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Electricity system optimization in the EUMENA region

Technical Report

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ANNEX

Definitions

AAGR	Average Annual Growth Rate
ADEREE	Agency for Development of Renewable Energy and Energy Efficiency
AfDB	African Development Bank
AUPDTE	Arab Union of Electricity
AUPTDE	Arab Union of Producers, Transporters and Distributors of Electricity
BODC	British Oceanographic Data Centre
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CFADS	Cash Flow Available for Debt Service
CORINE	Coordination of Information on the Environment Land Cover
CPV	Concentrating Photovoltaic
CSP	Concentrating Solar Power
CSR	Corporate Social Responsibility
CTF	Clean Technology Fund (World Bank)
Dii	Dii GmbH
DLR	Deutsches Zentrum für Luft- und Raumfahrt
DNI	Direct Normal Irradiation
DSCR	Debt Service Coverage Ratio
DSRA	Debt Service Reserve Account
EC	European Commission
EIB	European Investment Bank
EIRR	Equity Internal Rate of Return
ENTSO-E	European Network of Transmission System Operators for Electricity
EPIA	European Photovoltaic Industry Association
ESPI	European Space Policy Institute
ETP	Energy Technology Perspectives, a publication by the IEA (2008)
EU	European Union
EUMENA	Europe, the Middle East and North Africa
EURIBOR	Euro Interbank Offered Rate
EWEA	European Wind Energy Association
GCC	Gulf Co-operation Council
GEBCO	General Bathymetric Chart of the Oceans
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
GW	Gigawatt
GWEC	Global Wind Energy Council
HDI	Human Development Index
HSBC	Hong Kong and Shanghai Banking Corporation
HTF	Heat Transfer Fluid (of a CSP plant)
HV	High voltage
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IIF	Institute of International Finance

IKI	Internationale Klimaschutzinitiative
IKLU	Initiative für Klima und Umweltschutz
IMF	International Monetary Fund
IPP	Independent Power Producer
IRR	Internal Rate of Return
IUCN	*International Union for Conservation of Nature*
KfW	Kreditanstalt für Wiederaufbau (German Development Bank)
LCOE	Levelized Cost of Energy
LIBOR	London Interbank Offered Rate
MASEN	Moroccan Agency for Solar Energy
ME	Middle East
MEMEE	Moroccan Ministry of Energy, Mines, Water and Environment
MENA	Middle East and North Africa
MODIS	Moderate Resolution Imaging Spectroradiometer
MoU	Memorandum of Understanding
Mt Co2-eq.	Metric ton Carbon Dioxide equivalent
MW	Megawatt
MW_e/kW_e	Mega/Kilowatt electric, referring to the turbine capacity of a CSP plant
MWh	Megawatt hour
MW_p/kW_p	Mega/Kilowatt peak, referring to the nameplate capacity of a PV plant
NA	North Africa
NREAP	National Renewable Energy Action Plan
NREL	National Renewable Energy Laboratory
NUTS 3	Nomenclature des unités territoriales statistiques – Statistical area unit applied in the European Union
O&M	Operation and maintenance
OCGT	Open Cycle Gas Turbine
OHL	Overhead Line
OME	Observatoire Méditerranéen de l'Energie
OMEL	Operador del Mercado Ibérico de Electricidad - Polo Español S.A.
ONE	Office National d'Électricité
OPEX	Operating Expenses
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity
PV	Photovoltaic
PwC	PricewaterhouseCoopers
RE	Renewable Energy
REE	Red Eléctrica de España
RES	Renewable Energy Sources
RES-E	Renewable Energy Share - Electricity
ROE	Return on Equity
RoP	Rollout Plan
SAM	System Advisory Model (software for CSP performance simulation)
SCPC	Supercritical Pulverized Coal
SEGS	Solar Energy Generating System
SPV	Special Purpose Vehicle
SRTM	Space Radar Topographic Mission

STC	Standard Testing Conditions
TSO	Transport System Operator
TWh	Terawatt hour
UBS	Merged Union Bank of Switzerland (UBS) and Swiss Bank Corporation (SBC)
UDI	UmweltDirektInvest Beratungsgesellschaft mbH
UfM	Union for the Mediterranean
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
USGS	U.S. Geological Survey
USSR	Union of Soviet Socialist Republics
WACC	Weighted Average Cost of Capital
WEO	World Energy Outlook
WGG	Working Group Generation
WGM	Working Group Markets

1 Summary

This report describes results of a techno-economic model optimizing a potential electricity generation system in the EUMENA region for the year 2050. In 32 scenarios, cost optimal systems for electricity generation, transmission and storage are calculated. The optimization goal is minimization of total system cost for annualized investment, operation and maintenance costs as well as fuel costs for the complete system. This includes cost elements for power plants, transmission networks and large-scale hydro as well as thermal storage. Costs for the national distribution grid are not included in this model.

The optimized systems must satisfy a strict CO_2 reduction goal of 95 % compared specific emissions (g_{CO2}/kWh_{el}) in the year 1990. In some scenarios, this requirement is replaced by a fixed CO_2 price that increases costs for use of fossil fuels (Coal, Gas). All solutions are compared by contribution of energy resources to electricity generation and by the resulting cost of electricity.

Cost optimality together with the goal to reduce greenhouse gas emission renders the optimal solution in the *Base* scenario a mix of all available renewable energy sources, with an emphasis on onshore wind power. Major contributors are offshore wind, photovoltaic, concentrating solar power, biomass and hydro power; remaining fluctuations are regulated using combined cycle power plants fueled by natural gas, as far as the CO_2 reduction goal allows.

The possibility to connect EU and MENA is exploited in order to balance the power input of fluctuating renewable sources. In scenario *Base*, more than 25 % of European electricity demand is imported from MENA countries. The interconnectors between the two regions have a summed capacity of 188 GW and annual full load hours from 3100 to 7100. These values are significantly higher than other transport lines that have mean full load hours of 2200.

Annual total system cost – excluding national distribution – in the base scenario are as high as 324 B€, corresponding to electricity costs of 73.0 €/MWh consumed. This means 5 % lower system costs compared to disconnected EU and MENA systems (scenario 03). Approximately 77 % of the costs are dedicated to generation. Only 9 % are for transport network (neglecting the distribution grids) and 14 % for storage. These shares are quite stable for all investigated scenarios. For comparison, in the cheapest simulated scenario 22 (without restriction on CO_2 emissions and no CO_2 price), total system cost are as low as 243 B€ or 25 % below base scenario.

Wind power is dominating source for electricity production with a share on overall electricity production of around 50 % in all main scenarios. PV accounts for another 10-15 %, whereas the share of CSP is about 3-10 % in main scenarios. The remaining electricity is provided through hydro, biomass and gas fired power plants. Wind power is dominating because of its comparatively low investment costs as well as very good balancing of wind power between regions in a huge and connected power system.

Existing hydro storage capacities in European countries, in total 206 TWh from pumped storage and dam lakes, are sufficient to create feasible solutions in all scenarios; flexible CSP is thus used to a relatively small amount, indicating only a minor need for additional

storage capacities. In disconnected systems however, more CSP is used for stabilizing the local energy balance in MENA.

A sensitivity analysis shows major changes in the optimized system configuration. Changed investment costs for renewable energy technologies increase or decrease their share in the optimal electricity generation mix. Consequently, onshore wind exhibits the biggest absolute changes in the electricity generation. Availability of nuclear power dominates the electricity generation in all countries. CCS has only minor impact on the optimal solution. In scenarios without CO_2 limits and low CO_2 prices (0, 50 €/t), coal fired power plants provide major shares of electricity, while high CO_2 prices (100, 150 €/t) lead to solutions comparable to the base scenario with CO_2 limit.

The first four main scenarios investigate the influence of high and low future electricity demand and compare a connected EUMENA system with two separated systems in Europe and North African/Middle East countries without interconnections. The remaining 28 scenarios are about sensitivities to changed input parameters. In chapter 2, the model is briefly described. Chapter 3 describes all modeled scenarios. In chapter 4, results of the four main scenarios are discussed in detail. Chapter 5 then highlights the key changes in the system caused by the parameter changes in the remaining scenarios, grouped by scenario types: these are cost variations for technologies (wind onshore and offshore, PV, CSP), availability of technology (nuclear power and CCS), economic parameters (WACC) and political restrictions (grid restrictions, autarky). Parameters and data sources are presented in chapter 6.

2 Model description

The TUM energy system design model finds a minimum-cost system configuration among a set of technologies to meet a predetermined electricity demand. It works on a time resolution of one hour and a spatial resolution of countries. Optimized are capacities for production and transport of electrical energy and the time schedule for their operation. Optimization goal is minimum total costs for electricity generation, transmission and storage.

2.1 Time and space

Modeled countries are the 27 member states of the European Union[1], Norway, Switzerland and Turkey for the European area. In addition, Morocco, Algeria, Tunisia, Libya, Egypt, Syria, Jordan and Saudi Arabia are included to model Middle East and North Africa (MENA). Italy and Spain are split into two and three separate regions to better model the spatial distribution of desert power input from MENA countries.

The time span covered consists of 12 weeks, equal to 2016 time steps. Each week represents one month of the year. The model is fully deterministic, meaning that unforeseen events like power plant breakdowns or errors of wind or demand forecasts are not considered, i.e. balancing requirements as well as reserve margins for generation are not covered by the model.

2.2 Electricity conversion

Energy conversion is modeled as processes that convert a so-called input commodity (e.g. solar energy, natural gas) to an output commodity (electric energy) with a certain efficiency. Both electricity generation and storage are processes. For storage processes, input and output commodity are identical.

These process chains are also divided by whether their hourly output power is predetermined (e.g. hydro, solar, wind) or can be controlled by the model (e.g. coal, gas). Predetermined commodities rely on time series of data (so-called *capacity factors*) that are derived from measured climate data. Each country has its own time series, reflecting the highly different availability of renewable energy sources per country.

2.2.1 Must-run power plants

Power generation from must-run power plants is predetermined through the weather situation in each hour of the year. Technologies that are modeled as must-run power plants in this model are: wind power onshore, wind power offshore, photovoltaic, run-of-river hydro power and geothermal power plants. Geothermal power plants are assumed to run at constant value during the whole year. All predefined time series are normalized to an annual sum of one. Each value is thus the percentage of energy produced within a year that is produced in this hour. These time series are calculated from weather data for each technology in a separated step before the optimization process. Section 6.5 lists the weather data sources.

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[1] Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

For wind power, measured hourly mean wind speeds are transformed to electric output power by applying a typical characteristic curve of a wind turbine. Photovoltaic power output is derived linearly from hourly global horizontal irradiation. Output of run-of-river hydro power is derived from monthly data on hydro power production per country that is then smoothed to an hourly time series through spline interpolation.

2.2.2 Controllable power plants

Controllable power plants are all fossil, biomass or nuclear fired power plants. In each hour, the model can decide how much electricity should be produced by each technology. Restrictions are the global limit for CO_2 emissions and a maximum potential for biomass production per country.

2.2.3 Concentrating solar power

Concentrating solar power plants are also controllable due to their integrated storage, but their available input energy still depends on the weather situation. Figure 1 shows the main components of a CSP plant. Solar radiation is collected by the collector and transformed into heat. This heat can then be fed directly into the turbine to generate electricity or be stored first in a thermal storage. In addition, a gas boiler can be installed to provide heat in times without solar radiation.

In the TUM model, the hourly heat production is an input parameter which is calculated for each region by the System Advisory Model (SAM). These hourly values are normalized to MWh/h/m², so that it can be scaled according to the optimized collector size. The capacities and hourly generation of each component of the CSP plant are optimized for each country. Thus, optimal configurations of the components can be figured out.

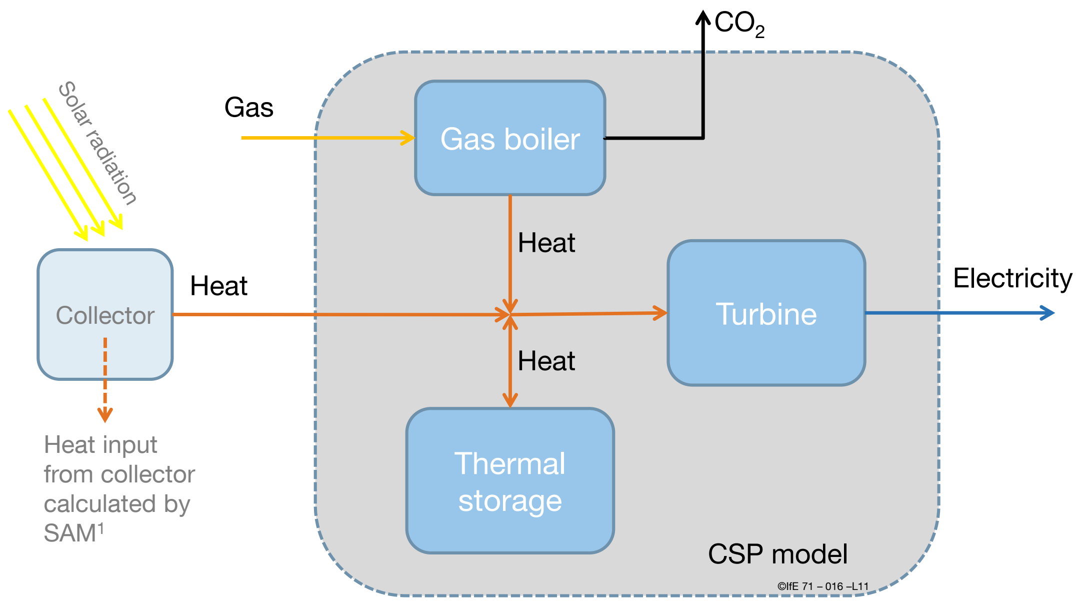

Figure 1: CSP model with its different components

2.2.4 Dam storage hydro power plants

Dam storage hydro power plants are also controllable but dependent on the weather situation. Opposed to run of river hydro power plants, water storage is included. Inflowing water can thus be stored first in this reservoir or fed directly to the turbine. The hourly water inflow is determined through monthly production of hydro plants according to data published by [3]. Full load hours of these time series can be seen in appendix A 4. All storage is initialized 50 % filled and must reach the same level at the end of the simulation timespan. In this model, capacity for dam storage is fixed and cannot be influenced through optimization.

2.3 Transmission

Electricity transmission among Europe is modeled using a country-to-country transport model, including losses according to the distance between two country's geographical center points. Transport model means that no load flow is simulated, but energy is allocated and transported like a physical good. Electricity transmission between MENA and Europe is modeled through designated DC power lines between certain countries, e.g. Morocco–Spain (south), Tunisia–Italy (north) or Algeria–France.

Distribution within a country is accounted for by 7.5 % losses. However, costs for the distribution network are not included in this model. For a discussion about costs for transmission vs. distribution networks, see chapter 5 in [17].

2.4 Storage

The model includes three different types of storage: Pumped hydro storage, dam storage, and thermal storage. The modeling approach for dam and thermal is described in the generation section as this storage only allows postponing electricity generation. In contrast, pumped hydro storage is the only possibility to feed with electricity from the grid, then store it and use it later. A pumped hydro storage consists of two processes: The pump transforms electricity to gravitational energy and the turbine transforms it back to electricity. Both processes have a specific efficiency as well as a maximum capacity assigned. In addition, the maximum energy content of the reservoir is limited. In the model, the reservoir level is half filled at the beginning of the optimization period and has to be half filled at the end again.

2.5 Model structure

The model itself consists of a huge set of parameters, variables and linear equations. Each parameter is a numeric value representing one aspect of the model, like availability of a renewable commodity, its costs, CO_2 emissions or efficiency. Each variable is a quantity whose value must be determined by the optimization algorithm. These are capacities of installed power plants and activity of controllable power plants for each country, process chain and time step.

Equations finally represent the connections between parameters and variables, thus forming the model structure. While some equations are used to calculate derived quantities (e.g. total electric energy generated per time step and country), other equations ensure that boundary conditions (e.g. emission limits, capacity constraints for power plants) are fulfilled.

2.6 Optimization

Each aspect of the model has costs attached to it. Installing capacities for any of the available processes causes investment costs, fixed annual costs for maintenance. Use of some power plants causes variable costs for actually converting energy (operating costs + fuel costs where applicable). Goal of the optimization is to find a system configuration of installed capacities and operation of plants, transmission, and storage so that total costs are minimized, while satisfying all boundary conditions. Considering storage, only the capacity of thermal storage can be optimized, capacities of other storage possibilities are set to a fixed level. The hourly operation however, can be optimized for all types of storage.

3 Scenario definitions

3.1 Main scenarios

Four main scenarios are considered in this study. These scenarios differ in level of net electricity demand and the possibility of electricity transport between European countries and North African/Middle East (MENA) countries. Turkey is considered European in this study. Table 1 shows major assumptions and parameter variations within the four main scenarios. All other parameters are kept constant to values which are described in chapter 6.

Table 1: Major scenario assumptions

Scenario	Net Demand EU+2 (TWh/a)	Net Demand Turkey (TWh/a)	Net Demand MENA (TWh/A)	Allowed CO_2 emissions (Mt/a)	EU – MENA interconnection allowed?
Base	3000	509	970	143	Yes
High demand	4521	763	2130	247	Yes
Disconnected systems	3000	509	970	143	No
Disc. systems / High demand	4521	763	2130	247	No

Base (scenario 01)

In the base scenario, transport between European and MENA countries is allowed through 14 interconnectors. A detailed description of the interconnectors can be found in chapter 6 *Input parameters*. The net electricity demand is kept constant at today's levels in EU+2 countries to 3000 TWh/a. In Turkey, demand increases to 509 TWh/a according to forecasts of the Turkish electricity transmission association [15]. In MENA countries, demand increases according WEO 2010 IEA 450 Policies scenarios to 970 TWh/a in the year 2050. Demand always means final electricity consumption. Electricity production however, is higher due to losses in transmission (depending on transport lines), distribution (7.5 %) as well as storage (Depending on storage type and utilization rate).

CO_2 emissions are limited in European countries (except Turkey) to a 95 % reduction in terms of specific emissions compared to 1990. In Turkey and MENA countries emissions are reduced to 50 % compared to the year 2000. Together, this means an overall CO_2 limit of 32 g/kWh consumed or 143 Mt/a in the EUMENA region.

High demand (scenario 02)

In the second scenario, net electricity demand is higher compared to the base scenario. In the European countries demand is increased from 3250 TWh in the base case to 4900 TWh. In Turkey, demand is increased from 550 TWh to 825 TWh and in MENA countries from 976 TWh to 2137 TWh.

The rational for the CO_2 limit is the same as in the base scenario. But as the increase in demand is higher in Turkey and MENA countries, the overall allowed CO_2 intensity is slightly higher with 31.4 g/kWh produced. Sum of allowed CO_2 emission for the EUMENA region is 247 Mt/a, equal to specific emission of 33.3 g/kWh consumed.

Disconnected systems (scenario 03)

In this scenario, transportation between MENA and European countries through interconnectors is completely forbidden. Electricity cannot be transported between continents. The electricity demand as well as the limit for CO_2 emissions is identical to scenario 01 *Base*. That means both EU and MENA share one common CO_2 limit.

Disconnected systems / High demand (scenario 04)

This scenario is a combination of scenarios 02 and 03. Transportation between MENA and European countries is forbidden. The electricity demand as well as the limit for CO2-Emissions is the same as in scenario 02 *High demand*.

3.2 Sensitivities

In the four main scenarios, only demand and allowed transmission lines are variable. In the following 28 sensitivity scenarios, the influence of other parameter variations is investigated. If not noted otherwise, electricity demand and CO_2 restrictions from scenario 01 *Base* is used. This section briefly lists the parameter changes in each scenario. Results are presented and discussed in chapter 5.

Technology cost variations (scenarios 05-09, 23, 28-31)

In scenario 05, investment and fixed costs for CSP (collector, cofiring, turbine and storage capacity) are at today's higher values. In scenario 28, all costs are decreased by 30 % compared to scenario 01. Investment and fixed costs for wind offshore are increased by 50 % in scenario 06 and decreased by 30 % in scenario 29. Investment and fixed costs for photovoltaic are increased by 50 % in scenario 07 and decreased by 30 % in scenario 30. Investment and fixed costs for wind onshore are increased by 50 % in scenario 08 and decreased by 30 % in scenario 31. Investment costs for transmission lines are increased by 50 % in scenario 09 and increased by 100 % in scenario 23.

WACC variation (scenarios 10-12)

WACC is 7 % in scenario 01 Base. It is decreased to 5 % in scenario 10 and increased to 9 % in scenario 11. In scenario 12, WACC is increased to 9 % only in MENA countries.

Availability of Nuclear & CCS (scenarios 13-18, 32)

In these scenarios, either construction of nuclear or CCS capacities is allowed. In scenario 13, nuclear power may be installed with investment cost of 3000 €/kW. This value is increased by 50 % in scenario 14, by 100 % in scenario 15 and by 150 % in scenario 32. In scenario 16, CCS (gas & coal) power may be installed with investment costs of 1500 €/kW (gas) and 2900 €/kW (coal). These values are increased by 50 % in scenario 17 and increased by 100 % in scenario 18.

CO_2 price instead of CO_2 limit (scenarios 19-21, 27)

No limit on CO_2 emissions is imposed in these scenarios. Instead, a CO_2 price increased variable costs for emitting processes. A price of 0 €/t is used in scenario 27, 50 €/t in scenario 20, 100 €/t in scenario 19 and 150 €/t in scenario 21.

Grid restrictions & autarky (scenarios 22, 24-26)

In scenario 22, European transmission capacities may only be increased to three times of today's NTCs. In scenarios 24-26, electricity demand per country must be satisfied in each hour by local electricity production with a share of 30, 50 and 70 %, respectively.

4 Main scenario results

4.1 Costs

One of the major question concerning desert power imports to Europe is system costs. System costs include annualized investment costs, O&M and fuel costs for generation, transmission and storage. Costs of distribution grids and other costs of the electricity supply system (e.g. balancing, reactive power, sales and marketing, metering) as well as taxes and other state burdens are not considered in the shown cost figures. Figure 2 shows EUMENA system costs of the four base scenarios. The gray part of the bars represents costs that are not influenced by the optimization process. It includes costs for power plants and grid that has to be build up according to political targets (i.e. given renewables targets for the year 2030 and additional pumped storage capacities; see chapter 6) as well as costs for pumped hydro storage. For both low and high demand, costs are lower in the interconnected system. In the base scenario annual system costs are 324 B€ compared to 340 B€ without EU-MENA interconnectors. In high demand scenarios costs are 533 B€ with and 567 B€ without the interconnectors.

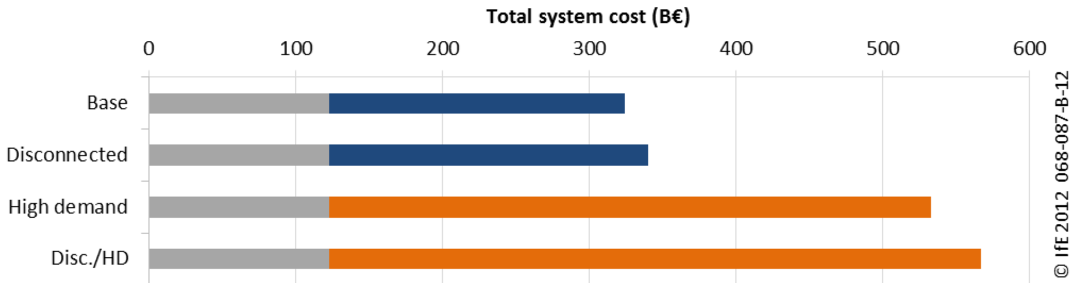

Figure 2: Total annual system cost (10^9 €) by scenario. Gray shows costs that are fixed by scenario definitions.

Relative cost differences are 4.7 % in the low demand and 6 % in the high demand scenario as illustrated in Figure 3. Considering only costs that can be influenced through optimization, reductions are higher with 7.3 % in the low demand and 7.8 % in the high demand scenario. The reason for higher cost reductions at high demand are restrictions to renewable energy resources in Europe. Especially wind power onshore – the most cost effective renewable technology in this model – is limited in European countries. In the high demand scenarios more expensive resources have to be used to provide enough electricity.

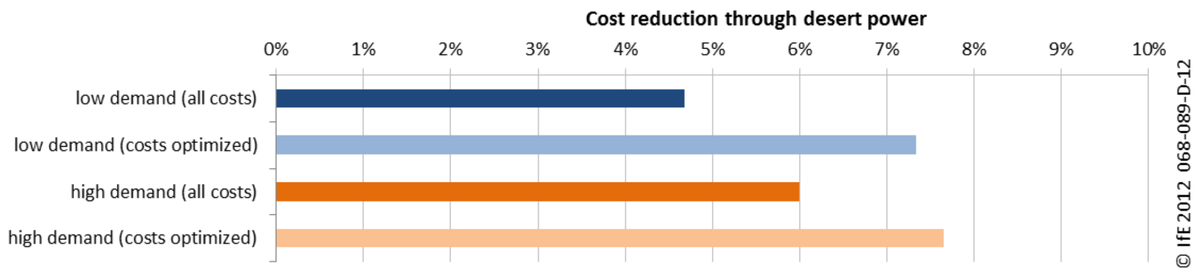

Figure 3: Relative cost difference between connected and disconnected systems.

Figure 4 shows resulting costs of electricity Costs of electricity are defined as system costs divided through the amount of consumed electricity. As stated earlier, these costs do only consider generation and transmission costs but do not include costs for national distribution and other system costs as well as taxes and state burdens. Costs can be reduced from 76.6 €/MWh to 73.0 €/MWh through a joint system optimization of connected systems in low demand scenarios and from 77.1 €/MWh to 72.5 €/MWh in high demand scenarios.

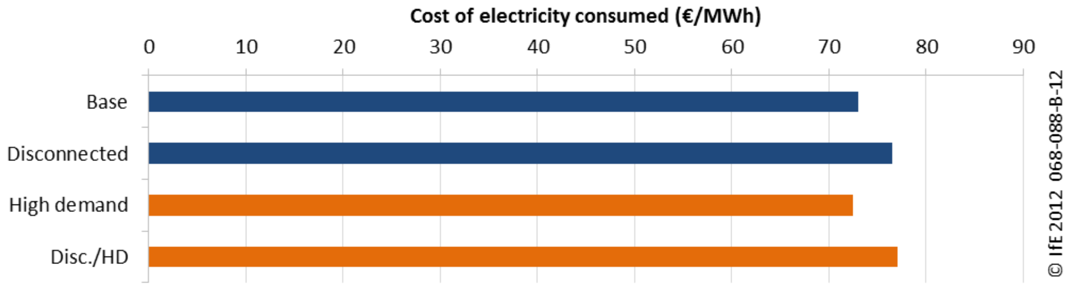

Figure 4: Costs of consumed electricity (€/MWh) by scenario.

Figure 5 shows the relative shares of system costs by electricity generation, transmission and storage. In all scenarios production has the highest share of costs with about 80 % of total costs. Transport and storage account for about 10 % each to total costs in all scenarios. Share for transport is higher in connected systems. In low demand scenarios it is 29.5 B€ in connected systems compared to 23.9 B€ in disconnected systems (24 % more). In high demand scenarios costs for transport are 60.1 B€ in connected systems and 44.6 B€ in the disconnected systems (35 % more). While storage costs stay relatively stable between scenarios *Base* and *High demand*, costs for transmission roughly double. That explains the rise in share of transmission costs in the *High demand* case. Costs for electricity losses in transmission or storage cannot be included explicitly to transmission or storage as the value of lost electricity varies over time. Costs occur in the generation process and thus, costs for losses are accounted to production in the model.

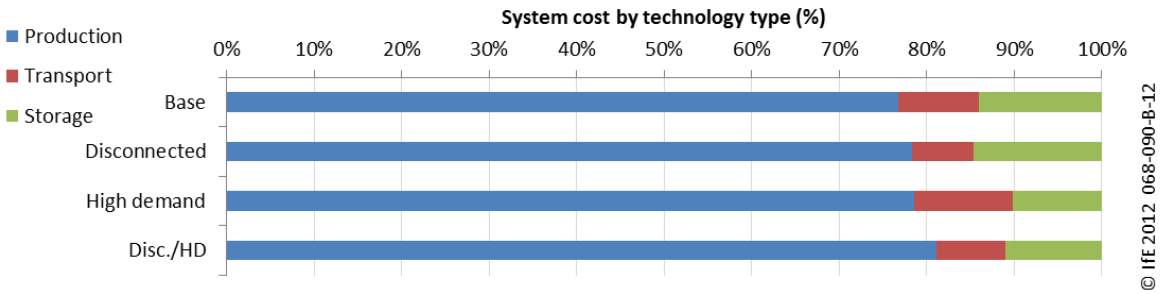

Figure 5: Relative shares of system costs by electricity generation, transmission and storage per scenario.

