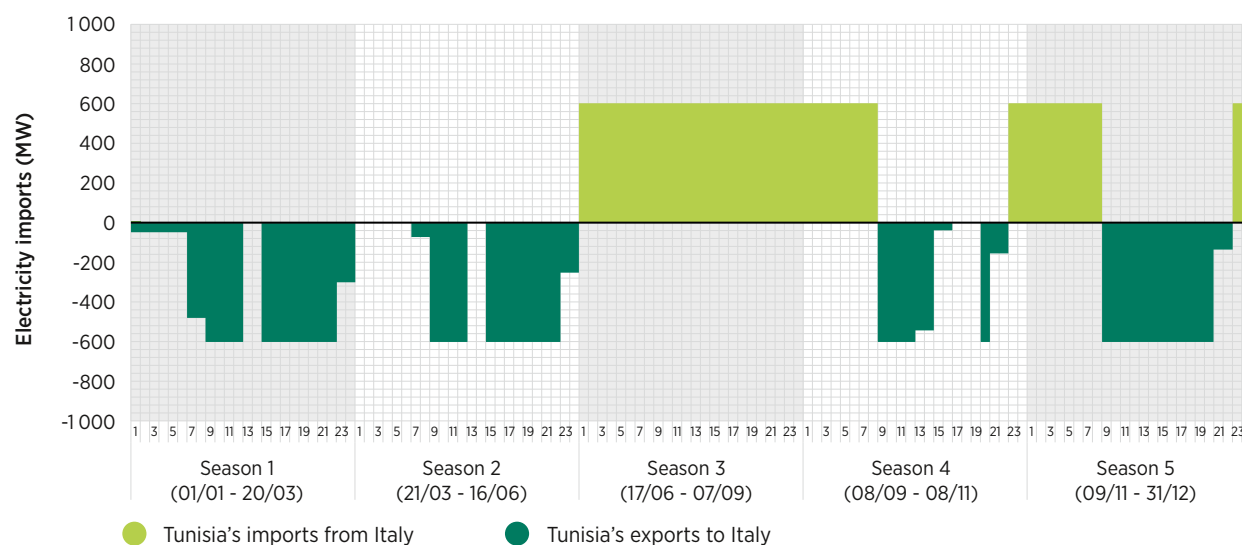
Morocco's imports from Spain - Transition + Batteries Scenario



Morocco's imports from Algeria - Transition + Batteries Scenario



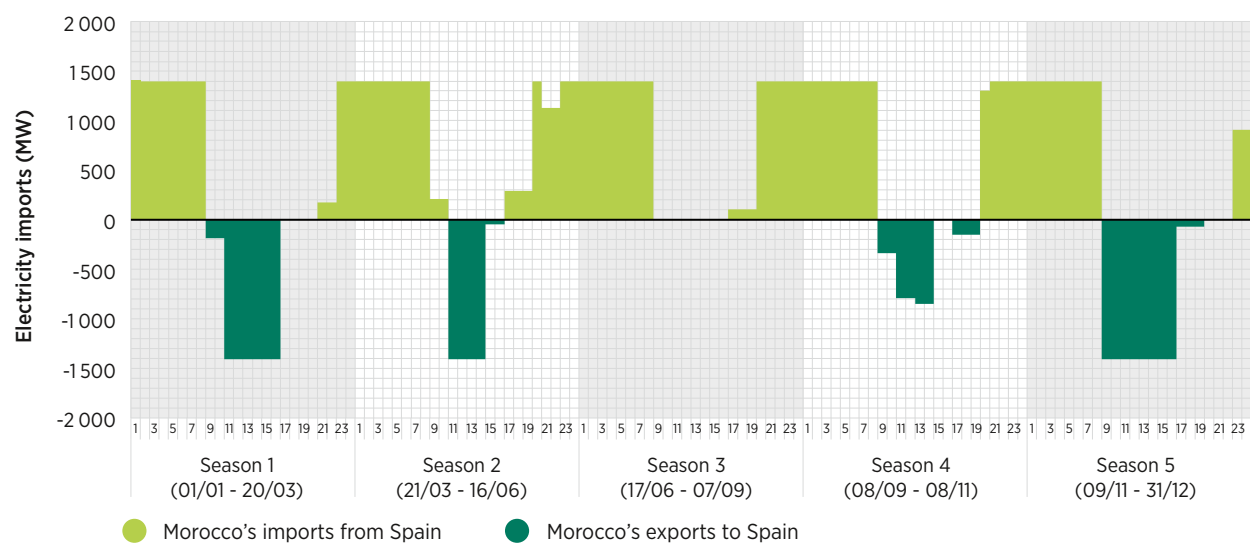
Tunisia's imports from Italy - Transition + Batteries Scenario



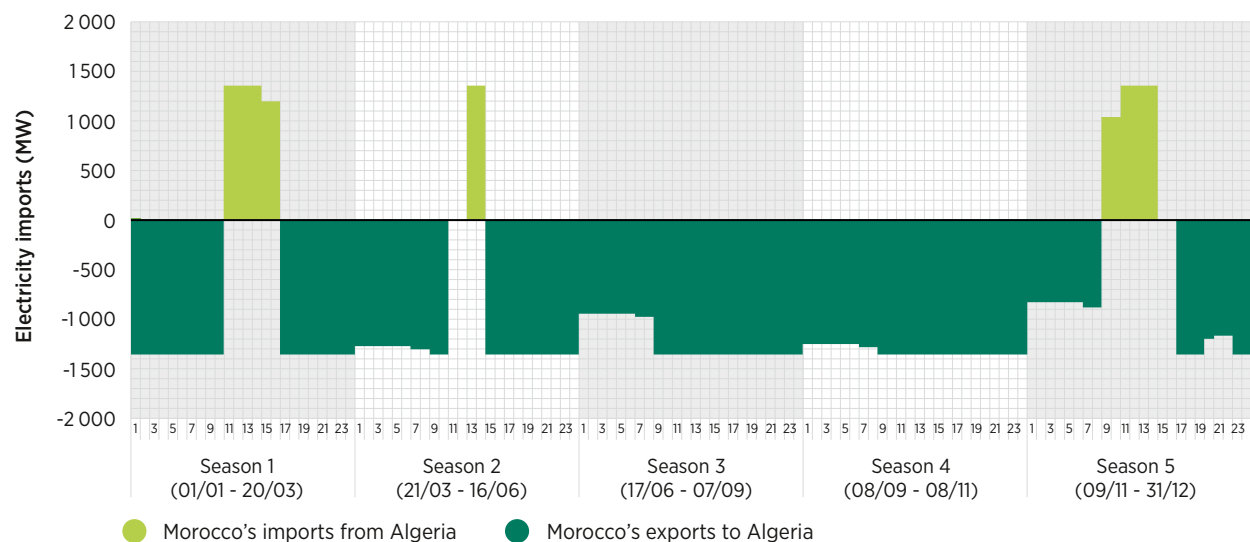
Note: MW = megawatt.

Figure 2-22 Daily profiles of exchanges in the Transition + Batteries + H₂ scenario, 2040

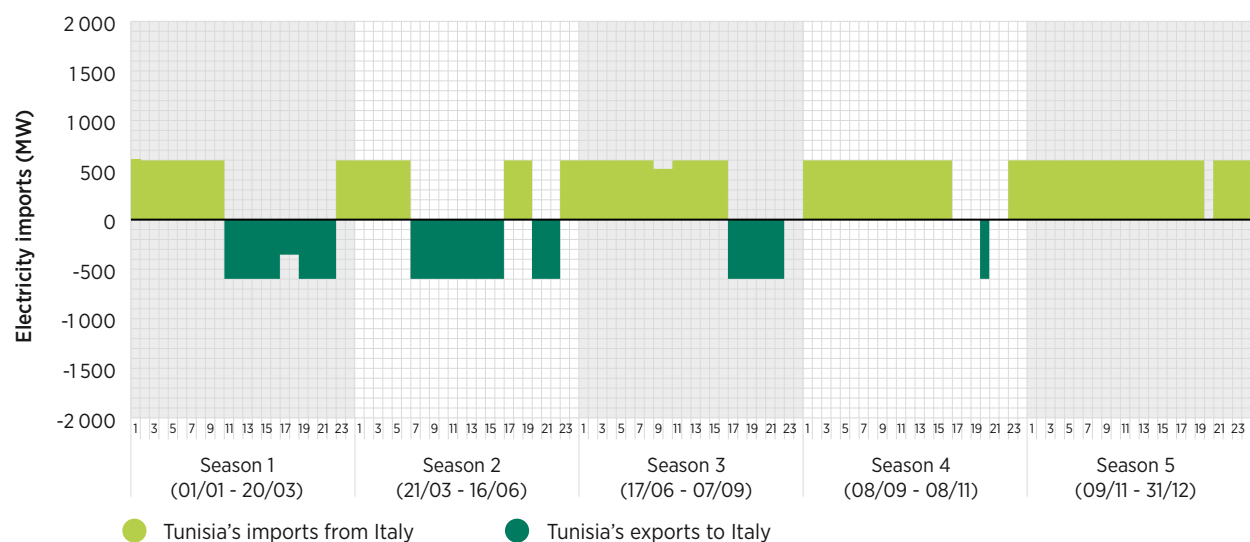
Morocco's imports from Spain - Transition + Batteries + H₂ Scenario



Morocco's imports from Algeria - Transition + Batteries + H₂ Scenario



Tunisia's imports from Italy - Transition + Batteries + H₂ Scenario



Note: H₂ = hydrogen; MW = megawatt.

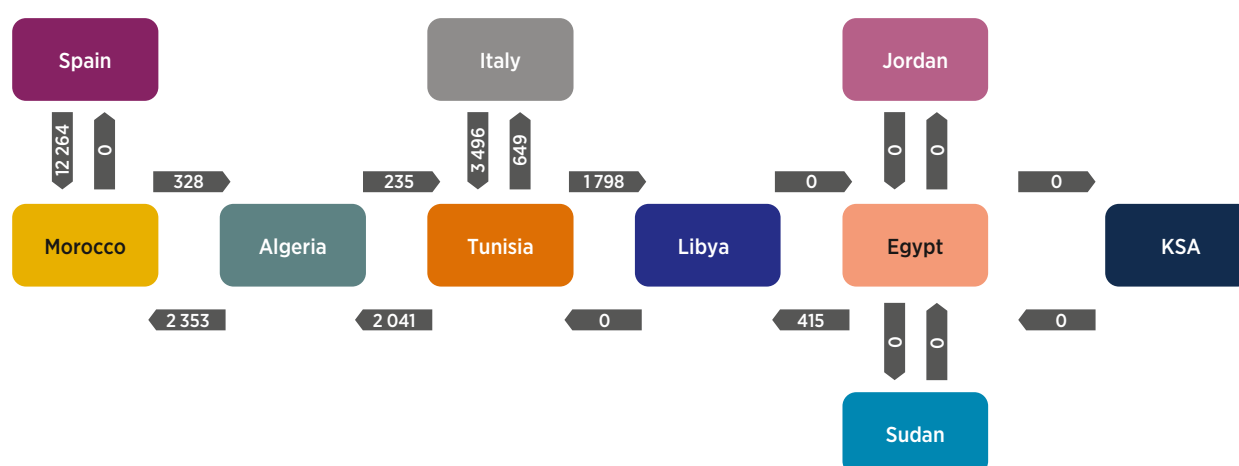
Table 2-8 Share of power exchanges in total electricity demand in North Africa

YEAR	SCENARIO	TOTAL SENT-OUT ELECTRICITY (TWH)	POWER EXCHANGES (TWH)	SHARE OF POWER EXCHANGES IN TOTAL POWER DEMAND
2018	Historical	363	6	1.5%
2040	Planned scenario	662	24	3.6%
	Transition scenario	795	69	8.7%
	Transition + Batteries scenario	795	56	7.0%
	Transition + Batteries + H ₂ scenario	795	43	5.4%

Note: H₂ = hydrogen; NA = North Africa; TWh = terawatt hour.

Figure 2-23 Electricity exchanges in North Africa in the four scenarios, 2040 (GWh)

Planned scenario 2040 – Exchanges in GWh



Transition scenario 2040 – Exchanges in GWh

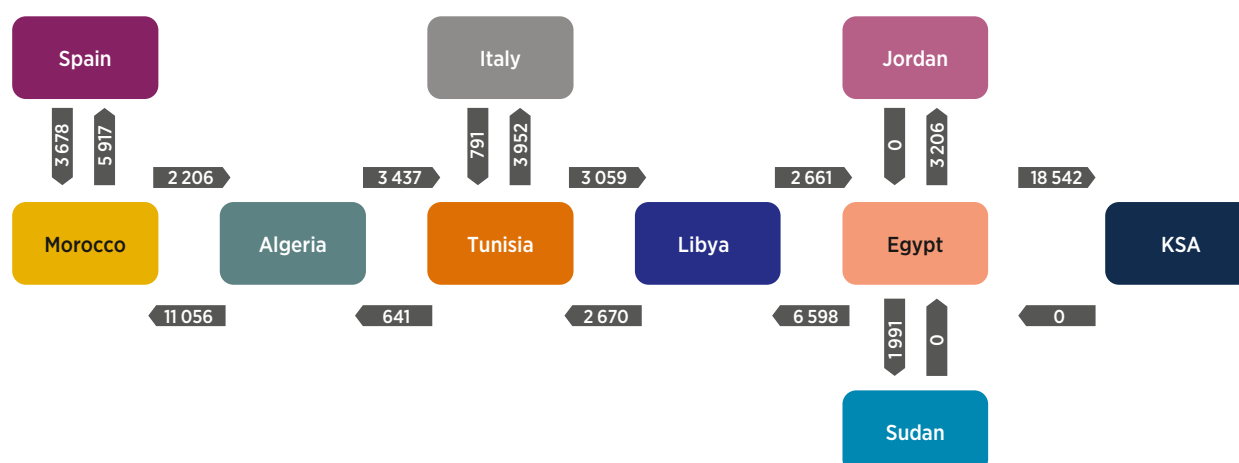
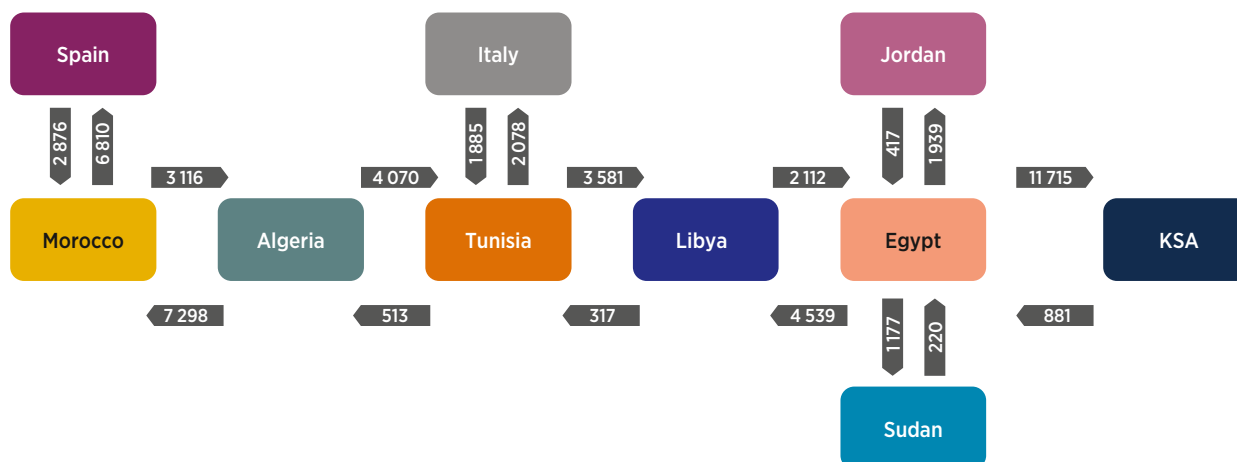
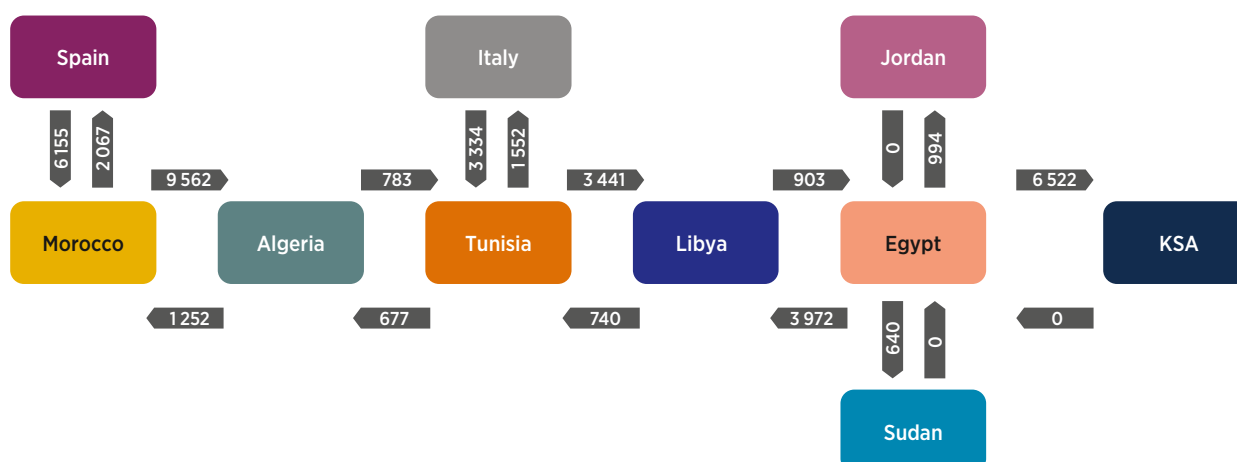


Figure 2-23 Electricity exchanges in North Africa in the four scenarios, 2040 (GWh)
(continued)

Transition + Batteries scenario 2040 – Exchanges in GWh



Transition + Batteries + H₂ scenario 2040 – Exchanges in GWh



Note: GWh = gigawatt hour; H₂ = hydrogen; KSA = Kingdom of Saudi Arabia.

