2050
Desert Power

Perspectives on a Sustainable Power System for EUMENA

Dii
Renewable energy bridging continents

Acknowledgements

Authors: Florian Zickfeld, Aglaia Wieland (Dii)

Co-authors: Julian Blohmke, Matthew Sohm, Ahmad Yousef (Dii)

Contributors: Frank Buttinger, Angelika Denk, Patrik Erroi, Philipp Godron, Jürgen Neubarth, Alexander Rietz, Fabian Wigand (Dii)
Dii Shareholders and Associated Partners as well as numerous third party experts have made significant contributions at all stages writing this report

Scientific authors: Martin Pudlik, Mario Ragwitz, Frank Sensfuß (Fraunhofer ISI)

Dii GmbH was founded as a private industry joint venture in October 2009. Today, Dii has 21 Shareholders and 35 Associated Partner companies from 16 countries in Europe as well as the Middle East and North Africa (MENA). Together with a wide range of stakeholders, Dii enables an industrial scale market for renewable energy in MENA. To this end, Dii is formulating a long-term vision and translating it into country specific assessments, a regulatory framework and concrete reference projects.

Since its inception in 1972, **Fraunhofer ISI** has been influential in shaping the German and international innovation landscape. The Fraunhofer Institute for Systems and Innovation Research ISI conducts applied research in seven Competence Centers with a total of 22 Business Units and sees itself as an independent institute for society, politics and industry.

Published in June 2012 by

Dii GmbH
Kaiserstr. 14
80801 Munich
Germany

For more information:

www.dii-eumena.com
dp2050@dii-eumena.com

MIX
Paper from responsible sources
FSC® C003404

Print CO2 compensated

2050
Desert Power

>> **Both regions are natural partners** and can enable this fundamental transformation together as EUMENA

>> MENA and Europe both need a **secure, affordable and clean supply of electricity**

>> **All countries benefit** from access to affordable renewable energy, the creation of new industries, and reduced cost of decarbonization

>> Supply and demand for renewable energy are **complementary** in the south and north in all seasons

>> It is essential to **act together today as EUMENA** to realize this enormous potential by 2050

>> Mutual reliance and technical complementarity across EUMENA enhance **security of supply**

Table of Contents

1 Executive Summary: The Case for Desert Power ... 6
1.1 From resources to electricity ... 7
1.2 Benefits of desert power ... 10
1.2.1 Competitiveness ... 10
1.2.2 Sustainability ... 12
1.2.3 Security of supply ... 14
1.3 Perspectives on desert power ... 18
1.4 Conclusion: time to get started ... 21
2 The Basis of Desert Power for EUMENA ... 23
2.1 Methodology ... 25
2.2 Demand and carbon emissions ... 29
2.3 Transmission technology ... 32
2.4 Power generation and storage technologies ... 35
2.4.1 Conventional power technologies ... 36
2.4.2 Non-Solar/Wind renewables ... 36
2.4.3 Storage technologies ... 39
2.4.4 Solar and Wind technologies ... 41
2.5 Solar and Wind potential in EUMENA ... 48
3 The Shape of Desert Power for EUMENA ... 54
3.1 Economic benefits of system integration ... 55
3.2 Climate action benefits of system integration ... 60
3.3 Power production for EUMENA ... 61
3.4 Power transmission in EUMENA ... 69
3.5 The integration miracle: what grids do for individual countries ... 79
3.5.1 The big picture: system level ... 79
3.5.2 Deep dives: implications on country level ... 83
3.6 Desert power enhances energy security across EUMENA ... 94
3.6.1 Desert power and the paradigm change of renewable energy ... 95
3.6.2 EU-MENA interdependence ... 96
3.6.3 Europe's insurance policy: gas back-up capacities ... 97
3.6.4 Desert power as a long-term, systemic transformation ... 98
3.6.5 A diversified power supply for EUMENA ... 98
4 Perspectives on Desert Power for EUMENA ... 99
4.1 Perspectives definitions ... 100
4.2 Perspectives overview ... 102

4.2.1 Perspectives on EUMENA-wide system integration 102
4.2.2 Perspectives on system cost 103
4.3 Benefits of low demand 106
4.4 Paradigm shift perspectives 111
4.4.1 Delayed climate action 111
4.4.2 Nuclear/CCS 114
4.5 Medium impact changes 116
4.5.1 High land use Europe 116
4.5.2 Delayed grids 118
4.5.3 High capital cost MENA 121
4.6 Low impact changes 123
4.6.1 Maximum cooperation 123
4.6.2 No NREAPs 124
4.6.3 Delayed renewables cost curves 125
4.6.4 Cheap batteries 126
5 Conclusion: Time to Get Started 127
5.1 Roll-out of Solar and Wind in MENA 128
5.2 Transmission highways between MENA and Europe 129
5.3 Support scheme design 130
5.4 Socio-economic effects 131
5.5 Last but not least 133
6 Definitions 134
7 List of Tables 137
8 List of Figures 138
9 Appendix 140

1 Executive Summary: The Case for Desert Power

Creating a secure, affordable and clean electricity supply is one of the key challenges facing North Africa, the Middle East and Europe. How can the Middle East and North Africa supply their growing economies with secure and affordable electricity? How can the EU reach its ambitious climate action goals in a way that is both sustainable and economic?

Desert Power 2050 (DP2050) examines the future energy challenges of Europe as well as the Middle East and North Africa (MENA). It shows that these challenges can best be addressed by moving beyond the currently predominant view of the two regions as separate entities. Indeed, Europe and MENA are not just neighbors, tied together by a long history of trade and cultural exchange; in a world of renewable energy, EUMENA should be viewed as a single region.

An integrated EUMENA power system allows Europe to meet its CO_2 reduction targets of 95% in the power sector more effectively and more economically by importing up to 20% of its electricity demand from MENA. Europe thereby saves a total of €33bn. annually, or €30 per MWh of power imported from MENA. Meanwhile, desert power enables MENA countries to supply their own energy needs reliably from the abundant solar and wind resources in the region. MENA can thereby contribute to a 50% CO_2 reduction in its power sector despite a massive increase in demand. At the same time, MENA benefits from an export industry worth up to €63bn. per year. Furthermore, Europe as well as MENA profit from a 40% drop in the marginal cost of CO_2 emission reductions in the power sector.

The idea that renewable electricity should be produced in areas with optimal resources and exported to regions with high demand has become known as the Desertec vision. This intuitive notion suggests that Europe should source some of its electricity production from the deserts on the southern shore of the Mediterranean, with their excellent solar and wind resources and sparsely populated land.

Desert Power 2050 shows how key aspects of the Desertec vision could work in practice while also moving beyond it. It demonstrates how, based on proven technologies, solar and wind resources can be combined with grids to securely supply North Africa, the Middle East and Europe with sustainable and affordable power. It thus expands on previous thinking and considers MENA as a consumer of renewable energy, not just as a producer.

There is great urgency to move towards such a system: the population in the EUMENA region is expected to grow by up to 45% to almost 1.2bn. in 2050, when power demand could exceed 8000TWh. With MENA growing faster than the EU, it is in the interest of the entire region to replace its reliance on volatile fossil fuel prices with a stable, sustainable power system.

Desert Power 2050 shows why an interconnected, renewables-based power system for EUMENA is valuable for reasons of competitiveness, sustainability and security of supply. This requires a paradigm shift from today's weakly interconnected, fossil fuel-based system to an integrated, sustainable one. Enabling this transition will be the topic of the second part of Dii's 2050 strategy, **Desert Power 2050: Getting Started**.

1.1 From resources to electricity

The sheer size of largely unused land and favorable climatic conditions in the MENA region makes it an ideal location for renewable electricity production. Figure 1 shows the availability of excellent solar resources in MENA. Prime sites can be found everywhere in the region, from the High Atlas and Tell Atlas in the Maghreb to the Asir Mountains in Saudi Arabia.

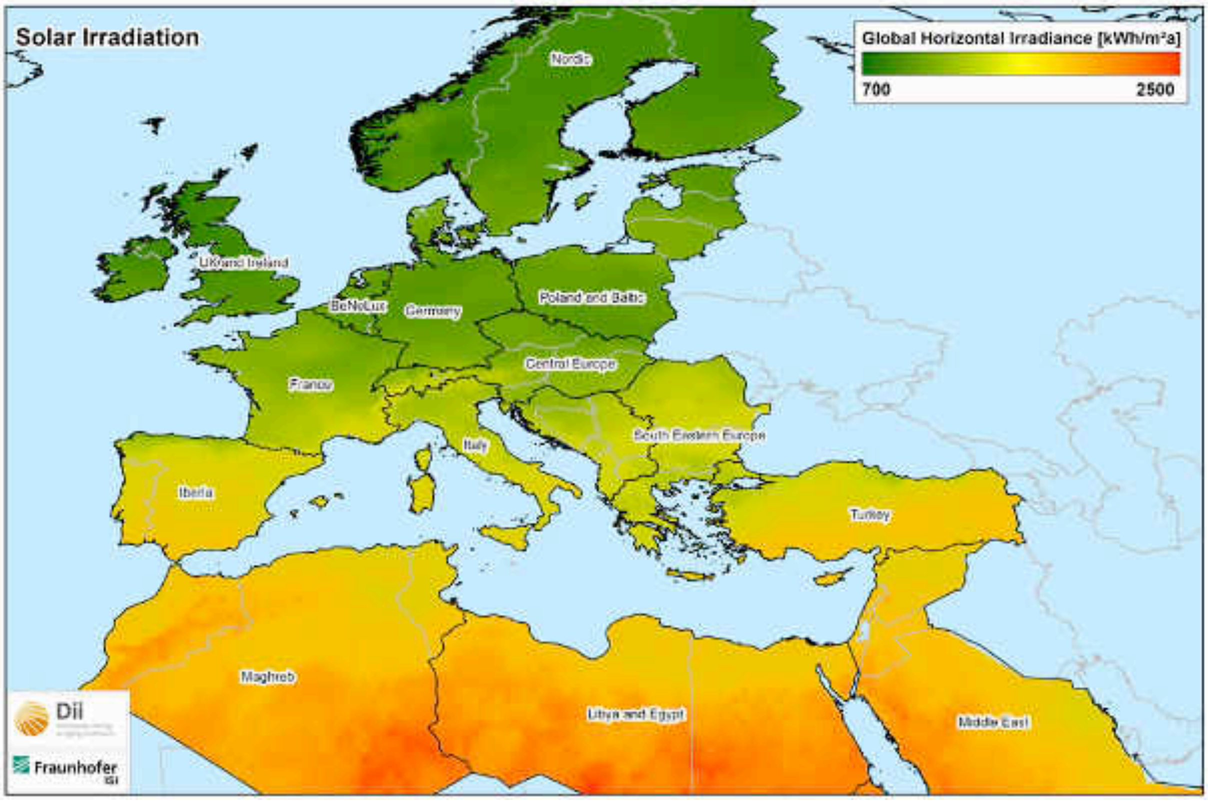


Figure 1: Solar resources in the EUMENA region

Less widely known, but no less important, MENA also has favorable wind conditions, as depicted in Figure 2. Exceptional wind potentials can be found, for example, on Morocco's Atlantic coast and the Red Sea. Furthermore, the entire continent, stretching between these two coasts, hosts attractive sites for wind power generation.

Of course, the mere abundance of renewables resources does not automatically translate into a power system that works reliably 24 hours a day, 365 days a year. Therefore, Dii has joined forces with Fraunhofer ISI to model the EUMENA power system in high time and spatial resolution. The continuous involvement of industry experts, particularly from Dii's network of 56 partner companies across the EUMENA region, was equally important for the whole analysis. Using ISI's proven PowerACE model, we demonstrate the potential of Solar and Wind[1] technologies to affordably

[1] Please note that "Solar", "Wind", etc. refer to the respective technologies, while "solar", "sun" and "wind" refer to the naturally occurring phenomena

supply demand across the entire EUMENA region in every single hour of a whole year. Figure 3 shows the basis for these analyses: compared to power demand, the Solar and Wind potential in EUMENA is virtually infinite, e.g. Wind and Solar potential costing less than 50€/MWh (in 2050) amounts to 10,000TWh.

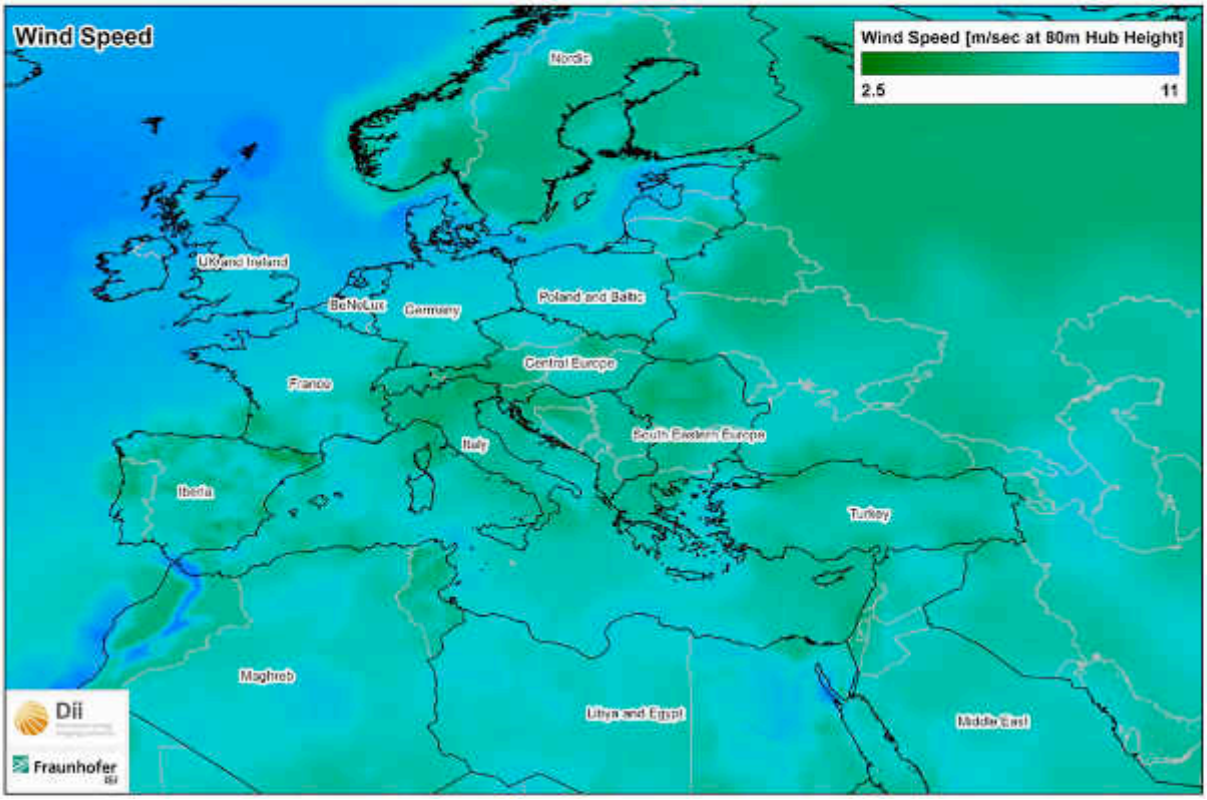


Figure 2: Wind resources in the EUMENA region

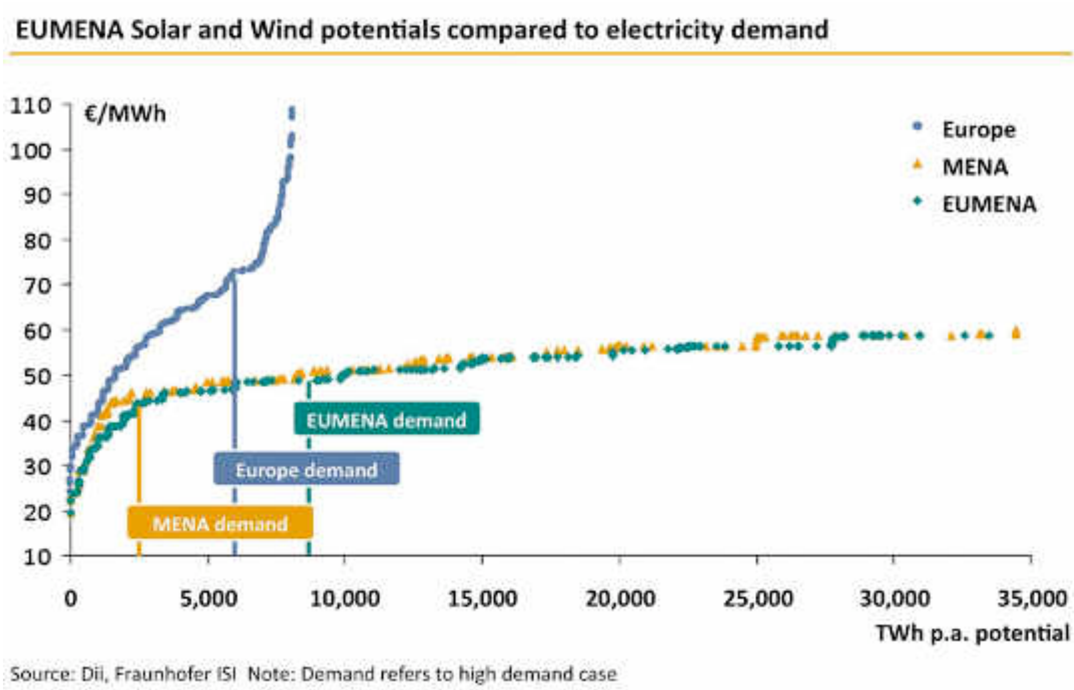


Figure 3: Renewable energy potentials and electricity demand 2050 in MENA and Europe

The use of proven technologies will ensure the technical feasibility of a sustainable power system. The focus technologies of this report are all widely used today – utility scale photovoltaic (Utility PV) and concentrating solar power (CSP) technologies as well as on-shore and off-shore Wind. Their worldwide installed capacity has reached gigawatt (GW) scale, with installations that have been in continuous use for more than two decades.

Economic viability, however, has not yet been achieved on a sufficiently broad scale. Renewables have shown impressive cost reductions in the past years. Yet they have not yet reached full cost competitiveness with conventional power technologies in many markets. One of the key aims of this study is to show how desert power optimizes cost and helps make a renewable energy-based power system economically viable.

With 2050 as a time horizon, we aim to understand the design of an optimized target picture based on cost projections for the four technologies under consideration. As Figure 4 shows, significant cost reductions of around 50% or more are expected for all technologies, except for Wind on-shore costs, which are estimated to decline by 20-30%, since this technology is already mature and cost competitive today. Just a few years ago, these projections may have appeared aggressive, but recent developments in PV and on-shore Wind show they are possible. Moreover, cost developments depend on market developments. This report will show that supporting the growth of such markets for Solar and Wind is in the interest of governments that seek to provide a competitive, sustainable and secure energy supply.

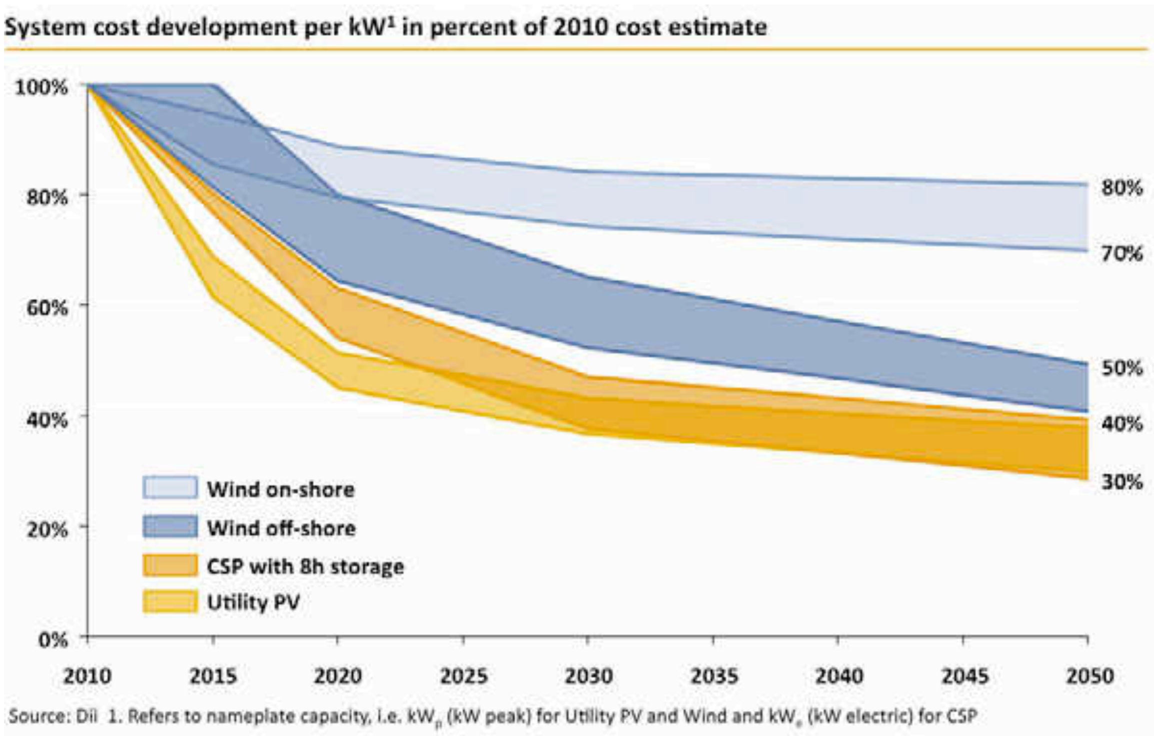


Figure 4: Cost reduction pathways for Wind and Solar technologies until 2050

In order to assess the added value of power system integration across the Mediterranean, we compare two scenarios. The 2050 target picture in the **Connected Scenario** examines a power system with full, EUMENA-wide integration. The **Reference Scenario**, meanwhile, depicts a situation where each region, Europe and MENA, is fully optimized in itself but without cooperation between the two systems. In other words, both DP2050 scenarios assume a paradigm shift to a renewables-based power system, with considerable investment in grids and renewable energy generation. Both the Connected and Reference Scenarios are optimized for minimum system cost under an EUMENA carbon emission cap of 0.25Gtonnes p.a., i.e. approx. 30g per kWh of demand[2]. Thus, in the Reference Scenario, the European part alone is similar to the optimized power systems analyzed in the European Commission's Roadmap 2050; the main difference is that it still profits from a common carbon cap with MENA.

1.2 Benefits of desert power

DP2050 adopts the three main pillars of European energy policy to assess the study's key findings. It shows how an integrated EUMENA power system is beneficial to the competitiveness of the EUMENA region, makes a signal contribution to affordable sustainability, and improves overall security of supply in EUMENA.

1.2.1 Competitiveness

Desert power helps improve the competitiveness of the EUMENA power system by making the achievement of ambitious CO_2 reduction goals more economic. The competitive advantage of an EUMENA-wide power system results from a total of 1110TWh of annual power exchange, thereof 1087TWh from MENA to Europe and 23TWh from Europe to MENA[3]. Thus, the trade balance amounts to 1064TWh of annual net exports from MENA to Europe. The Connected Scenario saves €33bn. per year in system cost. For the approx. 1110TWh of annual power exchange between MENA and Europe, this amounts to approx. 30€/MWh.

As the south to north power flows clearly dominate the power trade balance, Europe imports up to 20% of its electricity from North Africa. A minimum 70% self-supply rate has been imposed on a national basis to ensure that no country becomes overly reliant on imported power. Europe clearly benefits from its role as a net importer, due to system cost savings of €30 per MWh of its net imports, see Figure 5. Half of these system cost savings, 15€/MWh, stem from the direct cost advantage of desert power, as shown in Figure 5: the average cost of each additional MWh generated in MENA in the Connected Scenario is 58€/MWh by the time it arrives in Europe[4]. This is compared to the average cost of 73€/MWh for each additional MWh produced by Europe in the Reference Scenario. The other half of the savings results from the fact that a larger system offers more options to balance the load and the output of Solar and Wind power plants. Fewer gas peakers for balancing need to be built and less excess production by renewables, i.e. curtailment, occurs. This reduction in capacity leads to savings of an additional €15 per MWh of MENA exports to Europe.

[2] The minimum system cost includes the cost of power generation and transmission but not the cost of carbon emissions

[3] The power trade figures refer to the power arriving in either Europe or MENA, i.e. transmission losses have been subtracted from these figures

[4] 58€/MWh includes the cost of power production, power transmission and transmission losses

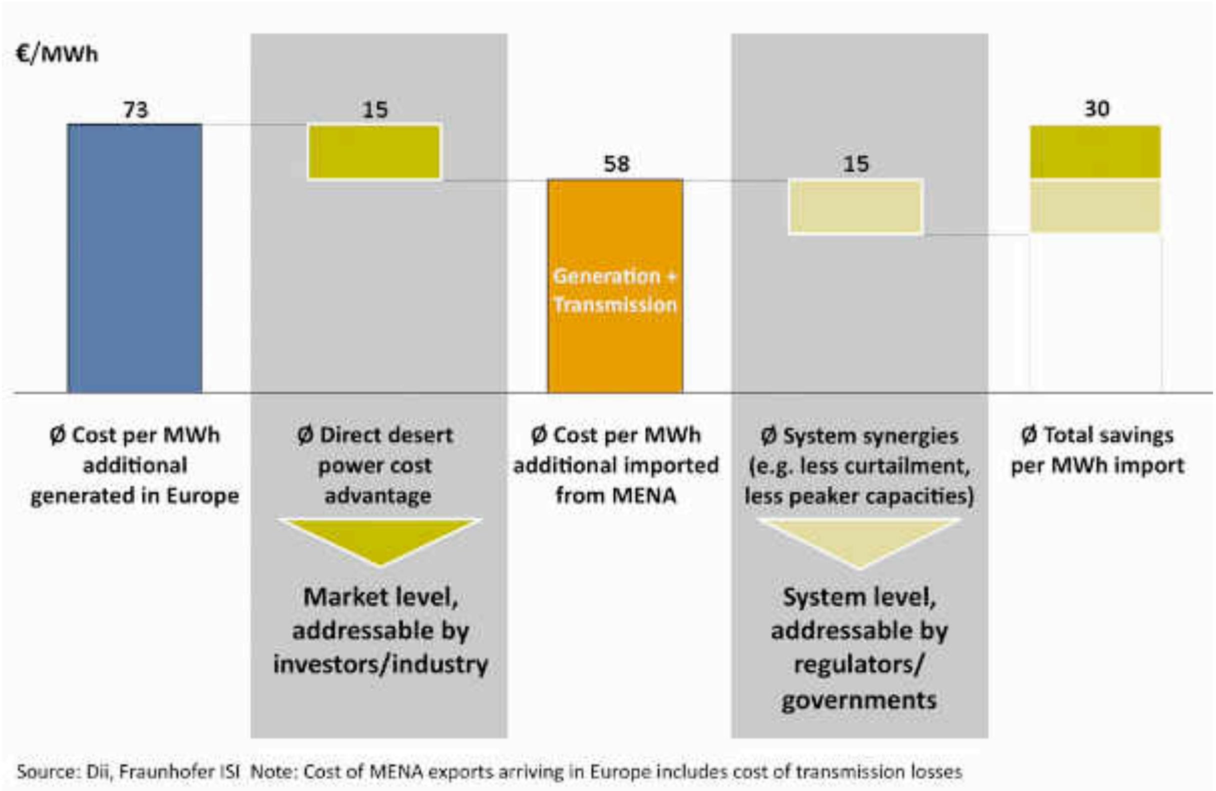


Figure 5: System cost savings per MWh of net power exports from MENA to Europe

It is crucial to differentiate between these two forms of cost savings. Producing power in MENA that arrives in Europe at a cost of approx. 20% below domestic European alternatives provides a viable business model: it can be realized by market players and investors. Thus, this part of the cost benefits will be addressed by industry once carbon emission limits are in place and renewables technologies have moved down the cost curve.

On the other hand, no market player can do business by delivering benefits to the system that are based on system-wide synergies, such as the 220TWh of electricity that no longer need to be produced in the Connected Scenario. These synergies are, however, a major economic benefit that, among other advantages, can add to the EUMENA region's competitiveness in the global economy. These system-level advantages therefore should be addressed by governments and regulators: public institutions need to provide the appropriate structures and incentive schemes for the market to realize these economic benefits.

Overcoming this situation, a classic Nash equilibrium, is a challenging task in a market-based economy. It is part of the reason why grid extensions are making such slow progress in Europe today, despite widespread agreement that more grids are needed. Thus, well-designed, reliable and purposeful policies for both renewables technologies and grids are urgently required to achieve system integration. The engagement of governments and regulators in this area would, in turn, trigger greater investment.

The resulting benefits for both Europe and MENA are significant: Europe achieves cost savings of approx. €33bn. p.a., while MENA acquires an export industry for renewable electricity worth up to €63bn. p.a. – more than all of the current exports of Egypt and Morocco combined.

1.2.2 Sustainability

Our analyses confirm that a power system based on more than 90% renewable energy is technically possible and economically viable. The effect of EUMENA-wide system integration on the marginal cost of carbon emission reductions in the power sector is impressive: it drops by 40% from 192€/tonne in the Reference Scenario to 113€/tonne in the Connected Scenario. Power system integration can thus play a major role in creating a robust and cost effective pathway towards decarbonization. This lower cost of carbon emission reduction is achieved through an optimized mix of renewables technologies, whereby power from the sun and wind is produced in the most favorable locations throughout EUMENA.

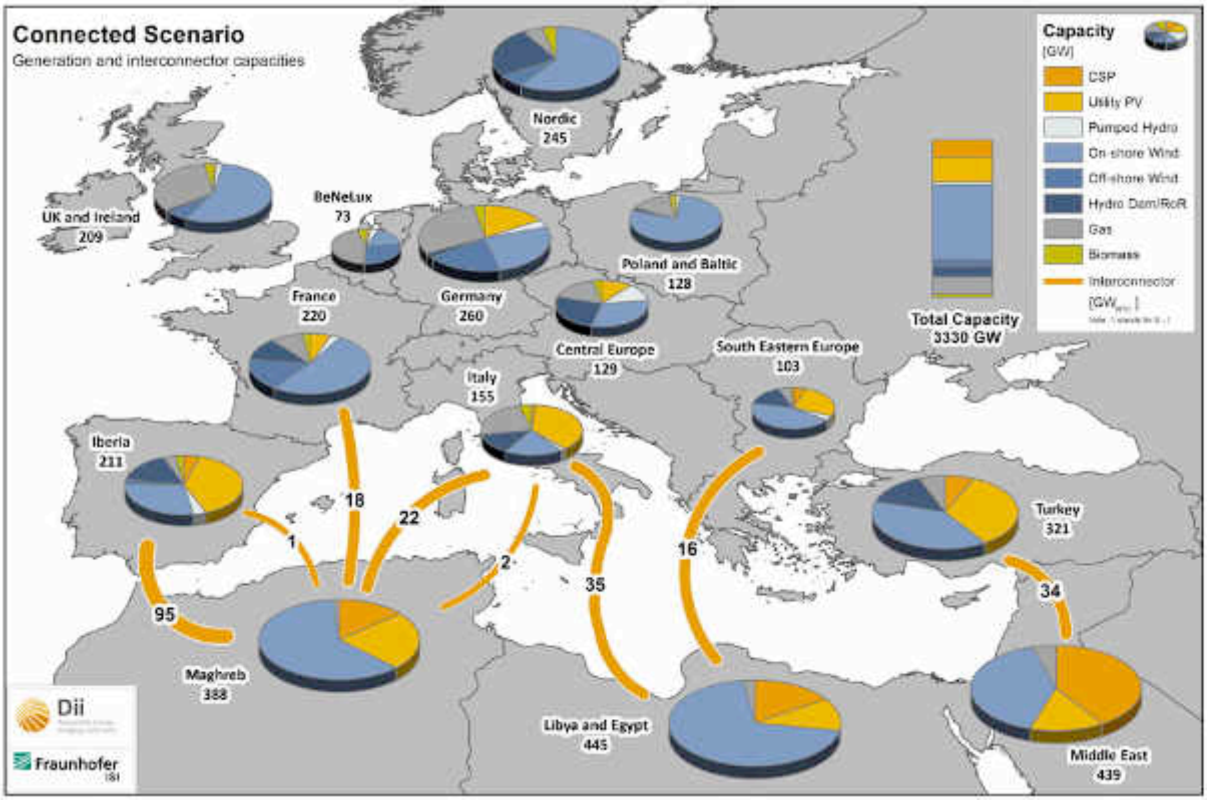


Figure 6: Generation and interconnector capacity, Connected Scenario

The Desert Power 2050 electricity mix is made up of 91% renewables and 9% natural gas. Wind contributes 53% to the mix, of which 48% on-shore and 5% off-shore Wind, and is installed everywhere in EUMENA, see Figure 6[5]. Solar contributes another 25%, with a concentration of installations in southern Europe and MENA. While the 16% share of CSP in the power mix is almost entirely allocated in MENA, the 9% share of Utility PV production is installed in MENA as well as in southern Europe[6]. Solar installations further north, especially in Germany, are based on the NREAPs[7] of the respective EU member states. In short, a cost optimized, sustainable EUMENA power system requires the installation of hundreds of gigawatts of the four focus Solar and Wind technologies:

[5] Off-shore Wind is only considered for Europe, since the conditions in MENA are not attractive enough

[6] Distributed PV installations are not addressed by the methodology used to analyze the benefits of a large-scale power system integration. That said, widespread Distributed PV can contribute to a scenario of low demand in the grid, which is the lowest cost scenario analyzed in DP2050

[7] National Renewable Energy Action Plans

Utility PV, CSP, on-shore Wind and off-shore Wind. The rest of the power mix consists of hydro power, biomass, geothermal and a few other renewables technologies.

This cost optimized power mix relies heavily on the use of a high voltage direct current transmission grid. Without such a grid, it will be impossible to bring power from the best solar, wind and hydro sites in the sparsely populated north and south to high demand regions in the center of the system, see Figure 7.

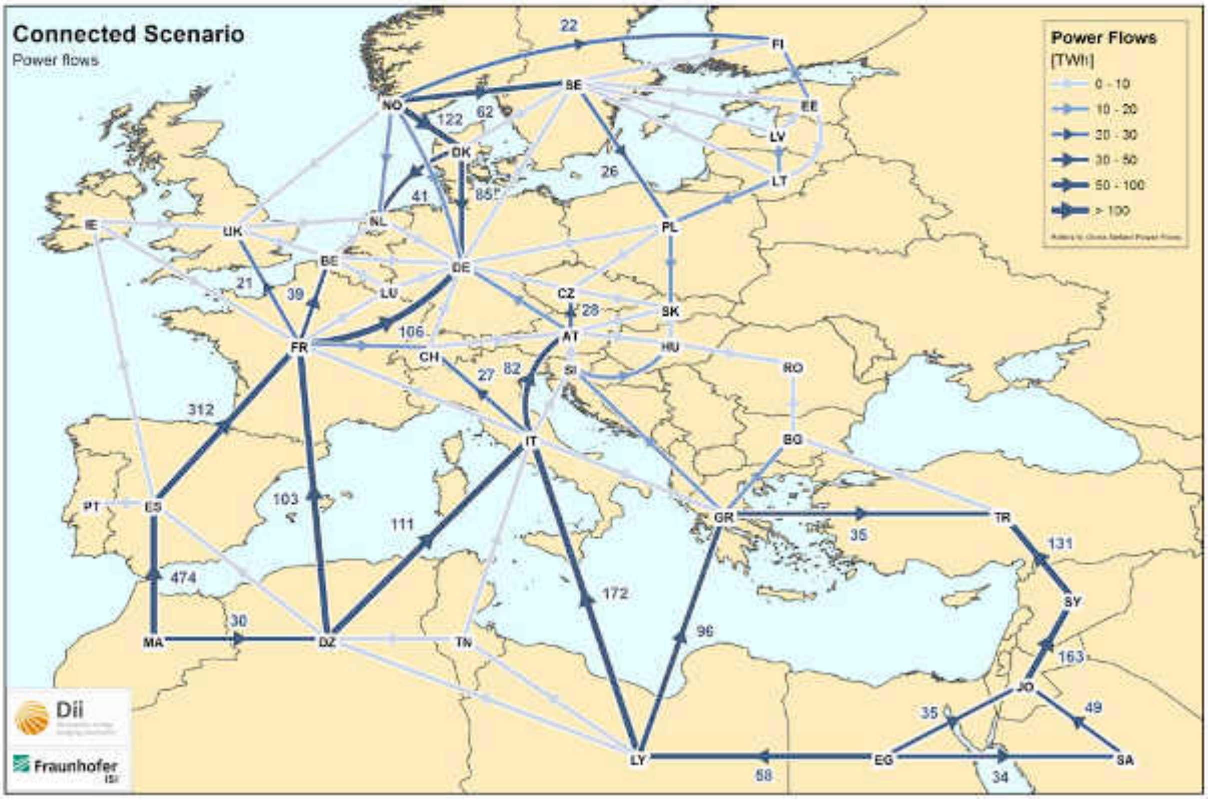


Figure 7: Power flows in the Connected Scenario

The Maghreb and Libya are the southern “powerhouses” of the region, while Scandinavia, especially Norway, plays the same role in the far north. Power flows from the south reach Europe via seven sub-Mediterranean transmission corridors and are then passed on north from Spain, France, Italy and Greece to the UK, BeNeLux countries, Germany, Austria, and the Czech Republic. In the belt from BeNeLux to the Czech Republic, desert power then meets the power flows from Norway via Denmark, Sweden and Poland. An eighth south-north corridor brings power from Egypt and Saudi Arabia on to Turkey.

An aspect emphasized by our study is the strong need for power in the south eastern part of the system. Indeed, Turkey and Egypt could well have the largest population and highest power demand in the region in 2050. Due to high per capita consumption, Saudi Arabia will likely be of a similar size in terms of power demand. These three countries, together with Jordan and Syria, contribute approx. 33% of total EUMENA demand – as much as the four largest EU economies Germany, France, the UK and Italy together. Unlike most of the major economies in the center of Europe, the region enjoys good solar and wind conditions and does not rely on imports. Due to the high demand in the Middle East and Egypt, most of the desert power produced there will be consumed locally. Given their relatively small populations and abundant renewables resources, the Maghreb countries and Libya export large quantities of power to Europe.

The total capacity of the sub-Mediterranean connections and the Syria-Turkey overland connection amounts to 222GW_{NTC}[8], see the left part of Figure 8. Around 1100TWh of electricity per year flows through these connections between MENA and Europe. Due to these interconnectors' high utilization rates, power transmission across the Mediterranean is affordable.

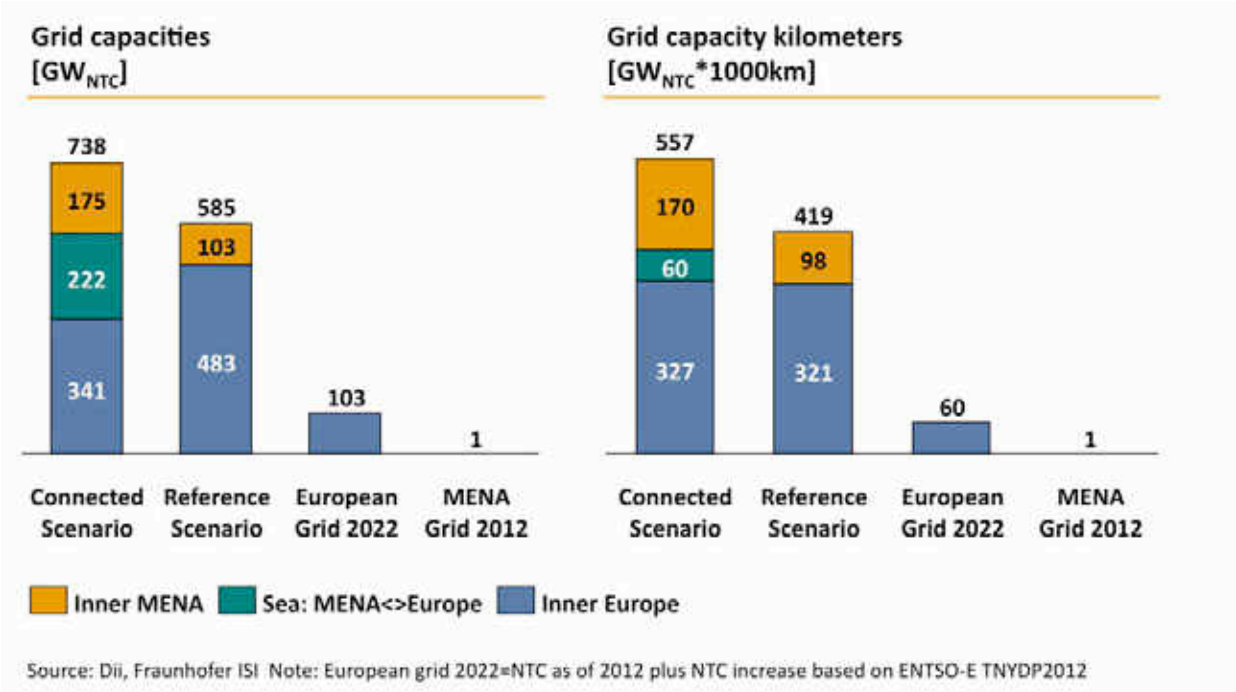


Figure 8: Transmission grid capacities in the Connected Scenario and the Reference Scenario

The 557,000GW_{NTC}*km capacity needed are not only much larger than the ones currently connecting the south and the north of the system[9] but are also far larger than any existing within Europe and MENA today. In comparison to the Reference Scenario of two separate cost optimized systems, most additional overland transmission infrastructure (measured in capacity kilometers) is needed in MENA, not the densely populated European mainland, as shown in the right part of Figure 8.

Europe needs to build grids in order to enable a cost efficient power system based on renewables – no matter whether such a system ends at Europe's borders or goes beyond them. The benefit to Europe of such grid expansion is a sustainable, affordable and reliable power supply; the further the integration of the grid reaches, the larger the benefits become.

1.2.3 Security of supply

Security of supply comprises both technical and political complementarities. As our analysis suggests, system integration makes a sustainable power system not only more affordable but also more

[8] GW_{NTC} refers to GW of net transfer capacity
[9] 250MW Turkey/Syria (not synchronized) and 900MW Spain/Morocco

reliable. In order to show how this occurs, we look first at technical complementarities and then proceed to examine the mutual reliance created by an integrated system.

Intuitively, the larger a connected system is, the higher the probability that the sun shines and the wind blows somewhere in the area covered. This is essential for a power system based on 90% renewables, since avoiding blackouts means ensuring that there are sufficient Solar and Wind resources to meet demand 24 hours a day, 365 days a year. Figure 9 shows that this intuition is not only correct, but that the natural correlation of sun and wind is favorable from a power supply point of view. In order to understand power supply over time, one needs to look at daily changes as well as seasonal variations. Figure 9 shows an average summer and an average winter day in EUMENA in terms of power demand and supply in hourly resolution. On the daily time scale, sun and wind fit well: the least Wind is in the system during the mid-day sunlight hours when demand is high. However, during these hours Solar is able to provide the necessary power. On a seasonal time scale, Wind production is higher in winter while Solar is stronger in summer.

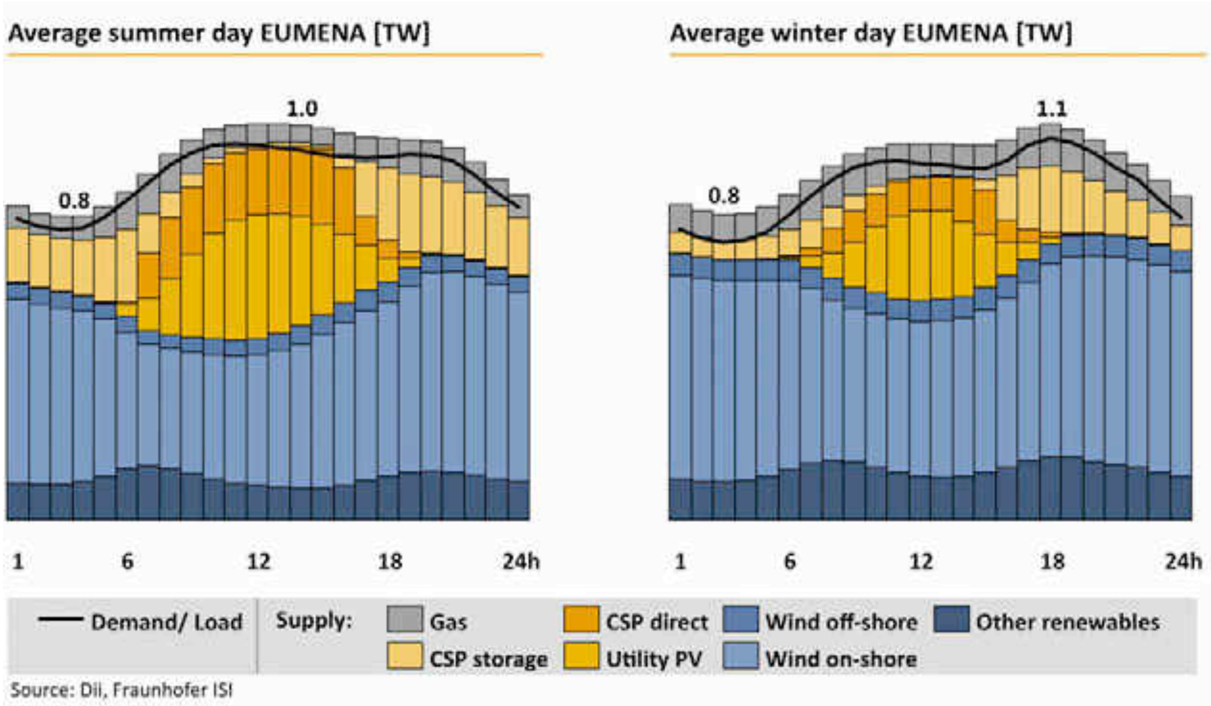


Figure 9: Daily and seasonal demand and supply in EUMENA

Figure 10 reveals that the good fit of demand, sun and wind shown in Figure 9 is the result of complementary demand and supply conditions in MENA and Europe. While load is higher in winter than in summer in Europe, the opposite is the case in MENA, where more extreme weather conditions prevail during the hot summer as opposed to Europe's cold winter. Also, while Wind production is higher in winter in Europe, it is stable throughout the year in MENA. Due to its high Solar yield, MENA is able to provide Europe with the power it needs during the summer, following the daily demand curve with the help of the CSP storage. Availability of gas generation is strictly limited by the common carbon emission cap for MENA and Europe. The strong allocation of gas generation to Europe not only ensures a well-functioning power system; it is also the reason for the 40% decrease in the marginal cost of carbon emission reduction.

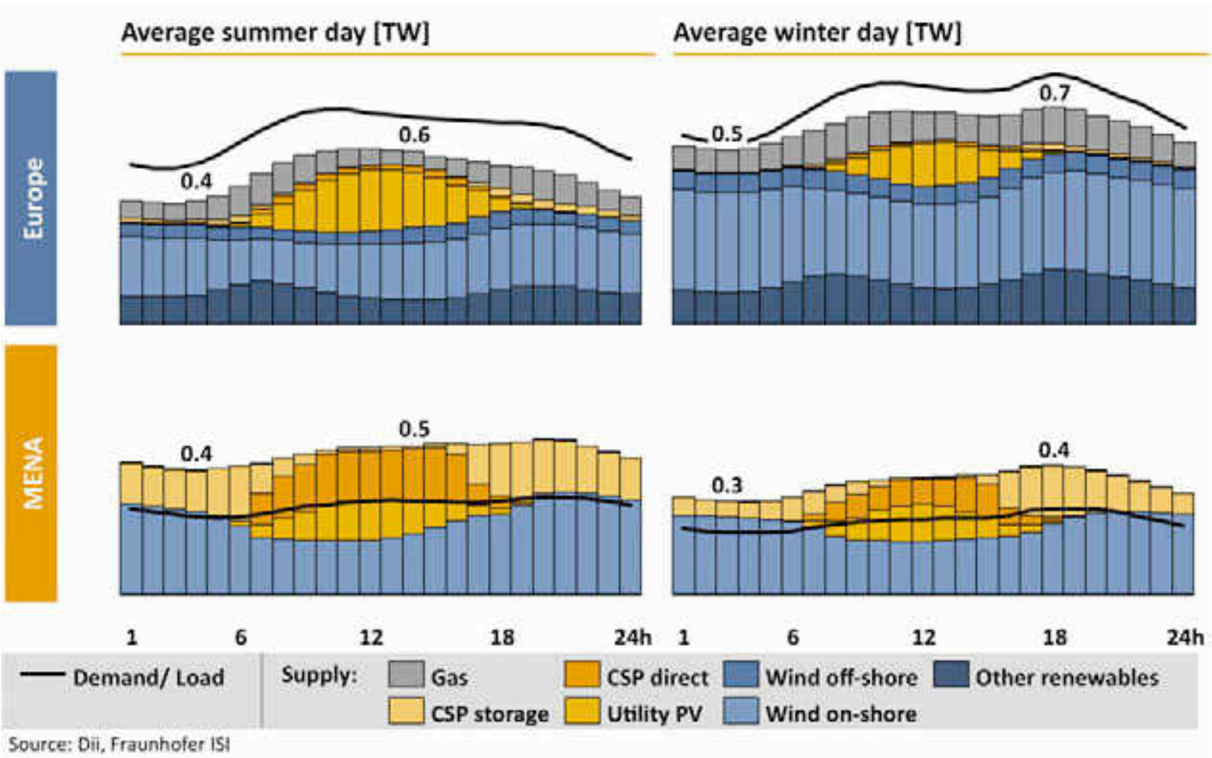


Figure 10: Daily and seasonal demand and supply in Europe and MENA

The roles of individual countries in this integrated system are essential to understand how the system becomes stable as well as competitive. We distinguish between three main types of countries: renewables super producers, importers, and countries with balanced renewables and demand. While each of these three types profits from system integration in a different way, they all benefit from being part of a large sustainable power system. At the same time, their complementary roles lead to a situation of mutual reliance, in which no one country is dependent on another but instead each country is reliant on the system as a whole.

Super producers are countries with excellent renewables resources and relatively low demand. Thus, they have enough excess in cheap renewables potentials for significant exports. Examples of super producers are the Maghreb and Libya in the south and Norway in the north. The super producers profit from system integration in two ways: from a large renewable electricity export industry and from a reliance on the overcapacities of renewables (compared to domestic load) as a means of ensuring their own security of supply at all times of the year.

Importers have high demand and, compared to demand, limited potentials of good renewables resources. This group of countries includes Germany, Italy, and – though less pronounced – also France and Turkey. These countries import cheap renewable power throughout the day and year in order to ensure an affordable sustainable power supply. They benefit not only from the cost advantage of the imported electricity, but also from the optimized allocation of the remaining conventional gas generation. Since gas, and thereby carbon emissions, are allocated under a common cap to where they are needed most, the countries with limited renewables can use more gas than in an isolated system.

Balancers have levels of demand and renewables resources that are largely proportionate to each other. They include Egypt, Saudi Arabia, Syria, Spain, the UK and Denmark. As mentioned, an assessment of renewables potentials must not only be based on the levelized cost of electricity but also on their fit with the load that needs to be satisfied at every point in time. This is why the balancers also profit from system integration: they build just as much renewables capacity as is economic to cover most of their domestic load. Covering the remaining minor share of the load with domestic renewables becomes less economical, since curtailment of excess energy would occur. Consequently, these countries import power when needed and export it when their production exceeds domestic demand. They thereby avoid building the final segment of domestic renewables, which would make the sustainable power system more expensive due to high curtailment.

Having addressed the different country roles in an integrated power system, it becomes clear that such a system is heavily interlinked and has advantages for all participating parties. This mutual reliance and interdependence is one of the reasons why an integrated sustainable power system enhances security of supply not only from a technical but also from a political and geopolitical point of view.

Desert power contributes to security of supply in several ways. First, most European and many MENA countries currently rely on fossil fuel imports for their electricity. Desert power facilitates an affordable shift across the region to a clean, renewables-based power system. This transition will make these countries independent of fossil fuels and their volatile price developments: in a sustainable power system with more than 90% renewables, less than 7% of system costs are fuel costs. In comparison, in today's gas plants almost 70% of all costs are fuel, in coal plants 30% and in nuclear plants about 15%. Thus, the reduced exposure to fuel price volatility leads to more stable power prices as a basis for a more stable and more competitive economy.

An integrated system also leads to a more diversified power supply for all countries. Importers in Europe, for example, buy power from several different countries; unlike today, no single exporter makes up more than 10% of European supply. Furthermore, being part of the same system leads to a situation of mutual reliance between importers and exporters. Exporters in North Africa, for example, rely on importers in Europe for the balancing effects of European gas capacity.

By making a paradigm shift to a renewables-based power system more affordable, desert power makes an important contribution to energy autonomy for countries throughout EUMENA. In an integrated system, even the importers in Europe will supply more of their own power in 2050 than they do today. Without such a paradigm shift, the negative effects of fossil fuel dependency will worsen for EUMENA as a whole, and for fossil fuel importers in particular. An integrated EUMENA system, on the other hand, will encourage a transition that benefits all parties, promotes mutual reliance across the region, and has the potential to extend beyond the power sector. Such increased cooperation with neighboring regions is already an explicit target of EU energy policy[10].

[10] See, for example, the European Commission communication *The EU Energy Policy: Engaging with partners beyond our borders* (2011), which highlights the importance of an EU-Southern Mediterranean Energy Partnership with a special focus on renewable energy

1.3 Perspectives on desert power

As Niels Bohr, physicist and Nobel Prize laureate put it, “Prediction is difficult, especially about the future”. Analyzing the design of a power system built to include more than 90% renewables 40 years into the future is necessarily subject to major uncertainties on a range of assumptions. The only way to address these uncertainties is to analyze so-called sensitivities, or perspectives, to show how the results react to changed parameters.

Beyond the Connected and the Reference Scenarios, we have analyzed a total of 16 additional perspectives on the EUMENA power supply in 2050, see Figure 11. They cover a wide range of major impact factors on the attractiveness of power system integration.

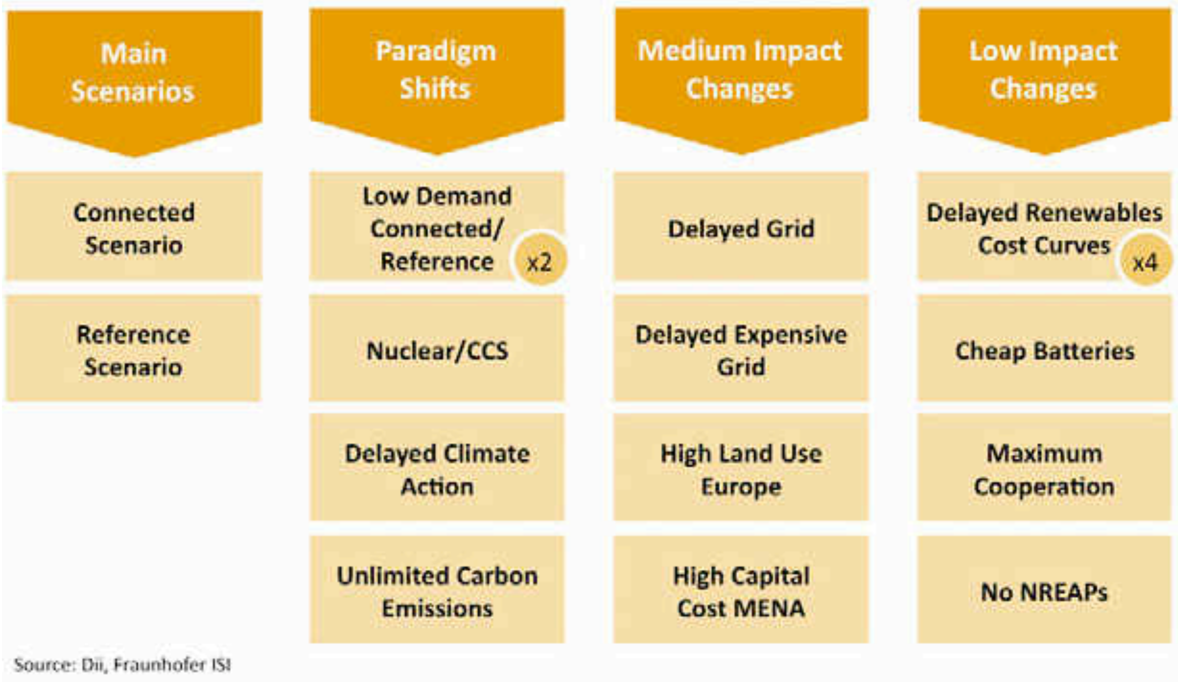


Figure 11: Scenarios assessed for robustness of EUMENA system integration

The sensitivities have been clustered into three categories. The first category, paradigm shifts, is dedicated to four substantially different pathways in shaping tomorrow’s power system. Among all sensitivities, the Low Demand Connected Scenario is of special importance. The other sensitivities show the impact of society’s success in establishing favorable prerequisites for an integrated sustainable power system in EUMENA. These eleven scenarios have been clustered according to how strongly they affect the attractiveness of EUMENA-wide power system integration. We now turn to summarizing the overall conclusions, and highlighting key details, of the sensitivity analysis.

The main message from the analysis of these different cases could not be clearer: grid integration across the Mediterranean is valuable under all foreseeable circumstances. Even in the **Unlimited Carbon Emissions Scenario**, with a power mix dominated by coal and carbon emissions 2.5 times higher than today, a total of 35GW_{NTC} of interconnector capacities across the full east-west width of the Mediterranean is built, see the right part of Figure 12. In all scenarios with a carbon emission cap, it is cost optimal to build at least 86GW_{NTC} of Mediterranean interconnectors. At least 301TWh net of desert power is exported by MENA to Europe, see the left part of Figure 12.

The **Low Demand Connected Scenario** assumes that Europe manages to keep the portion of its power demand supplied by utility scale power generation flat at today's levels, e.g. by successful energy efficiency measures or through decentralized power generation and storage. It shows that, even with 40% lower demand of 4900TWh per year for EUMENA, 114GW_{NTC} of interconnectors are built and 548TWh of annual net exports to Europe are optimal from a cost point of view. This scenario thereby demonstrates that energy efficiency and decentralized power generation, on the one hand, and EUMENA wide power system integration, on the other, are not mutually exclusive alternatives but instead complement each other extremely well. The Low Demand Connected Scenario is also the scenario with the lowest cost of all analyzed cases, including the Unlimited Carbon Emissions Scenario, which is €97bn. p.a. more expensive.

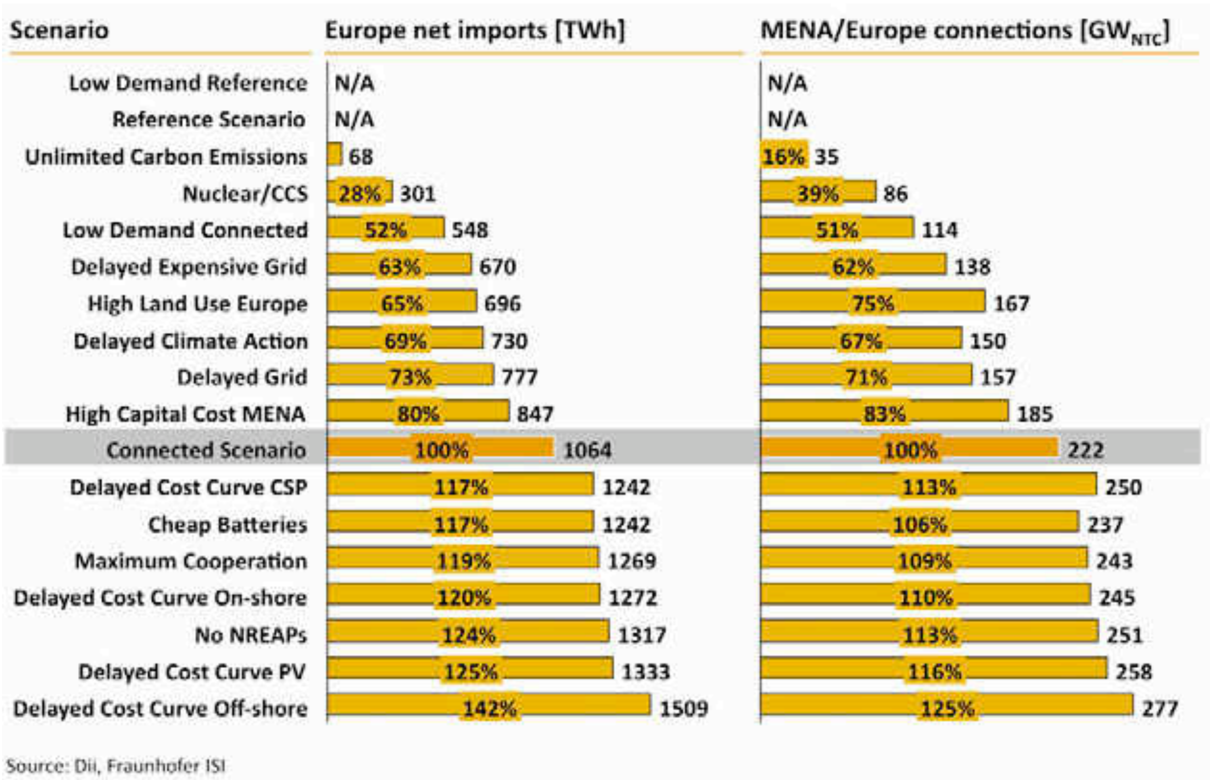


Figure 12: European net imports and interconnector capacities

It would be a major step in the right direction if Europe manages to exploit its best renewables potentials to a very high degree. A scenario based on this assumption, called **High Land Use Europe**, would mean for example that Germany alone installs 180GW of on-shore Wind in the most favorable half of its potential Wind sites. The result is that the cost optimal solution in this scenario includes approx. 700TWh of annual net exports from MENA to Europe. Thus, maximizing European effectiveness in renewables installations does not eliminate the benefits of desert power imports. Instead, both efforts should be combined to achieve the best possible sustainable power supply for EUMENA.

Solar and Wind technologies have consistently met or exceeded expectations concerning cost reductions and market growth. Unfortunately, this cannot yet be said for the extension of the transmission grid in Europe. Despite all efforts to overcome this major challenge in building the electricity system of the future, it seems only prudent to analyze the impact of **Delayed Grids**.

Already the cost assumptions of the Connected Scenario are based on the assumption that by 2050, 50% of all installed overland transmission in Europe will be HVDC underground cables. This takes into account cost increases related to public acceptance issues of overhead lines. The Delayed Grid Scenario assumes that no connection between two countries throughout EUMENA can exceed $20GW_{NTC}$. This assumption severely limits the most attractive sub-Mediterranean interconnectors compared to the Connected Scenario. It has no impact, though, on the grid within Europe except for the connection between Spain and France. In the **Delayed Expensive Grid Scenario**, the $20GW_{NTC}$ limit is maintained and the cost of transmission lines increases by 50% above the costs deemed realistic by industry experts. This causes only a minor drop in interconnector capacity across the Mediterranean, from $157GW_{NTC}$ to $138GW_{NTC}$. The result of this scenario is that those sub-Mediterranean interconnectors not used to the limit in the Connected Scenario are expanded to the allowed maximum. This replaces the lost import capabilities, see Figure 13. In other words, the attractiveness of desert power does not depend on the success of using a few interconnectors. Instead, all interconnectors can substantially contribute to lowering the cost of sustainable power supply for Europe.

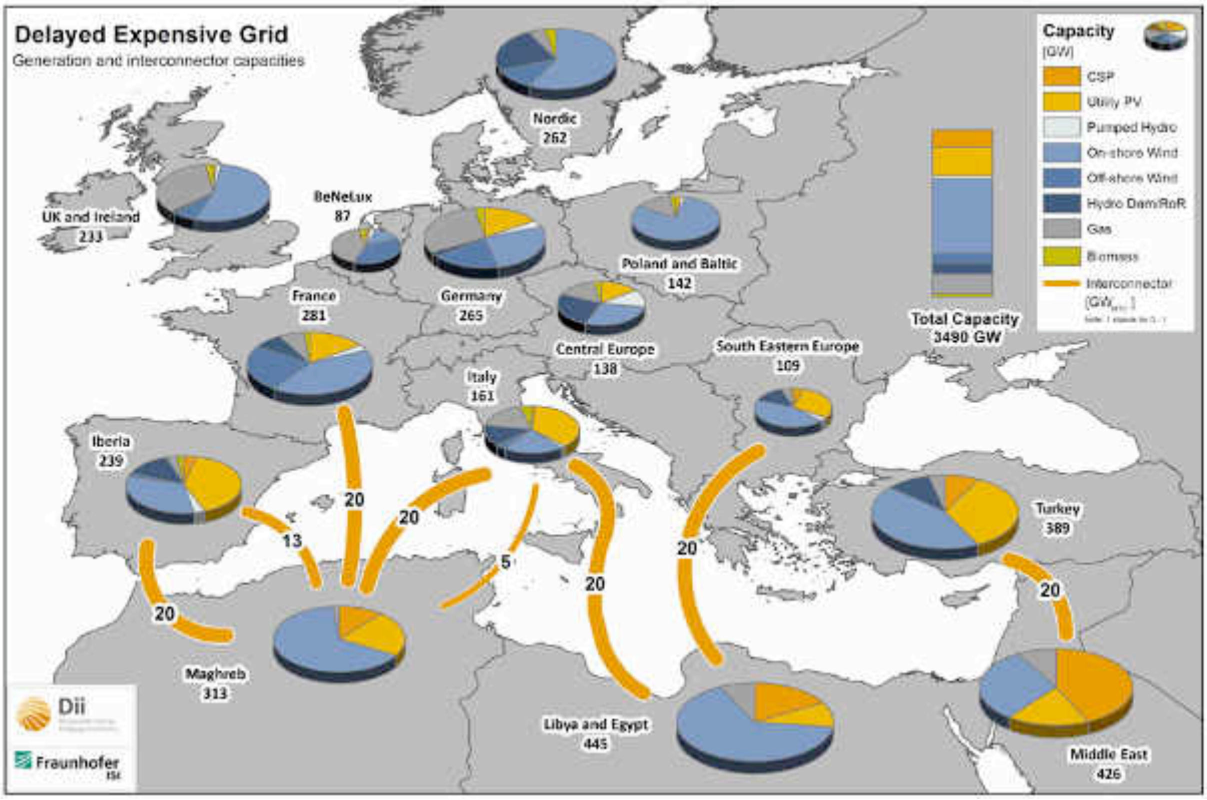


Figure 13: Generation and interconnector capacity, Delayed Expensive Grid Scenario

Another well-known obstacle to the faster diffusion of renewable power technologies is the financing needed for the construction of these capital intensive types of power plants. Financing depends on risk perception among investors, who ask for increased returns on capital for investments in renewables and in developing countries. The **High Capital Cost MENA** scenario analyzes the impact of 9% p.a. weighted average cost of capital for installations in MENA while the standard 7% p.a. still suffices for Europe. Despite the effect of higher capital costs in MENA on desert power's attractiveness in Europe, 847TWh or 80% of the annual net exports in the Connected Scenario remain. Thus, even if investments in MENA renewables continue to be perceived as high risk, the case for EUMENA-wide system integration remains strong.