Changing the electricity system from a mainly fossil based to a renewable energy based system means changing it to a very capital intense system. Figure 6 shows the split of costs into annualized investment, O&M (Fix and variable) as well as fuel costs. The share of investment costs is stable around 68 % with very small deviations between scenarios. Fuel costs only account to a small amount of about 7 % in all scenarios. Fuel costs however do not include any taxes or prices for carbon emissions. The CO_2 reduction of the power system is implemented through a fix limit and not through additional system costs. The marginal price for carbon emission as described in section 4.4 is the marginal value of this CO_2-limit constraint in the optimization model.

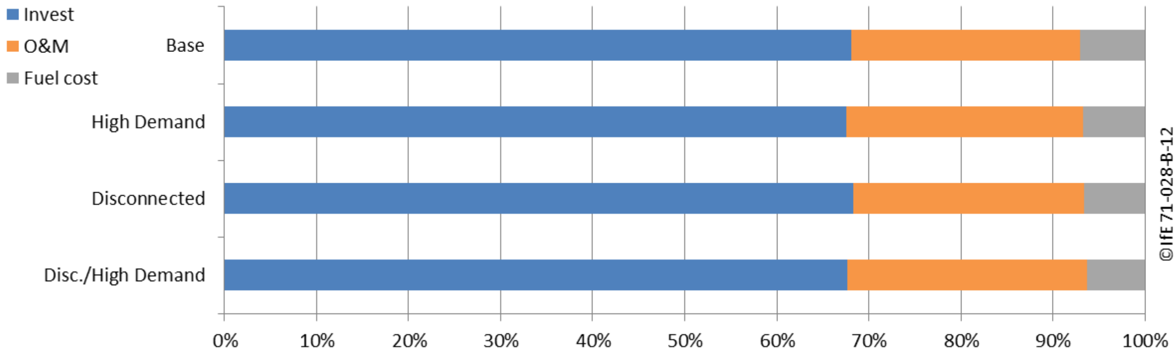

Figure 6: Annual system costs split into Invest & O&M

4.2 Electricity production

One focus of this study was to find optimal electricity generation mixes for different scenarios. This section will show the electricity mix in the four main scenarios and its distribution to 12 defined regions. All available renewable technologies were used in all scenarios with onshore wind power being the dominating technology. Wind power accounts for about 50 % of total electricity production. This means an electricity production of 2200 TWh up to 4700 TWh per year.

Figure 7 shows electricity production of different technologies in the four main scenarios in TWh, Figure 8 shows the relative shares respectively. The share of wind power is higher in the connected systems than in the disconnected systems (56 % vs. 51 % at low demand and 61 % vs. 55 % at high demand). Reasons for the higher share in connected systems are wind power balancing effects between regions and the high wind power potentials in MENA that allow exporting electricity from this most cost effective technology to Europe. PV accounts for about 10 % in all scenarios with slightly more in disconnected system as a “compensation” for wind power. The share of CSP varies between scenarios and is higher in disconnected systems and with higher demand. The higher shares in disconnected systems result from lower smoothening effects and resulting additional balancing power needed compared to connected systems. Higher demand also leads to a higher share of CSP as cheap wind power resources are scarcer and thus, CSP is more competitive. Shares of hydro power (run-of river and dam storage), pumped storage and geothermal power are the same in all scenarios as installed capacities are fixed and not subject for optimization. Biomass has a resource limit that is utilized almost to its maximum in all 4 scenarios. The production from gas fired power plants corresponds to the allowed CO_2 emissions in the scenarios and is thus the same in scenarios with low and in scenarios with high demand. CO_2 emissions are as high as allowed in all scenarios because gas based electricity generation is even in a heavily carbon restricted world with high carbon prices more economic than other flexible generation options. “Others” summarizes all other renewable technologies that are not explicitly mentioned according to EU Energy Trends 2030 [12].

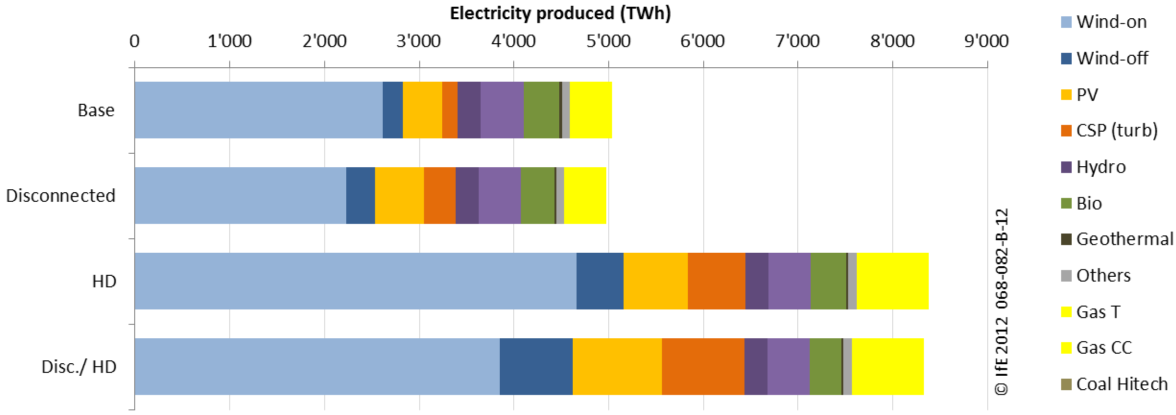

Figure 7: Generated electricity (TWh) by input commodity and scenario.

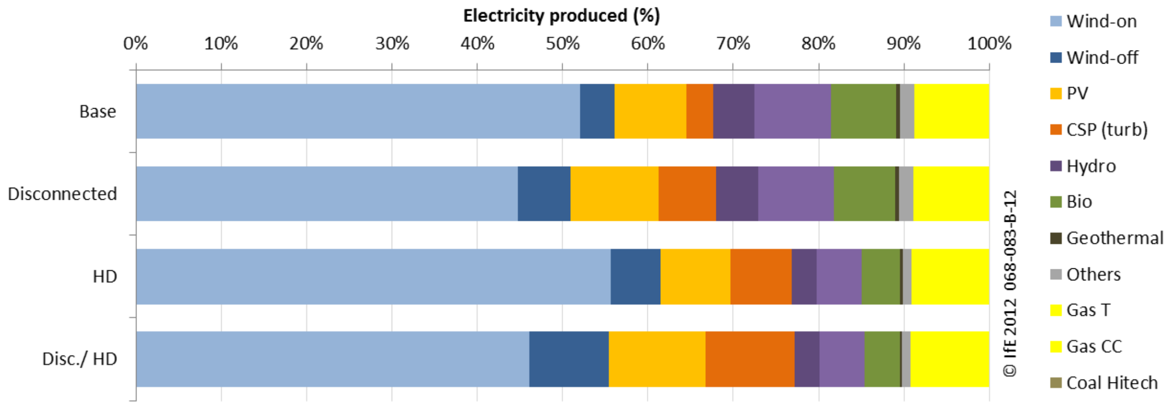

Figure 8: Relative shares of generated electricity by input commodity and scenario.

The next section describes the regional distribution of electricity production per technology. Figure 9 illustrates the generation distribution in the base scenario. MENA is the main electricity production region. All CSP and major parts of PV production facilities are installed in this sunny region. Gas fired power plants are distributed over all regions as transport losses for electricity from scarce gas resources are a not an optimal solution. Hydro power resources are concentrated mainly in Central Europe, Nordic countries as well as Turkey.

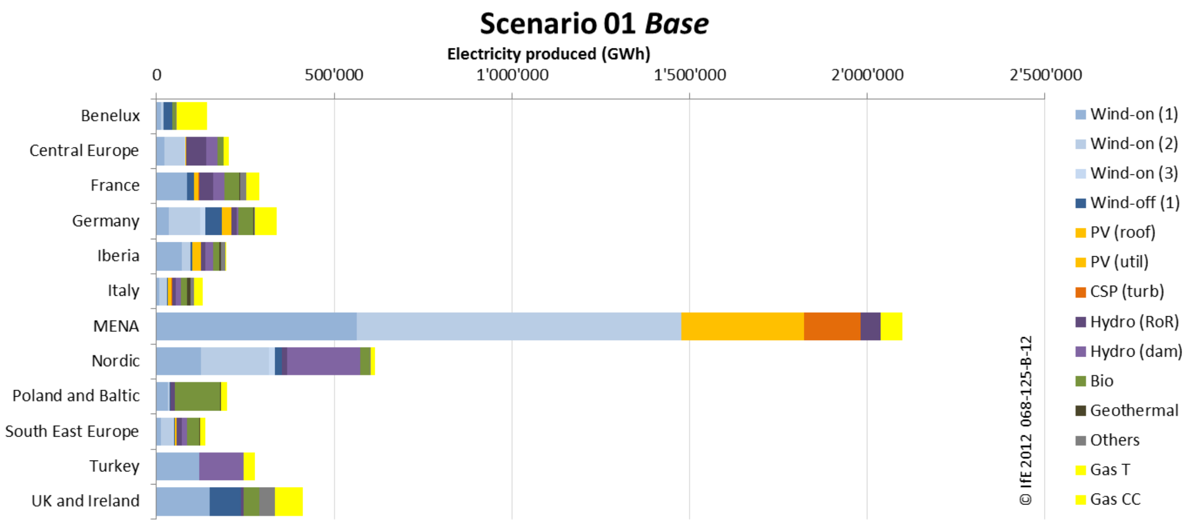

Figure 9: Electricity production by region and input commodity scenario 01 *Base*.

Figure 10 shows electricity generation in the low demand scenario with disconnected systems. In order to compare connected with disconnected systems, Figure 11 shows the difference in electricity production between those two scenarios with low demand. In disconnected systems production is shifted from MENA to European sites. Main sources of additional electricity generation in Europe are wind power in Nordic (onshore and offshore), Turkey and UK as well as PV in southern European regions. More CSP is needed in both Europe and MENA because of less balancing effects.

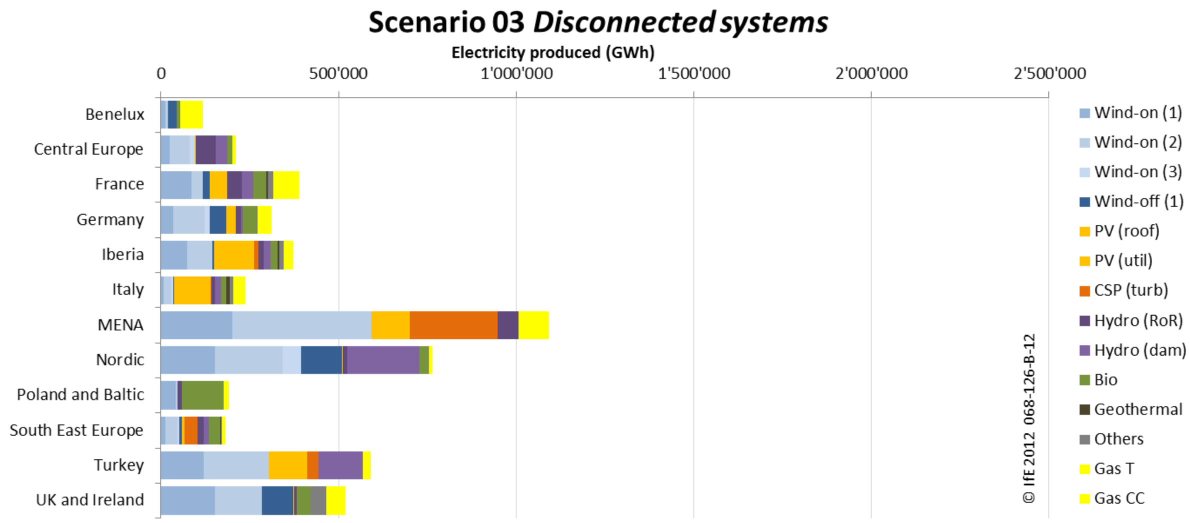

Figure 10: Electricity production by region and input commodity in scenario 03 *Disconnected systems*.

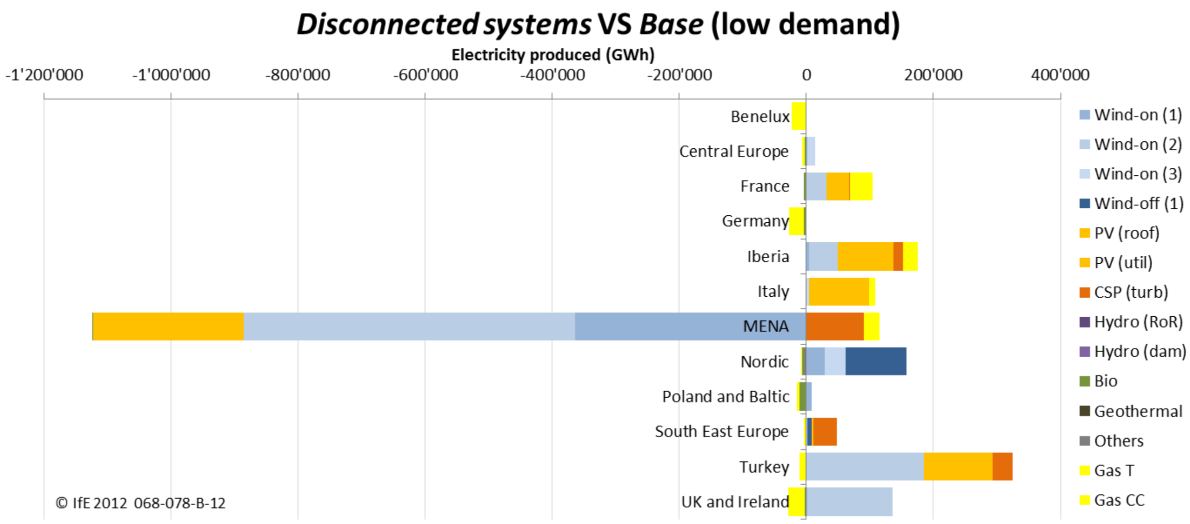

Figure 11: Difference in electricity production by region and input commodity between scenarios 01 and 03.

The following figures again show the geographic distribution of technologies for connected and disconnected systems but for high demand now (Figure 12, Figure 13 and Figure 14). Effects are closely the same as in low demand scenarios. One exception is less usage of CSP in MENA in disconnected systems compared to connected systems although the overall share of CSP is higher. A possible reason is the share of CSP that is placed in MENA but used to provide flexible power for Europe in connected systems.

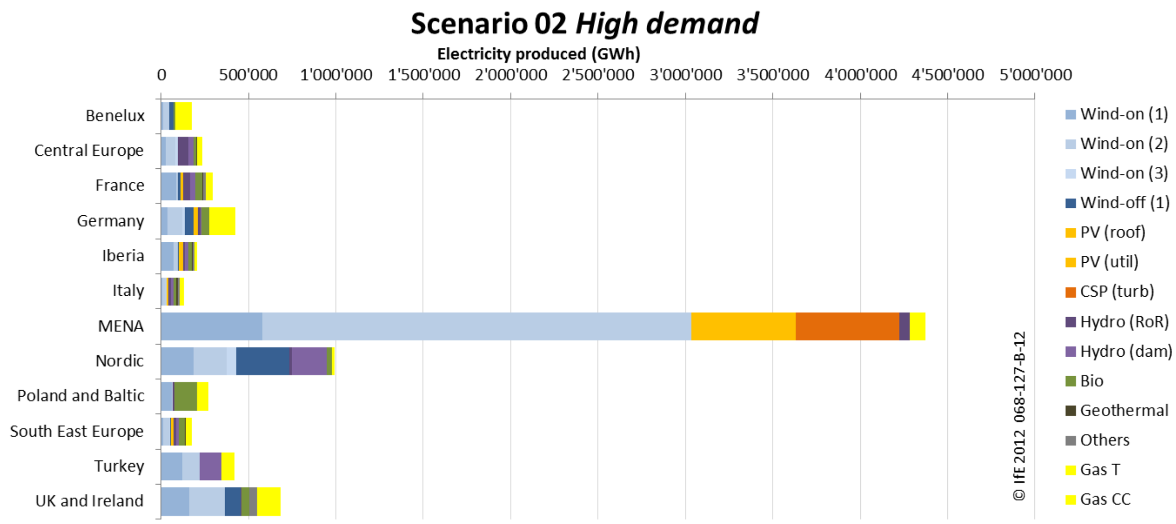

Figure 12: Electricity production by region and input commodity scenario 02 *High Demand*.

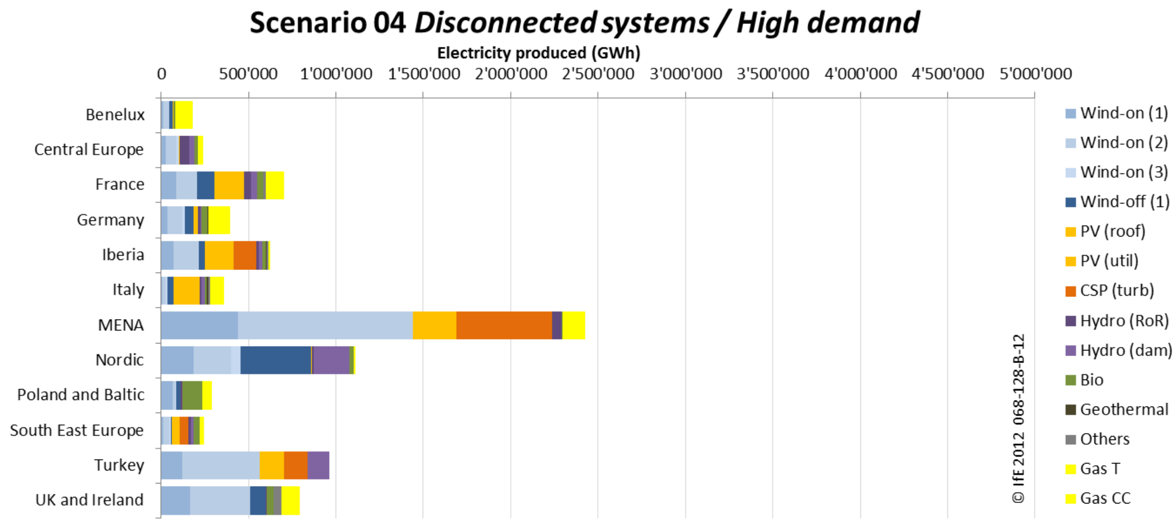

Figure 13: Electricity production by region and input commodity scenario 04 *Disconnected systems / High Demand*.

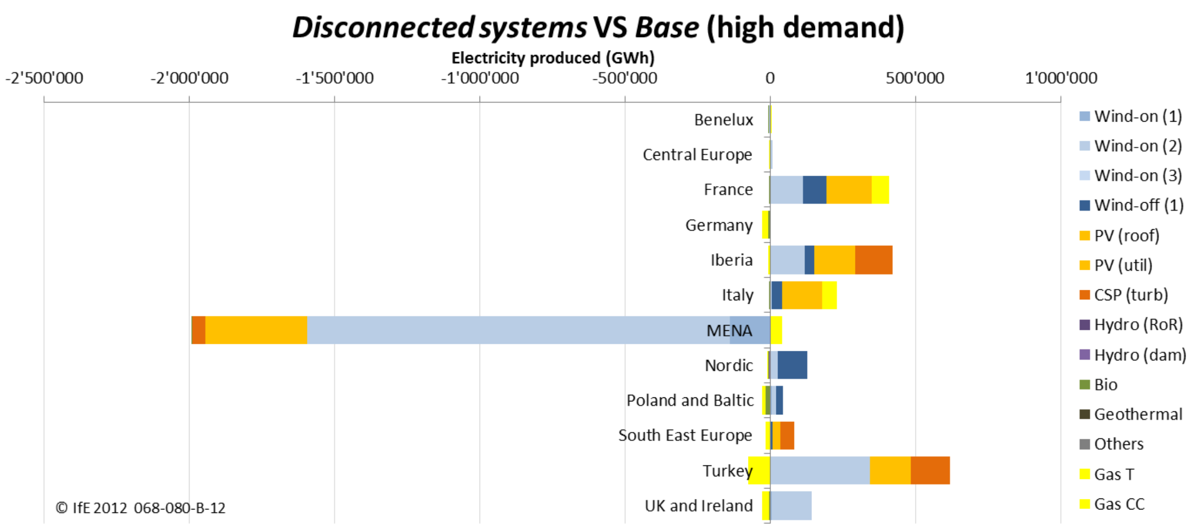

Figure 14: Difference in electricity production by region and input commodity between scenarios 04 and 02.

The next two figures compare high and low demand scenarios in connected systems (Figure 15) and disconnected systems (Figure 16). In scenarios with connected systems, additional electricity is mainly produced in MENA region. Offshore wind power is used in Nordic countries to a significant amount. In scenarios with disconnected systems, however, additional electricity is produced in mostly all regions. CSP and PV are used in southern countries and offshore wind power is installed in France, Iberia, Italy, the Nordic and the Baltics. In both cases additional electricity can be produced from natural gas as the CO_2 limit is higher (absolute value) in high demand scenarios.

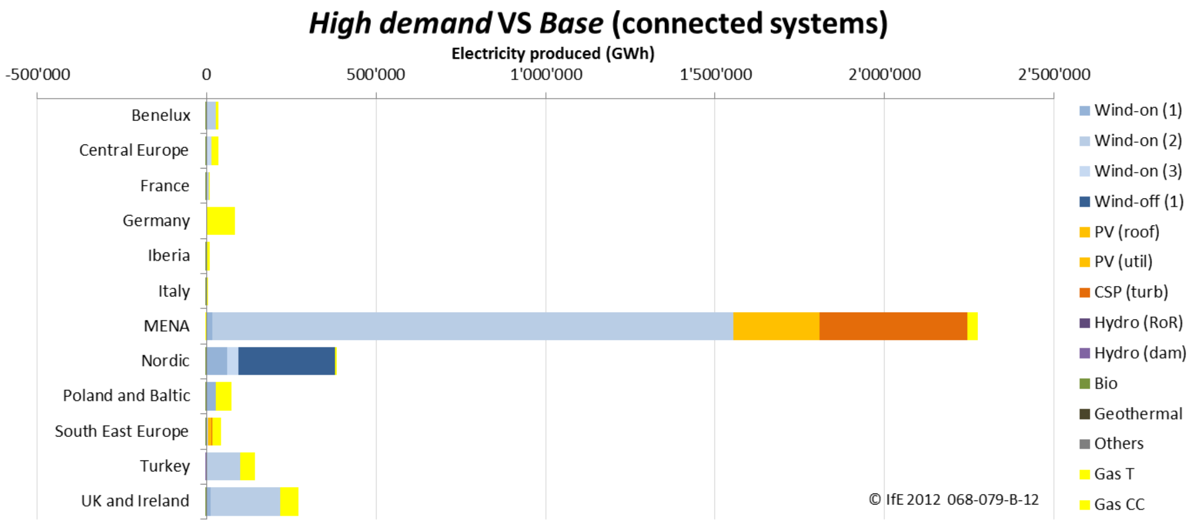

Figure 15: Difference in electricity production by region and input commodity between high and low demand (connected systems)

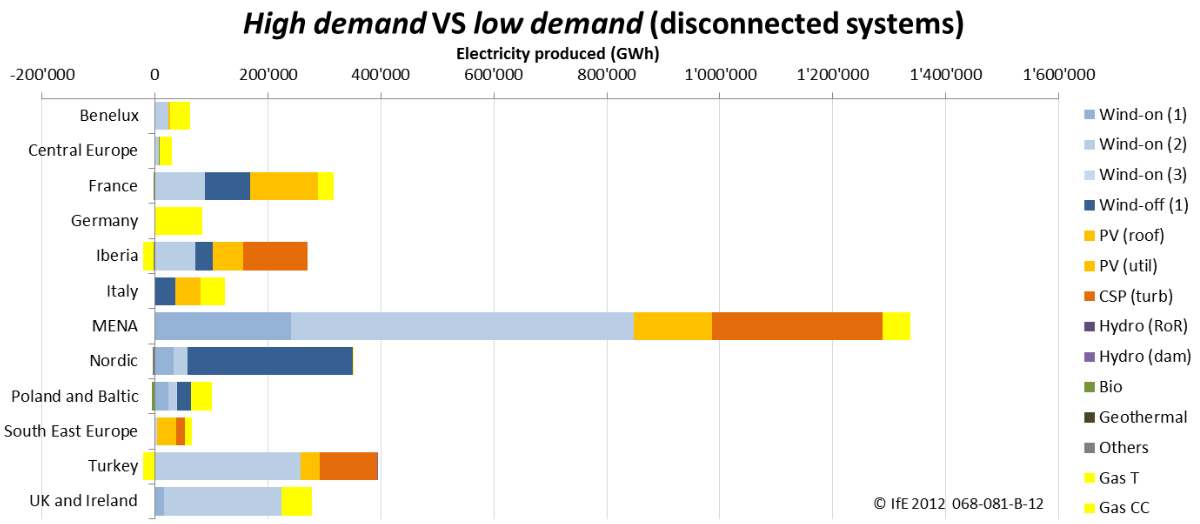

Figure 16: Difference in electricity production by region and input commodity between high and low demand (disconnected systems)

Figure 17 shows the share of renewable energy sources compared to each country's energy demand (increased by 7.5 % distribution losses for better comparison) for the base scenario. This includes all electricity production from biomass, geothermal, CSP, hydro, PV and mainly wind energy. It can be seen that all eight MENA countries generate more electricity from renewables than they consume. Algeria produces nearly eight times its demand with renewable energy, from which approximately 80 % are onshore wind. Libya, Morocco and Syria produce two to four times their demand from RES. Consequently, nearly all European countries are below the average of 93 % RES. Denmark and Norway are the only exceptions with 3.7 and 2.7 times their national demand.

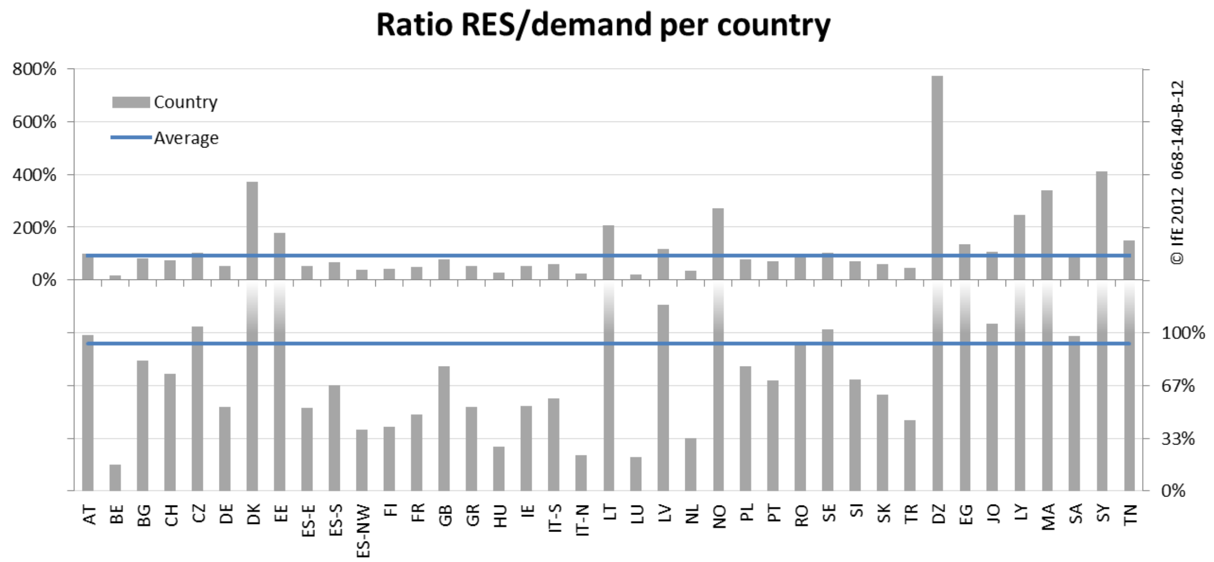

Figure 17: Share of RES of total electricity demand per country in scenario 01 *Base*

4.3 Generation capacities

In addition to electricity generation, corresponding installed capacities are a major result of the conducted optimization runs. Figure 18 shows installed capacities of the four main scenarios in absolute numbers and Figure 19 relative shares, respectively. The figures vary from those of electricity production (Figure 7 and Figure 8) as full load hours are different across technologies. The share of PV is higher in terms of capacities than in terms of electricity generation. However, all statements about regional distribution and differences between scenarios are the same as described in the chapter above for electricity production.