2.8 THE NEED FOR BATTERY STORAGE INCREASES WITH THE SHARE OF VARIABLE RENEWABLES IN THE ENERGY MIX

Battery storage is considered an option for all countries starting from 2025 in the Transition + Batteries and Transition + Batteries + H₂ scenarios (see Box 2-3). In the first, the deployment of batteries begins in 2027. In the second, their deployment starts in 2032.

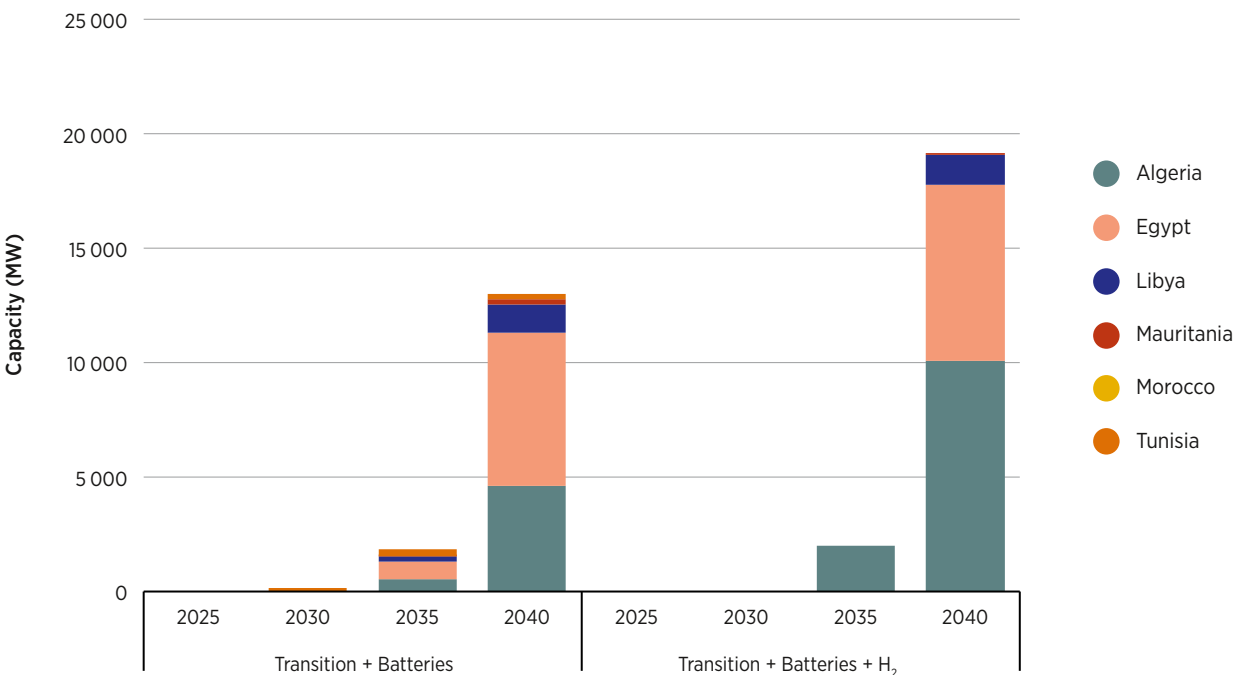
The impact of hydrogen production on battery deployment depends on each country's VRE generation profile, demand profile and the share of solar/wind installed.

The top countries for battery storage in the Transition + Batteries scenario are Egypt and Algeria. In 2040 they have 6.7 GW and 4.6 GW of installed battery storage, respectively. In the Transition + Batteries + H₂ scenario, installed capacity doubles in Algeria whereas it stays at the same level in other countries. In the Transition + Batteries + H₂ scenario, the installed capacity reaches 7.7 GW in Egypt and 10.1 GW in Algeria (Figure 2-24).

Figure 2-25 shows the daily battery use profile of the region’s countries by season. In all countries where this technology is selected by the model, batteries are generally charged when solar power is abundantly available and discharged during the evening peak and at night. In Algeria, Egypt and Libya, the battery use profile does not change when hydrogen production is added. In Tunisia, the introduction of hydrogen removes the need for batteries, and none are installed in the Transition + Batteries + H₂ scenario. The lower capacity needed in Tunisia may be explained by the interconnection with larger power systems (Algeria and Italy).

Like Tunisia in the Transition + Batteries + H₂ scenario and unlike the other countries, Morocco installs no batteries in the Transition + Batteries scenario. This can be explained by its low curtailment rate in the Transition scenario – 10% of available renewable energy is curtailed in 2040 compared with the regional average of 25%. In the Transition + Batteries scenario, more wind capacity is installed in Morocco but no additional solar PV over the Transition scenario. Curtailment reaches 13.6% in 2040 in the Transition + Batteries scenario. Figure 2-26 shows the daily use profile of pumped hydro in Morocco (which corresponds to the Afourer and Abdelmoumen power plants). The availability of this option in Morocco helps explain the country’s low curtailment. Notable is the lower use of pumped hydro in the Transition + Batteries scenario (although no batteries are installed in Morocco) as compared to the preceding scenarios. This can be explained by the batteries installed in neighbouring Algeria to store solar energy produced there, which results in lower exports from Algeria to Morocco in Season 1 and Season 2. In the Transition scenario, this energy was stored by pumped hydro in Morocco and dispatched in the evening.

Figure 2-24 Total installed battery capacity in the Transition + Batteries and the Transition + Batteries + H₂ scenarios



Note: H₂ = hydrogen; MW = megawatt.

Figure 2-25 Daily use profile of batteries by season and by country

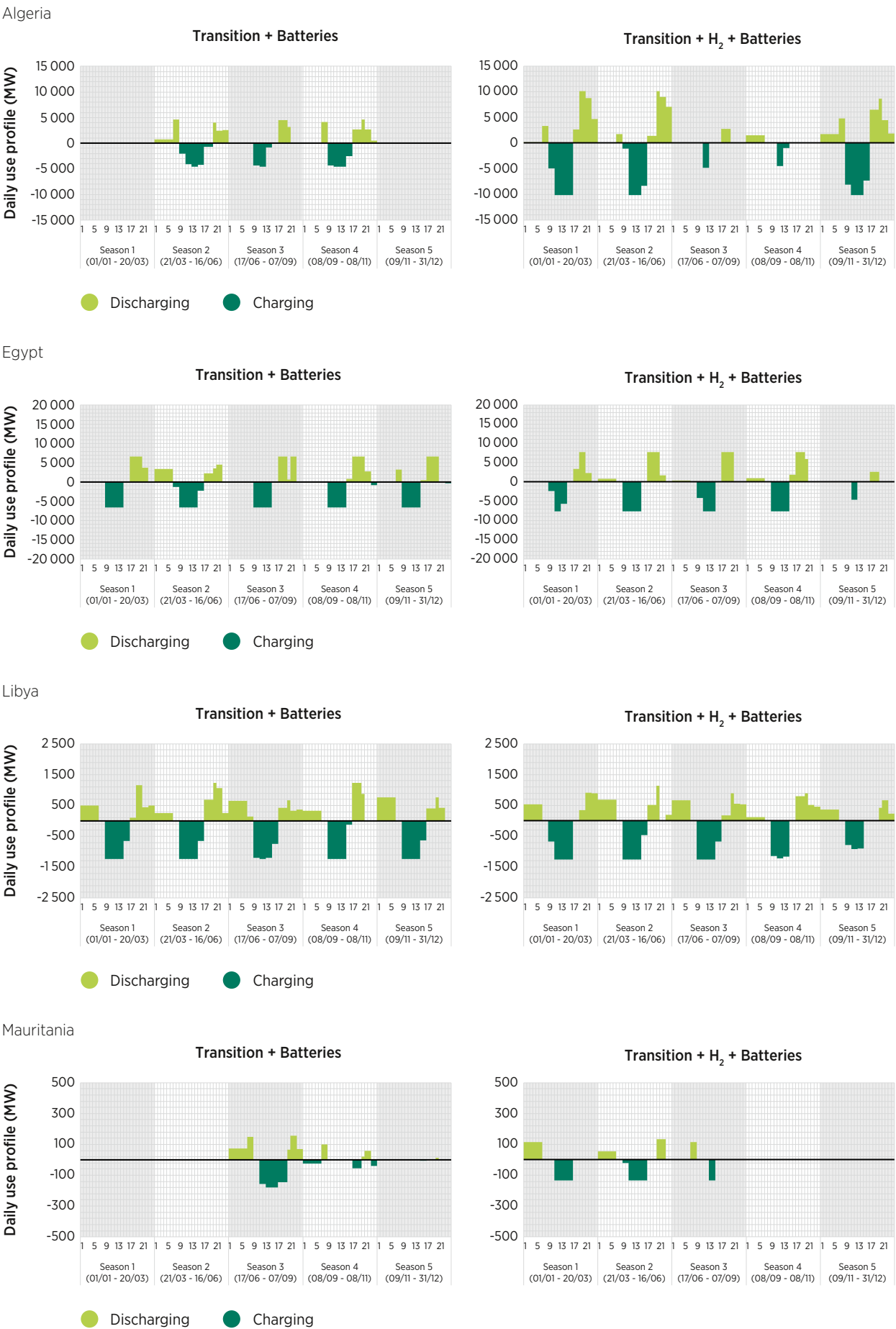
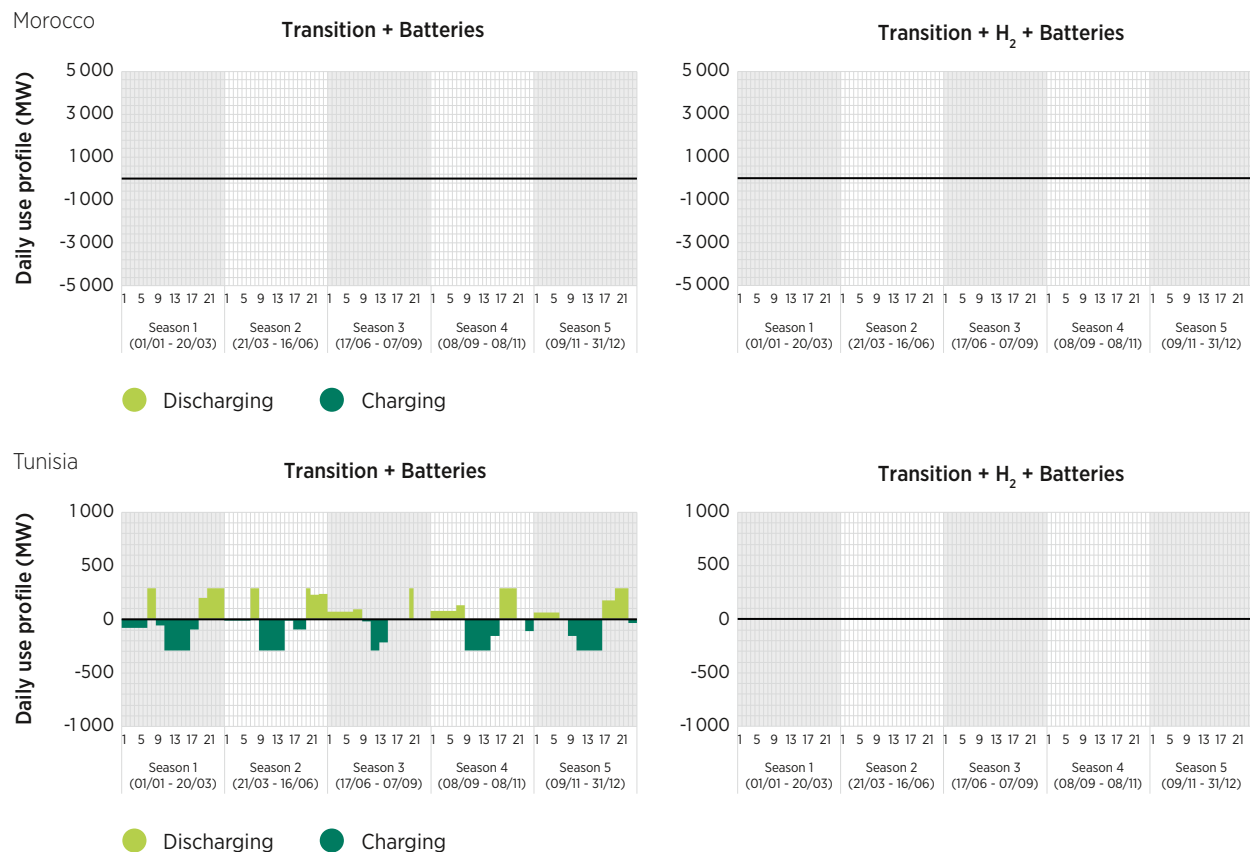
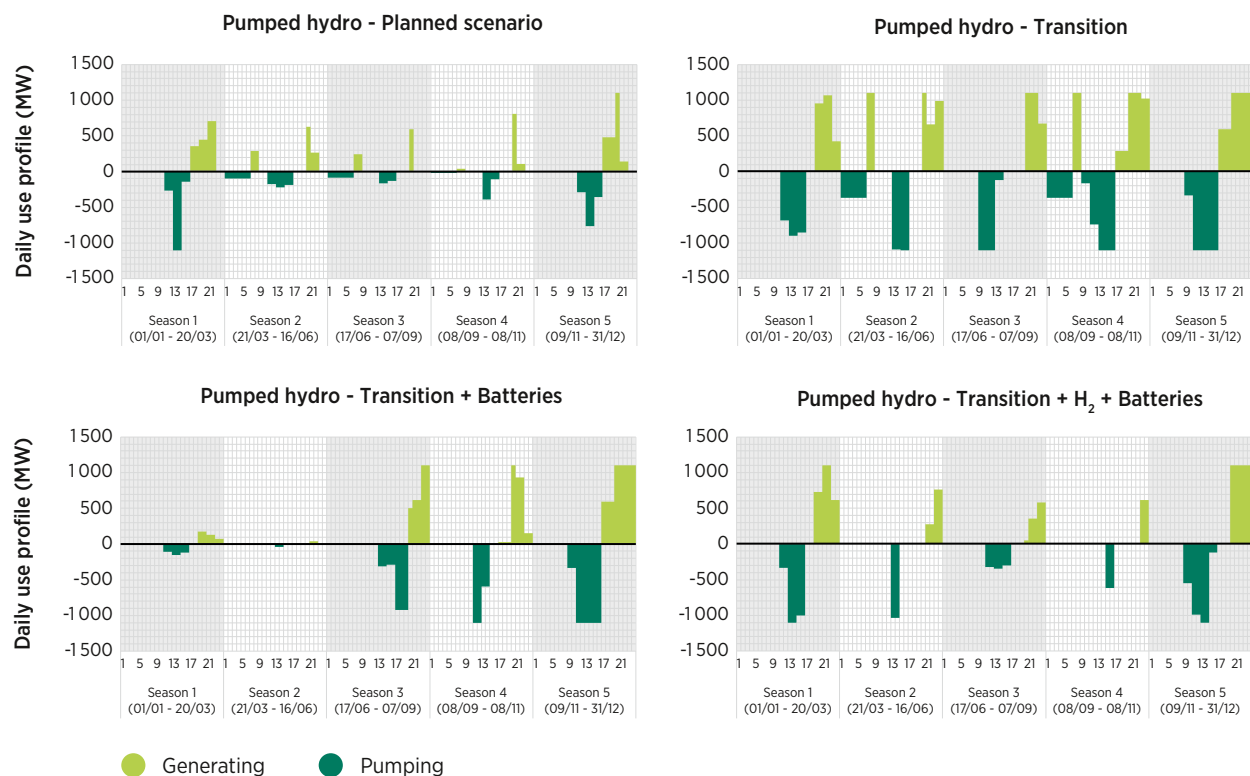


Figure 2-25 Daily use profile of batteries by season and by country (continued)



Note: H₂ = hydrogen; MW = megawatt.