Nuclear and CCS[11] are often considered alternative options for the decarbonization of the power sector. Thus, it is important to examine the interplay of these technologies and renewables. The result of the **Nuclear/CCS** scenario is that 55% of all power is produced from renewables and 301TWh imports of desert power to Europe are a cost optimal choice. Furthermore, neither Nuclear nor CCS are cost competitive with renewables in all of North Africa, which continues to rely on a mix of Solar and Wind power.

Despite their limited impact on the system, the conclusion from the **Low Impact** scenarios is still highly relevant: the attractiveness of EUMENA system integration and desert power for Europe does not depend on any of the technologies' ability to fully achieve the predicted cost reductions. Also, the impact of cheap daily storage with utility batteries is low. Finally, in the **Maximum Cooperation** scenario no lower limit on self-supply rates is imposed. The limited impact of removing this restriction shows that many countries' cautious attitudes towards electricity imports have only a limited impact on the value of desert power. The **No NREAPs** scenario underlines that current European policy on renewables is not in stark contrast to the case for desert power, although of course not optimal from a system cost point of view.

Given the robustness of the case for desert power under the full range of perspectives considered, the next question necessarily is what needs to be done to make it actually happen.

1.4 Conclusion: time to get started

Desert Power 2050 proves why the objective of an integrated, sustainable EUMENA power system is valuable. In addition to this long-term strategy, Dii is also developing individual country strategies, which in turn form the basis for concrete Reference Projects. These country studies present analyses on sites, grids, regulation, markets and socio-economic aspects that are decisive for the success of renewables in individual MENA countries. The long-term outlook of Desert Power 2050 ensures that this short- to medium-term focus contributes to a sustainable EUMENA power system.

In the power sector, 2050 is only one to two investment cycles away. Therefore, the policy choices made today will determine whether the path to a sustainable system can be pursued. With its next study, **Desert Power 2050: Getting Started**, Dii aims to formulate recommendations on the appropriate technology and policy choices to be made now.

DP2050: Getting Started will offer a closer look at the technology and geography of the first gigawatts of desert power leading to the hundreds of gigawatts shown in this study in a step-by-step process. We will also assess the action needed on grids and Europe-MENA interconnectors. This analysis aims to provide input for ten year development plans, such as that of the European Network of Transmission System Operators for Electricity (ENTSO-E).

[11] Carbon capture and storage

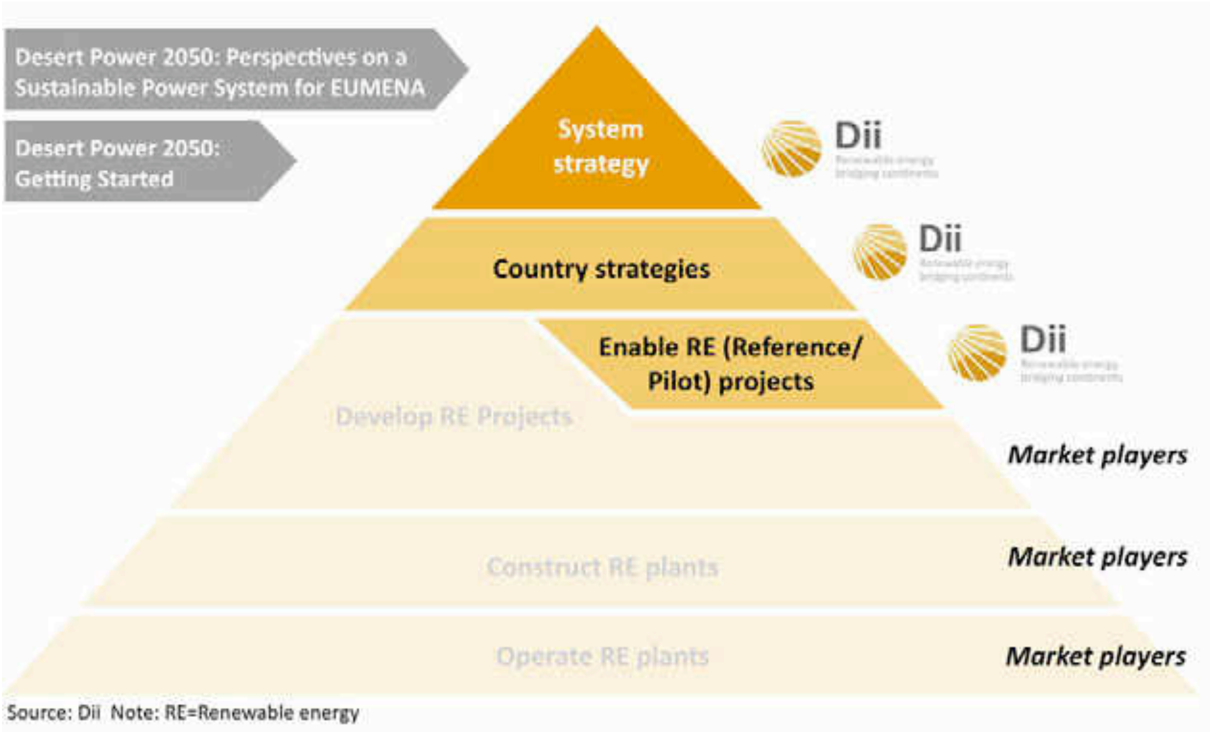


Figure 14: Dii strategy pyramid

Furthermore, it is crucial to show how these technical prerequisites for desert power can be implemented politically. In DP2050: Getting Started, Dii will model the impact of different support schemes over time in order to ensure that they provide value to stakeholders. This quantitative analysis will be combined with a qualitative assessment of the political feasibility of support scheme designs. Combined, the two will result in concrete and actionable recommendations for policymakers today.

Both parts of Desert Power 2050 reflect Dii's conviction that desert power is about more than electricity. To this end, DP2050: Getting Started will present the results of Dii's socio-economic assessment. Not only will desert power provide affordable, stable electricity – the key to economic growth – it could also create up to one million jobs by 2050. Understanding the GDP and labor market effects of desert power is another key input to policymakers that Dii is working on.

Reaching the goal of an integrated sustainable EUMENA power system will require combined efforts from all the countries involved. Today, we can choose to take the first step towards a common market for renewable energy in EUMENA – a vision of EUMENA supplying itself with sustainable and affordable power for future generations.

2 The Basis of Desert Power for EUMENA

Creating a secure, affordable and clean electricity supply is one of the key challenges facing North Africa, the Middle East and Europe. How can the Middle East and North Africa supply their growing economies with secure and affordable electricity? How can the EU reach its ambitious climate action goals in a way that is both sustainable and economic?

Desert Power 2050 examines the future energy challenges of Europe as well as the Middle East and North Africa (MENA). It shows that these challenges can best be addressed by moving beyond the currently predominant view of the two regions as separate entities.

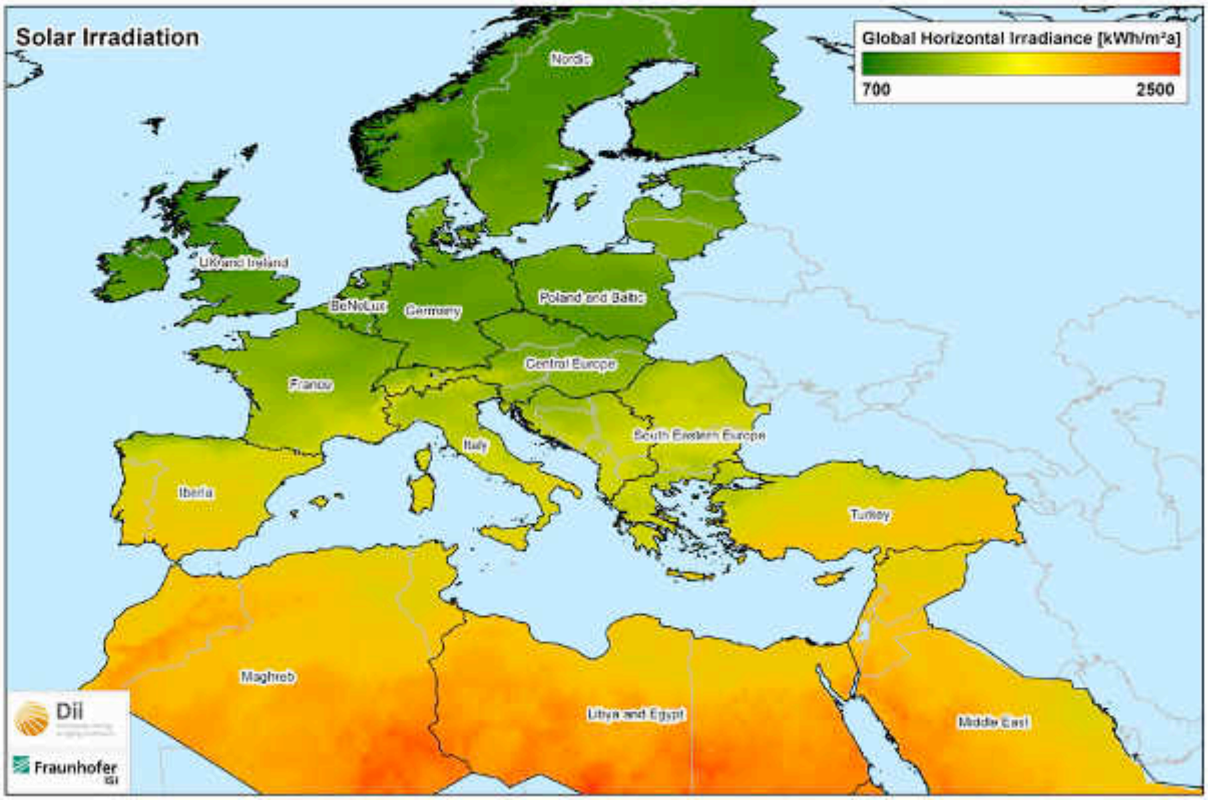


Figure 15: Solar resources in the EUMENA region

The sheer size of the largely unused landmass in the MENA region makes it an ideal location for electricity production from renewables. Figure 15 shows the availability of excellent solar resources in MENA. Prime sites can be found everywhere in the region, from the High Atlas and Tell Atlas in the Maghreb to the Asir Mountains in Saudi Arabia.

Less widely known, but no less important, MENA also has favorable wind conditions, as depicted in Figure 16. Exceptional wind potentials can be found, for example, on Morocco's Atlantic coast and around the Red Sea in Egypt. Furthermore, the entire continent, stretching between these two coasts, hosts attractive sites for Wind power generation.

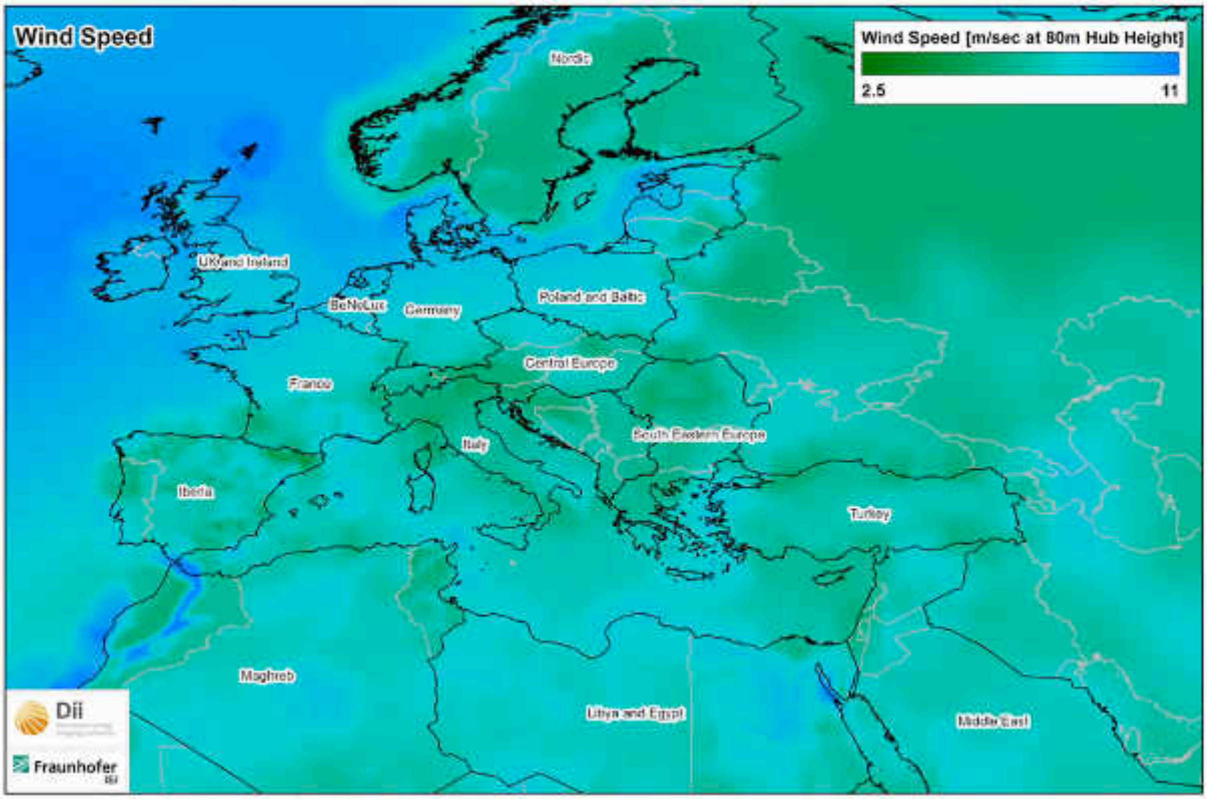


Figure 16: Wind resources in the EUMENA region

Of course, the mere abundance of renewables resources does not automatically translate into a power system that works reliably 24 hours a day, 365 days a year. Therefore, Dii has joined forces with Fraunhofer ISI to model the EUMENA power system with high spatial resolution. Using ISI's proven PowerACE model, we demonstrate the potential of Solar and Wind technologies to affordably supply demand across the entire EUMENA region in every single hour of a whole year.

A number of studies have been conducted and published on a sustainable power system with more than 90% renewables and 2050 as a time horizon [12]. These studies have focused primarily on the EU, though they have occasionally included certain non-EU member states or power imports to Europe from North Africa and the Middle East.

The idea that electricity from renewables should be produced in areas with optimal resources, and exported to regions with high demand, has become known as the Desertec vision. This intuitive notion suggests that Europe should source some of its electricity production from the deserts on the southern shore of the Mediterranean, with their excellent solar and wind resources and sparsely populated land.

[12] Eurelectric*, Power Choices: Pathways to Carbon-Neutral Electricity in Europe by 2050* (2009); European Climate Foundation et al., *Roadmap 2050* (2010); McKinsey & Company, *Transformation of Europe's power system until 2050* (2010); PricewaterhouseCoopers et al., *100% renewable electricity: A roadmap to 2050 for Europe and North Africa* (2010); EWI et al., *Roadmap 2050: a closer look* (2011); Greenpeace International, *Battle of the Grids* (2011); energynautics, *European Grid Study 2030/2050* (2011); WWF et al., *The Energy Report: 100% Renewable Energy by 2050* (2011); European Commission, *Energy Roadmap 2050* (2011)

Desert Power 2050 shows how key aspects of the Desertec vision could work in practice while also moving beyond it. It demonstrates how, based on proven technologies, solar and wind resources can be combined with grids to securely supply North Africa, the Middle East and Europe with sustainable and affordable power. It thus expands on previous thinking and considers MENA as a consumer of renewable energy, not just as a producer.

In order to assess the added value of power system integration across the Mediterranean, we compare two scenarios. The 2050 target picture in the **Connected Scenario** examines a power system with full, EUMENA-wide integration. The **Reference Scenario**, meanwhile, depicts a situation where each region, Europe and MENA, is fully optimized in itself but without cooperation between the two systems. In other words, both DP2050 scenarios assume a paradigm shift to a renewables-based power system, with considerable investment in grids and renewable energy generation. Both the Connected and Reference Scenarios are optimized for minimum system cost under an EUMENA carbon emission cap of 0.25Gtonnes p.a., i.e. approx. 30g per kWh of demand[13]. Thus, in the Reference Scenario, the European part alone is similar to the optimized power systems analyzed in other studies; the main difference is that it still profits from a common carbon cap with MENA.

2.1 Methodology

We aim to compare the fully integrated EUMENA system of the Connected Scenario with the two isolated ones in the Reference Scenario. To do so, an objective measure for the quality of the systems has to be defined. Since the primary task of a power system is to securely supply the economy with reliable and affordable electricity, an appropriate choice for this measure is system cost.

System cost, as defined for the purpose of this study, includes all major cost components of the power generation and transnational high-voltage transmission system. However, it does not include the transmission system on a purely national level or the medium and low voltage distribution system.

The PowerACE software of Fraunhofer ISI is applied to optimize the system costs of both scenarios under certain boundary conditions. PowerACE is a platform for the computational analysis of the electricity sector in the EUMENA region. The model optimizes the construction and dispatch of power plants, storage facilities, transmission grids between countries and renewables generation technologies through linear optimization. Detailed data on potentials for renewables generation technologies and hourly generation profiles are thus taken into account. The electricity system is optimized 24 hours a day, 7 days a week for all 365 days of the year. This means that demand in every country has to be met in every hour of the year by the selected technology mix. Additional restrictions such as a cap on CO_2[14] emissions or constraints on the transmission grid can be added to the analysis.

[13] The minimum system cost includes the cost of power generation and transmission but not the cost of carbon emission reductions

[14] In this report, CO_2 emissions and "carbon emissions" are used interchangeably.

Modeling with PowerACE requires a set of assumptions on the relevant exogenous input parameters for a power system in 2050. These assumptions are crucial for the outcome of the analysis and will therefore be explained in some detail in the remainder of this chapter.

Uncertainties inherent in the assumptions need to be carefully considered. This has been done with the help of sensitivities, i.e. scenarios with deliberate parameter changes. The results of these sensitivity scenarios have been analyzed for their impact on the value of EUMENA system integration and other key outcomes of the report.

The most important components to be taken into account for the calculation of annual system costs are capital expenditures, i.e. investments for power plants and transmission lines, including the cost of capital for the invested sums[15]. A 7% p.a. discount rate, also referred to as Weighted Average Cost of Capital (WACC), is used to calculate the annuity at which capital expenditures (CAPEX) are included in the system cost. Furthermore, the fixed cost of operation and maintenance (O&M) for all power plants and transmission lines is taken into account, together with fuel costs and the variable cost of operation and maintenance. The latter two constitute the variable cost component of the system, which depends on the production of the respective power plant, while CAPEX and fixed O&M are fixed costs that are incurred independently of the power plant's utilization once it is built. Carbon emission costs are not included, but the marginal cost of the carbon cap is a result of the modeling.

The 38 countries analyzed in this study include the EU27[16], Norway and Switzerland, Turkey, Syria, Jordan, Saudi Arabia, Egypt, Libya and the three Maghreb countries Tunisia, Algeria and Morocco. Of these countries, the EU27 plus Norway, Switzerland and Turkey make up "Europe", for the purposes of this study; the remaining countries make up "MENA". Thus, the system stretches from Scandinavia and the Baltic states in the north to southern Europe, and on to North Africa and the Arabian Peninsula. Consequently, our analyses capture the interplay of the good wind conditions in the north and the good solar and wind conditions around the Mediterranean.

For the purpose of the power system cost optimization, each country is represented as one node. Such a node has attached information on demand and load patterns, as well as renewables potentials and their production patterns, and transmission connections to neighboring countries. Thus, all geographical information has to be integrated into the data attached to a country a priori, and is not explicitly modeled by the PowerACE optimizer itself. We will describe below how the geographic information on renewables potentials and transmission is integrated into the system.

The challenge of analyzing problems simultaneously at very large and very small scales requires this treatment of geographic information. Still, the results of the analysis on each scale are extremely valuable by themselves. Desert Power 2050 is dedicated to an analysis of the power system on a large scale. The main consequence of this necessary simplification is that distributed generation, decentralized storage and the distribution grid are out of scope. We believe the analysis of the large-

[15] All cost statements in this report refer to Euro 2011, but for reasons of readability we shorten the formally correct notation "$€_{2011}$" to "€"

[16] The focus of the study is the analysis of a large connected system. The islands Malta and Cyprus have been included in terms of system cost but are not subject to detailed evaluation

scale effects to be a valuable approach, but will point out its inherent limits whenever necessary throughout this report.

While geographic information is not explicitly represented in the optimization procedure, the computing power is used to optimize the power system with high time resolution. This is essential in the analysis of a power system relying to a very large extent on sun and wind, which can strongly fluctuate within a day but also depend on the season. Due to the time horizon of a whole year as the focus of this study, sub-hourly timescales cannot be included in the analysis. Smoothening of power gradients, frequency control and other issues addressed by primary, secondary and tertiary control are thus not covered in the report.
We now turn to explaining the methodology behind the system optimization through the example of a winter week in Egypt, see Figure 17.

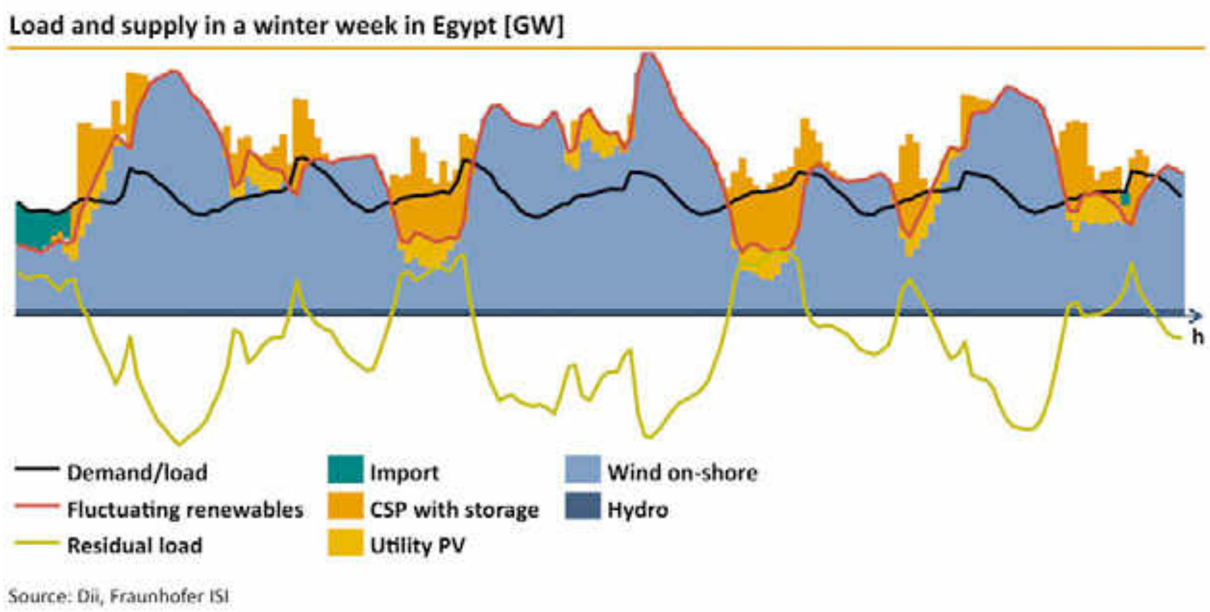


Figure 17: Residual load in a windy winter week in Egypt

Consumption and production patterns during such a week are shown hour by hour in Figure 17. The task of PowerACE is to ensure that the electricity available in a country is at least as high as the black load line, representing consumption in each of the 8760 hours of the year at minimum overall cost.

To meet this requirement, the system can choose to invest in a range of power generation technologies, which all have specific costs. The first categories of technologies have fixed production curves, i.e. each GW of installed capacity comes with a fixed curve of electricity produced for the entire year. This is an important characteristic of the system, called perfect foresight since it means that the whole year is known at the time of investment decisions. The most important technologies with fixed load patterns considered are on-shore and off-shore Wind and Utility PV. Since these technologies have low cost, the model usually uses as much of them as possible to satisfy demand. The result is the red curve in Figure 17, which represents the generation by the fluctuating renewables.

The green curve represents the residual load, i.e. the difference between the load and the fluctuating renewables Wind and Utility PV. When this curve is positive, the system has to use the second kind of technologies in the system, namely dispatchable technologies (e.g. CSP, gas, biomass, hydro dam), to satisfy the rest of the load. When not enough dispatchable technologies are available in the country, demand can also be satisfied with imports, as shown by the dark green area in Figure 17. When residual load is negative, the country can export electricity to other countries if a transmission line exists. The construction of transmission lines is an endogenous investment decision of the system, which, like the construction of power generation capacities, is used to minimize overall system cost. If no country connected by transmission lines needs the excess electricity, then the system can store it in a pumped hydro plant if such plants exist in the country. Otherwise, storage technologies with specified cost and efficiency can be built or curtailment occurs, i.e. electricity is lost in that hour of the year.

As mentioned above, this study considers one full year in hourly resolution. Weather and load data is based on the year 2007, which was an average year in terms of solar and wind conditions in EUMENA, compared to the years 2006-2010[17]. It is important to use hourly solar, wind, hydro and load data from the same year, since all of them are correlated to some extent and this correlation can impact the modeling results.

Considering a full year in hourly resolution means 8760 different combinations of sun, wind, hydro and load conditions throughout EUMENA are accounted for in the analysis. Of course, all four parameters change from one year to another. Thus, having the model consider demand and production patterns for more than one year can lead to higher installations and system cost. This can either be addressed by performing a stochastic analysis[18] or by including additional years in the analysis. While both options are highly valuable next steps, they are beyond the scope of this report.

Nevertheless, the element of an extended time horizon leading to the need for more generation capacities has been accounted for with respect to the system cost. This is done by including a reserve margin in the form of additional gas turbine capacities in the system cost calculation. Each country has open cycle gas turbine (OCGT) reserve capacities of 10% of its peak load installed, which are part of the system cost but cannot be dispatched by the system. This reserve margin, which is in line with transmission system operators' (TSOs) recommendations, not only covers the additional required back-up power that might arise due to an extension of the time scope to several years. It also addresses other aspects of system operation (e.g. provision of balancing and reactive power) that are relevant on sub-hourly time scales.

A further aspect is the handling of forecasting errors in sun and wind conditions, since PowerACE uses a perfect foresight analysis. Reserves for stochastic outages of power plants are considered by the assumption of 95% availability for all Wind installations and 99% for all Utility PV installations. Forecasting errors are already today a standard task of system operation in countries with high RES-E

[17] The hourly production for Solar and Wind plants is based on the year 2007, annual full load hours take the years 2006-2010 into account

[18] A stochastic analysis is simply the consideration of many possible combinations, each weighted with its entrance probability

such as Denmark, Spain and Germany[19]. First, they can normally be handled with the available dispatchable resources in the system and, to some extent, with fluctuating technologies, e.g. for negative balancing power. Second, flexibility could also be provided from load management, which has not been considered in our system modeling. Third, the gas peakers as reserve also provide additional security for this issue. Fourth, in the south of EUMENA, an alternative to gas-only OCGT back-up plants is to build CSP plants with the equipment needed to run entirely on gas (using the existing power block for solar operation). This would entail CSP plants with full dispatchability as needed for back-up plants.

2.2 Demand and carbon emissions

Having explained the methodology behind this power system analysis, we now turn to the explanation of input parameters starting with demand and carbon emissions. Forecasting demand for utility scale electricity production and transmission is a science in itself. It depends on many factors, such as economic and population development, electrification of transport, the level of distributed electricity production and – last but not least – the weather. For MENA countries, with their fast growing, rapidly urbanizing population, and quickly industrializing economies, certain specific factors play an especially large role in determining demand. The following and many more factors determine the future power demand throughout the EUMENA region: energy efficiency of new buildings, the use of solar powered heating/cooling, the amount of Distributed PV used, the electrification of the transport sector and the power need for water desalination.

The primary purpose of this study is to analyze whether an EUMENA-wide power system integration is able to deliver advantages in terms of system cost and security of supply. In order to cover variable levels of demand, we have complemented the analysis of the Connected and Reference Scenarios in Desert Power 2050 with a **Low Demand Connected** and a **Low Demand Reference Scenario**. These scenarios show that the key conclusions of Desert Power 2050 hold independently of demand development. The Connected and Reference Scenarios will also be referred to as the high demand scenarios.

Demand, as referred to in this report, is net final demand plus lump sum distribution losses of 7.5%. In other words, it does not include transmission losses on interconnectors, storage losses and self-consumption of power plants. Transmission losses on interconnectors are modeled in detail depending on the parameters of each connection in the system; storage losses are considered depending on the efficiency and utilization of storage technologies. Self-consumption of power plants is taken into account in the power plant output, i.e. the net efficiency of each generation technology is used.

Our assumptions for demand development are based on reputable, publicly available sources whenever possible. The low demand scenario for EU27+2 assumes that the total electricity demand in the year 2010 stagnates until 2050, see Figure 18. Allocation between countries differs slightly, reflecting the different pathways towards energy efficiency. The EU27+2 electricity demand for 2010 is taken from the European Commission study "EU energy trends 2030-Update 2009" (reference

[19] RES-E stands for renewable energy sources – electricity

scenario)[20]. Additionally, Norway is approximated with 90% of the Swedish demand and Switzerland with 94% of the Austrian demand, which reflects the geographical neighborhood, population differences and similar development expectations for energy efficiency. The high demand case for Europe is based on a scenario from the report "Transformation of Europe's Power System Until 2050"[21]. It assumes accelerated demand growth from a fuel shift in heat pumps and transport, and accelerated energy efficiency gains starting in 2030, which slow down demand growth. Similar to the low demand case, the total EU27+2 demand is allocated to countries according to the 2030 country share in the reference scenario of „EU energy trends to 2030-Update 2009". The country split is derived for high and low demand from the respective countries' 2030 shares in total EU electricity demand in the reference scenario of „EU energy trends to 2030-update 2009", including the above-mentioned approximation for Norway and Switzerland.

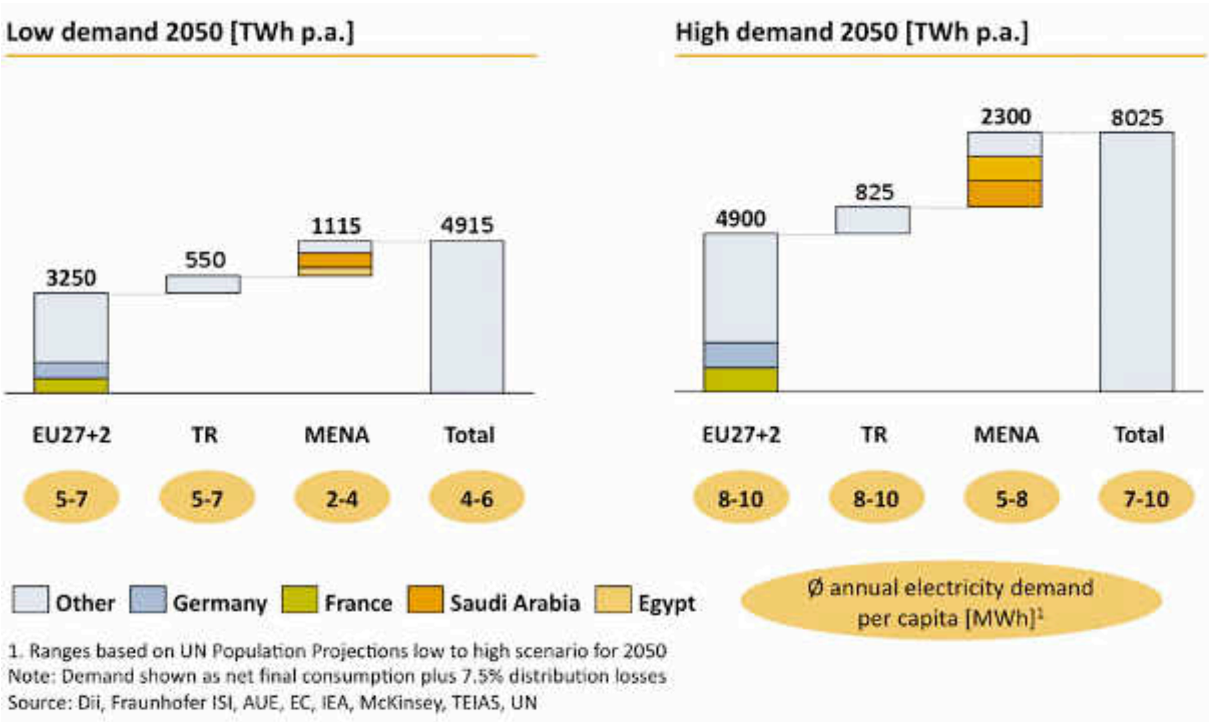


Figure 18: EUMENA demand assumptions 2050

The Low Demand Scenario for MENA is based on the IEA 450 Policies Scenario from the World Energy Outlook 2011 and applies a linear extrapolation of IEA demand projection after 2035. The country split for demand is taken from IEA Electricity Information 2010 and kept constant until 2050. For the high demand case, estimates are based on the extrapolation of data from the Arab Union of Electricity (AUE), which reflects the individual countries' demand forecasts until 2020[22]. To avoid exaggerating demand growth in some countries from this method, specific demand per capita[23] limits

[20] European Commission, *EU energy trends to 2030, Update 2009* (2010)
[21] McKinsey & Company, *Transformation of Europe's power system until 2050* (2010)
[22] Arab Union of Electricity (AUE), *Statistical Bulletin 2010* (2011)
[23] Per capita demand refers to the entire national demand divided by the number of inhabitants in a given country. In other words, it is not limited to individual or household demand. The base for the per capita consumption limit is the UN Population Projection medium scenario for 2050

have been applied: the demand in 2050 in Saudi Arabia is restricted to 15.0MWh per capita[24] and in Libya to 6.0MWh per capita[25].

For Turkey, the starting point is the demand forecast of the Turkish Electricity Transmission Corporation (TEIAS) 2010-2020[26], which is extrapolated until 2050 but restricted to 6.0MWh per capita in the low and 9.0MWh per capita[27] in the high demand scenario respectively.

The results of this approach are shown in Figure 18, and amount to total demand of 8025TWh p.a. for the high demand case and to almost 40% less, namely 4915TWh p.a., in the low demand scenario. This includes a lump sum of 7.5% for power losses in the national transmission and distribution grids for both scenarios. Hourly load data has been obtained from ENTSO-E and AUE, and are used to determine the pro rata distribution of 2050 demand to the hours of the year.

In this report, demand and supply figures as well as related parameters like carbon emissions will refer to annual values, unless otherwise stated. For the sake of simplicity, this will not always be mentioned explicitly.

Having explained the demand assumptions, we turn to another fundamental input parameter for power system analysis, the carbon emission limit. This study is based on the assumption of strong action against climate change that results in a strict carbon emission limit for the EUMENA region. Nevertheless, as the outcomes of the sensitivity analyses in Chapter 4 demonstrate, EUMENA-wide system integration is advantageous independently of the success of climate action.

The basis for the EU27+2 is a 95% carbon emission reduction in the power sector compared to 1990, see Figure 19. This is in line with the 80% overall greenhouse gas reduction target[28]. Specific carbon emissions per kWh demand have been derived by dividing the carbon emission cap by the low demand for the EU27+2, which yields 23g/kWh. The EU27+2 carbon emission cap for high demand is derived applying the same specific emissions to the higher demand figure.

For MENA and Turkey, which are not Annex B countries[29], a 50% carbon emission reduction compared to 2000 is assumed. Specific carbon emissions per kWh demand have been derived by dividing this carbon emission cap by the high demand for MENA and Turkey, which yields 41-44g/kWh. The MENA and Turkey carbon emission caps for low demand are derived by applying the same specific emissions to low demand. Overall, a carbon emission cap of approx. 30g/kWh demand is the result of this approach for both demand scenarios.

---

[24] Benchmark: Kuwait, Qatar and UAE in 2008, according to the AUE data

[25] Benchmark: Algeria, Egypt, Syria and Jordan in 2008, according to the AUE data

[26] Turkish Electricity Transmission Corporation (TEIAS), *Turkish Electrical Energy 10-year Generation Capacity Projection* (2010)

[27] Benchmark: Spain, Italy and Greece, according to the IEA data

[28] Based on the European Council's commitment to reduce carbon emissions by 80-95% compared to 1990 levels. EU commitments have been made subject to a successful outcome of the international climate change negotiations well as in the context of the UNFCCC's objective to stabilize GHG at a level that would prevent dangerous anthropogenic interference with the climate systems. See European Council, October 2009; confirmed by Extraordinary European Council, February 2011

[29] Annex B of the Kyoto Protocol of 1997 lists all countries which have committed themselves to concrete national or joint emission reduction targets, including all the Annex I countries to the UNFCCC (as amended in 1998) except for Turkey and Belarus. Annex B countries are often used synonymously for "industrialized countries". Turkey and MENA countries are not part of Annex B of the Kyoto Protocol of 1997

The carbon emission cap used allows for approx. 730TWh of highly efficient gas generation in the high demand scenario and approx. 430TWh in the low demand case. Thus, in the absence of nuclear or CCS technologies, more than 90% of all electricity is produced from renewables in the low as well as the high demand cases. The influence of CCS and nuclear is analyzed in a separate sensitivity.

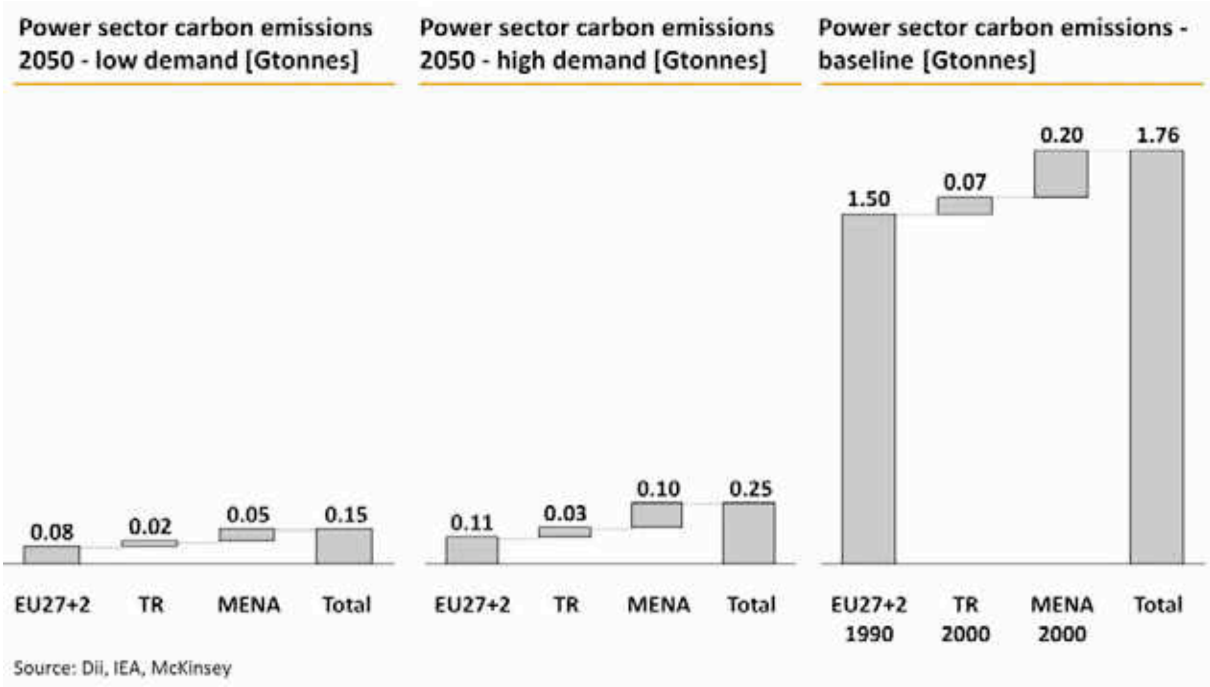


Figure 19: Carbon emission cap in 2050 compared to carbon emissions baseline

Having examined the 2050 scenarios for demand and carbon emissions, we now assess which transmission technologies could enable an integrated EUMENA power system.

2.3 Transmission technology

Transmission is a crucial component in making a power system based on the optimized use of renewables work in a very large region. Therefore, transmission is an endogenous part of the optimization procedure applied and also needs to be accounted for as a cost component.

Only high voltage transmission is also considered. Medium and low voltage distribution is not modeled explicitly, except that a lump sum of 7.5% losses in power distribution is part of the demand estimates used.

The definition of transmission lines is one of two interfaces in which spatial information is integrated implicitly into the power system model. In general, the transmission grid is modeled in a simplified way as a connection between country nodes, where the load and generation capacities of a country are virtually concentrated. The model allows for transmission lines between all neighboring countries. If it is technically and economically feasible, interconnections via submarine cables are also allowed between countries that do not share a land border, as shown in Figure 20.

The length of the transmission lines is defined as the distance between the two countries' geographical centers, except for Nordic and MENA countries, where the nodes are placed closer to the demand centers at the coast.

Special care has been taken in identifying and parameterizing the submarine transmission lines across the Mediterranean Sea from MENA to Europe and the overland Syria-Turkey transmission line. The total distance of the interconnectors between a MENA and a European country node is comprised of an intra-MENA part considering the overland distance to the origin of the interconnector at the coast, the submarine part, and the intra-European part connecting the landing point at the coast of the destination country with the country center. Besides these submarine interconnections, an eastern EUMENA corridor between Syria and Turkey via overland transmission lines is accounted for.

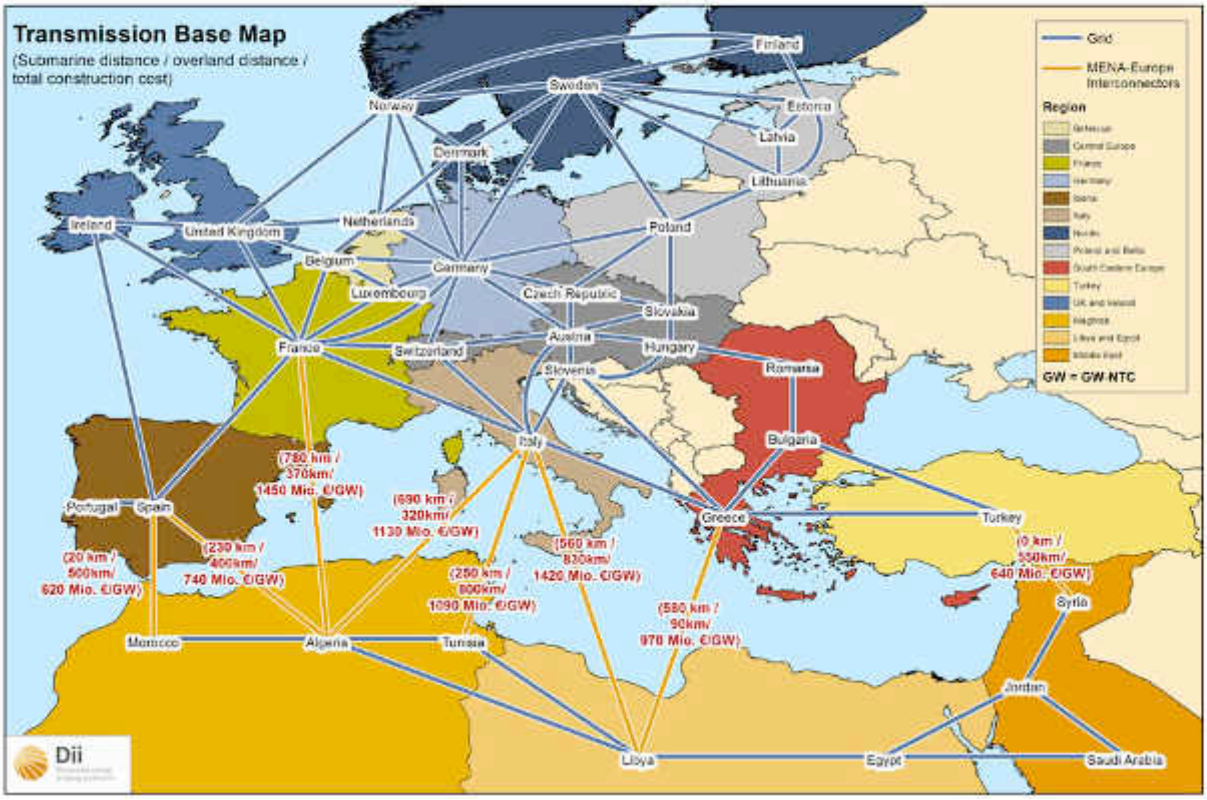


Figure 20: Schematic transmission grid 2050 for electricity system optimization

Within MENA countries, transmission lines are required to connect the Solar and Wind power from the southern deserts of the region to the interconnectors and demand centers on the Mediterranean coast. The costs of these transmission lines have been integrated into the renewables cost potential analysis. This is done in order to capture in greater detail the dependence of the electricity cost on the distance of generation sites from the coast. Thus, costs for this part of the transmission need not be considered in the applied distances for the interconnectors between MENA and Europe. Please note that the region definitions in Figure 20 will be used throughout the report.

Costs for operation and maintenance of transmission lines depend on the length of each interconnector and the chosen technology. Technological options are high voltage alternating current (HVAC) vs. high voltage direct current (HVDC), continental vs. submarine lines and overhead lines vs. underground cables for overhead transmission. The corresponding investments, costs for operation and maintenance as well as transmission losses have been derived individually for each country-to-country transmission line.

The estimates of investments and power losses are based on the expectation that the technology for HVDC transmission will be further developed in the coming decades. Higher power and voltage ratings will reduce specific cost and, especially, power losses, which allows for an even more efficient transmission of bulk power over long distances with HVDC systems. Therefore, the corresponding parameters are derived for transmission technology expected to be commercially available starting in the year 2030. In particular, it is assumed that, starting in 2030, 800kV submarine cables will be available, even though they are limited to 500kV as of today. Consequently, the power and voltage ratings for HVCD systems are higher than today's state of the art.

Specific construction costs for overhead lines and underground cables are calculated for an "average" European and MENA terrain. In other words, a lump sum 20% cost increase compared to the construction costs for flat land is taken into account. No further distinction between different topographical or geological conditions for individual country-to-country interconnection is applied. Additionally, all investment costs are already related to the Net Transfer Capacity (NTC), i.e. a reserve margin of 100% for HVAC and 20% for HVDC lines over NTCs is included in the corresponding cost assumptions. To derive the total costs and losses of a country-to-country transmission line, investment and O&M costs as well as losses of two AC-DC/DC-AC converter stations (at each end of the line) are included. As a result, shorter interconnectors have higher specific costs and losses, since the fixed share of costs and losses from the converter stations has a greater effect on the total costs and losses when compared to a longer interconnector.

As an additional boundary condition, it is further assumed that only HVDC systems will be built upon completion of the major grid extension projects considered in the ENTSO-E Ten Year Network Development Plan (TYNDP) 2012[30]. The existing NTC values for Europe and MENA, plus the NTC additions based on the TYNDP 2012, are the starting NTC values for the power system modeling.

Transmission 2050	Investment [€/MW_{NTC}*km]	O&M [% investment p.a.]	Power losses [%/1000 km]
Europe ground	828 €	0.6%	1.6%
MENA ground	396 €	0.9%	1.6%
Submarine	992 €	0.1%	1.6%
Converter pair	180,000 €/MW_{NTC}	1.0%	1.4%

Table 1: Blended rate HVDC transmission assumptions

[30] ENTSO-E, *10-Year Network Development Plan 2012 Project for Consultation, draft version for public consultation 1 March – 26 April* (2012)

With regard to the share of overhead lines to underground cables, an underground cable share of 50% within Europe and 10% within MENA is assumed for 2050. The resulting blended rates for transmission parameters throughout EUMENA are shown in Table 1.

2.4 Power generation and storage technologies

Having explained the basis of the grid modeling in this report, we now turn to the assumptions on the power plants that are connected by this grid.

Three categories of power generation technologies are included in the analysis of the Connected and Reference Scenarios. The first one consists of Wind and Solar, the focus technologies of this report. The second category comprises other renewables (e.g. biomass, geothermal, hydro power) and the third one the conventional, fossil fuel-based power technologies. Nuclear and CCS technologies are not included in the main scenarios and are instead considered as a sensitivity, see Subsection 4.4.2.

The purpose of Desert Power 2050 is to understand what a cost-efficient power system in 2050 would look like. We therefore take a Greenfield approach, where none of the power plants existing today still operates and all investments are at 2050 costs. The only exceptions are hydro power and hydro storage, for which we assume that all existing and a certain portfolio of future installations are in operation in 2050.

A number of factors make Solar and Wind stand out among renewables technologies. First, the amounts of sun and wind across the globe, and especially in EUMENA, are virtually infinite compared to the energy needed by societies globally and in the region, as shown in Figure 3. Second, compared to hydro power and geothermal, Solar and Wind are less dependent on specific topographic or geographical conditions, like basins, rivers, or ground formations. Third, especially in arid or sparsely populated areas, there is little to no competition with higher value-added sectors such as food or transport for sun and wind, unlike for biomass. Finally, these technologies are in use today across the globe on a large scale. While their technical reliability can be assumed, not all of them are yet cost competitive on a broad basis. At the same time, sizeable global industries with a diversity of strong industrial players along the entire value chain have evolved for Solar and Wind technologies. Since the industries involved in these technologies are becoming stable and large enough to survive under temporarily unfavorable market developments, they are also becoming less dependent on the success of single players or projects.

The system analyzed here in numerous scenarios is technologically feasible today. The wide range of scenarios analyzed shows that uncertainties regarding the exact technology mix and system cost remain, but the general feasibility of a EUMENA power system with approx. 80% Solar and Wind is not in question. Of course, other renewables might play a role in the future of renewable power supply – geothermal and marine power, for example, are not yet mature in EUMENA but might play a larger role in the future. That said, it is important to bear in mind that, in the power sector, a sustainable future does not depend on technological breakthroughs or the success of society in exploiting scarce and valuable resources like rivers, lakes or croplands.

The non-Solar/Wind renewables are represented in PowerACE as fixed generation assets, which are part of the system cost but cannot be scaled up or down by the system. The allocation of the two Wind technologies, on-shore and off-shore, as well as the two Solar technologies, Utility PV and CSP with 8h storage, is optimized endogenously by the system. This optimization is based on a detailed representation of these technologies' potential in all countries under consideration. As explained in Section 2.1, this study only examines utility scale power generation; decentralized sources, especially Distributed PV, are not included in its scope.

The rest of this section explains the assumptions for power generation modeling in DP2050. We later demonstrate that power generation from sun and wind, combined with a strong grid and a limited amount of gas and other renewables, can sustainably provide EUMENA with all the power it needs.

2.4.1 Conventional power technologies

The conventional technologies available for investment are combined cycle and open cycle gas turbines, supercritical pulverized coal plants and lignite. In other words, all major fossil fuel-based power technologies are accounted for. The cost and efficiency parameters for these technologies can be found in Table 2. It should be noted that the efficiencies in the table are average net efficiencies, i.e. they take into account self-consumption of the power plants and the fact that, on average, the power cycle has lower efficiency in practice than at its design point.

With regard to the strong carbon emission reduction assumption and in the absence of CCS technologies, the price assumption for fossil fuels was taken from the IEA 450ppm scenario of the World Energy Outlook 2011. This scenario assumes an approximately flat gas price of 7.1€/mmBTU, corresponding to approx. 24€/$MWh_{thermal}$[31] and a coal price of 51€/tonne, corresponding to approx. 6.3€/$MWh_{thermal}$[32].

Conventional power plants 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	O&M variable [€/MWh]	Net average efficiency	Lifetime
CCGT	750 €	11.1 €	2.7 €	60%	30a
OCGT	380 €	9.7 €	2.7 €	40%	30a
Coal	1450 €	34.5 €	1.5 €	48%	40a
Lignite	1500 €	45.0 €	1.5 €	47%	40a

Table 2: Cost and efficiency assumptions for fossil fuel based power plant technologies

2.4.2 Non-Solar/Wind renewables

EUMENA capacity potentials for hydro power, the most important non-Solar/non-Wind renewables technology, have been analyzed in detail, see Figure 21. Hydro power plants are the only existing power plants that are assumed still to be in operation in the year 2050. Pumped hydro storage plants are also assumed to have such a long lifetime, see Section 2.4.3. Figure 21 shows that capacity extensions beyond existing hydro generation have been taken into account for the year 2050. This

[31] Heating value
[32] Heating value

approach is based on the assumption that hydro extension targets from national NREAPs can be realized by 2030. For Norway, it is assumed that 50% of the remaining hydro potential can be exploited; for Switzerland, the Swiss Federal Office of Energy (SFOE) national hydro targets were considered; and for Turkey, the total economically feasible hydro power potential of 126TWh was taken into account[33] (i.e. additional potentials of 76TWh and 28GW respectively). For MENA, an additional hydro potential of approx. 16.5TWh, mainly in Egypt and to some extent in Morocco, is assumed to be available by 2030. The split of all EUMENA potentials between hydro run-of-river and hydro dam storage was made according to the current national share of the respective hydro power technologies included[34].

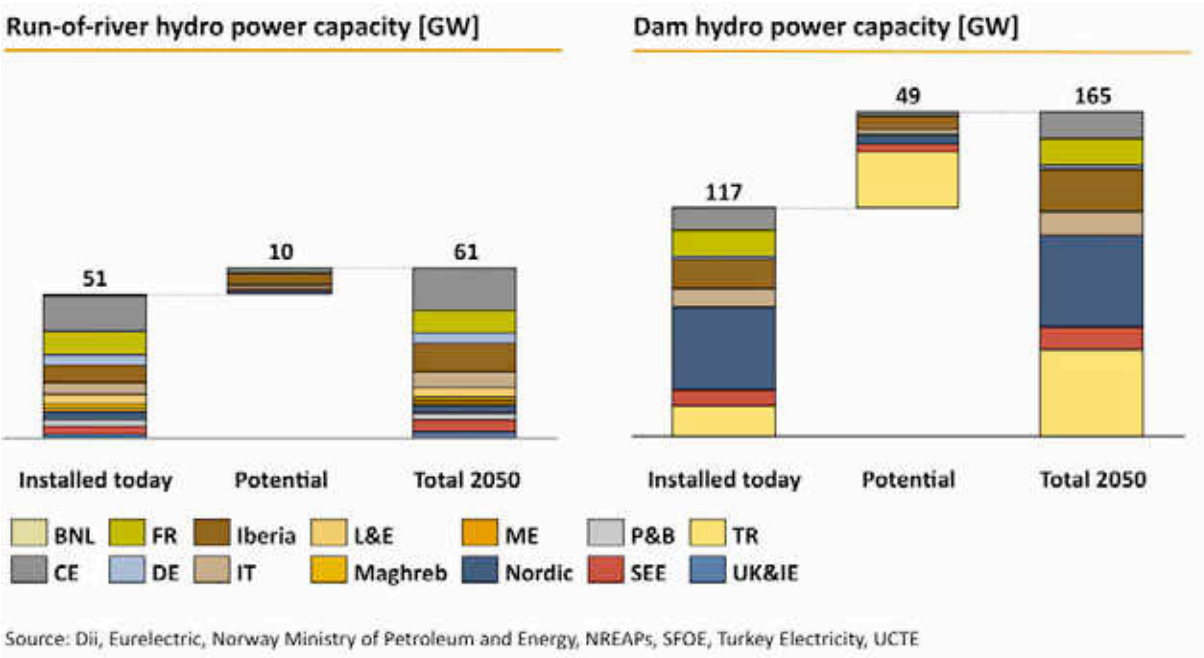


Figure 21: Hydro run-of-river and dam capacities today and 2050

Run-of-river plants are assumed to have a constant fixed load over the course of each month based on historical 2007 data (for some MENA countries, a fixed load over the whole year). Total generation from run-of-river plants amounts to 250TWh per year, see Figure 22. Hydro dam plants have a storage option and are dispatched endogenously by the model under water inflow and basin size constraints. These values were determined from the past generation of the respective hydro power plants for each country. Total generation from hydro power accounts for approximately 9% of the 8025TWh of demand in the high demand scenario. This excludes pumped hydro storage, which will be addressed in Section 2.4.3.

The cost assumptions shown in Table 3 are included in but do not influence the system costs resulting from the optimization procedure, since the installed capacities and cost of hydro power are exogenous parameters.

---

[33] Norwegian Ministry of Petroleum Energy and Energy, *Facts 2008: Energy and Water Resources in Norway* (2008); Swiss Federal Office of Energy (SFOE), *Energieperspektiven 2050 - Abschätzung des Ausbaupotenzials der Wasserkraftnutzung unter neuen Rahmenbedingungen* (2011), Turkey Electricity (http://www.turkey-electricity.com/)

[34] Eurelectric, *Power Statistics & Trends 2011* (2011); UCTE, *Statistical Yearbook 2008* (2008); ENTSO-E, *Production Data 2007* (2009)

Non-Solar/Wind technologies 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	Lifetime
Hydro (Run-of-River/Dam)	1600 €	20 €	50a
Geothermal and other	Ø100€/MWh		
Biomass	Ø90€/MWh		

Table 3: Parameters for non-Solar, non-Wind renewables considered

Biomass is integrated in the system partially as must-run generation with constant production over the year (73TWh), see Figure 22, and partially as dispatchable power (215TWh). Biomass generation has been incorporated based on a detailed analysis of biomass potentials for the power sector with consideration of competing uses in other sectors. Biomass generation costs an average of 90€/MWh, see Table 3. This again does not influence the technology mix optimization since the costs, as well as the 287TWh total generation from biomass, are exogenous model parameters[35].

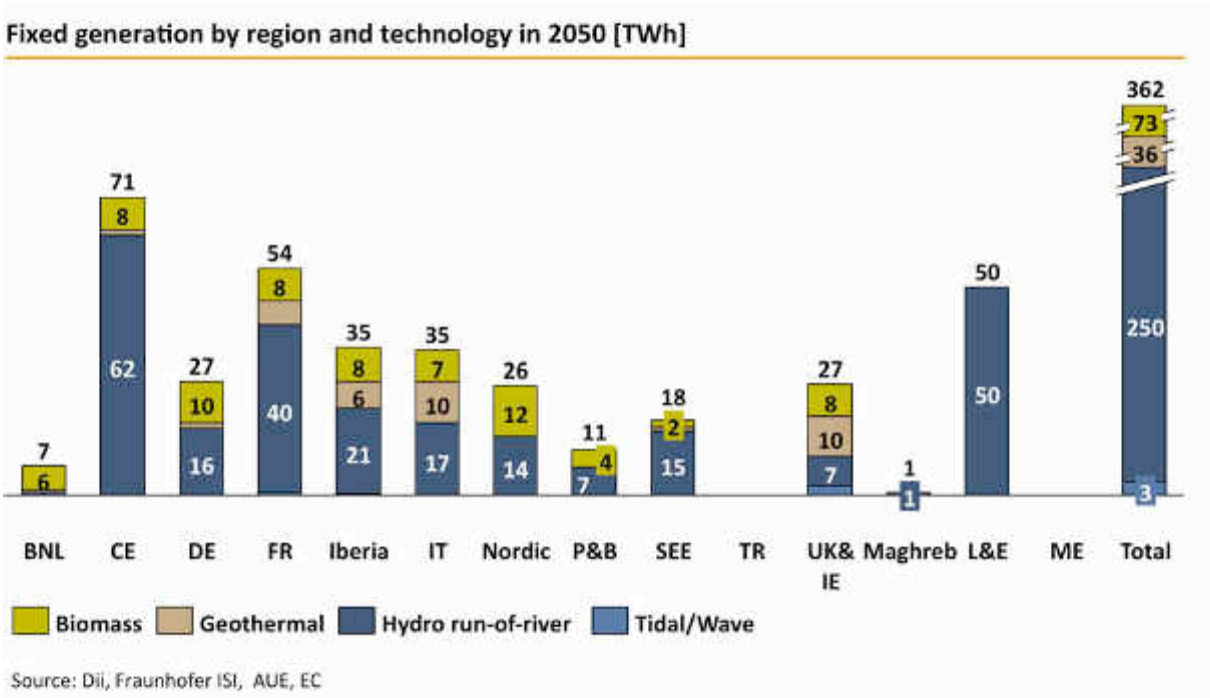


Figure 22: Fixed generation from renewables

Other technologies, such as geothermal, tidal and wave power have been taken into account according to the targets formulated in the Reference Scenario of the EU Energy Trends 2030[36]. It is assumed that the electricity produced by these technologies costs 100€/MWh on average, see Table 3. These cost assumptions are included but do not influence the system cost resulting from the optimization procedure, since the installed capacities and their costs are exogenous parameters.

[35] A. Held, Ph.D. Thesis, *Modeling future development of renewable energy technologies in the European electricity sector using agent-based simulation* (2010)
[36] European Commission, *EU energy trends to 2030 — Update 2009* (2010)

2.4.3 Storage technologies

Pumped hydro storage (PHS) is today by far the predominant power storage technology globally. Pumped hydro plants are represented by their pump and turbine capacity, their round-trip efficiency as well as their basin size, determining the amount of storable energy. The considered pumped hydro storage capacity is depicted in Figure 23. In Europe, a PHS capacity of about 32.5GW with a storage option of slightly above 3TWh is currently in operation[37]. Additionally, several gigawatts of PHS capacity build-up are already in concrete and advanced development or under consideration. As a starting point for our system modeling, we assume that a certain share of planned or discussed PHS projects will be available by 2030 and can therefore be considered as a fixed input to our model. Based on PHS targets in National Renewable Energy Action Plans (NREAPs) for 2020 and Eurelectric's projections[38], it is assumed that the NREAP targets and Eurelectric projections can be met by 2030. Since Eurelectric also considers projects with less certainty for realization, only 50% of the projected PHS extension was considered. If both NREAP and Eurelectric numbers are available for a specific country, the higher number was taken into account. As a result, PHS extensions of 26GW and 1.1TWh were considered for Europe and Turkey respectively.

In MENA only Morocco has PHS today, with approx. 0.5GW turbine capacity and 0.2TWh storage capacity available, according to the Moroccan Office Nationale de l'Electricité (ONE). Since no further PHS projects for MENA have been announced recently and the potential is very limited in the region, no PHS extension was assumed. Hence, the PHS figures provided in Figure 23 can be almost completely attributed to Europe and Turkey, with a strong focus on Austria, Switzerland, France, Iberia and Germany.

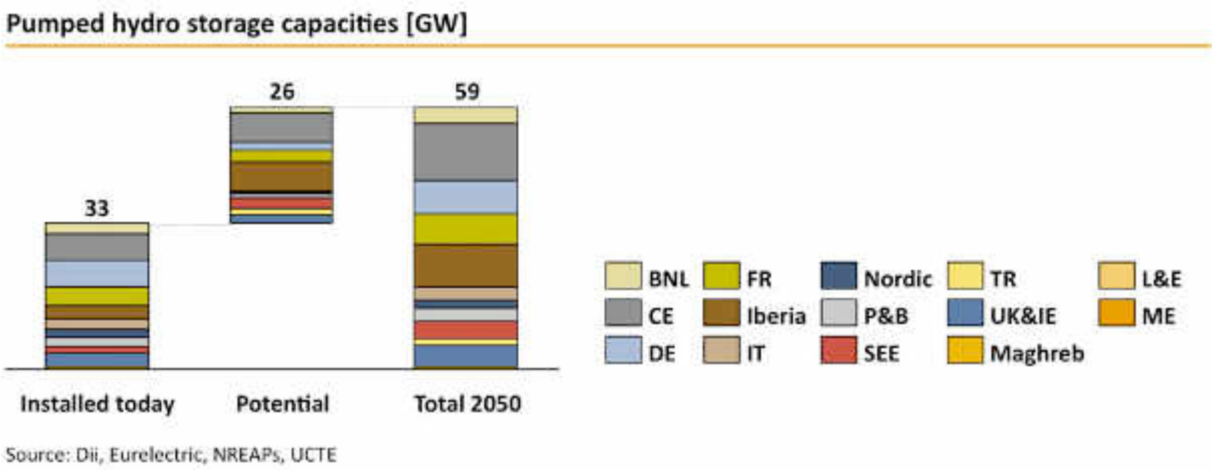


Figure 23: Pumped hydro and battery storage technology parameters

The cost assumptions for PHS shown in Table 4 are included but do not influence the system cost resulting from the optimization procedure, since the installed capacities and their costs are exogenous parameters.

[37] UCTE Statistical Yearbook 2008; Eurelectric, *Hydro in Europe: Powering Renewables* (2011); Eurelectric, *Power Statistics & Trends 2011* (2011); Dii analysis

[38] Eurelectric, *Hydro in Europe: Powering Renewables* (2011)

Batteries are considered as an additional storage technology, which is independent of a specific generation technology (unlike CSP thermal storage) and site independent (unlike pumped hydro storage). A generic utility scale battery system was considered with the parameters shown in Table 4. These parameters have been derived together with more than a dozen industry experts. They are based on the estimated potential for cost reductions of lead-acid, sodium-sulfur (NaS), Redox-flow and Li-Ion batteries. Long term energy storage cost forecasts have a high uncertainty due to the immaturity of the market. Hence, the battery system costs shown represent the optimistic case of an analysis with time horizon 2030 that is applied to 2050. We have also analyzed a sensitivity in which even cheaper batteries will be considered, Subsection 4.6.4.

Technology 2050	Investment [€/kW]	Fixed O&M [€/kW p.a.]	Net average efficiency	Lifetime
Pumped hydro storage	1000€	20€	80%	50a
Battery (~50MW, 8h storage)	1700€	29€	80%	20a

Table 4: Storage parameters

Adiabatic compressed air energy storage was also part of the storage assessment. However, since the technology is still in the R&D/pilot phase, it has not been included in the analysis.

The focus of this report is to analyze the first 95% of decarbonization. Renewable power methane and hydrogen technologies can play a crucial role when the last 5% of carbon emissions need to be eliminated. The storage technology assessment also considered hydrogen and renewable power methane technologies. Nevertheless, due to the uncertainty inherent in parameterizing such immature technologies, hydrogen and renewable power methane have been omitted in this report. Without further modeling it can be noted, though, that the gas power plants considered could run on renewable power methane for a 100% renewables scenario.

There are certain limits to the consideration of storage in this analysis. Since countries are represented as single nodes, decentralized storage, like Distributed PV and distribution grids, cannot be addressed explicitly. Instead, they are implicitly addressed by considering the Low Demand Connected and Reference Scenarios for utility scale generation and transmission. Furthermore, the results of this study rely on a fully functioning and very smart electricity grid, which in reality might have voltage fluctuations, technical load transmission restrictions, etc. In such cases, storage technologies can provide grid frequency regulation and grid stability; they can also handle ramping requirements, reactive power management for voltage control, and the short circuit capability of the grid. This market for storage technologies is out of scope of the power technology mixes presented in DP2050.

2.4.4 Solar and Wind technologies

The key technologies in this study are the solar technologies Utility PV and CSP, as well as on-shore and off-shore Wind. The following section provides an overview of these technologies' essential characteristics.