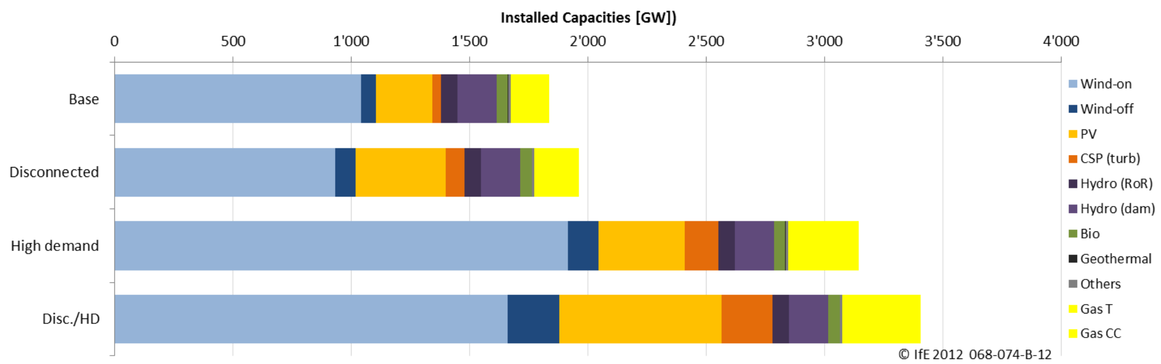

Figure 18: Installed production capacities by input commodity and scenarios 01 to 04.

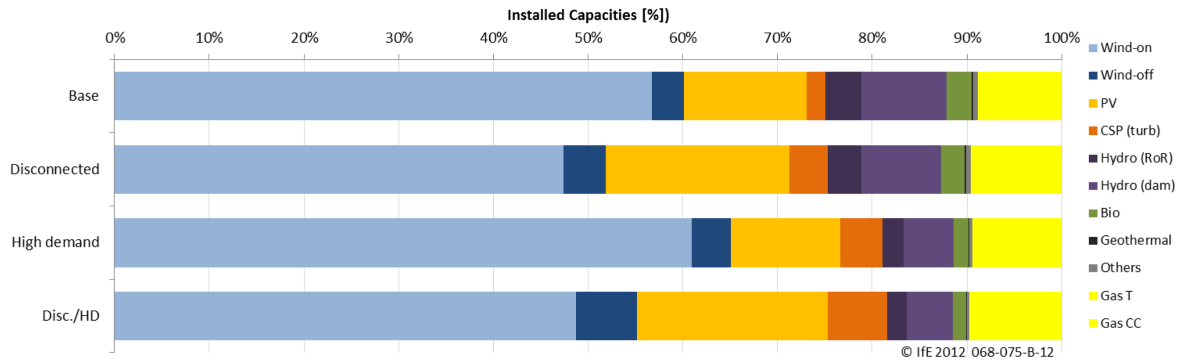

Figure 19: Relative shares of production capacities by input commodity and scenarios 01 to 04.

As it was stated earlier, wind power is dominating renewable technology in all main scenarios. This is caused by lower costs of electricity for wind power in most regions compared to PV and CSP as well as a generation characteristic fitting better to load. Figure 20 shows the levelized cost of electricity for wind and PV (blue and yellow bars). The accumulation of blue bars on the left side shows that only PV in MENA countries (EG, DZ, LY, MA and SY are the leftmost yellow bars) is competitive to wind power. Onshore wind (bright blue) generally is cheaper than offshore wind (dark blue) in this model, which explains its dominance in all optimized system configurations. CSP is not included in this figure as its costs are higher for all sites. The red dots show the share of installed capacity relative to the maximum potential in the country. Most of the very good sites for wind power are used to their maximum (share = 1). However, some are not as for example IE. This is caused by a combination of comparably high distance to demand centers, leading to inhibiting high transmission costs, and unfavorable time series for electricity production. Regarding PV, shares of maximum allowed capacity are very low for all sites due to very high potential limits in all sites (for resource limits in countries see chapter 6).

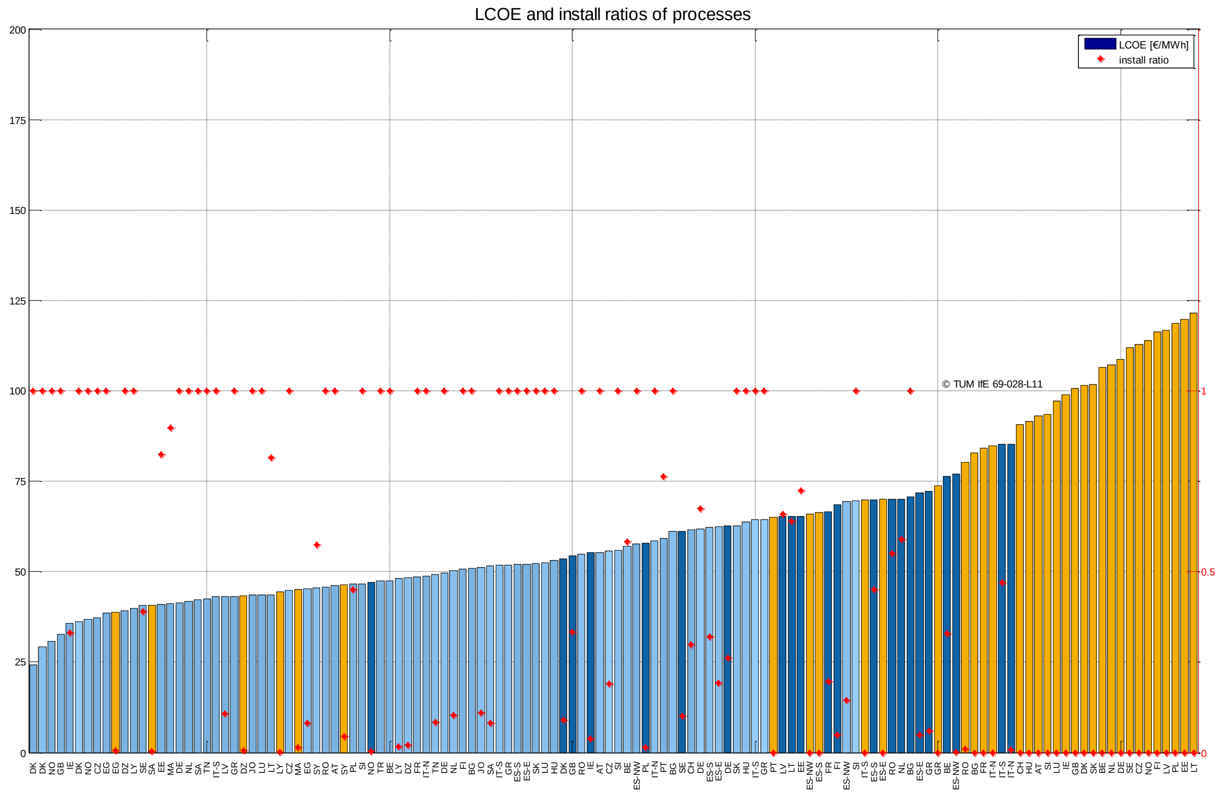

Figure 20: LCOE per process (bars), share of installed over allowed capacity (red dots), scenario 01 *Base*. Bright and dark blue correspond to onshore and offshore wind, yellow represents PV.

4.4 CO_2 emissions

In this study, CO_2 emissions were considered to be limited within the overall EUMENA region in all main scenarios. The regional distribution of these emissions was determined through the optimization process. In both, connected and disconnected systems, only one common limit was set. In order to analyze the resulting regional distribution, specific emissions (related to production) are compared in Figure 21. CO_2 emissions are much lower in regions with cheap resources for renewables as MENA and Iberia (wind and solar) as well as in Nordic countries (hydro and wind power). UK and Ireland have relatively high emissions despite having very good sites for wind power. A possible reason is its geographic situation away from continental Europe which leads to higher costs for transport of balancing power. Highest specific emissions occur in Benelux, because it is used for installing high capacities and high utilization of gas power plants. In scenarios with disconnected systems specific CO_2 emissions are higher in MENA as renewables electricity production is shifted to Europe and more flexible power is needed in MENA.

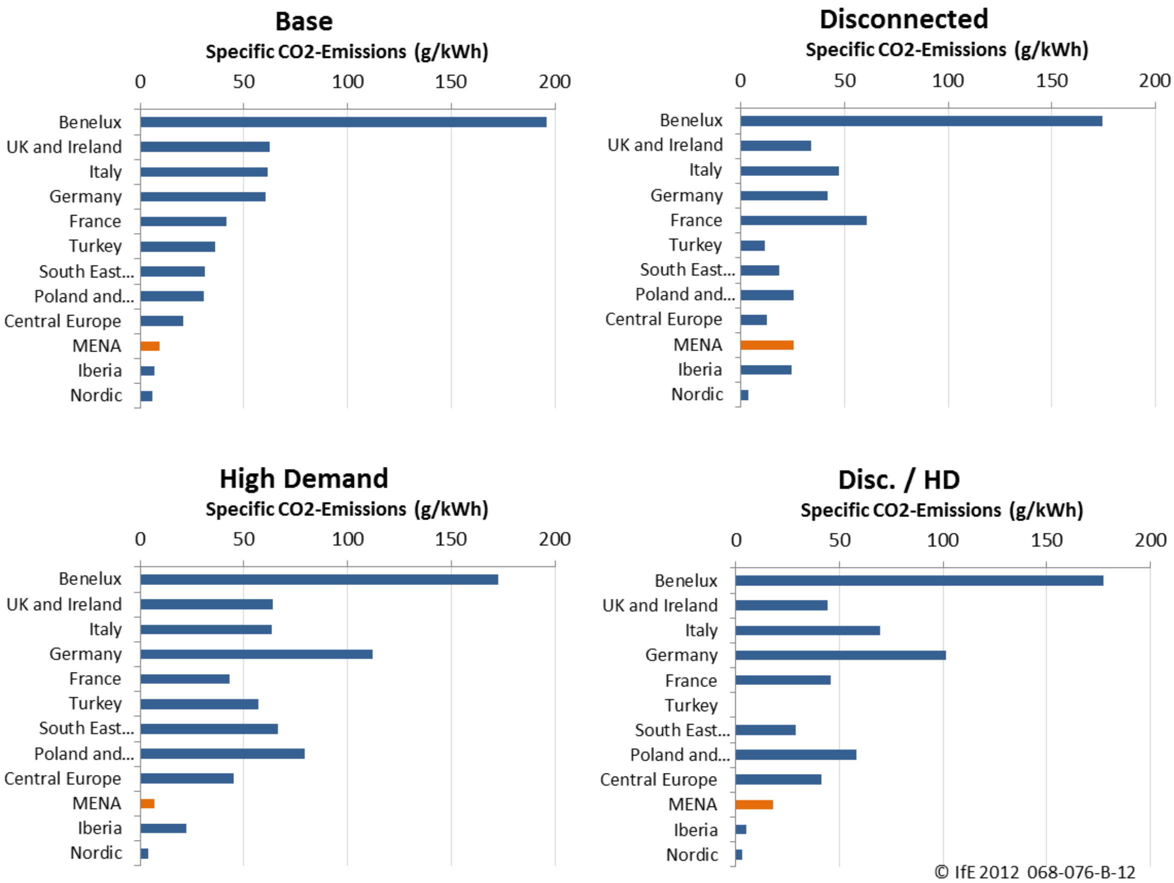

Figure 21: Specific CO_2 emissions by region and scenario.

As described above, there is a fixed limit for CO_2 emissions in this model for the overall power system. The marginal value of the CO_2 constraint is the marginal cost for CO_2 abatement and thus *can be interpreted* as a CO_2 price in a cap-and-trade system. Figure 22 shows resulting price of the four main scenarios. The price is higher in disconnected systems as in connected as CO_2 abatement is easier if generation from renewable energies can be balanced in a huge region. Also higher demand leads to higher abatement costs as the potential for cheap renewable energy production is limited.

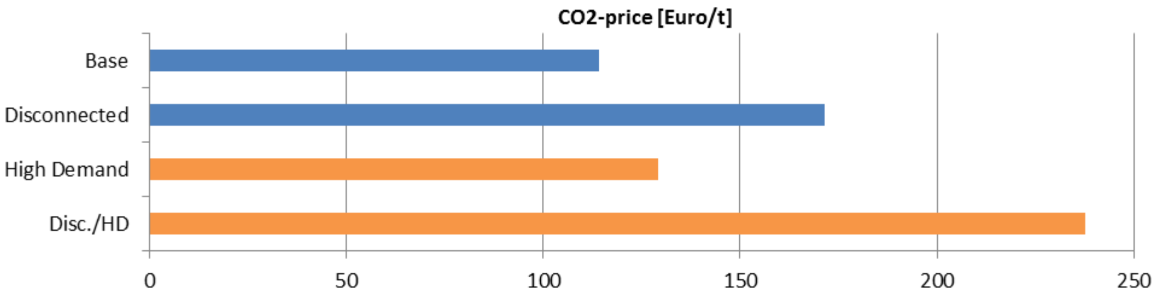

Figure 22: Resulting CO_2 price in four main scenarios

4.5 Role of CSP

A special focus of this study is the role of CSP in a possible future electricity system. It is analyzed to what extent and where CSP should contribute to an optimal generation mix. In addition, optimal configurations CSP power plants including collector, thermal storage, turbine and an optional gas cofiring are investigated. Modeling of CSP is described in section 2.2.3. Figure 23 shows full load hours of CSP in regions that use it in main scenarios. Average full load hours are in the range of 4000 across all scenarios. This means, the size of collector, storage and turbine is in a proportion to reach this value. The option to use gas cofiring was not used in any scenario considered as it is more expensive than building just gas fired power plants.

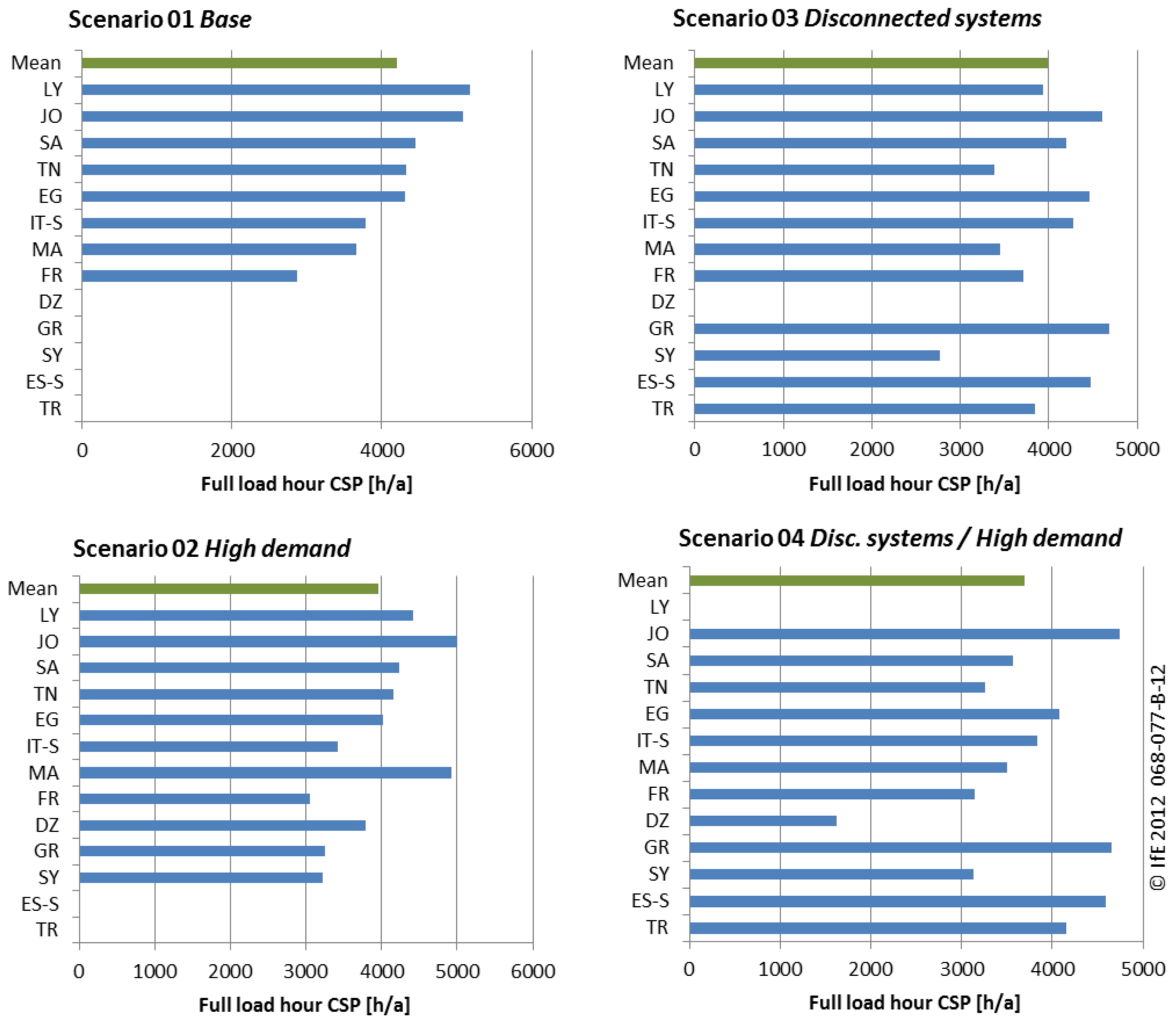

Figure 23: Full load hours of CSP for scenarios 01 to 04.

Another interesting result is the hourly CSP dispatch. Figure 24 shows an example of MENA CSP dispatch in three summer weeks. In the upper figure, a black line represents the heat fired to the turbine, orange shows heat production from solar panels and blue represents storage operation. In case the blue area is negative, storage is filled; when it is positive, heat is released from storage. Pink indicates heat overproduction: more heat is available than can be fed to the turbine economically. The figure below shows the storage content in each hour. The figure shows that storage is filled every day and released during nights. It also shows that electricity generation from CSP is more important at times with low or even no solar radiation as it is used to balance PV production.

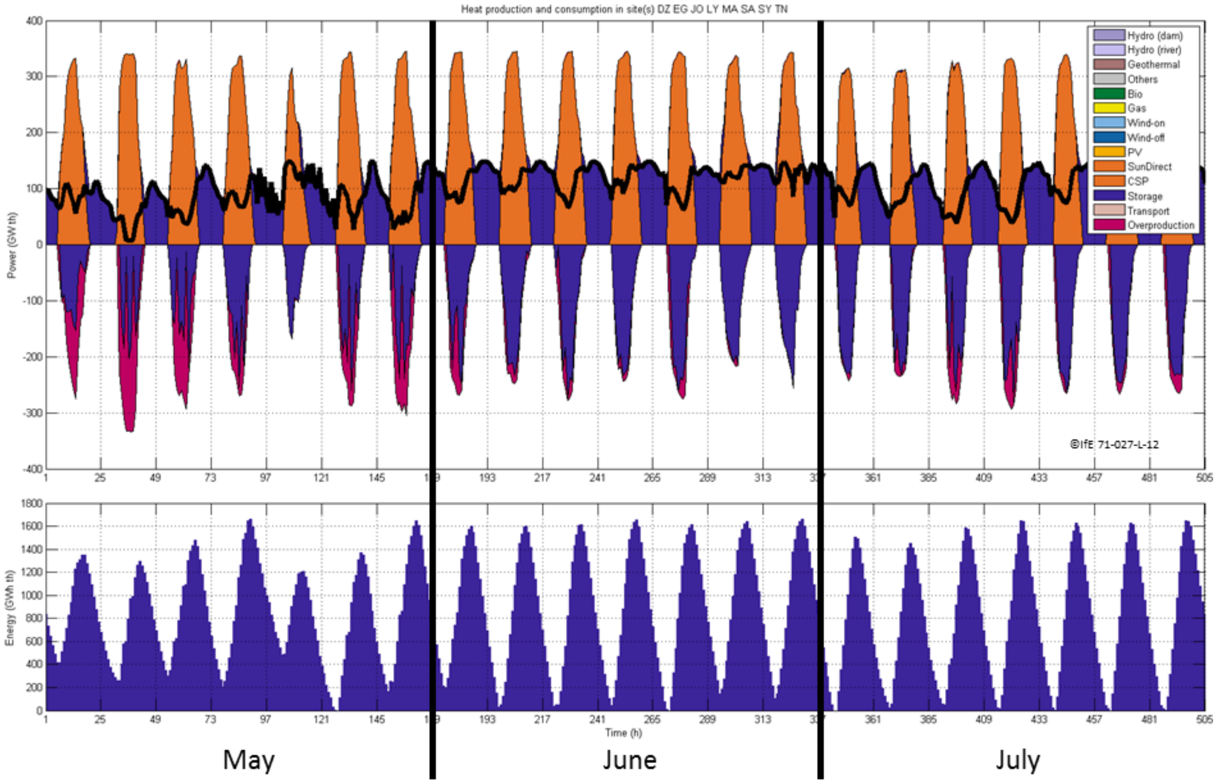

Figure 24: MENA use of CSP heat conversion (top) and storage (bottom) in scenario 03 *Disconnected systems*.

In section 4.2 a higher CSP share was stated in disconnected systems compared to connected systems. Figure 25 and Figure 26 illustrate the higher importance of CSP in disconnected systems. Figure 25 shows the hourly electricity generation by technology for the entire MENA region. In almost all hours electricity from wind power is enough to satisfy MENA demand (black line). Major parts of electricity production that exceeds demand can be exported to Europe (orange area below zero). In case exports are not allowed (disconnected systems, cf. Figure 26), production has to meet demand in each hour which makes flexible production from CSP more valuable.

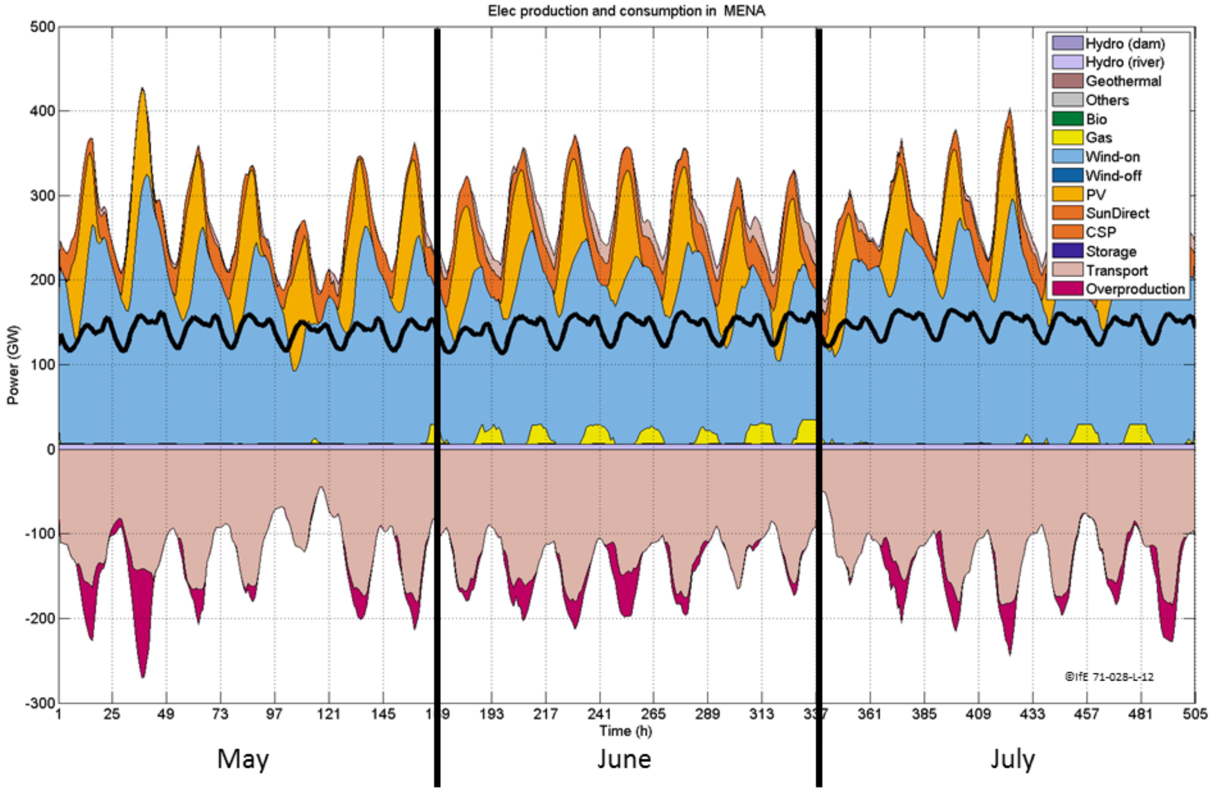

Figure 25: Electricity production time series with EU export (pale red) for MENA in scenario 01 *Base*.

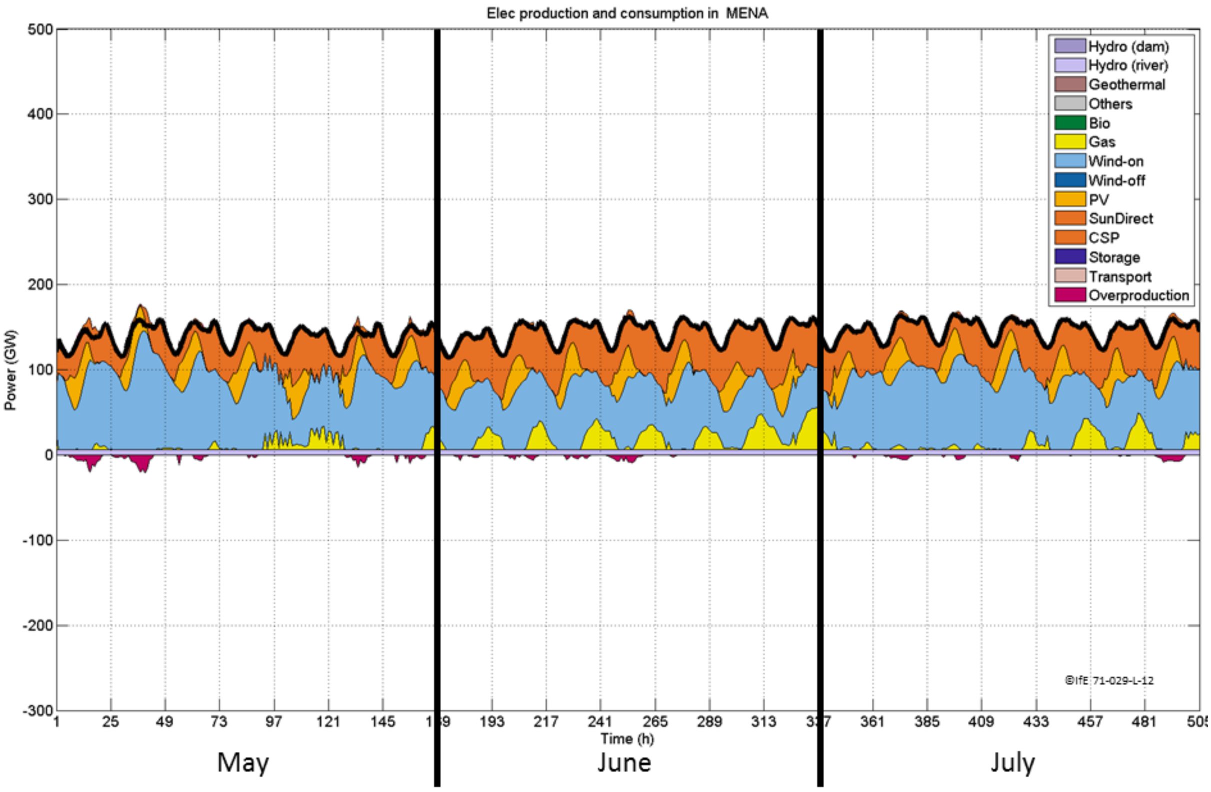

Figure 26: Electricity production time series for MENA in scenario 03 *Disconnected systems*.