Figure 2-26 Daily use of pumped hydropower in Morocco in all scenarios



Note: H₂ = hydrogen; MW = megawatt.

2.9 GREEN HYDROGEN PRODUCTION, COMBINED WITH VARIABLE RENEWABLES AND STORAGE, COULD BECOME AN INTEGRAL PART OF AN INTERCONNECTED ELECTRICITY SYSTEM

Hydrogen production in North Africa is considered only in the Transition + Batteries + H₂ scenario. Produced from renewable electricity, so-called green hydrogen is assumed to be for export only. The European Hydrogen Backbone (van Rossum *et al.*, 2022) estimates the cost of transporting hydrogen through repurposed offshore pipelines at EUR 0.14-0.15/kgH₂/1 000 kilometre (km) and through new offshore pipelines at EUR 0.32-0.60/kgH₂/1000 km. Transporting hydrogen through repurposed onshore pipelines would cost EUR 0.09-0.12/kgH₂/1000 km, while sending it through new onshore pipelines would cost EUR 0.19-0.35/kgH₂/1000 km. In the case of existing pipelines between North Africa and Europe, the offshore section of the pipelines is less than 250 km for the Transmed, Medgaz and Maghreb-Europe pipelines. In the case of repurposed pipelines, these transportation costs represent between 3% and 10% of the export prices used in this study.

The cost of hydrogen production from renewable electricity sources has two components: the costs associated with the electrolyser (investment, operation and maintenance; see Table A-19 of the accompanying Data appendix [IRENA, 2022b]) and the electricity supplied to it (IRENA, 2020c). The three types of electrolysers – the first coming into service in 2025; the second in 2030; and the third in 2035 – are expected to drop in cost and rise in efficiency over time. All of the foregoing costs are used to calculate the unit cost of the hydrogen produced, with the assumption that the hydrogen plant and the electricity generation plant are completely coupled – that is, that the hydrogen plant is using all the electricity generated by the plant and no other sources of electricity. Figure 2-27 shows that a cost of less than USD 3/kgH₂ is achievable in 2035 in Algeria, Egypt and Morocco, and even from 2030 in Egypt. The use of grid electricity generated by renewable sources (wind and solar) at various locations lowers costs as it benefits from the complementarity of the sources and enables electrolysers to produce hydrogen at a higher capacity factor, as shown in the following section.

As presented in Table A-20 in the Data appendix (IRENA, 2022b), the exogenously assumed hydrogen export price in the model falls from USD 3.5/kgH₂ in 2025 to USD 2/kgH₂ in 2040. These trends are chiefly driven by the declining capital and operating costs of renewable resources (see Table A-16). In the Transition + Batteries + H₂ scenario, the SPLAT-N model optimises the power system to exploit the possibility of exporting hydrogen at the exogenously set price shown in Table A-20. That possibility depends on electrolysers being built at the costs shown in Table 3-19. The model identifies the optimal amounts of electricity to be supplied to end users and to be used to produce hydrogen from the available mix of projects and resources.

To investigate the establishment of a hydrogen supply curve from North Africa, we optimise the model using different hydrogen export prices (USD 1/kgH₂, USD 2/kgH₂, USD 3/kgH₂ and USD 4/kgH₂). Exploiting the synergy between the energy sources (wind and solar) produces better electrolyser capacity factors and thus lower costs at an earlier point. The hydrogen supply curve resulting from the modelling is shown in Figure 2-28. In 2040, 23.6 megatonnes (Mt) of hydrogen could be produced in North Africa at the cost of USD 2/kgH₂ or less. In 2030, 1.9 Mt could be produced at the same cost.

The region's hydrogen production and electrolyser capacity in the Transition + Batteries + H₂ scenario are presented in Figure 2-29. Hydrogen production, which is assumed to be viable in five countries (Algeria, Egypt, Mauritania, Morocco and Tunisia), begins in Mauritania and Tunisia in 2025, followed by the three other countries in 2030. The total production in the region remains below 0.5 MtH₂/year between 2025 and 2029, before accelerating between 2030 and 2034 at a 41% average yearly growth rate (from 1.8 MtH₂ in 2030 to 7.2 MtH₂ in 2034). Growth is sustained until the end of the modelling period. The average yearly growth rate between 2035 and 2040 is 16%, with production growing from 11.3 MtH₂ in 2035 to 23.6 MtH₂ in 2040 thanks to the availability of cheaper and more efficient electrolysers. In 2040, hydrogen production in the

region is led by Morocco (6.3 MtH₂/year), followed by Algeria, Egypt, Mauritania and Tunisia (4.6, 4.6, 3.0 and 5.2 MtH₂/year, respectively). North Africa's electrolyser capacity expands from 13.6 GW in 2030 to 82.2 GW in 2035 before reaching 156 GW in 2040. Figure 2-29 also shows the evolution of the additional solar PV and wind capacity required for hydrogen production. In 2040, 327 GW of additional variable renewable capacity is needed to produce hydrogen, of which 213 GW are wind powered and 114 GW solar PV powered.

These results are worth comparing with other hydrogen projections in global, regional and national reports that have been published over the past few years. Table 2-9 and Table 2-10 present a comparison of hydrogen demand projections and electrolyser capacity estimates, respectively. More details can be found in the Data appendix (IRENA, 2022b).

As shown in Table 2-9, other sources project global hydrogen demand in the range of 80-200 MtH₂ in 2030, and 95-400 MtH₂ in 2040. North African production in our Transition + Batteries + H₂ scenario would thus represent 1-2% of the worldwide demand projected in those scenarios in 2030, and 6-25% in 2040. Other hydrogen demand projections have also been developed at the European level. The European Union has predicted hydrogen demand of 20 Mt in 2030 of which 10 Mt would be imported from neighbouring countries (European Commission, 2022a). According to the European Hydrogen Backbone study (EHB, 2021), Europe would need 10 Mt of hydrogen in 2030 and 40 Mt in 2040 to meet its demand, meaning that North Africa's production in the Transition + Batteries + H₂ scenario would represent 18% (1.8 MtH₂) and 59% (23.6 MtH₂) of European demand in 2030 and 2040, respectively. However, the share of hydrogen supplied by North Africa in 2030 could be significantly larger at a hydrogen price of USD 3/kgH₂. In that case, North Africa could supply 4.0 MtH₂ of hydrogen in 2030, equivalent to 40% of EHB's projected demand. Considering demand at the national level, Germany estimates in its hydrogen strategy that its hydrogen demand will be 2.7-3.3 MtH₂ by 2030, 15% of which will be supplied by electrolyzers installed in Germany (0.42 MtH₂) and the rest imported (2.5 MtH₂) (Federal Ministry for Economic Affairs and Energy, 2020). With a production of 1.8 MtH₂ of renewable hydrogen in 2030, North Africa could thus cover around 72% of the German imports. At a hydrogen price of USD 3/kgH₂, the North African hydrogen production potential would reach 4.0 MtH₂ in 2030, thus covering all German imports.

With regards to hydrogen production capacity, a comparison with the targets announced by several European countries that have published hydrogen strategies shows that the North African electrolyser capacity in 2030 resulting from the modelling (13.6 GW) would be a little less than three times that targeted by Germany, Italy or the United Kingdom (5 GW), and double the 6.5 GW capacity planned by France. An inventory of the various hydrogen capacity targets set by European countries can be found in Figure A-1 in section 1.6 of the accompanying Data appendix (IRENA, 2022b). Moreover, the North African electrolyser capacity in 2030 would represent 34% of the 40 GW that could be built in the Eastern and Southern neighbours of the European Union (such as Ukraine and North Africa) to cover EU hydrogen demand, according to the 2x40 GW Green Hydrogen Initiative supported by the European Commission (European Commission, 2020; Hydrogen Europe, 2020). At a global level, recent studies have estimated the electrolyser capacity that could be achieved worldwide, a selection of which can be found in Figure A-3 of the Data appendix (IRENA, 2022b). Overall, the projected electrolyser capacity in North Africa in 2030 in the Transition + Batteries + H₂ scenario would account for 5% of the 270 GW capacity projected in IRENA's Transforming Energy Scenario (IRENA, 2020d).

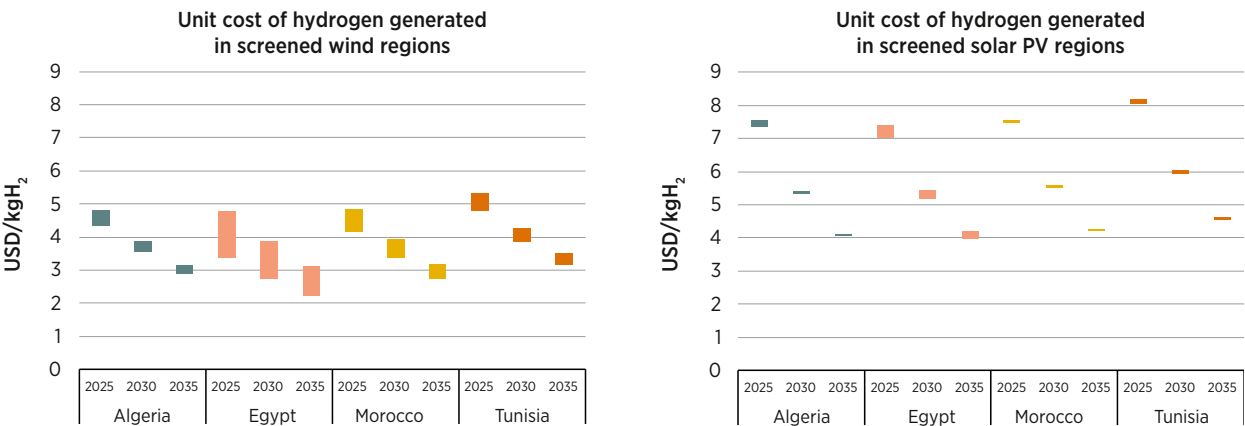
A tabular overview of the scenario results in terms of hydrogen production and electrolyser capacity is provided in Table 2-9 and Table 2-10, respectively.

One of the challenges of introducing hydrogen into energy systems is the seasonal nature of production and demand, which may create a need for hydrogen storage. The seasonal variations in hydrogen demand could result from the applications using it (for example, transportation or heating). Presently, at a few sites, hydrogen is stored underground in salt caverns. However, underground hydrogen storage may be incompatible with

certain applications, which may require faster cycles (IEA, 2021a). Figure 2-30 shows the seasonality of hydrogen production in the countries considered in this study, normalised to their maximum production. Algeria’s maximum daily hydrogen production occurs in November-December; Egypt’s in September-October; Mauritania’s, Tunisia’s and Morocco’s in March-June. These differences promise some complementarity, which can help to stabilise hydrogen supply from the region. Although the seasonal variation in hydrogen demand is not projected in this study, the complementarity between the countries may reduce the hydrogen storage capacity needed to ensure a reliable hydrogen supply to end users. The annual capacity factor of electrolyzers in North Africa is 80% in 2040 according to the model.

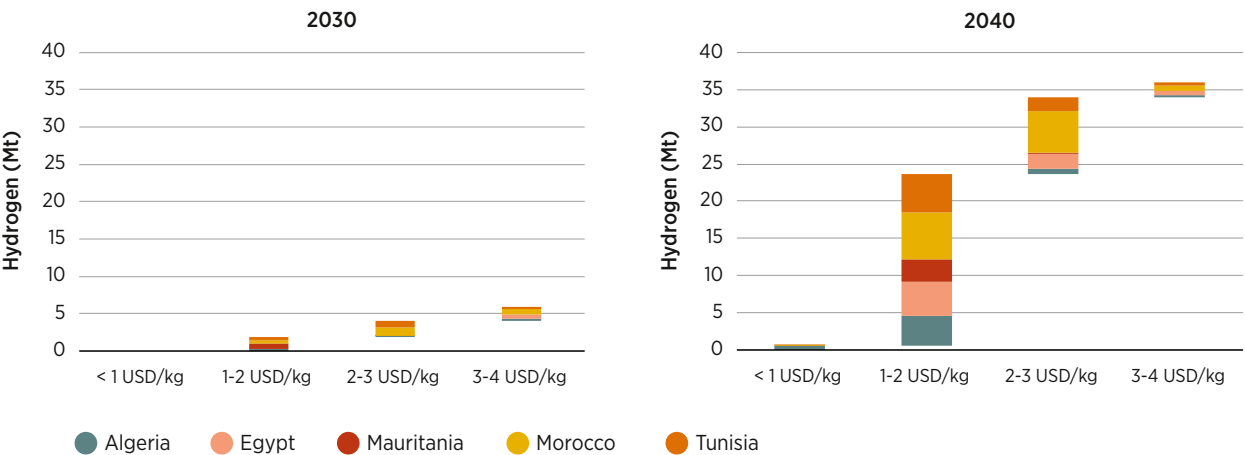
Figure 2-31 shows the daily production rate of hydrogen in the countries of the region. The rate varies from 58 kilotonnes of hydrogen (ktH₂)/day in September-October to 74 ktH₂/day in March-June. The latter peak reflects the combined potential of solar PV and wind power peaking at that time year, coupled with moderate demand. Figure 2-32 shows the hourly hydrogen production curve for each season in the different countries. It is characterised by higher production during the periods of greatest solar power availability.

Figure 2-27 Unit cost of hydrogen generated in screened wind and solar photovoltaic regions



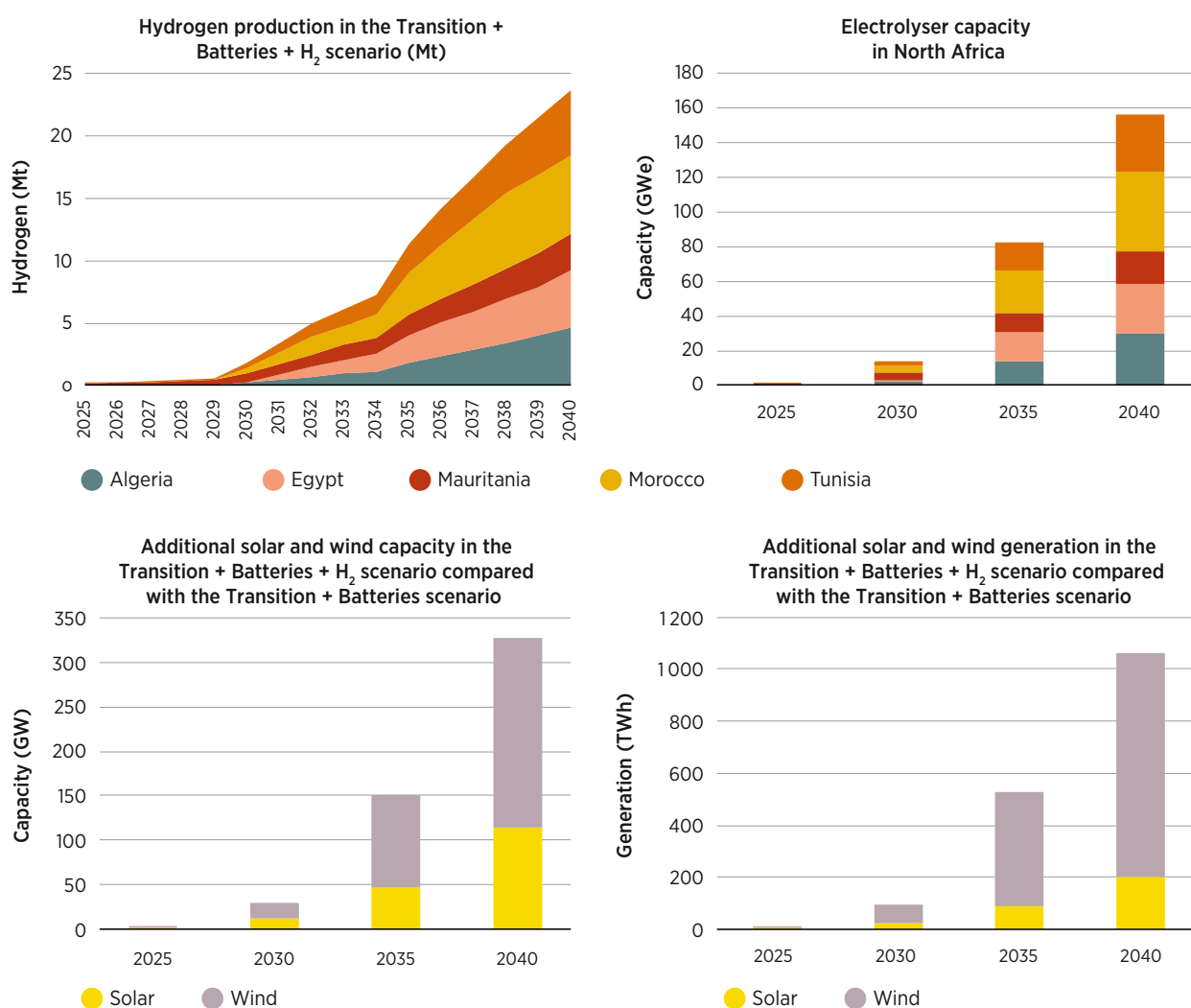
Note: kgH₂ = kilogramme of hydrogen; PV = photovoltaic.