CSP (concentrating solar power) plants belong to the group of thermal power plants in which heat, in this case generated by solar irradiation, is transformed into electricity. In order to reach the high temperatures necessary for power cycles, the unscattered part of solar irradiation (direct normal irradiation, DNI) is concentrated. It is reflected and thereby concentrated by the use of large reflectors or reflector fields onto receivers, which are perfused by a heat transfer medium. This medium is either directly used in a gas turbine or exchanges its heat into a water/steam cycle to power a standard steam turbine. A major advantage of CSP technology is that it is possible to integrate comparatively cheap thermal storage, which allows for more constant electricity production and a certain degree of dispatchability. This positions it somewhere between fluctuating PV/Wind and fully controllable gas power plants. For the concentration of sunlight, line-focusing collector systems (Parabolic Trough systems, Linear Fresnel systems) and point-focusing systems (Power Tower, Parabolic Dish) with different characteristics exist.

Parabolic Trough collector systems are a proven utility scale technology, in commercial operation since 1984, and currently the most common type of CSP worldwide. The first utility scale power plants based on Power Towers and Linear Fresnel technology show how these young technologies can be successfully utilized.

PV (photovoltaic) technology is based on the principle of direct conversion of solar irradiation into electrical power by using the photovoltaic effect. The resulting DC current can then be converted with an inverter into an AC current.

PV modules are generally distinguished by the semi-conductor cell material in which the photovoltaic effect occurs, which affects the modules' key characteristics, such as their efficiency. The dominant material and technology today is crystalline silicon, which accounts for approximately 90% of the globally installed PV capacity. It is followed by thin film PV, which uses other semiconductor materials. Besides the two leading PV technologies, many other innovative PV technologies are being developed and introduced to the market. They range from improved versions of established technologies (e.g. PERL solar cell design) to new combinations of technologies (e.g. Concentrated PV) and new materials, (e.g. organic materials).

PV systems' energy yield can be enhanced through tracking systems, which enable the modules to follow the sun's path and thereby produce more electricity. In practice, due to investors' risk perception concerning the failure of moving parts in systems with trackers, fixed systems remain the predominant kind of PV installations. A major advantage of PV is its scalability, from a few watts to MW class. PV also offers a high degree of modularity in the construction phase. The installation, maintenance and cleaning are simple and fast compared to other technologies.

Wind turbines convert the kinetic energy of the wind into electricity. A typical wind turbine consists of three main components: the tower, which supports the entire structure, a three-blade rotor and a nacelle. The nacelle contains the control equipment and gearbox with a generator, or alternatively a direct drive generator with inverter.

The rotor is put in motion above a certain wind speed and drives the generator, which then generates AC electricity. In direct drive (gearless) systems, the generated voltage has to be converted by the inverter into net synchronic voltage. While gearbox-based turbines currently dominate the global market, direct-drive turbines are gaining importance and currently reach close to 18% market share. The design of direct drive turbines is challenging but the technology has many potential advantages: significantly fewer moving parts lead to lower O&M requirements and a better performance under variable wind speed conditions.

Since 2000, the average size of Wind turbines installed in Europe has risen from 0.8MW to about 2.0MW. A similar pattern can also be observed for Wind projects in North Africa, where Wind turbines contracted for projects under construction and in the planning stage have moved beyond the sub-MW segment. The overall trend to use ever bigger rotors will continue as it increases the swept area on which wind energy can be harvested. The technical challenge lies in designing equipment that is capable of resisting the tremendous physical stress that the wind places on the large rotor area.

Since the extractable power of the wind rises at a higher rate than the wind velocity, sites with high mean wind velocities offer high energy yields and full load hours, similar to the conditions found off-shore. However, these sites present special challenges to the wind turbines, which must then be addressed separately.

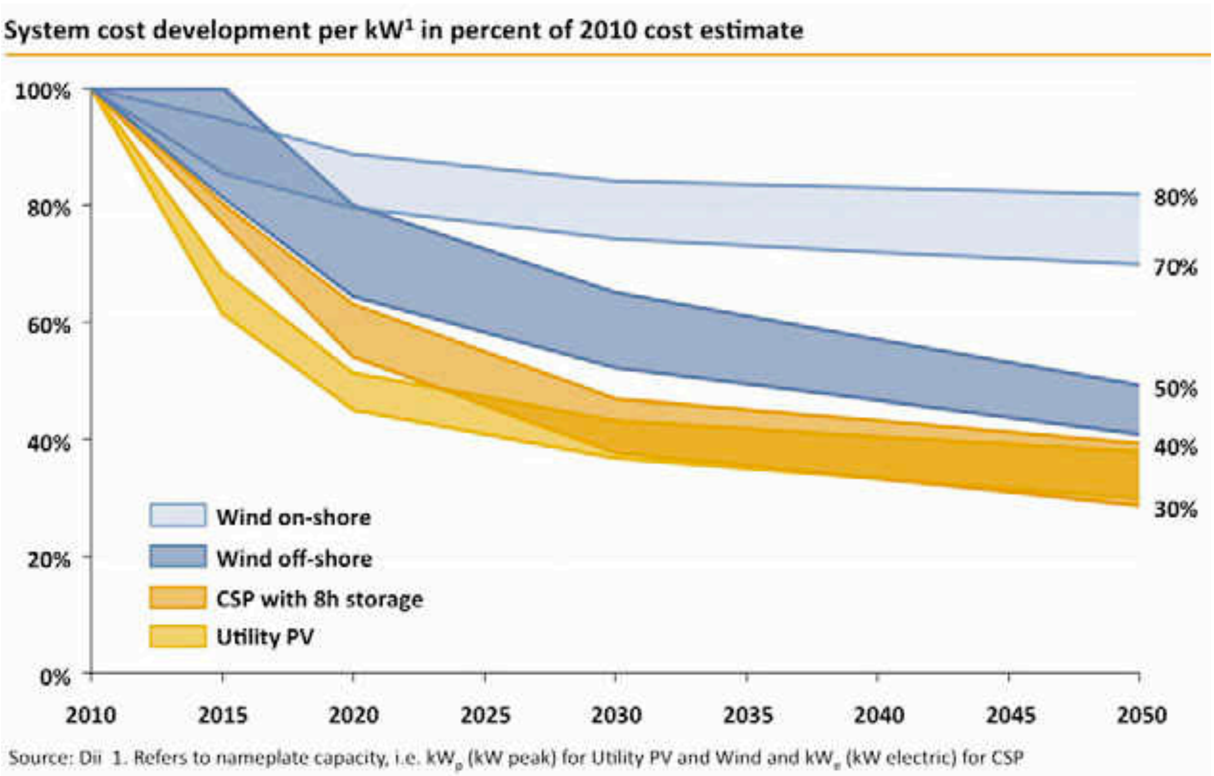


Figure 24: Cost reduction pathways for Wind and Solar technologies until 2050

This report assumes considerable yet – from an industry perspective – realistic cost reductions for Wind and Solar technologies. These have been developed for each technology based on publicly available reports as well as based on extensive interviews with industry experts both within and outside of Dii's network of companies.

Technology cost 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	Lifetime
Wind on-shore	900 €	30 € (3.33% of invest.)	25a
Wind off-shore	1340 – 1920 €[39]	54-76 € (4.00% of invest.)	20a
Utility PV	700 €	19 € (2.75% of invest.)	25a
CSP with 8h storage	2000 €	45 € (2.25% of invest.)	30a

Table 5: Parameters for Wind and Solar technologies

Cost estimates going 40 years into the future for technologies already on dynamic cost reduction paths are of course subject to major uncertainties. It is important, therefore, not to mistake current market price observations with cost reductions. Prices depend primarily on supply and demand and are thus subject to greater fluctuations, and influenced by other parameters, than costs. The cost reductions from 2010 to 2050, shown in Figure 24, assumed for the different technologies lead to the cost estimates shown in Table 5.

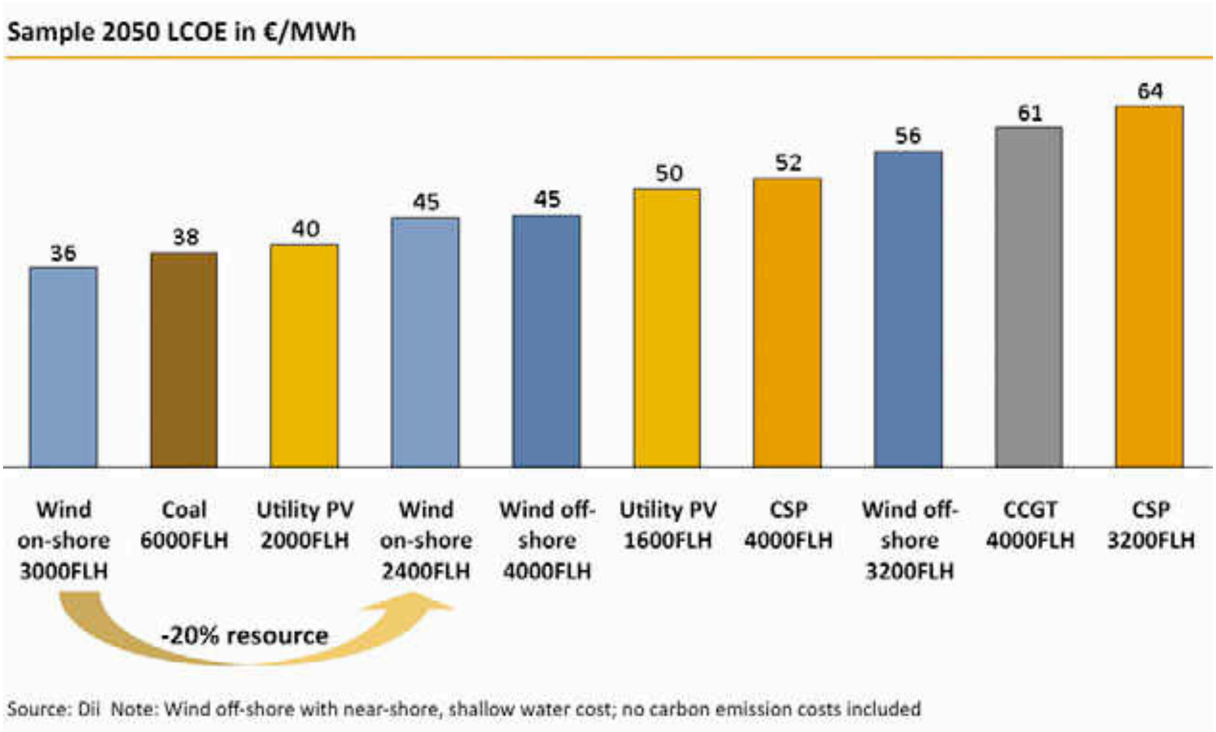


Figure 25: Sample 2050 LCOE resulting from technology assumptions

[39]Off-shore investment depending on sea depth, distance to coast

The determining factor for technology cost in the system optimization is not investment but the Levelized Cost of Electricity (LCOE). Before we go into the details concerning cost reduction assumptions, we therefore show their results in terms of LCOE[40]. Figure 25 shows the LCOE with the parameters from Table 2 and Table 5 and WACC of 7%, which is used for the analyses in DP2050. This LCOE calculation does not take into account systemic restrictions such as the carbon emission cap or curtailment, which have a significant impact on the simulation results presented in Chapters 3 and 4.

The full load hours (FLH) in the chart refer to the electricity produced per MW of installed capacity of per year, i.e. 1MW with 2000 FLH produces 2000MWh of energy per year. This shows that Wind and Utility PV reach LCOE around 35-45€/MWh under the conditions found in abundance in EUMENA and CSP reaches LCOE of approx. 50€/MWh in 2050. A crucial difference between the technologies is the dispatchable character of CSP due to the incorporated 8h storage. Hence, the LCOE of CSP and non-dispatchable technologies should not be compared without taking system-wide effects into account.

It is important to note that LCOE, as considered in this power strategy study, is not the same thing as the revenues needed to make a real-life financed project work. Calculation of the annual cost of a power plant for this report involves five parameters and an annuity formula. Filling a project finance model with life requires several dozen parameters, as shown in Table 7, at which point the real work for achieving a financial close has only just begun.

That said, it is neither possible nor essential for a system strategy study to consider all these project finance details. They depend on many volatile factors and, as long as all cost calculations within the study are done consistently, the result of the system study is not affected by them.

When interpreting the cost reduction curves from Figure 24, the different degree of maturity of the respective technologies needs to be taken into account. Expert opinions, technology specific analyses and learning curves, as shown in Table 6, have been taken into account for these cost reduction curves.

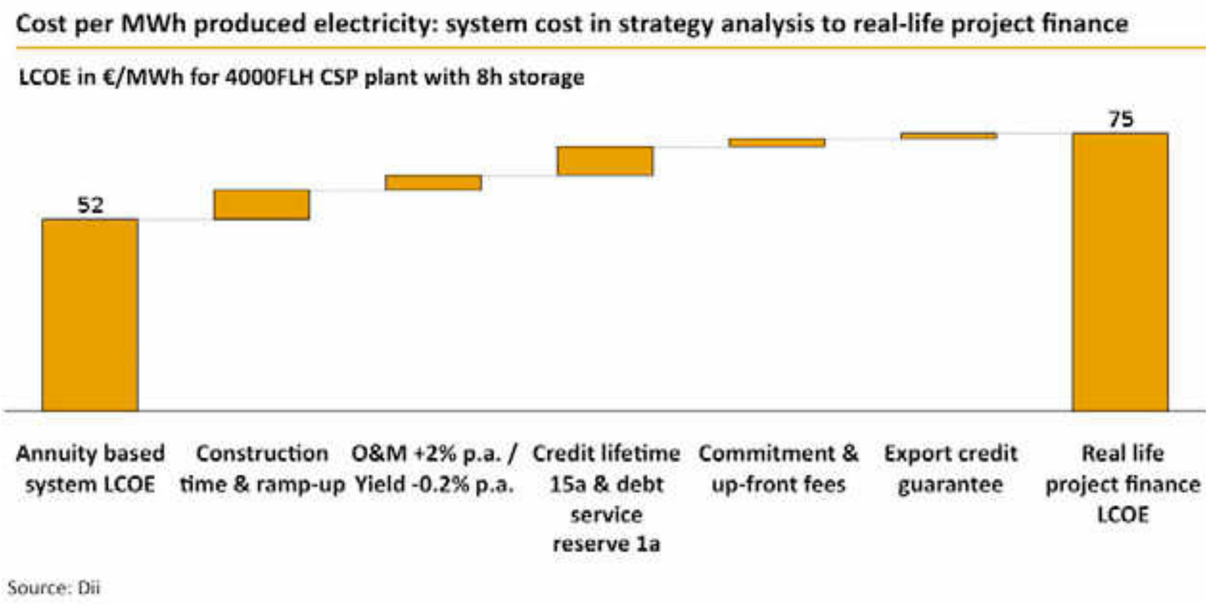
Table 6: Learning curve approach for technology cost reduction estimates

A common (and technology independent) way of estimating cost reductions over long time periods is that of learning curves. This empirically proven approach shows that maturing technologies undergo a rate of cost reductions that depends, in a roughly linear fashion, on how often the installed capacity of the technology doubles. Thus, the worldwide installed capacity of a technology at the beginning of the time horizon under consideration has a major influence on the rate of cost reduction per installed GW. For example, if 1GW of a technology is installed in 2010 and 100GW of another one, then two doublings of capacity would mean that the first technology reaches 4GW installed, while the second one reaches 400GW. Thus, if both technologies have the same 10% learning rate, then 3GW of the first technology and 300GW of the second one must be installed to achieve a 19% (10%+10%*90%) cost reduction.

[40] Costs of carbon emissions are not included

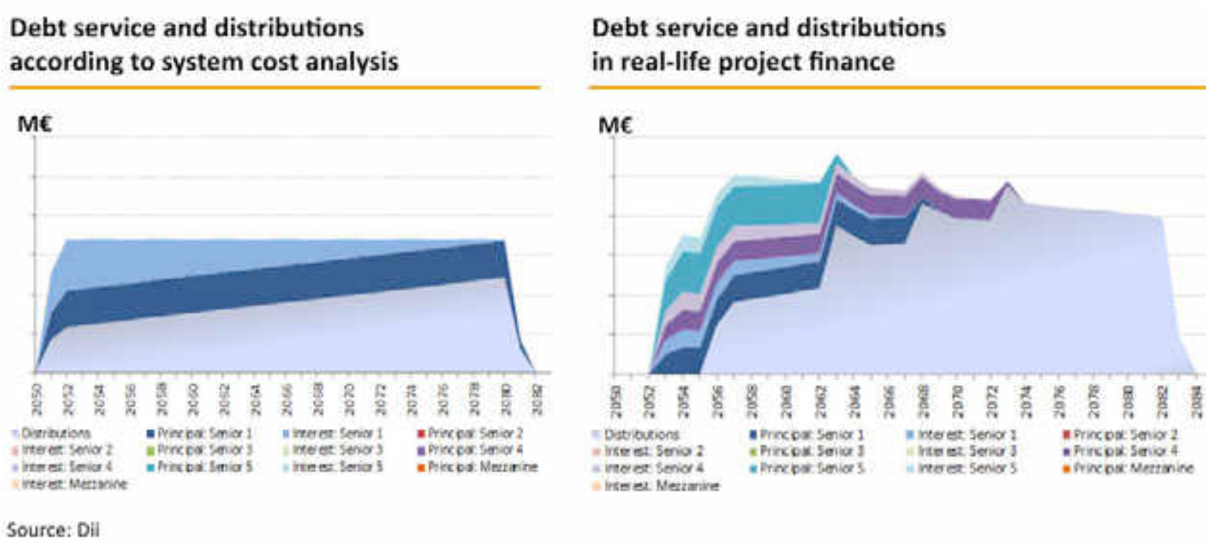
Table 7: LCOE for system cost in strategy analysis vs. real-life project finance

Example 1 shows an example of how the consideration of a range of variables – construction time, ramp-up phase, increase of operation costs and output degradation for aging power plants, reduced credit lifetimes, bank fees and export credit guarantees – can drive up the required revenue per MWh.



Example 1: LCOE in strategy analysis vs. real life project finance

The key reason for this is that all of these factors delay the return of cash on the invested equity, see Example 2, which shows two screenshots from Dii's project finance model. Since equity bears the highest risk in a project, it also has the highest return on capital. Delaying this return increases the lifetime cash-in needed for the project.



Example 2: Debt service and distributions in strategy analysis and project finance

In the rest of this section it is explained why each of the technologies analyzed in this study has the potential to reach the cost estimates for 2050. To account for the uncertainty of cost developments, we also present sensitivity analyses on the impact of higher renewables costs in Subsection 4.6.3.

On-shore Wind: Approx. 192GW of on-shore Wind have been installed worldwide, as of the end of 2010, and turn-key cost for installations with tier one turbines were approximately 1200€/kW_p. Worldwide installed capacity at the end of 2011 was approx. 234GW. A 25% cost reduction to 900€/kW_p in 2050 corresponds to a gradual decline of the learning rate from approx. 10% at the beginning of the 40 year time span to 6% towards the end. This assumes that worldwide on-shore wind installations reach 1.5-3.0TW by 2050. The latest Wind market developments show that some systems based on older turbine models in Europe have already reached system prices of approx. 1000€/kW_p, while those with the newest turbines still cost about 10-15% more. Since the performance estimates for this study have been performed with state-of-the art turbines and a hub-height of 120m, higher than most installations today, the cost and performance estimates used are consistent.

Off-shore Wind: Approx. 3GW of off-shore Wind were installed worldwide at the end of 2010 and system costs were approx. 3000€/kW_p. This increased to approx. 4GW by the end of 2011. The learning rates for off-shore Wind reaching the projected cost of 1340-1920€/kW_p are approx. 10-13%, assuming worldwide installed off-shore Wind capacities of 0.8-1.2TW. The installation costs of this technology depend heavily on sea depth and distance from the coast. This is one of the reasons why currently no decline in project costs can be observed: the most favorable spots are taken and projects have to move further out to deeper waters with ample space. Furthermore, off-shore Wind requires specialized heavy duty equipment, most notably ships, for construction and operation. As this heavy duty equipment itself undergoes a learning curve, this will also decrease off-shore Wind costs. These facts lead to the expectation that cost reductions in off-shore Wind will gain momentum after 2015.

Utility PV: Approx. 40GW of PV (including Utility and Distributed PV) were installed worldwide at the end of 2010, which increased to approx. 67GW at the end of 2011. A cost reduction of 2/3 from 2010 system prices of 2100€/kW_p corresponds to a learning rate gradually declining from 22% to 10% over the four decades considered. These learning rates are based on the assumption that worldwide PV installations will reach 2-4TW. A key difference between PV and the Wind and CSP technologies under consideration is the feasibility and widespread success of Distributed PV, be it on roof-tops or integrated into buildings. As explained before, Distributed PV cannot be included in the modeling that is the basis for this report. Thus, PV capacities resulting from the modeling represent Utility PV only and total PV installations (including Distributed PV) will be larger: in general, it would be reasonable to assume that Distributed PV will play a significant role in Europe and possibly also in MENA[41]. PV has a track record of achieving a 22% learning rate over the last four decades and has recently outperformed this by far. Thus, Utility PV can currently be built for less than 1500€/kW_p, and few still doubt that the technology can achieve system costs of 700€/kW_p. On the other hand, the recent price drop was not only due to cost reductions but also to a price war triggered by massive

[41] For the EU member states, the NREAP targets are considered as a lower limit and thereby the impact of Distributed PV is taken into account to a certain extent; the impact is limited except for Germany

overcapacities in the market. A series of bankruptcies resulted from this price war, as did a rush into tier two and tier three PV installations by manufacturers and EPCs struggling for survival. As with all other technologies, our performance estimates are based on tier one systems and therefore the cost estimate is justified also in the light of the latest drops in PV prices.

CSP: At the end of 2010, approx. 1GW of CSP was installed worldwide; the turn-key cost for the most common type, $50MW_e$ plants with 8h storage, was approx. 6000€/kW_e. By the end of 2011, 1.6GW CSP was installed worldwide. A 2/3 cost reduction to 2000€/kW_e corresponds to a gradual decline of the learning rate from approx. 12% in the first decade to 9-10% later on. This learning rate corresponds to a market estimate of 0.4-0.8TW worldwide installed capacity by 2050. There are several reasons why the learning rate approach is not optimal to understand CSP cost reduction: CSP is built in utility scale plants only, worldwide installed capacity is below 2GW as of today, and technologically different concepts are summarized under the name of CSP. Furthermore, some parts of CSP plants, especially the power block with the turbine, are similar to conventional power technology, although not exactly the same as steam power blocks in conventional coal plants. The cost estimate of 2000€/kW_e is based not only on reduced specific costs for the solar field and other plant components, but also on the expectation that CSP technology will improve substantially in terms of system design, temperatures and efficiencies. The higher temperatures will also enable significant savings in terms of storage volume and the higher heat to electricity efficiencies will allow for a reduction of the mirror area needed per kW_e. Concepts based on tower technology to reach these high temperatures and efficiencies with solar heat already receive significant funding for R&D and pilot installations.

O&M and plant lifetime: Across technologies, we have taken a cautious view concerning assumptions on lifetimes and O&M cost. This should be seen as a conservative approach towards analyzing a sustainable power system based on the optimal use of sun and wind throughout EUMENA. Often, the best wind and solar conditions are found in harsh environments, e.g. the hot and dry climates of MENA or the stormy northern seas with the best off-shore wind conditions. In order to account for this, we use conservative O&M cost and lifetime assumptions for all technologies. If lifetimes turn out to be longer, and O&M to be cheaper, this will make a sustainable power system even more attractive. For example, a 25% longer lifetime of 25 years for off-shore Wind results in 6% lower LCOE. Similarly, a 25% lower O&M cost assumption for Utility PV results in 13% lower LCOE.

With hindsight, the market estimates for all technologies used a priori to determine learning rates and cost reductions seem rather conservative compared to the capacities that result from the system modeling presented in this report. The reason is that the market outlooks used a priori for these estimates extrapolate from the present, while the system analysis answers what needs to be done to provide EUMENA with a sustainable power system based on the sun and wind. The key messages of this report concerning the technology mix would not change if technology costs decrease even more due to stronger markets – in fact, the opposite is the case.

Some might argue that the cost estimates presented here are too high, for a variety of possible reasons. While this could be true, many facts have to be taken into account. In functioning markets, prices have a tendency to be just low enough for a product to be sold. In other words, they are generally competitive but not much lower, since this is where the sellers earn their profits. Today renewables are constantly facing the challenge of reaching LCOE that are cost competitive with conventional power generation technologies. This challenge will disappear at some point in time in the next four decades when cost competitiveness with conventional technologies has been reached on a broad basis - for some technologies sooner, for others later. At this point, cost competition will be of another type as it will take place primarily among renewables. Due to the nature of the resources used, these technologies are complementary, as confirmed by the analyses in Desert Power 2050 and other reports. Consequently, some sort of equilibrium will be found by the market forces among these technologies: the results of this report show that our set of cost assumptions is one such equilibrium. Whether the technology equilibrium will look exactly like the one shown here is and will remain uncertain.

That said, these uncertainties do not compromise the main result of this report: a Solar- and Wind-based power system for EUMENA can work and each of the four technologies Utility PV, CSP, on-shore Wind and off-shore Wind will contribute to it with hundreds of GWs of installations.

2.5 Solar and Wind potential in EUMENA

In order to understand the LCOE and thus competitiveness of Solar and Wind technologies, cost assumptions for power plants and transmission are one of the two major ingredients. The other is the estimation of the electricity production potential of each technology across the EUMENA region. These potentials are the second of the two means used to implicitly integrate spatial information into the system optimization, where each country is represented as a single node.

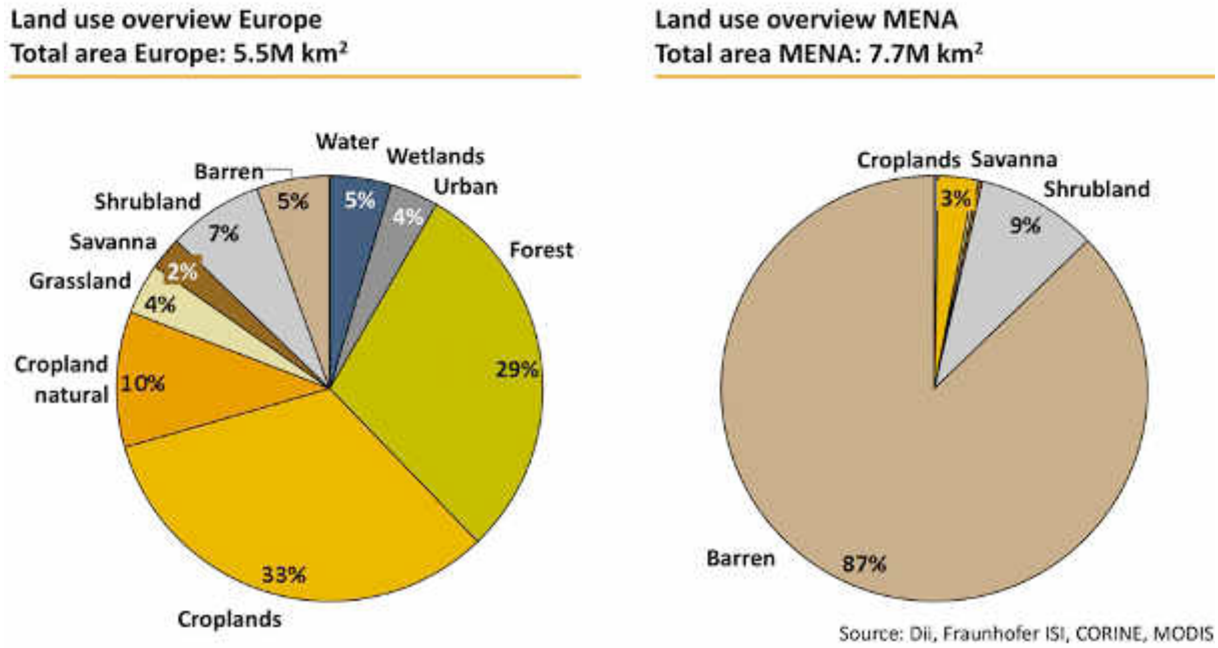


Figure 26: Land use overview Europe, MENA[42]

[42] For MENA: MODIS data (MCD12Q1) for 2009; for Europe: CORINE Land Cover 2000 raster data - version 15 (08/2011)

The high resolution renewables potential analyses for this study have been performed with a Geographic Information System (GIS) by Fraunhofer ISI and Dii. The basis for the analyses is high resolution land use data sets, which classify the land into categories such as urban area, cropland, forest and barren land. The varying intensity and types of land use in Europe and MENA are one of the key factors why EUMENA-wide power system integration is so useful: space is plentiful in the vast desert areas of North Africa and the Middle East, where barren land with few to no competing uses makes up more than 80% of the landmass, see Figure 26.

Some areas across EUMENA are completely excluded from the renewables potential analysis, i.e. it is assumed that no power plants will be built there. These areas include, for example, nature conservation areas and buffer zones around them, military sites (where information is available), sand dunes with a 10km buffer around them, and bird migration corridors.

In addition to the identification of exclusion areas, land use factors are applied to restrict the use of locations for renewables installations to a realistic level. For Utility PV and CSP, land use factors of 15% have been used for barren land, savanna, and shrubland, and 10% for grassland. Croplands and natural croplands have 1% utilization for CSP and Utility PV, and urban areas can be used up to 5% for Utility PV.

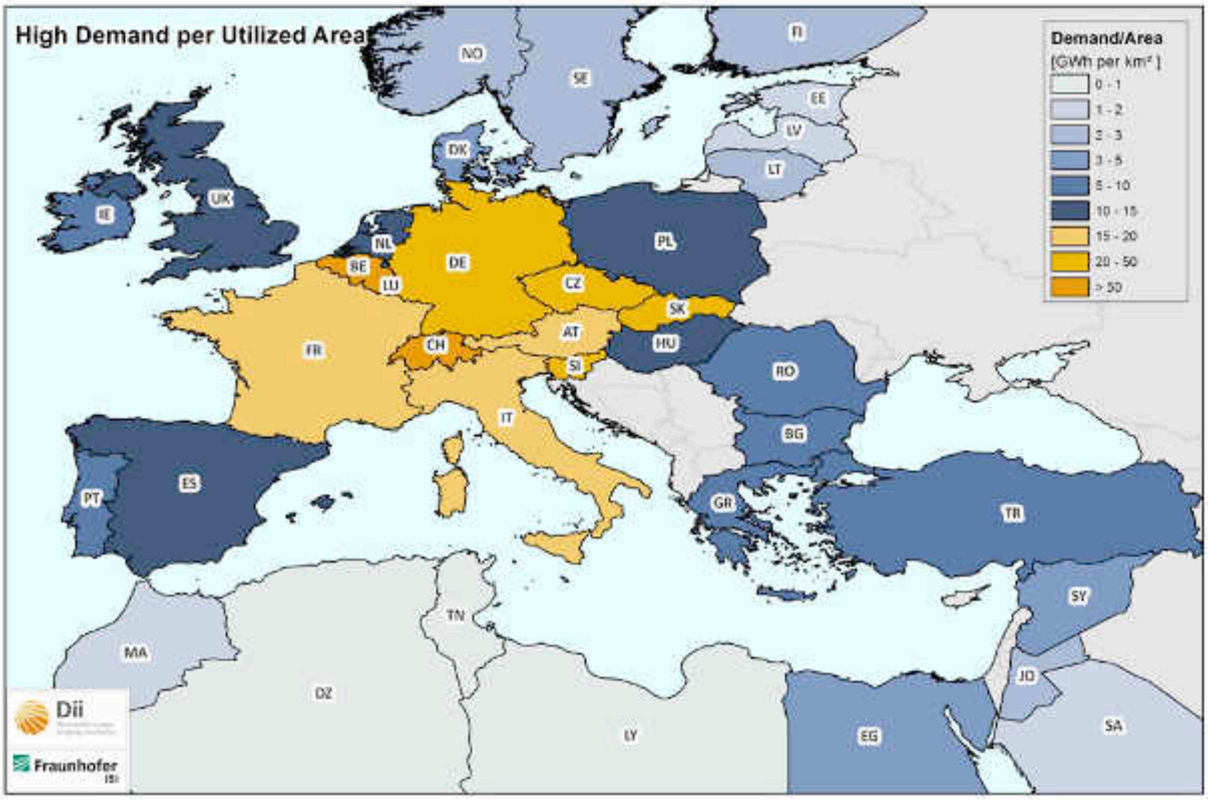


Figure 27: Country demand divided by area utilizable for Wind and Solar installations

Wind installations do not actually cover a large surface, but their area consumption is due to a minimum distance needed between Wind turbines to avoid wind shading effects. Therefore, higher land use rates are used for on-shore Wind. They amount to a utilization of 25% for barren land, savanna, and shrubland, and 10% for grassland and snow and ice. On-shore Wind can also use 8% of forests and 5% of croplands and natural croplands. For off-shore Wind, a usage factor of 30% of non-excluded off-shore areas is used. Overall, no more than 55% of any type of land is used for renewables. This ensures that double counting of renewables potentials cannot occur.

The land use factors have been chosen conservatively in order not to overestimate the Solar and Wind potentials in the region. They also account for differences between the technologies – e.g. while some Utility PV can be built in urban areas, CSP and Wind cannot. Figure 27 shows the ratio of each country's demand compared to the area available for Wind (on- and off-shore) and Solar (Utility PV and CSP) installations. This is a very rough measure for the balance of Wind and Solar potentials and demand in a country. Nevertheless, it gives a good impression of where Wind and Solar are relatively scarce and where they are abundant. The figure shows that this ratio is highest in the center of EUMENA, although France and Italy also have a high demand to area ratio. This ratio is very low in the Maghreb and Libya.

For the calculation of the respective technologies' electricity production potentials, other factors have been taken into account. These calculations will now be explained.

On-shore Wind: For the calculation of Wind generation, wind speed and air density are important, among other factors. The basis for the calculation of Wind potentials is the MERRA data set from NASA. This data set includes time series for the year 2007 in hourly resolution for approx. 7000 locations across EUMENA. The hourly energy yield calculation is based on 120m hub height (extrapolated from the 50m height MERRA data using area specific roughness lengths) and the power curve of two state-of-the art turbines, one for normal and one for strong wind zones. Furthermore, park effects are taken into account for the mutual interference of nearby turbines; availability is also considered.

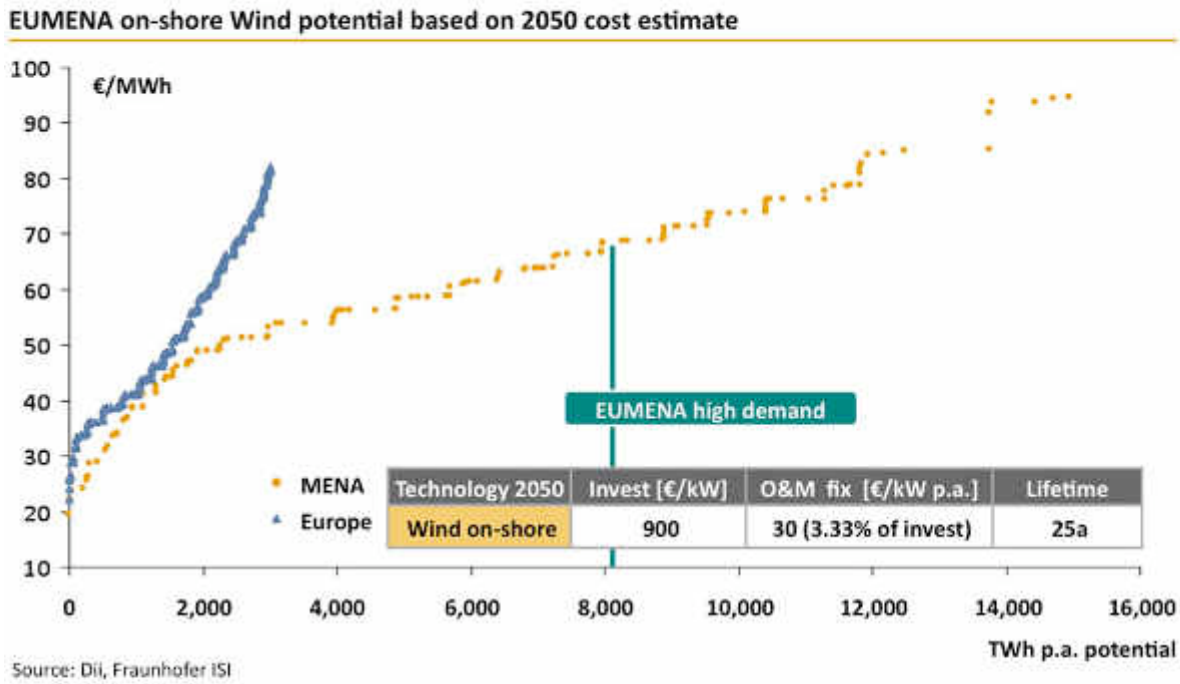


Figure 28: On-shore Wind potentials in Europe and MENA

For certain countries, wind atlases have been used to improve wind speed estimates based on MERRA data. In MENA, such atlases exist and have been used for Egypt, Tunisia and Morocco. For

Europe, such a procedure has been applied to Spain, the UK and Denmark since the Wind potentials in these countries are especially important for the overall system.

The resulting on-shore Wind cost potential curves for MENA and Europe are shown in Figure 28. This figure demonstrates that on-shore Wind in MENA alone would be able to provide enough energy to satisfy EUMENA's annual demand of 8025TWh. It also shows that MENA should not only be perceived as a region with good solar conditions. European on-shore Wind potentials are very high and start below 30€/MWh. However, due to its huge area and the good wind conditions in Morocco and Egypt, MENA not only has huge Wind potential but also has the best Wind sites in EUMENA.

Off-shore Wind: Off-shore Wind potentials have been calculated with a methodology similar to that used for on-shore Wind. A country's off-shore area is based on its exclusive economic zone[43]. A 100km limit to the maximum distance from the coast has been taken into account; similarly, only areas with up to 50m water depth are included in the potentials analysis. Since the cost of off-shore Wind installations depends strongly on sea depths and the distance from the coast, these two factors have been integrated into the analysis by escalating off-shore investments depending on these two parameters. Off-shore Wind was only taken into account for European countries, since off-shore conditions in MENA are rather less attractive. This is due to sea depths and relatively low off-shore wind speeds in the Mediterranean, as well as the good availability of on-shore areas for Wind installations. The resulting cost potential curve for off-shore Wind in Europe is shown in Figure 29. It depicts the huge potential of off-shore Wind in Europe of more than 3000TWh, and also reveals that off-shore Wind generation is more expensive than on-shore even with the cost reduction assumptions of 55% until 2050 applied here.

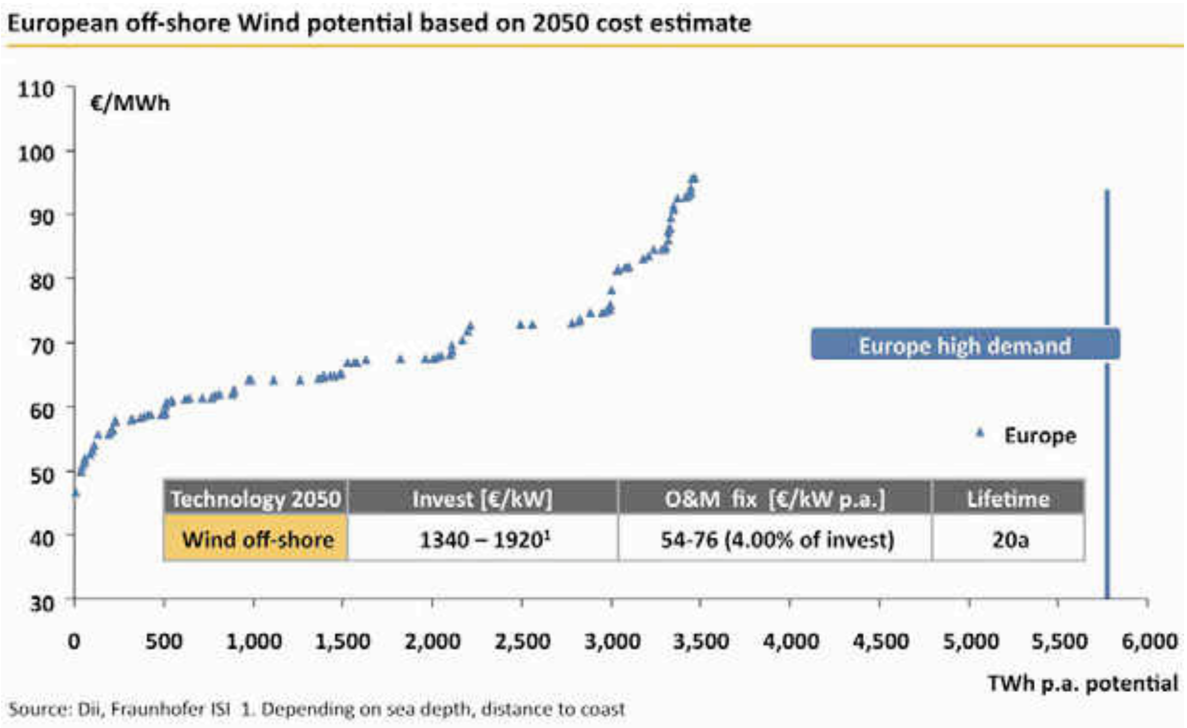


Figure 29: Off-shore Wind potentials in Europe

[43] See Art. 55, 57 (Part V) UNCLOS (area beyond and adjacent to the territorial sea which extends up to 200 nautical miles from the baseline)

Utility PV: For Utility PV, areas with a slope of 4% or more have been excluded, since above such slopes the orientation of the hangs has to be taken into account. Installing Utility PV on sites with a higher slope would lead to additional costs and has therefore not been taken into consideration.

As meteorological data, Helioclim time series for global horizontal irradiation (GHI) have been used. This data set includes time series for the year 2007 in hourly resolution for approx. 9000 locations across EUMENA. The estimation of Utility PV generation potentials takes into account the temperature dependence of the poly-crystalline silicon modules, cable and inverter losses and other factors influencing the yield of PV modules – the resulting cost potential curve is shown in Figure 30. This figure reveals that Utility PV potential, especially in MENA, is virtually infinite, with more than 20,000TWh of Utility PV potential below 60€/MWh.

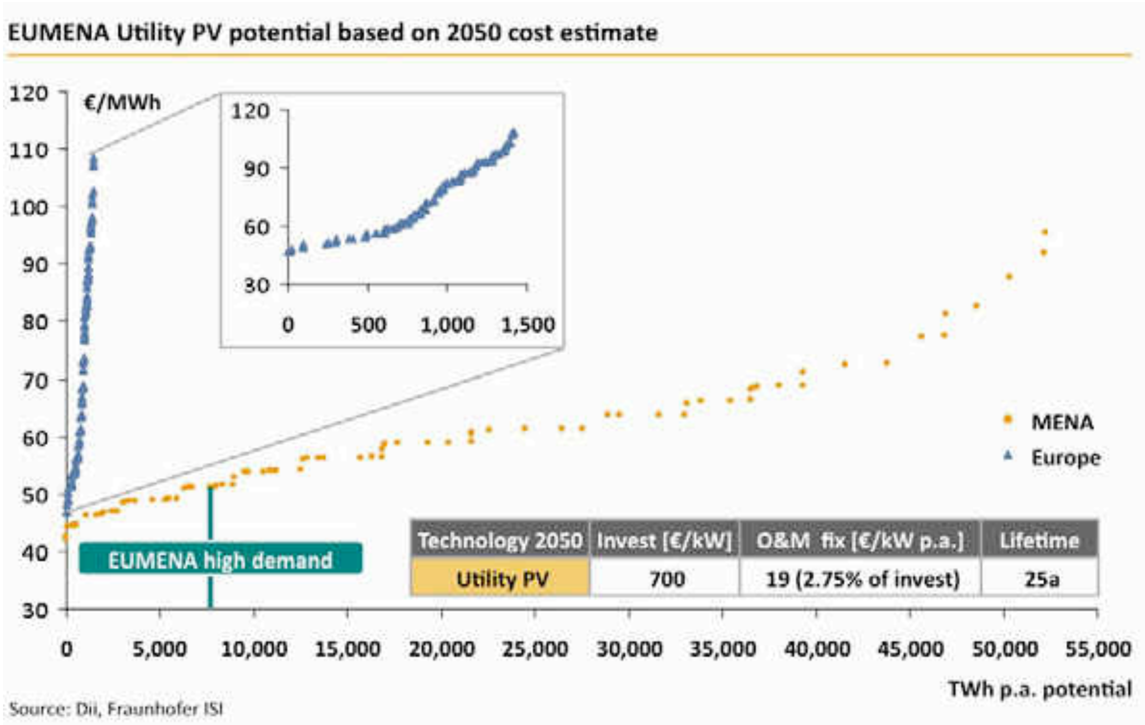


Figure 30: Utility PV potential in Europe and MENA based on 2050 cost estimate

CSP: For CSP, areas with a slope of more than 2% have been excluded. While this is important for parabolic trough or fresnel technology, with long exact, horizontally aligned receiver lines, tower installations can also be built in other topographic conditions. That said, non-flat terrains will increase construction cost for tower plants; the restriction to areas with less than 2% slope is thus consistent with our cost assumptions. Since we consider CSP plants with 8h storage (the storage amount has been determined based on preliminary model runs with endogenous storage amount optimization for CSP), their dispatchability needs to be accounted for. A CSP plant is represented in the optimization as a time series with hourly resolution for the solar field heat output. The heat can then be either directly converted into electricity in the turbine, with 56% net average thermal to electric efficiency, or be stored in the thermal storage unit if it is not yet full. In this case, thermal energy storage is subject to 7.5% storage losses. In a CSP plant, own consumption of the power plant, e.g. for pumps, is included in the 56% net average efficiency for the turbine. The hourly solar field heat output time series have been modeled with NREL's software for thermodynamic simulations of

CSP plants, SAM[44], for more than 100 locations in the countries with CSP potentials across the region. The resulting cost potential curve is shown in Figure 31. The figure shows that the CSP potential in the region is huge, with more than 20,000TWh for less than 70€/MWh, and that the cheapest CSP potentials are more expensive than the other solar technology considered, i.e. Utility PV. In the optimization with PowerACE, the additional value of CSP is its modeled endogenous dispatchability due to the thermal storage unit.

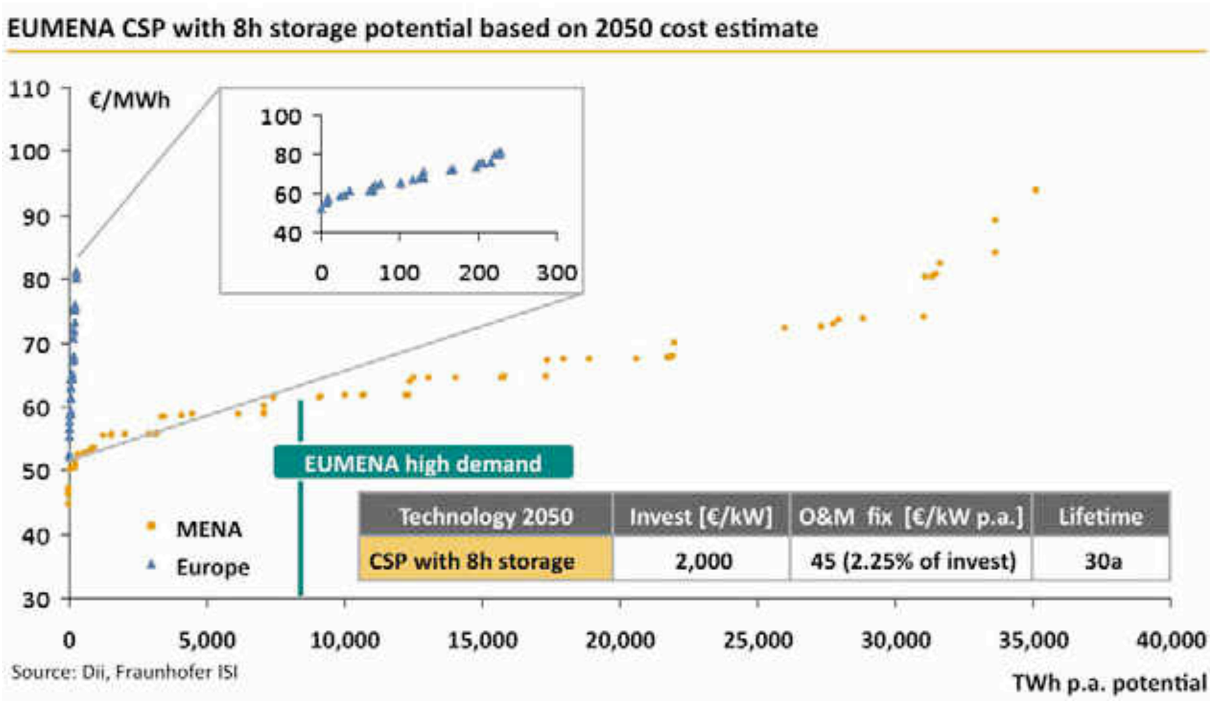


Figure 31: CSP potentials in Europe and MENA

For the EU27 countries, a lower limit on Solar and Wind installations has been taken into account. It is based on an extrapolation of the 2020 NREAP targets for renewables build-up to 2030[45]. Figure 32 shows the lower limits for renewables installations by technology and country in the system optimization. Except for a few countries, these lower limits do not influence the results of the analysis since the system builds more capacities based on a cost optimal approach. The remaining impact of the lower limits is analyzed in the so-called No NREAPs sensitivity in Section 4.6.

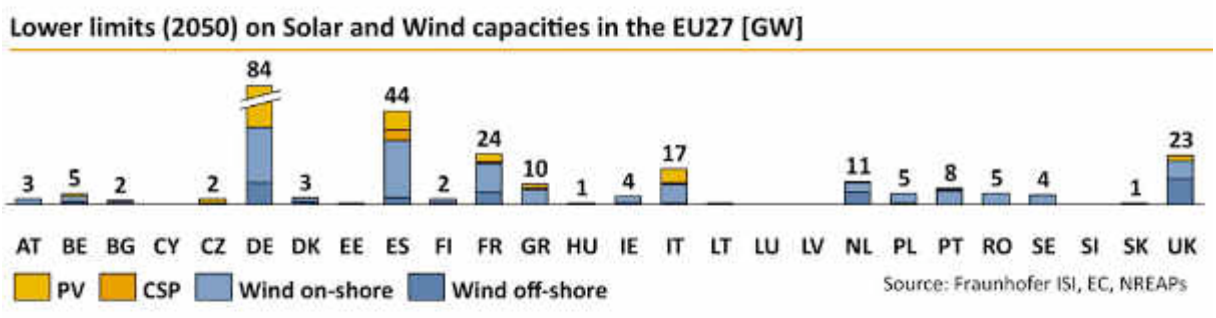


Figure 32: Lower limits (2050) on Solar and Wind capacities in EU27

[44] System advisory model: software developed by NREL for thermodynamic modeling of CSP plant performance
[45] European Commission, *EU energy trends to 2030 — Update 2009* (2010), analysis by Fraunhofer ISI

3 The Shape of Desert Power for EUMENA

We analyze and compare two power systems for EUMENA, both of which have to satisfy 8025TWh of annual demand under a carbon emission cap of 0.25Gtonnes p.a. The key difference between the two scenarios is the availability of transmission lines between MENA and Europe. In the Connected Scenario, transmission lines cannot only be built between countries either within MENA or within Europe, but also between MENA and European countries[46,47]. In the Reference Scenario, transmission lines between Europe and MENA are not available: as a result, there are two isolated but, internally, fully optimized power systems with a common carbon cap. A 70% self-supply rate on an annual basis for each country is ensured in the Connected Scenario but not in the Reference Scenario, giving the latter an additional degree of flexibility[48].

In the Connected Scenario, a total of 1087TWh is exported from MENA to Europe. Given that 23TWh also flows in the other direction, from Europe to MENA, the net power trade balance from MENA to Europe is 1064TWh per year of exports. These net exports from MENA to Europe amount to 19% of European demand and 46% of MENA domestic demand, as depicted in Figure 33.

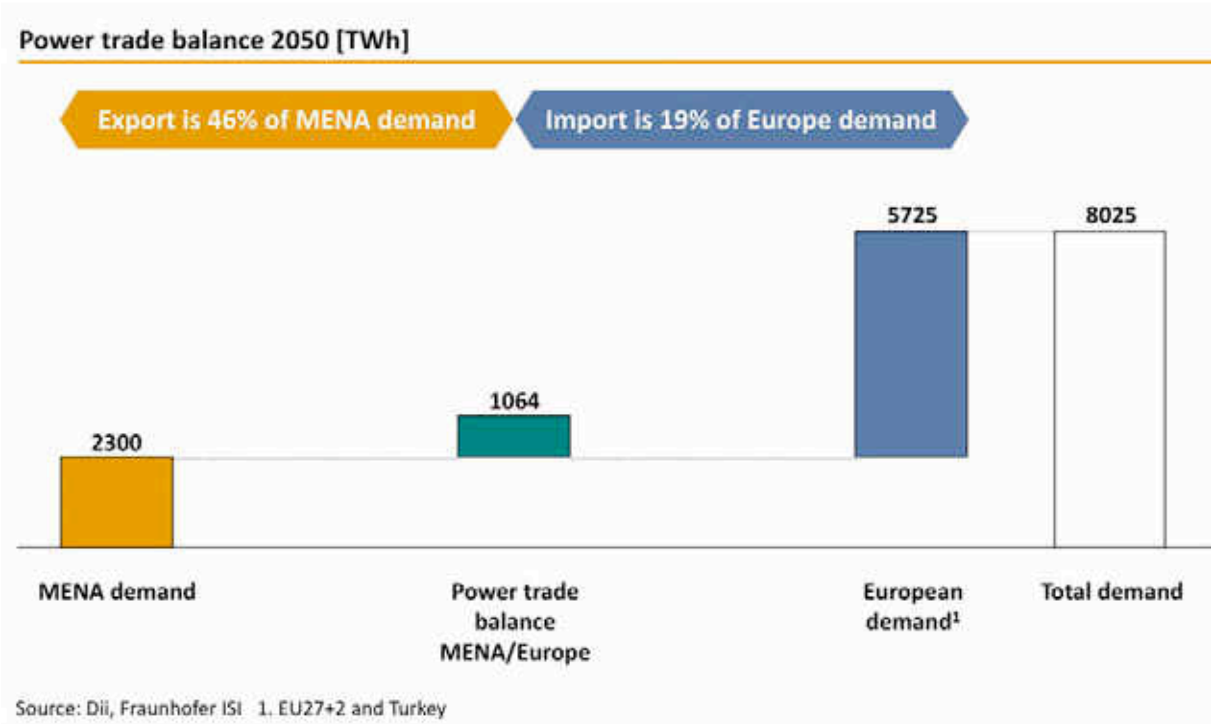


Figure 33: Electricity trade between MENA and Europe

System integration provides clear benefits in terms of competitiveness, sustainability, and security of supply. In this chapter, we first provide an analysis of the effects of desert power on system cost before going on to explain the underlying dynamics of power generation and power transmission. We then conclude with an assessment of the energy security aspects of system integration.

[46] "Neighboring" countries include those that can be connected by means of feasible submarine cables
[47] For feasible transmission lines between MENA and Europe, see Section 2.3
[48] The lack of a self-supply rate in the Reference Scenario has no significant effect on the results

3.1 Economic benefits of system integration

System integration provides clear economic benefits. The average system cost[49] can be reduced from 65€/MWh in the Reference Scenario to 61€/MWh in the Connected Scenario. The average cost of production in Europe decreases for all technologies in the Connected Scenario, as shown in Figure 34. The reason is that the most expensive part of the European renewables installations in the Reference Scenario is substituted by MENA imports with lower costs. For renewables in MENA, on the other hand, costs remain essentially flat when more electricity is produced for export to Europe. Indeed, the potentials are so large that the additional demand from Europe can still be satisfied by production at sites with excellent conditions (and thus low costs). The cost of transmission, which is excluded from the system cost in Figure 34, is approx. 5.7€/MWh in the Connected Scenario and 4.4€/MWh in the Reference Scenario, where the average transmission distance is lower.

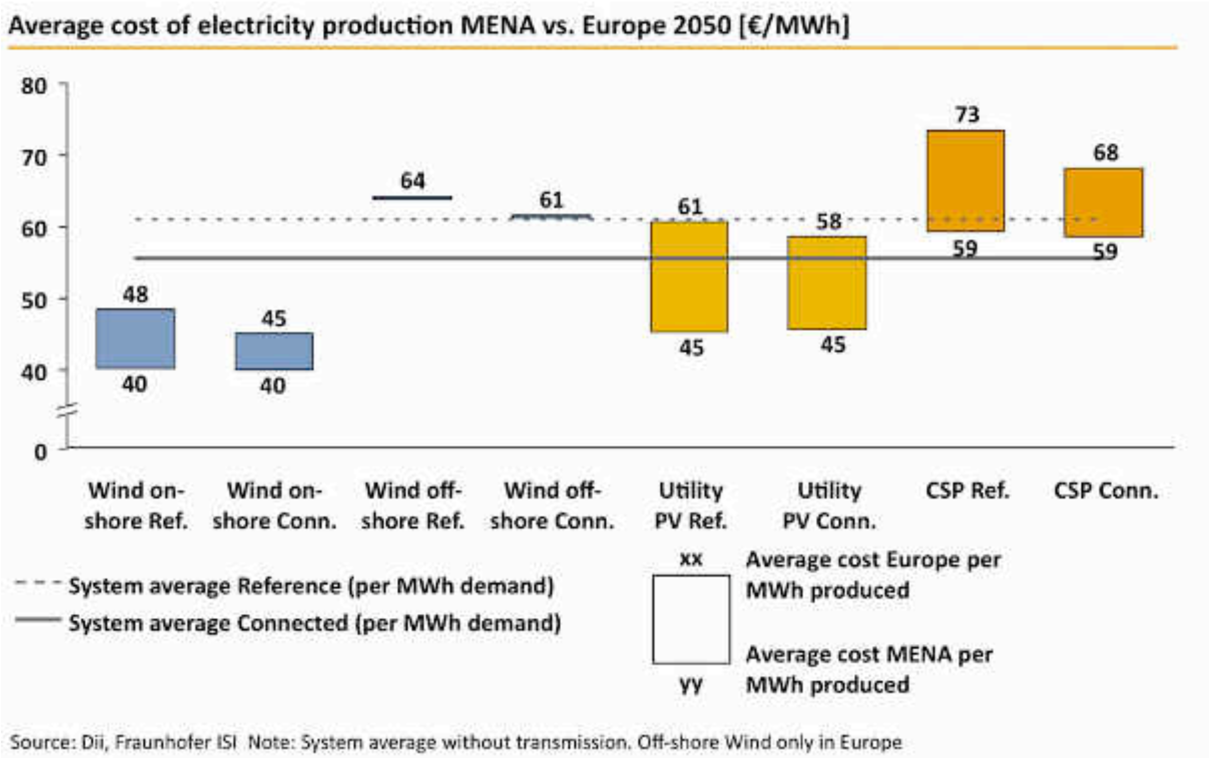


Figure 34: Average cost by technology in Connected and Reference Scenarios

Both MENA and Europe profit from an integrated power system for the entire region, in which 1087TWh of renewable power are exported from MENA to Europe and 23TWh from Europe to MENA. This amounts to a power trade balance of 1064TWh of net exports from MENA to Europe. Such an integrated system has a system cost advantage of €33.5bn. p.a. over a system in which MENA and Europe fully cooperate to achieve their carbon emission reduction targets (i.e. share a common carbon cap), but without a shared power system.

[49] Here, "system cost" refers to the complete system in scope, consisting of MENA and Europe, for both the Connected and the Reference Scenario, unless otherwise stated. This nomenclature is used throughout the report

The overall system costs in the Connected Scenario are approx. €490bn. p.a. In the Reference Scenario, the annual system costs are €524bn. The Connected Scenario saves Europe €33.5bn. per year in system costs. Thus, for each of the approx. 1110TWh of power exchange between MENA and Europe, this amounts to approx. €30 of savings.

While Europe profits from these cost savings, MENA is able to build up a renewable electricity industry, see Figure 35. This industry has an export volume of €47-63bn. p.a., more than the total annual exports of Morocco and Egypt combined. This creates an economic win-win situation for both MENA and Europe.

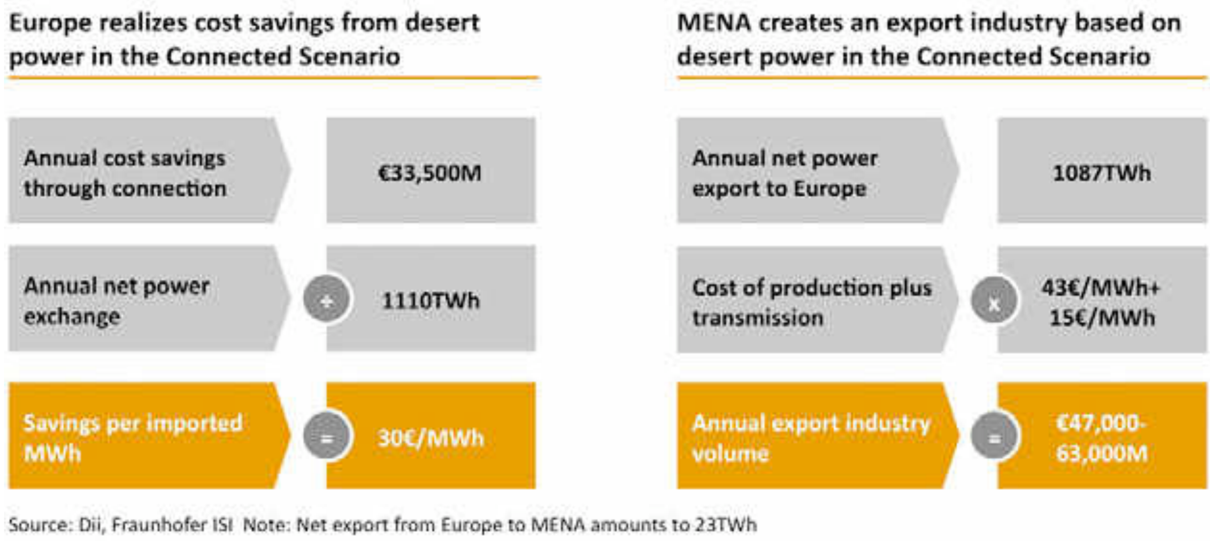


Figure 35: Cost savings for Europe and exports for MENA

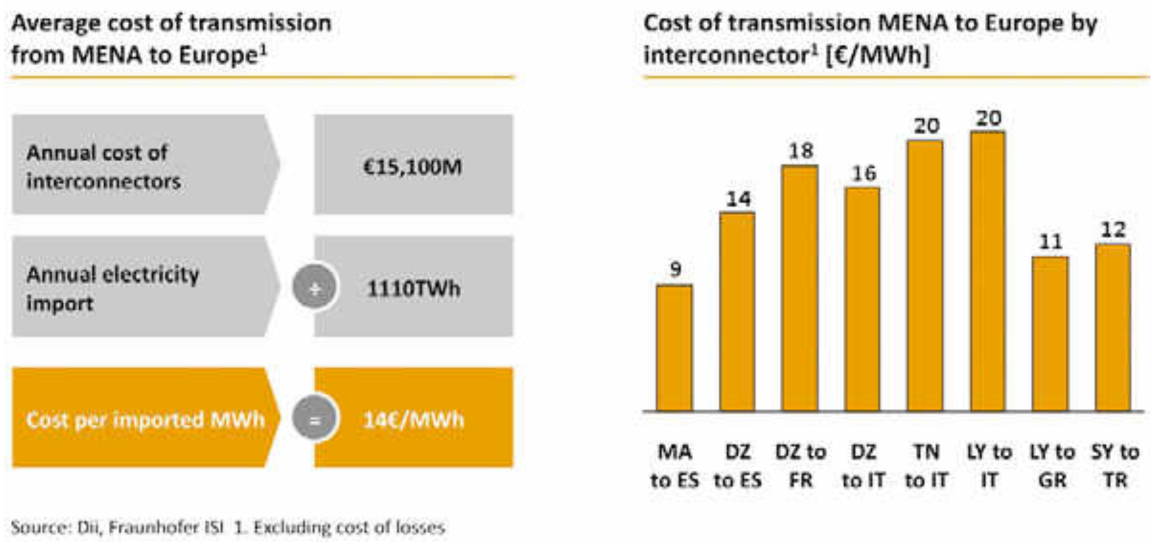


Figure 36: Total and interconnector-specific cost of MENA/Europe transmission

The cost of transmission across the Mediterranean per imported MWh is 14€/MWh on average. This average value is derived from the total annual cost of €15.1bn and the 1110TWh of net electricity trade across the Mediterranean, see Figure 36. Note that the 14€/MWh refer to the power arriving in Europe and MENA, i.e. to the transmitted power minus losses. The cost of the lost power, though, is not included in the 14€/MWh. The cost of transmission differs between interconnectors, depending on the investment and O&M costs of each interconnector and on the utilization of the interconnector. Full load hours are approx. 5000 p.a. for Morocco to Spain, for Algeria to Italy and for Libya to Italy. For Algeria to France and Libya to Greece, more than 6000FLH are reached, while Algeria to Spain, Tunisia to Italy and Syria to Turkey reach approx. 4000FLH.

We now focus on the main power flow from MENA to Europe in order to explain the nature of the cost savings of power trade across the Mediterranean. There are two reasons for the high savings of 30€/MWh in the Connected Scenario:

- The cost advantage of power production from the vast wind and solar potentials in MENA over that of European renewables.
- The benefits of integrating a power system over an area of 13.2M km^2 (of which 5.5Mkm^2 in Europe and 7.7Mkm^2 in MENA).

The cost advantage of desert power imports over European renewables can be derived from the following analysis. The cost of producing the 1087TWh in MENA for export to Europe is 43€/MWh on average. To this, the average cost of transmission from MENA to Europe has to be added, which is 14€/MWh. Furthermore, the cost of transmission losses has to be taken into account. The average losses incurred for transmission across the Mediterranean amount to 32TWh, i.e. 2.9% of 1119TWh of gross exports from MENA to Europe. Multiplied by the average cost of 43€/MWh, this yields costs of transmission losses of €1.4bn., or 1€/MWh for the 1087TWh of exports (excluding transmission losses) from MENA to Europe. Thus, the cost of desert power is 58€/MWh when it arrives in Europe.