4.6 Generation time series

In order to understand why balancing of wind power works so well, an analysis of generation time series is done in this section. In a first step the seasonal effects of renewable energy generation are investigated. Figure 27 shows the monthly production of must-run renewables (hydro run of river, PV, and on- and offshore wind) in Europe. More electricity is produced during winter month driven by more wind power. In contrast to Europe, more electricity from wind power is produced during summer months in MENA region as shown in Figure 28.

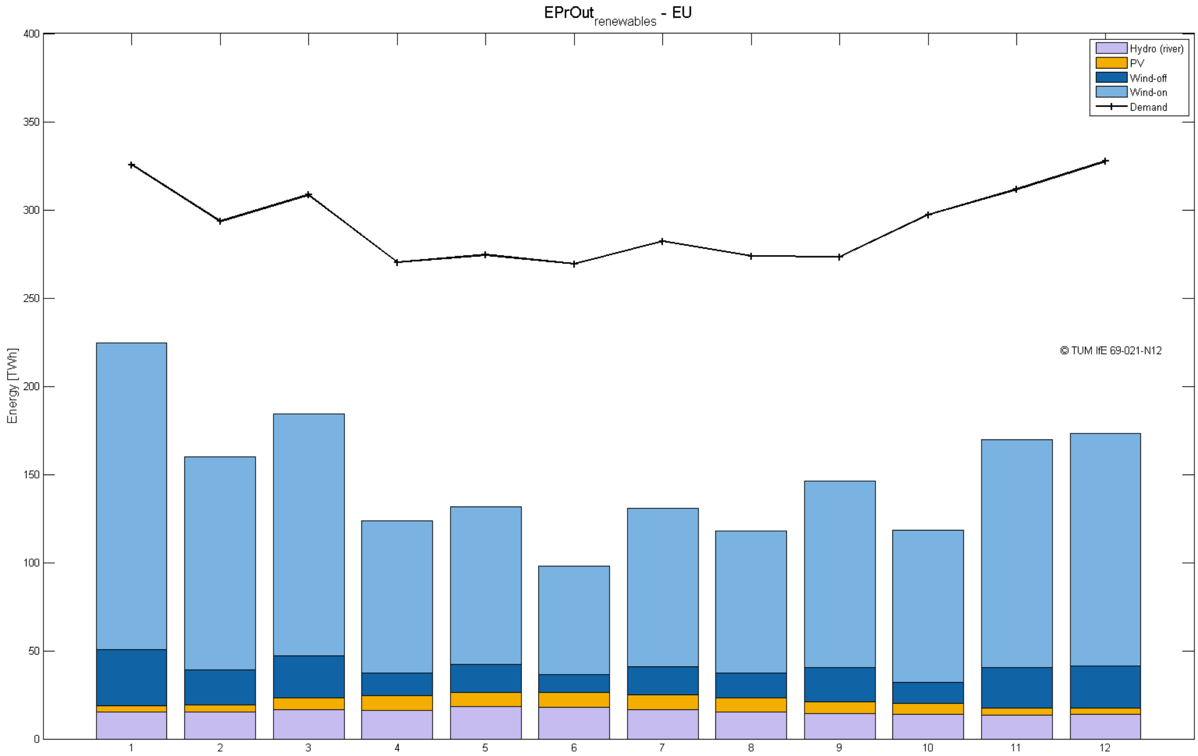

Figure 27: Monthly renewable power input VS demand in EU for scenario 01 ***Base***.

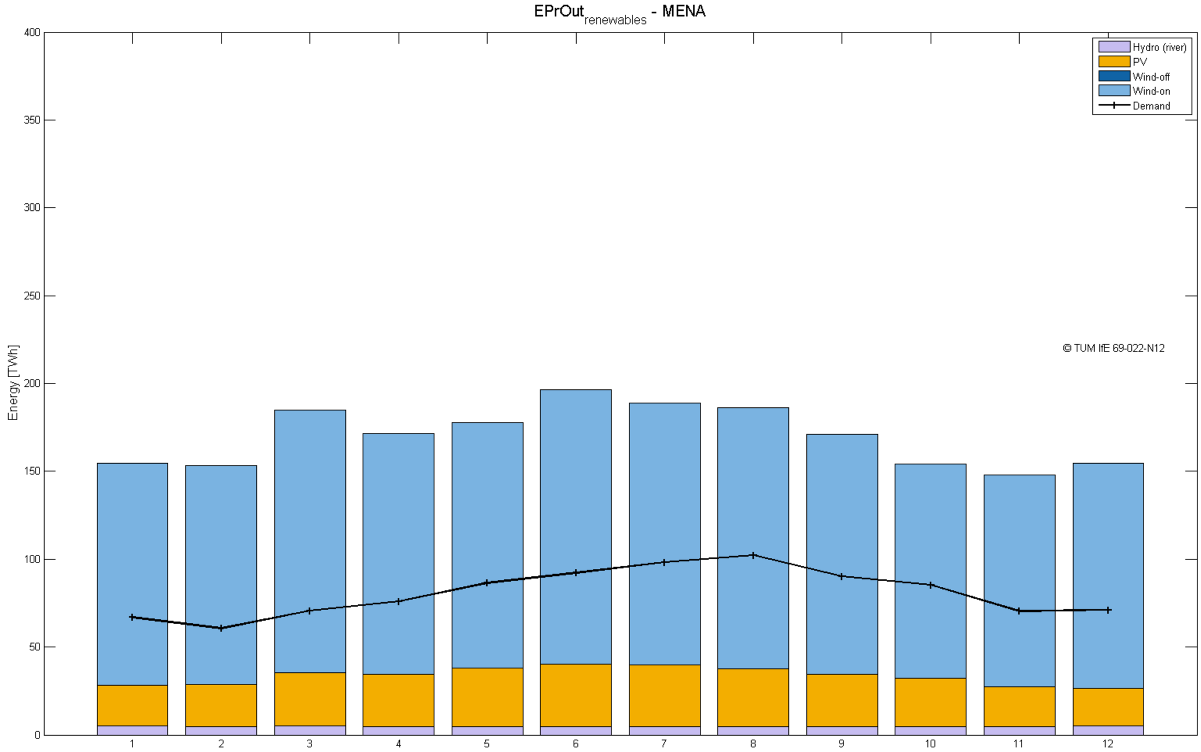

Figure 28: Monthly renewable power input VS demand in MENA for scenario 01 *Base*.

There are not only seasonal balancing effects of wind power but also hourly smoothening effects between regions. Figure 29 shows annual load duration curves of onshore wind power for Europe, MENA, as well as the overall EUMENA region. The Y-axis shows the capacity factor (relation of hourly power to installed power) and the X-axis shows the hours of a year. Data is plotted in a numerical order. The slope of the curve from Europe is steeper than the MENA or EUMENA curve. This means a more uneven distribution of wind power generation during the year. The combined EUMENA curve is the flattest meaning a very constant electricity generation during the year from wind power. In each hour of the year there is more than 15 % of installed power available, in more than 8000 hours per year 25 % of installed power is available.

The flattening of wind power generation in geographically widespread regions can also be seen very well in Figure 30. It shows the annual load curves of the 10 major wind producing countries and again the EUMENA curve. All single curves are much steeper than the curve of the overall EUMENA region.

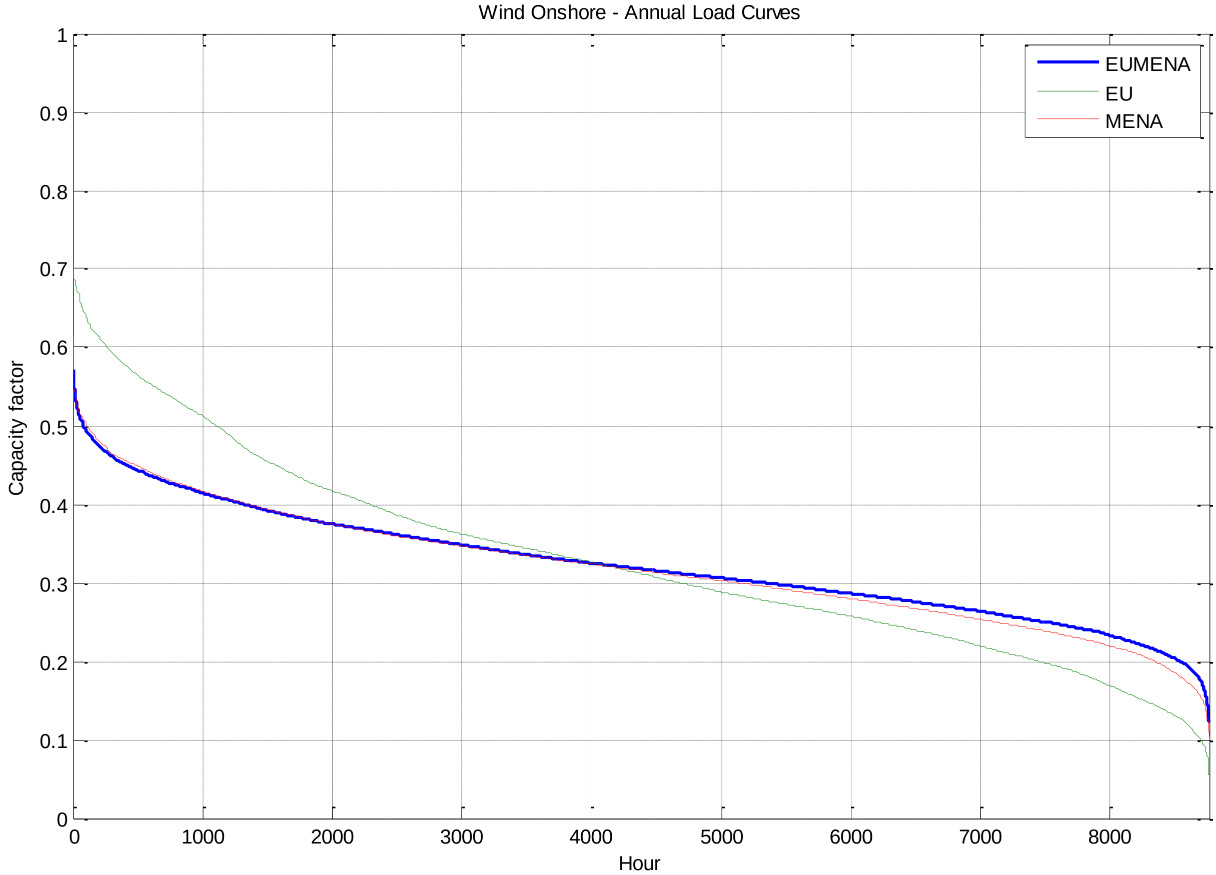

Figure 29: Standardized annual load curves of wind onshore capacity factors for connected EUMENA (scenario 01) and disconnected EU & MENA (scenario 03).

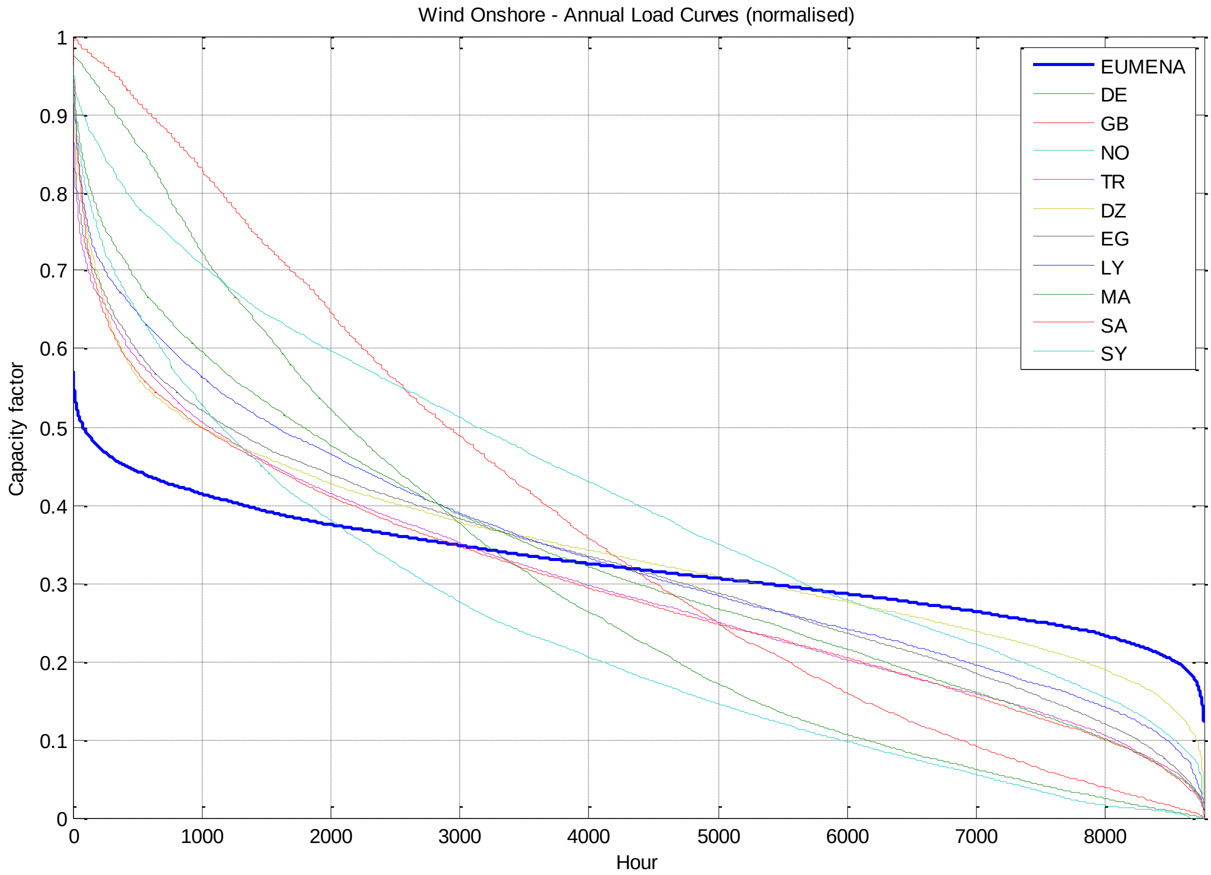

Figure 30: Standardized annual load curves of wind onshore capacity factors for EUMENA and 10 biggest contributors by installed capacity (scenario 01 *Base*).

The main benefit of smoother wind power generation however is the more predictable residual load with a lower peak load and less overproduction. The flatter the residual annual load curve is and the lower the maximum residual load, the less backup power plants are needed. Figure 31 shows residual loads for EU and MENA (scenario 03 *Disconnected systems*) as well as the EUMENA region (scenario 01 *Base*). The residual load is load minus the sum of all must run generation plants. Again, a smoothening of the curve through interconnecting systems can be reached. The curve for the EUMENA region is much flatter than the others.

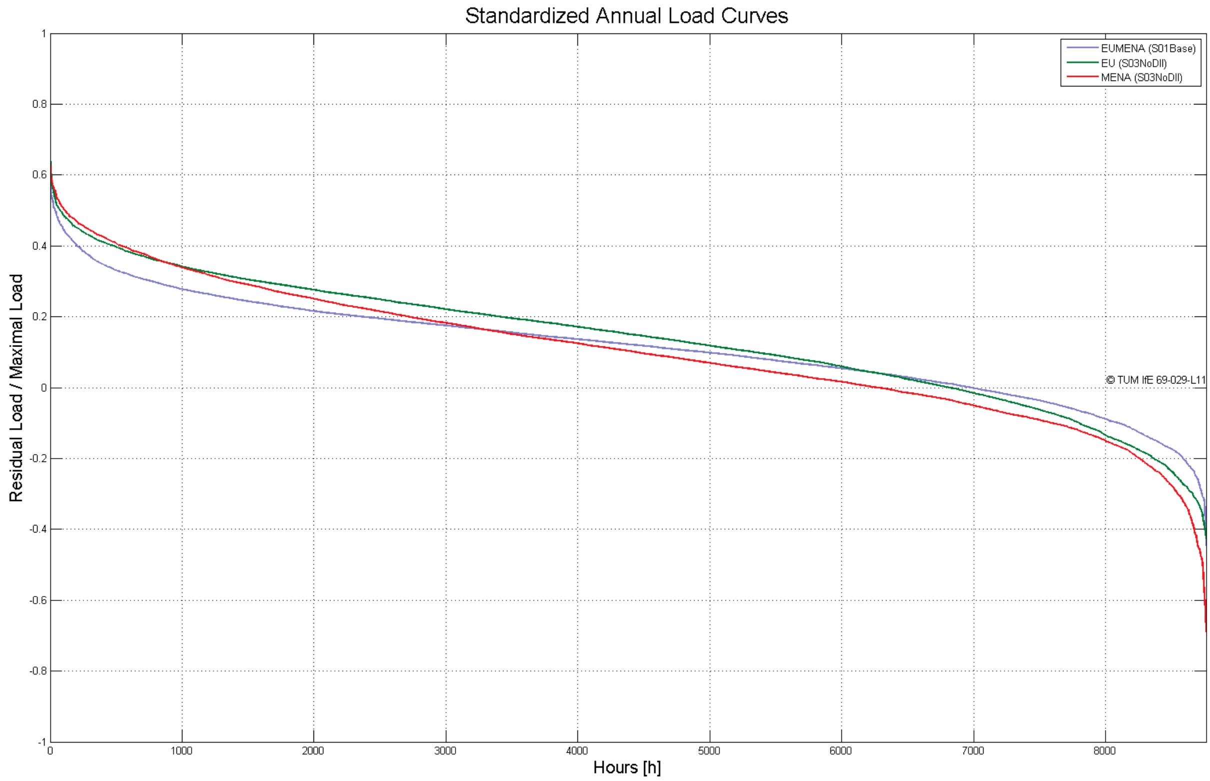

Figure 31: Standardized annual load curves of residual load for *connected* EUMENA (scenario 01) compared to *disconnected* EU & MENA (scenario 03).

As electricity imports are very high in an optimal electricity infrastructure the question arises how Europe generates its electricity in situations with very high imports (connected systems) when imports are not possible (disconnected system). Figure 32 shows the hourly generation mix for three winter weeks in scenario 02 (high demand, connected systems) for Europe. The orange area at the top represents MENA imports. In comparison, Figure 33 shows the same time slice but for scenario 04 (high demand, disconnected systems). Now more wind power and much more PV replace the imports in each hour. Additionally, some CSP is needed to balance fluctuating generation in Europe.

The same comparison is done for three summer weeks (Figure 34 and Figure 35). In summer weeks, imports are even higher due to low wind power generation in Europe. Instead of electricity imports there is now a high share of PV and CSP in the generation mix, especially during peak load. Generation from gas power has to be used concentrated in times with very low wind power (first week) in disconnected systems whereas more flexible usage is possible in connected systems.

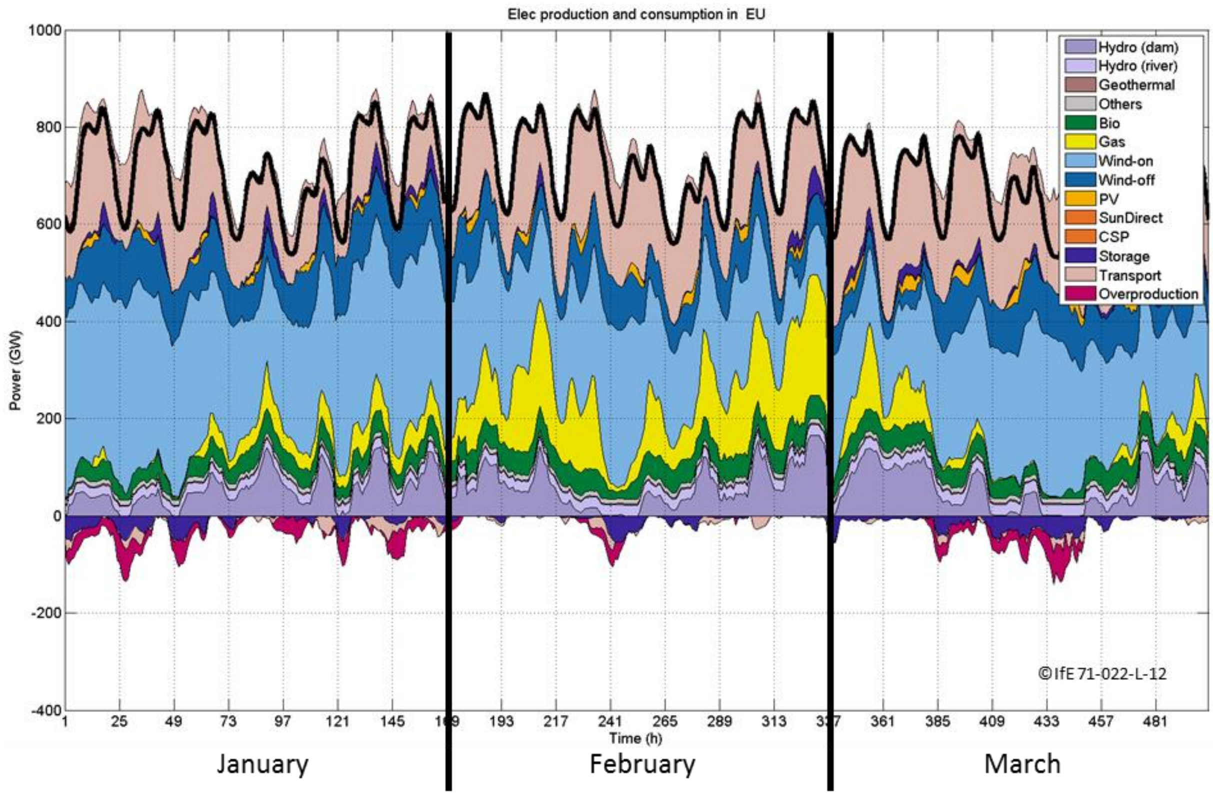

Figure 32: EU electricity production during three winter weeks in scenario 02 High demand.

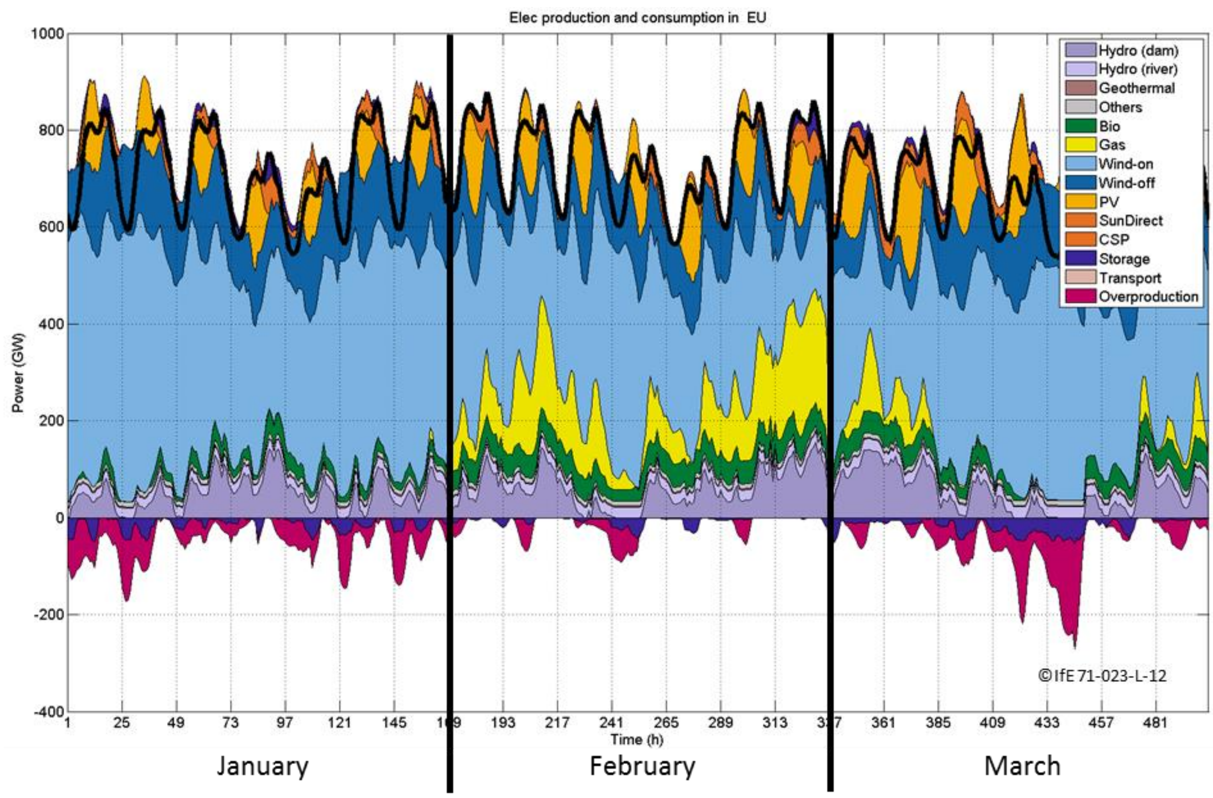

Figure 33: EU electricity production during three winter weeks in scenario 04 *High demand/Disconnected systems*.

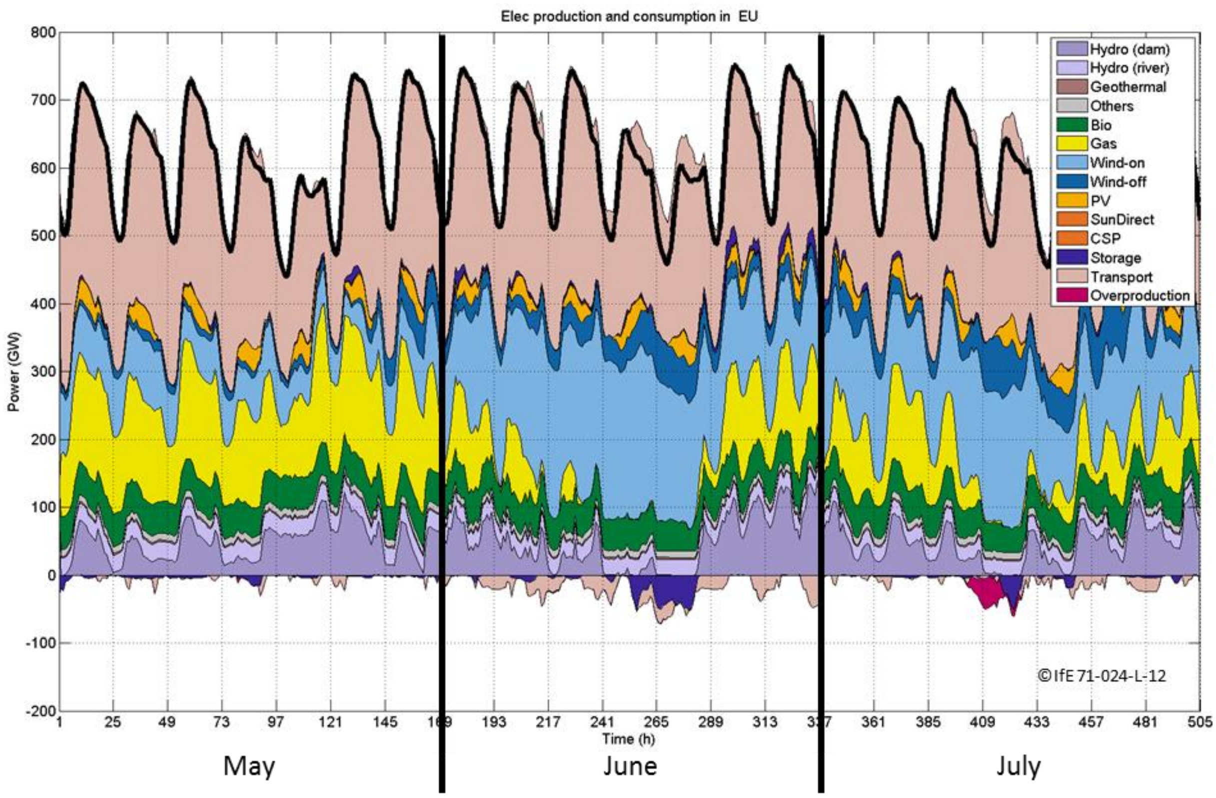

Figure 34: EU electricity production during three summer weeks in scenario 02 High demand.