Figure 2-28 Hydrogen supply curve in North Africa as determined by the model, 2030 and 2040



Note: kg = kilogramme; Mt = megatonne.

Figure 2-29 Evolution of hydrogen production, electrolyser capacity and generation from variable renewable energy in North Africa in the Transition + Batteries + H₂ scenario, 2025-2040



Note: GW = gigawatt; GWe = gigawatts electric; H₂ = hydrogen; Mt = megatonne; TWh = terawatt hour.

Table 2-9 Comparison of hydrogen production in the Transition + Batteries + H₂ scenario with national, regional and global hydrogen demand projections, 2030 and 2040

COUNTRY/REGION	SOURCE	DEMAND PROJECTIONS (MtH ₂ /YEAR)	
		2030	2040
Germany	National Hydrogen Strategy (Federal Ministry for Economic Affairs and Energy, 2020)	2.7-3.3	n/a
Europe	(EHB, 2021; Hydrogen Europe, 2020)	10-17.5	40
	(European Commission, 2022a)	20	
Globe	(Acil Allen, 2018; BP, 2020; COAG Energy Council, 2019; Global Alliance Powerfuels, 2020; Hydrogen Council, 2017; IEA, 2020c, 2021b; Shell, 2021; WEC, 2016)	80-212	94-391
North Africa	Transition + Batteries + H ₂ scenario	1.8	23.6

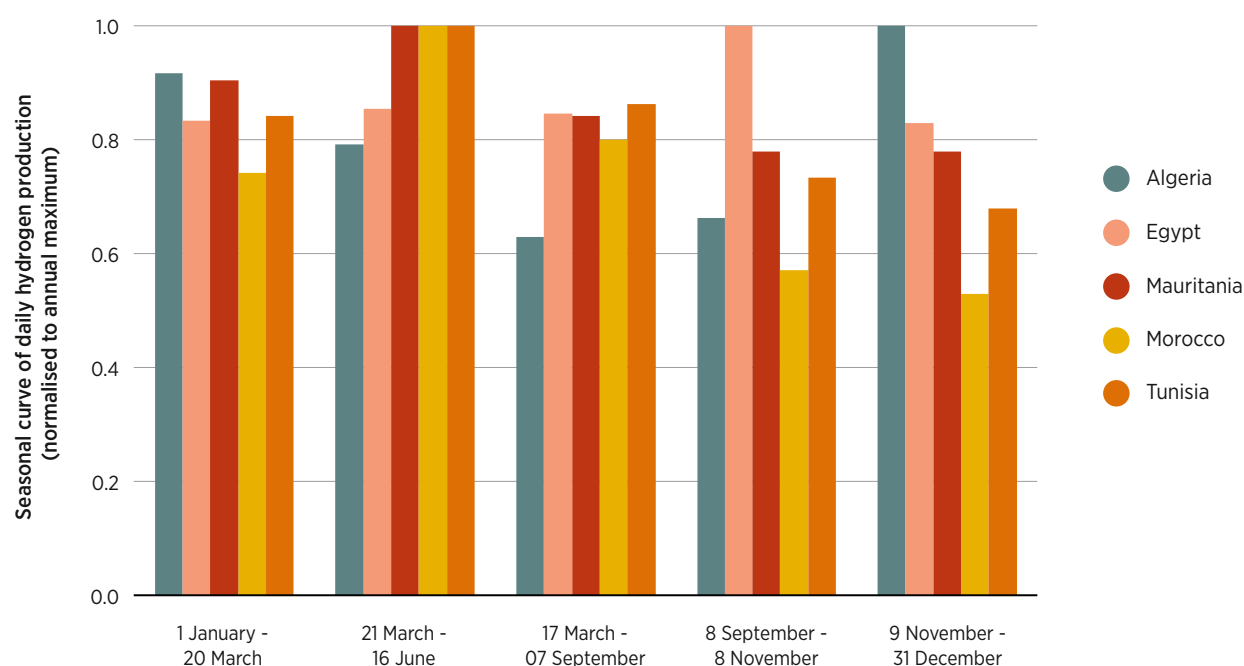
Note: MtH₂ = megatonne of hydrogen.

Table 2-10 Comparison of electrolyser capacity in the Transition + Batteries + H₂ scenario with national, regional and global hydrogen projections, 2030 and 2040

COUNTRY/REGION	SOURCE	ELECTROLYSER CAPACITY (GWe)	
		2030	2040
Germany	National Hydrogen Strategy (Federal Ministry for Economic Affairs and Energy, 2020)	5	10
Europe	(EHB, 2021; European Commission, 2020; FCH, 2019)	15-40	n/a
Globe	(Hydrogen Council, 2021; IEA, 2021b; IRENA, 2020d)	270-850	n/a
North Africa	Transition + Batteries + H ₂ scenario	13.6	156

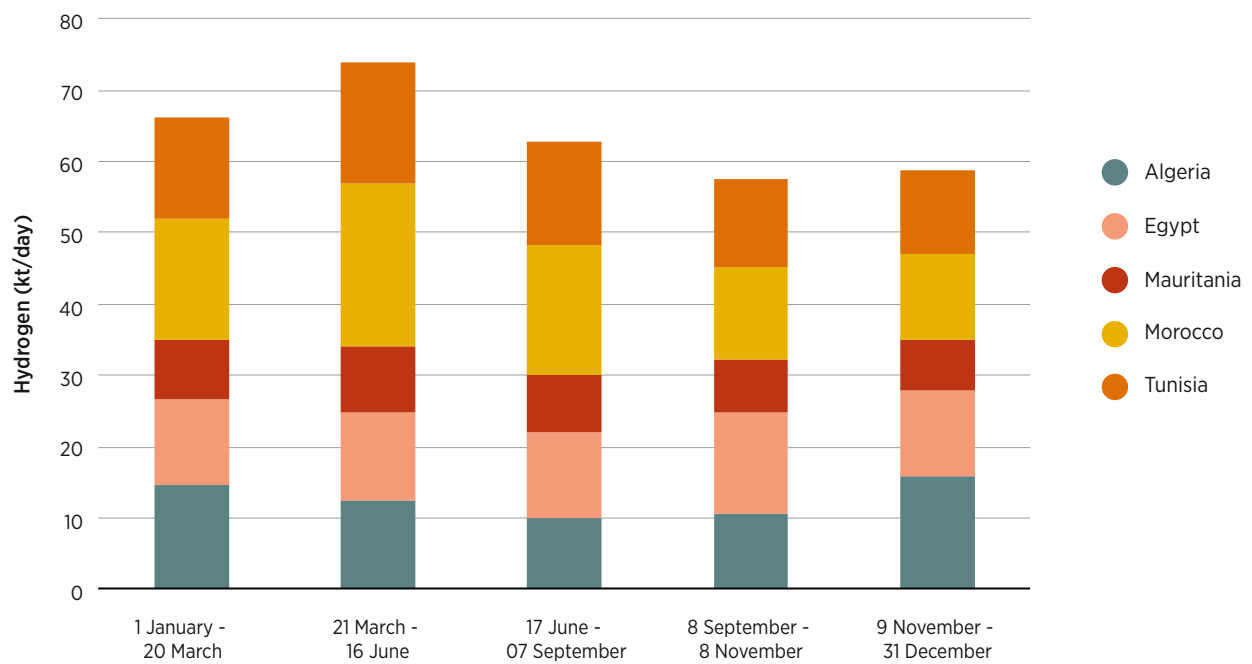
Note: GWe = gigawatts electric; H₂ = hydrogen.

Figure 2-30 Seasonal hydrogen production in the Transition + Batteries + H₂ scenario, by country and normalised (relative to maximum daily production in the year)



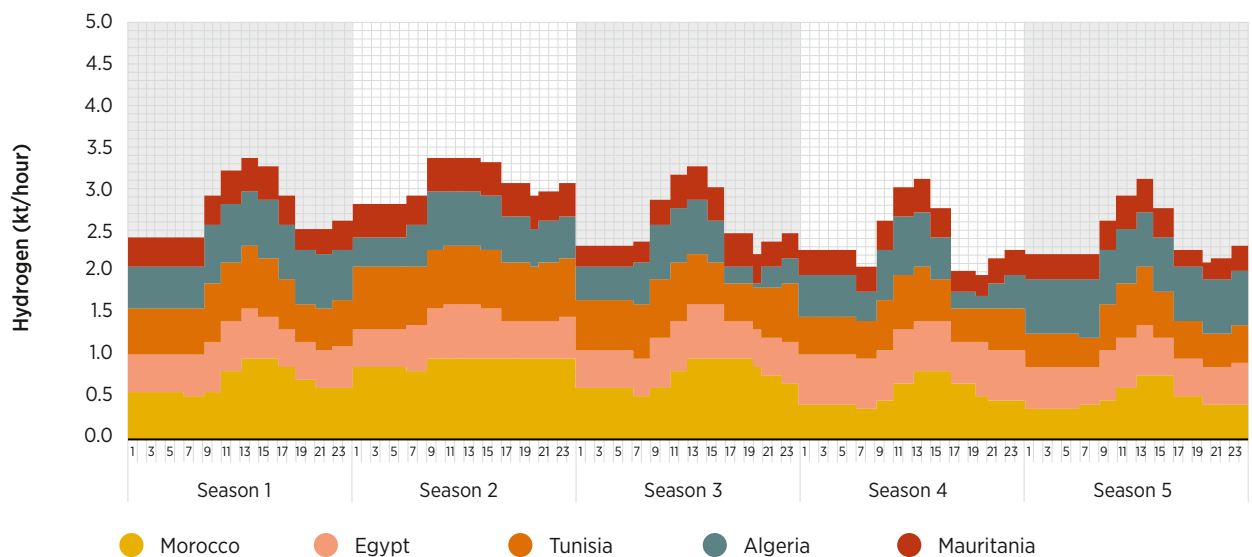
Note: H₂ = hydrogen; kt = kilotonne.

Figure 2-31 Daily hydrogen production rate in the Transition + Batteries + H₂ scenario, by country



Note: H₂ = hydrogen; kt = kilotonne.

Figure 2-32 Daily hydrogen production in the Transition + Batteries + H₂ scenario for each season, by country



Note: H₂ = hydrogen; kt = kilotonne.

2.10 CSP STORAGE WILL BE IMPORTANT TO ENSURE SYSTEM ADEQUACY

This section describes a post-model analysis of the optimisation results of the scenarios. The SPLAT-N model works with seasonal time slices but does not run at hourly resolution. For a proper assessment of system adequacy, simulations of the capacity mixes suggested by SPLAT-N are needed at hourly resolution to verify the robustness of the model results from an operational point of view.

According to the modelling assumptions, we consider a reserve margin of 10% over the annual peak load provided by fossil-fuel-based technologies in addition to CSP (with thermal energy storage) and batteries. In the Transition scenarios, this reserve margin is provided by CSP and batteries. In this section, we explore whether enough energy can be stored using these two technologies to supply demand when VRE is not available.

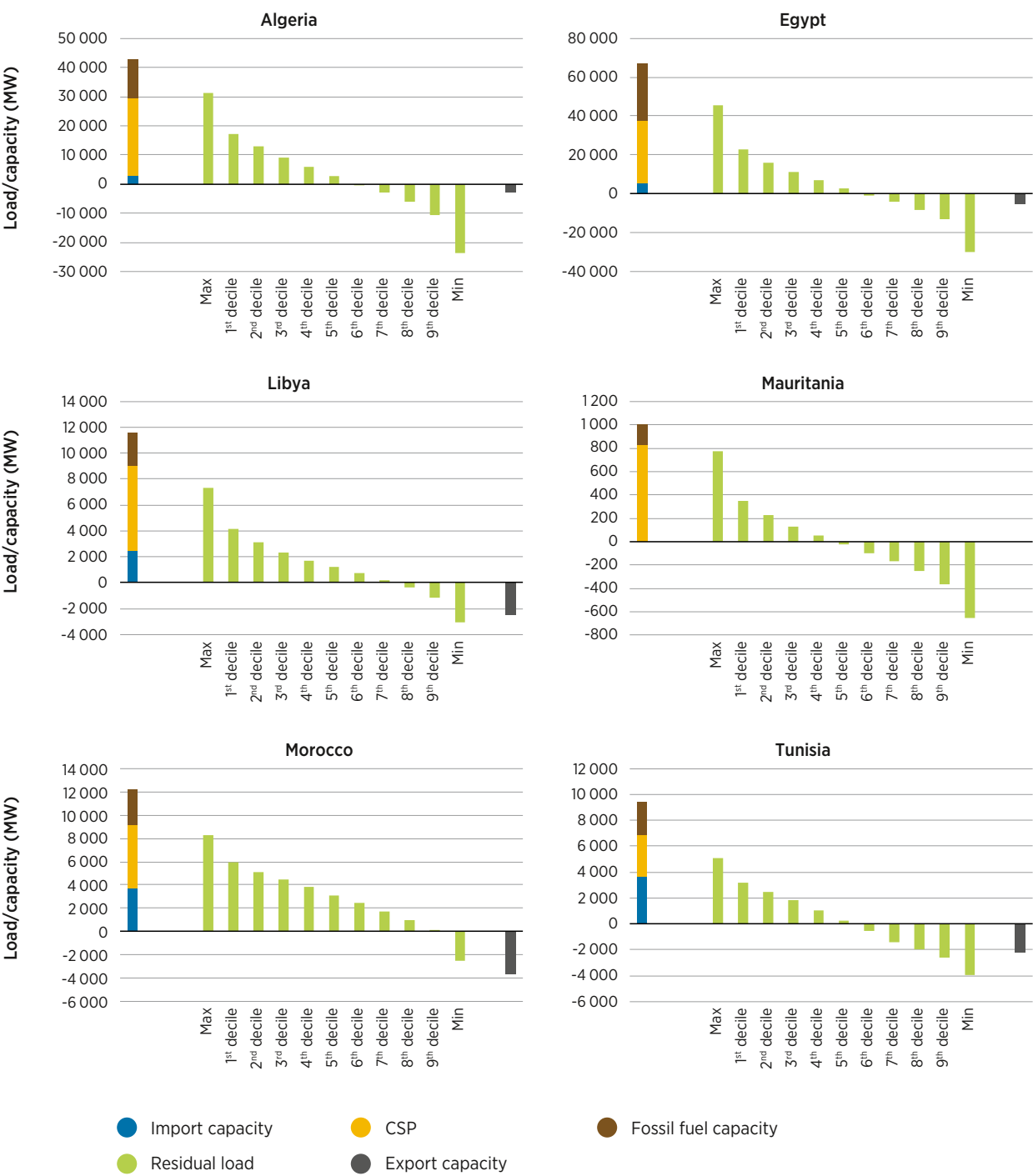
Although grid stability lies outside the scope of this study, we explore here the adequacy issues the system may face with respect to available capacity and intra-seasonal variability of wind and solar resources. These issues do not affect the energy generated annually by each technology.