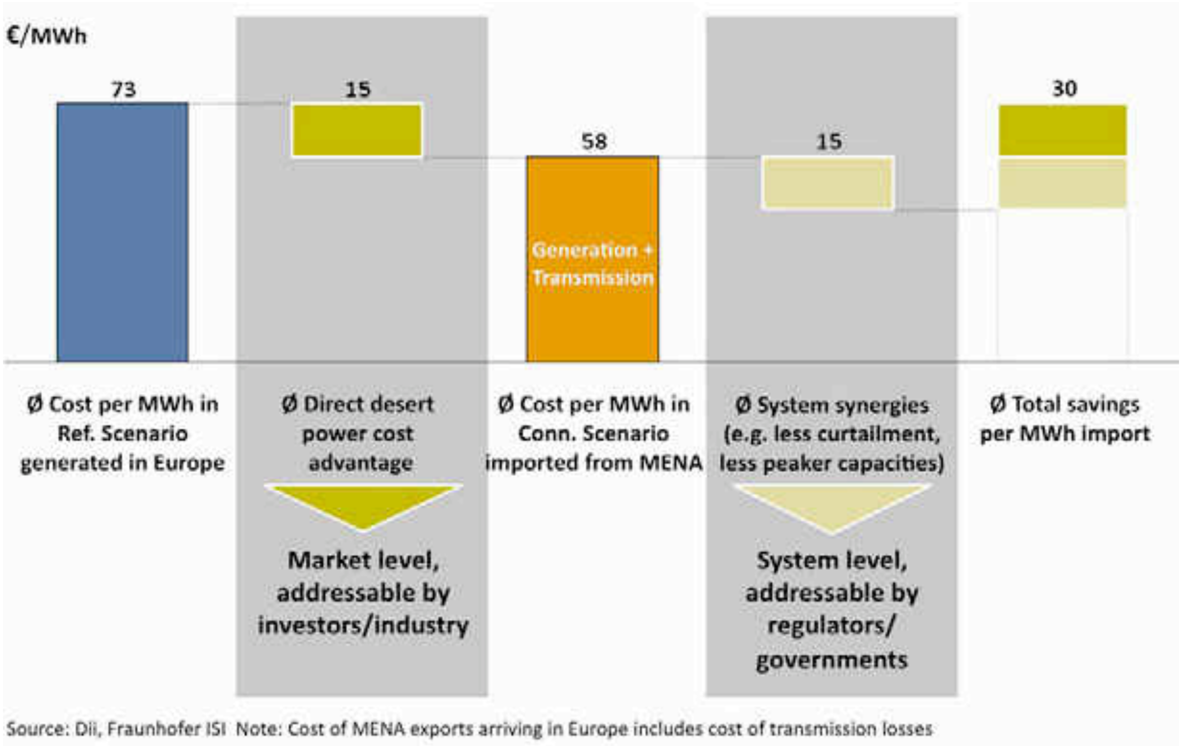


Figure 37: System cost savings per MWh of net power imports from MENA to Europe

The cost of replacing the imports in an isolated system in Europe is 73€/MWh, see Figure 37. In other words, desert power has a cost advantage of 15€/MWh. The cost of European renewables production replaced by desert power is as high as 73€/MWh, since it is the most expensive part of European renewables that is replaced by desert power. It is important to note that, in the Connected Scenario, economical European potentials keep being used too.

Furthermore, the system integration itself provides cost advantages. For example, 220TWh of electricity production can be avoided in the Connected Scenario, due to lower levels of curtailment. Another benefit of the Connected System is that 118GW less gas power plants, thereof 72GW of less efficient OCGT plants, have to be built. Since electricity produced from gas is limited to approx. 730TWh p.a. due to the carbon emission cap, the cost of electricity production from gas is higher in the Reference Scenario due to lower utilization of the generation assets. Overall, the benefits from the system integration amount to approx. 15€ for each MWh of power exports from MENA to Europe. These 15€/MWh of system cost advantages are the difference of the total system cost savings per MWh of net power trade: 30€/MWh minus the direct cost advantage of 15€/MWh.

The two kinds of cost savings need to be further explained, since there is a decisive difference between the direct cost advantage of desert power and the benefits of an integrated system.

The direct cost advantage of 15€/MWh can be addressed by market players, who can produce renewable desert power in MENA and be cost competitive when selling this electricity in Europe. Public support and incentives will only be needed in the initial phase of the system integration. Once renewables technologies have advanced far enough on the cost curve and have built up a sufficient track record to become cost competitive and bankable on a broad basis, desert power for Europe will be a market that does not need public support anymore[50].

On the other hand, no market player can do business by delivering benefits to the system that are based on system-wide synergies, such as the 220TWh of electricity that no longer need to be produced in the Connected Scenario. These synergies are, however, a major economic benefit that, among other advantages, can add to the EUMENA region's competitiveness in the global economy. The system-level advantages therefore should be addressed by governments and regulators: these public institutions need to provide the appropriate structures and incentive schemes for the market to realize such economic benefits.

In both, the Connected as well as the Reference Scenario, the system costs of a sustainable power system for EUMENA are dominated by 88% fixed cost; only 12% is variable cost, as shown in Figure 38. These 12% even take into account the cost of carbon emissions at 113€/tonne, unlike in the rest of this report. Carbon emission costs will be explained in more detail in Section 3.2. The cost distribution between fixed and variable cost is similar to that of nuclear power plants, while coal power plants have approximately 1/3 and gas power plants 2/3 variable cost. The transition to a sustainable power system might therefore also lead to significant implications for market design, as today's reliance on variable costs will be replaced by a higher share of fixed costs.

[50] Specific forms of regulation governing the build-up of grid infrastructure might still be necessary. This is due to the complex nature of grid business models. However, monetary support will not be needed.

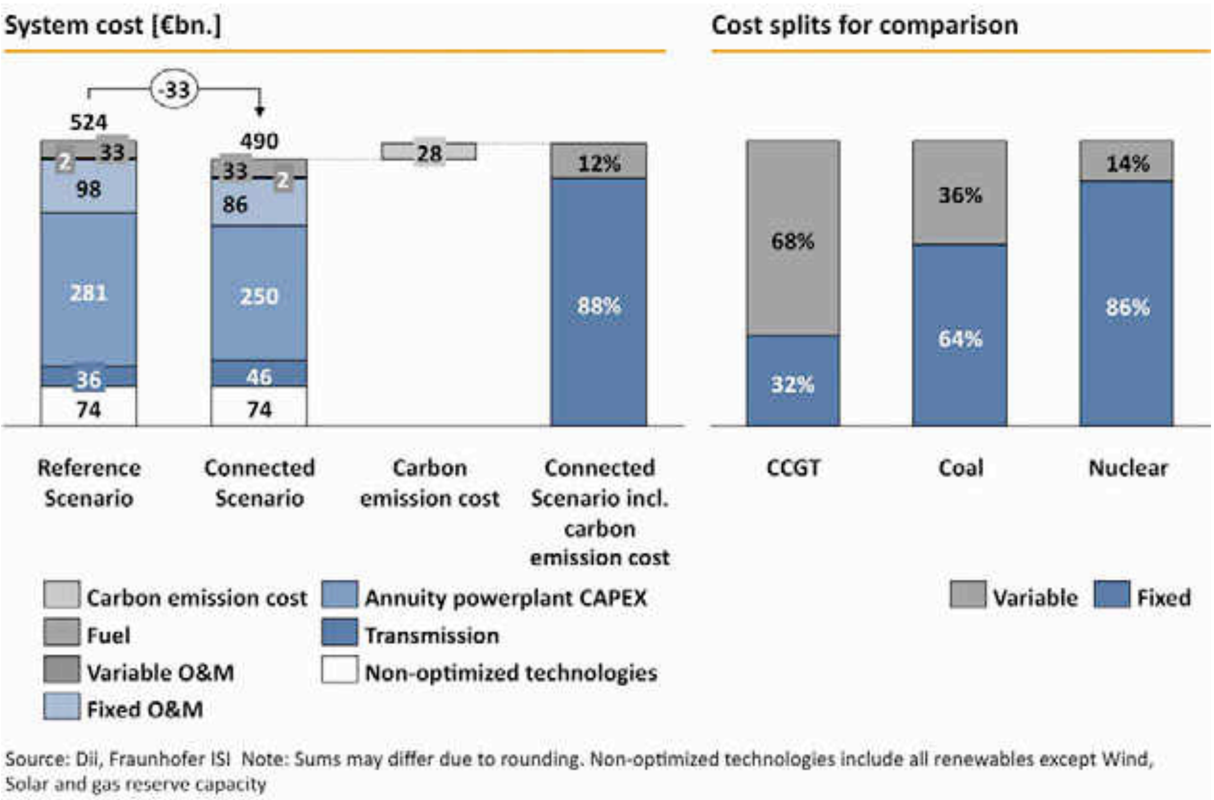


Figure 38: System cost comparison and fixed vs. variable cost shares

Questions about the appropriate market structure for sustainable power systems are widely discussed. The transition to a sustainable power system undoubtedly means that the average cost of electricity will decouple from the volatility of commodity markets for fossil fuels. Figure 39 shows hypothetically how the average system LCOE depends on market prices for fossil fuels in today's power systems, based on the examples of Morocco, Saudi Arabia and Germany[51]. Clearly, the renewable power system in the Connected Scenario is more immune to such volatilities.

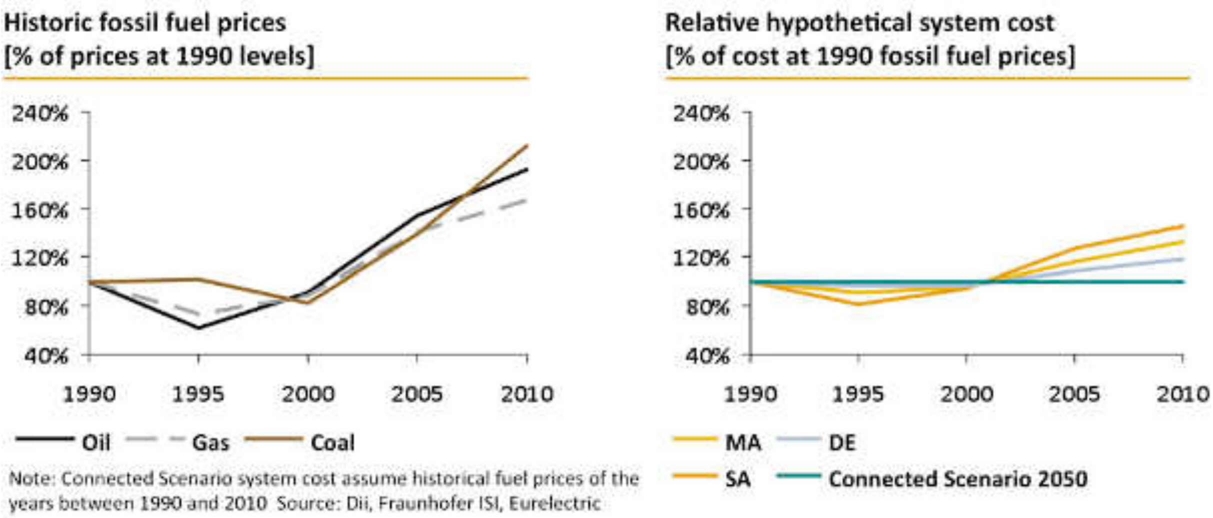


Figure 39: Historic fossil fuel prices and impact on power generation cost

[51] Power system fuel mix: Germany 44% coal, 19% gas, 1% oil (EU Energy Trends 2030), 21% Nuclear 15% renewables; Saudi Arabia 55% oil, 45% gas; Morocco 51% coal, 20% oil, 13% gas, 16% renewables (IEA)

3.2 Climate action benefits of system integration

In addition to reducing exposure to fossil fuel price volatility, an interconnected EUMENA power system also provides a robust pathway to decarbonization of the power sector. A measure of the robustness of such a pathway is the marginal cost of carbon emission reductions[52]. This is defined as the increase in system cost that would be incurred by reducing carbon emissions by an additional tonne. Thus, in an ideal market for carbon emission in the power sector, this would be exactly the price of carbon emission allowances under the carbon cap applied.

With the assumption of a common cap and market for carbon emissions in the power sector in both scenarios, the advantages of an interconnected system become especially apparent when comparing the cost of carbon emissions in the Connected and the Reference Scenarios. In the case of two isolated systems, the cost of carbon emissions is 192€/tonne. This value decreases by more than 40% to 113€/tonne if the EUMENA power system is integrated, as shown in the right-most part of Figure 40.

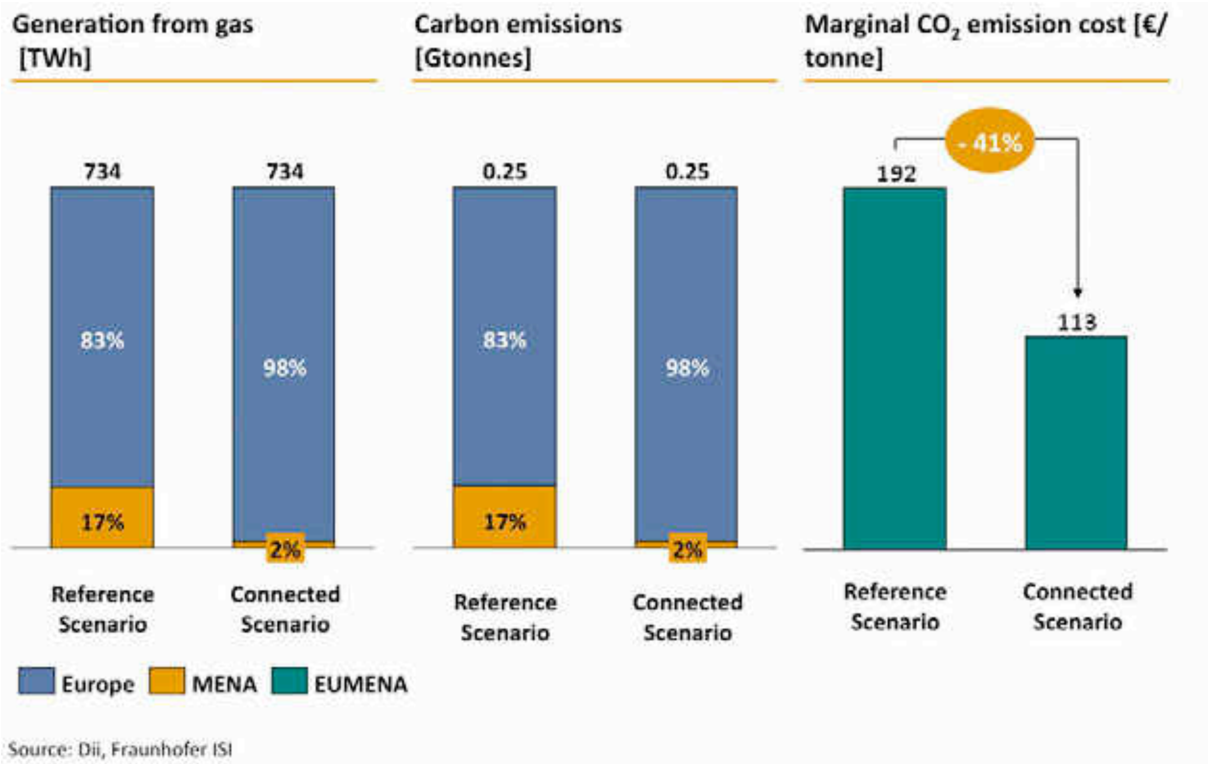


Figure 40: Electricity from gas and carbon emissions distribution/marginal cost

We now turn to explaining the reason for this decrease in carbon emission costs. Under the strict carbon emission cap for the power sector, electricity generation from gas is the only source of carbon emissions. This production from gas is allocated to the countries and hours with the highest cost of satisfying demand with domestic or imported CO_2-free electricity. In the Connected Scenario, countries have more options for sourcing their electricity. Therefore, competition for carbon emissions is relaxed, which in turn leads to a decrease in carbon emission costs.

[52] In the sequel „cost of carbon emission reductions“ is sometimes shortened to „cost of carbon emissions“

This effect can be seen from the significant shift in gas production from MENA to Europe when the MENA and European power systems are connected, see Figure 41. Without system integration, MENA countries need to build gas in addition to CSP in order to balance demand and supply from Wind and Utility PV. With system integration, MENA countries can install a large surplus of renewables and have a buyer in Europe for the electricity not required domestically. This enables them to use, besides CSP, exports to Europe as a way to balance their own supply and demand. As a result, they do not need to enter the competition for the scarce "resource" of carbon emissions.

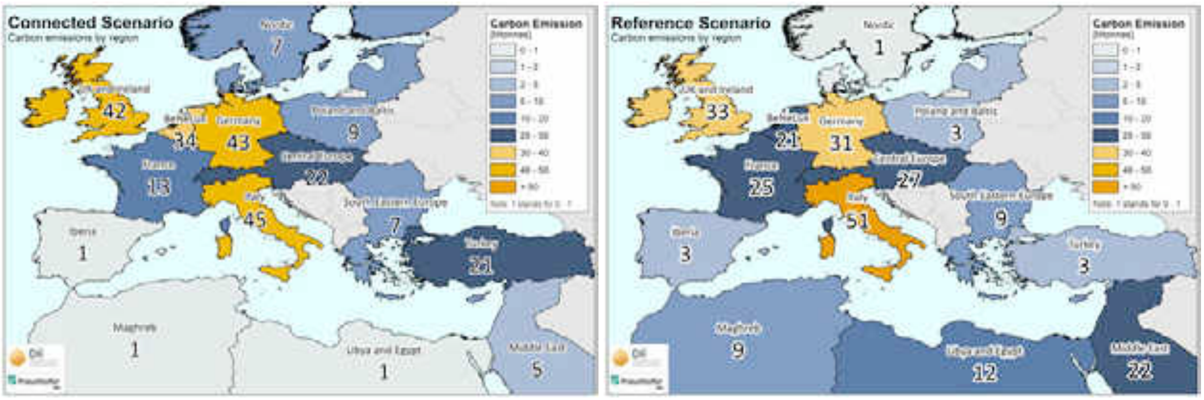


Figure 41: Carbon emissions by region Connected (left) vs. Reference Scenario (right)

This effect of shifting gas capacities can also be seen by looking at the additional gas power plants built in the Reference Scenario. Of the 118GW gas capacities built, 90GW are in MENA and 28GW in Europe. This corresponds to additions of 83% for MENA and 6% for Europe. Compared to the Connected Scenario, this difference is due to the high need for additional balancing power in MENA when there are no connections to Europe.

The 40% lower cost of carbon emission reductions in the connected system indicates that the power system integration of MENA and Europe will facilitate the transition to a low carbon economy that the EU is pursuing. At the same time, it shows that MENA, one of the regions most affected by climate change, has much to gain by joining Europe in its efforts to reduce carbon emissions – not least, a huge renewable electricity export industry in addition to the benefits of decisive climate action. Another lesson can be learnt from this analysis: the transition to renewables is relatively easy and cheap in MENA. Even in the Reference Scenario, 83% of carbon emissions are in Europe, i.e. 0.2Gtonnes, while only 0.15Gtonnes in the carbon emission cap stem from Europe. Thus, even without power system integration, a common carbon emissions cap and market for the power sector would be beneficial for Europe and MENA: MENA can earn money from selling carbon emission allowances to Europe, while Europe can save money on its carbon emission reductions by buying them.

3.3 Power production for EUMENA

Having understood the system and carbon cost advantages of the Connected Scenario, we now turn to the analysis of the power generation data that form the basis for these benefits.

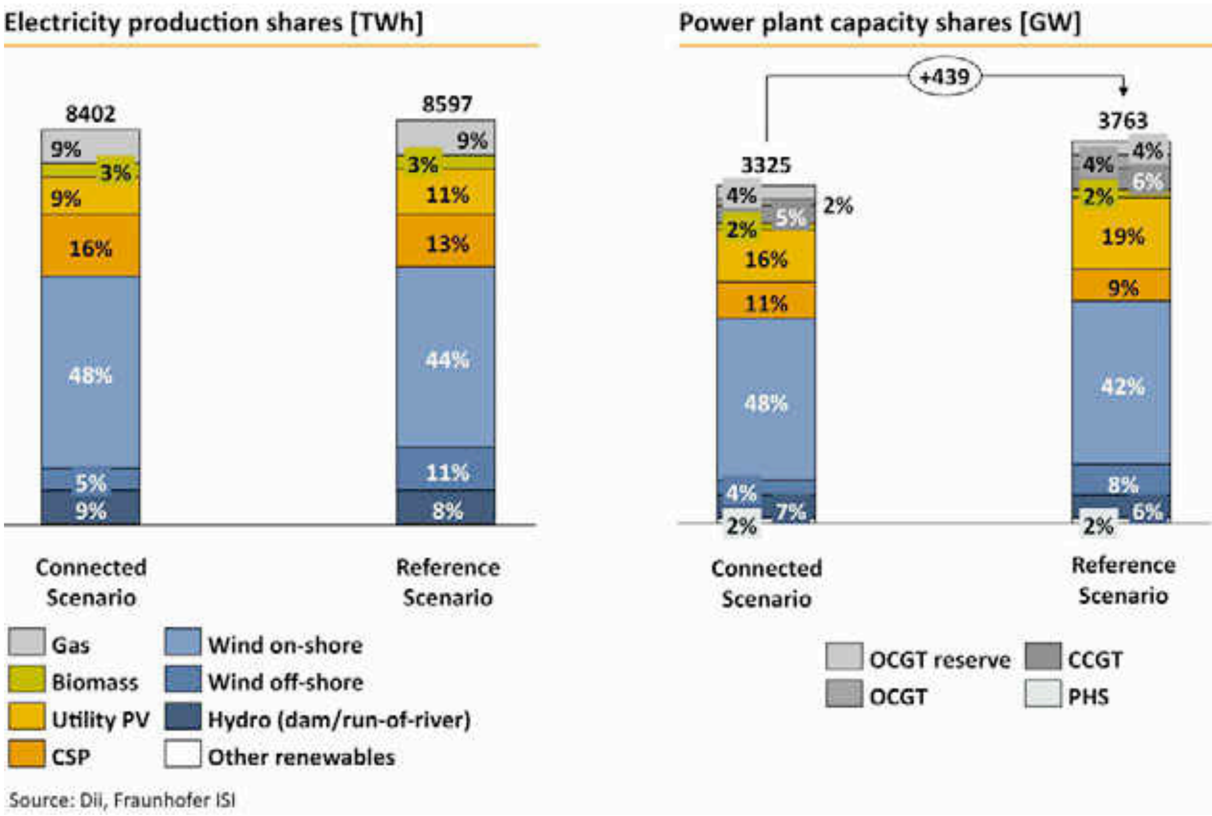


Figure 42: Electricity production and power plant capacities by technology

A sustainable EUMENA power system, as shown in Figure 42, is dominated by Wind power production, which accounts for 53% of all electricity produced, of which 48% on-shore and 5% off-shore. Wind installations throughout the region reach approx. 1580GW on-shore and approx. 140GW off-shore. The solar technologies CSP and Utility PV together contribute 25% of the electricity produced, with approx. 360GW of CSP with 8h storage producing 16% of total electricity production and approx. 520GW of Utility PV installations contributing another 9%. Due to the strict carbon limit, gas is the only fossil fuel-based technology in the system and, with approx. 230GW gas capacity (excluding reserve OCGT capacity), accounts for approx. 9% of total power production, i.e. approx. 730TWh. The other technologies in the system are dam and run-of-river hydro plants, with a 9% contribution, biomass with 3%, while other renewables contribute less than 1%.

The map in Figure 43 below shows that Wind installations can be found all over EUMENA while Solar is concentrated in the south, which is consistent with the solar and wind resource maps in Figure 15 and Figure 16. Some of the Utility PV installations in the northern parts of the system are forced by lower limits on renewables installations from the NREAPs[53]. A distinctive feature of this system is the huge installations in MENA, which total approx. 1270GW (thereof 1220GW renewables) and are quite evenly distributed over the three MENA regions. The Maghreb in particular is able to supply Europe with cheap sustainable power via massive interconnectors, due to its relatively low demand compared to the eastern MENA countries. Figure 43 also shows that the highest gas shares can be found in the UK and Ireland, BeNeLux and Germany. The UK and Ireland have a lateral position in the system and low solar resources. Therefore, they need a high share of gas to balance the seasonality

[53] National Renewable Energy Action Plans

of Wind power, which produces less in summer. Germany and BeNeLux have a very high demand compared to their renewables potentials and use a combination of gas and imports to meet their demand.

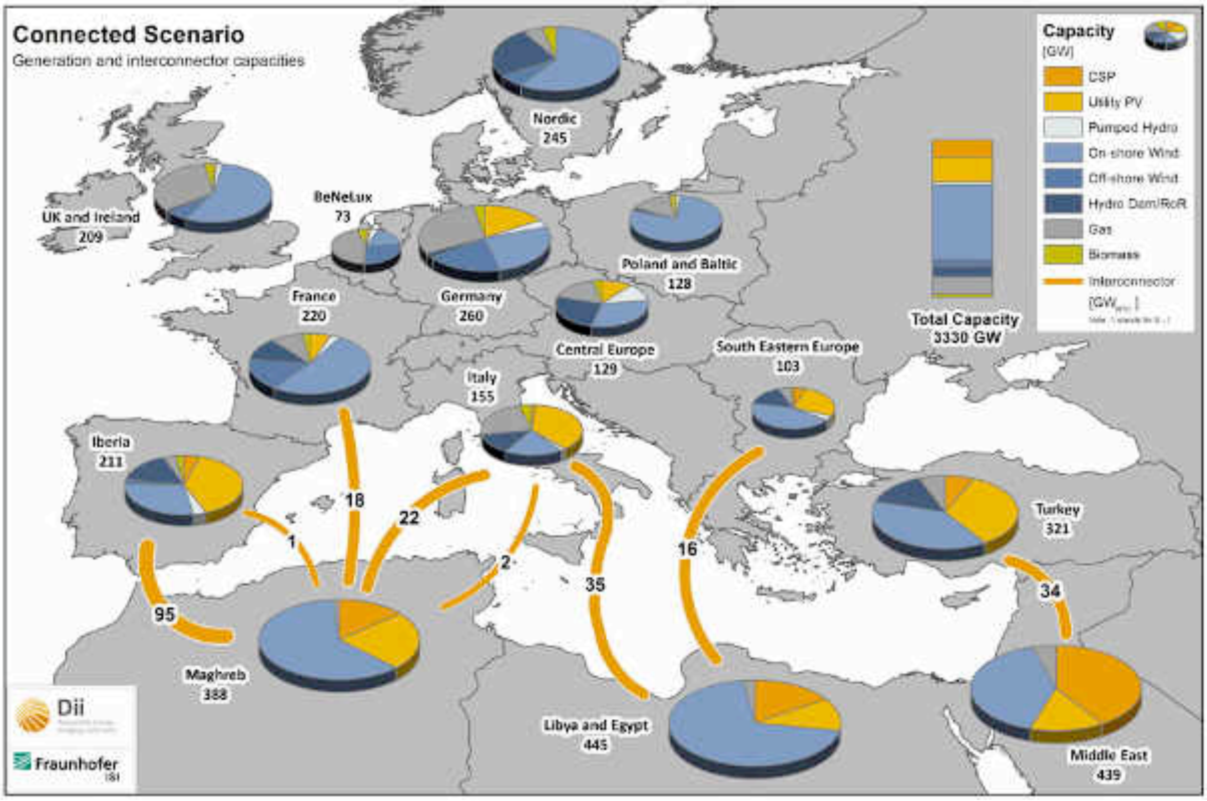


Figure 43: Generation and interconnector capacity, Connected Scenario

In the Reference Scenario, on the other hand, Europe needs to ramp up off-shore Wind by almost 160GW, to approx. 300GW, see Figure 44. Dispatchable CSP with storage is reduced by almost 40GW when exports from MENA to Europe are not possible. On the Utility PV side, approx. 190GW of additional capacities are needed. Furthermore, gas capacities need to be increased from approx. 230GW to almost 350GW. This increase in gas capacity does not result in additional electricity production from gas due to the carbon emission limit. Instead, this gas is required to do more of the balancing since less dispatchable CSP with storage is available. The result is that gas capacities have fewer hours of operation p.a. and thereby become less economical.

This is also reflected by the fact that more than 70GW of the total gas additions are OCGTs, i.e. peaker plants which are only more economical than CCGTs with production of less than 1600FLH p.a. and which emit 1.5 times more CO_2 per MWh produced due to their lower efficiency.

Besides the shifts in technologies, it is also instructive to understand the changes of technology build-up from a regional perspective. Without desert power, all regions of Europe have to build significantly more renewables capacities. As expected, large shifts occur in the southern parts of Europe, which become the prime solar area in Europe without access to the solar power of MENA (and are significant solar producers even with access to desert power). Turkey, Iberia and France in particular build up more than 120GW each, additions of more than 50% compared to installations in the Connected Scenario, see Figure 45. The Nordics add almost 100GW of mostly off-shore and on-shore Wind, which replaces the desert power missing to supply the center of Europe, e.g. Germany. Turkey, as the largest consumer in the whole system, significantly expands both Solar and Wind installations. It thereby substitutes the imports from the Middle East via Syria and North Africa via Greece. In addition, Turkey even becomes a net exporter in the Reference scenario, with exports of 37TWh via Greece to Italy and Central Europe.

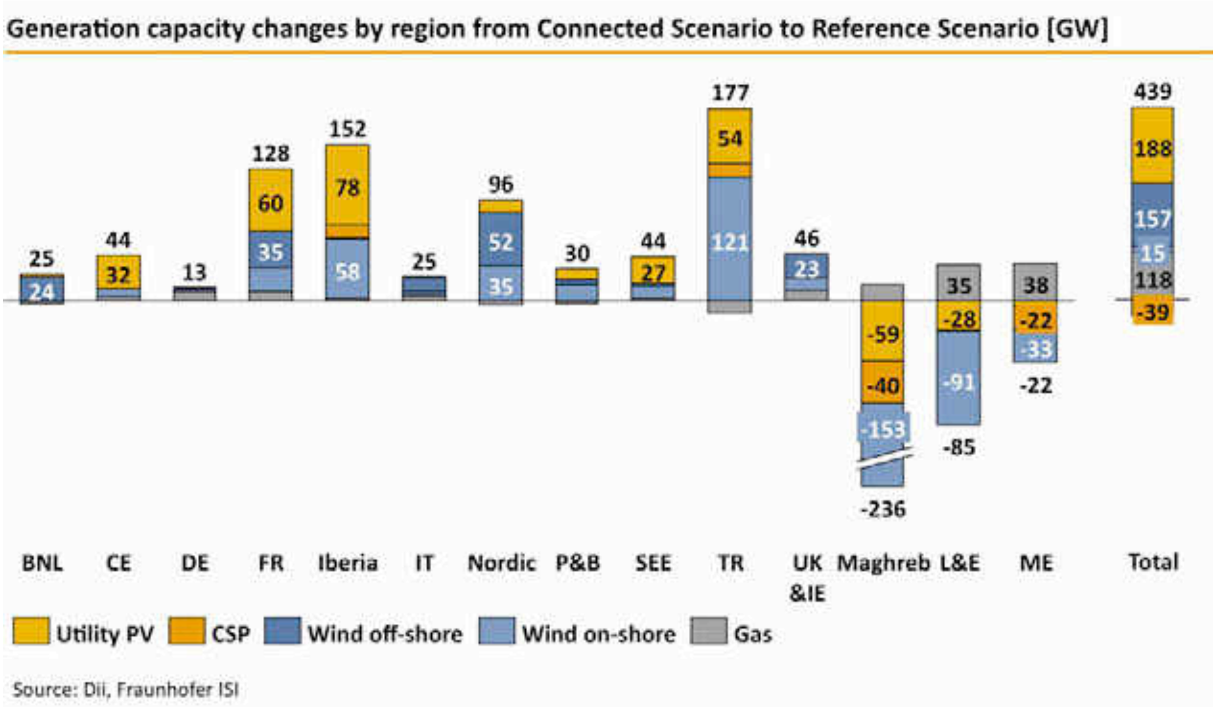


Figure 44: Generation capacity changes from Connected Scenario to Reference Scenario

Italy and Germany have the fewest additions relative to their installations in the Connected Scenario, see Figure 45. This is surprising since both are heavily importing countries in the Connected Scenario, as shown in Figure 57. Instead of building up own capacity, Germany imports power from the Nordics and Italy from France to replace desert power, as we will see in Section 3.4.

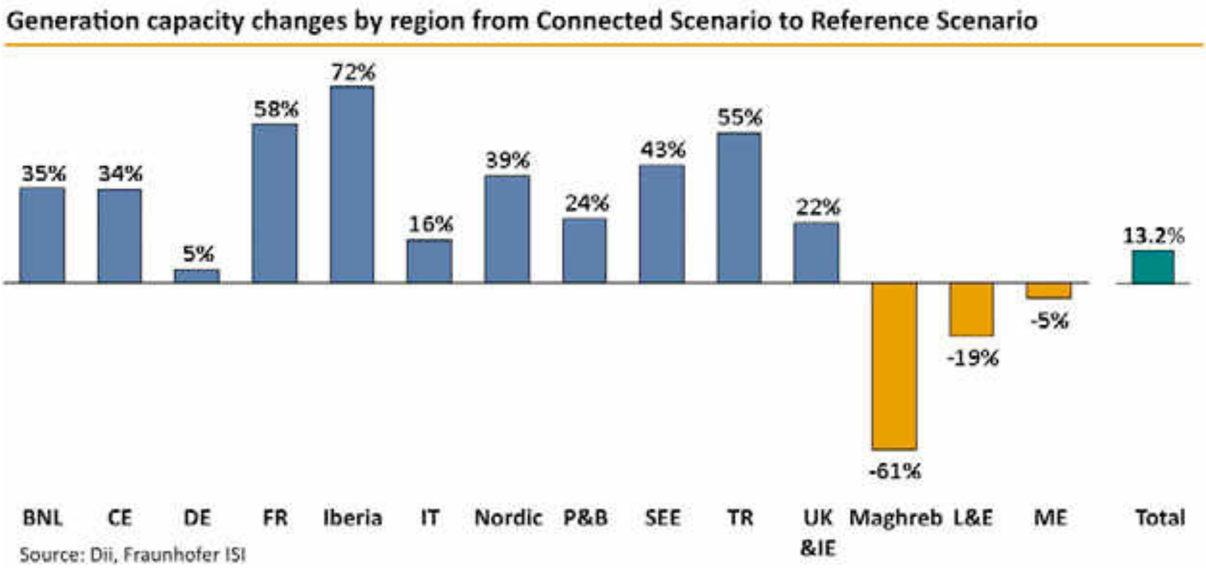


Figure 45: Relative regional change of installed capacities from Connected to Reference Scenario

All MENA countries install much less renewables capacity in the Reference Scenario. The Maghreb has by far the most reductions, since its domestic demand is small. Overall, renewables capacity reductions in MENA total approx. 430GW, of which approx. 280GW of Wind, 60GW of CSP and 90GW of Utility PV. As mentioned above, all three MENA regions have to build gas plants for balancing, which amounts to approx. 35GW each in Libya & Egypt and the Middle East respectively, and half that amount in the Maghreb, which has lower demand.

In terms of area use[54], in the Reference Scenario the additional installations (without off-shore Wind) needed in Europe require approx. 45,000km², an area roughly the size of Denmark. Of these 45,000km², approx. 37,000km² are on-shore Wind and approx. 28,000km² are located in the EU27+2.

In terms of investments (estimated at 2050 renewables investments, i.e. Greenfield in 2050) the reallocation of renewables in the Connected Scenario to the most favorable geographical locations results in savings of approx. €300bn., see Figure 46. The largest shift happens in the Maghreb, where investments increase by almost €260bn., and in Libya & Egypt with an increase of more than €100bn. in the Connected Scenario.

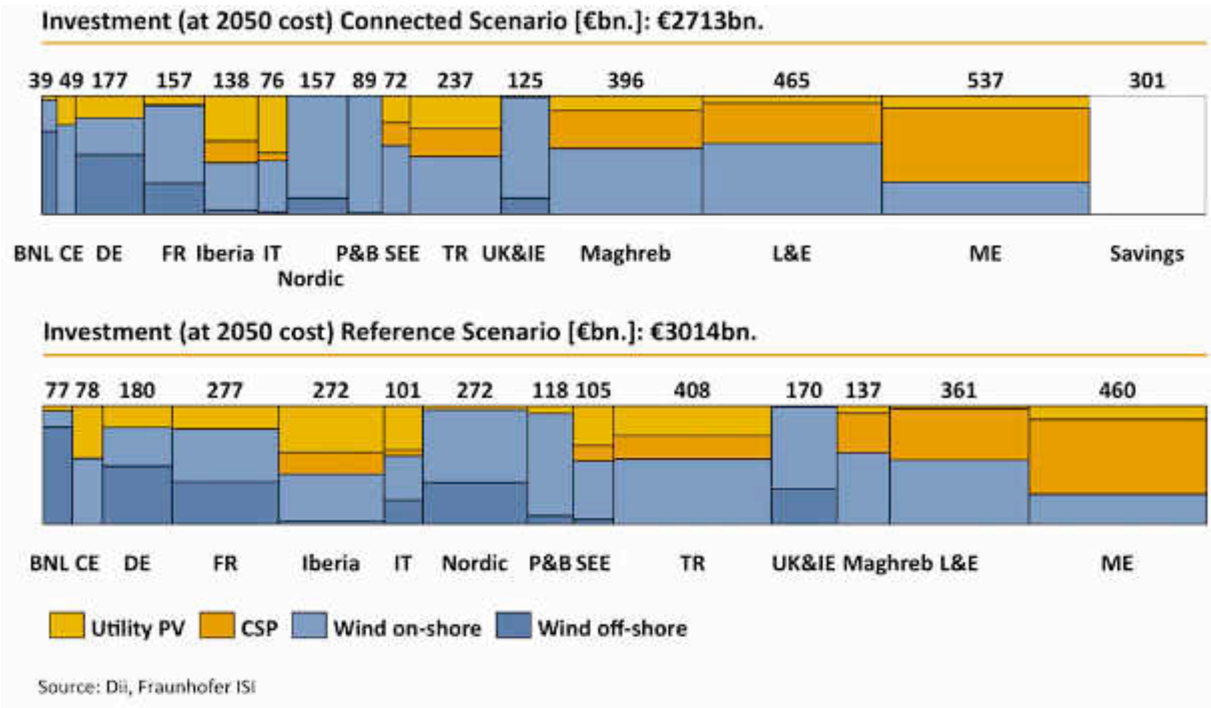


Figure 46: Investment in renewables technologies by region at 2050 costs

Furthermore, less need for gas capacities (70GW OCGT and 48GW CCGT) saves another €62bn. of investments. Together with the €300bn. saved on investment in renewables, this results in total saved investments for generation technologies of approx. €360bn.

Having taken a detailed look at the generation capacities and required investments, we now turn to the analysis of the electricity generated. The distribution of electricity production changes greatly

[54] Calculated with 40MW/km² PV, 16MW/km² CSP and 8MW/km² Wind on-shore

over the course of the year for renewables installations of a specific technology on a particular site. The left part of Figure 47 shows why a power system with more than 90% renewables requires a balanced technology mix to satisfy demand at all times.

Looking at the monthly time resolution of renewables production, it becomes apparent that the sun and wind resources complement each other very well over the year. Wind power makes a stronger contribution in winter, which is substituted in summer by Solar. Electricity is generated from gas throughout the year, but more so in winter; the same is true for hydro dam.

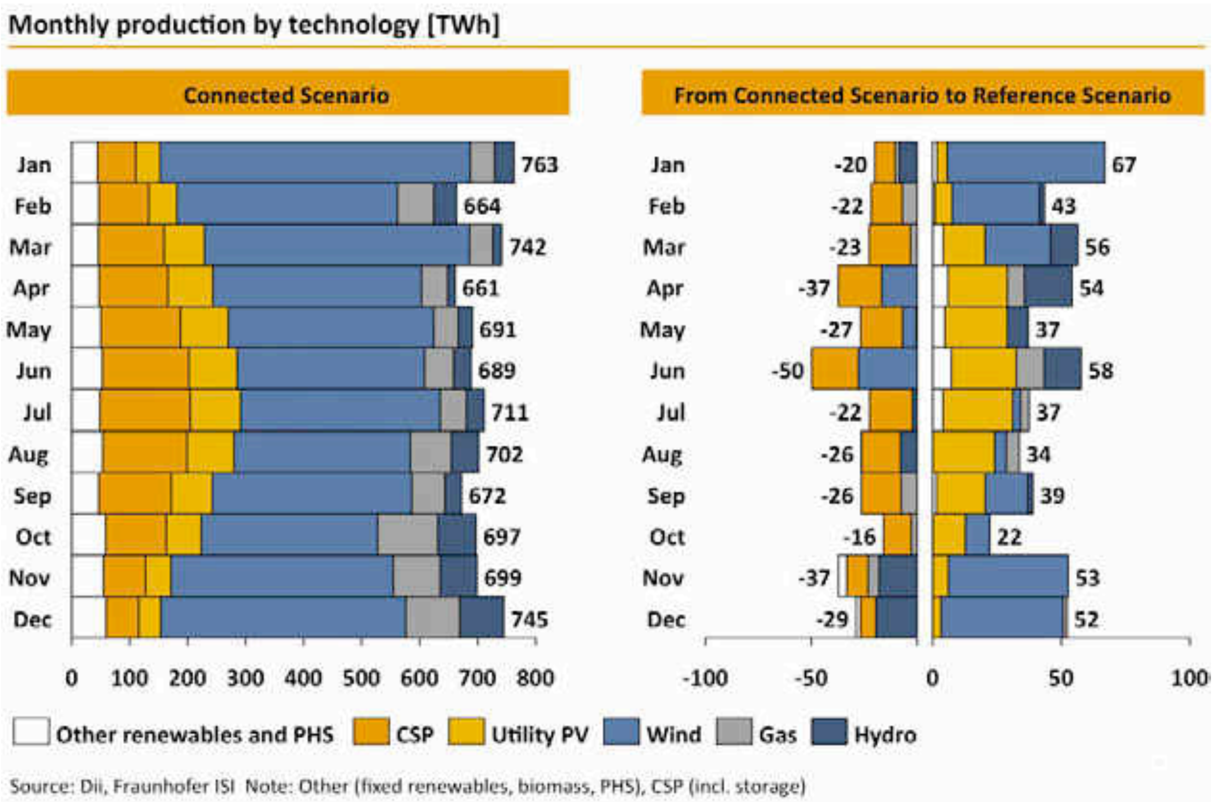


Figure 47: Monthly distribution of supply from different technologies

Compared to the Connected Scenario, CSP production is substituted by Utility PV and Wind throughout the year in the Reference Scenario, see the right part of Figure 47. As expected from the overall increase in generation capacities, more power has to be generated in the Reference Scenario. With two isolated systems, the time match between supply and demand is not as good as in the larger integrated system. For example, more Wind production occurs in winter in the Reference Scenario, and less in the second quarter of the year. The reason is that Wind production from MENA is substituted by Wind in northern Europe. In MENA the wind resource is distributed more evenly over the year than in northern Europe, where winter winds are stronger than summer ones. Thus, much of the additional European Wind production in winter is curtailed. For example, additional production from Wind and some Utility PV in January is 67TWh, while substituted production from CSP and other technologies is only 20TWh. Hence, only in January, 47TWh more are produced in the Reference Scenario than in the Connected scenario. The Wind installations leading to this production in winter are needed, though, to satisfy the European demand in summer, when no desert power is available.

Utility PV production is much stronger during summer in the Reference Scenario than in the Connected Scenario, while in winter there is hardly any difference. This is caused by the shift of Utility PV from MENA to Europe. The further north one goes, the longer the summer days become and the shorter the winter days. Hence, Utility PV production is also less evenly distributed over the year when installations are forced to migrate further north. This does not even take into account other seasonal weather effects that are more pronounced in the north.

Interestingly, since such a large region is connected by a strong grid, no storage is built beyond the existing mechanical hydro storage (dam and pumped storage) and the thermal storage of CSP. The grid does the rest of the job by shifting power between sources and sinks hour by hour; and no additional storage in the form of batteries is built. Indeed, it can be seen from Figure 48 that PHS utilization[55] is quite low[56] across all regions, with less than 1000FLH (discharging) p.a. The utilization increases 1.5-2.6 times in all regions except Italy – which has significant gas capacities for balancing.

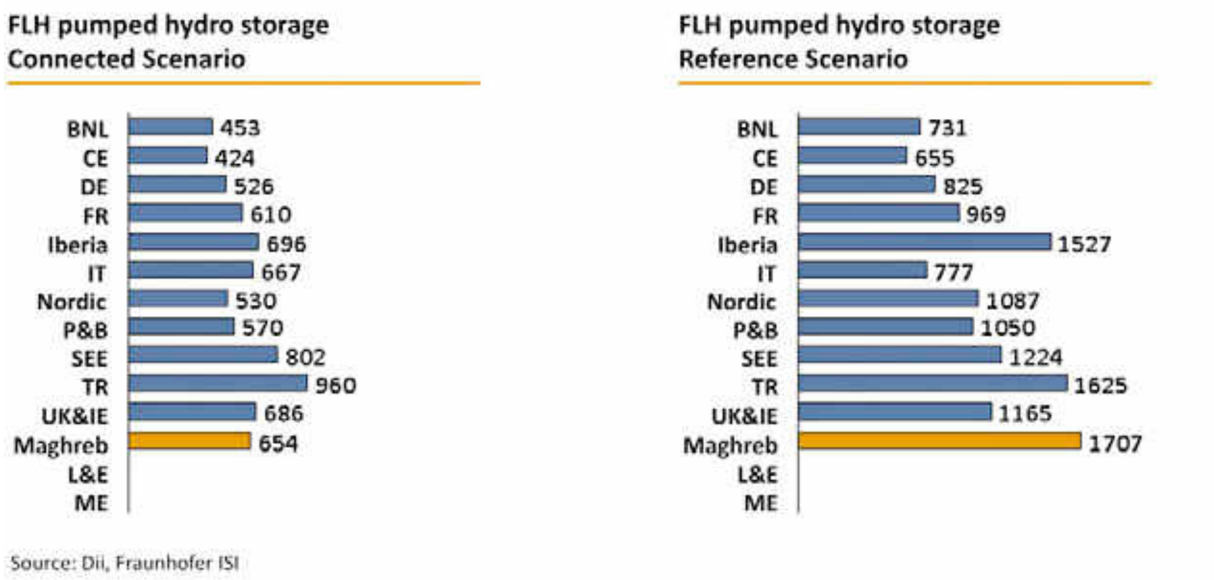


Figure 48: Pumped hydro storage utilization

Since 59GW of pumped hydro storage have been given as exogenous input to the system model, the interpretation of this finding needs to be carried out carefully. The low utilization indicates that PHS is only required to a certain extent for load shifting or peak shaving. In this context even higher system cost savings could be realized if the system had the choice not to build the additional 26GW of pumped hydro storage added to the existing ones, see 2.4.3. On the other hand, PHS is not only used for load shifting and peak shaving; it can also be used to maintain grid and system stability, e.g. balancing, reactive power and ramping management. This could lead to higher utilization hours and more need for PHS, than shown here.

[55] Storage full load hours need to be compared to power plant full load hours with care. While a power plant could, in theory, produce 8760hours p.a., a storage needs to charge in order to have energy for discharging. If charging capacity equals discharging capacity, then the storage can reach a maximum of 4380FLH

[56] It should be noted that PHS is dispatched due to system needs and not based on market prices. Also, balancing services and local grid services are not taken into account. Thus, FLH of PHS might well be higher if these effects were taken into account

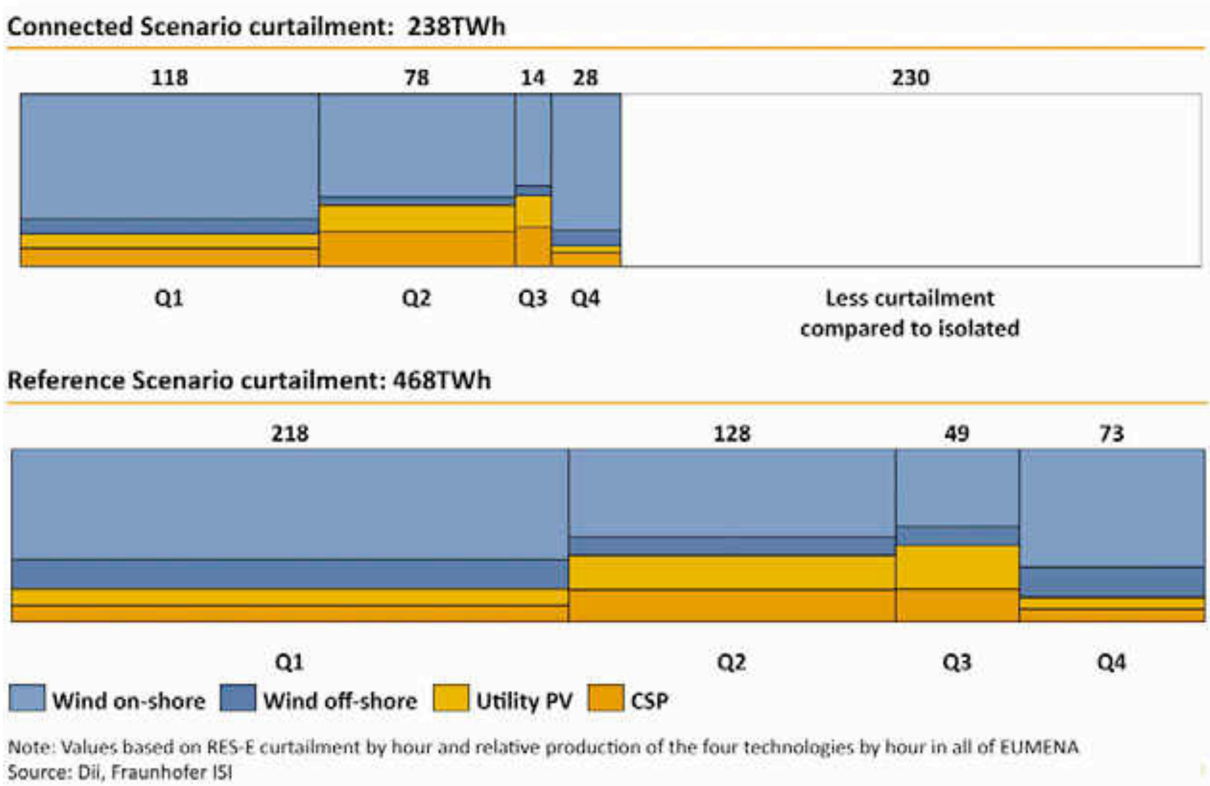


Figure 49: Curtailment by technology (pro rata) and season

The analysis shown in Figure 49 confirms the fact that more overproduction in the Reference Scenario occurs especially in winter, due to the stronger seasonal variation of wind in Europe compared to MENA. Out of the total increase of curtailment of 230TWh, 145TWh occur in winter. In summer, when Utility PV surplus is highest, the curtailment surplus is also 85TWh.

Not surprisingly, compared to today's system, the Connected Scenario foresees a massive build-up of all Wind and Solar technologies. The total Utility PV installations of approx. 520GW are more than ten times today's total installed capacities of PV (including Distributed) of 47GW in EUMENA (mostly Europe) today. CSP rises to approx. 360GW from 1GW today. Wind on-shore increases substantially to approx. 1580GW from 81GW today, while Wind off-shore increases to approx. 140GW from 4GW today.

Concerning power generation from gas, today's system and the 2050 system from the Connected Scenario are more similar. Figure 50 shows that, while total electricity production from gas decreases by 470TWh to approx. 730TWh, an additional 57GW in gas capacities are needed. MENA and Turkey account for almost 320TWh of reduced production from gas.

The amount of gas generation in the EU27+2 declines by 150TWh from almost 800TWh today. However, capacities increase by 74GW in the EU27+2 since OCGT peakers are installed to balance the renewables load. Compared to 2010, a reduction in gas capacity occurs only in Iberia and Italy, which can use MENA imports for balancing. Reductions in gas production takes place mainly in Iberia, the UK & Ireland and Italy. There is an increase in gas production in certain regions, especially in Central Europe and the BeNeLux states.

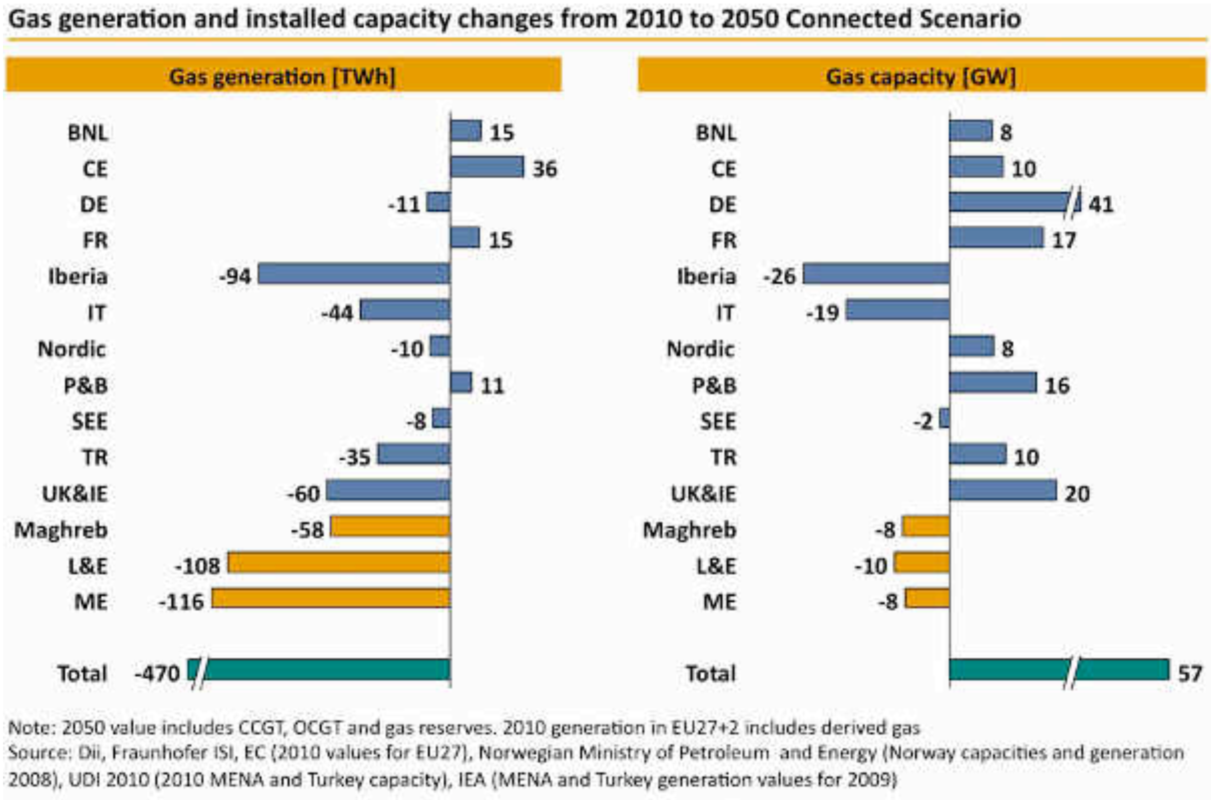


Figure 50: Connected Scenario 2050 and today's gas generation and capacities

3.4 Power transmission in EUMENA

We have now laid the basis for understanding how desert power can provide EUMENA with electricity. Next, we turn to the part of the system that connects the generation capacities throughout EUMENA and enables load and supply to be balanced over long distances.

For the successful realization of an integrated EUMENA power system, the high voltage transmission grid must be extended to a total of 557,000GW_{NTC}*km[57], including 60,000GW_{NTC}*km of sea cables between Europe and MENA, see Figure 51. The intra-European and intra-MENA values take into account the fact that desert power needs to be transported not only across the Mediterranean, but also from the starting points of the interconnectors in MENA to the coast and then from the northern shores of the Mediterranean to European demand centers.

Integrating the transmission system across EUMENA, as done in the Connected Scenario, requires more grid extensions than the Reference Scenario with two fully optimized but separate grids, see Figure 51. Overall, the two separate power grids in the Reference Scenario require 419,000GW_{NTC}*km of high voltage transmission. The main difference between the scenarios is that 60,000GW_{NTC}*km of interconnector sea cables and 72,000GW_{NTC}*km of overland transmission in MENA are not built in the Reference Scenario. The decrease of grid capacities in MENA is due to less

[57] Transmission infrastructure is best measured in capacity kilometers, since neither the length nor the capacity of a transmission line fully describes the line itself

power wheeling parallel to the coast towards the interconnectors, and via Jordan and Syria to Turkey.

The need for overland transmission in Europe remains essentially the same in the Connected as in the Reference Scenario. On the one hand, the European overland transmission parts of the interconnectors are not built in the Reference Scenario. On the other hand, more intra-European connections are needed in the Reference Scenario.

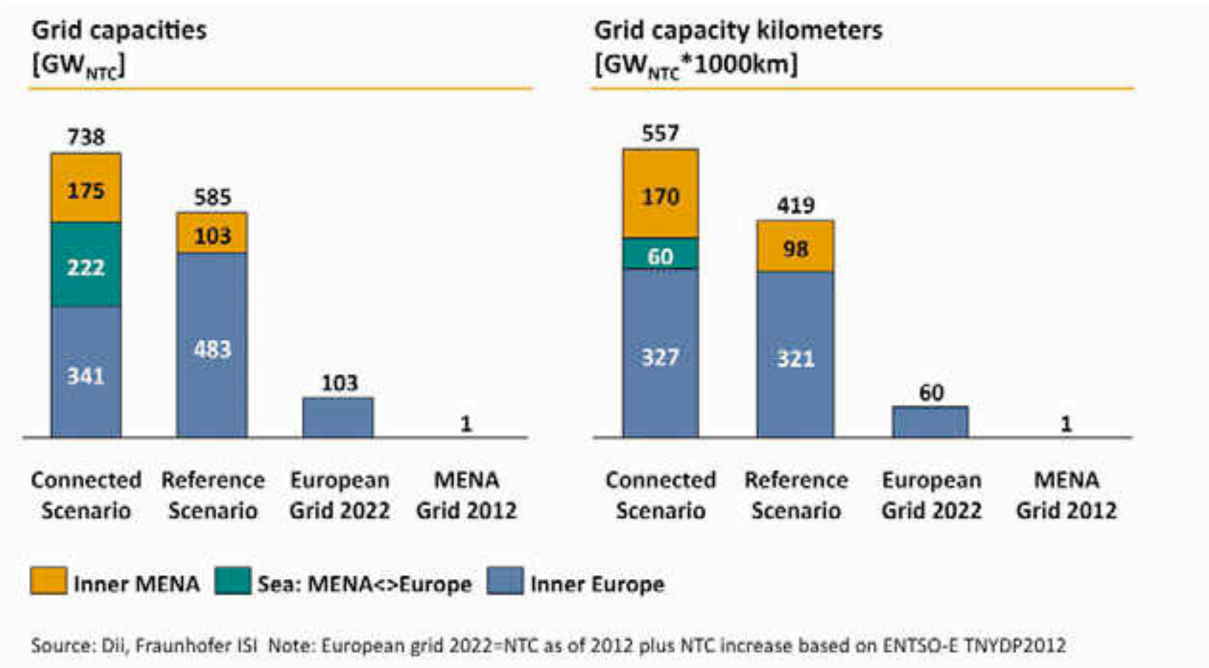


Figure 51: Grid capacities and capacity kilometers in the Connected and the Reference Scenario

Hence, the additional transmission infrastructure for connecting Europe and MENA's power systems needs to be built in the MENA deserts and in the form of sub-Mediterranean cables. The need to extend European overland transmission is roughly the same in an interconnected system as when the European system alone is optimized. Desert power allows Europe to benefit from more economical renewable electricity than intra-European integration can deliver. The same level of investment into European overland transmission is required for both scenarios – whether traditional (monetary) investment or the efforts needed to overcome public acceptance issues. Cheaper desert power faces the same issues with grid extension as European integration, but not more – and has additional benefits.

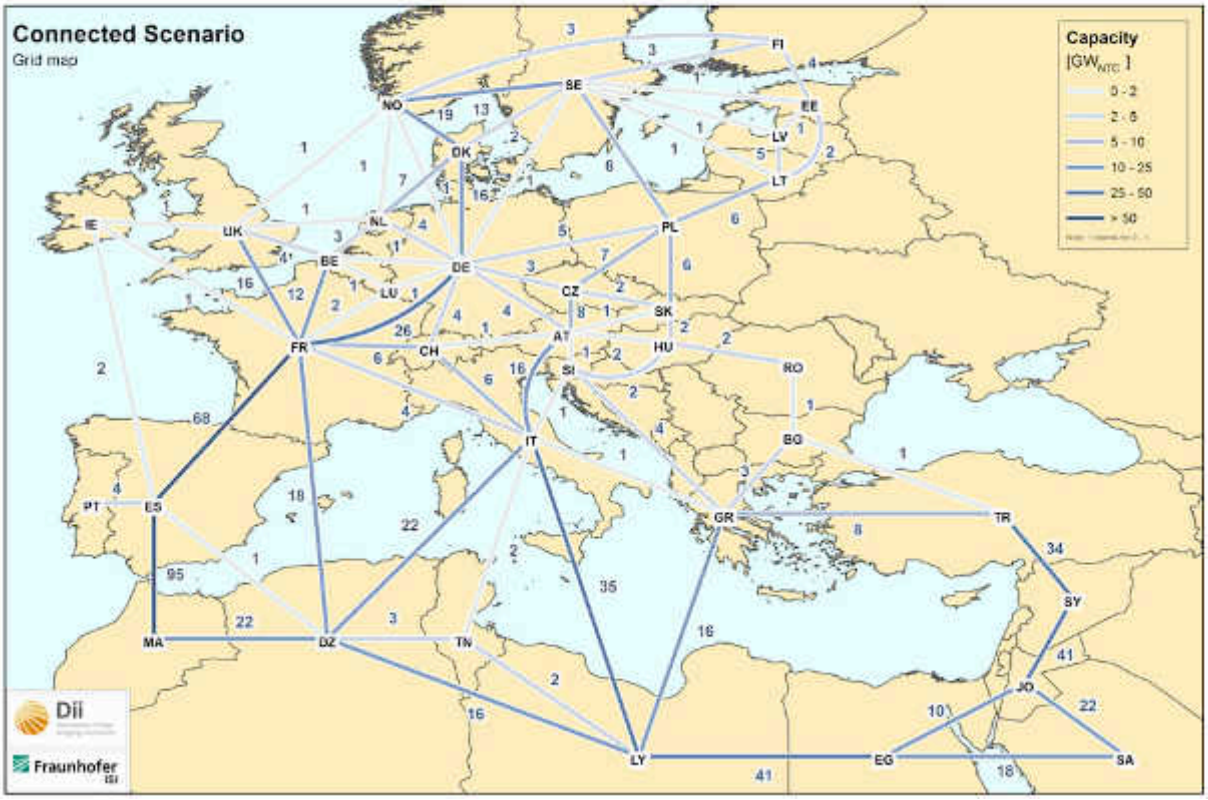


Figure 52: Grid map Connected Scenario

We now take a look at the main transmission corridors in the Connected Scenario, see also Figure 52.

- The largest interconnector required to integrate the MENA and European systems with desert power connects Morocco and Spain with 95GW$_{NTC}$ before continuing to France with 68GW$_{NTC}$. After passing through France, the corridor splits into several major routes. It continues to Germany with 26GW$_{NTC}$, to the UK with 16GW$_{NTC}$, and to Belgium with 12GW$_{NTC}$. The interconnector from Spain to France is already a major bottleneck of European grid extension today. Therefore, on this as on all other connectors, the grid cost assumptions include a share of 50% underground cables.

- Algeria is connected to France with 18GW$_{NTC}$[58]. From France, the power arriving on this line can be distributed on the same northward connections as that arriving from Spain.

- Algeria is also connected to Italy with 22GW$_{NTC}$. The interconnector linking Libya and Italy is even larger, with 35GW$_{NTC}$. From Italy a 16GW$_{NTC}$ connection to Austria, a 6GW$_{NTC}$ connection to Switzerland and a 4GW$_{NTC}$ connection to France distribute the power further. In this model, the system decides to build less capacity on the Tunisia-Italy interconnector than from Algeria and Libya. In reality, this interconnector might be further extended due to less complex implementation, a factor that cannot be included in the system model. Also, we will see in Subsection 4.5.2 that the Tunisia/Italy connection is significantly ramped up when an upper limit is applied to the alternative routes from Algeria and Libya.

[58] This connection is estimated to be feasible only after 2030, due to sea depths of more than 2000m

- A further sub-Mediterranean interconnector of $16GW_{NTC}$ connects Libya and Greece[59]. From Greece, the main connection is $8GW_{NTC}$ to Turkey.
- Finally, the eastern land connection between Turkey and Syria totals $34GW_{NTC}$.
- Apart from the sub-Mediterranean connections, Norway is connected to Germany via Denmark by $19/16GW_{NTC}$ connections. Other inner European connections are much smaller.
- A strong intra-MENA backbone is built along the entire east-west extension of the region. Most prominently on this new axis, Egypt and Libya are connected with $41GW_{NTC}$ and Jordan is connected to Syria with $41GW_{NTC}$.

Due to the lack of connections to MENA in the Reference Scenario, additional grids need to be built all over Europe, as can be seen in Figure 53 and Figure 54. In southern Europe, the Spain-France connection is reduced but still large, with $38GW_{NTC}$. France-Italy increases from 4 to $29GW_{NTC}$, since Italy substitutes the lack of imports from MENA with imports from France. There is a massive increase of capacities on connections from Greece, with $30GW_{NTC}$ to Turkey, $11GW_{NTC}$ to Slovenia and $19GW_{NTC}$ to Italy. These connections are mostly used for power wheeling from Turkey via Greece to Italy and Central Europe. Thus, in the Reference Scenario, southern Europe establishes a massive east-west axis from Spain via France and Italy to Turkey.

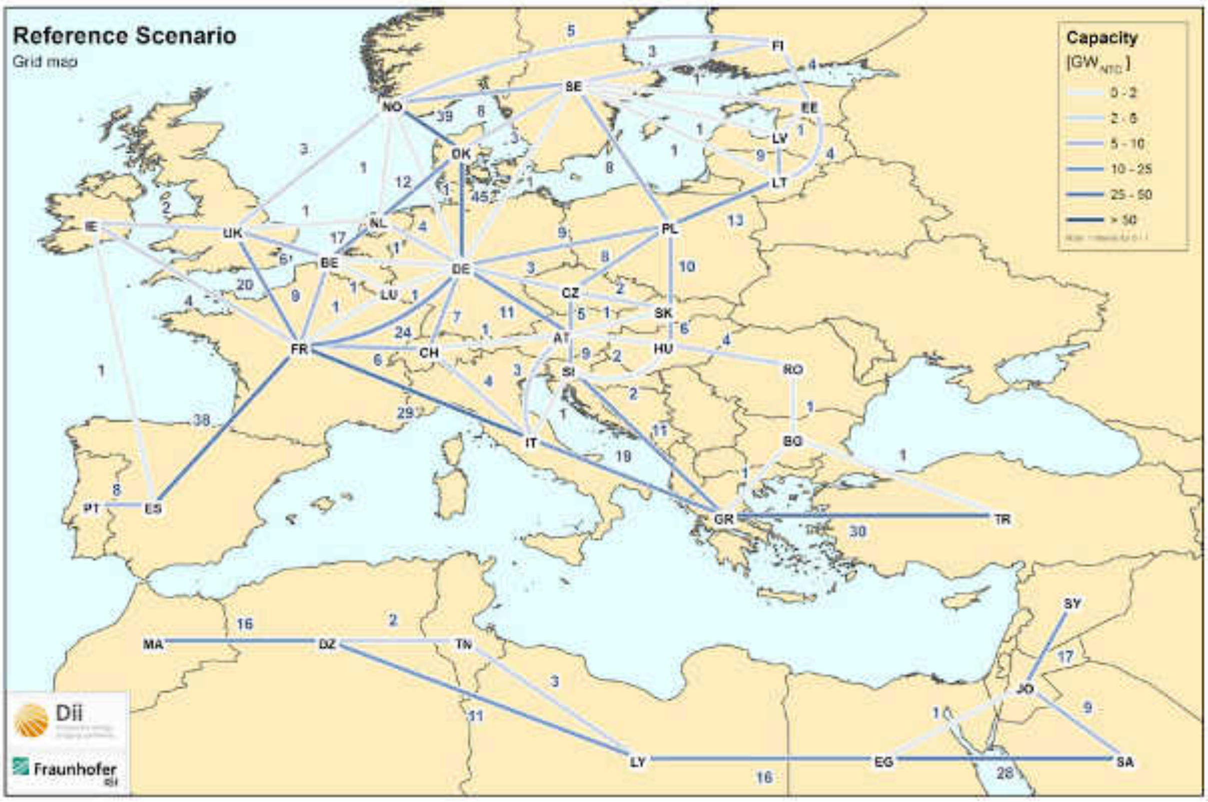


Figure 53: Grid map Reference Scenario

Grid capacities are not only extended in southern Europe in the Reference Scenario. Rather, the east-west axis described above meets a south-north axis from France via Germany and Denmark to

[59] This connection is estimated to be feasible only after 2030, due to sea depths of more than 2000m

Norway. Compared to the grid in the Connected Scenario, the Norway-Denmark-Germany interconnection is roughly doubled to $39/45GW_{NTC}$. The connections from Denmark to the Netherlands and on to Belgium also increase from $7/3GW_{NTC}$ to $12/17GW_{NTC}$.