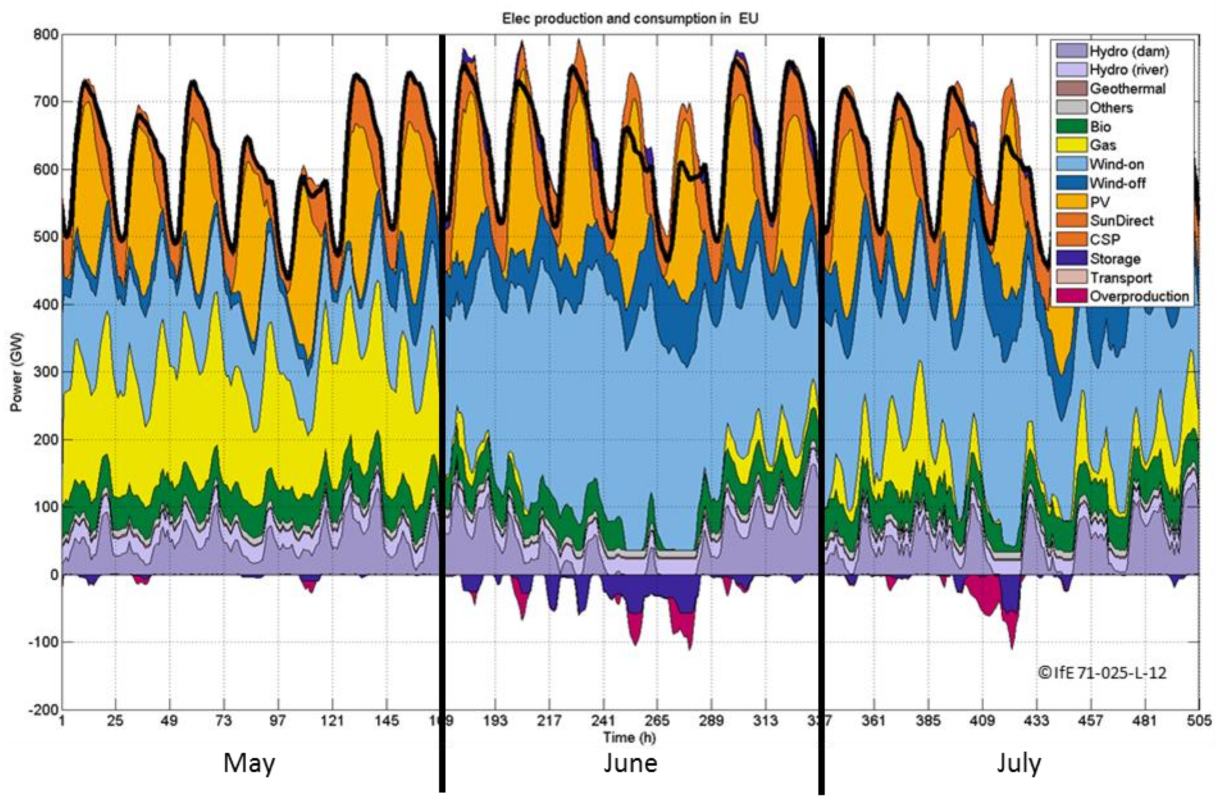

Figure 35: EU electricity production during three summer weeks in scenario 04 *Disconnected systems/High demand*.

4.7 Transmission

One of the most important aspects of integrating European and MENA electricity systems is building up transmission infrastructure. Optimal transmission capacities as well as hourly transports are defined through optimization. Figure 36 shows numerical values for transported energy within one year from MENA to Europe (Turkey is a considered as European). On the left side, imports to Europe in relation to Europe's demand are shown. The share of imports is very high in both, scenarios with low and high demand. In the low demand scenario, 26 % of Europe's electricity demand is provided through imports from MENA. In the high demand scenario even 35 % of electricity is imported to reach cost optimality. In contrast, only about 1 % of electricity is exported from Europe leading to net imports of 25 % for low demand and 34 % for high demand. This unidirectional transport of electricity is caused by large resources with very good conditions for renewables in the MENA region. On the right side of Figure 36, the absolute values of electricity imports are shown. Net imports are 965 TWh/a in the low demand scenario and 1944 TWh/a in the high demand scenario.

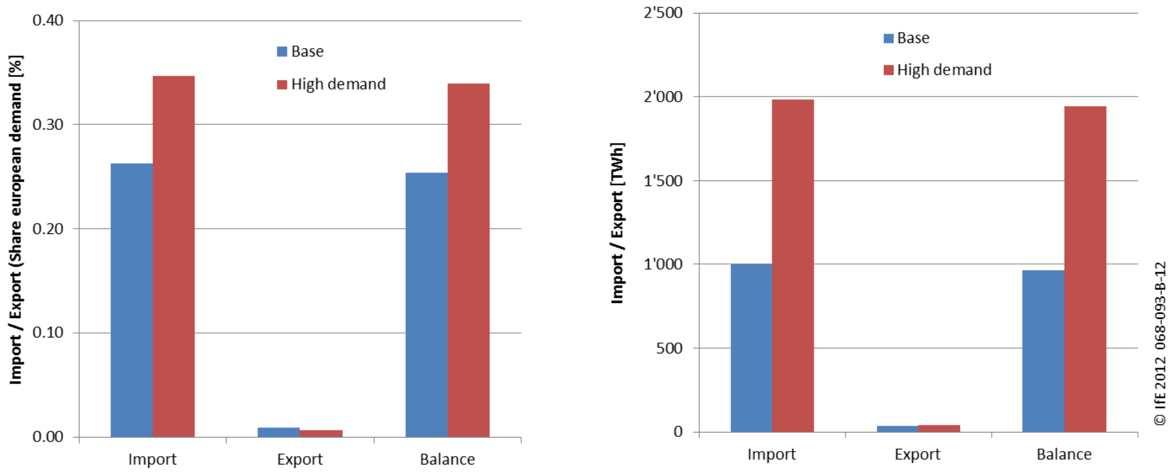

Figure 36: Relative share and absolute amount of EU import from/export to MENA for s01 *Base* and s02 *High demand*

This high share of imports leads to high full load hours of 5000 up to 7000 for MENA-EU transport lines in only one direction. In contrast, inner EU or inner MENA transport lines are mostly utilized with FLH of 1500 -3000 in both directions. This means a very steady import to Europe over time. This steady import is also illustrated in Figure 31 and Figure 34. This steady energy export is mostly produced by wind power, which has an annual production profile as illustrated in Figure 29.

It was investigated how much and on which routes transport capacities should be built up in a cost optimal system. Figure 37 shows these optimal capacities for both, the low and high demand scenario. All possible routes for interconnectors were used at least to some extent with a regional spread from west to east. The most important routes are from Algeria to Spain, France and Italy. This is caused by Algeria being the most important producer of cheap wind power and comparatively low interconnector costs from Algeria to Europe. The route from Morocco to Spain is also used extensively as it is the cheapest option to bring electricity from MENA to EU. Electricity that is produced more in the eastern part of the MENA region (e.g. Saudi Arabia of Syria) is mainly transported to Turkey.

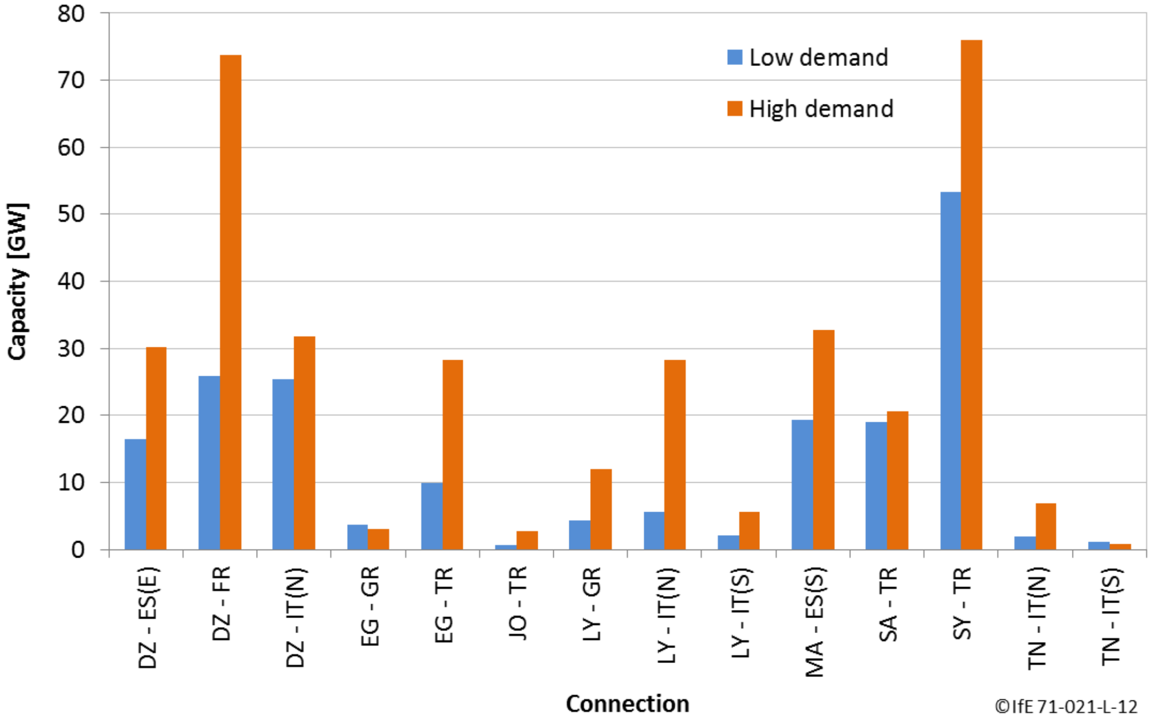

Figure 37: Capacities for EU-MENA interconnectors in low and high demand scenario

Table 2 shows the difference of transport capacities between high and low demand scenarios not only for interconnectors but also European transmission grid. As seen above, there is much more transport capacity from MENA to France in the high demand scenario. In Europe, only several transport capacities are increasing with higher electricity demand. There is more capacity from Nordic countries to Germany in order to transport additional wind power from north to south. More capacity is also needed within Iberia as electricity has to be transported from southern Spain to the north and to Portugal. In addition, transport capacities from France and Italy to their neighbors are built up to transport additional desert power.

Table 2: Difference of installed transport capacities between s02 *High demand* and s01 *Base*

High demand - Base (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	24'938	0	11'221	2'655	0	0	0	0	0	0	0	14'104
Central Europe	0	-238	2'501	7'588	0	13'252	0	0	2'384	3'148	0	0
France	11'221	2'501	0	158	812	0	47'879	0	0	0	0	7'307
Germany	2'655	7'588	158	0	0	0	0	35'494	0	0	0	0
Iberia	0	0	812	0	23'691	0	27'129	0	0	0	0	0
Italy	0	13'252	0	0	0	9'266	37'288	0	0	5'309	0	0
MENA	0	0	47'879	0	27'129	37'288	115'978	0	0	6'921	44'601	0
Nordic	0	0	0	35'494	0	0	0	110'014	6'541	0	0	-1'328
Poland and Baltic	0	2'384	0	0	0	0	0	6'541	320	0	0	0
South East Europe	0	3'148	0	0	0	5'309	6'921	0	0	4'099	7'612	0
Turkey	0	0	0	0	0	0	44'601	0	0	7'612	0	0
UK and Ireland	14'104	0	7'307	0	0	0	0	-1'328	0	0	0	1'840

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Table 3 shows differences in transport capacities between connected and disconnected systems. No capacities are built between MENA and Europe as it is not allowed in disconnected systems per definition. But it is a very interesting fact that even more transport capacities are needed within Europe in disconnected systems. Much capacity from UK and the Nordics to continental Europe has to be built in order to transport wind power. Fewer capacities are only built within Iberia region.

Table 3: Difference of installed transport capacities between s03 *Disconnected* and s01 *Base*

Disconnected - Base (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	-1'651	0	-668	2'647	0	0	0	0	0	0	0	2'932
Central Europe	0	6'398	0	18'087	0	18'933	0	0	2'293	521	0	0
France	-668	0	0	-544	3'586	7'832	-25'842	0	0	0	0	20'864
Germany	2'647	18'087	-544	0	0	0	0	22'835	0	0	0	0
Iberia	0	0	3'586	0	-17'592	0	-35'717	0	0	0	0	0
Italy	0	18'933	7'832	0	0	27'968	-35'997	0	0	11'894	0	0
MENA	0	0	-25'842	0	-35'717	-35'997	2'778	0	0	-7'985	-82'933	0
Nordic	0	0	0	22'835	0	0	0	45'104	1'494	0	0	2'177
Poland and Baltic	0	2'293	0	0	0	0	0	1'494	627	0	0	0
South East Europe	0	521	0	0	0	11'894	-7'985	0	0	727	7'367	0
Turkey	0	0	0	0	0	0	-82'933	0	0	7'367	0	0
UK and Ireland	2'932	0	20'864	0	0	0	0	2'177	0	0	0	607

Tables for absolute transmission capacities between regions are shown in appendix A 3 for all four main scenarios.

4.8 Market

In the optimization model, market mechanisms are not considered directly but short run marginal costs can be used as a proxy for market prices. Interconnected large electricity systems are assumed to reduce price spreads between regions. Figure 38 illustrates the average short run marginal costs across different regions for the four main scenarios. In all scenarios, marginal costs of electricity are lowest in MENA as it has the highest share of renewable energies (marginal cost = 0). The figure also shows that the regional distribution of marginal costs is more even in connected systems, as expected. Average marginal prices include the endogenous price for limited CO_2-emissions as described in section 4.4.

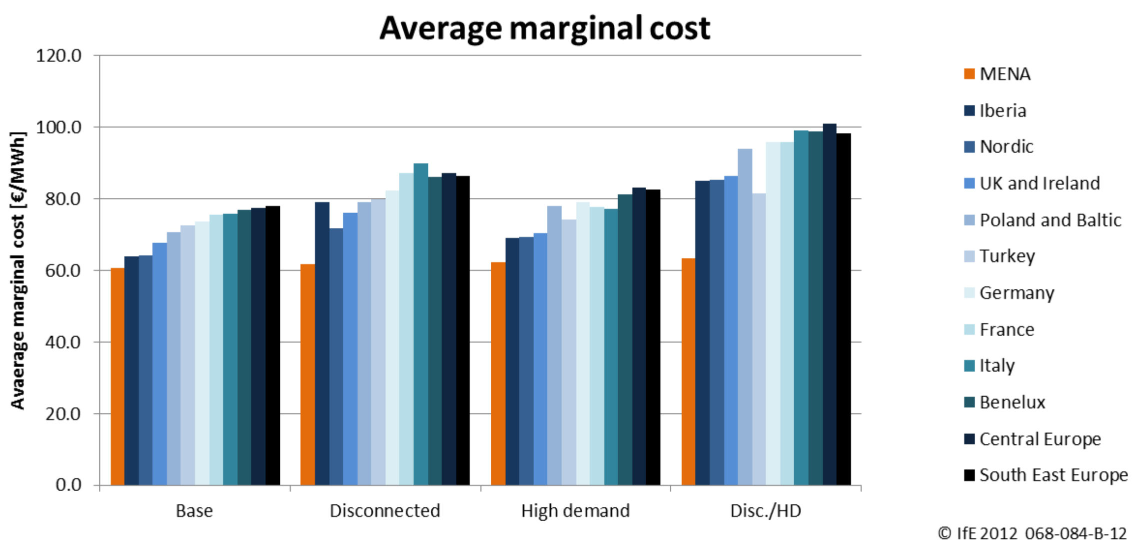


Figure 38: Average of hourly marginal costs of electricity by region and scenario

Another measure for the distribution of marginal costs is the share of hours with zero marginal costs as illustrated in Figure 39. Marginal costs are zero if more electricity is produced through must run technologies than consumed. (Marginal) higher electricity consumption would not cause additional costs in these situations. The share of hours with marginal costs of zero is highest in MENA as the share of renewables is highest there. Fewer situations with zero marginal costs occur in connected systems, i.e. renewable energy is better used. This again is a measure for a better balancing of prices throughout the system.

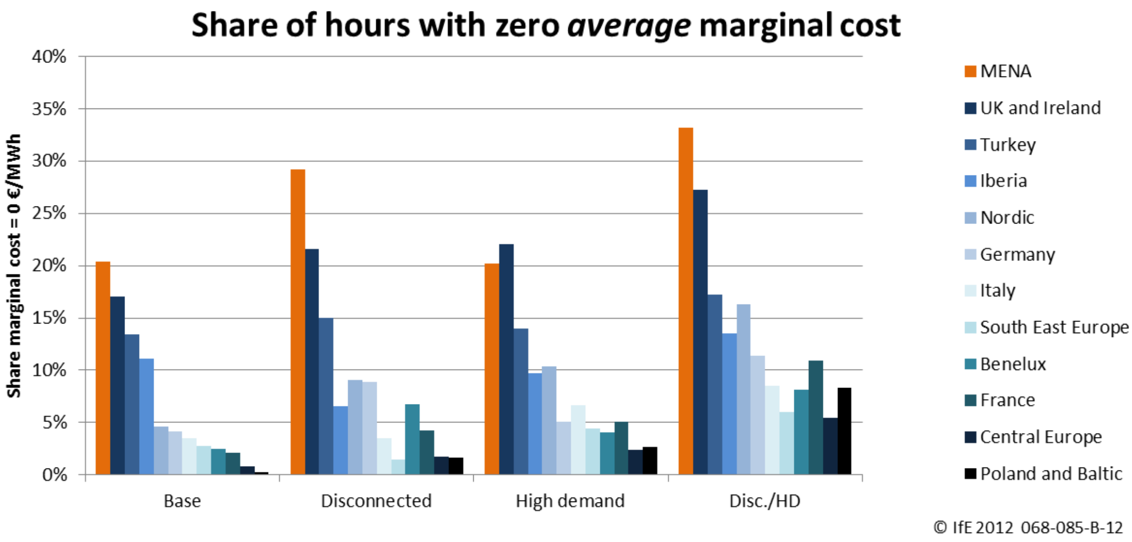


Figure 39: Relative count of hours with marginal cost equal to zero by region and scenario

5 Sensitivities

Having established a firm understanding of the simulation results in the previous chapter, in the following the influence of changed input parameter values is investigated. For that purpose, many additional scenarios are derived from Scenario 01 *Base* by changing only one parameter per scenario. This chapter highlights the changes caused by those changes on the optimal system configuration and total system costs. The main comparison method is electricity production by region and input commodity (wind, hydro, gas). Electricity production (MWh) is preferred to installed capacities (MW), because it better reflects the true contribution of a technology to the electricity mix.

Figure 40 first gives an overview on all scenarios, sorted by scenario groups. After the two main scenarios 01 and 03 with low demand (s02 and s04 are the corresponding high demand scenarios), the following ten scenarios are dedicated to changes in costs of electricity generation and transmission technologies.

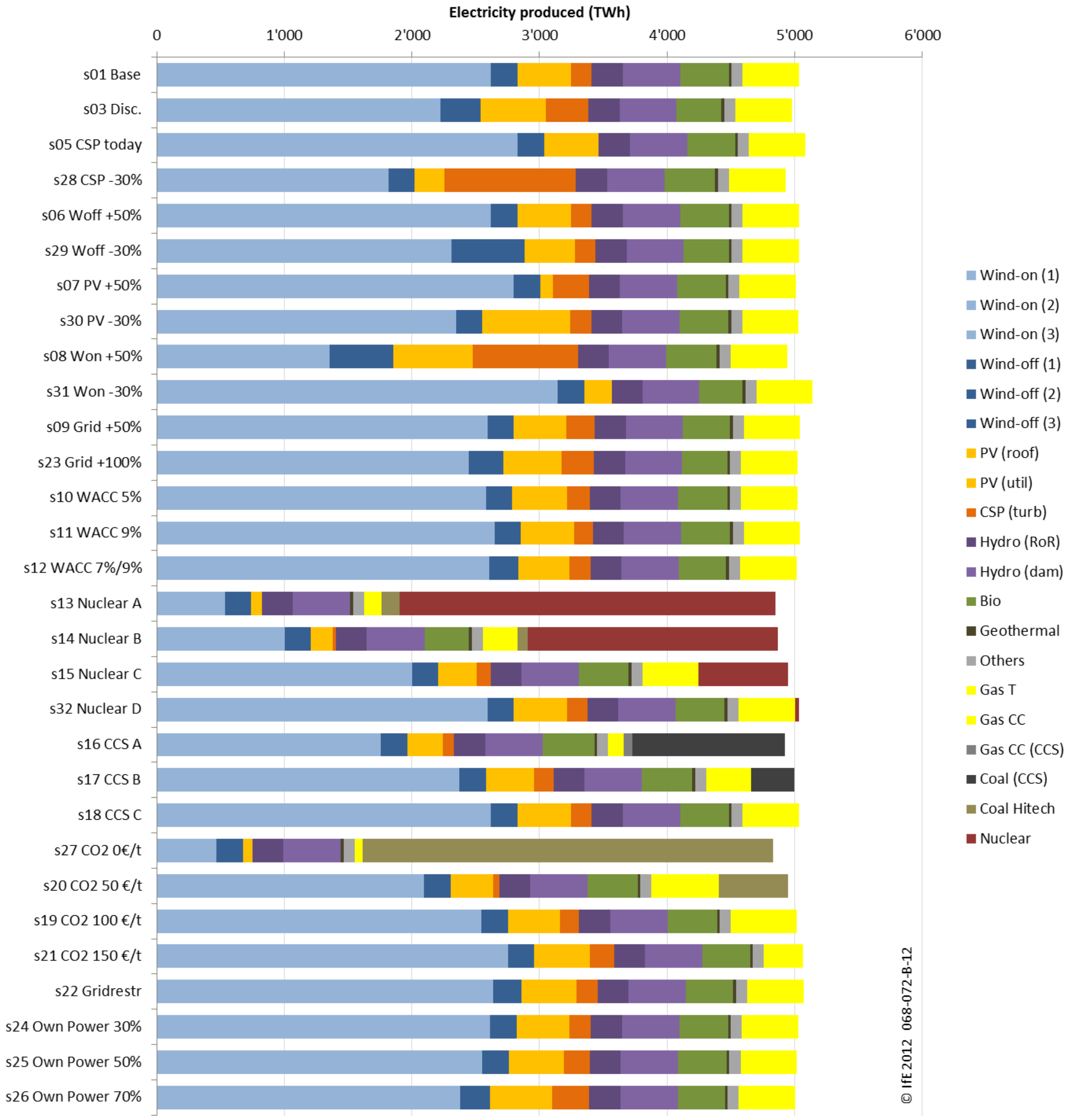


Figure 40: Total electricity production by commodity for all scenarios (except high demand scenarios)

Three scenarios dealing with varying weighted average cost of capital (WACC) in EU and MENA are then presented. Scenarios 13-18 and 32 are dedicated to the availability of nuclear power and carbon capture and storage (CCS). Scenarios 19-21 and 27 remove the requirement of limited CO_2 emissions and introduce a price for emission permits. Scenarios 22 and 24-26 investigate the influence of restrictions on transport capacity increase or enforce a minimum share of domestic electricity production in each hour.

5.1 Technology cost variations

In this section, costs for renewable electricity generation technologies are either increased or decreased in comparison to the base scenario. By comparing the resulting generation mix to the Base scenario, the sensitivity of the model to changes of the respective parameters can be derived.

5.1.1 CSP

In scenario *Base*, CSP contributes 160 TWh to the total electricity generation of 5035 TWh. This equals a share of 3.2 %, compared to 8.4 % provided by photovoltaic. However, this comparison neglects the ability of CSP to balance daily fluctuations, comparable to natural gas. Table 4 lists investment costs that are changed between scenarios. Fixed operation costs (€/kW/a) are scaled accordingly.

Figure 41 shows the resulting electricity production. For *today's cost of CSP*, no capacities of this technology are installed at all. It is completely replaced by onshore wind power by increasing installation of additional capacities in category two wind regions in MENA region, generating additional 200 TWh that replace the missing 160 TWh from CSP. Total system cost hardly increase from 324 B€ to 325 B€.

Table 4: Investment costs for CSP components in scenarios s01, s05, s28

Scenario	Collector (€/m²)	Cofiring (€/kW)	Heat turbine (€/kW)	Heat storage (€/kWh)
s01 — Base	146	248	721	32
s05 — CSP cost today	272	273	1021	63
s28 — CSP cost -30 %	102	174	505	22

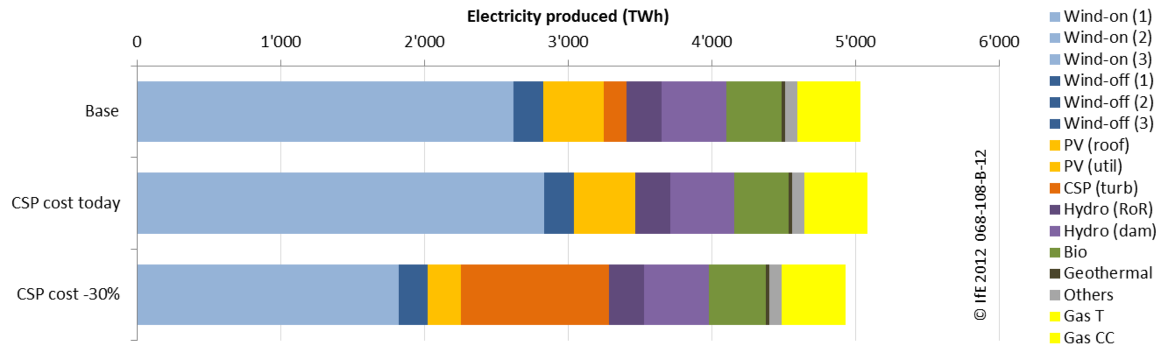


Figure 41: Electricity production by input commodity in *CSP cost* scenarios

By contrast, in scenario *CSP cost -30 %*, system cost reduce noticeably from 324 B€ to 312 B€ or by 3.7 %. CSP increases its contribution by over 5 times to nearly 1'000 TWh, mainly replacing onshore wind and photovoltaic in MENA, as shown in Figure 42.

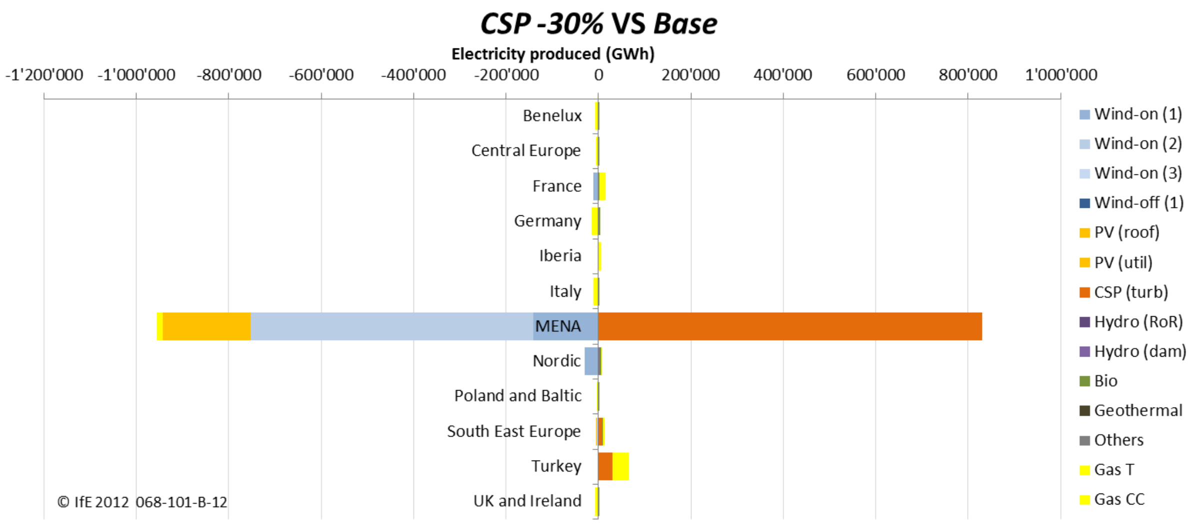


Figure 42: Difference in electricity production by region and input commodity between scenarios *CSP cost -30 %* and *Base*

In scenario *Base*, CSP from MENA contributes 1 TWh_{th} of heat storage capacity. In scenario *CSP cost -30 %*, the optimized heat storage capacity increases to 5.5 TWh_{th}, directly proportional to the increase in generated electricity. This implies that CSP storage remains being used as day-night storage, as outlined in section 4.5.

5.1.2 Wind offshore

In these scenarios, investment and annual fix costs of offshore wind turbines are varied. Starting from 1495 €/kW and 59.8 €/kW/a, these values are increased by 50 % for a high cost and decreased by 30 % for a low cost scenario. The resulting electricity generation mix is summarized in Figure 43.