As described in section 3.2.1, an average profile of electricity demand and VRE supply is created for each season, by time slice. Averaging by time slot results in an underestimation of the peak load, which may result in underestimation of the firm capacity needed to ensure that the system can meet the required load at all times (Poncelet *et al.*, 2016). In addition, as CSP and batteries are assumed to contribute to the reserve margin at full installed capacity, we must be sure that enough energy can be stored in these technologies when needed. Here, the hourly wind and solar profiles for the model supply regions (MSRs) in each country (see Box 2-2) are used in combination with hourly demand to calculate the residual demand that must be supplied using fossil fuels, imports or electricity storage systems, given the capacity expansion suggested by the SPLAT model results. The residual demand is equal to the demand minus the sum of solar PV generation and wind generation. Residual demand can be negative, as in Figure 2-33, when renewable generation exceeds demand. In that case, the options are to export, to produce hydrogen (if the option is available), to store the electricity in batteries or to curtail the excess electricity. Thus, the maximum positive residual demand must be compared with the sum of the firm capacity of non-VRE power plants (solar thermal, hydro, imports, batteries and fossil fuels), and the minimum residual load (or maximum excess VRE production beyond demand) must be compared with the capacity of the power-consuming technologies other than final demand (exports, batteries and hydrogen production plants). If the maximum excess VRE production is greater than the capacity of these technologies, this production should be curtailed.

In our model, most of the residual load is supplied using CSP. Thanks to the storage capacity associated with this technology, electricity supply can follow the load profile. The storage must be carefully designed, however, to adjust to the needs of the system. Indeed, if the hourly dispatch shows a need for energy from CSP storage over an extended period one must ensure that the available storage can hold enough energy. Figure 2-34 shows the periods in the year when CSP generation is needed (without considering the possibility of importing from neighbouring countries). The most critical times are evenings and nights in June, July, August and September, which are characterised by high solar power availability and high demand. Storage associated with CSP should therefore be designed with these times in mind. Long storage is especially necessary in the Transition scenario. In the Transition + Batteries scenario, the batteries improve the adequacy of the system, since electricity from the various generation technologies can be stored in them. In the Transition + Batteries + H₂ scenario, the total installed capacity is much higher than the capacity needed to supply local demand; for that reason, adequacy is ensured by reducing hydrogen production when electricity is needed to meet local demand.

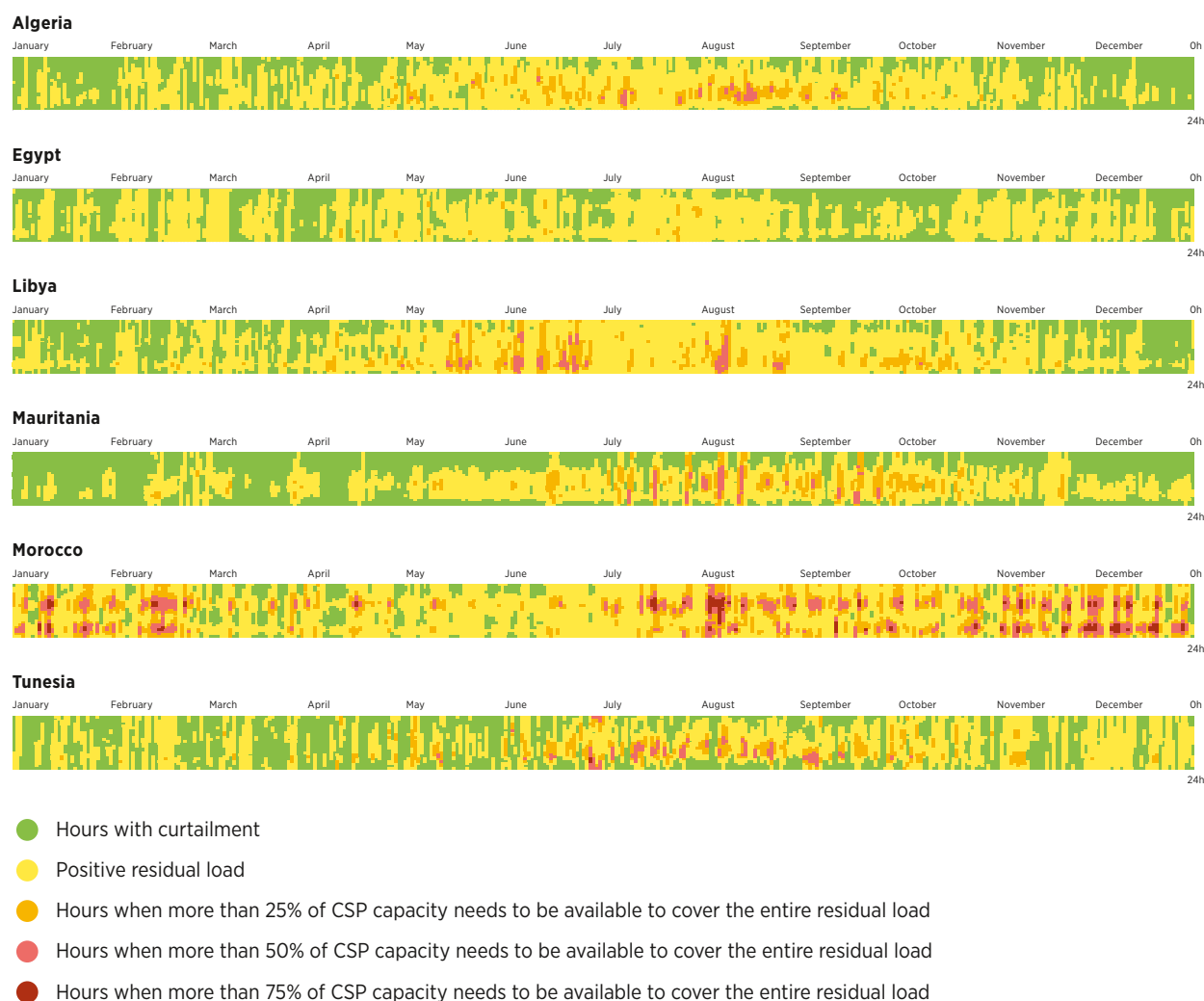
Like battery storage, hydrogen production can reduce VRE curtailment – from 25% of potential VRE generation in 2040 in the Transition scenario to 16% in the Transition + Batteries scenario and 5% in the Transition + Batteries + H₂ scenario. Because electrolyzers can ramp up and down on a timescale of minutes and even seconds (IRENA, 2019b), hydrogen production can also contribute to the flexibility of the system.

Figure 2-33 Residual load duration curve in the Transition scenario, by country, 2040



Note: CSP = concentrated solar power; MW = megawatt.

Figure 2-34 Hourly capacity factor of concentrated solar power needed to meet demand in the Transition scenario, 2040



Note: CSP = concentrated solar power.

2.11 DEPLOYMENT OF VRE WITH STORAGE SOLUTIONS CAN TEMPER SYSTEM COSTS IF FOSSIL FUEL INVESTMENTS ARE HALTED

The total cost of the electrical system, and therefore of each scenario, is determined by various components: investment costs, fixed and variable operation and maintenance costs, and fuel costs. The investment costs refer to the annualised capital costs. The annuities are calculated according to the useful life of the projects and the weighted average cost of capital of generation and transmission.

The difference in generation technologies between the four scenarios and the lower demand in the Planned scenario explain the changes in the cost structure of the electricity system in North Africa. Figure 2-35 shows the evolution of these costs in the four scenarios. On the one hand, there is a notable reduction in the fuel cost component between the Planned scenario and the three Transition scenarios, explained by the lower share of electricity derived from fossil fuel thermal power plants in the latter. The fuel costs approach zero as the share of renewable capacity increases in the three Transition scenarios. On the other hand, the investment cost component is higher in the three Transition scenarios compared with the Planned scenario, a result of significant growth in renewable capacity and total generation.

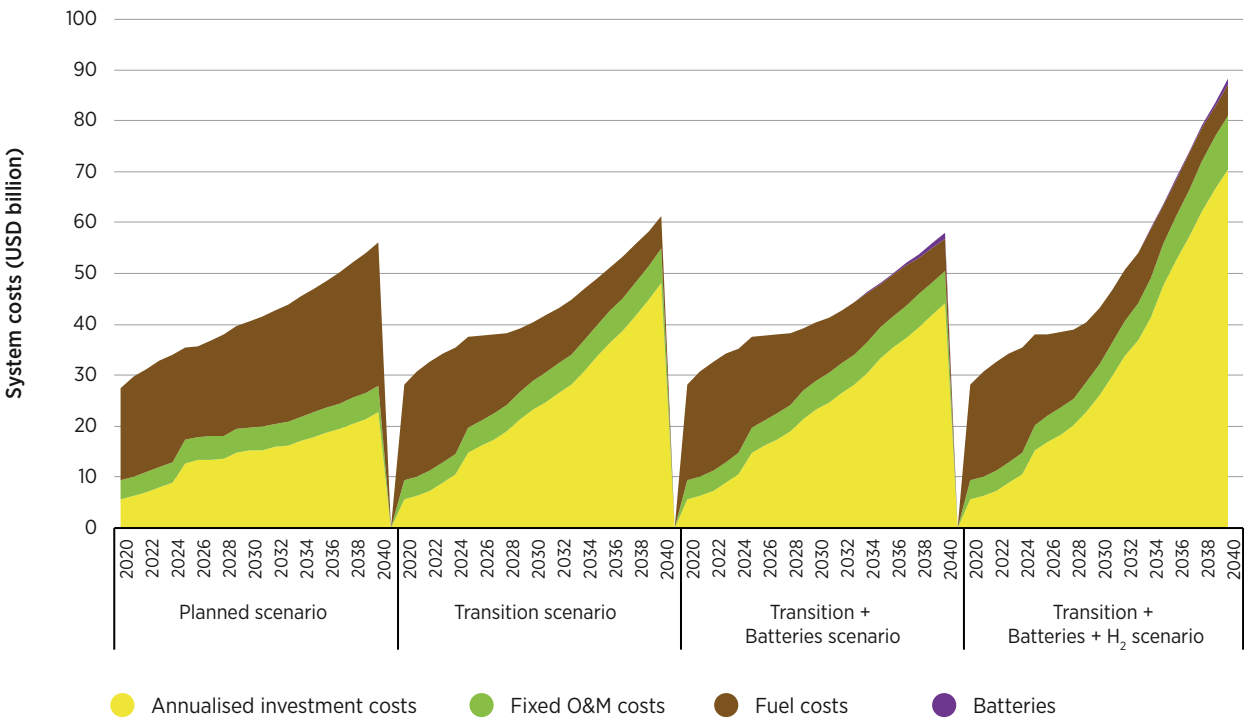
When hydrogen production is introduced, investment costs become significantly higher than in the two Transition scenarios that do not include hydrogen (Figure 2-35). This is due to the installation of new solar and wind energy capacity to supply additional electricity to power electrolyzers (Figure 2-36). However, the operating costs are relatively similar across all three Transition scenarios. In 2040, investment costs represent more than 75% of the system costs in the Transition + Batteries + H₂ scenario. The additional costs in the Transition + Batteries + H₂ scenario are compensated by hydrogen export revenues.

In the end, the average annual investment needed in the Planned scenario over the period 2020-2040 is USD 7.3 billion, a value on the same order of magnitude as the USD 8.5 billion in annual investments in renewable energy committed and planned for 2021-2025 in the region (see section 1.8). The average annual investments needed in the Transition and Transition + Batteries scenarios are USD 18 billion and USD 16.3 billion, respectively. The highest average annual investment costs are reached in the Transition + Batteries + H₂ scenario, which requires an average of USD 27.3 billion annually owing to the higher capacity needed to produce hydrogen.

As shown in Figure 2-36, the scenario with the highest total costs is the Transition + Batteries + H₂, with a total of USD 1067 billion costs over the period 2020-2040, compared with USD 885 billion in the Transition + Batteries scenario. But producing hydrogen can be cost-effective for North African countries since the production costs are compensated by the revenue generated from exports (USD 358 billion in revenue).

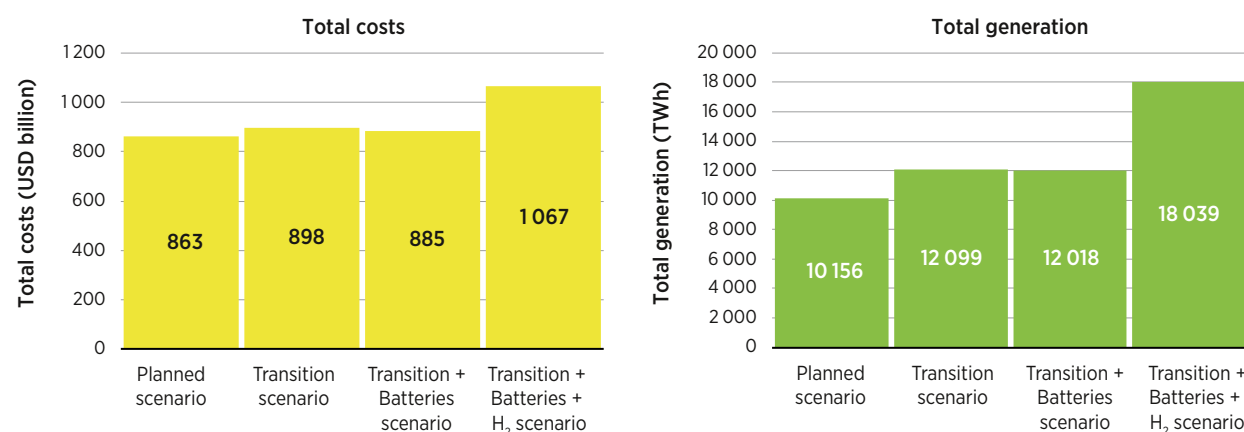
The system costs do not include additional equipment needed to ensure grid stability and expansion of transmission capacity in each country. Although the adequacy of generation to meet load at all hours would be guaranteed in the Transition + Batteries + H₂ scenario by the availability of enough dispatchable generation to handle the intra-seasonal variability of intermittent energy sources (see previous section), grid stability may require additional features to provide frequency and voltage control.

Figure 2-35 Evolution of system costs in the four scenarios



Note: H₂ = hydrogen; O&M = operation and maintenance.

Figure 2-36 Total costs and total generation in North Africa in the four scenarios, 2020-2040



Note: H₂ = hydrogen; TWh = terawatt hour.

2.12 HOLDING DOWN THE LEVELISED COST OF ELECTRICITY

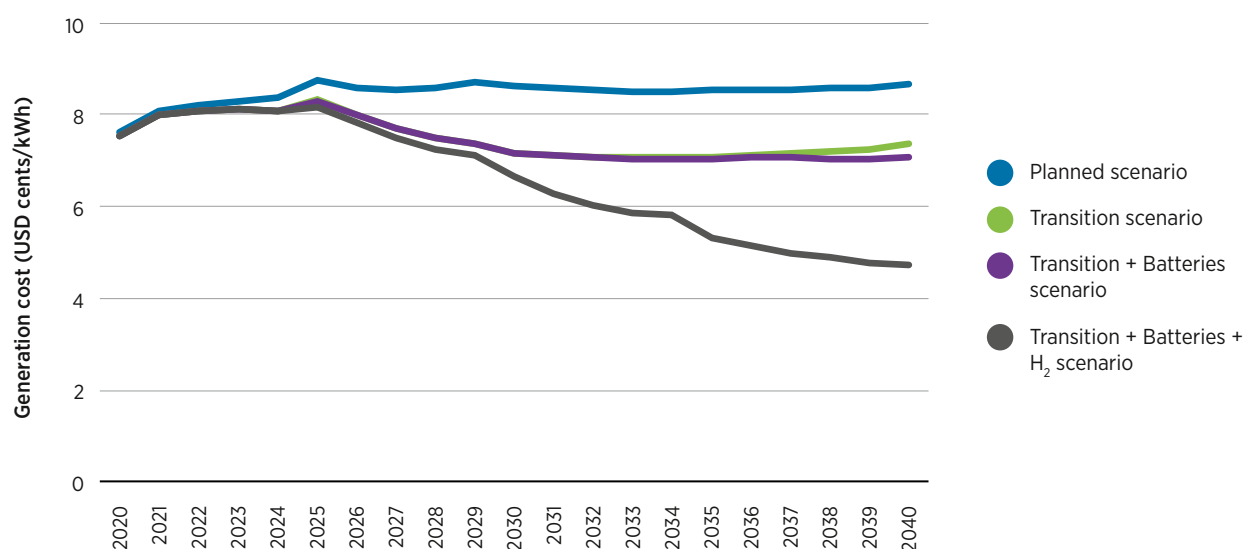
The planning model used in the study represents a simplified electricity grid of six countries in North Africa, where each country represents a node. The technologies associated with each node and their corresponding investment cost, operating costs and fuel costs determine the total cost of generating electricity. The average annual cost for the region is calculated in this study as the load-weighted average cost at all transmission system nodes.