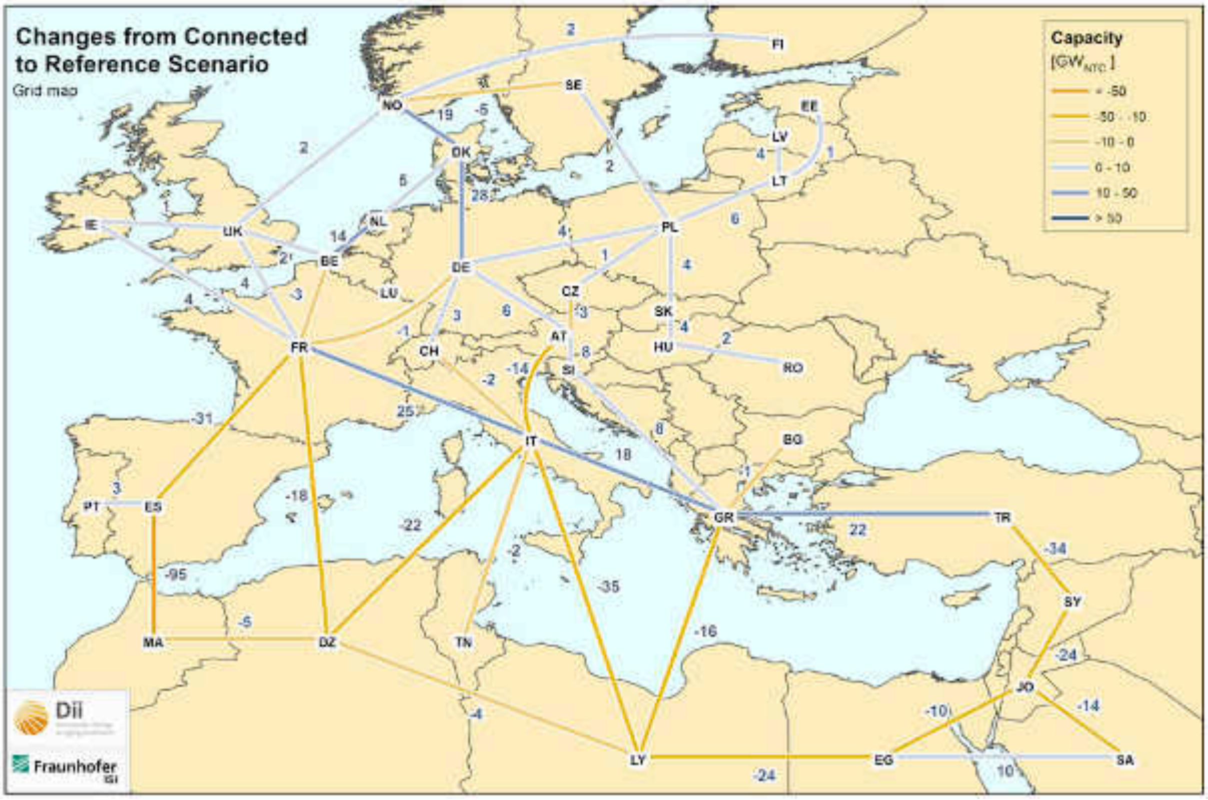


Figure 54: Grid changes from Connected to Reference Scenario

The east-west axis from Morocco to Egypt and on to Saudi Arabia remains strong, with connections over $10GW_{NTC}$ from all countries except Tunisia. It mirrors the east-west axis on the northern coast of the Mediterranean. Interestingly, the connection between the two countries with the highest demand, Egypt and Saudi Arabia, is the only one in MENA that increases by $10GW_{NTC}$. Thus, these two countries, each with more than 800TWh demand, intensify their mutual balancing when connections to other demand heavy-weights, which can only be found in Europe, are missing.

The investments into the high voltage transmission grid in the interconnected system total approx. €540bn., or approx. €130bn. more than the €410bn. of investments in the Reference Scenario, see

Figure 55. As expected, grid investments are reduced in the Reference Scenario for all regions neighboring the Mediterranean, both on the south and on the north shores. Instead, more grid investments are needed further north, especially between the Nordics and Germany. When the approx. €360bn. reduction in generation investment is taken into account, the connected system requires about €230bn. less in power infrastructure investments overall (at 2050 cost).

The relation between investments into grid and generation infrastructure is as follows: the grid investments account for approx. 20% of investment into Wind and Solar power plants in the Connected Scenario and for approx. 14% in the Reference Scenario. The relation between the Connected and Reference Scenarios is as follows: grid investment is approx. 23% lower in the

Reference Scenario than in the Connected Scenario, while investment into Solar and Wind power plants is approx. 11% higher.

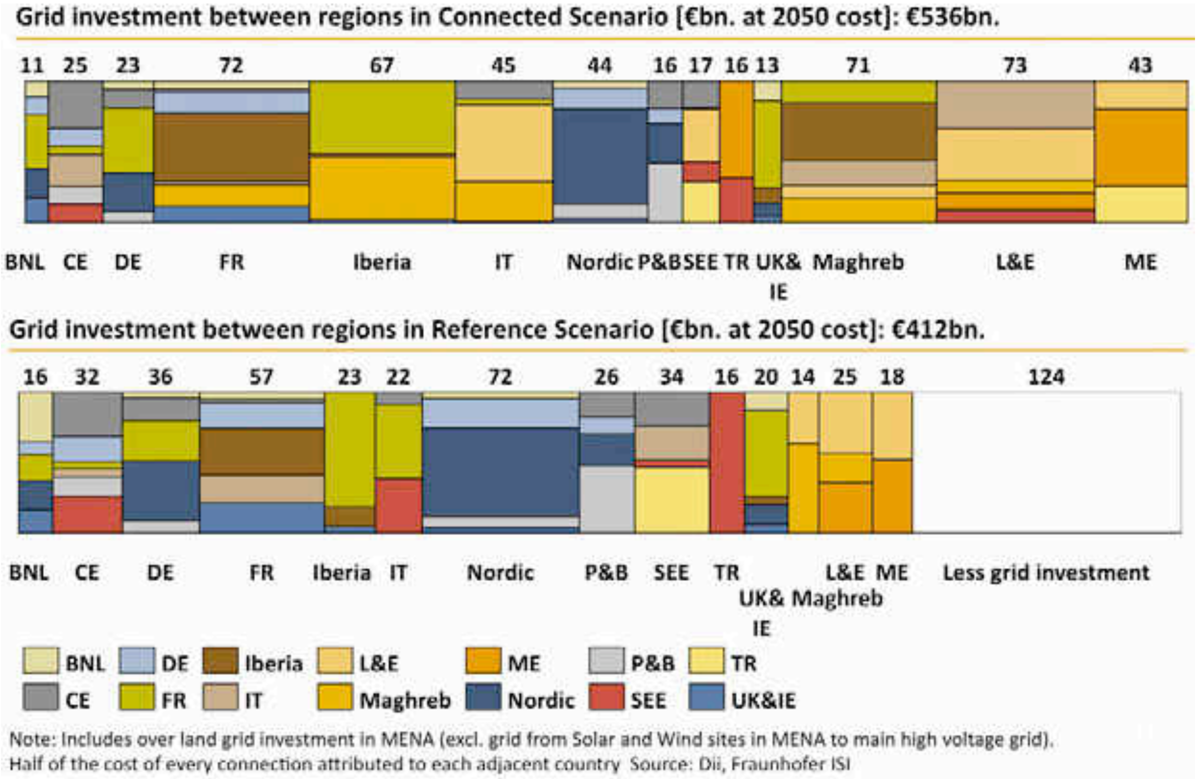


Figure 55: Investment (at 2050 cost) into grids from region to region

After this analysis of the grid capacities built, we now take a look at the power flows on the transmission lines. The main power flows in the system can be clustered into two categories, as shown in Figure 56: the desert power flows from the south and the northern power flows from Scandinavia and (to a much lesser extent) the Baltics. These two major power flow clusters meet in the central part of the system from the UK via BeNeLux and Germany on to Poland and the Czech Republic. Except for the UK, this central part of the system lacks very good wind or solar resources compared to the northern and southern parts.

The main power flows from the southern deserts are as follows:

- From Morocco via Spain and France to Germany, Belgium and the UK, where Spain and France each also absorb a significant portion of this massive power flow and pass on the rest.
- In France, a power flow directly from Algeria joins the one arriving from Morocco via Spain, where it is then distributed to Germany, Belgium and the UK.
- A second major entrance point for desert power is Italy, which receives power from Algeria, Tunisia and Libya. Italy absorbs a significant share of this power and passes on the rest to Switzerland and, especially, Austria. From Austria, some power is passed on to the Czech Republic and Germany.

- Libya exports power to Italy (see above) and Greece, while collecting power from Egypt for transit to Europe. The eastern power flow from Libya to Greece is passed on to Turkey as well as to Bulgaria and Slovenia[60].

- The easternmost power flow goes from Egypt and Saudi Arabia via Jordan and Syria to Turkey, where it is then absorbed.

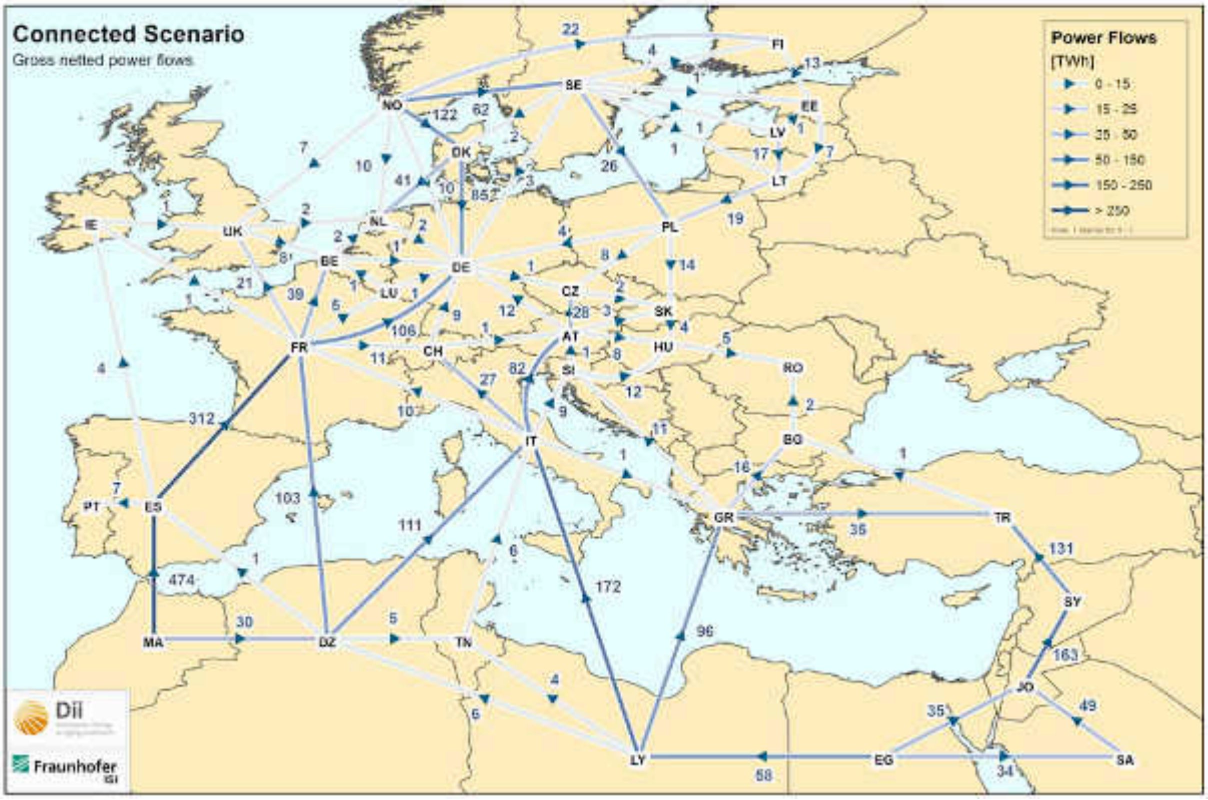


Figure 56: Netted power flows, Connected Scenario

The main power flows from Scandinavia are the following:

- The strongest power flow is from Norway via Denmark to Germany/the Netherlands.

- Power also flows from Norway via Sweden to Poland and from Norway to Finland.

- The Baltics export some power to Finland and Poland.

In the Connected Scenario, more than 100TWh of electricity transit occurs in a number of countries: Spain, France, Italy, Libya, Syria, Jordan, and Denmark see the right part of Figure 57. These values have been derived by analyzing incoming and outgoing power hour by hour for each country for the whole year. This approach, which focuses on short (hourly) time segments, leads to different results than the analysis of the annual netted power flows, which are shown in Figure 56. Two examples show why this is the case. In the first example, hourly analysis results in higher transit than the annual netted perspective suggests; in the second example, the opposite is the case.

[60] Note: The Balkans are not included in the model

- Morocco only has net outflows on its two interconnectors to Spain and Algeria, which would imply that there is no electricity transit in Morocco. Still, the transit analysis shows 17TWh of electricity transit – i.e. in some hours of the year, power flows from Algeria to Spain via Morocco or vice versa.

- Turning to Saudi Arabia, the annual netted power flows suggest that the country has electricity transit of 34TWh, going from Egypt via Saudi Arabia to Jordan. The more detailed hourly analysis instead results in only 16TWh of electricity transit. Hence, the time of Saudi imports from Egypt often does not coincide with the time of exports to Jordan. In other words, Saudi Arabia balances its supply and demand with imports from Egypt and exports to Jordan in different hours of the year. The remaining 16TWh of transit from Egypt via Saudi Arabia to Jordan also needs to be explained. It is more economical to use the direct Egypt/Jordan connection for transmission when this connection has high utilization. In relatively few hours of the year the capacity of this line does not suffice. However, it is more economic to accept higher losses due to transmission via Saudi Arabia than to invest in more capacity on the Egypt/Jordan connection for only a few hours of utilization per year.

These were just two examples of how different countries profit from the grid through electricity transit. More such examples will be provided in Section 3.5.

The left part of Figure 57 shows that the main exporters are Norway, Morocco, Algeria, and Libya. The large EU economies Germany, Italy and France as well as Turkey profit the most from power imports.

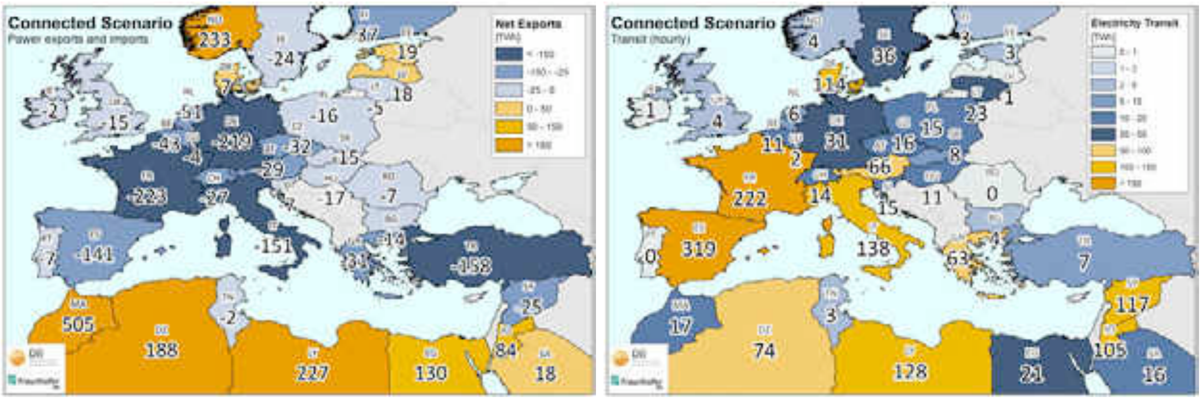


Figure 57: Electricity exporters/importers (left) and transit countries (right), Connected Scenario

Figure 56, which shows netted power flows between regions, appears to suggest that relatively little electricity exchange occurs within Europe. This impression is wrong, as Figure 58 shows. In fact, within Europe, the power flows on a line are often rather balanced in both directions and therefore the netted power flow is relatively small in comparison. It also reveals that the east-west axis in MENA is heavily used in both directions and that there is strong power exchange between the Maghreb and Libya, which cannot be seen from the netted power flows.

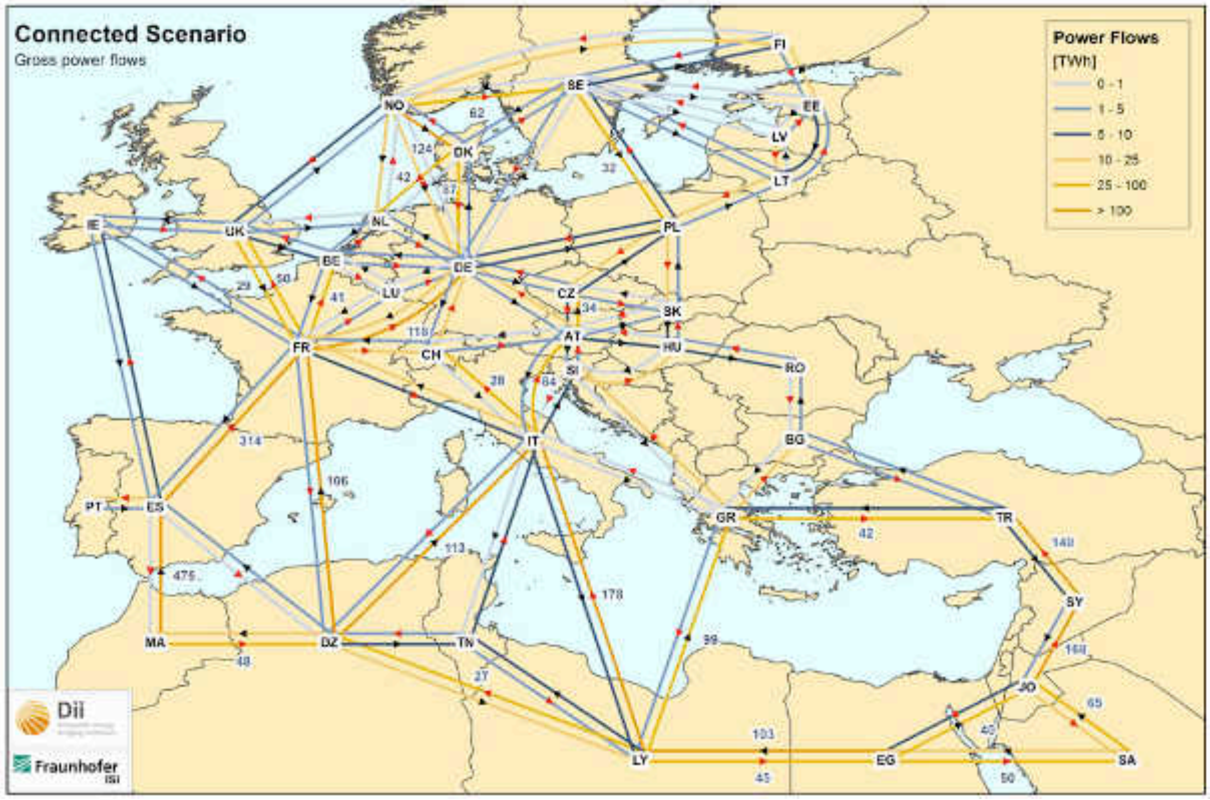


Figure 58: Gross power flows, Connected Scenario

The power flows from the north of the Mediterranean to the south are relatively limited compared to the strong opposite direction from MENA to Europe. Nevertheless, energy flows from north to south are important.

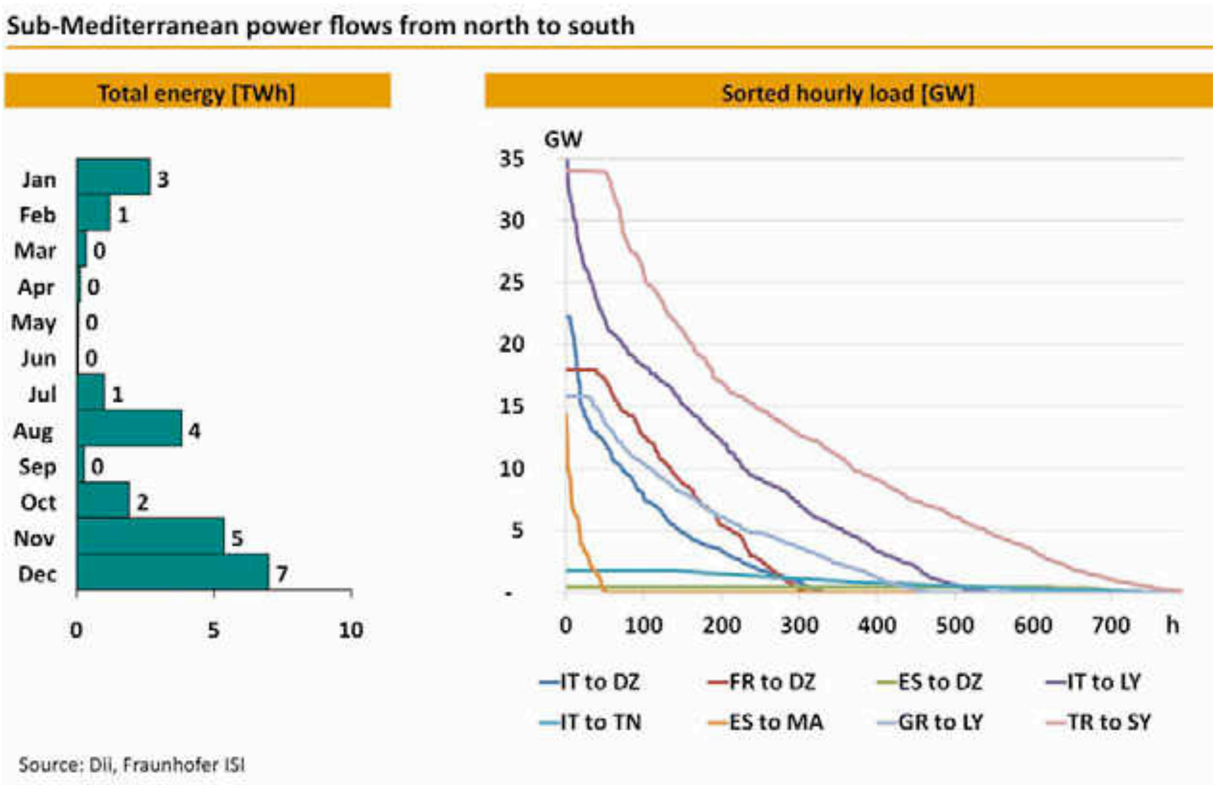


Figure 59: Sub-Mediterranean power flows from north to south

The north-south power flows occur mainly in the winter months and in relatively few hours but with high load, see Figure 59. Therefore these north-south power flows play a crucial role in balancing the MENA power system during these hours of import.

We now compare the Reference Scenario power flows, as shown in Figure 60, to the Connected Scenario. This not only confirms the comparison of the grid capacities, but also yields some further insights.

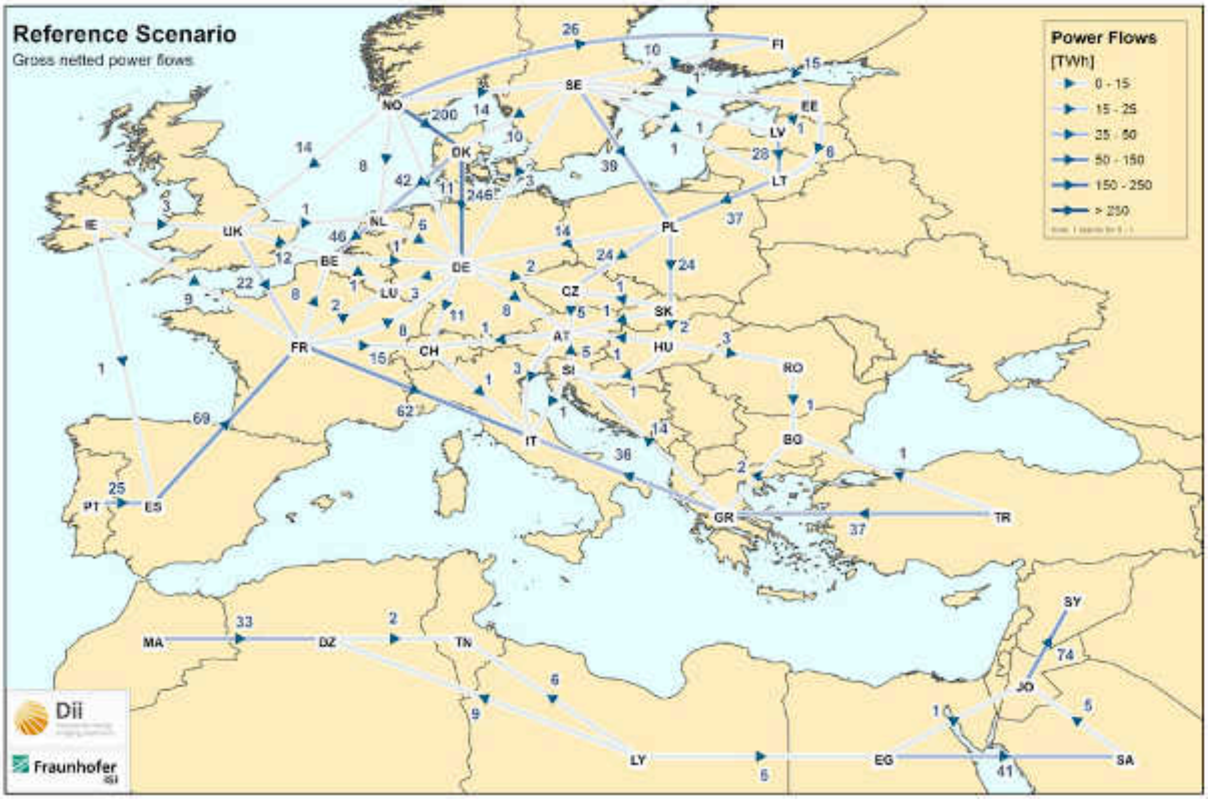


Figure 60: Power flows Reference Scenario

In the Reference Scenario, power flows within MENA decline, showing that EUMENA integration leads to a higher level of interconnection not just between MENA and Europe but within the MENA region, too. At the same time, power flows from the north to the central part of the system increase to compensate for the missing desert power. Most notably, the power flow from Denmark to Germany almost triples and Denmark's role changes from being predominantly an electricity transit country to a net exporter.

Turkey becomes a significant exporter in an isolated European system, and this power transits through Greece to Italy and Central Europe. Italy, meanwhile, imports heavily from France, a reversal of the (limited) power flow from North Africa via Italy to France in the Connected Scenario.

At the end of the analysis of the transmission results, we turn to the analysis of the seasonal changes of power transmission during the year, as shown in Figure 61. Power transmission in the Reference Scenario is highest in winter, when power from the northern winter winds must be distributed in Europe. During winter months, total transmission within Europe is higher in the Reference than in the Connected scenario, see the right-most part of Figure 61.

Transmission between MENA and Europe is strongest during summer months in the Connected Scenario and, with a maximum above 130TWh per month, approx. twice as high as in the lowest winter months.

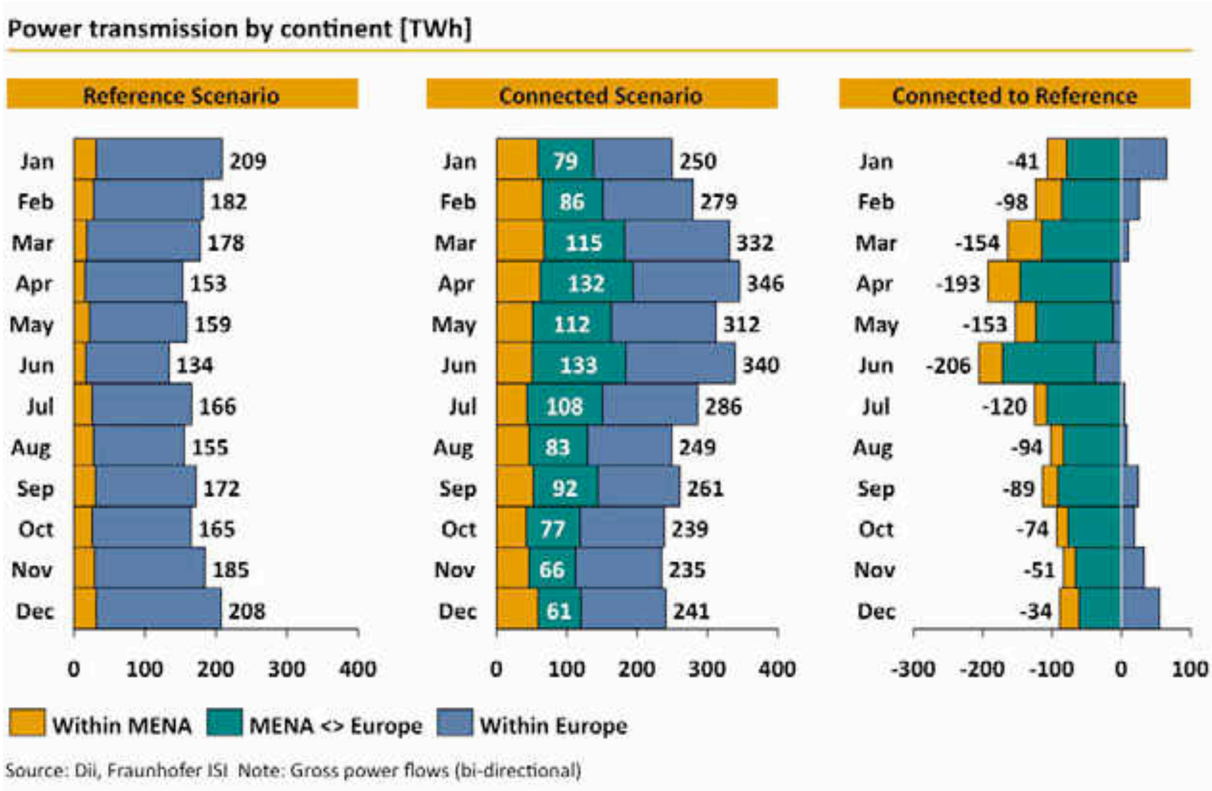


Figure 61: Monthly power flows in Europe, in MENA and on the interconnectors

3.5 The integration miracle: what grids do for individual countries

For a power system based on 90% renewables, it is essential to ensure that the technology mix based on sun and wind resources suffices to meet demand 24 hours a day, 365 days a year in order to avoid blackouts. Given natural variations over time and space, such a requirement is more easily met in larger systems. As our analysis makes clear, system integration makes a sustainable power system not just more affordable but also more reliable. In order to show how this occurs, we look first at technical complementarities and then proceed to examine the mutual reliance created by an integrated system. In general, this section aims to show how the system works as a whole and what this means for the different countries.

3.5.1 The big picture: system level

Intuitively, the larger a connected system is, the higher the probability that the sun shines and the wind blows somewhere in the area covered – and the easier it becomes to ensure the reliability of a system with 90% renewables. Figure 62 shows that this intuition is not only right, but that the natural correlation of sun and wind is favorable from a power supply point of view.

In order to understand power supply over time, one needs to look at intra-daily changes as well as seasonal variations. During the day, Solar produces electricity when demand is highest and Wind generation is lower than at night. When Solar production is reduced during the winter, then Wind production is higher. Thus, Solar and Wind are complementary on both time scales. They can be combined with hydro dam and other dispatchable and base load renewables, as well as a small share of gas to satisfy demand. The other renewables also contribute to demand/supply balancing by producing at dawn and dusk. The difference between the sum of the supply technologies and the black demand curve in Figure 62 is due to transmission losses, storage losses, and curtailment.

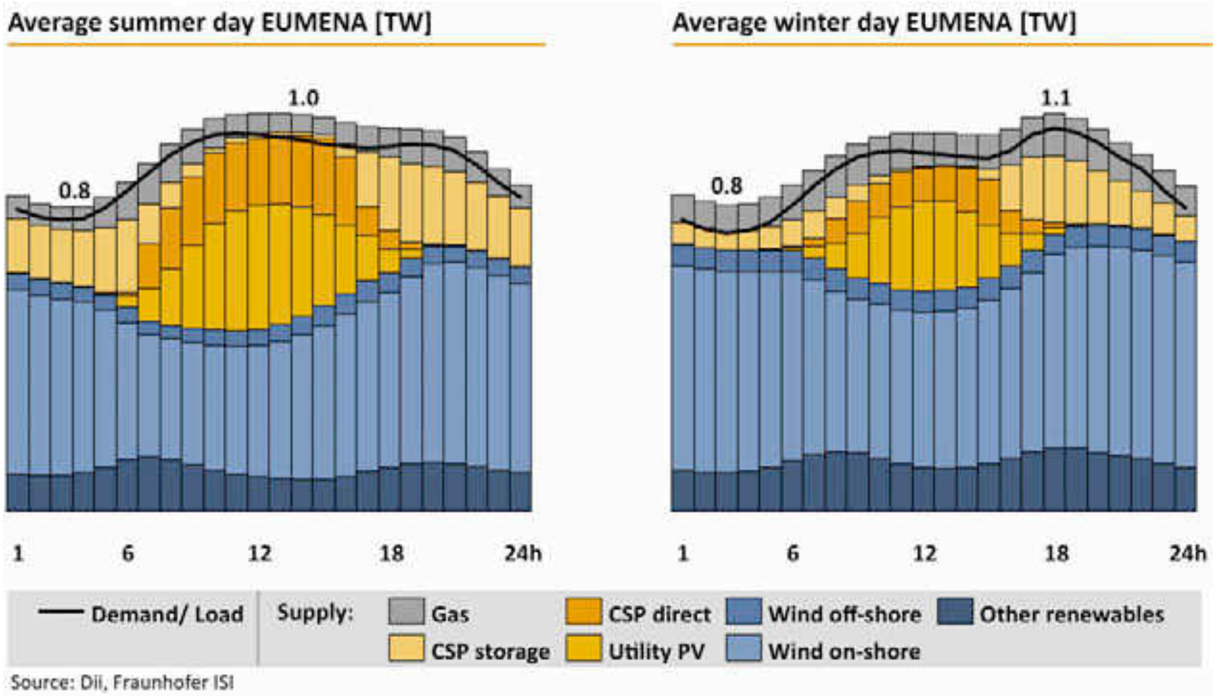


Figure 62: Daily and seasonal demand and supply in EUMENA

In addition to this natural correlation between power demand cycles and Solar and Wind capacities, other factors also contribute to making the system function effectively.

First of all, demand is smoothened when considered across the system as a whole rather than country by country, see Figure 63. This figure shows the sorted (descending) hourly load curves of the largest countries (based on demand) divided by their respective peak loads. For comparison, the figure also shows the blended load curves for Europe, MENA and EUMENA. To interpret this figure, it is essential to understand how the curves for the regions are obtained. The sorted load curve for a region is not the sum of the sorted curves of all countries in the region. Instead, it is the sum of all chronological country load curves in the region, which is then sorted by descending load value. Thus, a regional sorted curve can be smoother than that of the sum of its sorted country curves. This is because peak and valley loads in those countries do not occur at the same hours of the day.

Here the green curve, representing the entire EUMENA region, is obviously the flattest one, with a share of system peak demand between 60% and 90% during approx. 8500 hours of the year. This effect results from the system's extensive geographic spread, both in an east/west and in a north/south direction, as well as the result of aggregating the different consumption patterns of the numerous countries in the region into a single system.

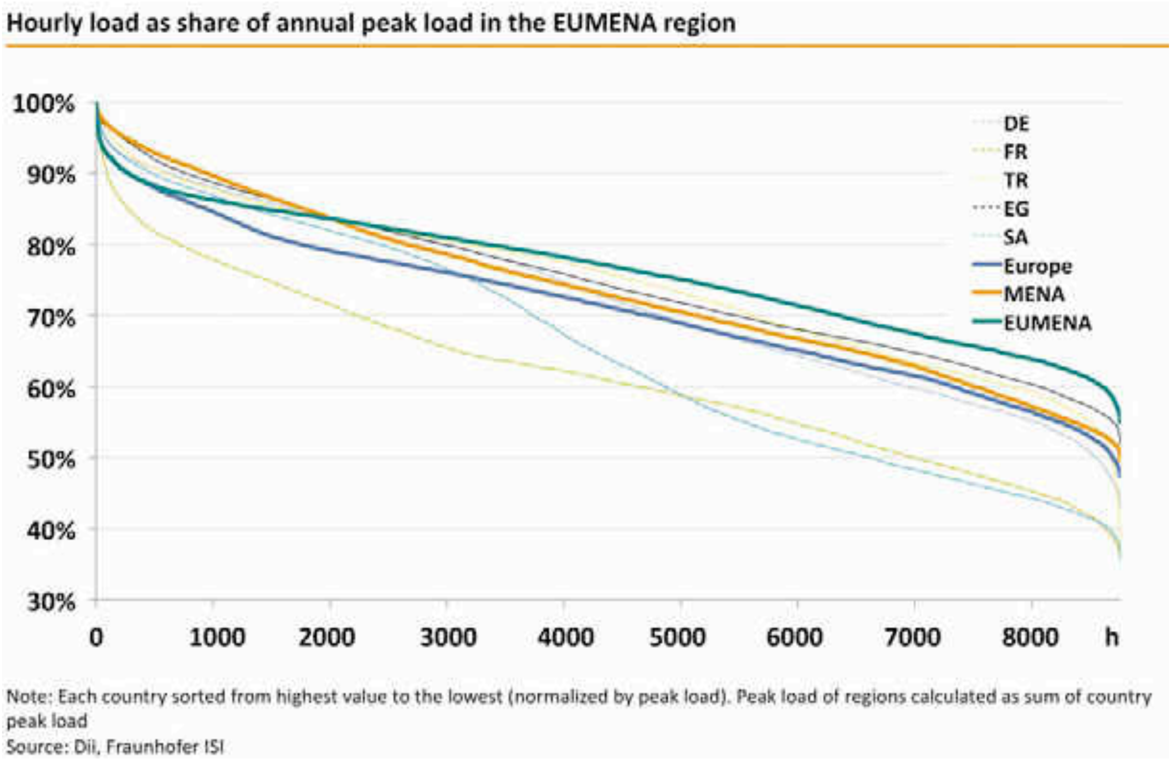


Figure 63: Demand as share of peak load in the EUMENA region and selected countries

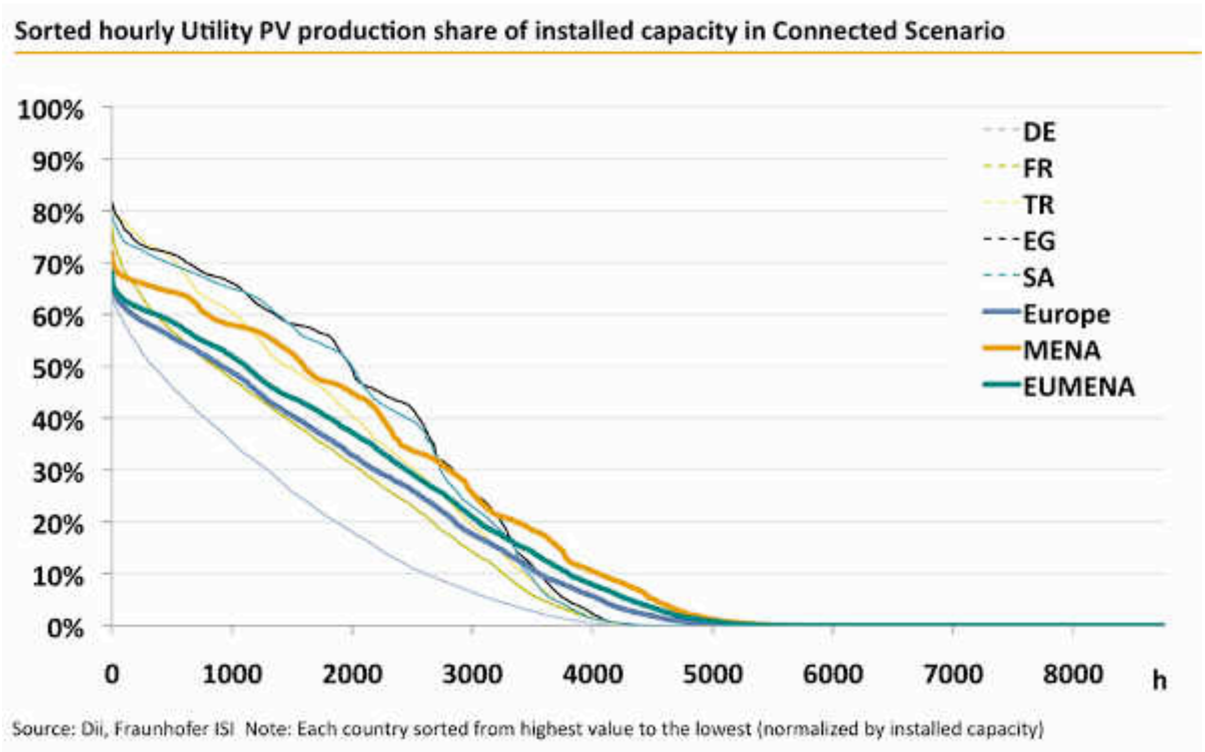


Figure 64: Utility PV production curve for EUMENA and selected countries, Connected Scenario

Similar effects as for load can be observed for both Solar and Wind production. Figure 64 depicts Utility PV production in countries with large Utility PV capacities and how they complement each other in a large region. It is interesting to note that the line representing EUMENA does not touch the x-axis before 5000 hours, despite daylight hours in any given location in EUMENA being limited to about 4500 hours per year. This effect is due to the large east/west extension of the system, where the sun rises early in Saudi Arabia and Turkey and sunset is late in Spain and Morocco.

The corresponding effects for Wind production are shown in Figure 65. Other than for Utility PV, there are no times in the year when none of the Wind turbines are in operation. In approx. 8000 hours of the year, at least 20% of all Wind turbines installed in all of EUMENA are generating electricity.

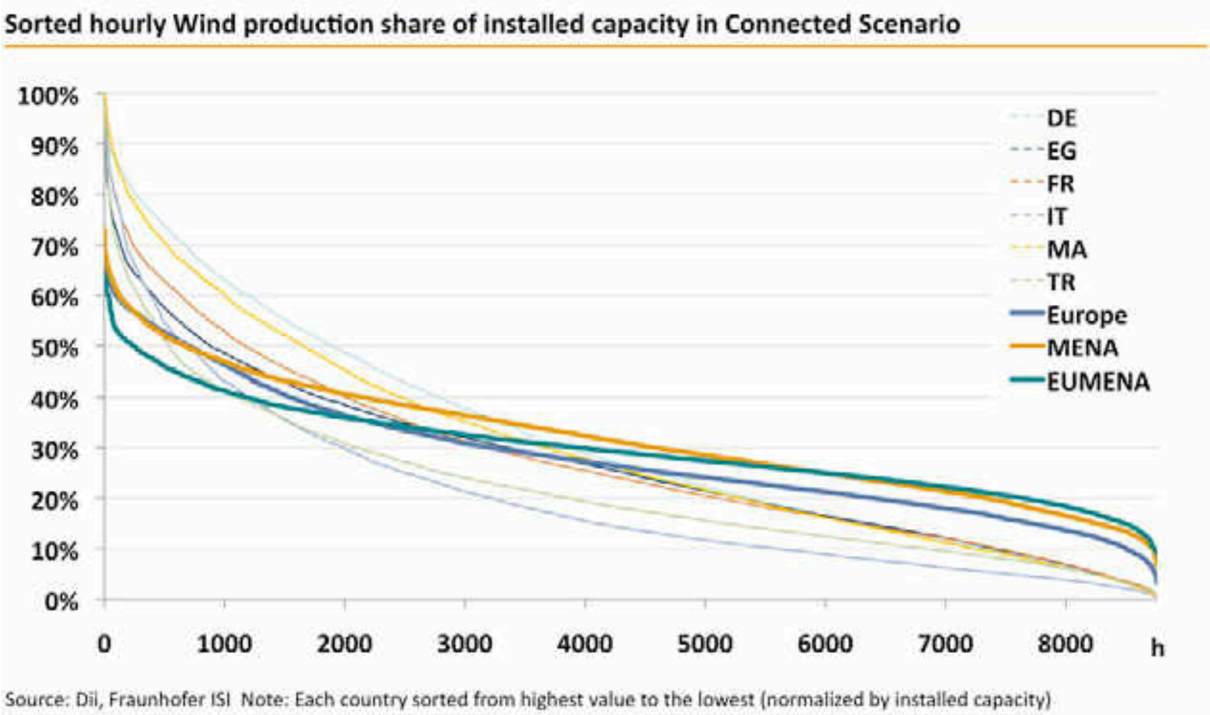


Figure 65: Wind production curve for EUMENA and selected countries, Connected Scenario

Figure 66 reveals that the good fit of demand, Solar and Wind is the result of complementary demand and supply conditions in MENA and Europe. It shows that European Wind production is much higher in winter than in summer and that this difference is even greater than seasonal changes in the European load. This seasonal effect is not compensated by European Utility PV and CSP alone. While load is higher in winter than in summer in Europe, the opposite is the case in MENA, where more extreme weather conditions occur during the hot summer as opposed to Europe’s cold winter. Also, while Wind production is higher in winter in Europe, it is relatively stable throughout the year in MENA. Due to its high solar yield, MENA is able to provide Europe with the power it needs during the summer, following the daily demand curve with the help of the CSP storage.

Concerning CSP storage, Figure 66 shows that, with an 8h CSP storage configuration, a profile close to base load can be generated. There are two reasons for this. First, the large east-west extent of the system causes an offset of CSP production, including storage, of 2-4 hours between Saudi Arabia/Turkey and Morocco/Spain. Second, hundreds of GWs of CSP are in the system, each with 8h storage. Thus, by combining so many CSP plants, a base load-like profile can be achieved.

Furthermore, almost all the gas production is allocated in Europe, since MENA balances its own system with CSP and by adapting export quantities to its own needs when necessary. This optimal allocation of the conventional generation under the given carbon emission cap not only ensures a well-functioning power system; it is also the reason for the 40% reduction in the marginal cost of carbon emission reduction, see Section 3.2. In general, these characteristics enable MENA to produce and export the additional power needed in Europe during the summer.

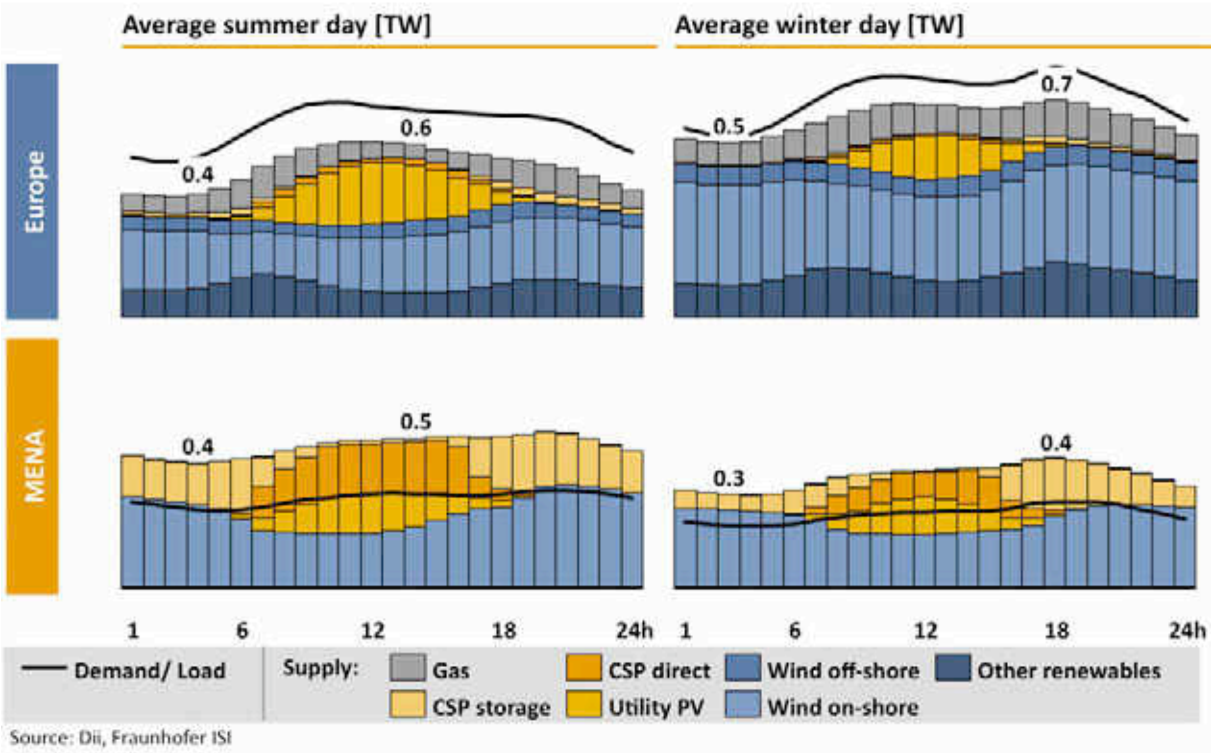


Figure 66: Daily and seasonal demand and supply in Europe & MENA

3.5.2 Deep dives: implications on country level

The roles of individual countries in this integrated system are also essential to understand how the system becomes not just competitive but also stable. We distinguish between three main types of countries: renewables super producers (super producers), renewables scarce countries (importers) and countries with balanced renewables and demand (balancers). While each of these three types profits from system integration in a different way, they all benefit from being part of a large sustainable power system. At the same time, their complementary roles lead to a situation of interdependence across the system, in which no single country is dependent on another but instead each country is reliant on the system as a whole.

Super producers benefit from the emergence of an export industry for renewables. At the same time, exports allow them to balance their own load.

Importers profit from cheaper renewable electricity instead of paying higher prices for less economic, local renewables. They thereby limit the marginal cost of carbon emission reductions and consequently can reach their CO_2 reduction goals more economically. Furthermore, under the common carbon cap, gas generation can be allocated more effectively to the importers, giving them a relatively high share of dispatchable generation assets. Note that no country imports more than 30% of its demand in the Connected Scenario.

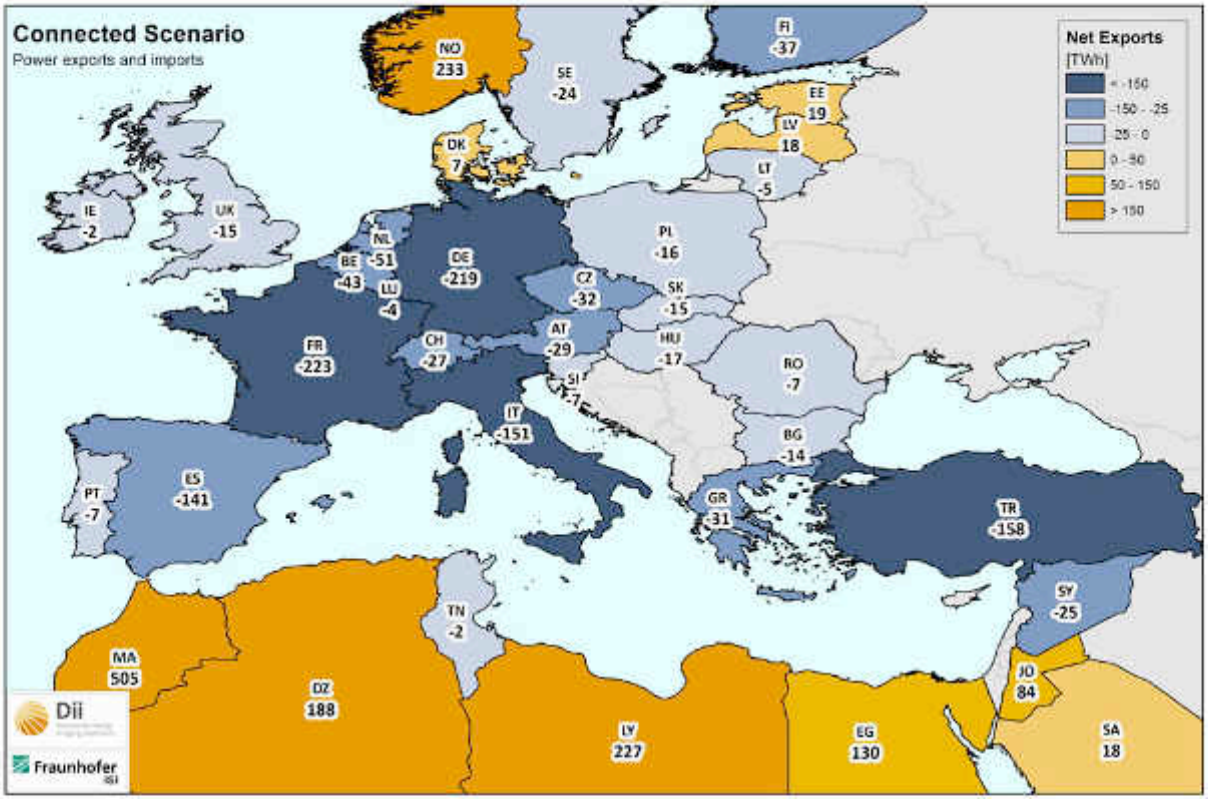


Figure 67: Net exporters and net importers in EUMENA

Countries that shift between imports and exports benefit from the balancing effect resulting from grid integration, and thus are called balancers in this report. These balancers are able to build enough of their cheapest renewables to be self-reliant during some times of the day/year. When these cheap renewables produce more than needed, they export and avoid curtailment; when they are not sufficient to meet demand, they import.

In the rest of this subsection, the concepts of super producer, importer and balancer will be explained using examples from the Connected Scenario. It is important to note that the roles described for each country are relative to the system. In other words, the role of a given country can change depending on whether system integration occurs. The examples in this section focus on the largest power producers and consumers in scope, which in total account for a total of 78% of power demand and 82% of total power supply in the Connected Scenario.

Super producers

Super producers are countries with excellent renewables resources and relatively low demand. Thus, they have enough excess in cheap renewables potentials for significant exports. Examples of super producers are the Maghreb countries (except for Tunisia) and Libya in the south and Norway in the north. The super producers profit from system integration in two key ways: from a large renewable electricity export industry and from a reliance on the overcapacities of renewables (compared to domestic load) as a means of ensuring their own security of supply at all times of the year. All of these countries produce at least twice the amount of power that they need to satisfy domestic demand, with Morocco and Libya producing almost five times more than they consume. In absolute terms, Morocco exports 505TWh, Norway 233TWh, Libya 227TWh, and Algeria 188TWh.

Norway's power generation is made up of on-shore Wind and hydro dam plants, as shown in Figure 68. Since its domestic demand amounts to around 50% of production during the whole year and throughout the day, the country's hydro capacity can be mostly used to match production with that of its main client, Germany (an importer) and that of the main transit country, Denmark (a balancer).

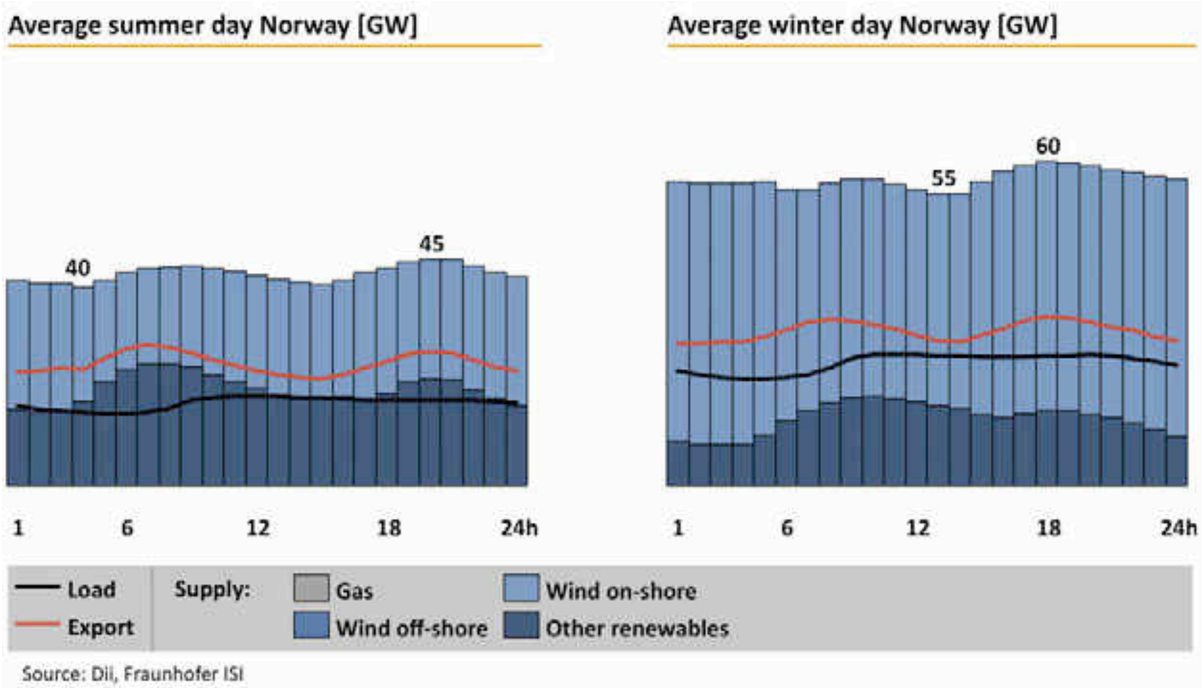


Figure 68: Daily and seasonal demand and supply in Norway

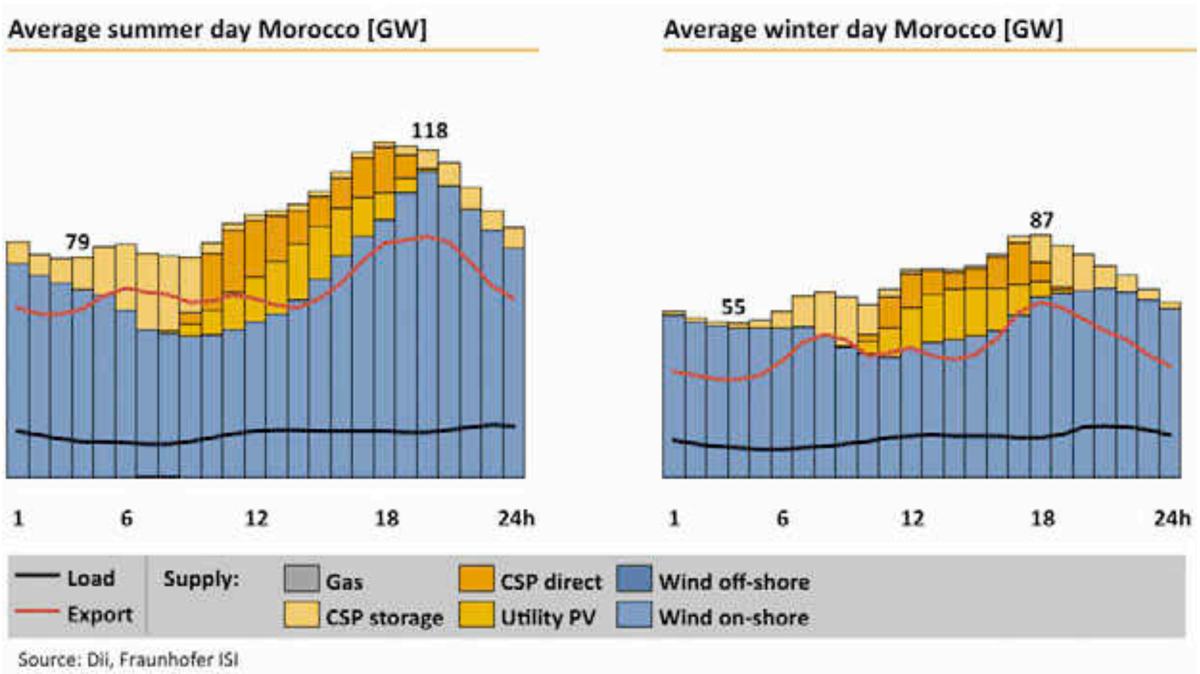


Figure 69: Daily and seasonal demand and supply in Morocco

Morocco and Libya produce huge amounts of Wind power, while also using some Utility PV and CSP in order to match their production to clients' demand, as shown in Figure 69 and Figure 70. For example, while the evening peak of Moroccan Wind fits the Spanish load quite well, CSP storage is used to deliver power to Spain during the Spanish morning/mid-day demand peak.

Libyan export shows two pronounced dips in the morning and evening, when solar (also from CSP storage) is not available but the windy evening/night has not yet started or is already over.

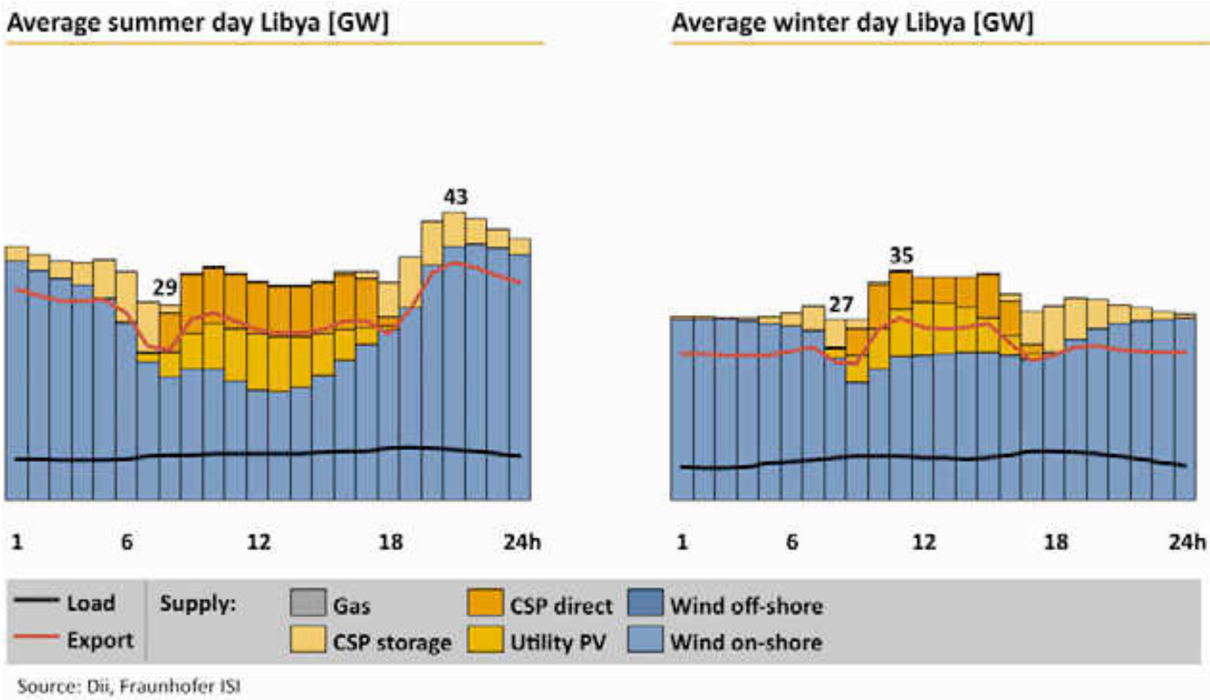


Figure 70: Daily and seasonal demand and supply in Libya

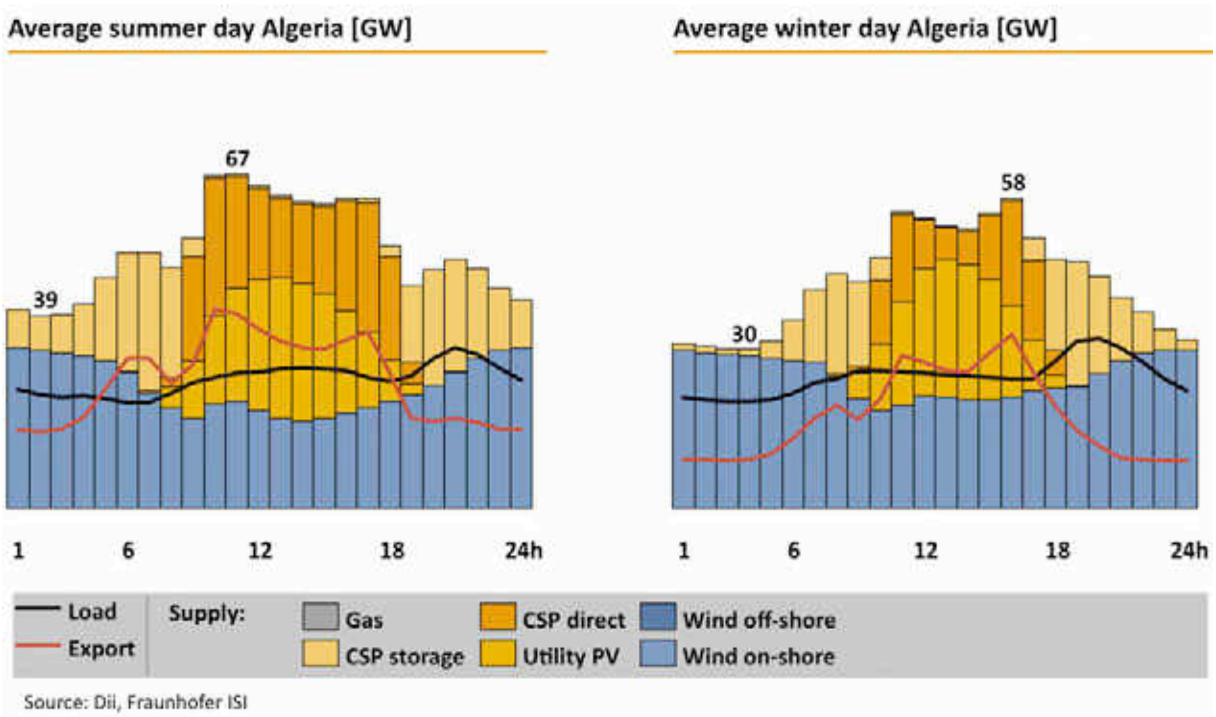


Figure 71: Daily and seasonal demand and supply in Algeria.