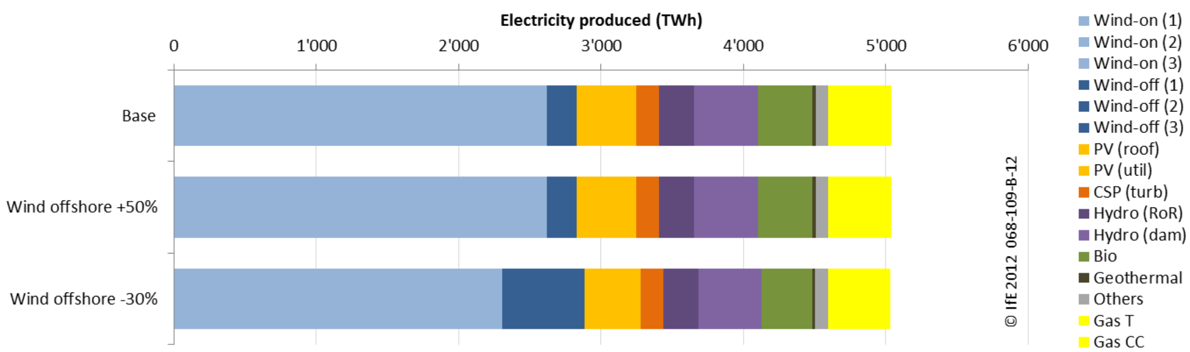


Figure 43: Electricity production by input commodity in *Wind offshore cost* scenarios

While increasing wind offshore costs hardly decreases their contribution (less than 1 TWh), low costs make it competitive against onshore wind in many locations, especially in Northern Europe and France, as shown in Figure 44. This leads to over 550 TWh electricity from offshore wind compared to approximately 200 TWh in scenario *Base*.

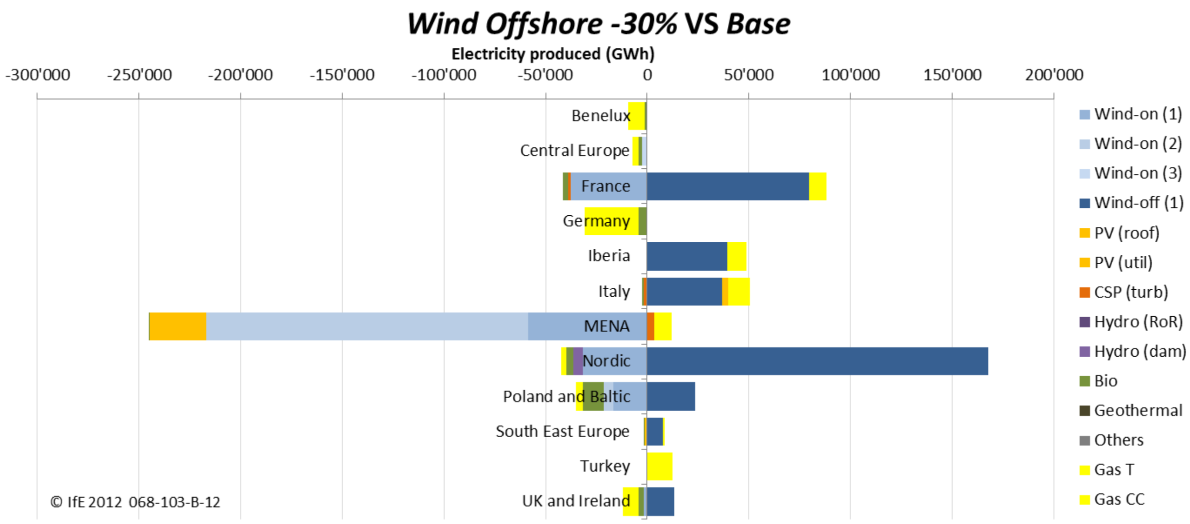


Figure 44: Difference in electricity production by region between scenarios *Base* and *Wind offshore cost -30 %*

5.1.3 Wind onshore

Being the biggest source of energy in the EUMENA electricity system, different costs for onshore wind turbines have a big impact on the optimal solution. In scenario *Base*, onshore wind has investment costs of 932 €/kW and fixed costs of 30.8 €/kW/a. These values are increased by 50 % and decreased by 30 %.

The impact of these changes on electricity production is shown in Figure 45. For high cost, the share of onshore wind drops from initial 52 % (2620 TWh) to 27 % (1360 TWh). In case of low cost onshore wind, contribution increases to 61 %.

In the high cost scenario, onshore wind is replaced mainly by a mix of offshore wind, photovoltaic and CSP. Figure 46 shows that this replacement happens mainly in Nordic countries for wind offshore and MENA for photovoltaic and CSP. In the low cost scenario, onshore wind substitutes photovoltaic and CSP in MENA, while leaving the remaining system unchanged.

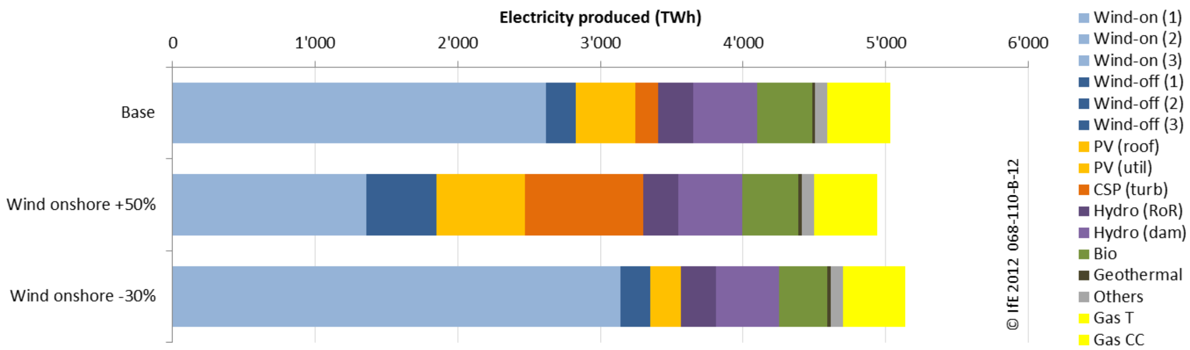


Figure 45: Electricity production by input commodity in *wind onshore* cost scenarios

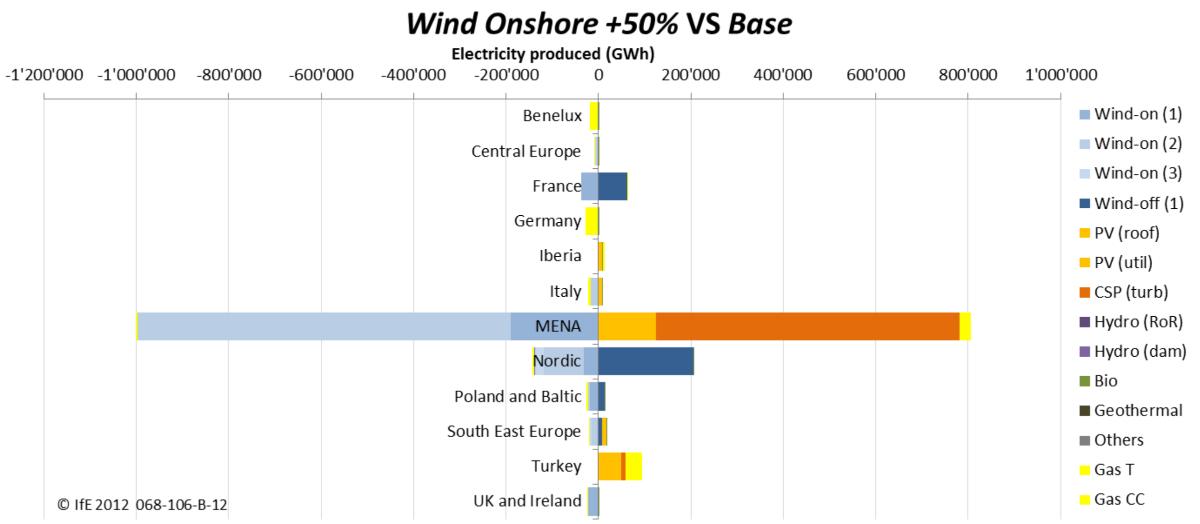


Figure 46: Difference of electricity production by region between scenario *Wind onshore cost +50 %* and *Base*

5.1.4 Photovoltaic

Effects of changing prices for PV are investigated in the next two scenarios. Like in all technology cost scenarios, specific investment and fix costs are increased by 50 % and decreased by 30 %.

In the PV +50 % scenario, as shown in Figure 48, 300 TWh electricity generation from PV in MENA is replaced by onshore wind and CSP in the same region and Turkey. Total system cost rise by 2.6 % to 332 B€, corresponding to cost of electricity of 74.9 €/MWh. The remaining system remains unchanged.

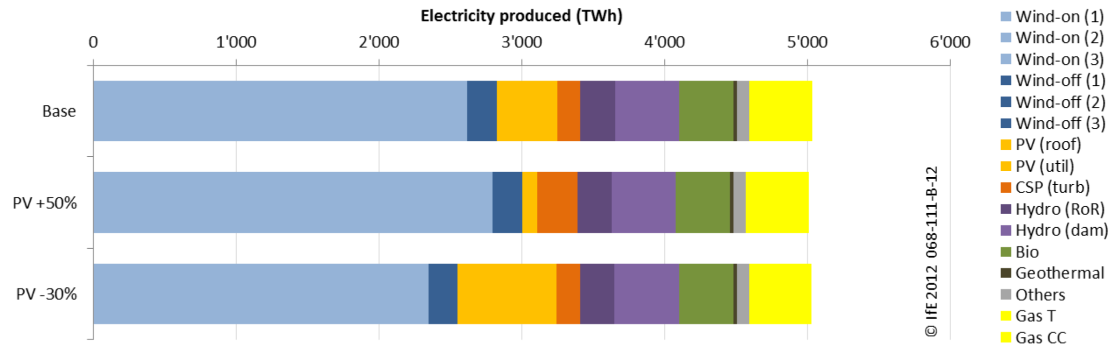


Figure 47: Electricity production by input commodity in photovoltaic cost scenarios

Figure 49 shows the change in electricity production for scenario *PV cost -30 %*. 250 TWh of electricity from onshore Wind in MENA are substituted by additional PV in all regions except Central and Northern Europe. Total system cost drop by 2.9 % to 315 B€, corresponding to 70.9 €/MWh cost of electricity. In this scenario, cost for transport reduce from 29.5 B€ to 25.8 B€ or by 13 % due to the more distributed electricity generation. At the same time, usage of pump storage increases by 25 %, their summed electrical output increases from 51 TWh to 63 TWh.

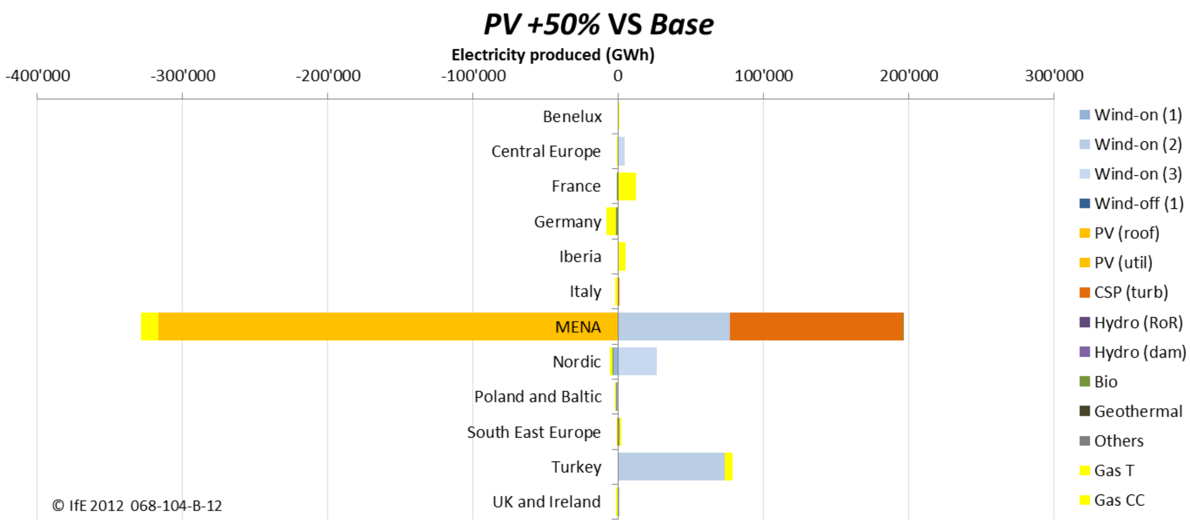


Figure 48: Difference of electricity production by region between scenario *PV cost +50 %* and *Base*

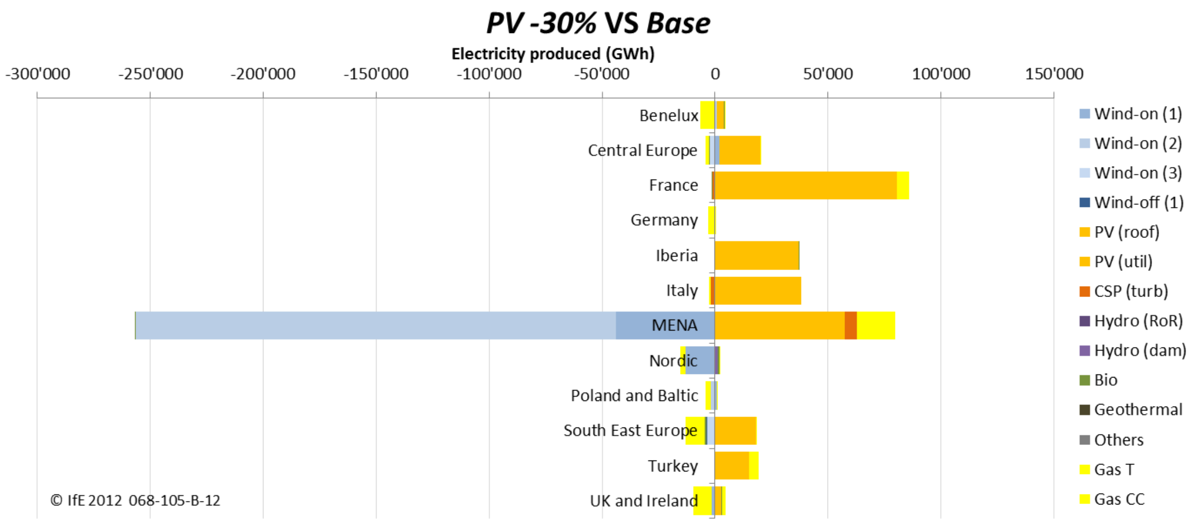


Figure 49: Difference of electricity production by region between scenario *PV cost -30 %* and *Base*

5.2 Cost of grid connection

The following two scenarios investigate the effect of increased cost for transmission capacities among countries. Specific investment cost therefore is increased by 50 % and 100 % compared to the *Base* scenario.

Figure 50 shows the resulting change in overall electricity production. Except for a small drop in electricity production from onshore wind in the Grid cost +100 % scenario, no big changes are evident.

If regional distribution of electricity generation is respected, as shown in Figure 51 and Figure 52, it can be seen that approximately 100 TWh (*Grid +50 %*) or 400 TWh (*Grid +100 %*) are moved from MENA countries to all other regions. Additionally, some 50- 70 TWh of electricity from CSP is generated in MENA countries in order to be able to better balance short-term fluctuations of renewable electricity generation due to reduced grid capacities.

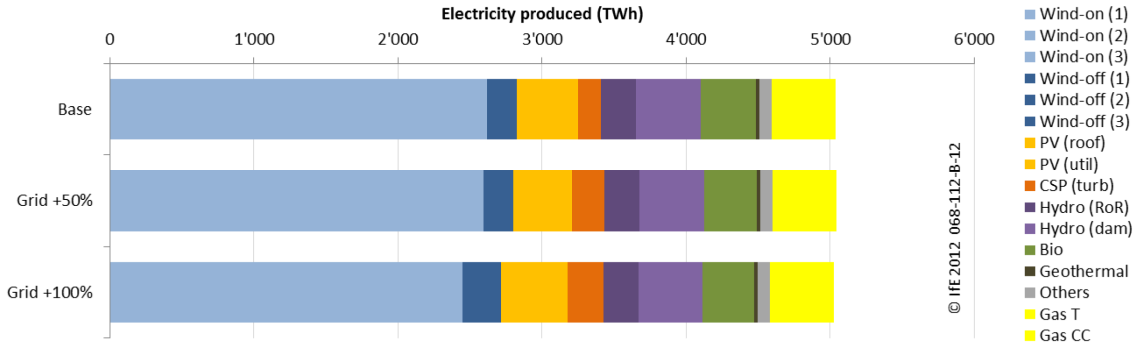


Figure 50: Electricity production by input commodity in grid cost scenarios

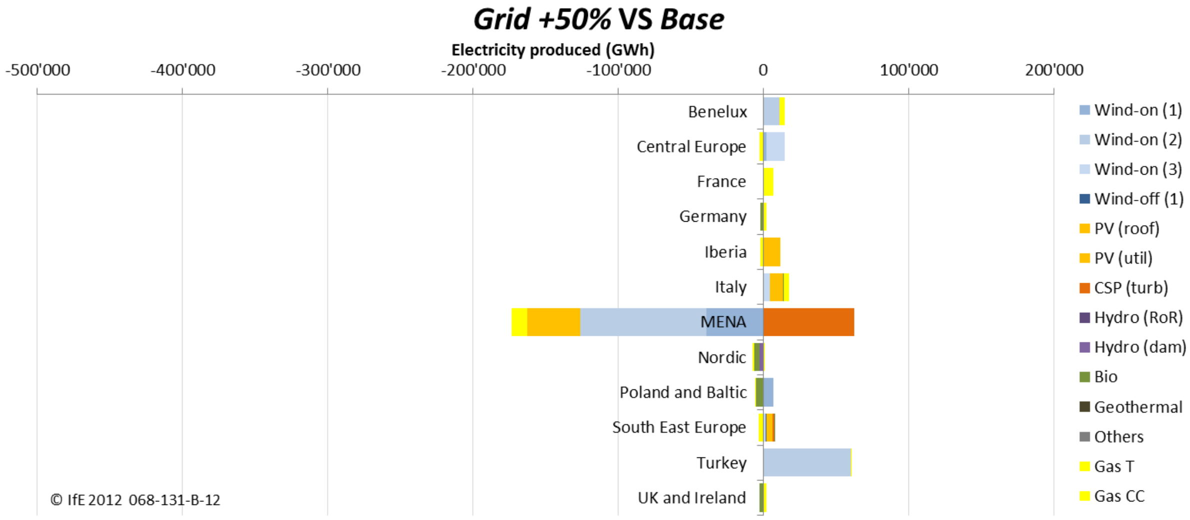


Figure 51: Difference of electricity production by region between scenario *Grid cost +50 %* and *Base*

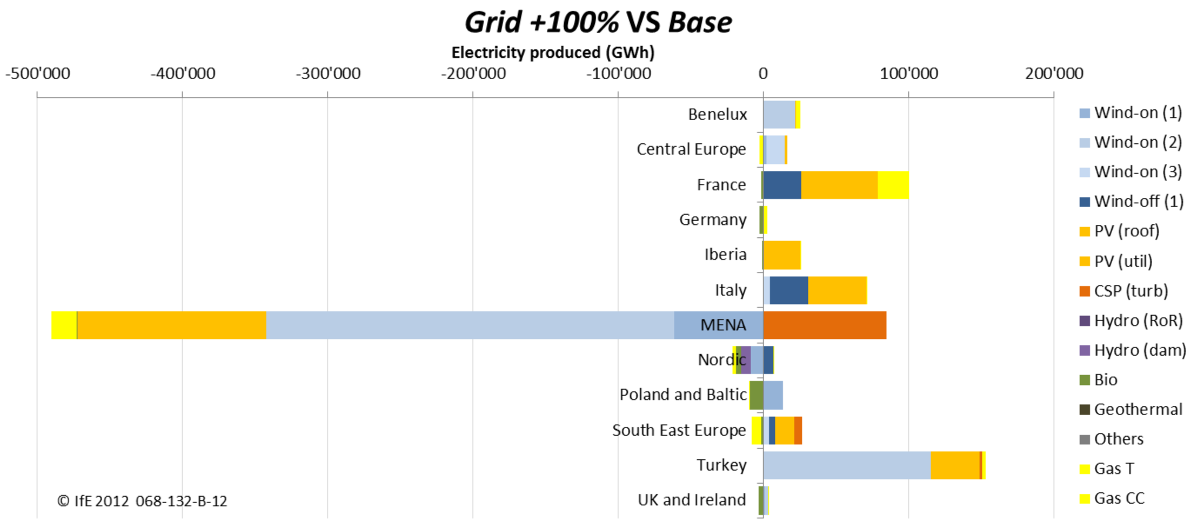


Figure 52: Difference of electricity production by region between scenario *Grid cost +100 %* and *Base*

In terms of electricity exchange between EU and MENA, *grid cost +50 %* only decreases EU's import share from 26 % to 23 % of its demand, while in *Grid cost +100 %*, this share goes down to 16 %.

5.3 WACC variation

The next three scenarios investigate the influence of different weighted average costs of capital (WACC). The default value is 7 % for EU and MENA. In these scenarios, it is changed to 5 % and to 9 % for both regions, as well as to 9 % for MENA alone. Changing WACC influences the technology mix as technologies vary in depreciation times (see Table 11).

One of the major interests is the influence of WACC variations on the share of electricity imports from MENA to Europe. Figure 53 shows that simultaneous variations of WACC in all regions do not significantly affect import shares. Net imports are 25 % with a WACC of 5 %, 7 % as well as with 9 %. Increasing WACC only for MENA to 9 %, however, lower imports from MENA of 17 % and net imports of 16 % are the consequence. Annualized investment costs are higher in MENA and thus, production is shifted to Europe.

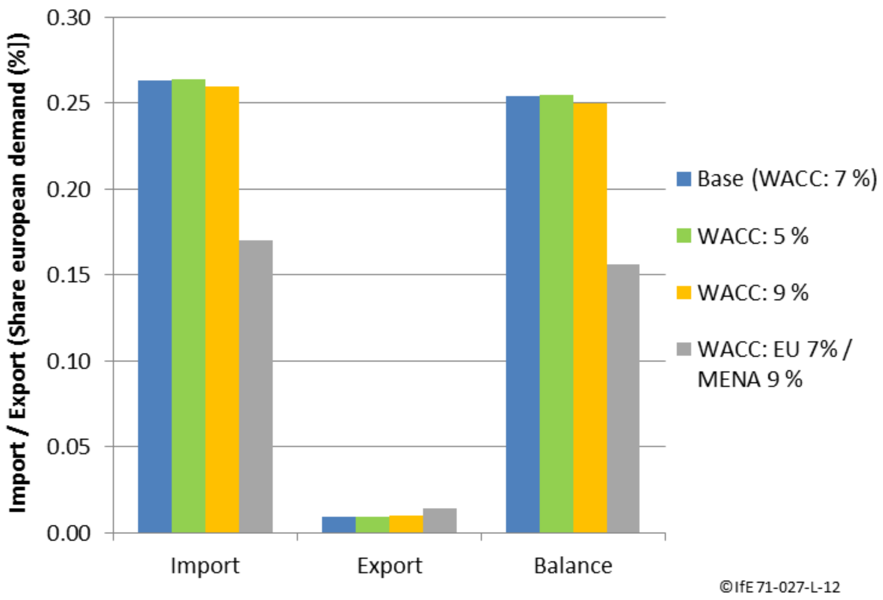


Figure 53: Influence of WACC variations on share of electricity imports to Europe

Having lower imports means less investment in transport infrastructure. Figure 54 shows a comparison of transport capacities from MENA to different European regions. In scenarios with higher WACC in MENA, lower capacities are built especially from MENA to France and to Turkey. Capacities to Iberia, Italy and South East Europe are about the same in all considered scenarios.

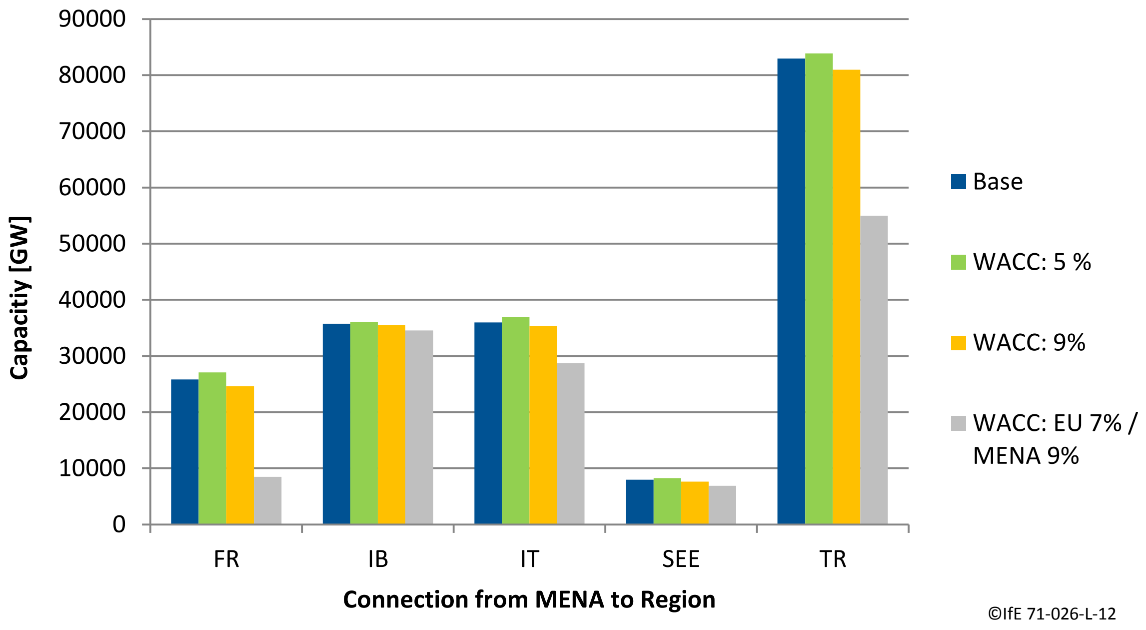


Figure 54: Installed transmission capacities between MENA and European regions for *WACC* scenarios

Less imports from MENA to Europe is caused by a regional shift in electricity generation. Figure 54 shows these shifts in a regional split. Less capacities for wind power, PV and CSP are built in MENA. This is compensated through higher capacities of wind power in Nordic countries, Turkey as well as UK and Ireland on the one hand and more PV and CSP in southern European countries on the other hand. Moreover, a shift in electricity from gas power plants can be observed: More gas power is used in France and less in Germany, Turkey as well as UK and Ireland. France needs more gas now as the connection from MENA to France suffers most of import cuts (cf. Figure 55). Turkey installs Wind power, PV and CSP to compensate gas power; UK and Ireland can replace it through more wind power alone.

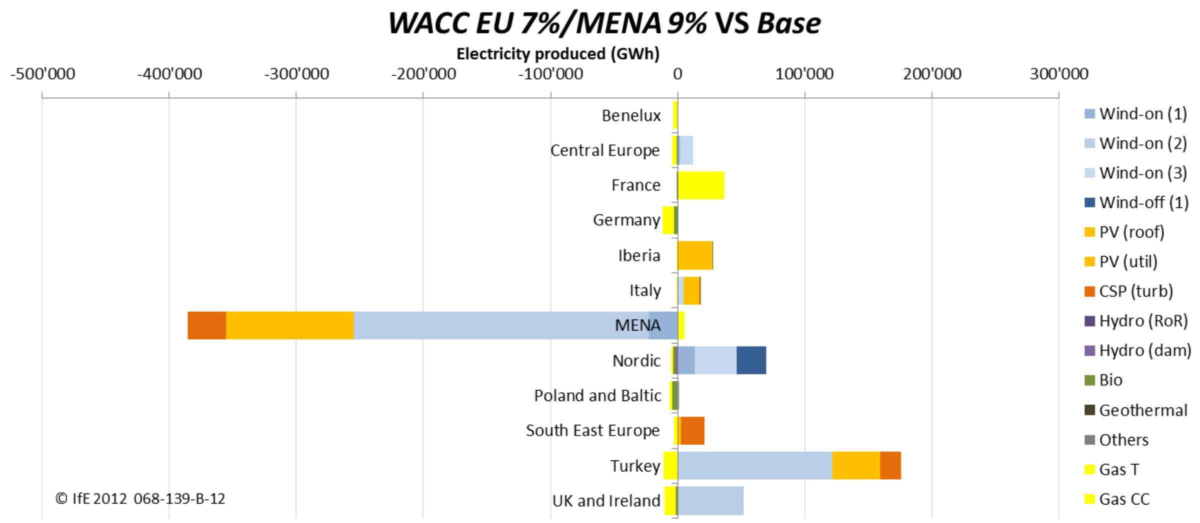


Figure 55: Difference of electricity production by region between scenarios *WACC EU 7%/MENA 9%* and *Base*

Annual system costs are affected through WACC variations per definition. Figure 56 shows these effects in detail: the higher the WACC, the higher annual system costs are.