Figure 2-37 shows the evolution of the unit generation cost in North Africa over the period 2020-2040 in the four scenarios. Under the Planned scenario, generation cost increases slightly between 2020 and 2025 and remains constant afterward at close to USD 0.09/kilowatt hour (kWh). This is directly linked to the price of fossil fuels, which represent a high share of the power generation in this scenario, which are assumed to rise up to 2025 before stabilising (Table A-15 of the Data appendix [IRENA, 2022b]). In contrast, average annual costs fall after 2025 in the three other scenarios, thanks to the increasing penetration of VRE. Even though the stronger deployment of renewables translates into higher investments, the heavy reduction of fuel costs induced by these scenarios reduces the overall cost of generation.

The Planned scenario has a significantly higher thermal generation component due to the constraint imposed to limit renewables to current national targets and not exceed them, which implies that more expensive (and less efficient) thermal plants are used more often, resulting in a higher regional average cost. The Transition, Transition + Batteries and Transition + Batteries + H₂ scenarios have proportionally lower thermal generation, and the regional average cost in these cases is lower, with the lowest being in the last scenario. In these three scenarios, thermal energy is progressively replaced by solar and wind renewable energy over the study horizon.

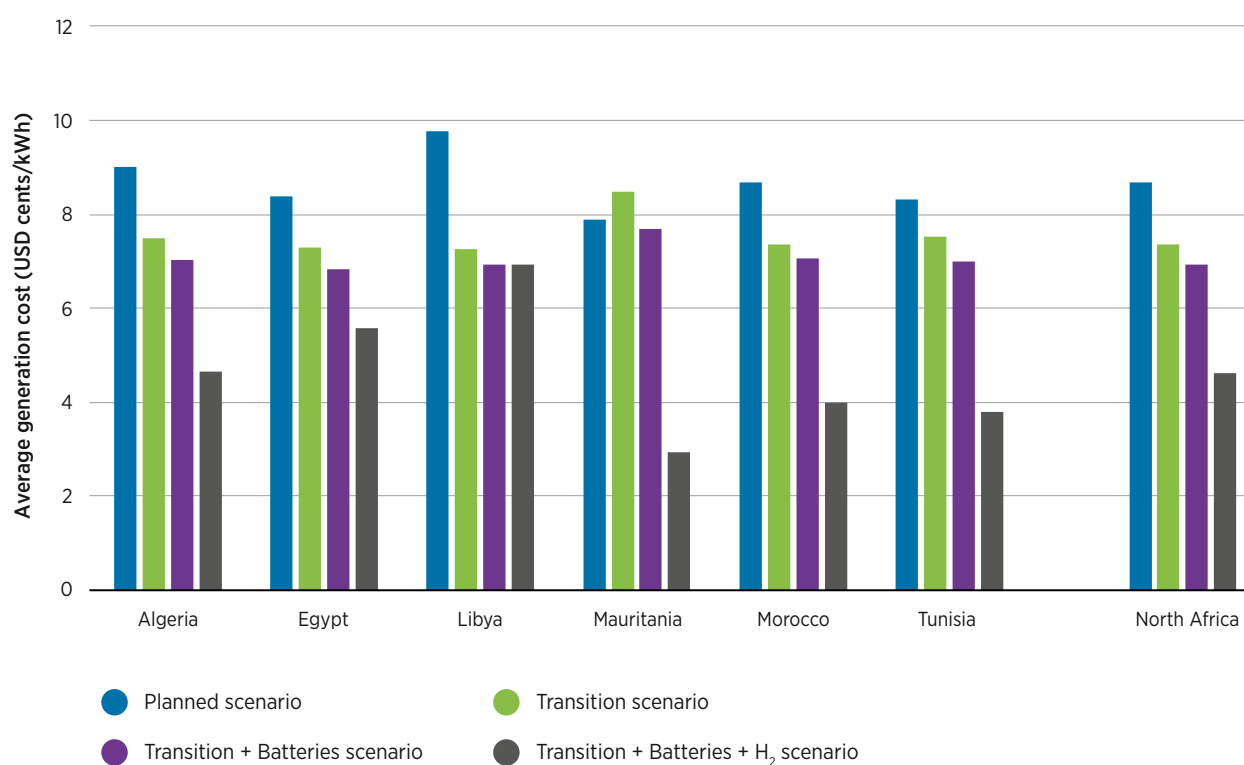
The unit costs of generation by country are presented in Figure 2-38 for the year 2040. For all countries, the lowest costs at the end of the modelling horizon are found in the Transition + Batteries + H₂ scenario. Mauritania shows the lowest generation costs in North Africa, with net costs of less than USD 0.03/kWh; Morocco and Tunisia both achieve a cost below USD 0.04/kWh by 2040.

Figure 2-37 Evolution of total generation cost in North Africa in the four scenarios (annual system cost divided by annual generation)



Note: H₂ = hydrogen; kWh = kilowatt hour.

Figure 2-38 Average generation cost in the four scenarios, by country, 2040



Note: H₂ = hydrogen; kWh = kilowatt hour.

2.13 THE PROPOSED TRANSITION TOWARDS VRE WOULD SUBSTANTIALLY LOWER CO₂ EMISSIONS FROM POWER GENERATION

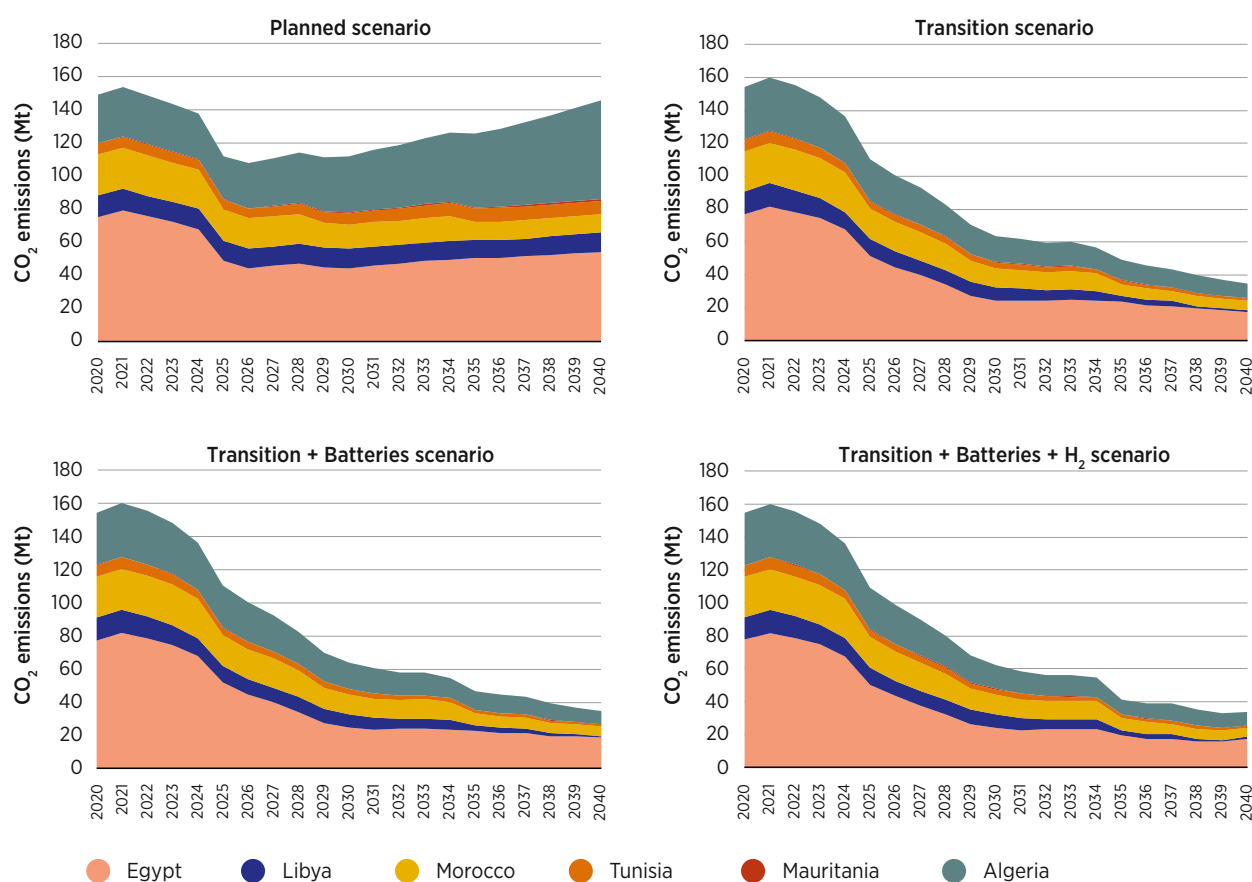
The generation of electricity from oil, natural gas and coal emits CO₂. The evolution of those emissions in the four scenarios in North Africa are presented in Figure 2-39. In the Planned scenario, CO₂ emissions drop by about 25% in the period 2020-2030, reflecting the impact of current targets for renewable capacity deployment. However, they begin to rise again in 2030 and continue to rise through the end of the modelling period. Most of the effect is explained by growing emissions in Algeria owing to growing demand without a commensurately greater share of renewable energy in the electricity mix. (The Planned scenario used as a baseline in this study assumes that countries' current renewable targets are achieved but not exceeded.)

The addition of new renewable power plants can offset the growth in emissions and decouple it from demand growth. In the three Transition scenarios, power demand is higher than in the Planned scenario, but fossil-fuel-based power generation is 75% lower by 2040, as renewable generation takes its place, both in absolute value and as a share of total generation. The transition scenarios are thus characterised by a decline in CO₂ emissions over the modelling period. Whereas the power sector was responsible for emitting 154 megatonnes of carbon dioxide equivalent (MtCO₂eq) in 2020, those emissions are reduced to 64 MtCO₂eq in 2030 and to less than 35 MtCO₂eq in 2040 – a 78% drop over the 2020-2040 period.

In terms of cumulative CO₂ emissions released by the power sector over the 20-year modelling period, the scenarios showcase possibilities to reduce cumulative emissions despite the substantial increase in electricity demand in North Africa. Between 2020 and 2040, the cumulative CO₂ emissions caused by the electricity sector are significantly lower in the Transition, Transition + Batteries and Transition + Batteries + H₂ scenarios (1 763 MtCO₂eq, 1 746 MtCO₂eq and 1 703 MtCO₂eq, respectively) than in the Planned scenario (2 698 MtCO₂eq) (Figure 2-40). The equivalent annual averages are 128 MtCO₂/year in the Planned scenario, 84 MtCO₂/year in the Transition scenario, 83 MtCO₂/year in the Transition + Batteries scenario and 81 MtCO₂/year in the Transition + batteries + H₂ scenario. In other words, the Transition and Transition + Batteries scenarios bring about a 35% reduction in cumulative CO₂ emissions over the period 2020-2040 compared with the Planned scenario; the Transition + Batteries + H₂ scenario yields a 37% reduction.

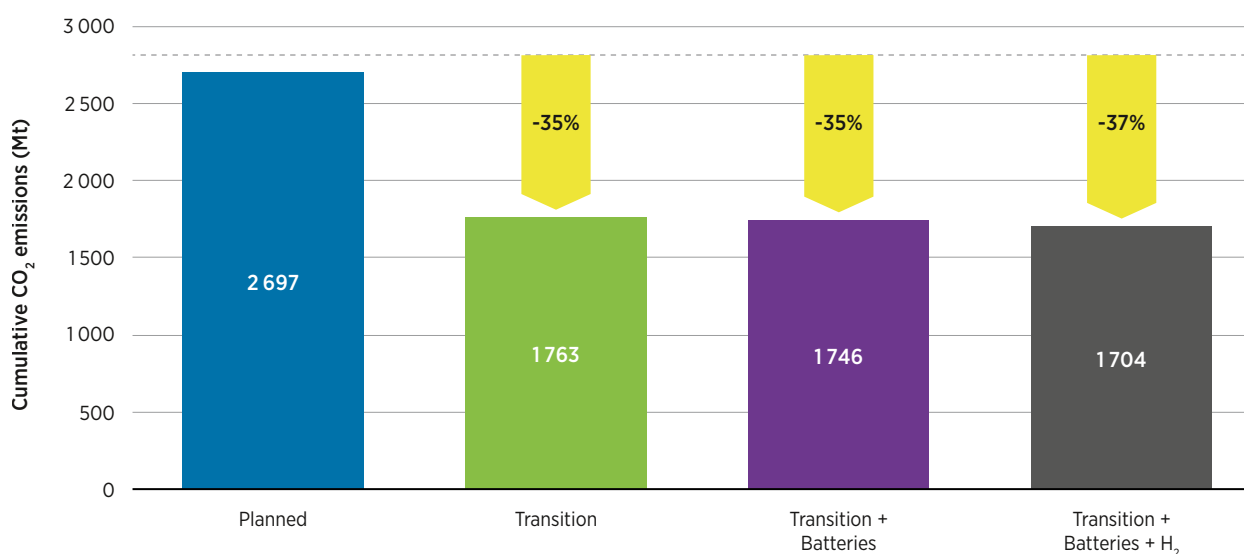


Figure 2-39 Evolution of carbon dioxide emissions from the electricity sector in North Africa in the four scenarios



Note: CO₂ = carbon dioxide; H₂ = hydrogen; Mt = megatonne.

Figure 2-40 Cumulative carbon dioxide emissions and reductions in the four scenarios, 2020-2040



Note: CO₂ = carbon dioxide; H₂ = hydrogen; Mt = megatonne.

2.14 ADDITIONAL STUDIES COULD SHED MORE LIGHT ON THE NORTH AFRICAN POWER SYSTEM

Demand and load curves. In some North African countries, peak load growth is much higher than growth in annual electricity usage. Because this study used demand load curves available in the public domain for all countries, the load curve had the same shape for all the modelled years. For the sake of accuracy, future work with North African countries should project evolving load curves. More efficient air conditioning may reduce the growth of peak load. At the same time, higher temperatures resulting from climate change may increase the need for air conditioning. In addition, increasing electrification of end uses (e.g. introduction of electric vehicles) may result in different hourly electricity demand load curves. Fortunately, SPLAT is able to integrate different load curves for different years.

Domestic hydrogen demand. In this study, we assume that all hydrogen produced in North Africa will be exported. Using hydrogen locally could help decarbonise the region's economies, but demand for that purpose cannot yet be determined endogenously within SPLAT. Several countries are presently preparing their hydrogen strategy and may include relevant projections.

Flexibility and grid reliability. Although in this study we checked the adequacy of supply and demand, further modelling focusing specifically on the grid may offer more insight on the grid investments needed as renewables come to make up a very high share of the power system. To assess the flexibility of capacity expansion plans, IRENA developed the FlexTool model (IRENA, 2018b). Studies using FlexTool help to identify the least-cost mix of solutions to shortages of flexibility. FlexTool is a detailed but user-friendly tool designed to analyse not only the traditional concept of flexibility (for example, flexible thermal and hydropower generation with high ramping capability and very low start-up time), but also other innovative technologies that enrich the concept of flexibility, such as flexible demand, energy storage and sector coupling.

Economic impact of higher shares of renewables. IRENA approaches the socio-economic analysis of the energy transition using a macro-econometric model (E3ME) that links the energy system with the world's economies within a single quantitative framework. E3ME measures the impacts of transition scenarios and their accompanying climate policy baskets by evaluating their effects on GDP, employment and welfare. (Carbon pricing and international co-operation are two key elements that have been considered in the climate policy baskets.) The ultimate goal is to inform energy system planning and policy making to ensure a just and inclusive energy transition at the global, regional and national levels. Box 2-4 contains an example of socio-economic analysis of the energy transition carried out by IRENA in collaboration with the African Development Bank.

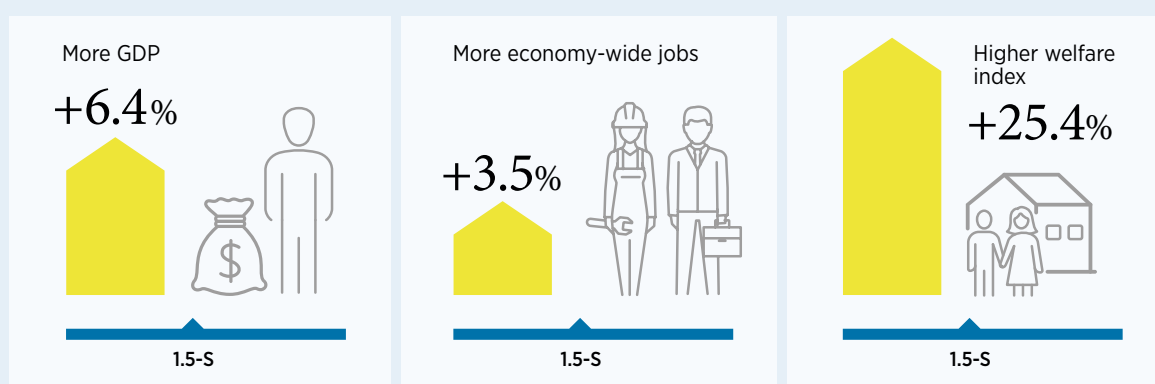
Box 2-4 An example of IRENA's socio-economic analysis of energy transition roadmaps

IRENA's latest modelling results, obtained in collaboration with African Development Bank (IRENA and AfDB, 2022), reveal how the energy transition benefits Africa's economies and people – beyond emissions reductions – through 2050. Two scenarios have been analysed: (1) an ambitious energy transition scenario (called the 1.5°C Scenario) that aims to reach the global goal of limiting the rise in the global average temperature to no more than 1.5°C by 2050; and (2) the Planned Energy Scenario based on the status quo. The 1.5°C Scenario not only assumes that the provisions of the Paris Agreement are being met, but also that the transition is accompanied by a proactive set of policies designed to maximise the socio-economic benefits of transforming energy systems.