This is where Algeria comes into the picture, see Figure 71. While Algeria also has a large amount of Wind installations, it has a higher share of Solar than Morocco and Libya. Other than those two countries, Algerian domestic demand is sometimes higher than its Wind production, and Solar is needed to meet it. The export curve of Algeria shows two pronounced peaks in the morning and evening, which match the dips in Libyan export (in the morning with the help of CSP storage). By combining Wind and Solar production from both countries, their common client, Italy, is provided with the power it needs when it needs it.

Latvia and Estonia are examples of smaller super producers, with renewables generation more than twice domestic demand. Estonia relies on Wind for its production, in Latvia Wind is combined with some hydro power.

Importers

Importers have high demand and, compared to demand, limited potentials of good renewables resources. This group of countries includes Germany, Italy, and – though less pronounced – also France and Turkey. A lower limit on the electricity self-supply rate has been imposed in the system so that no country relies on power imports for more than 30% of its supply. These countries import cheap renewable power throughout the year to ensure an affordable sustainable power supply. They benefit not only from the cost advantage of the imported electricity, but also from the optimized allocation of the conventional gas generation remaining under the given carbon emission cap. Since gas generation is allocated under this common cap to where it is needed most, the countries with limited renewables can use more gas than in an isolated system.

The four sample countries in this group are among the largest consumers of power in the system: France (223TWh imports), Germany (219TWh), Turkey (158TWh) and Italy (151TWh). The three other very large consumers – the UK, Saudi Arabia and Egypt – have good Wind (UK) or Solar (Saudi Arabia) conditions, or both (Egypt). As a result, these three countries belong to the balancer group.

The importers can be further divided into two pairs, based on their use of gas in addition to renewables: while Germany and Italy rely heavily on gas on top of their renewables imports, France and Turkey have better renewables potentials and therefore use little gas.

As a result, France and Turkey, shown in Figure 72 and Figure 73, use imports to balance their load and domestic production. In this respect, France profits from its role as a power transit country: due to its location at the center of a transit corridor, there is always enough power in France travelling from south to north for France to adapt to domestic needs. Turkey, on the other hand, is able to balance imports as needed due to power coming from two directions: Syria in the south east and Libya via Greece in the west.

Germany and Italy, as shown in Figure 74 and Figure 75, are two of the main gas consumers in the system and use this gas for balancing, especially during summer when imports have a base load-like profile. In winter, when demand in both countries is higher but North Africa exports less (due to less solar production), imports and gas are combined in similar shares as needed to meet demand.

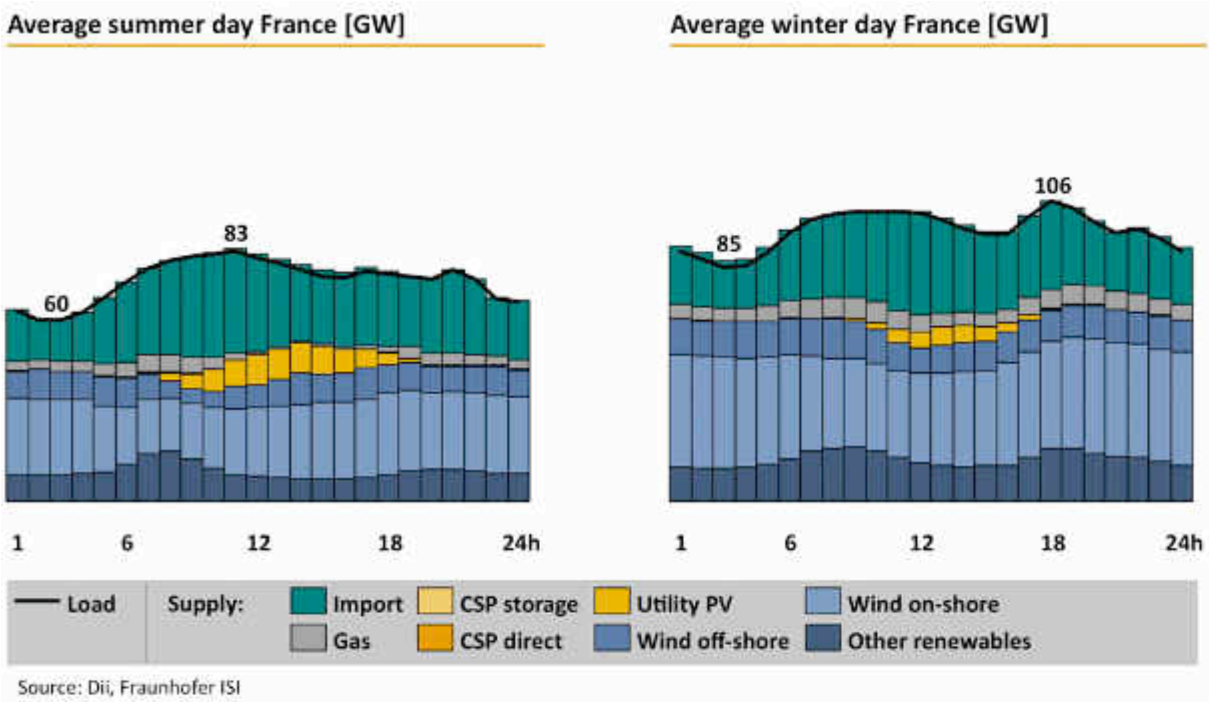


Figure 72: Daily and seasonal demand and supply in France

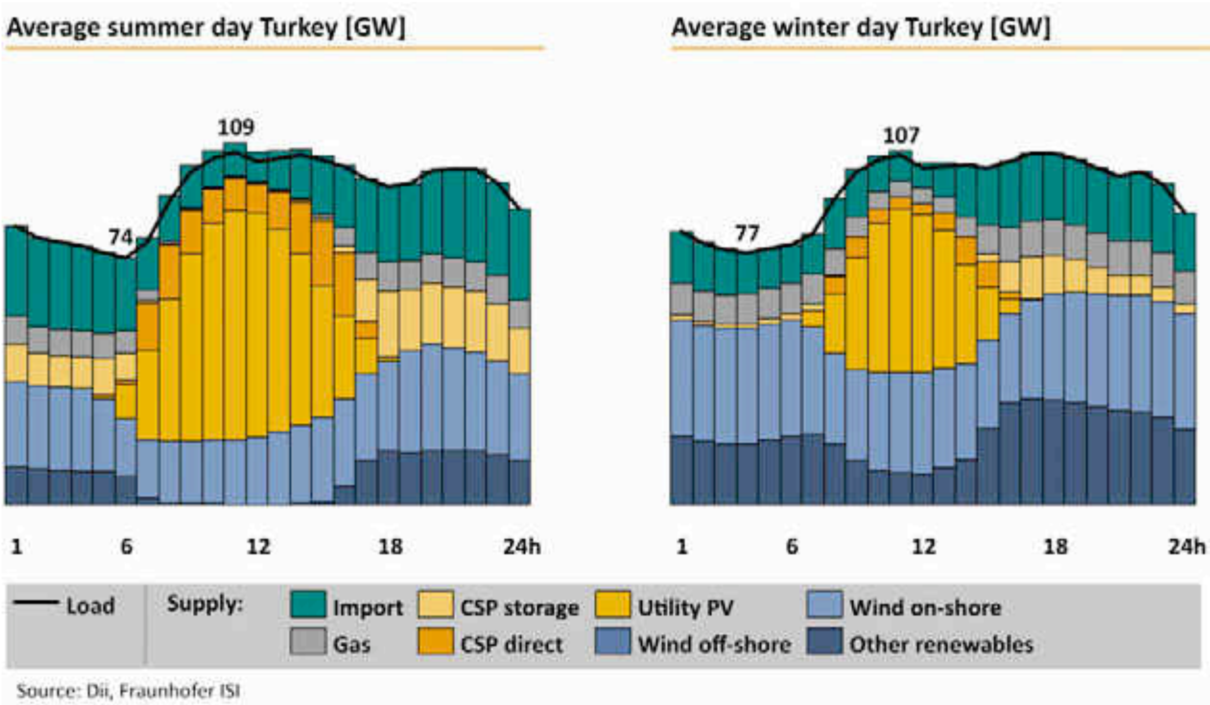


Figure 73: Daily and seasonal demand and supply in Turkey

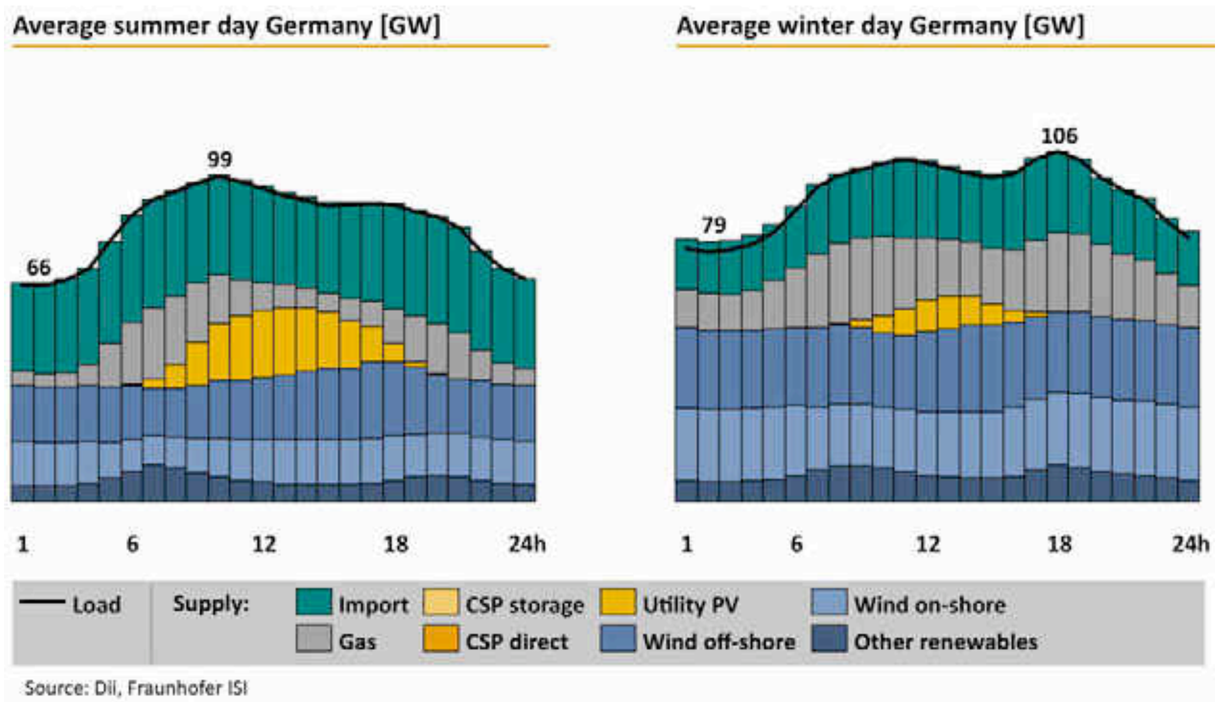


Figure 74: Daily and seasonal demand and supply in Germany

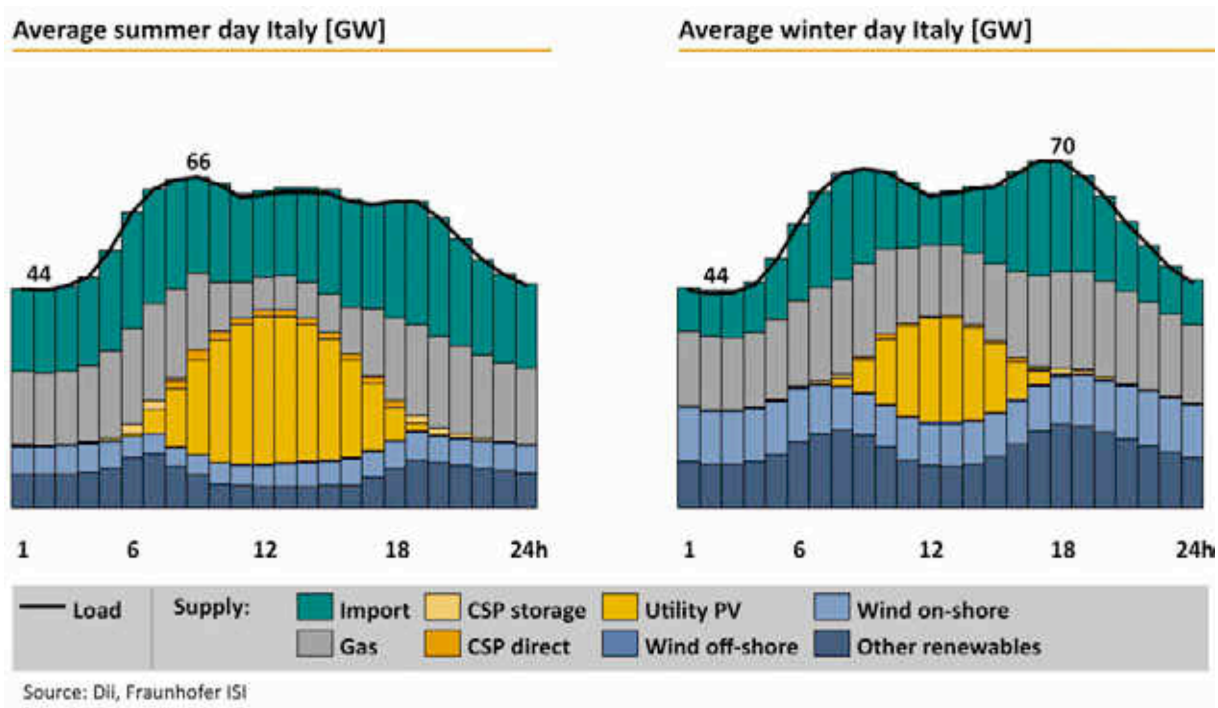


Figure 75: Daily and seasonal demand and supply in Italy

Balancers

Balancers have levels of demand and renewables resources that are largely proportionate to each other. They include Egypt, Saudi Arabia, Syria, Spain, the UK and Denmark. An assessment of renewables potentials must not only be based on the levelized cost of electricity but also on their fit with the load that needs to be satisfied at every point in time. This is why the balancers also profit from system integration: they build just as much renewables capacity as is economic to cover most of their domestic load. Covering the remaining minor share of the load with domestic renewables becomes less economic, since curtailment of excess energy would occur. Consequently, these countries import power when needed and export it when their production exceeds domestic demand. They thereby avoid building the final segment of domestic renewables, which would make the sustainable power system more expensive due to high curtailment.

This group includes countries with a range of demand levels. Some have very high demand, such as Saudi Arabia, Egypt and the UK, as well as Spain and comparably small countries such as Denmark, Tunisia and Syria. Many of these countries (Spain, Denmark and Syria) are major transit countries, which profit from their location on an electricity highway to extract or inject electricity into the grid as needed.

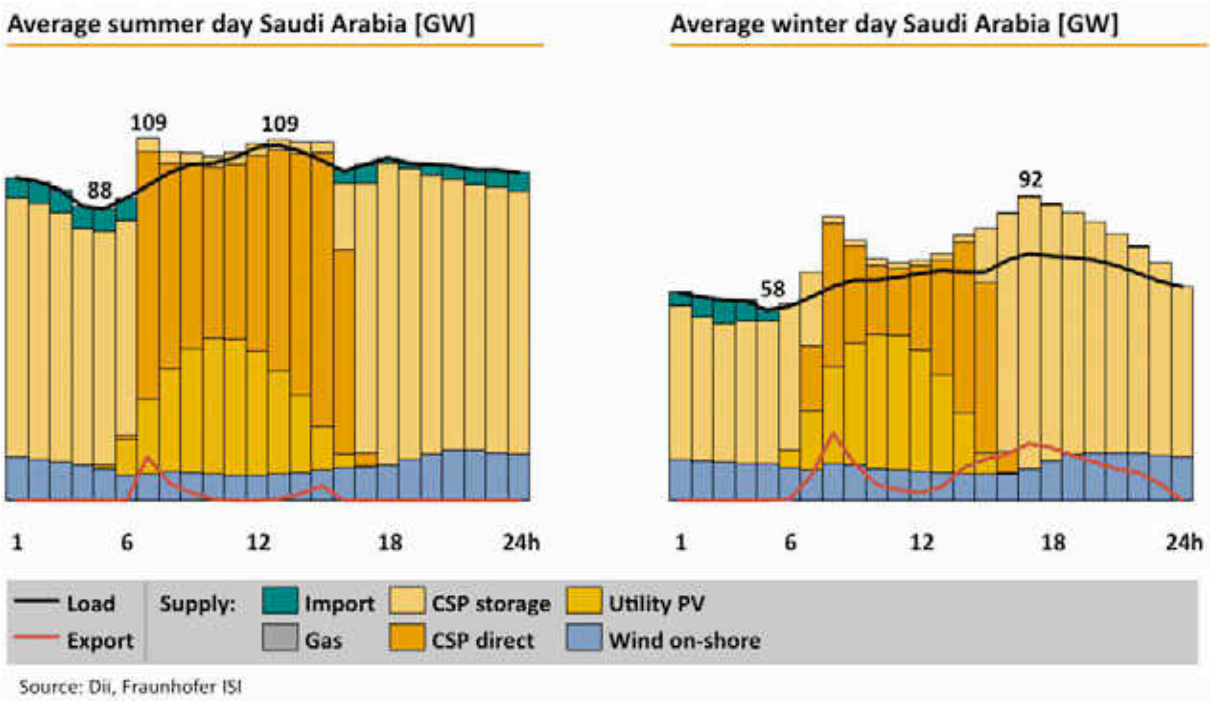


Figure 76: Daily and seasonal demand and supply in Saudi Arabia

Saudi Arabia is dominated by CSP production due to its quite stable load throughout the day. This pattern also mirrors seasonal changes, with demand slightly lower in the winter, as shown in Figure 76. In the early morning hours throughout the year and in the late evening hours in the summer, imports are used to fill the gap left by CSP storage. Electricity can be exported in the early morning hours, when Solar installations already produce but local demand has yet to reach its peak (due to still low air conditioning consumption).

Despite what its classification as a balancer might seem to indicate, Egypt exports throughout the average winter and summer day. Nevertheless it fits into the balancers group since exports are marginal compared to load overall, especially on winter afternoons. Even more important, exports enable Egypt to build enough Wind capacity to almost satisfy its load entirely with Wind during non-daylight hours in the summer. In the winter, on the other hand, Wind production exceeds the load during some hours of the day and thus is used for increased exports.

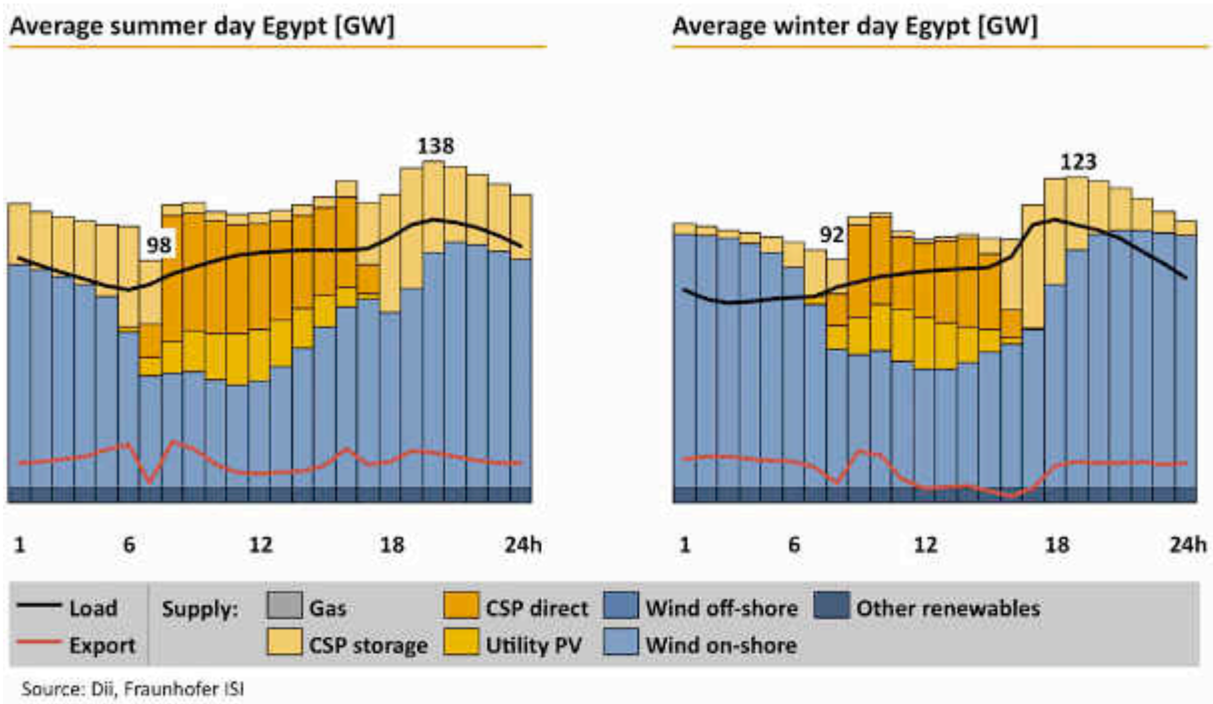


Figure 77: Daily and seasonal demand and supply in Egypt

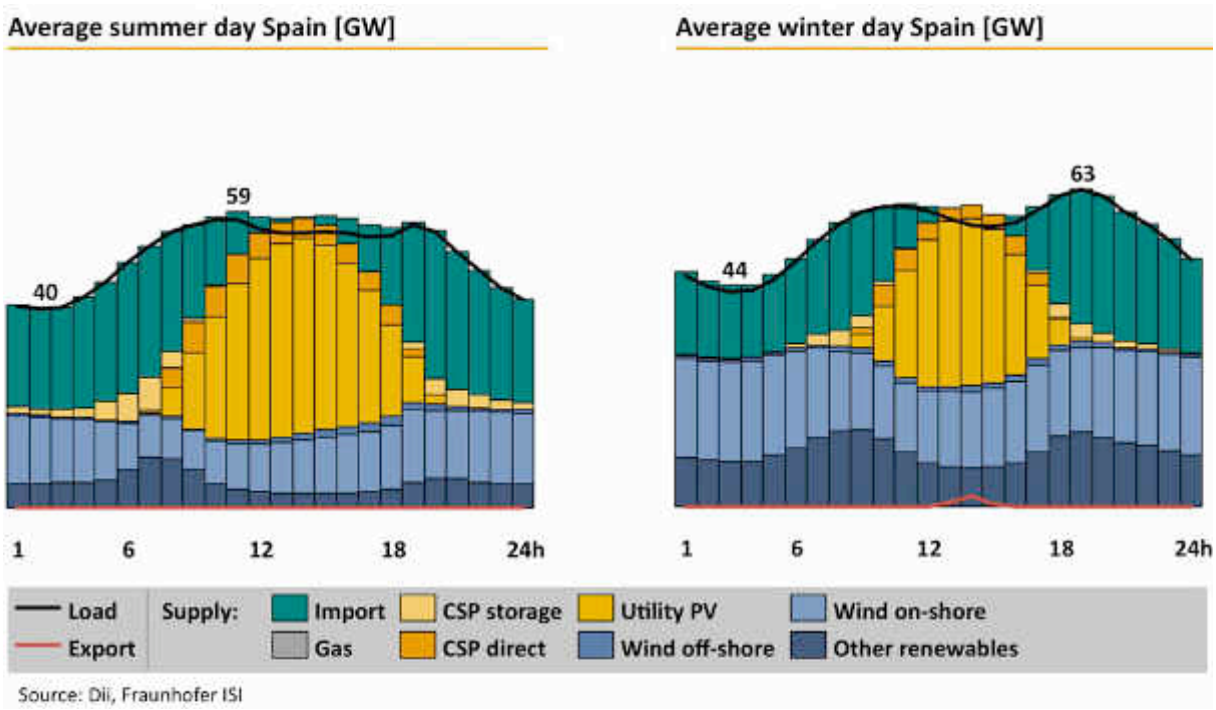


Figure 78: Daily and seasonal demand and supply in Spain

Spain, depicted in Figure 78, matches its load completely with domestic renewables during the slight load dip between morning and evening peaks. This is done with Utility PV and some CSP. Hydro and biomass production, on the other hand, is reduced at this time of day, but used during the morning and evening peaks. Except for Utility PV production during daylight hours, Spain uses imports to satisfy demand.

Tunisia's integration into the system works similarly to Spain's, except that Wind production is higher compared to load and suffices to cover load during a part of the non-daylight hours. Utility PV is used to fit the mid-day peak together with imports, thus leaving excess electricity to be exported during the middle of the day in the winter. The pronounced winter evening peak is covered with imports.

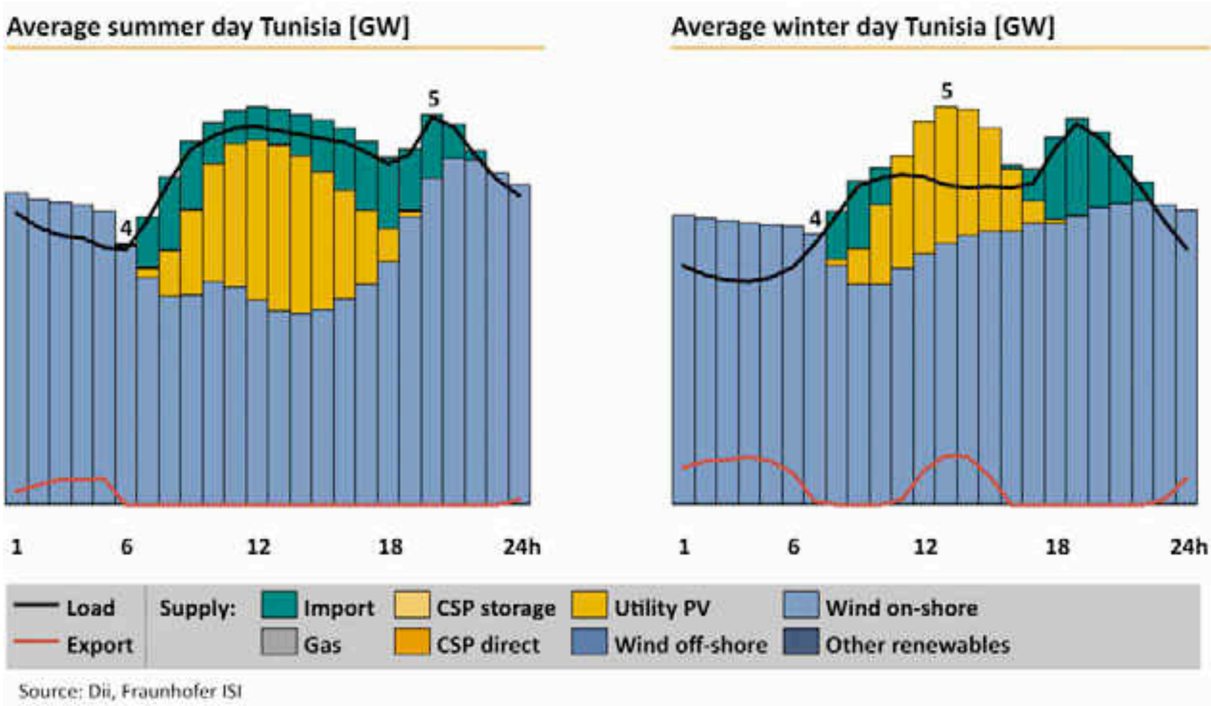


Figure 79: Daily and seasonal demand and supply in Tunisia

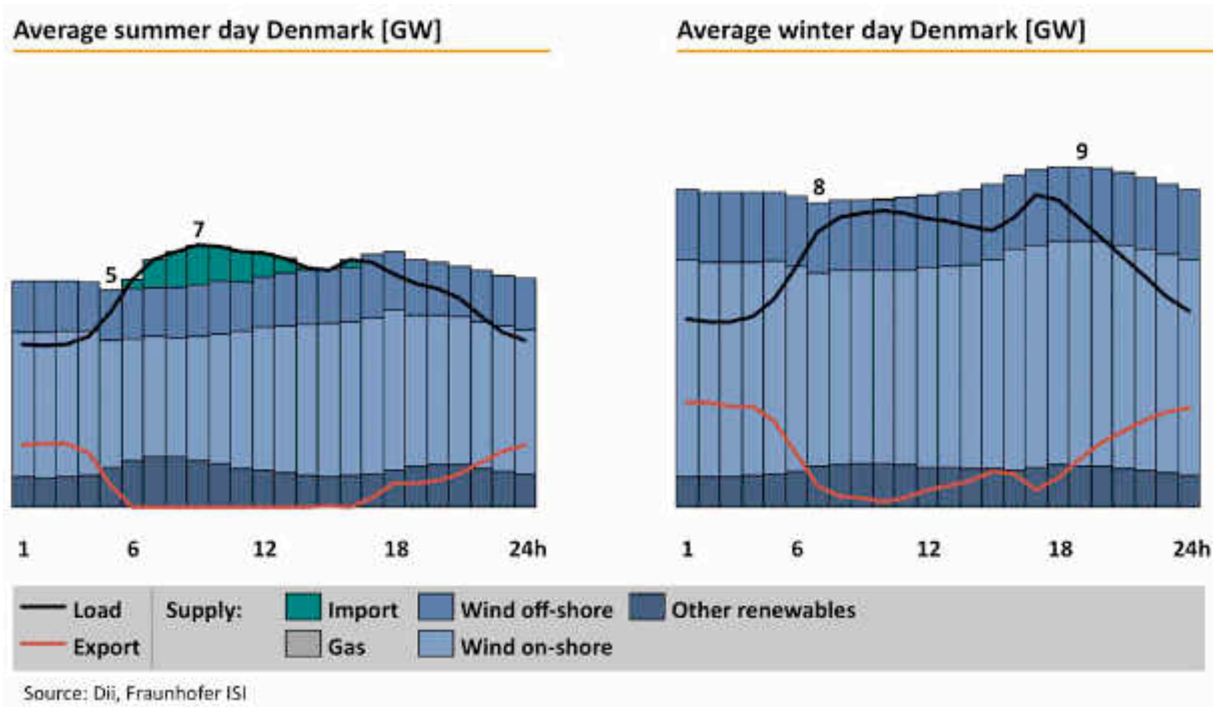


Figure 80: Daily and seasonal demand and supply in Denmark

Denmark produces more than enough power to satisfy domestic demand during most of the average winter and summer day, except for certain peak load hours during the late morning in summer. Since

Wind production is lower in summer than in winter and other renewables (mostly biomass) do not suffice to cover this peak, imports are used.

Syria and the UK are special cases, since they rely on imports during one season and export during the other season. While Syria imports in winter, the UK imports in summer, which again underlines the complementarity of MENA and Europe renewables.

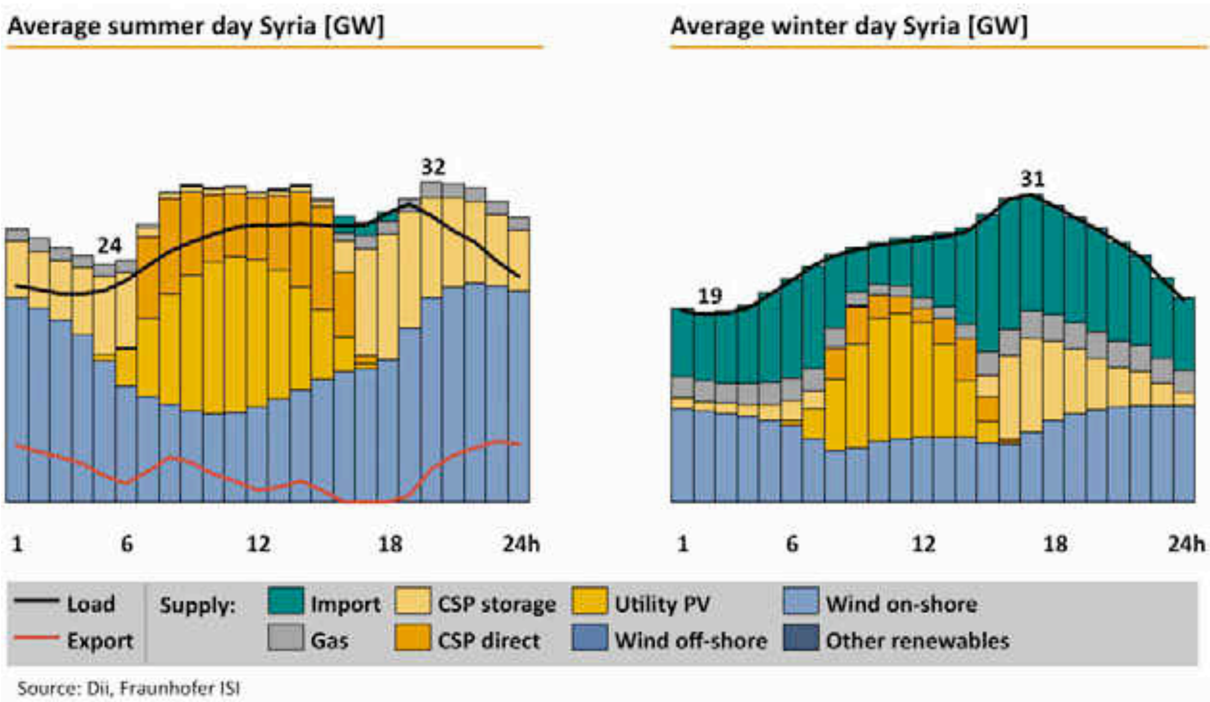


Figure 81: Daily and seasonal demand and supply in Syria

We first turn to Syria, which is an exporter during most of the average summer day and an importer throughout the average winter day. This is due to the fact that both wind and sun are scarcer in winter than in summer in Syria. System integration allows Syria to adapt to this situation and balance between the seasons without investing in generation assets that are only needed for half of the year.

We conclude the country analysis with the example of the UK. The UK relies on Wind power, which has much lower yield in summer than in winter in this part of EUMENA, see Figure 82. Therefore, in summer it generates power from gas and relies also on imports to meet non-valley loads. As we have seen before, the UK imports desert power that arrives from North Africa via France. Thus, the UK profits from the fit of strong domestic winter winds and sunny North African summers. The gas assets that the UK needs during summer to ensure its domestic supply are only partially needed for that purpose in winter, when wind production is strong. During winter, the UK exports power from gas and thus increases the utilization of these generation assets – a very good example of system synergies.

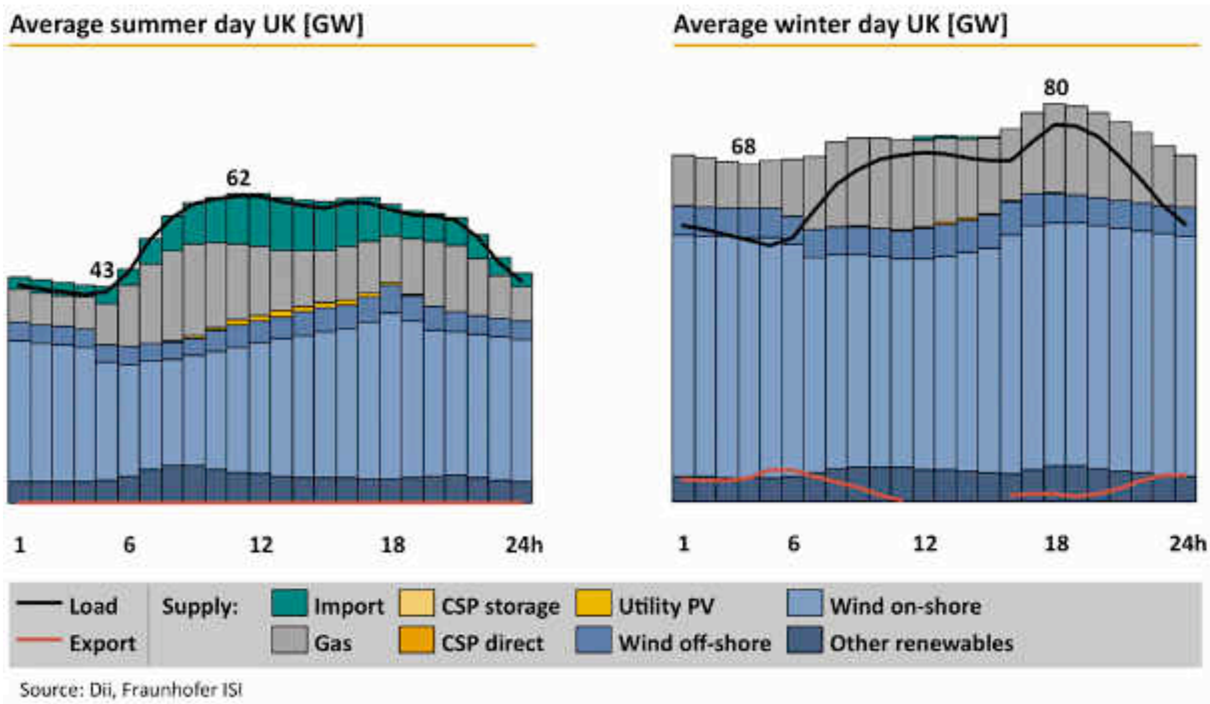


Figure 82: Daily and seasonal demand and supply in the UK

Having addressed the different country roles in an integrated power system, it becomes clear that such a system is heavily interlinked and offers advantages for all involved parties. This mutual reliance and interdependence is one of the reasons why an integrated sustainable power system enhances security of supply not only from a technical but also from a political point of view. In a power system based on 90% renewables, avoiding blackouts means ensuring that there are sufficient Solar and Wind resources to meet demand 24 hours a day 365 days a year. Given natural variations over time and space, such a requirement is more easily met in larger systems. As our analysis makes clear, system integration makes a sustainable power system not just more affordable but also more reliable. Both technical and political complementarities will result from the system integration required to supply desert power to EUMENA. We now turn to the political components of energy security and show how an integrated EUMENA system will encourage mutual reliance between all countries in the region.

3.6 Desert power enhances energy security across EUMENA

One of the most frequent criticisms of desert power focuses on energy security. Critics charge that desert power will make Europe “dependent” on unreliable suppliers of electricity. In fact, desert power will lead to greater energy independence and security for both MENA and Europe.

An integrated EUMENA system with desert power is something that will occur over a long range of time and will be part of a broader shift in the power sector; this section examines this transformation in greater detail.

3.6.1 Desert power and the paradigm change of renewable energy

The first step towards assessing the impact of desert power on the energy security of a country or region is establishing a method of comparison between two separate paradigms. Simply comparing the location of electricity generation unduly favors the current paradigm over a renewables-based paradigm. This is because today the fuels used in power generation – and not the power itself – are traded. In any renewables-based system, on the other hand, electricity will move across borders. As such, any meaningful comparison between the current, fuel-trading paradigm, and a future, electricity-trading one, will need to look beyond the place of generation and include the origins of all its components.

Of the fuels currently used in EU27 power generation, the majority – coal, uranium, gas and oil – rely heavily on imports from outside the EU27. Only renewables come overwhelmingly from domestic sources. Given this reliance on imported fuels for EU electricity generation today, simply comparing the location of electricity production would leave out crucial information: the actual origins of the fuels used.

To show the energy security effects of an integrated EUMENA power system, we compare countries' current self-supply rates with those in 2050. Current self-supply rates are based on the origin of fuels. In order to calculate current self-supply rates, we take the percentage of a fuel in a country's power mix and multiply it by the country's import share of that fuel[61]. This yields the overall power system external dependency for 2007[62]. It is then compared against the 2050 system, in which electricity, not the fuels for power generation, are exported and imported. As such, the self-supply rates are based on the location of electricity production and the origin of the gas used in the system (assumed to be 100% imported). For 2050, a country's gas consumption is subtracted from its self-supply rate[63].

The results of the comparison described above are shown in Figure 83. Far from making the EU27 more dependent on third country sources of electricity, desert power leads to higher overall self-supply rates in almost every country. The five largest EU economies all see higher, and in some cases significantly higher, self-supply rates. Germany's increases from 50% in 2009 to 56%; Italy's moves from 31% to 44%; Spain's jumps from 28% today to 69%; the UK's from 47% to 75%. France, which relies on imported uranium for its fleet of nuclear plants, goes from 14% today to 64% in 2050.

At first this process appears somewhat counterintuitive: why would importing desert power lead to higher European self-supply rates? The reason is, in fact, a key benefit of desert power: it facilitates the transition to a renewables-based power system that allows the EU to shift away from largely imported fossil fuels.

[61] Fuels reported as "other" are assumed to be 100% local for 2009, in order not to bias results in favor of the 2050 system

[62] Sources for origins of fuels and percentage of fuels in a national power mix: EC, EEA, Euratom

[63] Gas is assumed to be 100% imported, in order not to overestimate 2050 self-supply rates

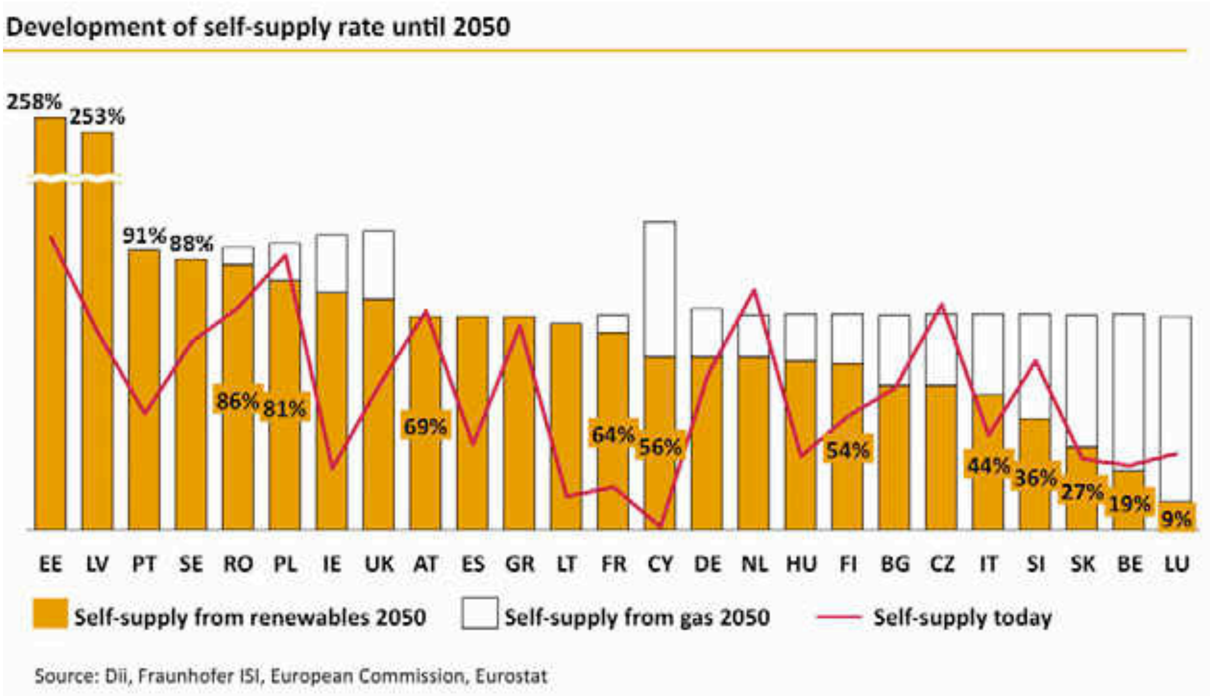


Figure 83: Overall self-supply rates of the power sector, 2009 vs. 2050[64]

3.6.2 EU-MENA interdependence

The portion of electricity exported from MENA to the EU27+2 remains secure from technical and political supply cuts, for a range of reasons. First, with a maximum share of 19% of electricity divided between three main suppliers (Morocco, Libya and Algeria), no supplier is in a position to exercise monopolistic influence over buyers.

These relatively low import shares of desert power encourage interdependence between MENA suppliers and EU buyers, rather than dependence of the latter on the former. Interdependence is the result of many factors. First, according to recent research[65], the overall losses caused by a supply cut in a desert power scenario would fall overwhelmingly on the MENA exporters rather than the European importers. Any cut longer than two to three hours would be significantly more costly for MENA suppliers than for the EU importers, while a short supply cut of less than two-three hours would inflict heavier costs on the EU than MENA but would cause such long-term reputational damage as to render this cost "savings" irrelevant.

Second, Europe's dependence on foreign sources of energy tends to make Europeans overlook the fact that regions such as MENA are equally or more dependent on foreign (including European) sources of food imports, foreign investment, political support and, if they are a net energy exporter, revenues. Such trends are likely to continue and even increase in the coming decades. MENA, for example, is already a net food importer, and is projected to grow increasingly dependent on the

[64] Please note that, while a 70% minimum self-supply rate has been imposed, this refers to the location of electricity production. As such, certain countries may be below this, since their gas is assumed to be 100% imported in order not to distort results in favor of the DP2050 system

[65] Lilliestam, J., Ellenbeck, S., *Energy security and renewable electricity trade – Will Desertec make Europe vulnerable to the "energy weapon"?,* (2011)

outside world (including Europe) for a significant portion of its food. Combined with reliance on Europe for desert power revenues, it is clearly not in these countries' interests to use energy exports as a political weapon – particularly because, given their low share of the overall EU electricity supply, the impact would be limited due to EU countries' abilities to simply replace capacity from unreliable with either local renewables or gas production.

3.6.3 Europe's insurance policy: gas back-up capacities

Indeed, Europe can largely protect itself against MENA supply cuts and still enjoy the benefits of an interconnected system, since gas back-up fully covering MENA imports would only cost about 10% of the system cost savings gained by interconnection. If Europe were to opt for such an "insurance" policy against potential MENA supply cuts, it would not only benefit from savings and other positive effects of an interconnected EU-MENA system; it would also further reduce the risk of a supply cut in the first place, by removing any possible incentive for an exporter to cut supplies.

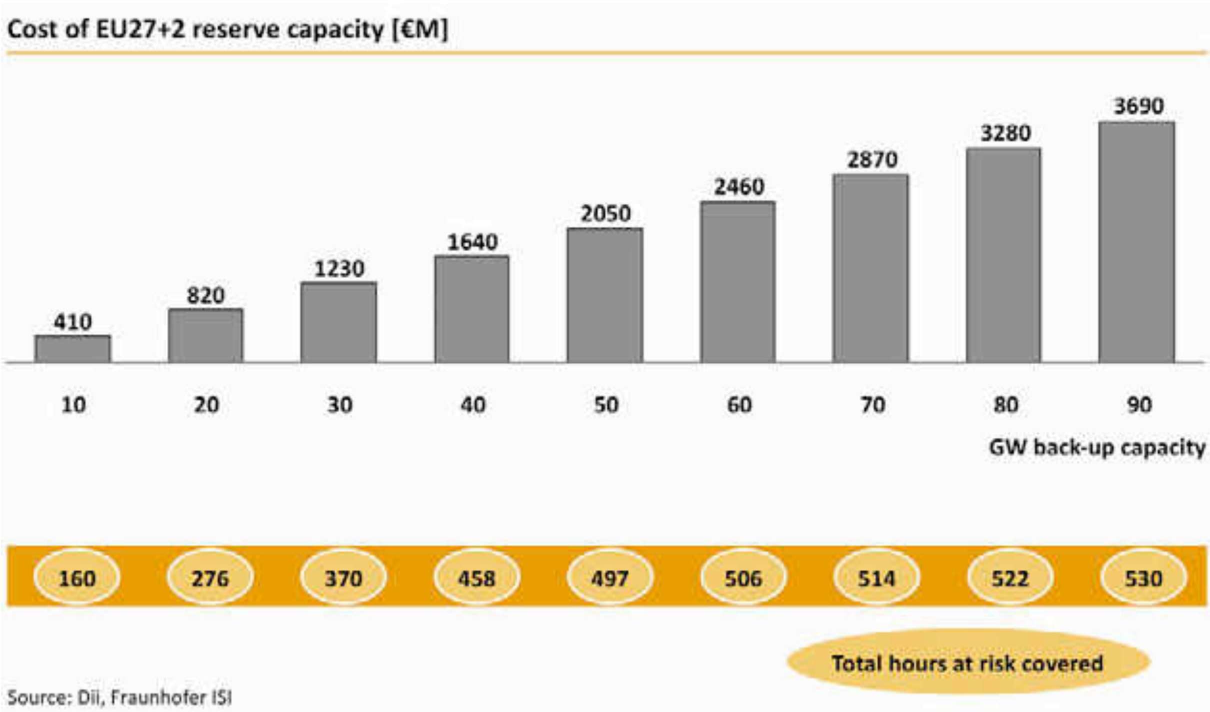


Figure 84: Costs of EU27+2 reserve capacity (€M)

We define an hour at risk for the EU27+2 as an hour during which imports from MENA exceed idle gas capacities in the EU27+2. The capacity at risk in such an hour, therefore, is equivalent to imports from MENA minus the idle gas capacities. The maximum capacity at risk during the course of the year is 88GW. If the EU27+2 were to decide to cover this with 90GW additional gas turbine capacity, it would need to spend approx. 10% of the system cost savings from EUMENA integration, or approx. €3.7bn. per year[66]. With only 60GW of reserve capacities, costing €2.5bn. per year, the EU27+2 could cover 95% of its supply from MENA, i.e. 506 out of the 530 hours, see Figure 84.

[66] This amount refers to 90GW of additional OCGT capacity

Reserve capacity requirements depend on perceived risk and costs incurred. As such, it is impossible to predict today whether, when approaching 2050, the EU27+2 would decide that covering 506 hours of blackout risk is worth €2.5bn. p.a. or indeed whether moving to 24-hour blackout coverage is worth an additional €1.2bn. p.a. The important point to make today is that, whatever level of protection Europe chooses, it is both possible and affordable – and does not detract from the overall savings or desirability of introducing desert power to Europe's power system.

3.6.4 Desert power as a long-term, systemic transformation

Some speculate that trading electricity is less safe than trading fossil fuels, because the former cannot be stored while the latter generally can. This is essentially an argument in favor of the status quo: it overestimates the risks of a new paradigm while discounting the role that institutional structures and long-term changes play in the stability of any system. In particular, it overlooks the crucial fact that the development of renewable energy trading between Europe and MENA will be a gradual, long-term process; it will not occur overnight. Such long-term processes encourage and lead to the development of institutional frameworks that stabilize the system and protect the interests of both parties.

It is important to note that if desert power supplies up to 19% of the EU27+2's electricity, it will likely be accompanied and stabilized by an institutional framework that is different, and even unimaginable, from today's perspective. In the shorter term – today and in the first 10-20 years of building an integrated EUMENA power system – the limited import amounts would not affect Europe's energy security.

3.6.5 A diversified power supply for EUMENA

Desert power will contribute to a diversified supply of power for Europe; it will not become its dominant source of power. In other words, it will never occupy the position that Russia holds today – supplying 30-35% of Europe's oil and gas, far ahead of competing sources. Instead, it will be comparable to the far more diversified portfolio of EU uranium suppliers – where there is true competition among several suppliers, each occupying 20% or less of the market, and where the influence of each supplier is limited by the diversification of the market.

In brief, the perception that an interconnected system will increase energy security risks in the EU is mistaken. Instead, MENA electricity import diversifies the EU's energy supply basis, facilitates the economical realization of a system that actually leads to higher self-supply rates for many key countries, and thus, on balance, contributes to greater energy security.

The energy security effects on MENA countries, meanwhile, are highly beneficial. For current net exporters like Saudi Arabia, Libya and Algeria, it represents a chance to diversify their power portfolio for both local consumption and export. For countries like Morocco and Egypt, desert power is a game changer, since it will make them (like their neighbors) energy independent while allowing them to profit from a MENA-wide export market worth up to €63bn. per year.

4 Perspectives on Desert Power for EUMENA

Given the difficulty of predicting conditions in 2050, it is essential to see how a variety of different scenarios affect the benefits of desert power discussed in Chapter 3. What if, for example, grid extensions are delayed or substantially limited? What if countries continue using nuclear power as a way to achieve low carbon electricity supply? How would the use of CCS in the EUMENA region impact desert power? What if the carbon emission reduction targets for 2050 are delayed or become less ambitious? And what will happen if countries ignore climate change and abandon efforts to limit carbon emissions entirely? These are just a few examples of how the world in 2050 could differ from the main scenarios analyzed in this study.

To account for such uncertainty, we have complemented our analysis of the main scenarios with a total of 16 so-called sensitivity scenarios, depicted in Figure 85. Each of these sensitivities provides a different perspective on what the world could look like in 2050. That said, this chapter is not about judging the desirability or likelihood of the respective perspectives. Instead, it investigates the uncertainties inherent in a 2050 study by analyzing the impact of input changes on the study's findings. This approach is meant to provide decision makers with the information needed to evaluate a range of circumstances.

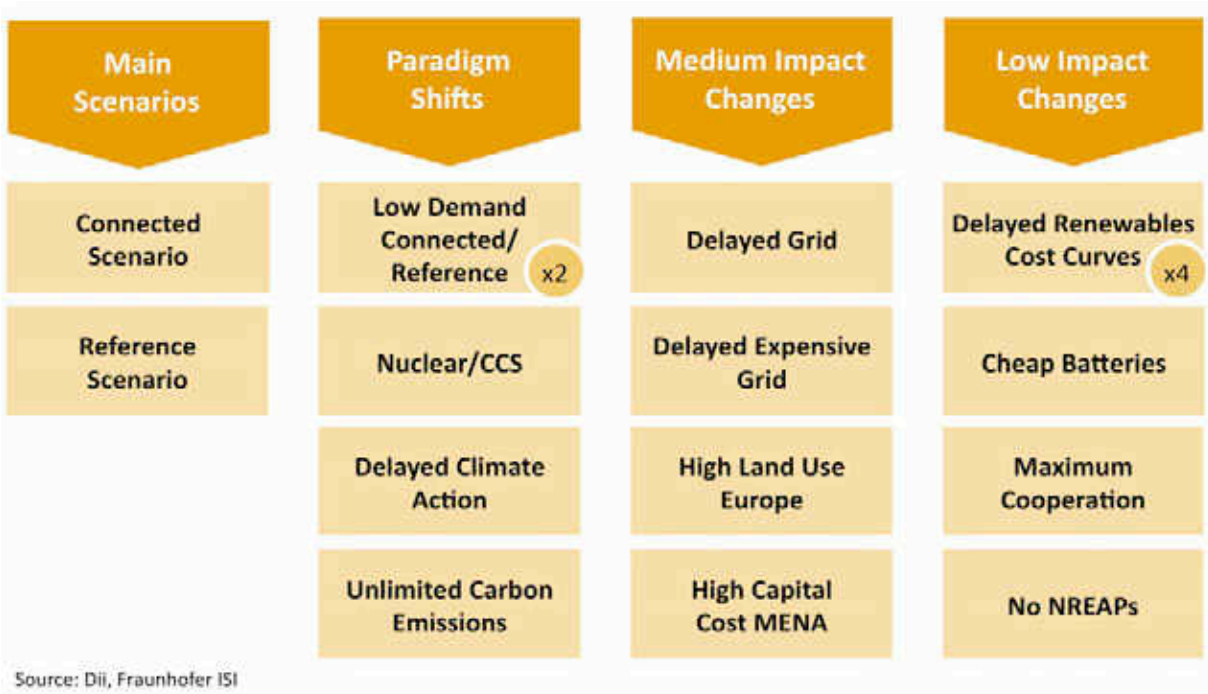


Figure 85: Sensitivities analyzed

The perspectives have been clustered into three categories. Paradigm Shifts describe a world in 2050 that is fundamentally different from the main scenarios – whether in terms of electricity demand (e.g. due to the success of energy efficiency measures), climate action or the technologies available for carbon emission reductions. The other perspectives all remain within the same fundamental framework of demand, carbon emission cap and technologies, and examine different outcomes within this framework. They have been clustered according to their impact on the value of desert power.

The full optimization procedure performed for the main scenarios has been applied to each of the 16 perspectives. In each of these perspectives, we apply different input parameters (representing changed conditions) to the model and allow connections to be built according to the same criteria as in the Connected and Reference Scenarios. The key measure used to illustrate the impact of a given perspective on the value of desert power is the amount of grid capacities (in GW_{NTC}) and power flows (in TWh) across the Mediterranean (and between Syria and Turkey). These amounts are then compared to the Connected and Reference Scenarios, thereby making it possible to examine the effect of different circumstances on the value of desert power for EUMENA.

The general conclusion from this extensive scenario analysis is that EUMENA system integration is beneficial to both MENA and Europe under all perspectives. We now turn to a thorough explanation of the assumptions adopted for all the perspectives and then provide details of the results.

4.1 Perspectives definitions

The assumptions for the Connected and the Reference Scenarios, as well as the corresponding low demand perspectives, have been explained in detail in Chapter 2.

Scenarios	Description
Connected Scenario	One power system, NREAPs as lower limits, 70% lower limit on self-supply
Reference Scenario	Two power systems, no self-supply limit
Low Demand Connected	Low demand, no self-supply limit
Low Demand Reference	Low demand, two power systems, no self- supply limit
Nuclear/CCS	Nuclear/CCS allowed, higher fuel prices, no self-supply limit
Delayed Climate Action	More carbon emissions, higher fuel prices, no self-supply limit
Unlimited Carbon Emissions	No carbon emission limit, higher fuel prices, no self-supply limit
Delayed Grid	Max $20GW_{NTC}$ per connection, 70% lower limit on self-supply
Delayed Expensive Grid	Grid cost +50%, max $20GW_{NTC}$ per connection, 70% lower limit on self-supply
High Land Use Europe	Higher land use Europe, no self-supply limit
High Capital Cost MENA	WACC MENA 9%, no self-supply limit
Delayed Cost Curve PV	Utility PV cost 860€/kW (20% less cost reduction), no self-supply limit
Delayed Cost Curve CSP	CSP cost 2600€/kW (20% less cost reduction), no self-supply limit
Delayed Cost Curve Off-shore Wind	Wind on-shore cost 960€/kW (20% less cost reduction), no self-supply limit
Delayed Cost Curve On-shore Wind	Wind off-shore cost 1670€/kW (20% less cost reduction), no self-supply limit
Cheap batteries	Cheap batteries, no self-supply limit
Maximum Cooperation	No self-supply limit
No NREAPs	No NREAPs, no self-supply limit

Table 8: Overview scenario definitions

Table 8 summarizes the key characteristics of the Connected Scenario and how each perspective differs from the standard assumptions of the Connected Scenario. For some scenarios, additional information is needed to complete these brief definitions.

In the case of Unlimited Carbon Emissions, Nuclear/CCS and Delayed Climate Action, higher fossil fuel prices have been assumed, based on the IEA Current Policy Scenario from the World Energy Outlook 2011. The prices used are €105 per barrel for oil, €9.8 per mmBTU for gas and €89 per tonne of coal. Nuclear fuel rods cost 3.1€/$MWh_{thermal}$ in the Nuclear/CCS scenario.

Nuclear and CCS are considered alternatives to renewables in terms of low carbon emissions power generation. Therefore, the cost assumptions used in the Nuclear/CCS perspective have been chosen to reflect a conservative choice in assessing their impact on the value of desert power. For CCS technologies, we have assumed a 100% increase of investment and fixed O&M cost, and an increase of 150% in variable O&M cost. Furthermore, a decrease in efficiency of nine percentage points was assumed. The carbon emissions of power plants are reduced by 90% when combined with CCS technology. The LCOE of the conventional power plants equipped with CCS increase by approx. 50-80%.

Technology 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	O&M var. [€/MWh]	Net average efficiency	Lifetime
CCGT	750 €	11.1 €	2.7 €	60%	30a
Coal	1450 €	34.5 €	1.5 €	48%	40a
Lignite	1500 €	45.0 €	1.5 €	47%	40a
CCGT CCS	1500 €	22.2 €	6.8 €	51%	30a
Coal CCS	2900 €	69.0 €	3.8 €	39%	30a
Lignite CCS	3000 €	90.0 €	3.8 €	38%	40a

Table 9: Conventional and CCS fossil fuel technology parameters

For nuclear, the parameters are shown in Table 10. This set of parameters leads to LCOE for nuclear of just below 60€/MWh. Nuclear is only allowed in countries that do not already have a declared nuclear phase out. In other words, it is not an option in Austria, Cyprus, Denmark, Germany, Greece, Ireland, Italy, Luxembourg, Malta, the Netherlands, Portugal and Switzerland.

Technology 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	Net average efficiency	Lifetime
Nuclear	4000 €	92.0 €	35%	40a

Table 10: Nuclear input parameters

The carbon limit in the Delayed Climate action is 0.97Gtonnes and the Cheap Battery Scenario uses the parameters from Table 11.

Technology 2050	Investment [€/kW]	O&M fix [€/kW p.a.]	Net average efficiency	Lifetime
Cheap battery (~50MW, 8h storage)	500 €	5 €	80%	20a

Table 11: Cheap Battery input parameters

Table 12 summarizes the investment assumptions used in the Delayed Cost Curve Scenarios for the four main Solar/Wind technologies.

Technology cost sensitivities	2011 estimate [€/kW]	2050 estimate [€/kW]	Change from 2011 to 2050 [€/kW]	Sensitivity cost [€/kW]
CSP with 8h TES	5000 €	2000 €	3000 €	2600 €
Utility PV	1500 €	700 €	800 €	860 €
Wind on-shore	1200 €	900 €	300 €	960 €
Wind off-shore	3000 €	1340 €	1660 €	1670 €

Table 12: Input parameters Wind/Solar technology investment for sensitivities

Finally, for the High Land Use Europe perspective, it is assumed that far more land can be used for renewables – up to 75% of all crop land and 20% of all forests can be used for on-shore Wind, compared to the standard 5% and 8% respectively.

4.2 Perspectives overview

In this section we provide an overview of the key results for all perspectives, which we divide into two parts: the impact of the perspectives on EUMENA-wide system integration and on system cost.

4.2.1 Perspectives on EUMENA-wide system integration

The value of desert power for EUMENA becomes particularly clear in scenarios with a carbon emission cap: in all such scenarios, MENA net exports to Europe are at least 300TWh[67].

Even in the Unlimited Carbon Emissions scenario, grid interconnection remains favorable. Under this perspective, which is dominated by coal and generates carbon emissions around 2.5 times greater than today, 35GW_{NTC} of grids are built between south and north, and MENA exports almost 70TWh net to Europe, as shown in Figure 86.

[67] As mentioned in Section 2.2, referral of demand, supply and related parameters to an annual time horizon will not be explicitly stated but is to be understood unless otherwise stated

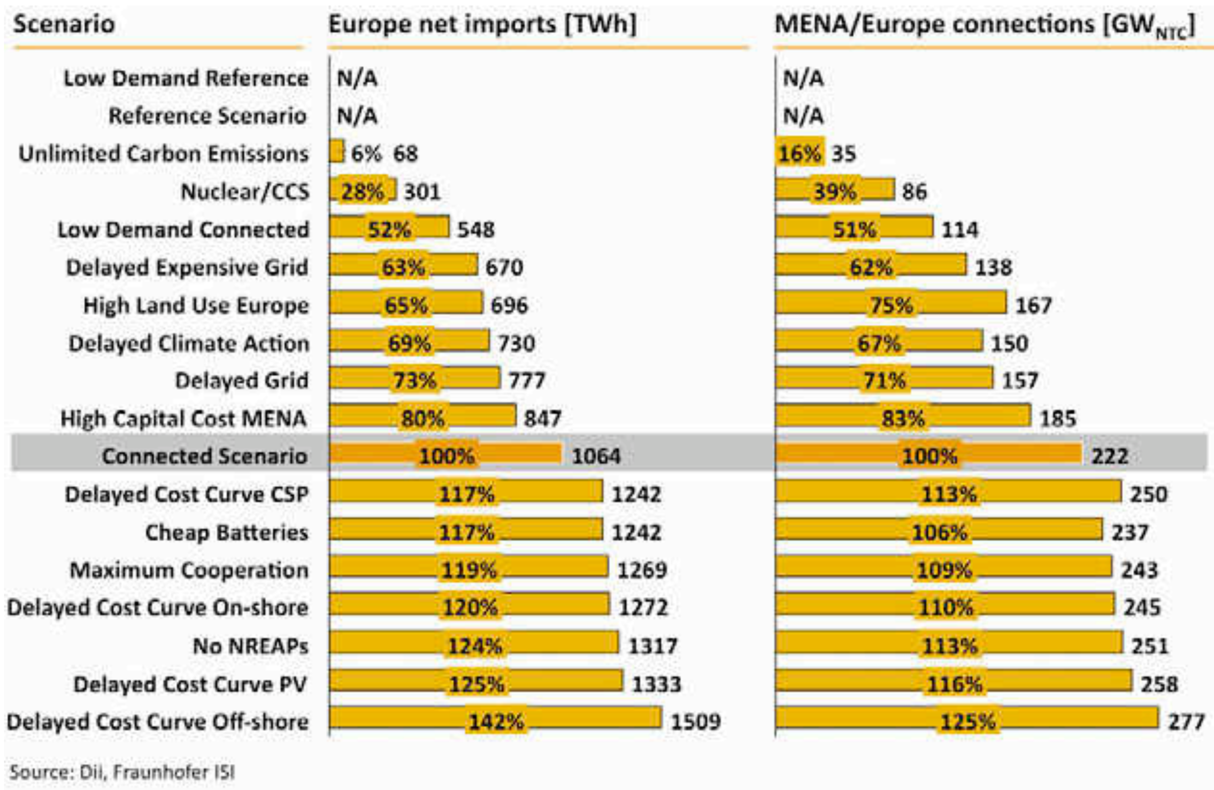


Figure 86: Summary MENA net exports to Europe and MENA/Europe interconnectors

There is only one other scenario with less than 500TWh of imports: Nuclear/CCS. In this scenario, 300TWh of MENA net exports arrive in Europe through 86GW$_{NTC}$ of transmission lines across the Mediterranean. The Nuclear/CCS scenario has a 55% RES-E share, as can be seen in Figure 87.

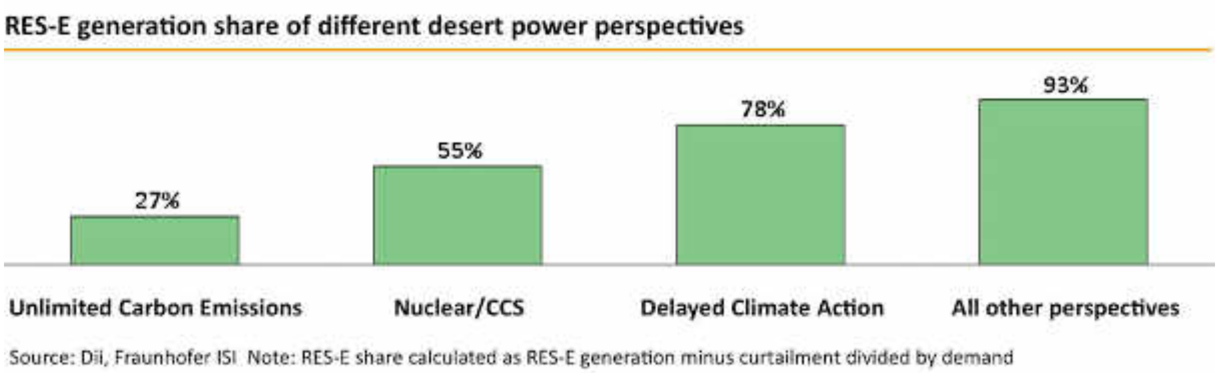


Figure 87: RES-E shares of different scenarios

All other scenarios result in more than 500TWh of MENA net exports to Europe – the same order of magnitude as the annual electricity demands of Europe's biggest economies today. In other words, scenarios with approx. 40% less demand (Low Demand), Delayed Expensive Grids, High Land Use in Europe, and Delayed Climate Action all lead to significant MENA exports to Europe.