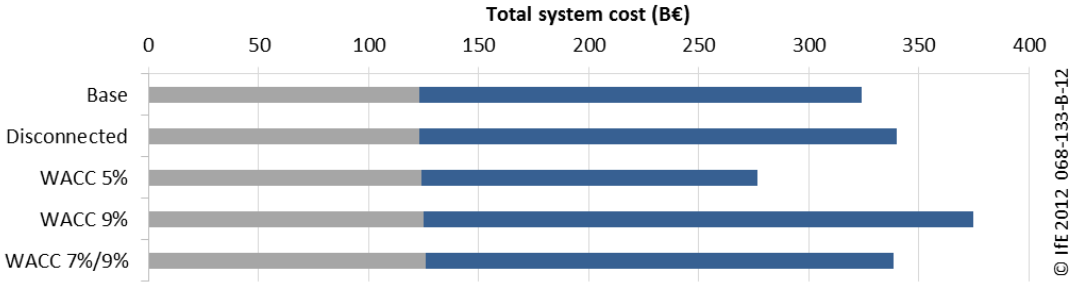


Figure 56: Total system costs for *WACC* scenarios

5.4 Availability of Nuclear & CCS

With four different investment/fixed costs, the impact of allowing nuclear power is investigated. Starting from initial 3000 €/kW investment and 91.7 €/kW/a fixed costs, investment costs are increased by 50 %, 100 % and 150 %, yielding 4500 €/kW, 6000 €/kW and 7500 €/kW. This way, higher costs for next generation reactors and/or nuclear waste storage are approximated.

Figure 57 summarizes the results of all four scenarios. In the low price scenario, nuclear power provides 61 % of all generated electricity. Total system costs drop by 17 % to annual 267 B€, corresponding to generation and transmission of 60.3 €/MWh. This is the cheapest scenario modeled that satisfies CO_2 emission reduction goals. Costs for transport can be reduced from 30 B€ to 9.5 B€ due to local electricity generation. Energy exchange between EU and MENA drops to almost zero, rendering useless big transport capacities.

With 50 % increased costs, nuclear still gets a share of 40 % on electricity production. EU's import share is still very low (2 % of demand), generation and transmission cost of electricity of 68.1 €/MWh or still 7 % below *Base* scenario. At 6000 €/kW or 100 % increase, still 14 % of all electricity is produced in nuclear power plants in Turkey, France and Italy. However, cost of electricity and system cost are already comparable to scenario *Base* (1 % difference). At 7500 €/kW, nuclear power is rendered unattractive and only provides less than 1 % of electricity, making this scenario almost identical to the *Base* scenario.

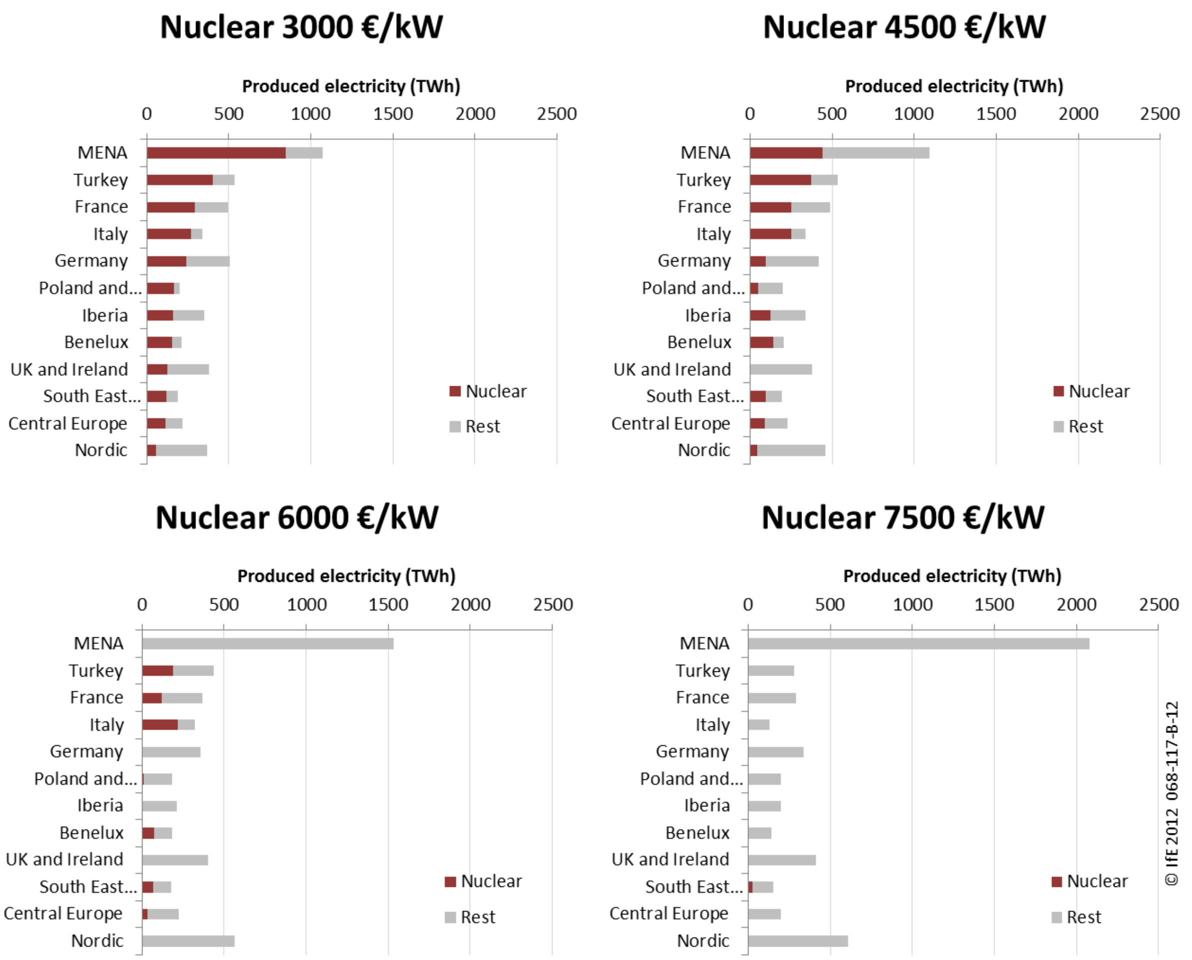
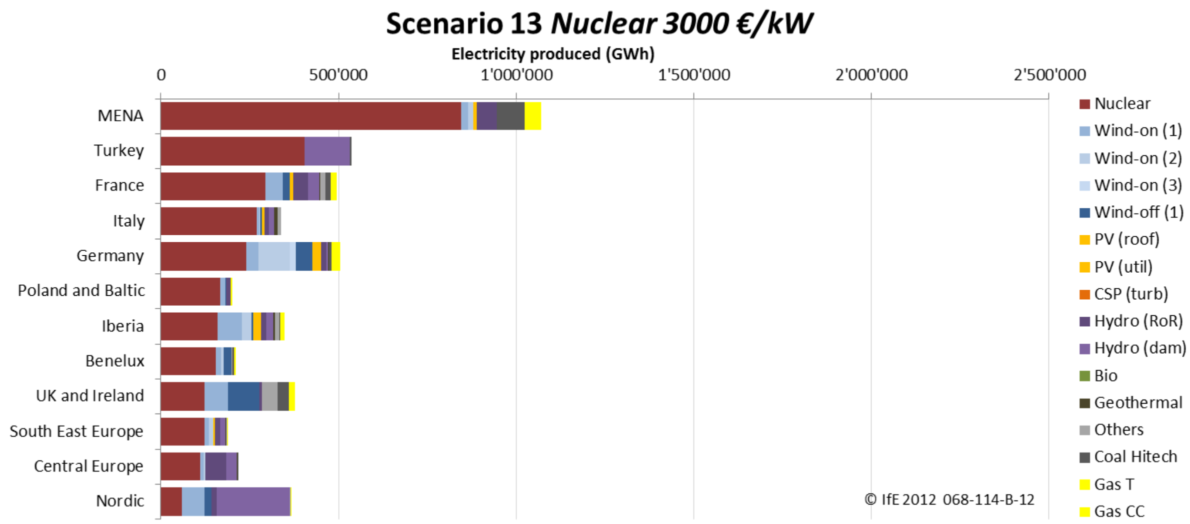
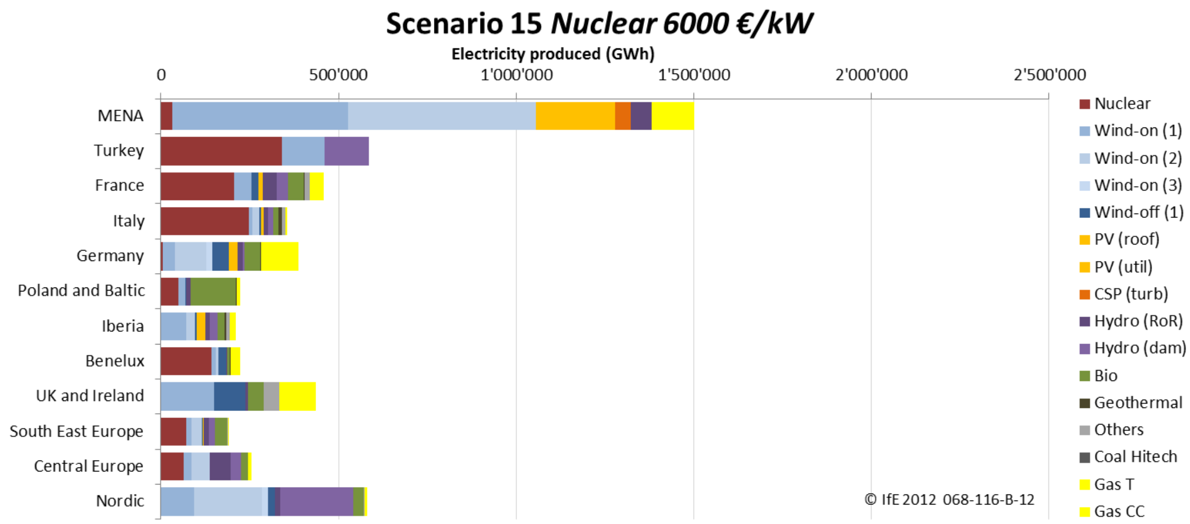


Figure 57: Nuclear electricity generation overview

Figure 58 shows electricity production by technology and region for three of the four scenarios. While nuclear power is built in all regions uniformly (relative to demand) in the low price scenario, renewable generation becomes more and more focused to regions with the best sites for renewable electricity generation, i.e. especially MENA countries.





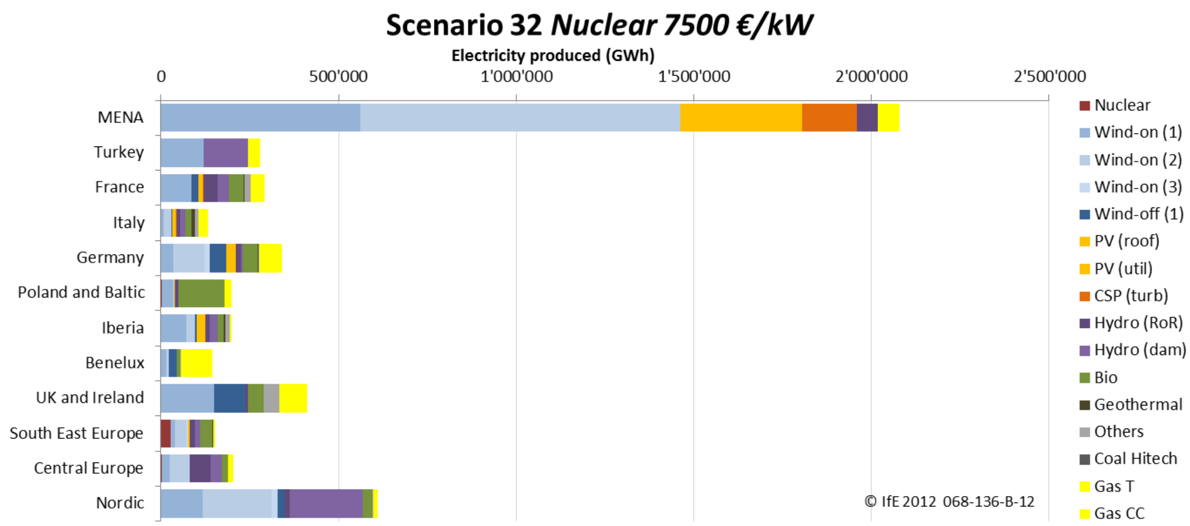


Figure 58: Electricity production by region and input commodity for nuclear scenarios

In CCS scenarios, the optimization model is allowed to install generation power of both Coal CCS and combined cycle Gas CCS power plants per country. CCS catches 90 % of the power plants' CO2-emissions. In scenario A, Gas CCS has investment costs of 1500 €/kW, Coal CCS 2900 €/kW. In scenario B, these values are increased by +50 %, to 2250 €/kW and 4350 €/kW. In scenario C, investment costs are increased by +100 % to 3000 €/kW for Gas CCS and 5800 €/kW for Coal CCS. Fixed costs are not increased in these scenarios. The increased investment costs are proxies for carbon storage costs, for which no reliable estimate is available yet.

Figure 59 shows the produced electricity by region in all three scenarios, labeled by the costs for the dominating Coal CCS technology. Shares of electricity produced by CCS are 25.8 %, 6.8 % and 0.0 %, while Gas CCS is negligible.

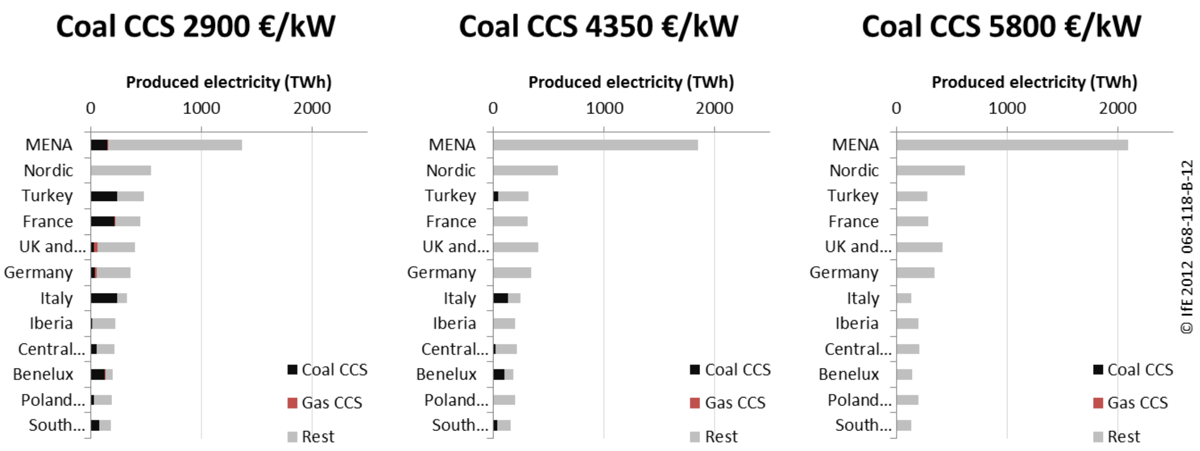


Figure 59: Electricity production by region in *CCS* scenarios

All in all, CCS is not a major option under the (cost) assumptions it is modeled here. Gas CCS seems least likely to be able to compete against conventional Gas power plants due to the relatively low GHG savings, whereas Coal CCS makes a cheap energy source available while satisfying strict emission goals. This explains its occurrence in the low cost scenario.

5.5 CO_2 price instead of CO_2 limit

In this scenario group, CO_2 emissions are not limited unlike in all other scenarios. Instead, processes with GHG emissions have increased variable costs according to their emission intensity that is listed in Table 5. Four different prices for CO_2 certificates are investigated: 0, 50, 100 and 150 €/t.

Table 5: CO_2 intensity of commodities

Commodity	CO_2 intensity (kg/MWh_{th})
Coal	330
Gas	200
Lignite	400
Oil	270

Figure 60 shows electricity generation by input commodity for all four scenarios. In case of free emissions, Coal power plants produce over 3000 TWh electricity. System cost drop to 243 B€, corresponding to 55 €/MWh cost of electricity for generation and transmission. This equals a reduction of 25 % compared to *Base* and is — not surprisingly — the cheapest of all modeled scenarios. The downside of this can be seen in Figure 61, showing CO_2 emissions by scenario. In case of free emissions, more than 2200 Mt are emitted, more than 15 times of the *Base* limit of 143 Mt. In scenario *CO_2 50 €/t*, emissions are at 500 Mt, while greatly reducing the amount of coal that is used for electricity production. Beginning with scenario *100 €/t*, gas burnt in combined cycle power plants becomes the cheapest fossil energy source for electricity. In scenario *150 €/t*, the original emission limit is reached with CO_2 emissions of only 98 Mt by replacing gas with onshore wind.

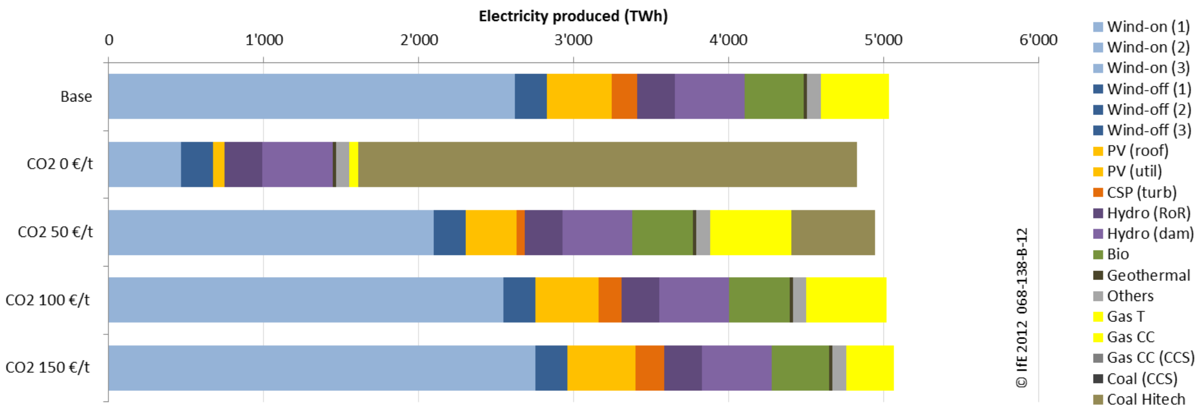


Figure 60: Electricity production by input commodity in *CO_2 price* scenarios

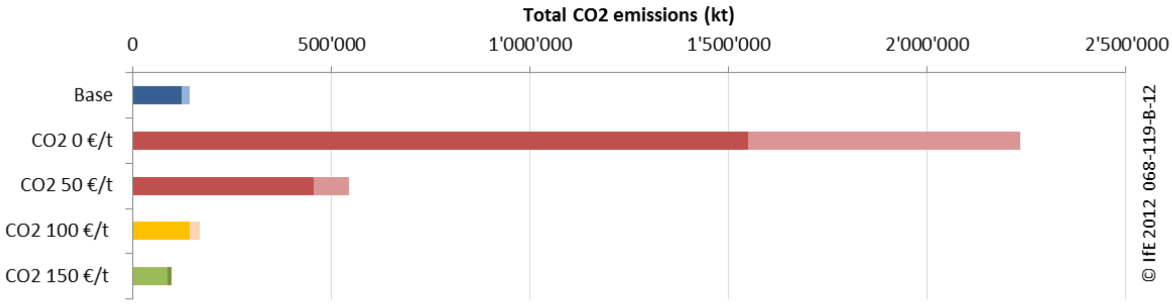


Figure 61: Total CO_2 emissions (kt) in *CO_2 price* scenarios in Europe (dark shading) and MENA (bright)

5.6 Grid restrictions & autarky

In scenario 22, a limit on the amount of new transmission capacities between European countries is imposed. This is done by limiting the maximum installable grid capacity to three times of today's NTC among European countries. Maximum allowed transmission capacities among MENA countries and EU-MENA interconnectors remain unlimited. Figure 62 shows the resulting changes in the electricity generation by region. Approximately 150 TWh of electricity from onshore wind moves from Nordic to MENA due to a lack of transmission capacities between northern and central Europe. This equals a rise of 3 % points in EU import share from 26 % in the base scenario to 29 % of its demand.

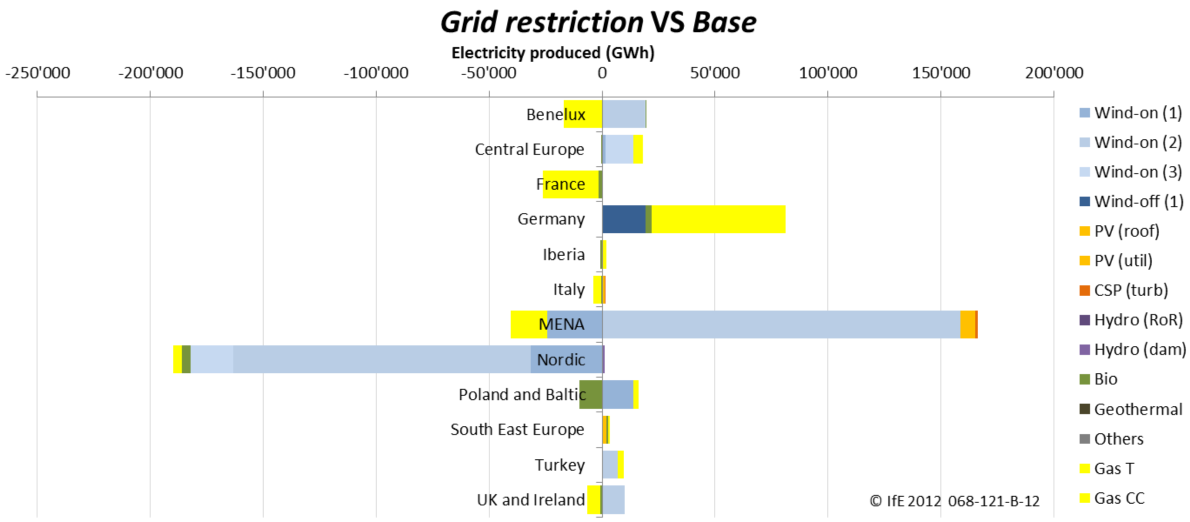


Figure 62: Difference of electricity production by region between s22 *Grid restriction* and s01 *Base*

The changes in transmission capacities compared to the base scenario are summarized in Table 6. The biggest change happens between Nordic countries and Germany, with 37 GW less capacity. Most inter-regional connections have a drop in capacity with the exception of MENA–FR (+18 GW) and Benelux—FR (+5 GW). 83 GW less of transport capacity are installed in the whole system.

From a system cost perspective, the restriction has minor impact: cost of electricity rises from 73.0 €/MWh to 74.0 €/MWh. Volatility of average marginal cost of electricity is slightly reduced, due to the steadier weather conditions (wind time series) in MENA countries.

Table 6 Difference of interregional transport capacities (MW) between s22 *Grid restriction* and s01 *Base*.

Grid restriction - Base (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	7'549	0	5'132	-5'455	0	0	0	1'400	0	0	0	151
Central Europe	0	-8'218	0	1'319	0	1'597	0	0	1'846	-1'343	0	0
France	5'132	0	0	1'036	-6'375	0	18'247	0	0	0	0	843
Germany	-5'455	1'319	1'036	0	0	0	0	-36'879	2'027	0	0	0
Iberia	0	0	-6'375	0	-9'438	0	-4'245	0	0	0	0	0
Italy	0	1'597	0	0	0	-2'891	2'381	0	0	-2'776	0	0
MENA	0	0	18'247	0	-4'245	2'381	23'977	0	0	-719	-2'394	0
Nordic	1'400	0	0	-36'879	0	0	0	-28'627	-1'195	0	0	-1'328
Poland and Baltic	0	1'846	0	2'027	0	0	0	-1'195	-1'636	1'494	0	0
South East Europe	0	-1'343	0	0	0	-2'776	-719	0	1'494	954	-7'211	0
Turkey	0	0	0	0	0	0	-2'394	0	0	-7'211	0	0
UK and Ireland	151	0	843	0	0	0	0	-1'328	0	0	0	111

In scenarios 24 to 26, three levels of autarky per country are imposed. In each hour, all individual countries must provide a share of their electricity demand from domestic electricity generation. These shares are 30 %, 50 % and 70 %. While the low and medium autarky scenarios show only negligible effect on system cost and generation, an imposed 70 % level of domestic electricity production has major impact on the technology distribution that is shown in Figure 63.

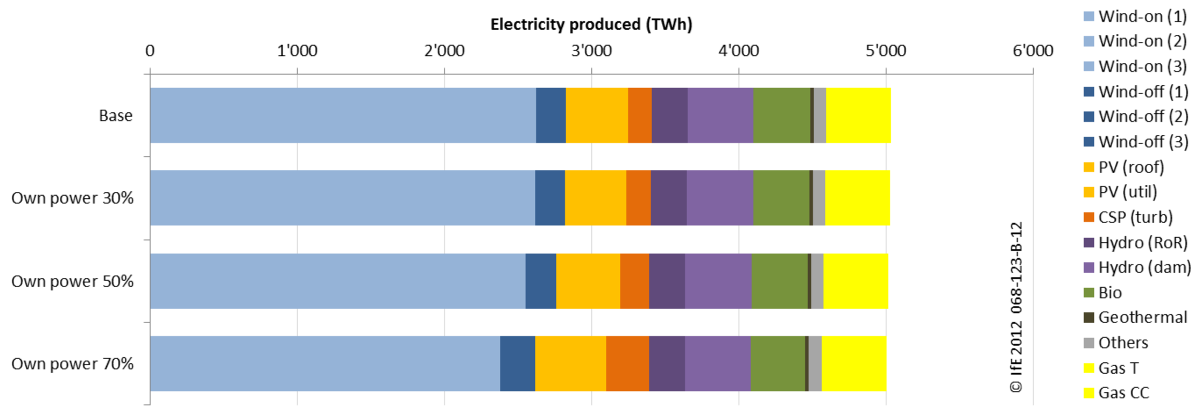


Figure 63: Electricity production by autarky scenarios (s24-s26) compared to s01 *Base*

Figure 64 shows the difference in electricity production by region and commodity between *Base* and *70 % autarky* scenario. Over 400 TWh of wind power is replaced by a mix of photovoltaic, CSP and wind onshore in Turkey and Southern Europe. Gas power is relocated as well to these regions, as well as Germany. In short, electricity generation is forced to be more distributed among countries. System cost in this scenario rises by 3 % to 333 B€, mainly due to higher LCOE for production technologies.

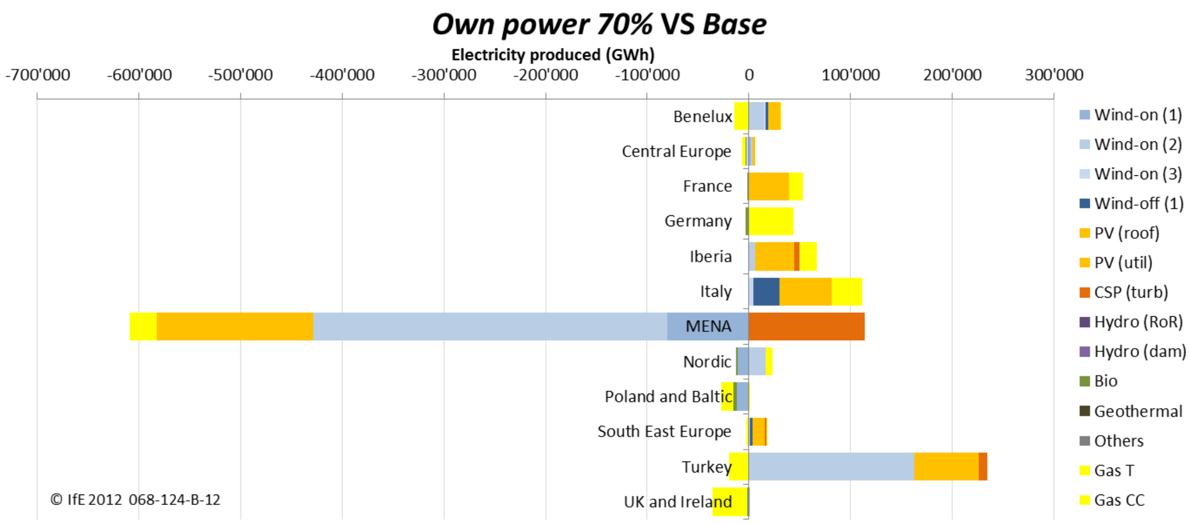


Figure 64: Difference of electricity production by region between s26 *Own power 70%* and s01 *Base*

In terms of energy exchange between EU and MENA countries, the 70 % autarky scenario has major impact: EU import share drops from 26 % to 14 % of its electricity demand.