Box 2-4 An example of IRENA's socio-economic analysis of energy transition roadmaps (continued)

Results from Africa show that, despite the difficult shift away from carbon-intensive energy sources, the energy transition – when accompanied by appropriate policies – holds huge promise. The 1.5°C Scenario predicts 6.4% higher GDP, 3.5% more jobs and a 25.4% higher welfare index across the continent than what could be realised under current plans (Figure 2-41). In the renewable energy sector, the energy transition could boost employment substantially in Africa, from around 0.35 million in 2020 to 4.3 million by 2030 and more than 8 million by 2050 under the 1.5°C Scenario, a 20-fold increase by 2050 from today's values. IRENA's analysis also shows Africa prospering from a diversified economy, industrial development and innovation, energy access, and profound benefits for the environment, all of which are critical to more equitable socio-economic development across the continent.

Figure 2-41 Average differences between the 1.5°C Scenario and Planned Energy Scenario for Africa, 2021-2050



Note: 1.5-S = 1.5°C scenario; GDP = gross domestic product.

Global impacts of the energy transition will be unevenly distributed across regions and countries, depending on local socio-economic structures, the degree of reliance on fossil fuels and the depth of the renewables supply chain, among other factors. Thus, IRENA has deepened and broadened its socio-economic impact analysis within Africa's five regions. In the case of North Africa, better results on GDP, economy-wide employment and welfare are obtained over the 2021-2050 period with a more progressive policy basket.

Beyond their impact on the socio-economic footprint of energy transition models such as the 1.5°C Scenario, the greatest value of using progressive policy baskets to address the equity and justice dimensions of the transition is that they increase the changes that ambitious mitigation plans will be realised by triggering the required collaborative effort.

2.15 PATHWAYS TO LOWER-COST ELECTRICITY GENERATION IN NORTH AFRICA

The SPLAT-N model, developed by IRENA for this study, suggests that it is technically and economically possible for North African countries to reduce their reliance on fossil fuels by raising the share of renewables in power generation far beyond countries' current targets. Ambitious increases could be facilitated by utility-scale battery storage and hydrogen production over an interconnected North African grid. These options would reduce the unit cost of electricity in the long term compared with continued reliance on fossil-fuel-powered generation of electricity.

As shown by the Transition scenario, lower power generation costs are possible even if fossil fuel plant investments are fully halted after 2025, thanks to the widespread potential for solar and wind power in North Africa, including solar thermal with a well-designed storage capacity. Reinforced cross-border interconnections make it possible to harness the substantial spatio-temporal complementarities of solar and wind power across the region, enabling greater use of these variable resources. Interconnections are vital when a surplus of generation is available in North Africa for export to Europe and when peak loads shift within the countries of the region.

As shown by the Transition + Batteries scenario, battery-based storage can play an important role in cost-effectively supporting grid integration of VRE. The Transition + Batteries + Hydrogen scenario demonstrates that hydrogen production in the region opens yet another opportunity to integrate renewables into the region's electricity system, thereby lowering the unit cost of generation and earning revenue from the exportation of hydrogen through existing infrastructure (natural gas pipelines) or new infrastructure.

The three Transition scenarios would yield a 75% reduction in emissions by 2030 over 2020 levels. They would reduce cumulative emissions for 2020–2040 by more than 30% over the Planned scenario. This reduction is achievable thanks to the massive introduction of renewables – supported by battery storage and hydrogen production destined for export – and by ceasing investments in new fossil fuel generation in 2025. In the Transition + Batteries + H₂ scenario, the region's fossil fuel consumption for electricity generation in 2040 falls from 2 537 PJ/year to 565 PJ/year.

The immense opportunity of lowering electricity generation costs in the region, harnessing its solar and wind resources to export hydrogen, and reducing emissions could become a reality through cooperation among North African countries to exploit available synergies in electricity generation and export infrastructure. The transition requires large investments, investments best made by the public and private sectors working in concert and with the explicit intent to include local industries in the effort.

The SPLAT-N model was developed and populated largely with publicly available information. Because this may well skew or limit the analysis presented here, IRENA welcomes further validation from national and regional experts in North Africa to enhance the robustness of the modelling and analysis. Various assumptions relating to fuel costs, infrastructure and policy developments, among other matters, may be challenged or viewed differently by stakeholders in the region. This is as it should be. IRENA will make the SPLAT-N model freely available to experts from its member countries to enable them to explore various assumptions, to validate the assumptions of the model, to develop and compare their own scenarios, and to analyse in greater depth the benefits and challenges of an accelerated roll-out of renewable power generation technologies.

REFERENCES

Acil Allen (2018), *Opportunities for Australia from Hydrogen Exports*, Acil Allen Consulting for the Australian Renewable Energy Agency (ARENA), Australia, <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>

Afrik 21 (2020), “Morocco: Partnership with Germany for green hydrogen”, www.afrik21.africa/en/morocco-partnership-with-germany-for-green-hydrogen/

Afrik 21 (2019), “Algeria: Condor selected to build 50-megawatt solar power plant”, www.afrik21.africa/en/algeria-condor-selected-to-build-50-megawatt-solar-power-plant/ (accessed 2 August 2021).

Aghahosseini, A., D. Bogdanov, and C. Breyer (2020), “Towards sustainable development in the MENA region: Analysing the feasibility of a 100% renewable electricity system in 2030”, *Energy Strategy Reviews*, Vol. 28/March, pp. 100466, <https://doi.org/10.1016/j.esr.2020.100466>

Ahram Online (2021), “Egypt’s president urges establishing integrated strategy for producing green hydrogen”, <https://english.ahram.org.eg/NewsContent/3/12/416914/Business/Economy/Egypt%E2%80%99s-president-urges-establishing-integrated-st.aspx>

AMEA Power (2019), “AMEA signs PPAs with EETC for renewable projects in Egypt”, <https://ameapower.com/amea-signs-ppas-with-eetc-for-renewable-projects-in-egypt/> (accessed 4 August 2021).

APICORP (2021), *MENA Energy Investment Outlook 2021-2025*, Arab Petroleum Investments Corporation, Dammam, Saudi Arabia, <https://www.apicorp.org/wp-content/uploads/2021/12/MENA-Energy-Investment-Outlook-2021-2025.pdf>.

Arab Fund for Economic & Social Development (2017), “Construction of a 50 megawatt photovoltaic power station in the city of Kom Ombo”, www.arabfund.org/Default.aspx?pageId=359&pId=2366

Azeroual et al. (2018). “Renewable Energy Potential and Available Capacity for Wind and Solar Power in Morocco Towards 2030.” *Journal of Engineering Science and Technology Review* 11 (1) 189-198.

Bloomberg (2021a), “Egyptian plan to supply Europe’s LNG gets boost as plant reopens”, www.bloomberg.com/news/articles/2021-02-17/egypt-lng-revives-with-first-cargo-in-eight-years-at-idled-plant (accessed 8 July 2021).

Bloomberg (2021b), “Egyptian Plan to Supply Europe’s LNG Gets Boost as Plant Reopens”, www.bloomberg.com/news/articles/2021-02-17/egypt-lng-revives-with-first-cargo-in-eight-years-at-idled-plant (accessed 29 June 2021).

BNEF (2020), “Battery pack prices cited below \$100/kWh for the first time in 2020, while market average sits at \$137/kWh”, Bloomberg New Energy Finance, <https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/>

BP (2020), *Energy Outlook 2020*, BP, London, United Kingdom, www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2020.pdf

Chariot Transitional Energy (2022), “Green hydrogen MoU with the Port of Rotterdam”, www.chariotenergygroup.com/wp-content/uploads/2022/04/Green-Hydrogen-to-Rotterdam-MOU_Chariot-Limited.pdf (accessed 19 May 2022).

Chariot Transitional Energy (2021), “MoU for development of large-scale green hydrogen project in Mauritania”, <https://globalenergyinfrastructure.com/news/2021/09-september/mou-for-development-of-large-scale-green-hydrogen-project-in-mauritania/>

COAG Energy Council (2019), *Australia’s National Hydrogen Strategy*, Council of Australian Governments Energy Council, www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf

Commission de régulation de l’Electricité et du Gaz d’Algérie (2019), “National call of tenders on auctions mechanisms concerning realization and operation of solar photovoltaic power plants with 150 MWc total capacity”, www.creg.dz/index.php/en/news-creg/363-ao-pv150-ouverture-des-plis-financiers?highlight=WyJkaWZmZWwiXQ== (accessed 29 June 2021).

CWP (2021), “CWP and Mauritania sign MoU for the development of a US\$40 billion green hydrogen project”, media release, www.cwp.global/wp-content/uploads/2021/05/CWP-Mauritania-Press-Release-1.pdf

Daily News Egypt (2021), “Egypt, DEMA sign cooperation agreement to start green hydrogen production studies.” <https://dailynewsegyp.com/2021/03/04/egypt-deme-sign-cooperation-agreement-to-start-green-hydrogen-production-studies/>

Edwardes-Evans (2020), “Green hydrogen costs can hit 2\$/kg benchmark by 2030 - BNEF.” <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/033020-green-hydrogen-costs-can-hit-2kg-benchmark-by-2030-bnef>

Egypt Today (2021), “Egypt signs MoU with Siemens to develop green hydrogen industry”, <https://www.egypttoday.com/Article/3/107216/Egypt-signs-MoU-with-Siemens-to-develop-green-hydrogen-industry>

EHB (2021), *Analysing Future Demand, Supply, and Transport of Hydrogen*, European Hydrogen Backbone, https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf

Elgendy, K. (2022), “Egypt as an Eastern Mediterranean power in the age of energy transition”, Middle East Institute, www.mei.edu/publications/egypt-eastern-mediterranean-power-age-energy-transition

Eni (2021a), “Eni signs an agreement to produce hydrogen in Egypt”, www.eni.com/en-IT/media/press-release/2021/07/cs-eni-firma-accordo-produzione-idrogeno-egitto.html

Eni (2021b), “Meeting between the CEO of Sonatrach, Toufik Hakkar, and the general manager of Eni – natural resources, Alessandro Puliti”, press release, www.eni.com/en-IT/media/press-release/2021/07/cs-incontro-ad-sonatrach-dg-eni-nr.html

Eni (2020), “Zohr: The giant offshore field in Egypt”, www.eni.com/en-IT/operations/egypt-zohr.html

ENTSO-G and ENTSO-E (2021), *Scenario Building Guidelines*, European Network of Transmission System Operators for Gas and European Network of Transmission System Operators for Electricity, Brussels, Belgium, www.entsog.eu/sites/default/files/2021-10/entsos_TYNDP_2022_Scenario_Building_Guidelines_211007_1.pdf

EQ International (2021), “Egypt: NREA approves the construction of a 50 MWp solar power plant in Zaafarana”, www.eqmagpro.com/egypt-nrea-approves-the-construction-of-a-50-mwp-solar-power-plant-in-zaafarana/

European Commission (2022a), “REPowerEU plan”, <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483> (accessed 19 May 2022).

European Commission (2022b), “EU external energy engagement in a changing world”, <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=JOIN%3A2022%3A23%3AFIN&qid=1653033264976> (accessed 19 May 2022).

European Commission (2020), “A hydrogen strategy for a climate-neutral Europe”, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Farag, M. (2022), “Work on Egypt-Saudi electrical interconnection underway, to conclude in 2026: Minister”, Daily News Egypt, www.zawya.com/en/projects/utilities/work-on-egypt-saudi-electrical-interconnection-underway-to-conclude-in-2026-minister-uanlejtq

FCH (2019), *Hydrogen Roadmap Europe*, Fuel Cells and Hydrogen Joint Undertaking, www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf (accessed 29 June 2021)

Federal Ministry for Economic Affairs and Energy (2020), *The National Hydrogen Strategy*, Federal Ministry for Economic Affairs and Energy, Berlin, Germany, www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html

Fusion Fuel Green PLC (2021), “Press release – Fusion Fuel announces HEVO ammonia Morocco project, aims to produce 183,000 Tons of green ammonia by 2026”, www.globenewswire.com/en/news-release/2021/07/14/2263073/0/en/Fusion-Fuel-Announces-HEVO-Ammonia-Morocco-Project-Aims-to-Produce-183-000-Tons-of-Green-Ammonia-by-2026.html

Gabinete do Ministro do ambiente e da ação climática (2020), “Estratégia Nacional para o Hidrogénio”, Minister of Environment and Climate Action, Portugal, www.portugal.gov.pt/download-ficheiros/ficheiro.aspx?v=%3d%3dBQAAAB%2bLCAAAAAAABAAzNDCyMAUARNeLzAUAAAA%3d

Global Alliance Powerfuels (2020), *Powerfuels in a Renewable Energy World – Global Volumes, Costs, and Trading 2030 to 2050*, LUT University and Deutsche Energie-Agentur GmbH (dena), Berlin, www.powerfuels.org/test/user_upload/Global_Alliance_Powerfuels_Study_Powerfuels_in_a_Renewable_Energy_World_final.pdf

GlobalData (2020), “Data on power sector”, www.globaldata.com/industries-we-cover/power/ (accessed 7 July 2021).

GME (2021), “Historical hourly electricity market prices in Italy”, Gestore dei Mercati Energetici, www.mercatoelettrico.org/En/Default.aspx

Government of the Netherlands (2020), “Government strategy on hydrogen”, www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen

HM Government (2021), “UK hydrogen strategy”, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

Hungarian Government (2021), “Hungary’s national hydrogen strategy”, <https://cdn.kormany.hu/uploads/document/a/a2/a2b/a2b2b7ed5179b17694659b8f050ba9648e75a0bf.pdf>

Hydrogen Council (2021), *Hydrogen Decarbonization Pathways: Potential Supply Scenarios*, Hydrogen Council, Brussels, https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-2_Supply-Scenarios.pdf

Hydrogen Council (2017), *Hydrogen Scaling Up: A Sustainable Pathway for the Global Energy Transition*, Hydrogen Council, Brussels, <https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf>

Hydrogen Europe (2020), *Green Hydrogen for a European Green Deal: A 2x40 GW Initiative*, Hydrogen Europe, Brussels, Belgium, https://static1.squarespace.com/static/5d3f0387728026000121b2a2/t/5e85aa53179bb450f86a4efb/1585818266517/2020-04-01_Dii_Hydrogen_Studie2020_v13_SP.pdf

IEA (2021a), *Global Hydrogen Review 2021*, International Energy Agency, Paris, www.iea.org/reports/global-hydrogen-review-2021

IEA (2021b), *Net Zero by 2050*, International Energy Agency, Paris, www.iea.org/reports/net-zero-by-2050

IEA (2020a), “Data and statistics – Data tables”, International Energy Agency, <https://www.iea.org/data-and-statistics>

IEA (2020b), *Clean Energy Transitions in North Africa*, International Energy Agency, Paris, www.iea.org/reports/clean-energy-transitions-in-north-africa (accessed 5 July 2021).

IEA (2020c), *Energy Technology Perspectives 2020*, International Energy Agency, Paris, www.iea.org/reports/energy-technology-perspectives-2020

IRENA (2022a), *Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part I – Trade Outlook for 2050 and Way Forward*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Global_hydrogen_trade_part_1_2022_.pdf.

IRENA (2022b), *Planning and prospects for renewable power: North Africa; Data appendix*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Dec/IRENA_Planning_Prospects_NAfrica_2022_Data_Appendix.pdf.

IRENA (2021a), *World Energy Transitions Outlook: 1.5°C Pathway*, International Renewable Energy Agency, Abu Dhabi, <https://irena.org/publications/2021/Jun/World-Energy-Transitions-Outlook>

IRENA (2021b), *Planning and Prospects for Renewable Power: Eastern and Southern Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2021/Apr/Planning-and-prospects-for-renewable-power-Eastern-and-Southern-Africa (accessed 6 July 2021).