4.2.2 Perspectives on system cost

While the different perspectives show a case to be made for desert power in every scenario, their impact on overall system cost varies, as depicted in Figure 88.

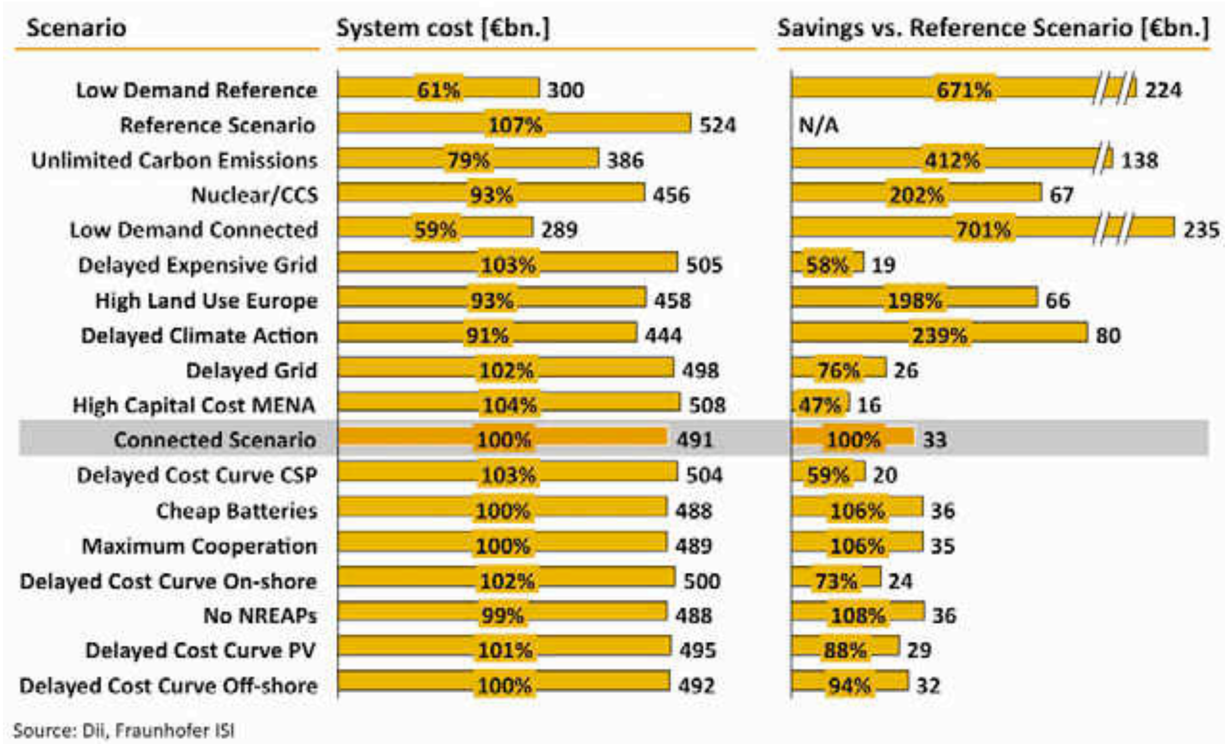


Figure 88: System cost and system cost savings sorted by MENA net exports to Europe

The low demand scenarios, with 39% less demand than the high demand cases, achieve the highest system cost savings by a wide margin. In the Low Demand Connected case, system costs are €289bn., or a 45% cost reduction over the Reference Scenario and 41% over the Connected Scenario. The low demand scenarios will be analyzed in some detail in Section 4.3, since they have the greatest impact on the value of desert power.

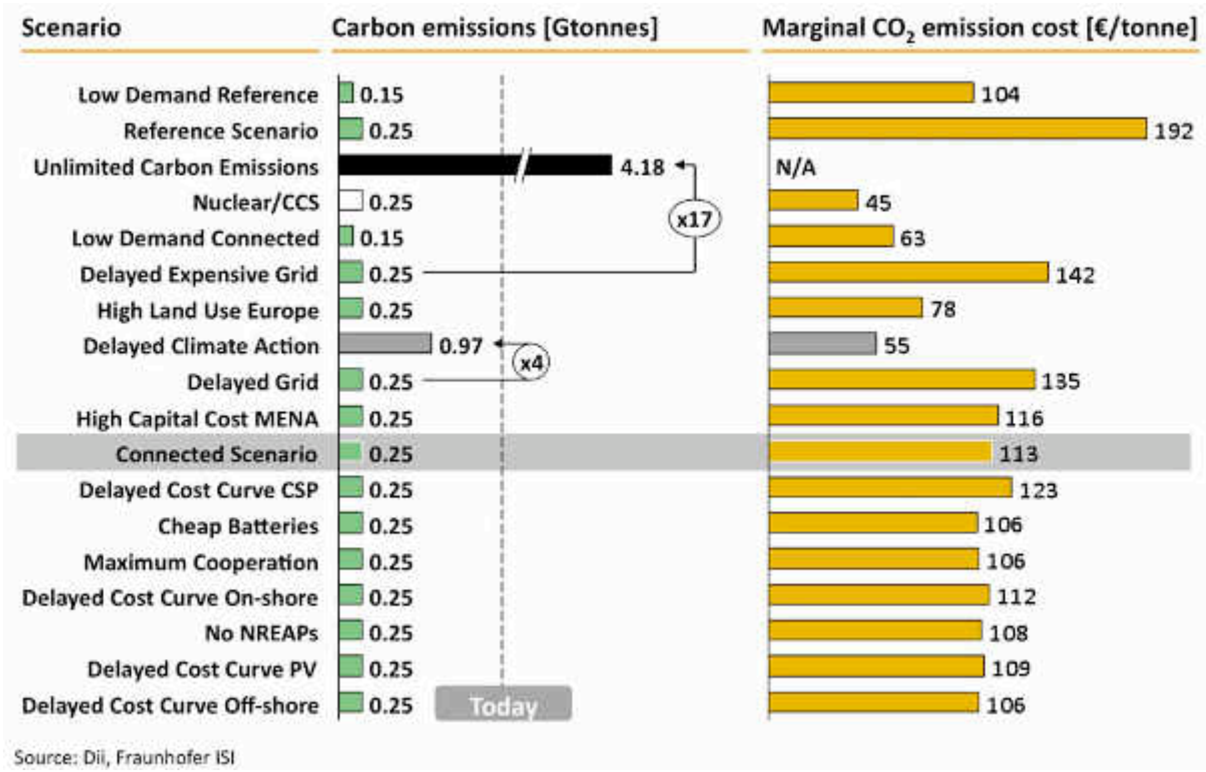


Figure 89: Carbon emissions and marginal cost of carbon emission reduction overview

The third highest system cost reduction compared to the Connected Scenario, of 21%, occurs in the Unlimited Carbon Emissions Scenario, but at a staggering environmental cost. Carbon emissions are 2.5 times today's rate and 17 times the rate of the Connected Scenario, shown in Figure 89. Cost savings come at the expense of high additional carbon emissions, with cost savings of only €26 for each additional tonne of CO_2 emissions compared to the Connected Scenario, see Figure 90.

The low demand scenarios are not only less expensive, but also lead to lower carbon emissions of 0.15Gtonnes, instead of the 0.25Gtonnes in the Connected Scenario. In other words, energy efficiency combined with renewable energy can deliver a clean power system that is much more economical than any power system based on coal and high consumption.

Delayed Climate Action leads to cost reductions of €80bn. p.a. compared to the Reference Scenario, and €47bn. compared to the Connected Scenario, but with 0.72Gtonnes higher carbon emissions. Thus, each tonne of additional carbon abatement costs €110 on average in the Reference Scenario, but only €65 in the Connected Scenario. It is important to note that the cost advantage of Delayed Climate Action compared to the Reference Scenario not only comes from the relaxed carbon emission limit. Instead, cost savings are also achieved by relying on 730TWh of net desert power exports from MENA to Europe in a system with a RES-E share of 78%. Thus, even if the decarbonization process takes longer, EUMENA power system integration remains of great value in facilitating the transition to a decarbonized electricity mix.

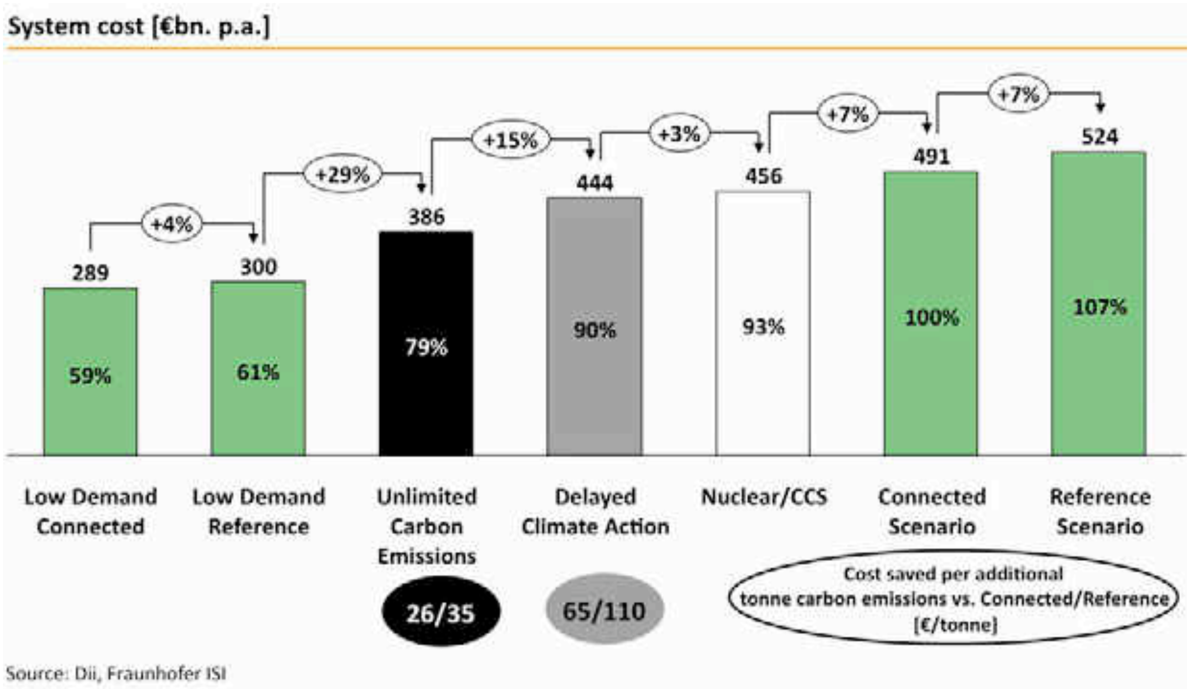


Figure 90: System cost of selected scenarios

The next order of magnitude in system cost savings occurs with the High Land Use Europe and the Nuclear/CCS Scenarios. They lead to cost savings of €66bn. and €67bn. respectively over the Reference Scenario, and to €33bn. and €34bn. respectively over the Connected Scenario, see Figure 88. Both scenarios still rely on significant exports of desert power from MENA to Europe: High Land Use Europe relies on 696TWh of MENA net exports, while the Nuclear/CCS scenario includes 301TWh of MENA net exports to Europe.

The RES-E share of the Nuclear/CCS scenario, at 55%, is much lower than in the main scenarios. Half the €67bn. cost advantage of Nuclear/CCS over the Reference Scenario can be achieved by system integration alone, i.e. without a massive build-up of technologies relying on non-renewable resources. It should also be noted that neither the availability nor long-term cost of waste disposal has been taken into account for nuclear and CCS; taking both into account could lead to higher system costs for Nuclear/CCS. That said, this scenario was not intended to provide an assessment of the technologies' advantages and disadvantages, but rather to compare them with desert power. It clearly shows that, even based on a conservative analysis of their costs, desert power is valuable in combination with Nuclear/CCS.

The scenarios examining the effects of Delayed (Expensive) Grids and a persistent difference in the cost of capital between Europe and MENA (High Capital Cost MENA) lead to reduced amounts of desert power imports, but do not save system cost. Delayed Grids reduce desert power imports to 777TWh and the scenario is €7bn. p.a. more expensive than the Connected Scenario. Delayed Expensive Grids reduce desert power imports only slightly more to 730TWh but lead to an additional €7bn. p.a. of system costs compared to Delayed Grids only. High Capital Cost MENA leads to 847TWh of imports but entails €17bn. p.a. in higher costs than the main Connected Scenario.

Finally, the seven scenarios examining the impacts of Maximum Cooperation between countries, Delayed Cost Curves of renewables technologies, No NREAPs in Europe, and the availability of Cheap Batteries all have a minor effect on system cost and increase desert power imports by 17-42%.

In the remainder of this chapter we analyze the reasons behind the changed outcomes for the most important perspectives described above.

4.3 Benefits of low demand

Among the various sensitivities analyzed, the Low Demand Connected Scenario has the lowest overall costs. Indeed, with lower costs than the Unlimited Carbon Emissions Scenario, it demonstrates that greater energy efficiency is the most effective way to overall cost savings irrespective of the amount of carbon emissions. The Low Demand Connected Scenario also shows that desert power is beneficial even with modest demand growth in MENA and Turkey, and with no demand growth in the EU27+2. The low demand in this scenario could result from a range of potential developments in energy consumption in the coming decades. Such potential developments include the implementation of energy efficiency measures, energy-efficient/generating buildings (especially with regard to the electricity need for heating/air-conditioning) and the expansion of Distributed PV, possibly in combination with decentralized storage. All of these enable consumers to consume their "own" electricity and thus reduce demand for power from the transmission grid. This scenario does not assume a given self-supply rate.

The Low Demand Connected Scenario presents several benefits compared to high demand. 39% less demand yields cost savings and capacity reductions of 41%, i.e. a reduction from 3325GW in the Connected Scenario to 1944GW in the Low Demand Connected Scenario. Approx. 550TWh net are exported from MENA to Europe, which corresponds to 14% of European electricity demand and to 49% of MENA electricity demand.

The generation mix in this scenario includes more than 52% Wind, of which 48% on-shore and 4% off-shore, and 19% Solar technologies, of which 11% CSP and 8% Utility PV, as shown in Figure 91.

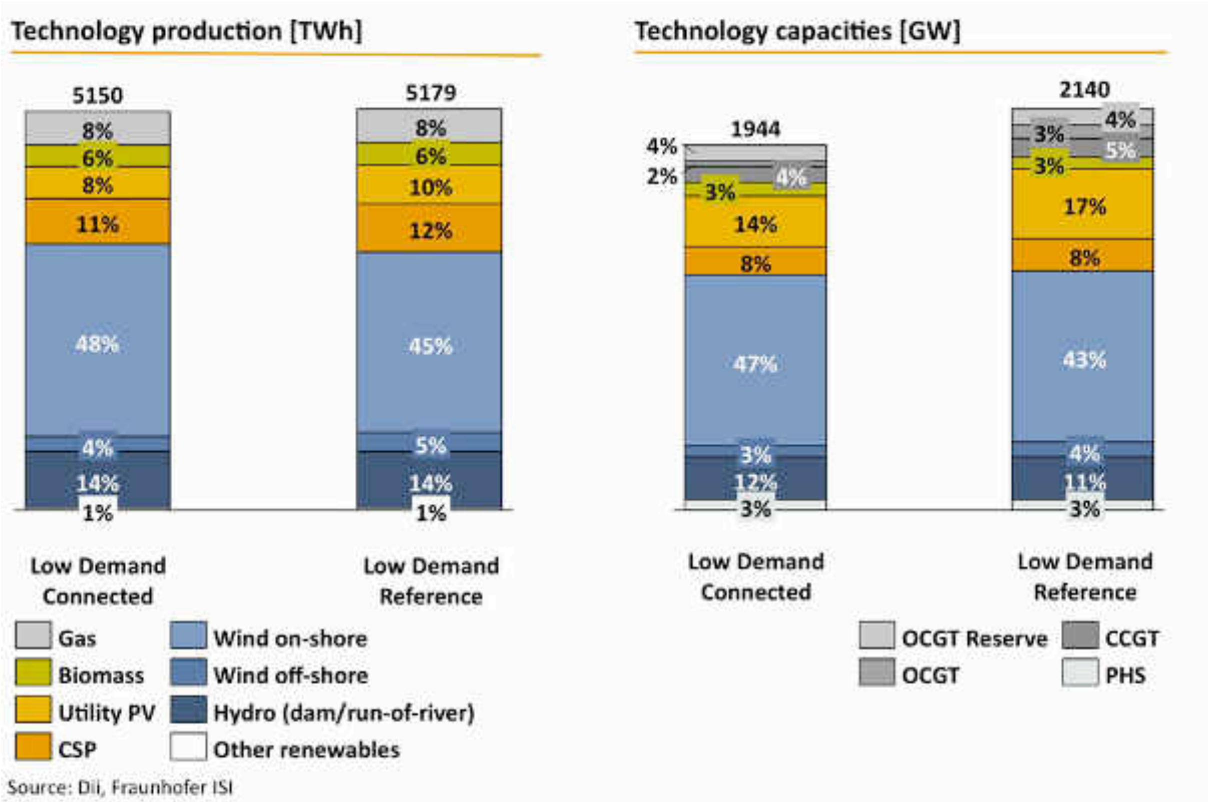


Figure 91: Low demand production and capacities by technology

Since a carbon emission cap with the same specific carbon emissions per MWh demand is applied, the share of conventional technologies in the mix is 8%. All conventional power in the mix comes from gas power plants due to this strict carbon emission cap. The shares of hydro, biomass and other renewables technologies in the low demand case are higher, since their production is fixed exogenously independently of demand. They account for approx. 22% of production, of which 14% hydro, 6% biomass and 1% other renewables technologies.

The difference in generation between the connected scenarios with high and low demand consists mainly in additional power production from Wind and CSP, see Figure 92. The additional electricity from gas with high demand is almost exclusively used in winter. The Low Demand Reference Scenario leads to less Wind production, more Utility PV and a slight increase of CSP compared to the Low Demand Connected case, as shown in the right graph of Figure 92. This is a notable difference between the low and the high demand case. In the latter, CSP generation is significantly reduced from the Connected to the Reference Scenario. The reason for this difference is that, with high demand, it is most economic for Europe to use CSP with storage from MENA for its balancing. When demand is lower, Europe relies less on this option.

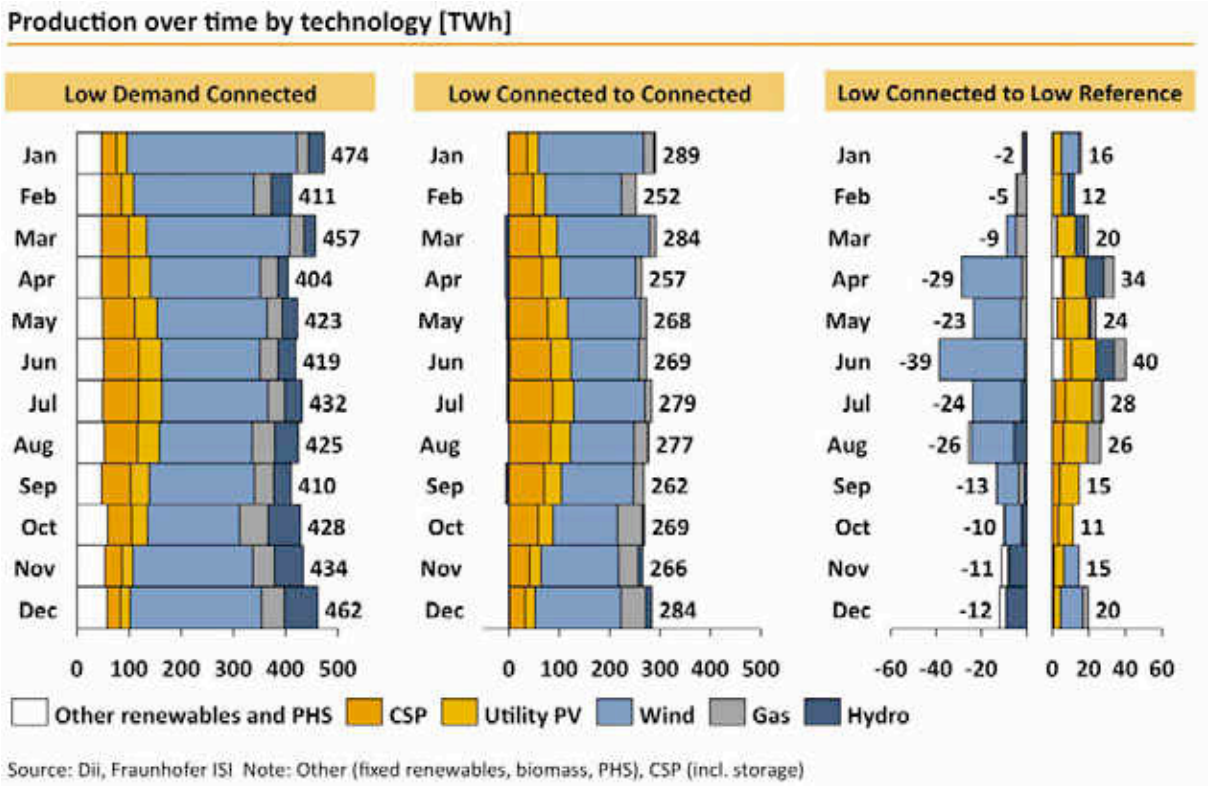


Figure 92: Monthly generation Low Connected/Reference and Connected Scenario

Just as important, the low demand case requires approx. 47% less grid capacities than needed with high demand, as depicted in Figure 93.

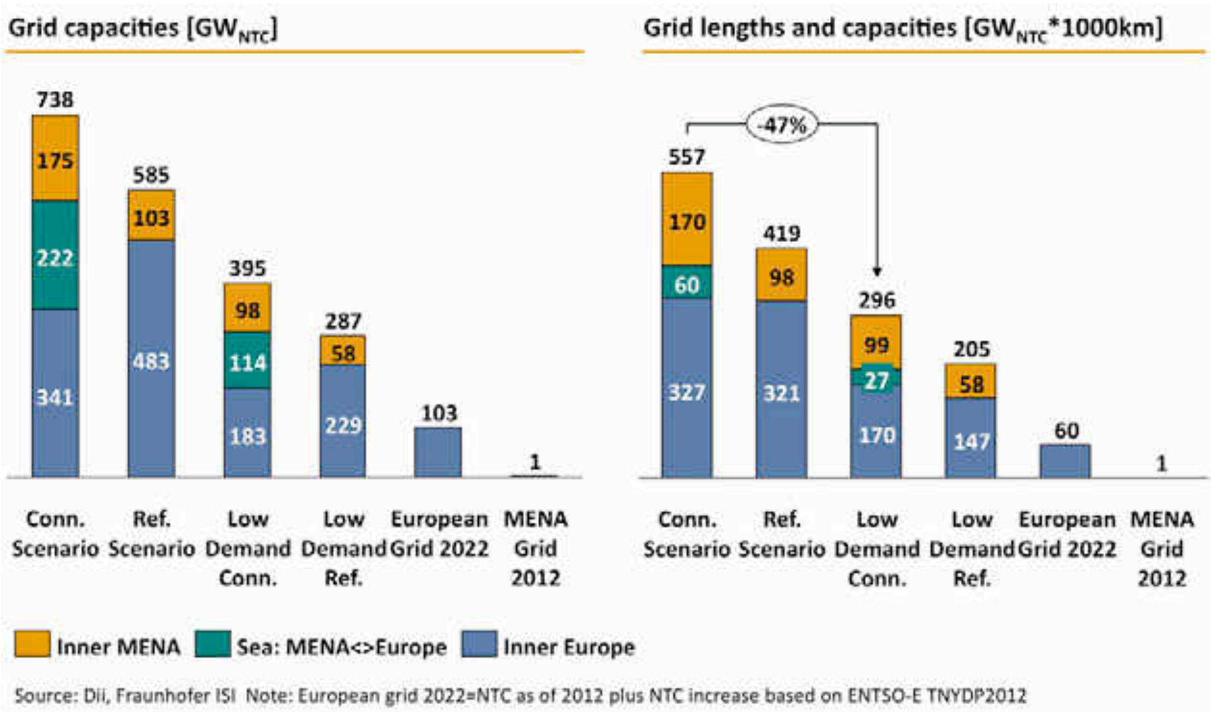


Figure 93: Grid capacities low demand

This is an important advantage in facing the public acceptance issues of building transmission infrastructure, since it would prevent the creation of extremely large transmission corridors in Europe. Indeed, only a few lines in Europe exceed $5GW_{NTC}$ in this scenario, see Figure 94.

Approximately $91{,}000GW_{NTC}$*km more are needed in the Low Connected vs. the Low Reference Case, of which $23{,}000GW_{NTC}$*km in Europe. The proportion of installations and south/north interconnectors, meanwhile, is similar to the high demand scenario, see Figure 94.

In terms of investments in 2050, the Low Demand Connected Scenario leads to savings of €168bn. of investments into power plants, of which €138bn. in Solar and Wind and €30bn. in gas, compared to the Low Demand Reference Scenario. The required transmission investments increase by €84bn. in the Connected Scenario. Taking generation and transmission into account, €84bn. less investment is required in the Low Demand Connected Scenario than in the Low Demand Reference Scenario.

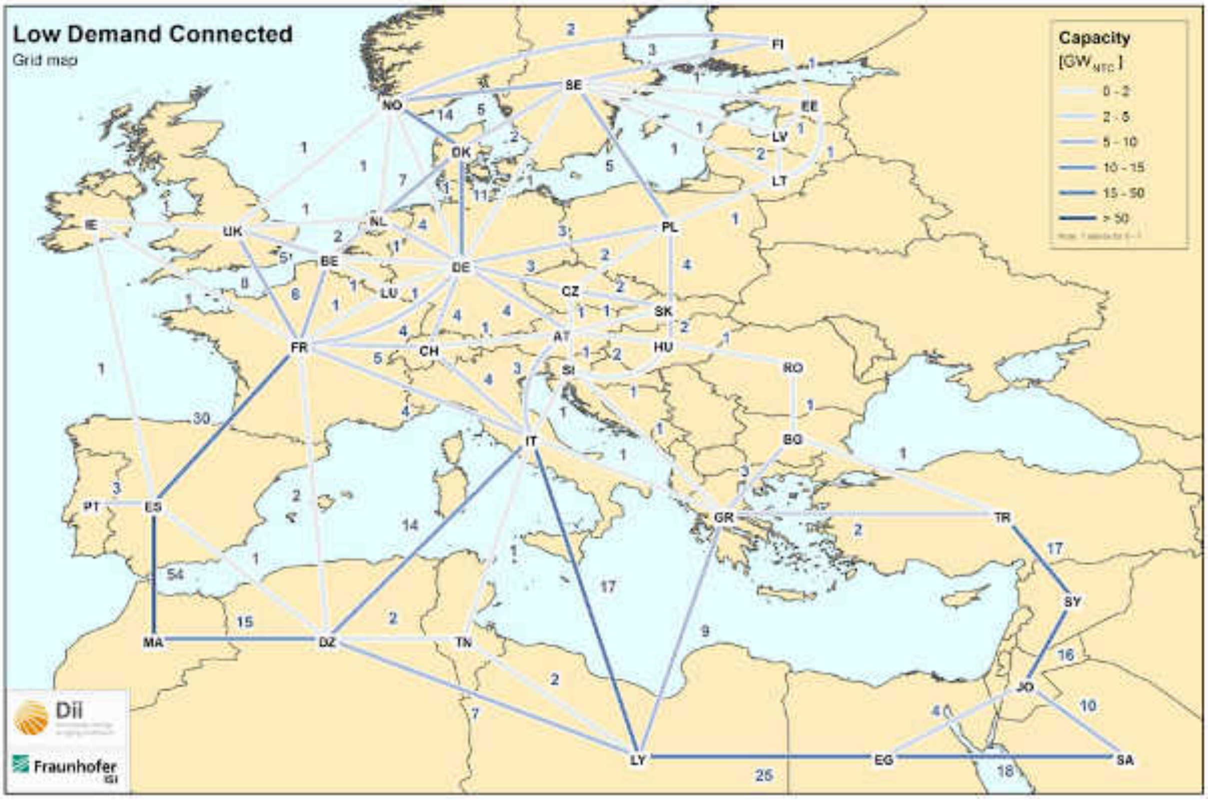


Figure 94: Low Demand Connected grid

Meanwhile, the Low Demand Connected Scenario also clearly retains the benefits of desert power. It leads to an overall cost advantage of €10bn. p.a. compared to the Low Demand Reference Scenario, equivalent to cost savings of €18 for each MWh of net power trade between MENA and Europe. Total power trade amounts to 558TWh of net exports from MENA to Europe and 10TWh in the opposite direction, i.e. a total of 568TWh. While Europe profits from cheaper carbon-free electricity, MENA profits from an electricity export industry, see Figure 95. Electricity exports from MENA are worth €20-28bn. p.a., an amount roughly equivalent to the total current exports of a country such as Morocco or Egypt.

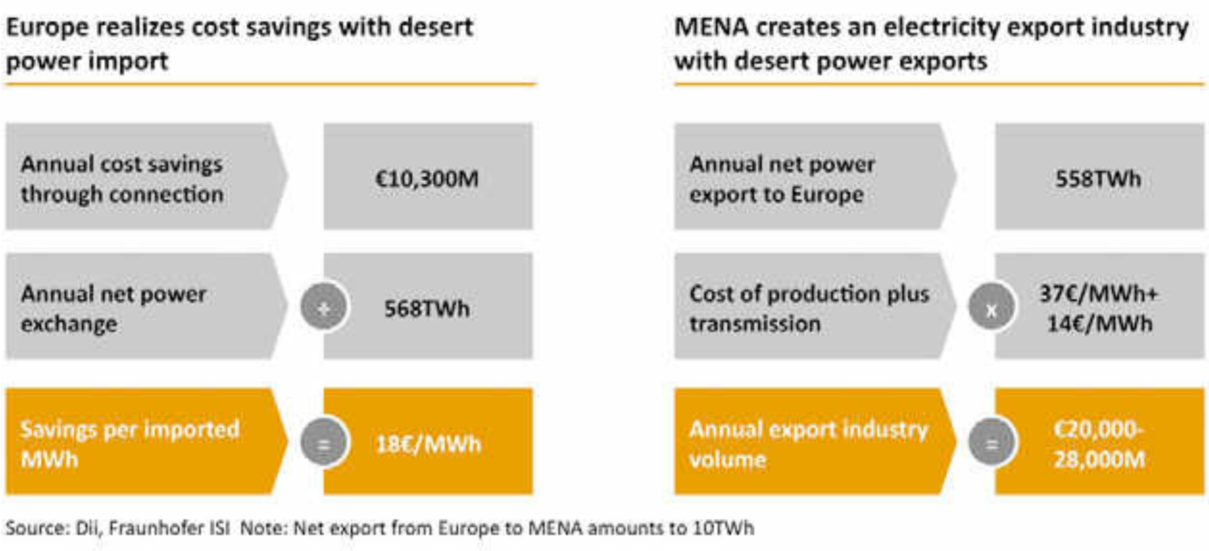


Figure 95: Low demand cost advantage Europe and export volume MENA

Of the savings of 18€/MWh, approx. 11€/MWh are the direct result of desert power's cost advantage, see Figure 96. As such, it is market driven and will be addressed by investors and industry. This cost advantage takes into account the 37€/MWh cost of production in MENA, the 13€/MWh cost of transmission of net exports from MENA to Europe and 1€/MWh of transmission losses.

The remaining 7€/MWh, meanwhile, result from system benefits such as lower levels of curtailment and less need for gas capacities with low utilization for balancing purposes. In other words, this 7€/MWh is a result of system synergies that cannot be addressed by market participants. Consequently, this economic benefit will need to be addressed with the help of regulators and/or governments.

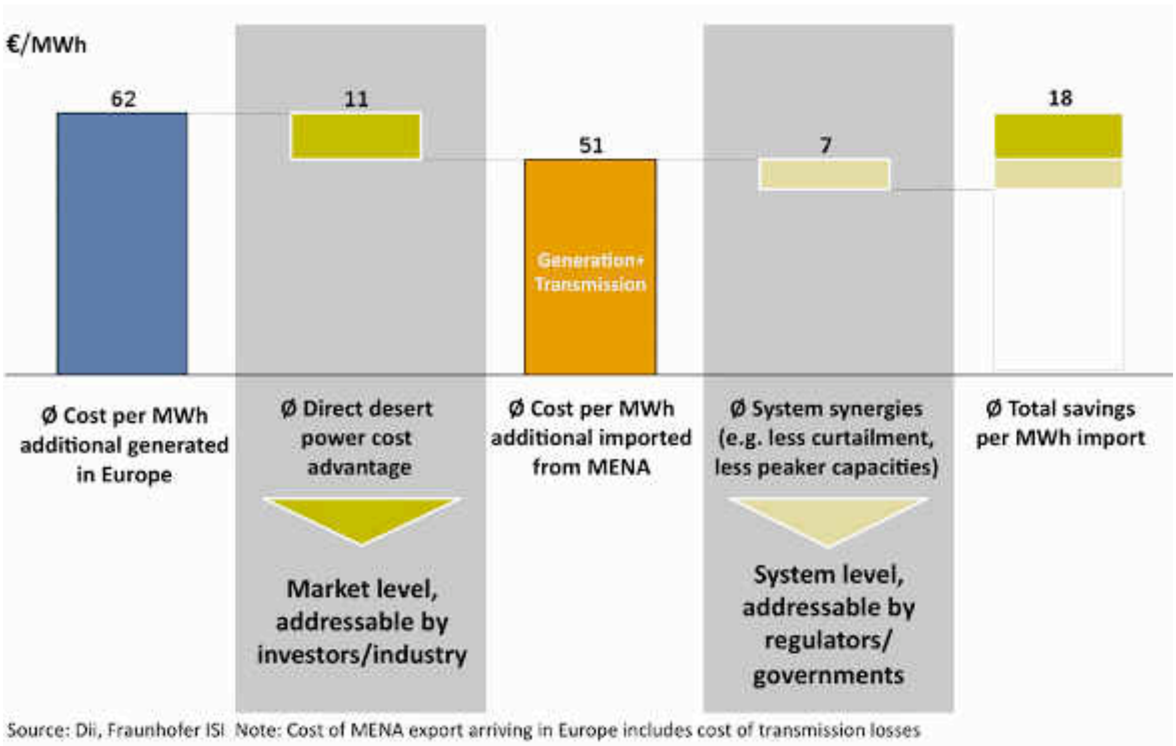


Figure 96: Cost advantage per MWh net exports from MENA to Europe

Also in the low demand case, system interconnection makes reaching CO_2 reduction goals far more affordable by reducing the marginal cost of carbon emission reduction by 39%. As in the high demand case, this is enabled by a more efficient allocation of gas plants.

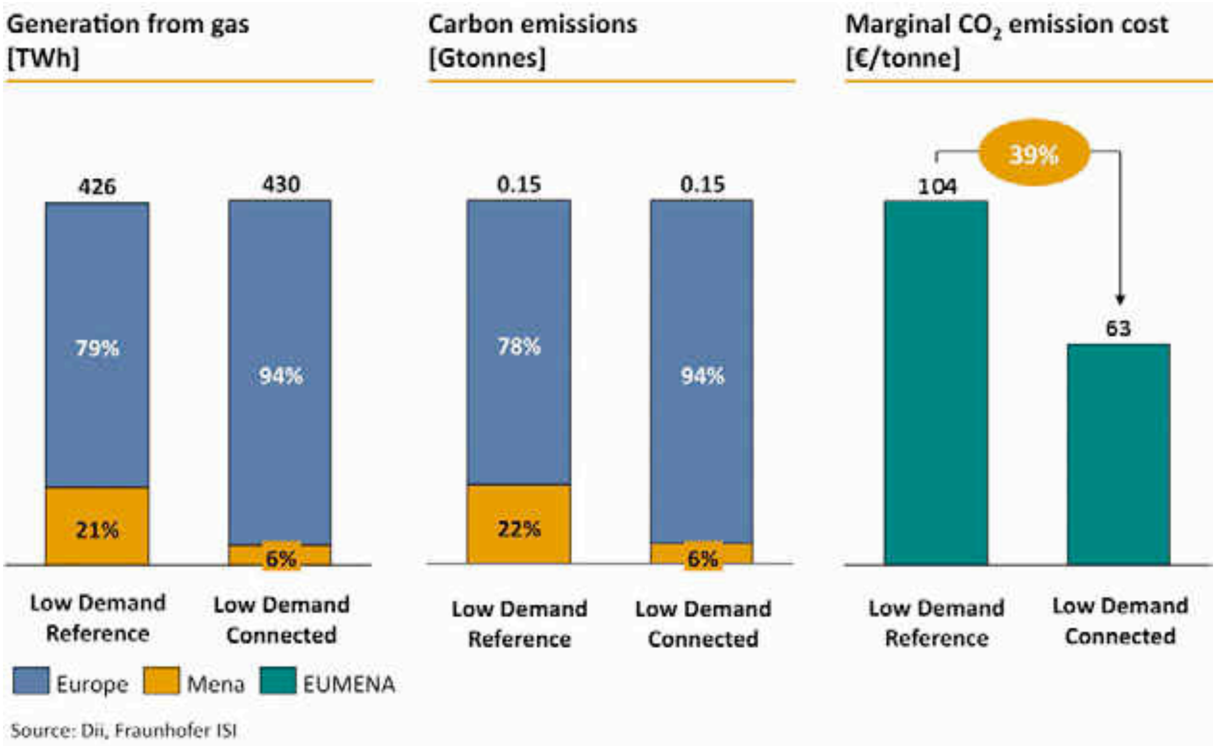


Figure 97: Low Demand electricity from gas and carbon emissions distribution/marginal cost

Summing up, the low demand scenarios show the wide range of positive effects that lower levels of demand have on the case for desert power. Desert power and measures leading to lower demand on the transmission grid, like Distributed PV and energy efficiency, should be seen as complementary methods for realizing an affordable and sustainable power system in EUMENA.

4.4 Paradigm shift perspectives

Having analyzed the effects of low electricity demand in detail, we now turn to a brief analysis of the most important effects of the perspectives reflecting paradigm shifts away from our main scenarios.

4.4.1 Delayed climate action

This scenario examines the effects of delayed carbon emission reduction and has a carbon emission limit of 0.97Gtonnes, around four times greater than the 0.25Gtonnes in the Connected Scenario. It thus provides the perspective of a 2050 system in which progress in climate action is made, but the ambitious carbon emission reduction goals in the main scenarios have not yet been met. Due to the excellent Solar and Wind potentials in MENA, meeting the relaxed common carbon emission cap in this scenario is not difficult in the Delayed Climate Action Scenario. Power generation from cheaper coal instead of cleaner gas persists in some countries while, due to its superb resources, MENA relies on renewables for almost 100% of its demand, as can be seen in Figure 98.

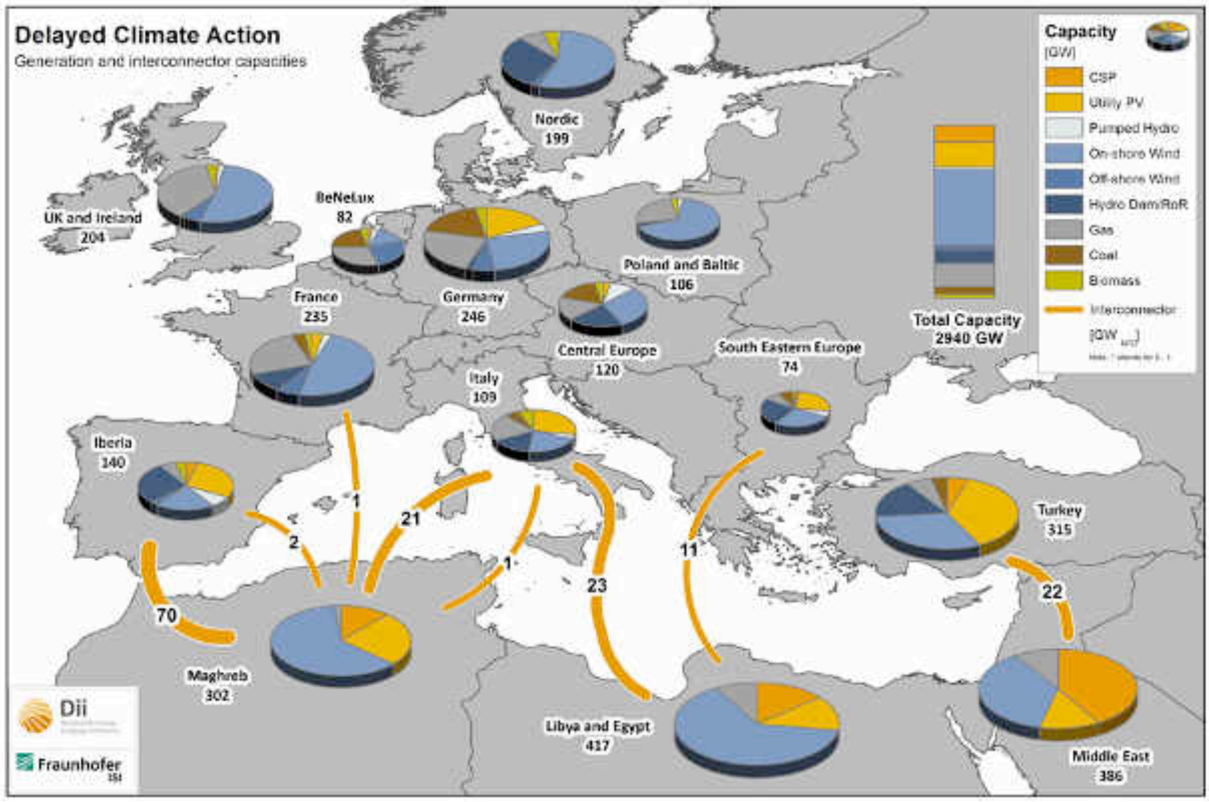


Figure 98: Generation and interconnector capacity, Delayed Climate Action Scenario

122GW of coal capacity is installed across the system in this scenario: 44GW in Germany, 20GW in Central Europe, 16GW in BeNeLux and Turkey respectively, as shown in Figure 99. While coal replaces some gas capacity, this scenario also leads to an additional 36GW of gas (25GW CCGT, 11GW OCGT), especially in Libya & Egypt, with an additional 31GW gas (of which 22GW OCGT for Wind balancing), the Middle East (18GW, -5GW OCGT, +23GW CCGT, replacing CSP), France (26GW, of which 24GW CCGT), and in the UK & Ireland (7GW).

In total, as shown in Figure 99, Solar and Wind capacities are reduced by almost 550GW, of which approx. 310GW on-shore and 60GW off-shore Wind. Utility PV is reduced by approx. 110GW and CSP by almost 70GW. The largest reductions in Solar and Wind capacities occur in MENA, with a total of 215GW, as well as in Iberia[68] and in the Nordic countries. In Germany, the impact is smaller, with only off-shore Wind replaced. Meanwhile, Turkey exchanges CSP for Utility PV, since conventional power plants can now perform a greater share of balancing.

Grid expansion is lower with Delayed Climate Action, with a 37% reduction from 557,000GW_{NTC}*km to 349,000GW_{NTC}*km. While lower than in the Connected Scenario, this is still a grid expansion almost six times greater than the existing grid combined with ENTSO-E's 2012 TYNDP, which covers projects until 2022. South/north interconnector capacities total 150GW_{NTC}, with MENA net exports to Europe amounting to 730TWh.

[68] The reduction of renewables in Iberia without build-up of gas or coal is due to lack of a lower limit on self-supply. Solar and Wind for Spain are sourced from Morocco

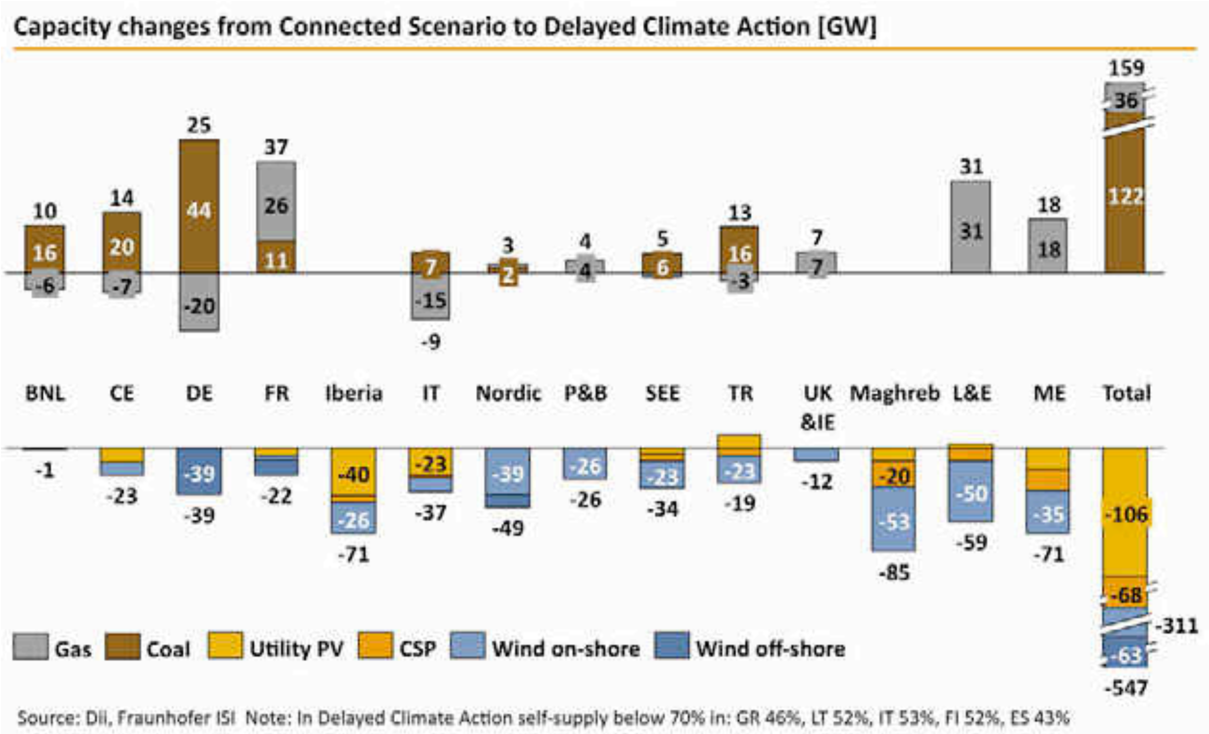


Figure 99: Capacity changes from Connected Scenario to Delayed Climate Action

Even with Delayed Climate Action, a system-wide RES-E share of 78% is reached, as shown in Figure 100. In general, the RES-E share is spread across regions, though in varying concentrations: Italy and BeNeLux have an RES-E share of approx. one third, while Central Europe, Southeastern Europe and Iberia reach a maximum of 50%. France has slightly more than half (58%); Turkey, UK & Ireland, Poland & Baltic reach 69-76%. The regions with the highest RES-E share are the Middle East, with 92% of local demand, and the EUMENA renewables powerhouses of North Africa, as well as the Nordic countries – in these regions, renewables generation exceeds demand and is thus exported.

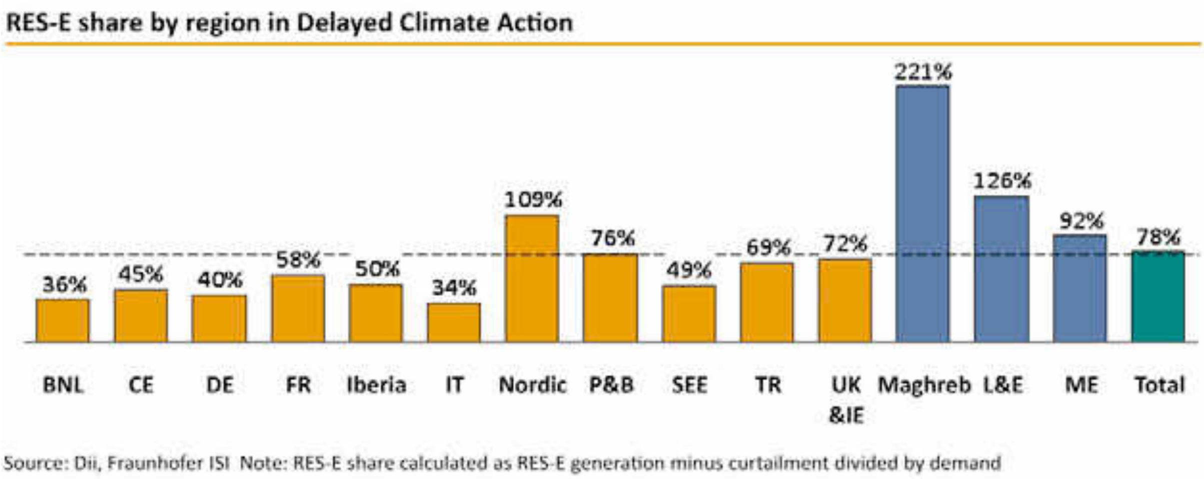


Figure 100: RES-E shares by region with Delayed Climate Action

4.4.2 Nuclear/CCS

This perspective aims to understand the potential impact on desert power of the widespread use of power generation with nuclear and CCS technologies. The model is not allowed to build nuclear in countries that have decided to phase out nuclear. Since CCS is allowed in all countries, the phase out countries also have an alternative to renewables in this scenario. It should be noted that the purpose of this scenario is to provide a conservative analysis of the impact on desert power of Nuclear/CCS. Therefore, factors such as nuclear waste disposal, insurance of nuclear power plants and technological availability and public acceptance for carbon dioxide storage have been neglected. In reality, these factors might further reduce the attractiveness of Nuclear/CCS.

The relevant conclusion from this perspective for the desert power case is clear: renewables from MENA are competitive in a system with widespread use of nuclear and CCS.

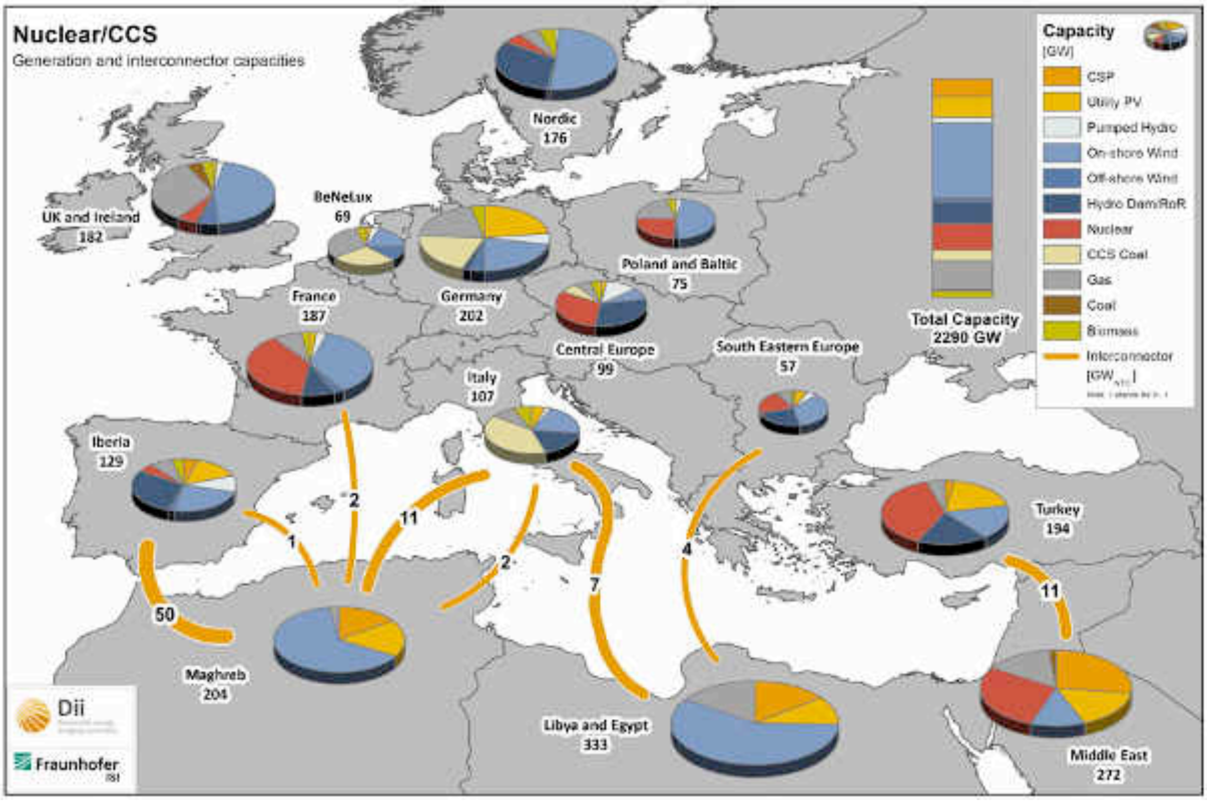


Figure 101: Generation and interconnector capacity, Nuclear/CCS Scenario

In the Nuclear/CCS perspective, MENA net exports to Europe remain substantial, with 301TWh transported across 86GW$_{NTC}$ of interconnector capacities, see Figure 101. Grid build up is reduced by 58% from the Connected Scenario to 233,000GW$_{NTC}$*km. Overland transmission infrastructure expansion in Europe is strongly reduced in this scenario, though with 122,000GW$_{NTC}$*km it remains more than double the grid capacity that will exist after the ENTSO-E 2012 TYNDP grid extension is implemented.

Nuclear and CCS account for a significant share of the power plant capacities, with 278GW of nuclear and 133GW of CCS in countries that have already (as of 2012) decided to phase out nuclear, as shown in Figure 102. Among the CCS regions, BeNeLux and Germany have good on-shore storage possibilities in salt caverns, while this is not certain for the third one, Italy. Remaining free carbon emissions allow for 16GW of coal to be built, while gas capacities are reduced by approx. 60GW (plus approx. 45GW OCGT as peaker, minus approx. 105GW CCGT).

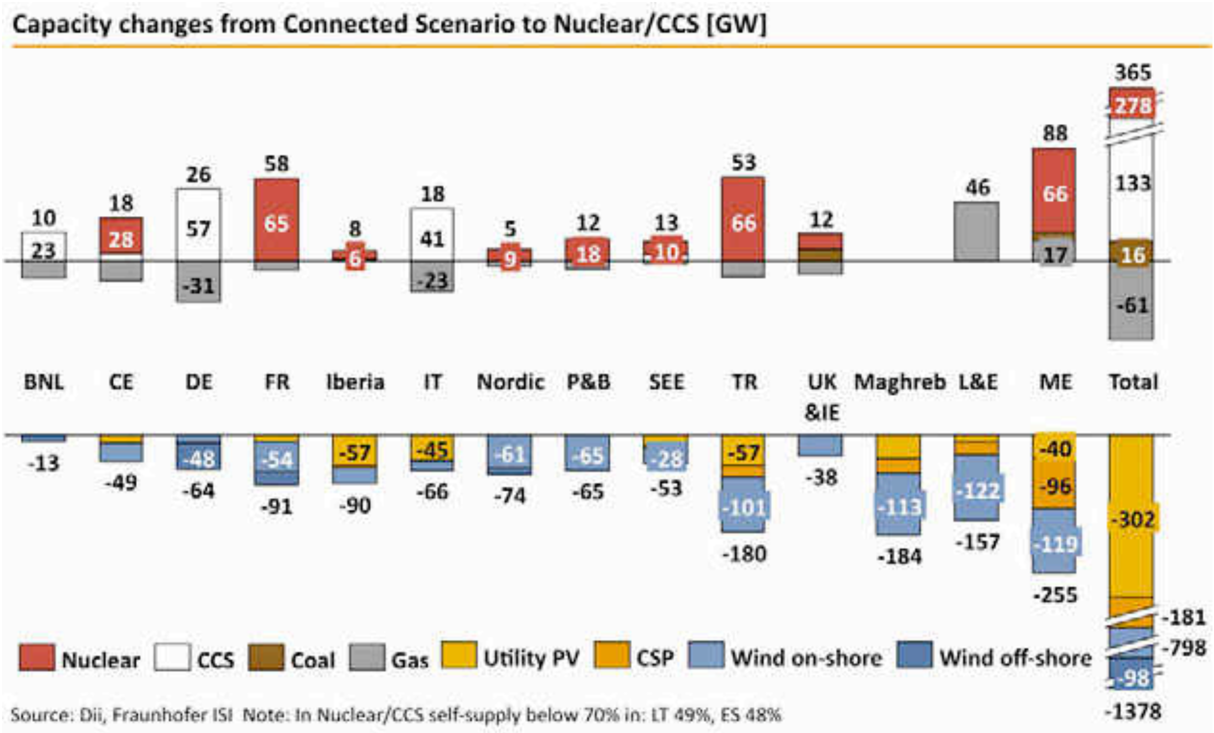


Figure 102: Capacity changes Connected Scenario to Nuclear/CCS

Overall, the reduction in renewables capacities totals almost 1400GW, of which almost 800GW on-shore and almost 100GW off-shore Wind, as well as more than 300GW Utility PV and more than 180GW CSP. A high reduction in renewables is seen in Turkey and the Middle East, which both have significant nuclear build-up. This is also the case in the Maghreb, which exports less renewables but does not need nuclear or CCS itself. Egypt also replaces significant amounts of renewables, but in exchange for conventional gas: 62GW of Wind is exchanged for 23GW CCGTs and 23GW OCGTs.

In the main European nuclear phase-out countries, Germany and Italy, gas and off-shore Wind are replaced by CCS, while in Italy there is also some replacement of Utility PV. Even in the Nordics, some on-shore Wind is replaced by nuclear.

Desert power remains a major source of power for the entire system. Together with Wind in northern Europe and some Solar in southern Europe, renewables from MENA are a major driver behind the system-wide RES-E share of 55%, depicted in Figure 103. The Maghreb generates 166% of its demand from renewables, the Nordics and Libya and Egypt almost 100%. All of North Africa has such abundant and economical Solar and Wind potentials that neither nuclear nor CCS are built. The balancing ability provided by the grid enables them to rely on these – except for CSP with storage – fluctuating resources and some gas capacities.

Other regions have significantly lower levels of renewables production: UK&IE at 62% of its demand and the remaining ones all below 45%. At 25%, Italy and BeNeLux have the lowest RES-E share.

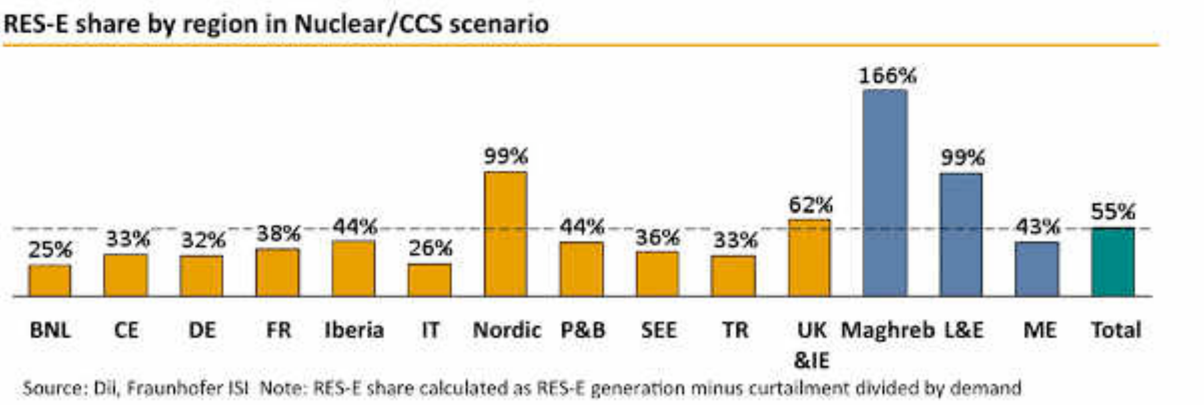


Figure 103: RES-E shares by region with Nuclear/CCS

4.5 Medium impact changes

We now turn to the analysis of the perspectives that are not based on a paradigm shift but nevertheless have a notable impact on desert power: High Land Use Europe, Delayed (Expensive) Grids and High Capital Cost MENA.

4.5.1 High land use Europe

If Europe achieves strongly increased build-up of renewables in the most favorable sites, less desert power could be needed. This is the subject of the High Land Use Europe perspective, see Figure 104.

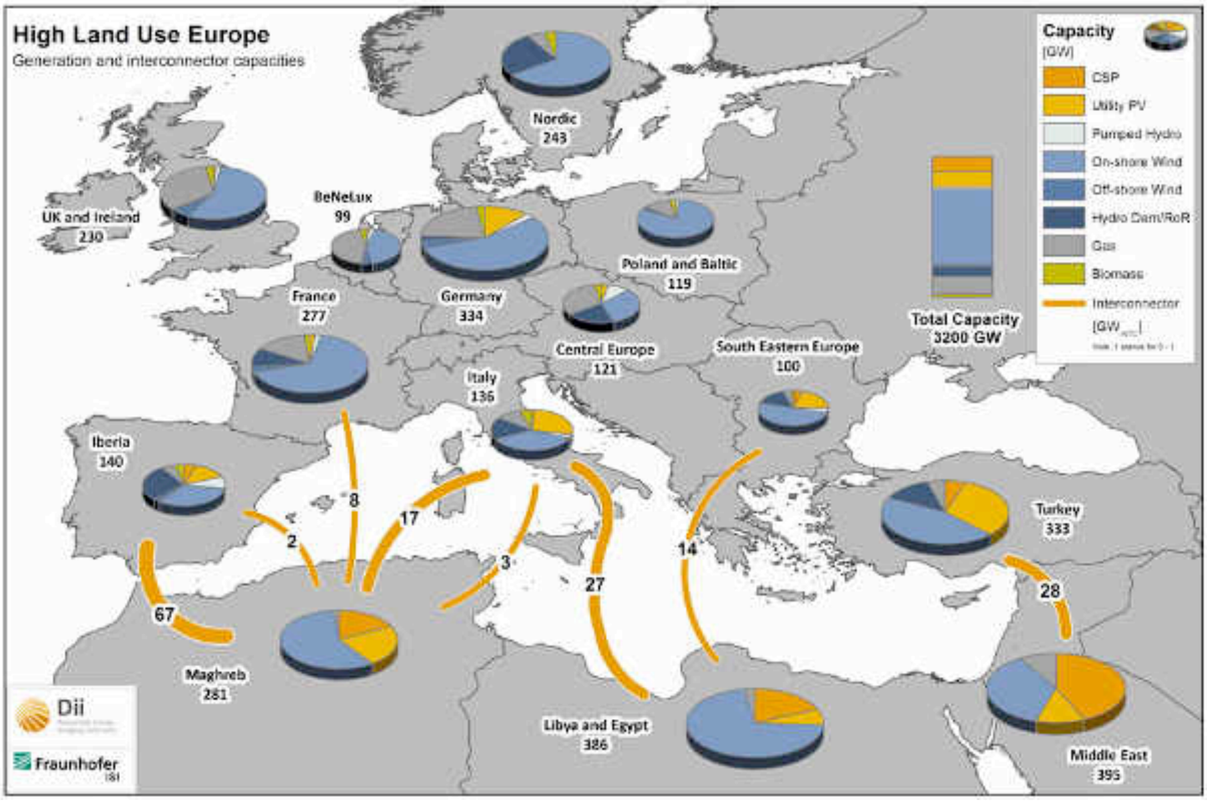


Figure 104: Generation and interconnector capacity, High Land Use Europe Scenario

Even under the very favorable land use assumptions for Europe examined in this sensitivity, almost 700TWh p.a. of desert power net exports from MENA to Europe still occur. This corresponds to approx. 12% of Europe's electricity demand.

This scenario is €33bn. p.a. cheaper than the Connected Scenario since more of the best renewables resources across the entire system, excluded in the main scenario due to land use restrictions, can be deployed. It also leads to additional use of land for on-shore Wind installations in Europe totaling more than 30,000km², or roughly the size of Belgium.

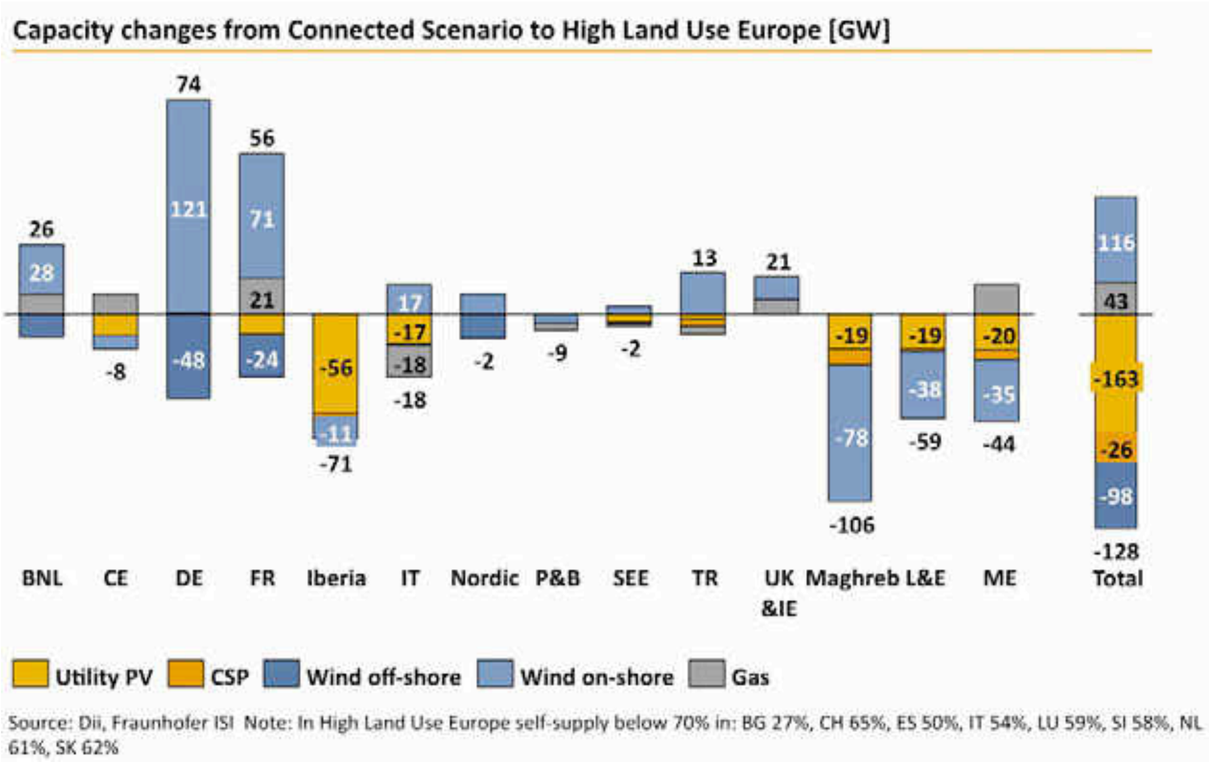


Figure 105: Capacity changes Connected Scenario to High Land Use Europe

In this scenario, no technology in any country under consideration comes close to its potential limit[69]. While increased domestic renewables production might be considered positive, e.g. from the perspective of energy independence, this scenario could potentially lead to greater public acceptance issues. It results in a 266GW increase of on-shore Wind installations in Europe (of which 24GW in Turkey), as shown in Figure 105. This includes an increase of 121GW in Germany and 71GW in France. In other words, one of the most distinctive features of this scenario is huge installations in countries such as Germany, which has a total of 180GW on-shore Wind compared to 27GW today. The increase in on-shore Wind stems primarily from the higher usage of European croplands and forests, which can be used to a very high degree in this scenario. Offset by a 151GW reduction in MENA on-shore Wind capacity, this leads to a net increase of 116GW in on-shore Wind installations. Since the highest usage of any country's on-shore Wind potential is 51%, the renewables potential limits have no impact on this result and Solar and Wind from different geographical areas compete solely on cost.