IRENA (2020a), “Data & statistics”, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Statistics (accessed 7 July 2021).

IRENA (2020b), “Global trends dashboard”, International Renewable Energy Agency, Abu Dhabi, <https://irena.org/Statistics/View-Data-by-Topic/Costs/Global-Trends> (accessed 7 July 2021).

IRENA (2020c), *Green Hydrogen Cost Reduction: Scaling Up Electrolysers to Meet the 1.50C Climate Goal*, International Renewable Energy Agency, Abu Dhabi, https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

IRENA (2020d), *Global Renewables Outlook*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Apr/IRENA_Global_Renewables_Outlook_2020.pdf

IRENA (2019a), “Utility scale batteries: Innovation landscape brief”, International Renewable Energy Agency, Abu Dhabi, www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Utility-scale-batteries_2019.pdf

IRENA (2019b), *Hydrogen: A Renewable Energy Perspective*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective

IRENA (2018a), *Planning and Prospects for Renewable Power: West Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2018/Nov/Planning-and-prospects-for-renewable-power (accessed 29 June 2021).

IRENA (2018b), *Power System Flexibility for the Energy Transition: Part II: IRENA FlexTool Methodology*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Power_system_flexibility_2_2018.pdf?la=en&hash=B7028E2E169CF239269EC9695D53276E084A29AE

IRENA (2017), *Electricity Storage and Renewables: Costs and Markets to 2030*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2017/oct/electricity-storage-and-renewables-costs-and-markets

IRENA and AfDB (2022). “Renewable Energy Market Analysis: Africa and its Regions.” https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jan/IRENA_Market_Africa_2022.pdf

IRENA and LBNL (2015). Renewable Energy Zones for the Africa Clean Energy Corridor - Multi-Criteria Analysis for Planning Renewable Energy. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA-LBNL_Africa-RE-CEC_2015.pdf

Jewkes, S. (2021), “Snam buys stake in Algerian gas pipelines to pave way for hydrogen highway”, Reuters, www.reuters.com/business/eni-agrees-sell-snam-499-stake-algeria-gas-pipelines-385-mln-euros-2021-11-27/

Killer, M., M. Farrokhseresht and N. G. Paterakis (2020), “Implementation of large-scale Li-ion battery energy storage systems within the EMEA region”, *Applied Energy*, Vol. 260/February, pp. 114166, <https://doi.org/10.1016/j.apenergy.2019.114166>

Masen (2021), “Le Maroc s’allie au Portugal pour développer l’hydrogène vert”, Moroccan Agency for Sustainable Energy, www.masen.ma/fr/actualites-masen/le-maroc-sallie-au-portugal-pour-developper-lhydrogene-vert

Masen (2020), “Masen prépare un méga projet dans l’hydrogène vert, une 1ère en Afrique”, Moroccan Agency for Sustainable Energy, www.masen.ma/fr/actualites-masen/masen-prepare-un-mega-projet-dans-lhydrogene-vert-une-1ere-en-afrique

Masen (2016), “Noor Solar Power Station, Ouarzazate”, Moroccan Agency for Sustainable Energy, www.masen.ma/en/projects/noor-ouarzazate (accessed 7 July 2021).

Masen (2015), “National energy strategy”, Moroccan Agency for Sustainable Energy. https://www.masen.ma/themes/custom/masen/assets/files/Brochure__Fiches_Fr.pdf

MAZARS (2016), “Moroccan Agency for Solar Agency S.A.: Rapport d’audit sur les états financiers du projet de centrale solaire d’Ouarzazate (Noor III). Période du 1er Janvier 2015 au 31 Décembre 2015”, <https://documents1.worldbank.org/curated/en/713041542814208881/pdf/Morocco-Noor-Solar-Power-Project-audited-financial-statement-January-1-2015-December-31-2015.pdf>

Med-TSO (2020), “Deliverable 2.2.A: ‘Candidates for pilot projects’”, Mediterranean Transmission System Operators, www.med-tso.com/publications/Deliverable_2.2.A_Candidates_for_Pilot_Projects.pdf

METRE (2015), “National renewable energy development strategy 2015-2030”, Ministry of Energy Transition and Renewable Energies, Algeria. See <https://www.enerdata.net/publications/daily-energy-news/algeria-adopts-renewable-energy-development-plan.html>

Ministère de l’Economie, des Finances et de la Relance (2020), “Stratégie nationale pour le développement de l’hydrogène décarboné en France”, https://minefi.hosting.augure.com/Augure_Minefi/r/ContenuEnLigne/Download?id=5C30E7B2-2092-4339-8B92-FE24984E8E42&filename=DP%20-%20Strat%C3%A9gie%20nationale%20pour%20le%20d%C3%A9veloppement%20de%20l%27hydrog%C3%A8ne%20d%C3%A9carbon%C3%A9%20en%20France.pdf

Ministère de l'Énergie, des Mines et de l'Environnement du Maroc (2021a), “Communiqué de presse du Ministère de l'Énergie, des Mines et de l'Environnement – Conférence sur le thème ‘Les défis de la transition énergétique au Maroc’”, <https://www.mem.gov.ma/Pages/CommuniqueDePresse.aspx?CommuniqueDePresse-427.aspx>

Ministère de l'Énergie, des Mines et de l'Environnement du Maroc (2021b), “Morocco's green hydrogen strategy”, www.mem.gov.ma/Lists/Lst_rapports/Attachments/28/Strategie%20nationale%20de%20l%20Hydrogene%20vert.pdf

Ministère de l'Énergie, des Mines et de l'Environnement du Maroc (2021c), “Press release – Hydrogène vert vecteur de transition énergétique et de croissance durable”, www.mem.gov.ma/Pages/actualite.aspx?act=278

Ministère de l'Énergie, des Mines et de l'Environnement du Maroc (2021d), “Feuille de Route Nationale pour la Valorisation Énergétique de la Biomasse”, www.mem.gov.ma/Lists/Lst_rapports/Attachments/29/ValorisationEnerg%C3%A9tiqueBiomasseMaroc.pdf

Ministère de l'Énergie et des Mines, Algérie (2015), “Énergies nouvelles, renouvelables et maîtrise de l'énergie”, www.energy.gov.dz/?rubrique=energies-nouvelles-renouvelables-et-maitrise-de-lrenergie (accessed 8 July 2021).

Ministerio para la transición ecológica y el reto demográfico (2020), “Hoja de ruta del hidrógeno: Una apuesta por el hidrógeno renovable”, https://energia.gob.es/es-es/Novedades/Documents/hoja_de_ruta_del_hidrogeno.pdf

Ministero dello sviluppo economico (2020), “Strategia Nazionale Idrogeno: Linee guida preliminari”, www.mise.gov.it/images/stories/documenti/Strategia_Nazionale_Idrogeno_Linee_guida_preliminari_nov20.pdf

Ministry of Climate and Environment of Poland (2021), “Draft of the Polish hydrogen strategy for 2030”, www.gov.pl/web/klimat/rozpoczely-sie-konsultacje-publiczne-projektu-polskiej-strategii-wodorowej

Ministry of Electricity and Renewable Energy of Egypt (2016), “Egyptian energy strategy”, <http://nrea.gov.eg/test/en/About/Strategy>

Ministry of Electricity and Renewable Energy of Egypt (2012), “Egyptian solar plan”, https://unece.org/fileadmin/DAM/energy/se/pp/eneff/6th_IFESD_Yerevan_Oct.15/d1_ps1/Ahmed.Mehina.Egypt.pdf

Ministry of Electricity and Renewable Energy of Libya (2013), “Renewable energy strategic plan 2013-2025”, <https://www.iea.org/policies/5908-libya-renewable-energy-strategic-plan-2013-2025>

Ministry of Energy and Mining of Algeria (2015), “Renewable energy and energy efficiency development plan 2015-2030”, <https://www.iea.org/policies/6103-renewable-energy-and-energy-efficiency-development-plan-2015-2030>

Ministry of Environment and Sustainable Development of Tunisia (2015), “Intended Nationally Determined Contribution of Tunisia”, www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Tunisia%20First/INDC-Tunisia-English%20Version.pdf

Ministry of Industry, Energy and Mines of Tunisia (2015), “Énergies renouvelables – Projets et programmes”, www.energiemines.gov.tn/fr/themes/energies-renouvelables/projets-et-programmes/

NEPCO (2019), *Annual Report 2019*, Technical Report, National Electric Power Company, The Hashemite Kingdom of Jordan, www.nepco.com.jo/store/DOCS/web/2019_en.pdf

NREL (2021), *Cost Projections for Utility-Scale Battery Storage: 2021 Update*, National Renewable Energy Laboratory, Golden, CO, www.nrel.gov/docs/fy21osti/79236.pdf

OMIE (2021), “Historical hourly electricity market prices in Spain”, <https://www.omie.es/>

ONEE (2019), “Conseil d’Administration de l’ONEE – L’office inaugure une nouvelle etape avec un ambitieux programme d’investissement pour la periode 2019-2023”, Office National de l’Electricité et de l’Eau Potable, Morocco, www.onep.ma/news/2019/CA-2019/Dos-spec-CA-ONEE_Fr.pdf

Poncelet, K., E. Delarue, D. Six, J. Duerinck and W. D’haeseleer (2016), “Impact of the level of temporal and operational detail in energy-system planning models”, *Applied Energy*, Vol. 162/ January, pp. 631-643, <https://doi.org/10.1016/j.apenergy.2015.10.100>

Radio Algérienne (2021), “Energie solaire: lancement d’un appel d’offre pour la réalisation de centrales de 1000 Mw”, www.radioalgerie.dz/news/fr/article/20210617/213403.html (accessed 2 August 2021).

Redouane, A., M. Masaki, M. Meijer and H. Essakkati (2018), *Business Opportunities Report for Morocco’s Renewable Energy Sector*, Netherlands Enterprise Agency – RVO, Utrecht, The Netherlands, www.rvo.nl/sites/default/files/2018/06/Business-opportunities-report-for-moroccos-renewable-energy-sector.pdf

Reuters (2021a), “Egypt aims to generate 42% of power from renewables by 2030”, [www.reuters.com/business/sustainable-business/egypt-aims-generate-42-power-renewables-by-2030-2021-11-04/#:~:text=CAIRO%2C%20Nov%204%20\(Reuters\),petroleum%20minister%20Tarek%20el%20Molla](http://www.reuters.com/business/sustainable-business/egypt-aims-generate-42-power-renewables-by-2030-2021-11-04/#:~:text=CAIRO%2C%20Nov%204%20(Reuters),petroleum%20minister%20Tarek%20el%20Molla)

Reuters (2021b), “Eni teaming up with Sonatrach for production of hydrogen in Algeria”, www.reuters.com/business/energy/eni-teaming-up-with-sonatrach-production-hydrogen-algeria-2021-07-07/ (accessed 2 August 2021).

Shell (2021), “The energy transformation scenarios”, <https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/the-energy-transformation-scenarios.html>

Siemens (2021), “Press Release – Siemens Energy supports Egypt to develop green hydrogen industry”, <https://press.siemens-energy.com/mea/en/pressrelease/siemens-energy-supports-egypt-develop-green-hydrogen-industry>

SolarPACES (2011a), “ISCC Hassi R’mel power plant”, www.solarpaces.org/csp-technologies/csp-potential-solar-thermal-energy-by-member-nation/algeria/ (accessed 8 July 2021).

SolarPACES (2011b), “ISCC Kuraymat CSP project”, <https://solarpaces.nrel.gov/iscc-kuraymat> (accessed 8 July 2021).

Sonelgaz (2019), “Hybridation de centrales diesels et turbines à gaz dans le grand Sud – Signature des contrats de réalisation de 50 MWc en photovoltaïque”, www.sonelgaz.dz/fr/2886/hybridation-de-centrales-diesels-et-turbines-a-gaz-dans-le-grand-sud (accessed 2 August 2021).

S&P Global Platts (2019), “BP says gas finds offshore Mauritania, Senegal of ‘world-class scale’”, www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/121619-bp-says-gas-finds-offshore-mauritania-senegal-of-world-class-scale (accessed 29 June 2021).

S&P Global Platts (2021), “Scatec partners with Fertiglobe on 100-MW Egypt green hydrogen plant for ammonia”, www.spglobal.com/platts/en/market-insights/latest-news/electric-power/101421-scatec-partners-with-fertiglobe-on-100-mw-egypt-green-hydrogen-plant-for-ammonia

Sterl, S. (2021), “A grid for all seasons: Enhancing the integration of variable solar and wind power in electricity systems across Africa”, *Current Sustainable/Renewable Energy Reports*, Vol. 8, pp. 274-281, <https://doi.org/10.1007/s40518-021-00192-6>

Sterl, S., A. Devillers, C. J. Chawanda, A. van Griensven, W. Thiery and D. Russo (2021), “A spatiotemporal atlas of hydropower in Africa for energy modelling purposes”, *Open Research Europe*, Vol. 1, pp. 29, <https://doi.org/10.12688/openreseurope.13392.3>

Stevenson, P. (2022), “Zohr production cap pushes Egypt output lower”, MEES, www.mees.com/2022/6/17/oil-gas/zohr-production-cap-pushes-egypt-output-lower/2e930280-ee37-11ec-80ab-1f22145b8e02

Timmerberg, S. and M. Kaltschmitt (2019), “Hydrogen from renewables: Supply from North Africa to Central Europe as blend in existing pipelines – Potentials and costs”, *Applied Energy*, Vol. 237/March, pp. 795-809, <https://doi.org/10.1016/j.apenergy.2019.01.030>

Toktarova et al. (2019). “Long term load projection in high resolution for all countries globally.” *Int. J. Elec. Power Energy Syst.* 111, 160–181 (2019).

Tunisian Ministry of Industry, Energy and Mines (2020), “Signature MoU alliance tuniso-allemande sur l’hydrogène”, https://www.energiemines.gov.tn/fr/tc/actualites/news/signature-mou-alliance-tuniso-allemande-sur-lhydrogene/?tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Baction%5D=detail&cHash=122be77299a093545f88b662e74bf558

Tunisian Ministry of Industry, Energy and Mines (2019), “Concession regime for renewable energy”, www.energiemines.gov.tn/fr/themes/energies-renouvelables/projets-et-programmes/regime-des-concessions/ (accessed 7 July 2021).

UNFCCC (2021a), “All LT-LEDS”, Long-Term Strategies Portal, United Nations Framework Convention on Climate Change, <https://unfccc.int/process/the-paris-agreement/long-term-strategies> (accessed 25 June 2021).

UNFCCC (2021b), “All NDCs”, NDC Registry, United Nations Framework Convention on Climate Change, www4.unfccc.int/sites/NDCStaging/Pages/All.aspx (accessed 25 June 2021).

UNSD (2022), “Energy balance database 1990-2019”, United Nations Statistics Division, <https://unstats.un.org/unsd/energystats/dataPortal/>

van Rossum, R., J. Jens, G. La Guardia, A. Wang, L. Kühnen and M. Overgaag (2022), “European hydrogen backbone”, <https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf> (accessed 19 May 2022).

WEC (2016), *World Energy Scenarios 2016: The Grand Transition*, World Energy Council, London, www.worldenergy.org/publications/entry/world-energy-scenarios-2016-the-grand-transition.

World Bank (2021), “World Bank database – GDP”, <https://data.worldbank.org/indicator/NY.GDP.MKTP.CD>

World Bank (2020), “Power system implications of subsidy removal, regional electricity trade, and carbon constraints in MENA economies”, Policy Research Working Paper 9297, World Bank, Washington, DC, <https://openknowledge.worldbank.org/handle/10986/33992>

World Bank (2019), “World Bank database – Access to electricity”, <https://data.worldbank.org/indicator/EG.ELC.ACCS.ZS>.

Timilsina and Deluque Curiel (2020). Power System Implications of Subsidy Removal, Regional Electricity Trade, and Carbon Constraints in MENA Economies. World Bank Policy Research Working Paper 9297. <https://documents1.worldbank.org/curated/en/783251592940144153/pdf/Power-System-Implications-of-Subsidy-Removal-Regional-Electricity-Trade-and-Carbon-Constraints-in-MENA-Economies.pdf>

ZAWYA (2019), “Egypt’s NREA to launch tender for 20MW solar power plant in Hurghada in September”, <https://www.zawya.com/en/business/egypts-nrea-to-launch-tender-for-20mw-solar-power-plant-in-hurghada-in-september-nx6bsxsv>

Zgheib, N. (2022), “EBRD assesses low-carbon hydrogen in Egypt”, www.ebrd.com/news/2022/ebrd-assesses-lowcarbon-hydrogen-in-egypt.html (accessed 19 May 2022).



© IRENA 2023

www.irena.org