[69] Except for CSP in Cyprus and France, which does not impact the overall result

Off-shore Wind installations decline by 98GW, of which 48GW in Germany – in other words, off-shore Wind is substituted by on-shore. There is also a significant reduction of Utility PV, e.g. a 56GW reduction in Iberia[70]. An additional 43GW in gas capacities, thereof 30GW OCGT, needed for balancing, is built in the countries with expanded Wind capacity. By better matching renewables generation with renewables resources across EUMENA, the High Land Use Europe scenario leads to a 128GW net reduction in installed capacities, with a 209GW decrease in MENA offset by an 81GW net increase in European capacity. Within Europe, this scenario leads to a shift into Germany, France, and BeNeLux, since these countries offer areas with good renewables resources that**,** under standard assumptions, are not available for renewables generation due to land use restrictions.

An optimistic view of Europe's technical and economic renewables potentials also favors the development of a cheap power system for the entire EUMENA region. Expanded European land use provides clear benefits by building on-shore Wind in European forests and croplands. By improving Europe's capacity to tap its own renewables resources, the need for grids is reduced by 17% compared to the Connected Scenario, i.e. from 557,000GW_{NTC}*km to 463,000GW_{NTC}*km. Likewise, the need for overland transmission in Europe is reduced by 23% from 320,000GW_{NTC}*km to 245,000GW_{NTC}*km. This latter amount is still four times the 2022 target of ENTSO-E's 2012 TYNDP.

Still, Europe's success in developing domestic renewables does not render desert power unattractive. With almost 700TWh of desert power imports, transported over interconnector capacities of 167GW_{NTC}, system integration remains a crucial part of keeping system costs down. Indeed, while this perspective leads to a €66bn. savings compared to the Reference Scenario, it reduces costs by €33bn. compared to the Connected Scenario. Thus, more than half of the system cost savings of High Land Use Europe compared the Reference Scenario can be reached by system integration.

This scenario clearly demonstrates that European domestic renewables and desert power are not competitors. Instead, when the best renewables potentials across the whole region can be tapped and combined, the EUMENA power system becomes even better and cheaper. No matter how optimistic the assumption for European land use, desert power plays an important role in this system.

4.5.2 Delayed grids

Europe's improved access to domestic renewables potentials, discussed above, both reduces desert power exports from MENA to Europe and lowers total system cost. On the contrary, Delayed Grids lead to higher system costs while also limiting the impact of desert power. Given the persistent difficulties involved in building new transmission lines today, it is important to account for the effects of a delayed build-up of transmission infrastructure. Two scenarios are dedicated to this issue: the first one, Delayed Grids, limits the expansion of any connection between two countries to 20GW_{NTC}, which would mean building 0.5GW_{NTC} p.a. from now until 2050; the second one, Delayed Expensive Grids, additionally increases the cost of transmission by 50%. Both scenarios enforce a 70% lower limit on self-supply.

[70] The reduction of renewables in Spain is partially due to the lack of a lower limit on self-supply. Solar and Wind for Spain are sourced from Morocco

As can be seen from Figure 106, the effect of limiting transmission capacities to $20GW_{NTC}$ is that desert power exports are partly shifted to other interconnectors – all but one is used up to the given limit. This demonstrates that the case for desert power does not depend on the success of building a specific sub-Mediterranean interconnector. Instead, it shows that all interconnectors offer conditions for desert power exports that are favorable compared to further domestic renewables production in Europe.

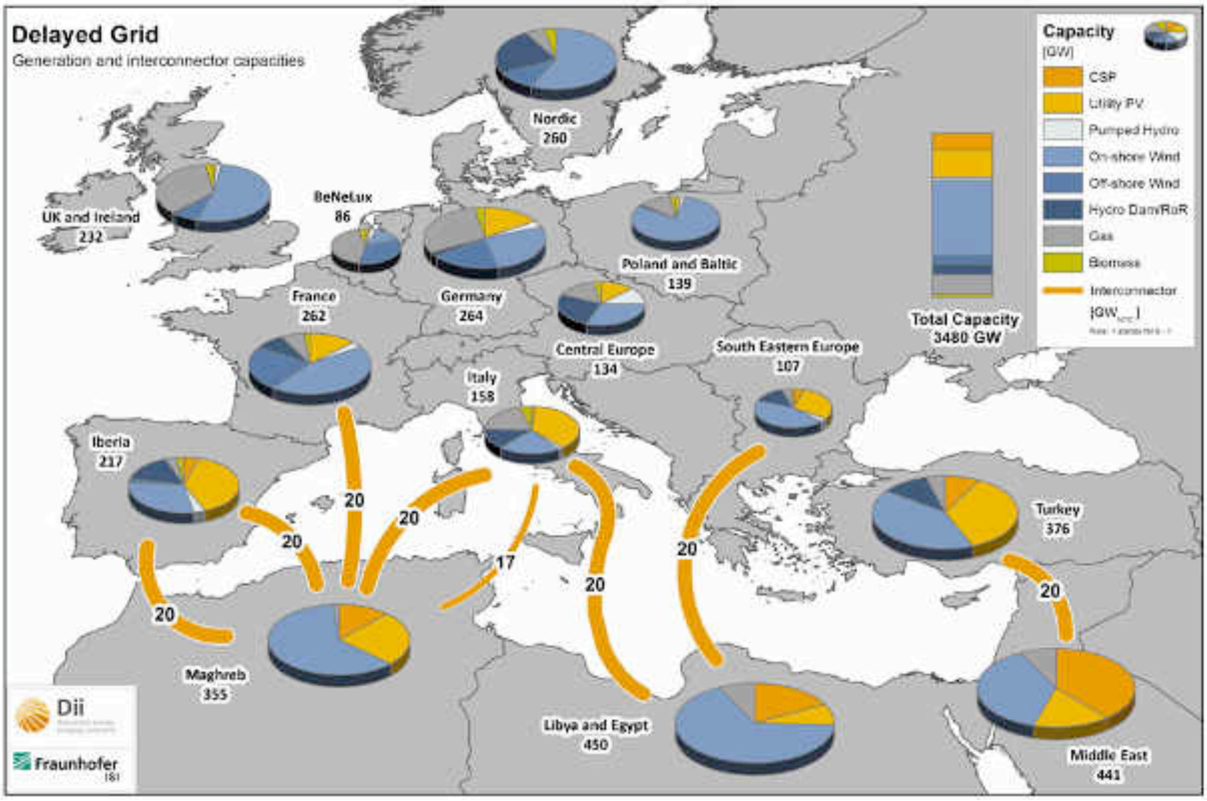


Figure 106: Generation and interconnector capacity, Delayed Grid Scenario

Delayed Grids lead to the installation of $157GW_{NTC}$ sub-Mediterranean interconnectors, with the reduction of the largest interconnectors' capacity compensated by others. As a result, significant south/north power flows of almost 780TWh remain.

Delayed transmission leads to 155GW in additional installations, due to the reduced capacity available for transporting power across the system and therefore more regional balancing of demand, as seen in Figure 107. In particular, there is 51GW in gas (41GW OCGT, 10GW CCGT) for balancing, a 55GW increase in Utility PV and 46GW more off-shore Wind[71]. CSP capacity is reduced only slightly, but shifts geographically: from the Middle East to Turkey and from the Maghreb to Libya. The shift from the Middle East to Turkey also explains the lower FLH on the Syria to Turkey interconnector. It reaches approx. 3700FLH p.a. instead of 4400FLH p.a., since electricity from CSP storage no longer drives up utilization.

A 20% reduction in grid capacities takes place compared to the Connected Scenario, with a total of $446{,}000GW_{NTC}$*km. There is no reduction in capacity kilometers of sub-Mediterranean sea cables,

[71] Note that off-shore Wind connection grids are included in the cost assumptions but not in the grid capacities

since longer interconnectors are expanded. Overland transmission infrastructure in Europe is reduced by 60,000GW$_{NTC}$*km to approx. 260,000GW$_{NTC}$*km, and grids within MENA are also reduced. Most interconnectors reach over 5000FLH in the north/south direction, except for Syria to Turkey, which reaches approx. 2150FLH south/north and approx. 1550FLH north/south; Tunisia to Italy reaches 4700FLH.

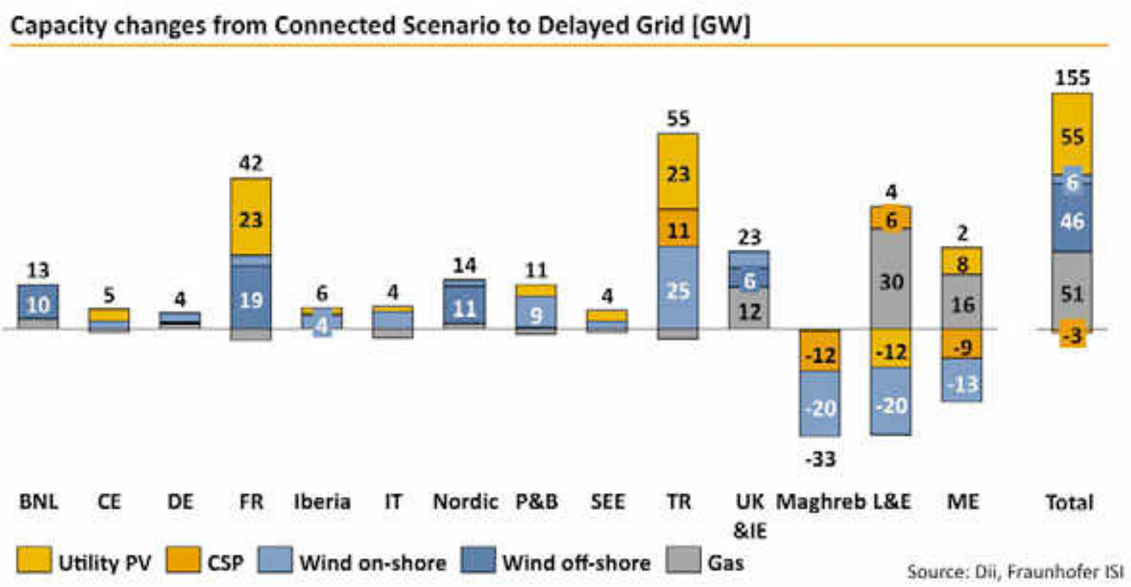


Figure 107: Capacity changes Connected Scenario to Delayed Grid

The 50% increase in grid costs in the Delayed Expensive Grid perspective has no major additional impact on the case for desert power, see Figure 108.

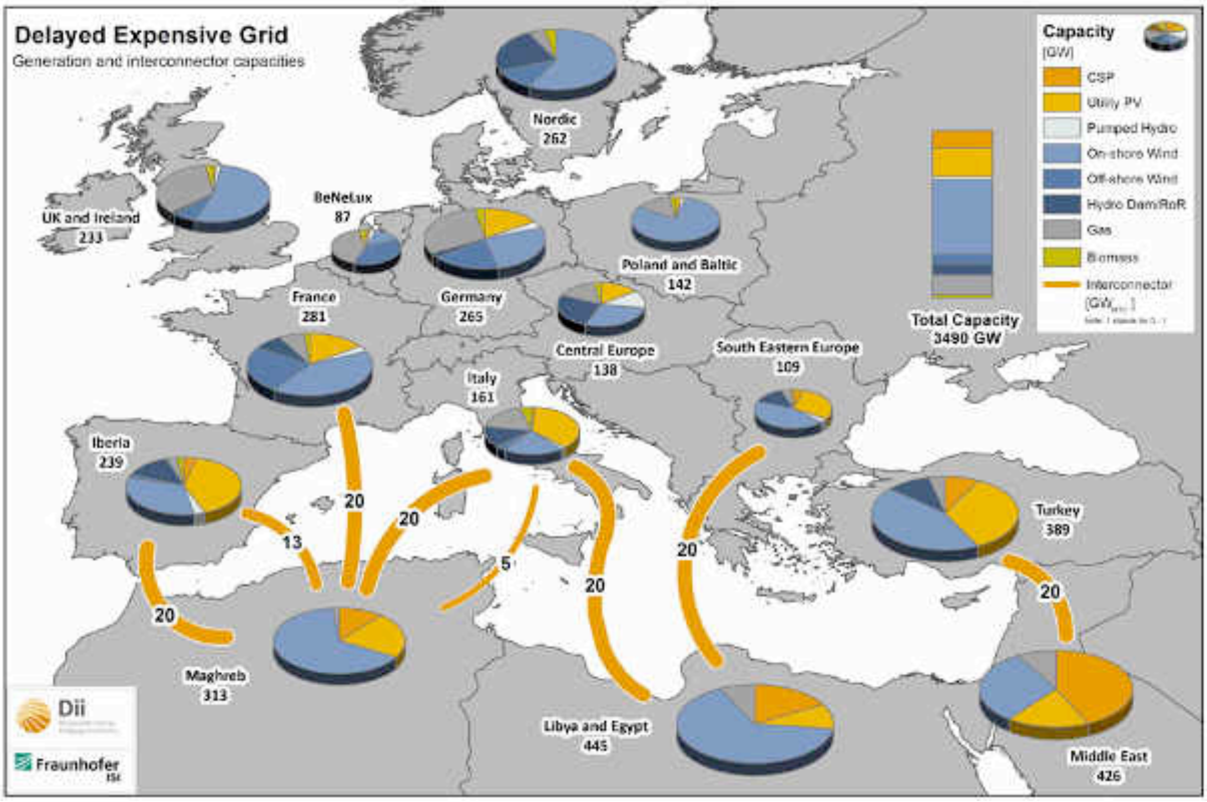


Figure 108: Generation and interconnector capacity, Delayed Expensive Grid Scenario

Only two interconnectors, Tunisia to Italy and Algeria to Spain, decrease in comparison to Delayed Grids. For this scenario, it is important to note that the standard grid cost assumptions already include the assumption of 50% underground cables in Europe – this cost is increased by 50%, just like the cost of the sub-marine cables. The outcome of this scenario shows that the cost of grids will not be a show-stopper for the desert power case; in reality, social and political factors rather than costs tend to prevent the creation of these connections.

Figure 109 shows that the power flows shift away from the Spain-France-Northern Europe corridor compared to the Connected Scenario. With Delayed Expensive, Grids Italy replaces France as the major European transit hub.

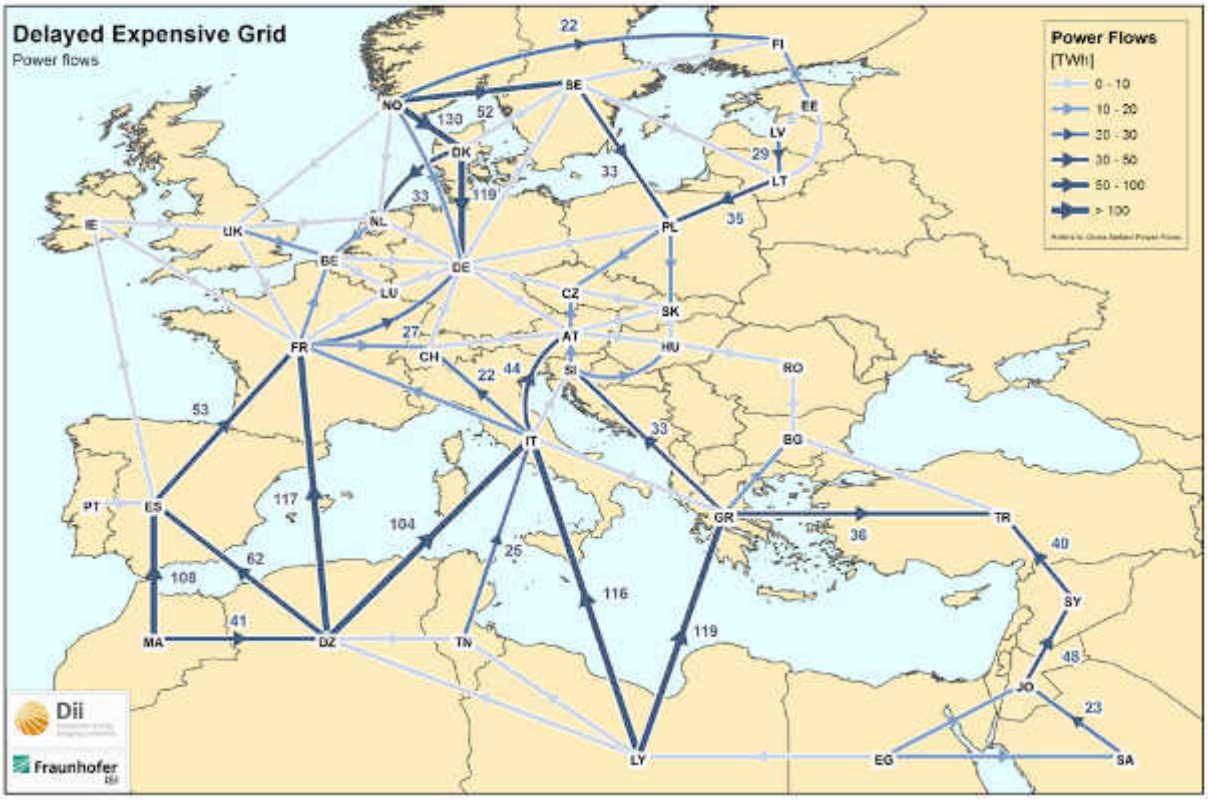


Figure 109: Major power flows in Delayed Expensive Grid Scenario

4.5.3 High capital cost MENA

Besides delays in the build-up of transmission infrastructure, the increased cost of capital for power plants in MENA could also have a notable impact on the case for desert power. Wind and Solar power plants have high up-front investments and low costs once in operation. Thus, they are particularly vulnerable to an increase in the cost of capital, which is hard to predict and depends greatly on perceptions of specific kinds of risk (e.g. political risk). The High Capital Cost MENA scenario assumes a MENA WACC of 9% p.a., which reflects an above average risk perception of a project. This 30% increase from 7% p.a. WACC to 9% p.a. reflects a serious disadvantage for MENA renewables compared to European Solar and Wind installations, and covers a wide range of possible reasons for this higher capital cost.

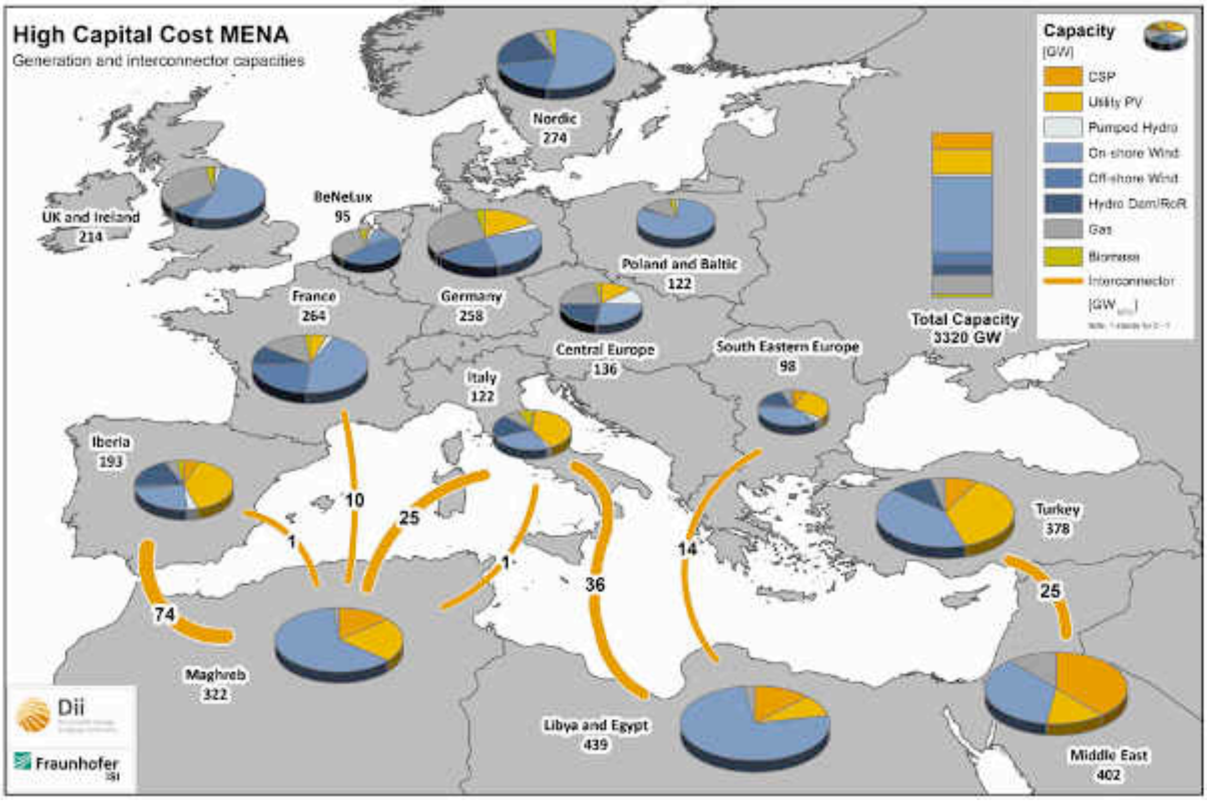


Figure 110: Generation and interconnector capacity, High Capital Cost MENA Scenario

Even with higher capital costs in the region, MENA still builds significant export capacities, as shown in Figure 110. Net exports from MENA to Europe remain significant, at almost 850TWh, though this is a reduction of 20% compared to the Connected Scenario. This underlines the robustness of the case for desert power even if risk perception, and consequently the cost of capital, remains higher for MENA than Europe.

Higher capital costs in MENA do not cause a significant shift in grid capacities. South-north interconnector capacities total 185GW_{NTC}, with lower utilization despite greater use in a north-south direction (34TWh, up from 23TWh). The higher cost of capital reduces interconnector capacities by 37GW_{NTC}, i.e. a 17% decrease compared to the Connected Scenario. Sub-Mediterranean capacity kilometers are reduced only 6% due to the increased build-up of the long Italy/Libya interconnectors – the result of removing the 70% lower limit on self-supply in the High Capital Cost MENA scenario.

Overall, higher capital costs in MENA lead to an approx. 109GW reduction in MENA capacity, as shown in Figure 111. This decrease in MENA capacity is offset in the system as a whole by 98GW of additional off-shore Wind in Europe, mostly in France, BeNeLux and the Nordic countries. Turkey sees stronger build-up in this scenario, with an additional 57GW of capacity: of this, 31GW additional Utility PV is built, along with 22GW on-shore Wind and 11GW CSP, while gas is reduced by 7GW. Other capacity shifts are due to the removal of the 70% lower limit on the self-supply rate. In particular, gas shifts out of Italy. Gas capacities do not shift from Italy to Germany, as in the Maximum Cooperation Scenario, but to the Middle East. This is due to the higher WACC in MENA, which makes conventional power with lower up-front investment more attractive. Economical renewables are so abundant in North Africa that, even in this scenario, no gas shifts to the region.

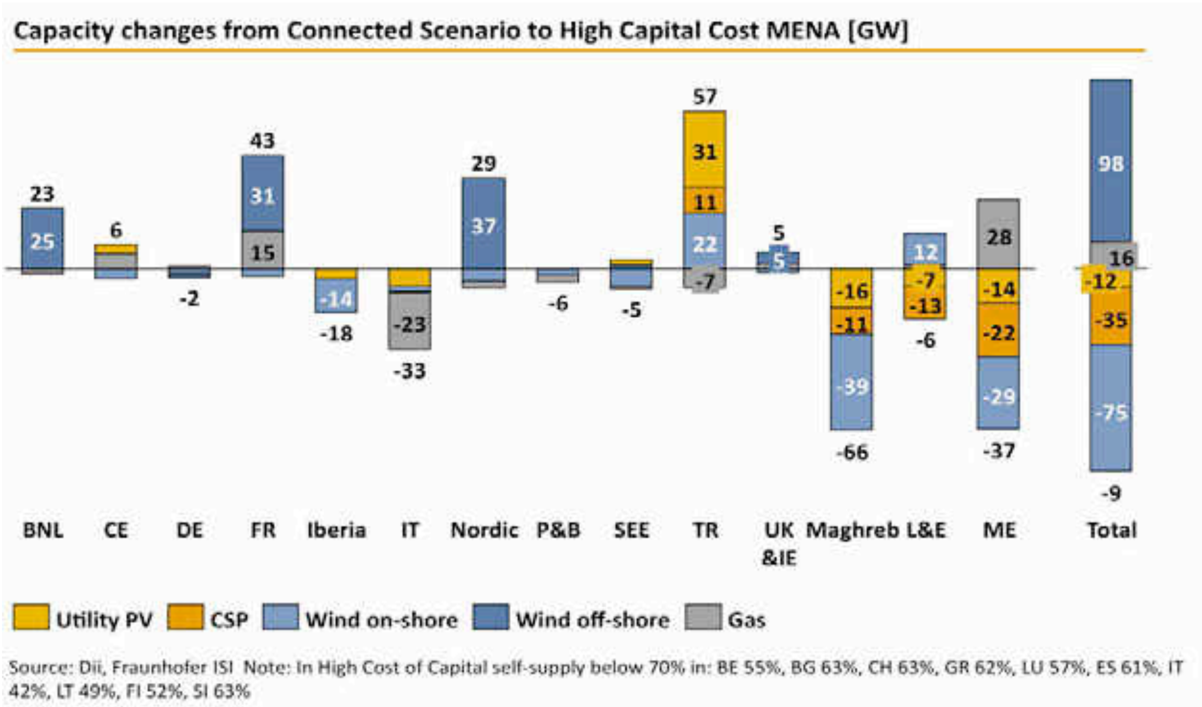


Figure 111: Capacity changes Connected Scenario to High Capital Cost MENA

A scenario accounting for higher capital costs in MENA still leads to a cost reduction of €16bn. compared to the Reference Scenario. It should be noted that the cost increase in the High Capital Cost MENA Scenario not only increases the cost of exports to Europe but also the cost of power in MENA itself.

4.6 Low impact changes

We conclude our analysis of different desert power perspectives with a brief summary of those perspectives that have a low impact on the case for desert power.

4.6.1 Maximum cooperation

By removing the 70% self-supply limit in a scenario aiming for the maximum level of cooperation between countries, a number of European countries fall below the limit. Those particularly affected are countries in close proximity to desert power, such as Italy with a 36% self-supply rate and Spain with 48%. The main difference between these two “low self-supply” countries is that Spain builds renewables to meet its self-supply rate target in the Connected Scenario, while Italy attracts more gas generation capacity from other regions, especially Germany.

There is only a minor impact on costs in this scenario, since removing the self-supply limit results primarily in the more efficient allocation of gas across the system, especially in Germany. In turn, more of the balancing and base load for Iberia and Italy can be performed by CSP from the Maghreb. Overall, capacities shift from Spain and Italy to the Maghreb and Libya, primarily in Utility PV and Wind. As a result, more power is imported from MENA to Europe, but less power is transported further north in Europe. In other words, in a Maximum Cooperation Scenario it is economically more efficient to shift electricity to the north in the form of gas power plants instead of building transmission infrastructure. The impact is limited, though: the Maximum Cooperation Scenario is less than €2bn. p.a. cheaper than the Connected Scenario. This cost difference is approx. 6% of the system cost savings that result from integrating the EU and MENA power systems in the main scenarios (i.e. the system cost savings of the Connected compared to the Reference Scenario).

Like the Maximum Cooperation Scenario, the rest of the low impact scenarios do not include a lower limit on the self-supply. For this reason, we will compare them to the Maximum Cooperation Scenario, not the Connected Scenario. This comparison ensures that, despite the low impact of the changes discussed, the real effects of these changes can be properly understood and are not disguised by the change in the self-supply rate.

4.6.2 No NREAPs

The European Union uses National Renewable Energy Action Plans (NREAPs) as the key policy tool to meet its decarbonization and renewable energy targets. The NREAPs are the result of EU and member state political considerations, not a mere system cost optimization approach like the one applied in this report. Therefore, while they promote the development of renewables in the short term, it is unavoidable that they will not fully optimize system costs. In the main scenarios we have forced the system to take these political goals into consideration as lower limits for renewable energy allocation by country. In this perspective, we aim to show the effect of NREAPs and how a system without them might look. We do this examining a purely cost-optimized system.

It is important to note that this scenario should not be viewed as a judgment on NREAPs or the build-up of renewables resulting from their implementation. The German PV program, for example, has contributed to a substantial reduction in the cost of PV by about 2/3 in the past five years. As a result, it has made PV commercially viable in sun-rich parts of the world. Instead, this scenario simply intends to illustrate the different outcomes achieved by a political strategy to advance renewables compared to a pure cost optimization of the renewables mix in EUMENA.

In such a scenario, European imports increase by 5% and cost savings over the Reference Scenario increase by 2% compared to the Maximum Cooperation Scenario. The most significant change is a reduction of German Utility PV installations by 43GW to 4GW. The total reduction in Utility PV capacities in Europe is 43GW, with reductions in some northern countries and increases in Iberia and Turkey. Since some Utility PV is built in MENA, the system wide reduction of Utility PV capacities amounts to 35GW. Off-shore Wind is reduced by 6GW system-wide, while an additional 12GW of on-shore Wind and 3GW of CSP are installed. Overall, renewables installations in Europe are reduced by 49GW and only partially offset by a 22GW increase in MENA. This leads to a net reduction of 27GW, as well as savings of 2GW gas capacity, due to a more efficient allocation of renewables.

The result that a system without NREAPs is cheaper than the Connected Scenario was to be expected, since the NREAPs are not tailored primarily for optimal renewables allocation. The effects on system cost, though, are relatively minor, as NREAP capacities are relatively small compared to the more than 3000GW total installations in the Connected Scenario.

4.6.3 Delayed renewables cost curves

Projecting cost developments 40 years into the future for highly dynamic industries is naturally subject to uncertainties. We address this issue by studying four perspectives, one for each focus technology, in which the projected cost curves are not met and 20% less cost reduction than expected occurs. In other words, these scenarios examine the effects of a technology presenting higher costs in 2050 than is assumed to be the case in the main scenarios.

The impact of all four analyses on desert power is quite clear: higher costs of renewables do not lead to dramatic changes and actually increase MENA exports to Europe (except for CSP) compared to the Maximum Cooperation Scenario.

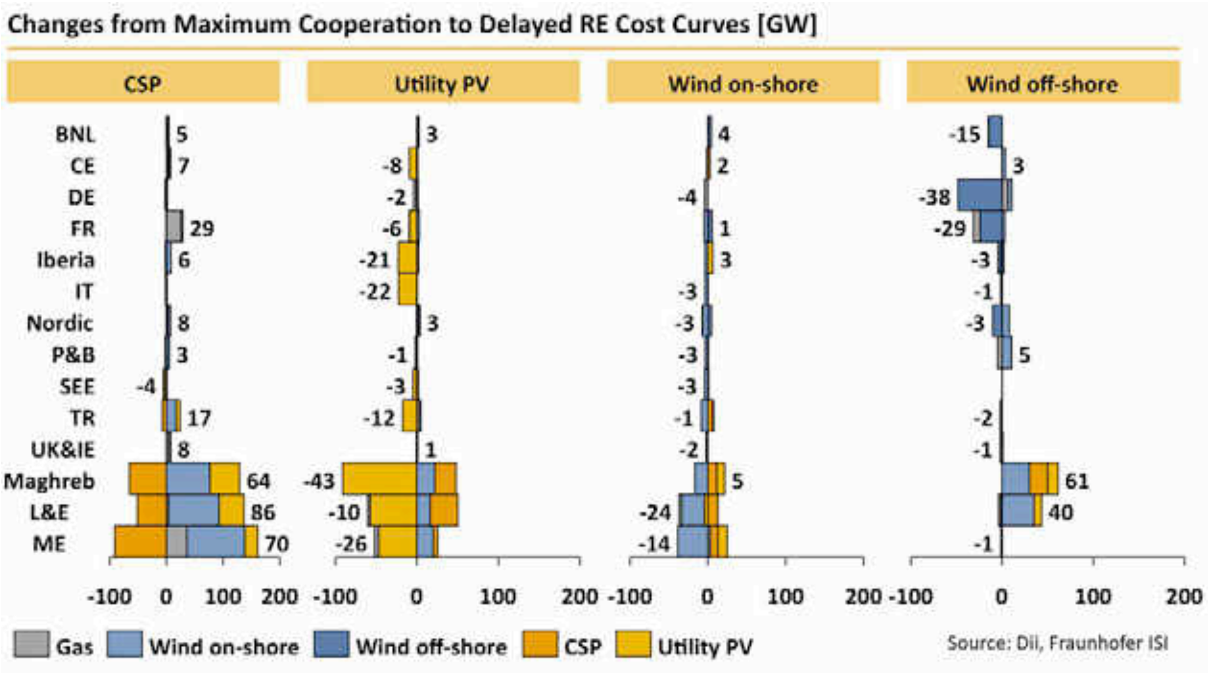


Figure 112: Capacity changes Maximum Cooperation Scenario to Delayed Cost Curves

On a technology basis, MENA exports to Europe decrease by 2% if CSP is more expensive and remain the same if the costs of on-shore Wind increase. If Utility PV is more expensive, MENA exports to Europe increase by 5%. An increase in off-shore Wind costs leads to 19% more MENA exports to Europe compared to the Maximum Cooperation Scenario.

While higher off-shore Wind costs lead to the highest increase in desert power imports, higher CSP costs lead to the highest system cost increase: €15bn. more per year than in the Maximum Cooperation Scenario. System cost increases amount to €11bn. for more expensive on-shore Wind, €6bn. for Utility PV and €4bn. for off-shore Wind. Despite causing the largest change in desert power imports, the cost of replacing off-shore Wind is the lowest due to easy replacement with desert power.

Higher CSP costs cause the most significant changes in renewables capacities, with a move into more on-shore Wind and Utility PV, see Figure 112. At the same time, higher CSP costs also lead to a disproportionately large increase in south/north interconnector capacities compared to imports, due to the negative impact on the utilization of transmission infrastructure. If CSP becomes more expensive, 220GW of the technology is replaced by approx. 310GW on-shore Wind, 130GW Utility PV and 76GW more gas for balancing. This shift takes place mostly within MENA countries. If Utility PV is more expensive, approx. 280GW are replaced by approx. 65GW of CSP and approx. 70GW of on-shore Wind. This shift also takes place primarily within MENA, except for the replacement of approx. 20GW Utility PV each in Spain and Italy. Utility PV is almost completely replaced in North Africa. Shifts in on-shore Wind also take place mostly within the MENA regions, with approx. 120GW replaced by approx. 40GW CSP and 30GW Utility PV. Finally, approx. 100GW of off-shore Wind is replaced by approx. 100GW of on-shore Wind. This reduction in off-shore Wind capacity takes place primarily in BeNeLux, France and Germany, and is replaced by additional capacity in North Africa. Off-shore Wind is completely replaced in Iberia.

4.6.4 Cheap batteries

DP2050 analyzes how a very large power system based on Wind and Solar can be optimized. This involves enormous grids, a result that is quite robust under a range of limitations, as shown above.

Additional storage can be built everywhere in EUMENA in all scenarios at the cost of an advanced utility scale battery with 8h storage. By the system endogenous decision, storage is not installed in any of the scenarios analyzed so far. Therefore, we complete our analysis with a perspective that contains even cheaper storage. The storage cost of 500€/kW, equal to 63€/MWh storage capacity, of a battery with 8h storage in this scenario is an aggressive cost assumption that has been chosen in order to analyze the impact of storage on the system. Due to the diversity and low maturity of storage technology in general and batteries in particular, there is a high degree of uncertainty in storage cost estimates. Storage cost analysis beyond 2030 is therefore extremely difficult. The analysis for the standard battery assumption used is based on an optimistic analysis for 2030 storage costs. We hedge against this uncertainty with the Cheap Batteries sensitivity. Whether and how such costs can be reached is not the focus of this scenario.

Despite an overall limited effect of this very cheap storage, the expected effects of storage can be observed in the system. Cheap Batteries enable greater Utility PV production. For example, 14GW of batteries enable the use of 28GW of Utility PV in Turkey, thereby replacing 4GW of CCGT. Cheap Batteries also leads to the replacement of gas peakers in remote Wind regions – 7GW in the UK & Ireland as well as 3GW in Poland & Baltic. The gas generation freed up by storage is used instead for 4GW CCGT in the Middle East, thereby replacing 5GW of CSP and 3GW of Wind. In Libya & Egypt 4GW OCGT replace 6GW of on-shore Wind.

The results of this scenario show how that, far from being a competitor to an integrated EUMENA power system, very cheap batteries actually complement such a system and increase the level of MENA exports to Europe.

5 Conclusion: Time to Get Started

In this report we have analyzed the implications of desert power for EUMENA in 2050. The benefits of such a system are numerous and convincing. Now the question is how to make it happen.

While 40 years is a long time in most contexts, it is not in the power sector: in terms of electricity infrastructure, 2050 is only one to two investment cycles away. Therefore, the policy choices made today will determine whether a sustainable power system for EUMENA will be built by 2050.

Dii acts as a catalyst for industry, governments, civil society and other initiatives also working towards sustainable power for EUMENA. The DP2050 vision of a sustainable power system for EUMENA is so ambitious that only market forces will be able to achieve it. Market forces will, however, need appropriate framework conditions in order to gain momentum.

Dii's goal is to enable these conditions. In order to achieve its target, Dii is following a three step approach, as illustrated in Figure 113. Beyond the system strategy addressed in this report, Dii is also aiming to foster Solar, Wind and grid development on a country level in MENA. The resulting country strategies then guide the identification of reference projects that Dii seeks to enable. These reference projects provide concrete examples of the first steps on the path towards the DP2050 vision.

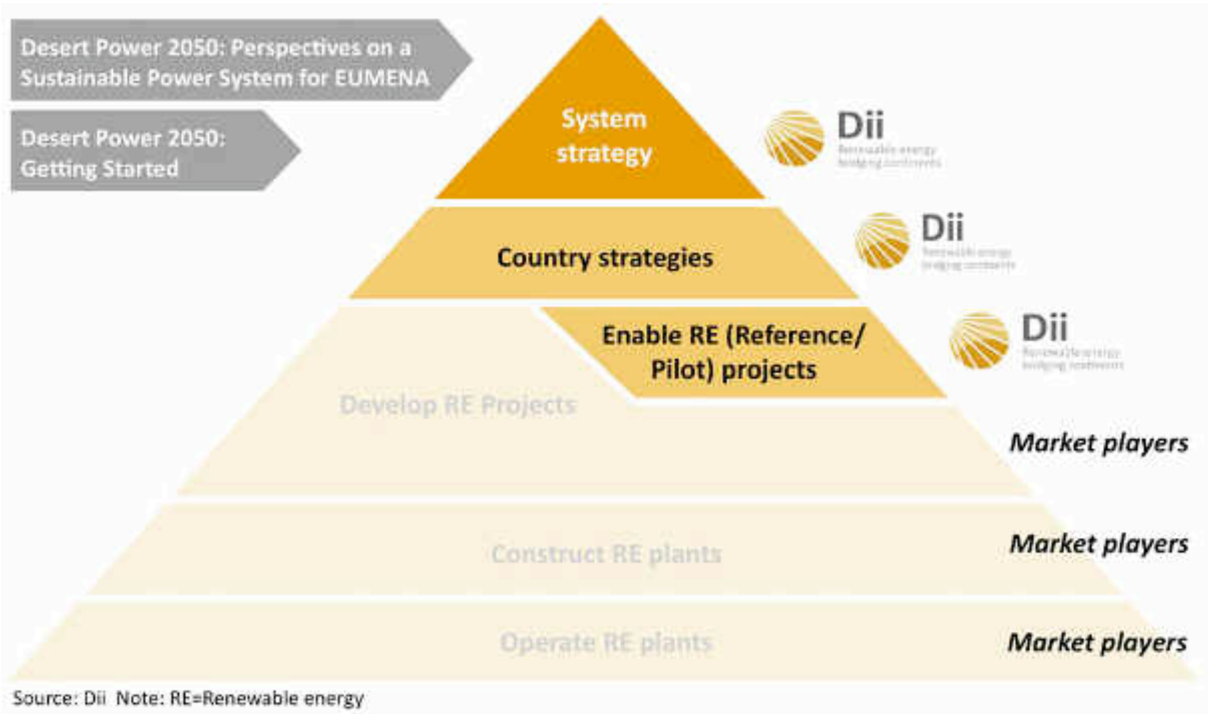


Figure 113: Dii strategy pyramid

The missing link in this three step approach is a system level view of the path leading from today to the 2050 target picture described in DP2050. **Desert Power 2050: Getting Started** will be dedicated to outlining such a path from a system perspective. While DP2050 describes a vision, DP2050: Getting Started ("Getting Started") will outline the corresponding mission.

Getting Started aims to provide decision makers with inputs on the key investment and policy choices that need to be made now. It will take a closer look at the technology and geography of the first gigawatts of desert power, by analyzing a roll-out path to 2050 in ten year time steps. It will assess the action needed to build interconnectors, especially in the next 20 years, with the aim to provide input for grid development plans, such as ENTSO-E's Ten Year Network Development Plans.

In addition to examining these interim goals, Getting Started will illustrate the policy choices needed to make the DP2050 vision a reality – the roll-back view complementing the above roll-out approach. This policy analysis will be based on a qualitative and quantitative assessment of relevant regulation in general and the right support schemes in particular. Finally, the benefits and implications of a sustainable power system for EUMENA beyond the power sector will be analyzed – the focus here will be on the socio-economic impacts of desert power, from job effects to macro-economic implications.

In Getting Started, we will outline in greater detail the key challenges on the way to implementing a sustainable EUMENA power system and how they can best be addressed.

5.1 Roll-out of Solar and Wind in MENA

Which technologies should be built when? In which parts of EUMENA in general? Where in MENA in particular? These are some of the central questions addressed by Getting Started.

In a first step, the details of a cost optimal path for the roll-out of a sustainable EUMENA power system will be analyzed. This will complement the cost optimal target picture from this report. These two approaches differ in an important way: the transition from today's power system to 2050 will take into account the cost of the transition steps in 2020, 2030 and 2040. In the early time steps of this procedure, much smaller quantities of renewables will need to be considered than in the target picture. This requires a system optimization based on even more detailed geographical information than in DP2050, which also takes into account existing generation and grid infrastructure. In turn, this makes it possible to answer questions concerning where and when Solar and Wind plants should be built.

Due to the different maturity levels of technologies today and varying cost reductions paths over the next forty years, the outcome of the path analysis will likely differ from the target picture shown in DP2050. For this reason, it is not enough simply to look at the roll-out picture leading to a decarbonized EUMENA power system. Instead, we complement this roll-out with a roll-back approach that identifies the paths to the vision presented in DP2050, described in greater detail in Section 5.3.

Making desert power for EUMENA a reality by 2050 requires the build-up of hundreds of gigawatts of renewables in MENA. This part of Getting Started will shed light on the location and timing of this build-up of CSP, Utility PV and Wind capacities.

5.2 Transmission highways between MENA and Europe

An integrated, sustainable EUMENA power system requires new grids. As DP2050 has made clear, the high voltage transmission grid must reach another order of magnitude by 2050, not only compared to today but also to the ENTSO-E's plans for the next decade. Successful build-up of transmission infrastructure is crucial for any renewable power system, including the integration of MENA and European grids.

It is therefore essential to understand not just how and where new grids should be built. Additionally, it is important to identify the technical and regulatory implications of this process for the power system overall and for the key north-south corridors identified in this study in particular.

The grid study part of Getting Started will provide a pre-feasibility analysis of such power highways for the EUMENA region. This study is being performed together with specialized consultancies with expert knowledge of power transmission around the Mediterranean and in close cooperation with transmission system operators. It is based on the results of the simplified grid modeling in DP2050 with one node per country. For 2050, a grid vision will be developed. The main corridors linking the key resource and load centers in the MENA region to load centers in Europe will be determined and a first set of possible routes for a high-voltage direct current (HVDC) grid will be proposed. This will split major countries into several sub-regions. For 2030, the results of DP2050 will be converted into a high voltage grid model based on an actual load-flow analysis. This makes it possible to examine in detail a first set of EUMENA highways to be built in HVDC or high-voltage alternating current (HVAC) technology by 2030 – as well as their integration into the existing transmission grids in Europe and MENA. This model will include possible connection points between the existing HVAC system grid and the future HVDC grids.

Since the need for power transmission within Europe remains essentially the same in the Connected and Reference Scenarios presented in DP2050, Europe will need to build grids in order to optimize its own power system – whether or not it imports desert power from MENA. For this reason, the grid study aims to provide valuable input to decision makers on how to maximize the benefits from a process that will need to be undertaken whether or not desert power is an explicit goal.

Beyond the question of where transmission infrastructure should be built, finding ways to incentivize the construction of this new infrastructure will be a key challenge. Consequently, in cooperation with key stakeholders, Dii will develop a detailed vision of the transmission and regulatory tools that could feasibly incentivize transmission infrastructure between Europe and MENA countries. This will be complemented by an assessment of the organizational changes that could help foster such developments. To this end, an economic analysis will be carried out in order to identify which regulatory and transmission tools could be implemented, and how efficient these tools are. The analysis will look at cost regulation, planning and permitting processes and associated costs, as well as access to and capacity allocation of interconnections. In addition, we will analyze which institutions are suitable to carry out these tasks and how the current institutional landscape might need to be enhanced, e.g. by regulatory authorities, transnational system operators or associations of TSOs or regulatory bodies.

5.3 Support scheme design

Having gained an understanding of the cost optimal roll-out of Wind and Solar in MENA and the corresponding grid extensions necessary to reach the DP2050 target picture, the next question arises. What is the appropriate policy framework for enabling the implementation of a sustainable power system for EUMENA? How can this framework be designed to minimize the public support needed? These questions concern the general regulation of the power sector as well as support scheme designs. Support schemes will be needed until renewables technologies reach broad cost competitiveness. They are also required for the realization of the system-level benefits of EUMENA-wide integration.

The period between 2020 and 2030 will be decisive in determining the success of desert power's transition to a larger scale. To this end, different policy pathways will be evaluated for their suitability to foster desert power in both Europe and MENA. The key criteria for this include European demand for renewables imports from third countries, the ability to support specific technologies, the dependence on fast grid build-up and the competitiveness of desert power with domestic European renewables. Support schemes will need to be efficient, effective by providing sufficient investor security, equitable and politically feasible. By providing input to policy makers on medium- to long-term support mechanism designs, the analysis will move beyond the current toolbox of tailored support mechanisms, which are useful for the first desert power reference projects.

A variety of support schemes are in principle suitable vehicles to promote renewables from MENA in both MENA and Europe. They can be classified according to two dimensions. The first dimension is the *degree of harmonization*, i.e. at which administrative level RES-E targets are set and decisions on support schemes are taken. The second dimension covers the specifications of the pathway, including the *type of support instrument* chosen, as well as its specific *design elements*, *cost allocation* and others.

Regarding the degree of harmonization, the spectrum stretches from full harmonization at EUMENA level to a continuation of national support schemes, which are coordinated according to best practice criteria to allow for gradual convergence.

Concerning the type of instrument banded quota systems, feed-in tariffs or premiums and tendering systems are possible, albeit not the only, candidates. In a quota scheme with tradable green certificates (TGCs), a renewables target is set obliging parties such as distributors to ensure that a certain percentage of electricity is from renewables. RES-E producers thereby obtain TGCs depending on the number of kWh of electricity they feed into the grid. Selling those TGCs on a specialized market provides extra revenue and compensates the RES-E producers for the additional cost of producing electricity from renewables sources. Under a feed-in tariff scheme, RES-E producers receive a fixed tariff for a specified amount of time (usually 15-20 years) for the electricity they feed into the grid. A feed-in premium scheme (FiP), in addition, links RES-E support to the general electricity market: RES-E producers sell their electricity on the market and receive a fixed or floating premium for every kWh sold in addition to the regular electricity price. Each type of instrument offers a variety of specific design mechanisms to optimize the scheme. For feasible mechanisms, detailed design elements will be determined. These may include a concept for the determination of the tariff level including dynamic adjustments (e.g. for FiP), options for resource specific / site specific remuneration of RES-E, options to combine generation-based and investment-based support schemes, a concept for the determination of reference electricity price (for FiP), and the duration of support. Based on such a thorough analysis of suitable support schemes, a quantitative comparison of the roll-out and the roll-back approaches to reaching a sustainable power system for EUMENA will be possible. This will create additional transparency for decision makers.

Such transparency is essential since the aim of Getting Started is to identify the path towards desert power that relies on as little public support as possible. This goal can best be met by promoting the optimal use of renewables in prime locations; specific support scheme designs will be proposed for this purpose. These designs will aim to leverage market players early on, be predictable as well as limited in scope, and to have clear phase-out provisions.

5.4 Socio-economic effects

A key factor for decision makers is the impact that regulation for a sustainable EUMENA power system will have beyond the power sector. This will be addressed by a socio-economic assessment that is part of Getting Started.

The socio-economic assessment will show how desert power not only encourages economic growth by providing affordable, stable electricity; but how it contributes directly to socio-economic benefits, such as the creation of new jobs, the growth of new industries, and economic development in general.

Technology	Sector	EUMENA capacity in 2050	Lifetime of plant	Annual capacity replacement	Estimated job multiplier 2050	People employed 2050
CSP	Manufacturing	~360GW	30 years	~12GW	3.0 people/MW	36,000
	Construction		30 years	~12GW	5.2 people/MW	62,400
	O&M		→	→	0.5 people/MW	180,000
	Total					**278,400**
PV	Manufacturing	~520GW	25 years	~21GW	2.0 people/MW	42,000
	Construction		25 years	~21GW	2.2 people/MW	46,200
	O&M		→	→	0.3 people/MW	156,000
	Total					**244,200**
Wind[1]	Manufacturing	~1,720GW	25 years	~69GW	2.4 people/MW	165,600
	Construction		25 years	~69GW	0.7 people/MW	48,300
	O&M		→	→	0.1 people/MW	172,000
	Total					**385,900**
Grid	Manufacturing	~100,000km	40 years	2,500km	0.5 people/km	1,250
	Construction		40 years	2,500km	0.7 people/km	1,750
	O&M		→	→	0.3 people/km	30,000
	Total					**33,000**
All	Grand total					**~941,500**

Figure 114: Preliminary analysis of job effects related to a sustainable power for EUMENA

A simple preliminary analysis is intended to demonstrate the order of magnitude of these socio-economic benefits. The industry related to a system of this size alone can lead to the creation of up to 1,000,000 new jobs. Figure 114 shows how this estimate has been derived[72,73]. This figure refers both to the jobs in operating and maintaining plants and grids (O&M), as well as to the jobs in construction and manufacturing needed to build and renew such a power system.

It should be noted that, while the job effects analysis above includes both direct and indirect jobs in the renewables sector, it does not yet include induced impacts, i.e. the additional labor effects of these new jobs across the economy. At the current stage, the analysis also neglects labor productivity differences across regions, and skills availability in specific regions. The induced impacts of permanent jobs created by renewable energy tend to be sizeable and are likely to have a significant additional effect on MENA economies. For Getting Started, a comprehensive job effects analysis will be extended to form part of a broader localization study that will examine the conditions and characteristics of a local renewable energy industry in MENA.

Job effects are part of a range of socio-economic effects. The localization study will therefore be embedded in an economic impact assessment of DP2050 scenarios, with a focus on their economic implications across sectors and across regions. A macro-economic general equilibrium model will be used to quantify the impacts on regional and sectoral macro-economic variables such as GDP, investment, imports and exports of different renewable energy build-up paths and investment strategies.

A competitive local renewables industry is essential for MENA to fully benefit from desert power's socio-economic impacts. For a successful local industry to emerge, however, the MENA region's pressing human capital challenges need to be addressed. Without improvement, the region's current deficits in education will limit the availability of skilled workers and, thus, will impede the expansion of a local renewables industry. What is required is an enabling MENA education policy – an education policy that will allow the groundwork to be laid for a renewables industry, but will also encourage the greater accumulation of skills in MENA countries.

Education reform in MENA therefore needs to become more centered on labor market demand. A focus on content and quality is essential for this to occur. The same holds true for greater interaction between private-sector employers and educational institutions. At all levels, industry and the education system in MENA are still too separate from one another, leading to negative effects on many levels, from a shortage of marketable skills among graduates to a lack of private-sector involvement in research and development (R&D).

Education policy reform and capacity building more generally are part of a longer process involving different stakeholders. As an industrial initiative, Dii sees its role in this area as a bridge between industry and the education system in MENA, as well as a voice for educational reforms supported by many MENA governments and key international institutions. While these institutions address the

[72] Job multipliers are based on NREL Transmission Job creation study (2011) and expert knowledge; labor productivity improvements have been extrapolated from the 2008 rates

[73] No differentiation between on-shore and off-shore Wind and various transmission cable technologies

education topic as a whole, Dii is trying to make a difference in the daily work with its local partners, e.g. on country studies, reference projects and with an internship program.

5.5 Last but not least

DP2050 showed that a sustainable, integrated EUMENA power system is a highly valuable goal for the entire region. Getting Started will demonstrate that this goal is not just desirable but can be implemented.

Leaving the system strategy aside, the above brief on education policy and Dii's contributions is intended to remind readers of two crucial facts. First, the whole process of moving towards a sustainable EUMENA power system is primarily about people – their choices, decisions and visions. Second, everybody can make a contribution and the total impact can be greater than the sum of its parts.

The fact that the vision of a sustainable power system for EUMENA is still a paradigm shift away should not be taken as a reason that it will not be achieved. "Win-win" paradigm shifts have occurred in the past and can happen in the future, too. In 1951, the European Coal and Steel Community was the first step towards European integration.

Today, we can choose to take the first step towards a common market for renewable energy in EUMENA – a vision of EUMENA supplying itself with sustainable and affordable power for future generations.

6 Definitions

Europe	
BNL	**BeNeLux**
BE	Belgium
LU	Luxembourg
NL	Netherlands
CE	**Central Europe**
AT	Austria
CH	Switzerland
CZ	Czech Republic
HU	Hungary
SI	Slovenia
SK	Slovakia
DE	**Germany**
FR	**France**
Iberia	**Iberia**
ES	Spain
PT	Portugal
IT	**Italy**
Nordic	**Nordic**
DK	Denmark
FI	Finland
NO	Norway
SE	Sweden
P&B	**Poland & Baltic**
EE	Estonia
LT	Lithuania
LV	Latvia
PL	Poland
SEE	**South Eastern Europe**
BG	Bulgaria
CY	Cyprus
GR	Greece
RO	Romania
MT	Malta
TR	**Turkey**
UK&IE	**UK and Ireland**
IE	Ireland
UK	United Kingdom
MENA	
Maghreb	**Maghreb**
DZ	Algeria
MA	Morocco
TN	Tunisia
L&E	**Libya & Egypt**
EG	Egypt
LY	Libya
ME	**Middle East**
JO	Jordan
SA	Saudi Arabia
SY	Syria

€	Euro
€M	Euro Millions
a	Years
AC	Alternating Current
approx.	Approximately
AUE	Arab Union of Electricity
bn.	Billion
CAPEX	Capital Expenditure
Carbon Emissions	CO_2 Emissions
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CORINE	Coordination of Information on the Environment Land Cover
CSP	Concentrating Solar Power
DC	Direct Current
Dii	Dii GmbH
DNI	Direct Normal Irradiation
DP2050	Desert Power 2050
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EU27	European Union as of 31/05/2012
EU27+2	EU27 + (Switzerland and Norway)
EUMENA	Europe, the Middle East and North Africa

FiP	Feed-In Premium
FLH	Full Load Hours
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
Gtonnes	Gigatonnes
GW(h)	Gigawatt (hour) = 1,000,000 kW(h)
GWEC	Global Wind Energy Council
GW_{NTC}	Gigawatt Net Transfer Capacity
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
ISI	Fraunhofer Institute for Systems and Innovation Research
km	Kilometer
kV	kilovolt
kW(h)	Kilowatt (hour)
kW_e	Kilowatt Electric, referring to the turbine capacity of a CSP plant
kW_p	Kilowatt Peak, referring to the nameplate capacity of a PV plant
LCOE	Levelized Cost of Electricity
ME	Middle East
MENA	Middle East and North Africa
MERRA	Modern-Era Retrospective Analysis for Research and Applications
MODIS	Moderate Resolution Imaging Spectroradiometer

Mtonnes	Megatonnes
MW(h)	Megawatt (hour) = 1,000 kW(h)
$MWh_{thermal}$	Megawatt hour, calorific value of a fuel
NaS	Sodium Sulfur
NASA	National Aeronautics and Space Administration
NREAP	National Renewable Energy Action Plan
NREL	National Renewable Energy Laboratory
NTC	Net Transfer Capacity
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
ONE	Office National d'Électricité
p.a.	Per Annum
PHS	Pumped Hydro Storage
ppm	Parts Per Million
PV	Photovoltaic
R&D	Research and Development
RE	Renewable Energy
RES	Renewable Energy Sources
RES-E	Renewable Energy Share – Electricity
SFOE	Swiss Federal Office of Energy
Summer	April-September
TEIAS	Turkish Electricity Transmission Company
TSO	Transmission System Operator
TW(h)	Terawatt (hour) = 1,000,000,000 kW(h)
TYNDP	Ten Year Network Development Plan
UCTE	Union for the Coordination of the Transmission of Electricity
UN	United Nations
UNCLOS	United Nations Convention on the Law of the Sea
UNFCCC	United Nations Framework Convention on Climate Change
WACC	Weighted Average Cost of Capital
WEO	World Energy Outlook
Winter	October-March

7 List of Tables

Table 1: Blended rate HVDC transmission assumptions 34
Table 2: Cost and efficiency assumptions for fossil fuel based power plant technologies 36
Table 3: Parameters for non-Solar, non-Wind renewables considered 38
Table 4: Storage parameters 40
Table 5: Parameters for Wind and Solar technologies 43
Table 6: Learning curve approach for technology cost reduction estimates 44
Table 7: LCOE for system cost in strategy analysis vs. real-life project finance 45
Table 8: Overview scenario definitions 100
Table 9: Conventional and CCS fossil fuel technology parameters 101
Table 10: Nuclear input parameters 101
Table 11: Cheap Battery input parameters 102
Table 12: Input parameters Wind/Solar technology investment for sensitivities 102

8 List of Figures

Figure 1: Solar resources in the EUMENA region 7
Figure 2: Wind resources in the EUMENA region 8
Figure 3: Renewable energy potentials and electricity demand 2050 in MENA and Europe 8
Figure 4: Cost reduction pathways for Wind and Solar technologies until 2050 9
Figure 5: System cost savings per MWh of net power exports from MENA to Europe 11
Figure 6: Generation and interconnector capacity, Connected Scenario 12
Figure 7: Power flows in the Connected Scenario 13
Figure 8: Transmission grid capacities in the Connected Scenario and the Reference Scenario 14
Figure 9: Daily and seasonal demand and supply in EUMENA 15
Figure 10: Daily and seasonal demand and supply in Europe and MENA 16
Figure 11: Scenarios assessed for robustness of EUMENA system integration 18
Figure 12: European net imports and interconnector capacities 19
Figure 13: Generation and interconnector capacity, Delayed Expensive Grid Scenario 20
Figure 14: Dii strategy pyramid 22
Figure 15: Solar resources in the EUMENA region 23
Figure 16: Wind resources in the EUMENA region 24
Figure 17: Residual load in a windy winter week in Egypt 27
Figure 18: EUMENA demand assumptions 2050 30
Figure 19: Carbon emission cap in 2050 compared to carbon emissions baseline 32
Figure 20: Schematic transmission grid 2050 for electricity system optimization 33
Figure 21: Hydro run-of-river and dam capacities today and 2050 37
Figure 22: Fixed generation from renewables 38
Figure 23: Pumped hydro and battery storage technology parameters 39
Figure 24: Cost reduction pathways for Wind and Solar technologies until 2050 42
Figure 25: Sample 2050 LCOE resulting from technology assumptions 43
Figure 26: Land use overview Europe, MENA 48
Figure 27: Country demand divided by area utilizable for Wind and Solar installations 49
Figure 28: On-shore Wind potentials in Europe and MENA 50
Figure 29: Off-shore Wind potentials in Europe 51
Figure 30: Utility PV potential in Europe and MENA based on 2050 cost estimate 52
Figure 31: CSP potentials in Europe and MENA 53
Figure 32: Lower limits (2050) on Solar and Wind capacities in EU27 53
Figure 33: Electricity trade between MENA and Europe 54
Figure 34: Average cost by technology in Connected and Reference Scenarios 55
Figure 35: Cost savings for Europe and exports for MENA 56
Figure 36: Total and interconnector-specific cost of MENA/Europe transmission 56
Figure 37: System cost savings per MWh of net power imports from MENA to Europe 57
Figure 38: System cost comparison and fixed vs. variable cost shares 59
Figure 39: Historic fossil fuel prices and impact on power generation cost 59
Figure 40: Electricity from gas and carbon emissions distribution/marginal cost 60
Figure 41: Carbon emissions by region Connected (left) vs. Reference Scenario (right) 61
Figure 42: Electricity production and power plant capacities by technology 62
Figure 43: Generation and interconnector capacity, Connected Scenario 63

Figure 44: Generation capacity changes from Connected Scenario to Reference Scenario 64
Figure 45: Relative regional change of installed capacities from Connected to Reference Scenario ... 64
Figure 46: Investment in renewables technologies by region at 2050 costs 65
Figure 47: Monthly distribution of supply from different technologies 66
Figure 48: Pumped hydro storage utilization 67
Figure 49: Curtailment by technology (pro rata) and season 68
Figure 50: Connected Scenario 2050 and today's gas generation and capacities 69
Figure 51: Grid capacities and capacity kilometers in the Connected and the Reference Scenario 70
Figure 52: Grid map Connected Scenario 71
Figure 53: Grid map Reference Scenario 72
Figure 54: Grid changes from Connected to Reference Scenario 73
Figure 55: Investment (at 2050 cost) into grids from region to region 74
Figure 56: Netted power flows, Connected Scenario 75
Figure 57: Electricity exporters/importers (left) and transit countries (right), Connected Scenario 76
Figure 58: Gross power flows, Connected Scenario 77
Figure 59: Sub-Mediterranean power flows from north to south 77
Figure 60: Power flows Reference Scenario 78
Figure 61: Monthly power flows in Europe, in MENA and on the interconnectors 79
Figure 62: Daily and seasonal demand and supply in EUMENA 80
Figure 63: Demand as share of peak load in the EUMENA region and selected countries 81
Figure 64: Utility PV production curve for EUMENA and selected countries, Connected Scenario. 81
Figure 65: Wind production curve for EUMENA and selected countries, Connected Scenario. 82
Figure 66: Daily and seasonal demand and supply in Europe & MENA 83
Figure 67: Net exporters and net importers in EUMENA 84
Figure 68: Daily and seasonal demand and supply in Norway 85
Figure 69: Daily and seasonal demand and supply in Morocco 85
Figure 70: Daily and seasonal demand and supply in Libya 86
Figure 71: Daily and seasonal demand and supply in Algeria. 86
Figure 72: Daily and seasonal demand and supply in France 88
Figure 73: Daily and seasonal demand and supply in Turkey 88
Figure 74: Daily and seasonal demand and supply in Germany 89
Figure 75: Daily and seasonal demand and supply in Italy 89
Figure 76: Daily and seasonal demand and supply in Saudi Arabia 90
Figure 77: Daily and seasonal demand and supply in Egypt 91
Figure 78: Daily and seasonal demand and supply in Spain 91
Figure 79: Daily and seasonal demand and supply in Tunisia 92
Figure 80: Daily and seasonal demand and supply in Denmark 92
Figure 81: Daily and seasonal demand and supply in Syria 93
Figure 82: Daily and seasonal demand and supply in the UK 94
Figure 83: Overall self-supply rates of the power sector, 2009 vs. 2050 96
Figure 84: Costs of EU27+2 reserve capacity (€M) 97
Figure 85: Sensitivities analyzed 99
Figure 86: Summary MENA net exports to Europe and MENA/Europe interconnectors 103
Figure 87: RES-E shares of different scenarios 103
Figure 88: System cost and system cost savings sorted by MENA net exports to Europe 104
Figure 89: Carbon emissions and marginal cost of carbon emission reduction overview 104

Figure 90: System cost of selected scenarios 105
Figure 91: Low demand production and capacities by technology 107
Figure 92: Monthly generation Low Connected/Reference and Connected Scenario 108
Figure 93: Grid capacities low demand........ 108
Figure 94: Low Demand Connected grid........ 109
Figure 95: Low demand cost advantage Europe and export volume MENA 110
Figure 96: Cost advantage per MWh net exports from MENA to Europe 110
Figure 97: Low Demand electricity from gas and carbon emissions distribution/marginal cost........ 111
Figure 98: Generation and interconnector capacity, Delayed Climate Action Scenario........ 112
Figure 99: Capacity changes from Connected Scenario to Delayed Climate Action........ 113
Figure 100: RES-E shares by region with Delayed Climate Action 113
Figure 101: Generation and interconnector capacity, Nuclear/CCS Scenario 114
Figure 102: Capacity changes Connected Scenario to Nuclear/CCS 115
Figure 103: RES-E shares by region with Nuclear/CCS........ 116
Figure 104: Generation and interconnector capacity, High Land Use Europe Scenario........ 116
Figure 105: Capacity changes Connected Scenario to High Land Use Europe........ 117
Figure 106: Generation and interconnector capacity, Delayed Grid Scenario 119
Figure 107: Capacity changes Connected Scenario to Delayed Grid 120
Figure 108: Generation and interconnector capacity, Delayed Expensive Grid Scenario........ 120
Figure 109: Major power flows in Delayed Expensive Grid Scenario 121
Figure 110: Generation and interconnector capacity, High Capital Cost MENA Scenario........ 122
Figure 111: Capacity changes Connected Scenario to High Capital Cost MENA........ 123
Figure 112: Capacity changes Maximum Cooperation Scenario to Delayed Cost Curves........ 125
Figure 113: Dii strategy pyramid........ 127
Figure 114: Preliminary analysis of job effects related to a sustainable power for EUMENA 131

9 Appendix

For appendix data, please contact us at www.dii-eumena.com, or info@dii-eumena.com.

English 06/2012

Dii Network