Crucial for reaching the 70 % requirement is the use of existing pump storage capacities. The total electrical output of pump storage is 126 TWh which is more than twice as much as in the Base scenario (51 TWh). CSP heat storage fulfills the same purpose in MENA countries.

6 Input parameters

The following chapter gives an overview of the most important input data and their processing in the model. Data that cannot be displayed in this report are hourly time series for electricity demand and for the feed in of renewable energies (capacity factors). As complete time series are too long, only summarized values for the whole year are displayed. All data for the model are values projected to the year 2050 according to published studies or institute knowledge and expertise.

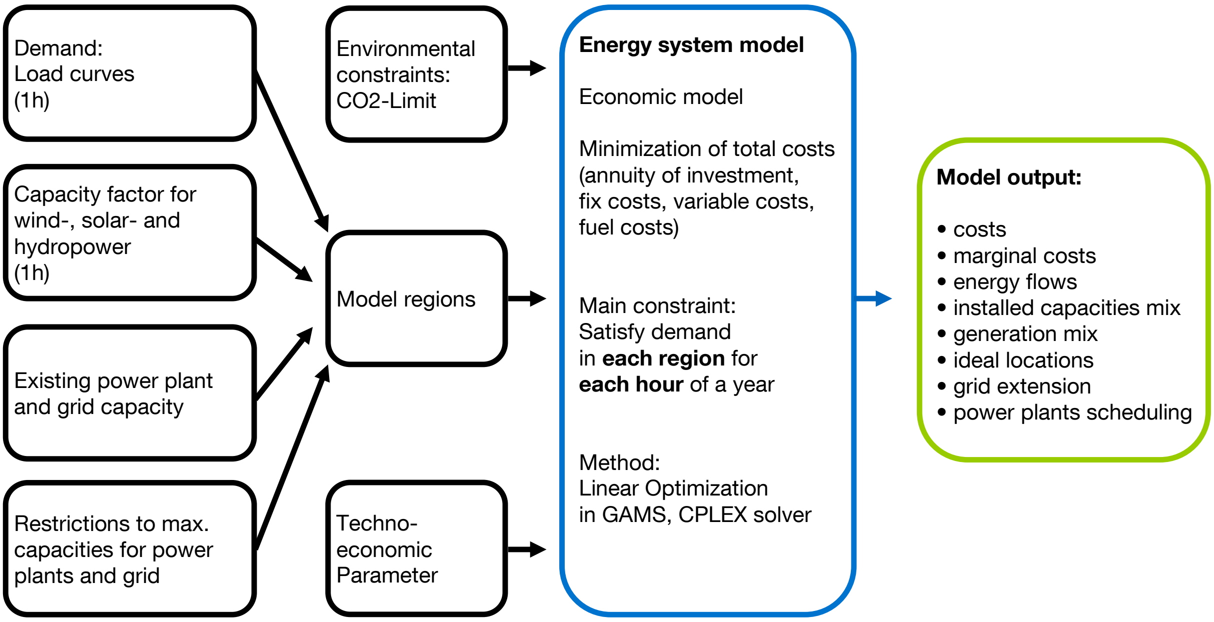


Figure 65: Overview of model input and output

6.1 Commodities

Commodities are the goods that are generated, transported and consumed in this model. This includes both renewable energy sources like solar irradiation, wind, water and fossil fuels like coal, gas, oil. Electricity is the consumed commodity which must be provided by conversion from other commodities. CO_2 finally is an environmental commodity that is created as a by-product of certain conversion processes. Its total amount is limited, which constitutes the main restriction for allowed system configurations.

6.1.1 Demand in detail

As it was stated in the model description, in each hour of a year, demand has to be satisfied in each country. The data for hourly demand in each country in Europe (without Turkey) is provided by Siemens and consists of a data set produced by [2] for the year 2007. The dataset is equal to data published by ENSO-E [3] for 2007. This hourly demand is scaled to the annual demand for each region accordingly. Table 7 below shows all modeled regions and the annual electricity demand in TWh, respectively. Two scenarios for the annual demand are considered: low demand and high demand. The low demand scenario is used in scenario 01 *Base* and for benchmarking all the sensitivities. The low demand scenario represents the current demand as published by ENTSO-E [3]. Original data from ENTSO-E include grid losses (distribution and transmission). These were assumed to be 7.5 % and subtracted to get to final consumption data. The high demand scenario is based on a study by McKinsey [4]. Turkey is considered as being part of Europe in this study. In historic data however, it is separated and thus source for demand are different. Load pattern from 2009 were used and a demand forecast from the Turkish electricity transmission corporation TEIAS was taken. High demand data is used only in scenarios 02 and 04.

Table 7: Annual net electricity demand in Europe [3]

Region	Low demand [TWh]	High demand [TWh]
AT	57.9	87.3
BE	86.7	130.8
BG	28.0	42.3
CH	54.4	82.1
CZ	65.1	98.2
DE	477.2	719.4
DK	32.1	48.4
EE	7.5	11.4
ES-E	117.2	176.6
ES-N	136.1	205.3
ES-S	29.6	44.6
FI	74.6	112.5
FR	451.4	680.6
GB	317.9	479.4
GR	62.1	93.6
HU	35.2	53.1
IE	28.9	43.6
IT-N	262.2	395.2
IT-S	48.3	72.8
LT	8.9	12.5
LU	7.4	11.2
LV	7.1	10.8
NL	101.1	152.4
NO	105.8	159.5
PL	135.8	204.7
PT	48.7	73.4
RO	49.1	74.1
SE	117.5	177.2
SI	13.8	20.8
SK	30.9	46.6
TR	509.0	763
Sum	**3507.7**	**5284.1**

Eight countries from the MENA region are selected for the model. Again, historic hourly demand pattern were scaled to annual demand forecasts. Basis for the hourly demand were as follows:

- *DZ: Time shifted data of MA*
- *EG: Time shifted data of MA*
- *LY: Time shifted data of MA*
- *MA: Historic data from 2010*
- *SA: Historic data*
- *TN: Historic data*
- *JO: Historic data*
- *SY: Time shifted data of MA*

The annual demand for these countries in 2050 is taken from an IEA forecast [6] in the low demand scenario. In the high demand scenario, a more optimistic forecast from AUPTDE 2010 (Arab Union of Electricity Site) was taken.

Table 8: Annual electricity demand in selected MENA countries [6]

Region	Low demand [TWh]	High demand [TWh]
DZ	64	206
EG	239	763
LY	45	53
MA	46	121
SA	449	675
TN	27	35
JO	30	72
SY	70	205
Sum	970	2130

6.1.2 Fuels in detail

Table 9 gives an overview of fuel prices as assumed for scenario calculations. These forecasts for fuel prices in 2050 are mostly based on the 450 ppm scenario from the International Energy Outlook 2010 [6]. Fuel prices for Uranium are institute knowledge of IfE, but values in the same range can be found in [7]. The price for biomass is in the mean of the range stated by [5]. Price for lignite is institute knowledge; a public study that can be cited for this value is not available. However, lignite is not used in the scenarios.

Table 9: Assumptions for fuel prices in 2050 [6]

Technology	Fuel price [$€_{2010}$/MWh]
Coal	6.860
Lignite	3.750
Gas	26.820
Oil	47.000
Uranium	3.110
Biomass	5.400

6.1.3 CO_2 in detail

As major challenge and driver for a change in energy system, restrictions for emission of CO_2 are imposed.

A reduction of specific CO_2 emissions of 95 % for power generation compared to 1990 is considered for EU+2. In Turkey and the MENA region, the reduction is set to 50 % compared to 2000. Table 10 summarizes the maximum CO2-emissions for the regions

Table 10: Restrictions on CO_2 emissions for modeled regions

Region	Low demand CO_2 emissions [Mt]	High demand CO_2 emissions [Mt]
EU+2	75	113
Turkey	23	34
MENA	46	101

CO_2 emission limits are defined for these three regions. In the model however, one limit for the overall region is set. In the low demand scenarios this limit is 143 Mt/a (32 g/kWh net electricity consumption); in the high demand scenario it is 248 Mt/a (33 g/kWh).

In scenarios 19 to 21, the CO_2 limits are replaced by a price for CO_2 emissions. Method and results are explained in section 5.5.

6.2 Generation technologies

As the model optimizes overall system costs, assumptions for costs of different technologies are an essential model input. The model distinguishes between four different types of cost: investment costs, fix operation costs, variable operation costs and fuel costs. Investment costs are considered on an annuity base in the optimization. In order to allow a better understanding and comparison, full Investment costs are displayed in the following tables. Annuities are calculated with a WACC of 7 % in the base scenario. Another parameter for calculation of annuities is the depreciation period, which was set to the technical lifetime (see Table 11).

Table 11: Technical lifetime of technologies

Technology	Technical Lifetime [a]
CSP	30
PV	25
Wind On	25
Wind Off	20
Biomass	25
Hydro	50
Coal	40
GT	30
CCGT	30
Nuclear	40

Table 12 shows an overview of investment, fixed and variable costs for different technologies in €2010. Must run generation technologies (Wind, PV, and Hydro) as well as CSP have variable costs of zero in this model. All O&M is included in annual fix costs.

Table 12: Cost assumptions for generation technologies

Technology	Investment Cost [€/kW]	Fix Cost [€/kW]	Variable Cost [€/kW]
CSP: Collector [€/m²]	146	36.50	0.0
CSP: Turbine	721	18.03	0.0
CSP: Gas boiler	248	6.2	0.0
PV Rooftop	1080	29.16	0.0
PV Utility	801	21.63	0.0
Wind Onshore	932	30.76	0.0
Wind Offshore	1495	59.80	0.0
Biomass	2450	80.00	4.0
Hydro	1600	20.00	0.0
Coal	1450	34.50	1.5
GT	380	96.50	2.7
CCGT	750	11.10	2.7
Nuclear	3000	91.7	included in fuel
CCS Coal	2900	69	2.25
CCS CCGT	1500	22.2	4.05

In power plants fired with fossil fuels or biomass, input commodities are converted to electricity with certain efficiencies as shown in Table 13. The efficiencies are the same in all operating points of the power plants. As the input commodities are storable and available at every time, the hourly use of these technologies is controllable in the model.

Table 13: Assumptions on fuel efficiencies of generation technologies

Technology	Efficiency [%]
CSP: Turbine	40
CSP: Gas boiler	90
Biomass	38
CCGT	62
GT	40
Coal	48
CCS Coal	39
CCS Gas	53

Renewable energy technologies using solar, wind, or water resources depend on weather conditions and are thus considered as not being controllable in the model. The power from photovoltaic (PV), from onshore and offshore wind, and to some extend power from concentrated solar power (CSP) is predetermined in each hour and region. A "capacity factor" for each hour and region is calculated by [2] for all European countries. This value between 0 and 1 is multiplied with the installed capacity in the region in order to get the hourly power output. For MENA countries, capacity factors are calculated by IfE with data from [9] for wind power and from [10] for photovoltaic. The capacity factor for CSP is calculated by experts from Dii.

In case of onshore and offshore wind time series, a non-linear scaling is applied to the normalized capacity factors. For the power function $c'(t) = c(t)^x$ an exponent x is determined so that $\sum_{t=1}^{8760} c'(t)$ matches the full load hours given in Table 14 for wind onshore (category 1) and wind offshore. The power function is used so that hours with high ($c(t) \approx 1$) and low ($c(t) \approx 0$) are preserved in the transformed time series. Capacity factors for categories 2 and 3 of wind onshore are then derived in the model by linear scaling of c'.

To give an idea about the data from the sources named above, the resulting full load hours for each technology and region are summarized in Table 14. As wind potentials are very high and wind speeds vary within one region, three classes of full load hours were used. In European countries the classes were derived from the average full load hours provided by ISI. 20 % of the potential was assumed to have 20 % higher full load hours and 20 % of the potential to have 20 % lower full load hours. In the MENA region and Turkey, the classes were defined according to GIS analysis conducted by Dii. Full load hours for hydro power plants include run of river as well as dam storage. These values result from monthly generation according to [3] and installed capacities according to [3], [12], [14], and [16]. Dam storage power plants are assumed to have the same seasonal generation pattern as run of river. Generation can be scheduled hourly but the monthly influx to the storage is pre-determined through [3] generation patterns.

Table 14: Full load hours for different technologies in modeled regions

Region	PV [h/a]	W-On1 [h/a]	W-On2 [h/a]	W-On3 [h/a]	Wind-Off [h/a]	DNI [kWh/m²/a]	Hydro [h/a]
AT	1000	2250	1867	1507	0	0	4886
BE	792	2618	2173	1754	3260	0	4838
BG	1092	2192	1819	1468	2784	0	4041
CH	1000	1879	1560	1259	0	0	2947
CZ	848	2936	2439	1967	0	0	4000
DE	831	2730	2266	1829	3366	0	4055
DK	828	4499	3734	3014	3637	0	2818
EE	840	2539	2108	1701	2900	0	1800
ES-NW	1372	2241	1860	1501	2907	0	1503
ES-E	1267	2241	1860	1501	2907	0	1503
ES-S	1356	2241	1860	1501	2907	1977	1503
FI	775	2185	1813	1464	2952	0	4469
FR	1047	2488	2065	1667	3456	1838	5150
GB	791	3347	2778	2242	4021	0	2986
GR	1217	2643	2193	1771	2987	1924	4000
HU	1019	2000	1660	1340	0	0	4447
IE	809	3559	2954	2384	4000	0	3361
IT-N	1074	2561	2125	1716	2575	0	2191
IT-S	1310	2561	2125	1716	2575	1850	2191
LT	828	2376	1972	1592	2900	0	3268
LU	871	2764	1194	1852	0	0	5000
LV	862	2403	1995	1610	2900	0	2300
NL	792	3104	2576	2080	3345	0	2622
NO	786	3701	3072	2480	0	0	4000
PL	848	2218	1841	1486	3325	0	3947
PT	1350	2228	1849	1493	2872	0	1280
RO	1126	2403	1995	1610	2784	0	4816
SE	786	2697	2239	1807	3168	0	4000
SI	981	2320	1925	1554	0	0	3782
SK	933	2119	1759	1420	0	0	2676
DZ	2083	2882	2219	1265	0	2246	759
EG	2339	2691	2153	1292	0	2248	4302
LY	2036	2787	2146	1395	0	2330	4000
MA	1988	2784	1893	1003	0	2698	2636
SA	2239	2454	1890	1134	0	2121	4000
TN	1625	2691	2207	1479	0	2231	2584
JO	2051	2219	1753	1104	0	2397	4000
SY	1955	2090	2090	1588	0	2487	2083
TR	1501	2480	16586	927	0	1907	4000

The way towards an optimized future power system is at least to some extent conducted by a regulatory and political framework. In order to take this into account, the political targets for the use of different renewable technologies were considered as input parameter to the model. The EU Energy trends to 2030 [12] were considered as the leading political targets for EU countries.

Table 15 shows the targets for each technology and country until 2030. In the model, these numbers are considered as minimum capacities for respective renewable energy capacities in the year 2050.There is no split of wind power into three categories available in [12]. It was thus assumed that best sites are used first. When the potential in the best category is less than the minimum capacity, the second best is used and so forth. Political target according to [12] were always lower than the overall potential, respectively.

Table 15: Installed capacities of renewable energies according to political targets in 2030 [12]

Region	Hydro RoR [GW]	W-On1 [GW]	W-On2 [GW]	W-On3 [GW]	W-Off [GW]	PV [GW]	Bio [GW]	Geo [GW]	Others [GW]
AT	6.579	1.455	1.546	0.000	0.000	1.226	0.000	0.008	0.008
BE	0.111	1.004	1757	0.000	2.208	0.554	0.000	0.000	0.000
BG	2.600	1.044	0.000	0.000	0.116	0.384	0.000	0.022	0.022
CH	6.553	0.500	0.000	0.000	.000	1.000	0.000	0.000	0.000
CZ	0.252	1.483	0.000	0.000	0.000	0.576	0.000	0.000	0.000
DE	3.946	13.086	39.204	8.811	14.543	59.864	0.000	0.170	0.170
DK	0.011	4.018	0.000	0.000	2.512	0.312	0.000	0.000	0.000
EE	0.005	1.086	0.000	0.000	0.217	0.040	0.000	0.000	0.000
ES-E	2.313	11.717	6.783	0.000	0.532	16.674	0.000	0.237	0.233
ES-NW	2.313	13.619	5.891	0.000	0.007	4.552	0.000	0.250	0.271
ES-S	0.000	2.956	2.839	0.000	1.064	7.228	0.000	0.074	0.059
FI	3.133	1.325	0.000	0.000	0.662	0.298	0.000	0.000	0.000
FR	7.766	21.451	0.000	0.000	6.435	22.138	0.000	0.367	1728
GB	2.130	16.373	0.000	0.000	23.389	1.140	0.000	0.009	4.206
GR	0.000	2.078	4.940	0.000	0.169	4.970	0.000	0.069	0.069
HU	0.047	0.499	0.412	0.000	0.000	0.500	0.000	0.097	0.097
IE	0.216	3.375	0.000	0.000	0.563	0.128	0.000	0.000	0.778
IT-N	4.482	2.059	0.000	0.000	0.121	5.206	0.000	0.100	0.947
IT-S	1.494	0.550	1.649	0.550	1.235	9.200	0.000	1.021	0.174
LT	0.122	0.959	0.000	0.000	0.096	0.222	0.000	0.000	0.000
LU	0.015	0.136	0.134	0.000	0.000	0.216	0.000	0.000	0.000
LV	1.520	0.395	0.000	0.000	0.198	0.048	0.000	0.000	0.000
NL	0.037	4.044	1.257	0.000	5.891	0.482	0.000	0.042	0.137
NO	0.000	0.250	0.000	0.000	0.000	0.400	0.000	0.000	0.250
PL	0.680	2.593	0.000	0.000	0.108	0.148	0.000	0.018	0.018
PT	5.211	6.687	0.000	0.000	0.000	6.088	0.000	0.025	0.674

RO	2.964	1.833	0.407	0.000	0.000	0.630	0.000	0.018	0.018
SE	0.000	4.567	0.000	0.000	1.713	0.318	0.000	0.000	0.000
SI	1.354	0.075	0.226	0.075	0.000	0.280	0.000	0.004	0.004
SK	1.686	0.935	0.101	0.000	0.000	0.186	0.000	0.013	0.013
DZ	0.228	2.000	2.000	2.000	0.000	0.000	0.000	0.000	0.000
EG	11.624	7.200	7.200	7.200	0.000	0.000	0.000	0.000	0.000
LY	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MA	1.518	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TN	0.062	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
JO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SY	1.250	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

The extension of renewable energies has limits. There is a finite area to install wind power, PV or plants for biomass. Hydroelectric or geothermal power plants need scarce natural resources. In order to take this into accounts, limits for the capacities of each technology were set. Hydroelectric and geothermal power plants are assumed to reach their potential limit with reaching the EU 2030 targets. Thus, potential limits equal installed capacities. The limit for wind power and PV was determined by ISI for all European countries and by Dii for the MENA region and Turkey.

Table 16: Potential limits of renewable energies in modeled regions

Region	Hydro RoR [GW]	W-On1 [GW]	W-On2 [GW]	W-On3 [GW]	W-Off [GW]	PV [GW]	Bio [GW]	Geo [GW]	Others [GW]
AT	6.579	1.455	4.365	1.455	0.000	27.159	0.785	0.008	0.008
BE	0.111	1.004	3.011	1.004	6.700	21.735	0.407	0.000	0.000
BG	2.600	1.061	3.182	1.061	0.116	40.626	1.496	0.022	0.022
CH	6.553	1.673	5.018	1.673	0.000	2.650	0.273	0.000	0.000
CZ	0.252	6.230	18.691	6.230	0.000	34.073	0.538	0.000	0.000
DE	3.946	13.068	39.204	13.068	55.806	196.184	5.541	0.170	0.170
DK	0.011	6.114	18.343	6.114	27.800	19.942	0.431	0.000	0.000
EE	0.005	4.752	14.257	4.752	0.300	6.759	0.433	0.000	0.000
ES-E	2.313	11.717	35.150	11.717	10.879	66.216	0.757	0.237	0.233
ES-NW	2.313	13.619	40.857	13.619	9.359	70.891	0.880	0.250	0.271
ES-S	0.000	2.956	8.868	2.956	2.36	71.694	0.191	0.074	0.059
FI	3.133	3.733	11.198	3.733	13.400	19.607	1.027	0.000	0.000
FR	7.766	38.000	113.999	38.000	21.800	228.678	5.191	0.367	1.728
GB	2.130	40.280	120.841	40.280	70.000	168.789	6.221	0.009	4.206
GR	0.000	2.078	6.233	2.078	2.850	59.745	0.362	0.069	0.069
HU	0.047	0.499	1.496	0.499	0.000	41.575	0.661	0.097	0.097
IE	0.216	12.049	36.148	12.049	15.000	27.501	0.220	0.000	0.778
IT-N	4.482	2.984	8.953	2.984	14.272	70.072	1.619	0.100	0.947

IT-S	1.494	0.550	1.649	0.550	2.628	85.465	0.298	1.021	0.174
LT	0.122	1.175	3.526	1.175	0.150	1.294	2.142	0.000	0.000
LU	0.015	0.136	0.407	0.136	0.000	15.205	0.035	0.000	0.000
LV	1.520	3.677	11.032	3.677	0.300	21.607	0.512	0.000	0.000
NL	0.037	4.044	12.133	4.044	10.000	31.848	0.732	0.042	0.137
NO	0.000	13.482	40.446	13.482	70.000	3.190	0.122	0.000	0.250
PL	0.680	15.675	47.024	15.675	7.500	139.214	11.062	0.018	0.018
PT	5.211	8.750	26.250	8.750	10.000	31.505	0.814	0.025	0.674
RO	2.964	1.833	5.500	1.833	0.116	100.528	1.529	0.018	0.018
SE	0.000	36.697	110.090	36.697	17.000	27.738	2.408	0.000	0.000
SI	1.354	0.075	0.226	0.075	0.000	5.93	0.513	0.004	0.004
SK	1.686	0.935	2.806	0.935	0.000	18.817	0.999	0.013	0.013
DZ	0.228	121.725	1838.181	280.838	0.000	8206.008	0.000	0.000	0.000
EG	11.624	10.027	1048.919	21.006	0.000	2403.558	0.000	0.000	0.000
LY	0.000	11.573	1713.793	0.994	0.000	6483.122	0.000	0.000	0.000
MA	1.518	58.171	1173.550	89.492	0.000	875.932	0.000	0.000	0.000
SA	0.000	6.027	1567.509	34.354	0.000	10811.218	0.000	0.000	0.000
TN	0.062	0.602	173.657	1.812	0.000	349.186	0.000	0.000	0.000
JO	0.000	0.315	54.030	5.652	0.000	1491.394	0.000	0.000	0.000
SY	1.250	0.000	163.297	27.580	0.000	935.238	0.188	0.000	0.000
TR	0.000	51.337	340.712	58.915	0.000	147.130	0.000	0.000	0.000

6.3 Transmission technologies

Each modeled transport line is defined by its maximum net transfer capacity (NTC) and electric losses. Transport capacities are determined endogenous by the optimization process. Transport lines are modeled as center to center connection from one to another region (i.e. geographical country center). The length from center to center is thus the length of the transport line. The model optimizes overall system costs. Regarding the grid, these include investment and annual fix costs. Costs as well as losses of each transport line depend on the length of the connection as well as on the underlying assumptions on the mix of AC/DC and OHL/Cable. Table 17 shows the cost assumptions for the different transport technologies. Converter costs are independent of the connection length. These costs were increased for all country to country connections reflecting security margins as well as loop flow effects. Inner EU and inner MENA connections are increased by a factor 2, interconnectors between continents were increased by a factor 1.5.

Table 17: Costs assumptions for transmission technologies

Technology	Investment Cost [€/MW/km]	Fix Cost [% of Invest]
AC OHL	250	1
AC cable	2025	0.1
HVDC OHL	200	1
HVDC underground cable	950	0.1
HVDC submarine cable	825	0.1

Converters (2 Terminals)	0.15	1

Table 18 shows the specific losses of the same technologies. Again, losses of the converter stations are independent of connection length.

Table 18: Assumption for transportation losses

Technology	Losses [%/1000 km]
AC OHL	10.5
AC cable	5.5
HVDC OHL	1.3
HVDC underground cable	1.3
HVDC submarine cable	1.3
Converters (2 Terminals)	1.4

All center to center connections were assigned with a specific mix of these technologies above. Different mixes were assumed for inner European connections, inner MENA connections and EU- MENA interconnectors.

Interconnectors between continents are considered on different possible routes in this model. These routes are in as follows:

- *DZ – IT-N*
- *DZ – FR*
- *DZ – ES-E*
- *LY – IT-S*
- *LY – IT-N*
- *MA – ES-S*
- *TN – IT-S*
- *TN – IT-N*
- *SY – TR*
- *JO – TR (via SY)*
- *SA – TR (via SY)*
- *EG – TR (via SY)*
- *LY – GR*
- *EG – GR*

6.4 Storage technologies

Pumped hydro storage capacities that are installed according to PLATTS [8] were adjusted according to data from [16] and expert knowledge from [14]. In addition, an extension of capacities was assumed according to the same data sources. Table 19 shows the resulting capacities for pump and turbine as well as the maximum energy content of the reservoir.

Table 19: Overview of installed capacities for pump storage in 2030

Region	Pump [MW]	Turbine [MW]	Reservoir [GWh]
AT	5350	5350	338.87
BE	1310	1310	7.32
BG	420	420	6.35
CH	4410	4410	557.49
CZ	1150	1150	6.90
DE	7600	7600	61.48
DK	0	0	0.00
EE	300	300	4.50
ES-E	3020	3020	847.00
ES-NW	3020	3020	847.00
ES-S	0	0	0.00
FI	0	0	0.00
FR	6860	6860	314.00
GB	4160	4160	30.30
GR	1450	1450	47.69
HU	300	300	2.40
IE	750	750	6.35
IT-N	2030	2030	82.54
IT-S	680	680	27.51
LT	930	930	11.18
LU	1300	1300	7.80
LV	0	0	0.00
NL	1000	1000	8.00
NO	1520	1520	683.38
PL	1790	1790	11.05
PT	3510	3510	231.11
RO	1150	1150	8.00
SE	480	480	3.58
SI	280	280	1.84
SK	1710	1710	11.94
DZ	0	0	0.00
EG	0	0	0.00
LY	0	0	0.00
MA	470	470	163.00
SA	0	0	0.00
TN	0	0	0.00
JO	0	0	0.00
SY	0	0	0.00
TR	1600	1600	80.00

Table 20 shows installed capacity and maximum energy content of the reservoir of dam storage power plants. Dam storage power plants don't have pumps by definition. Only natural influx of water can be stored in a reservoir and used to produce electricity time shifted.

Table 20: Overview of installed capacities for dam storage in 2030

Region	Turbine [MW]	Reservoir [GWh]
AT	5418	3063
BE	0	0
BG	2462	209
CH	7547	8746
CZ	729	11
DE	1400	10
DK	0.00	0.00
EE	0.00	0.00
ES-E	8868	9887
ES-NW	8868	9887
ES-S	0	0
FI	0	0
FR	13734	11175
GB	0.00	0.00
GR	4531	548
HU	0	0
IE	0	0
IT-N	8868	4458
IT-S	2956	1486
LT	0	0
LU	17	3
LV	0	0
NL	0	0
NO	30700	102850
PL	167	10
PT	4337	3231
RO	4765	500
SE	16317	35148
SI	0	0
SK	0	0
DZ	0	0
EG	0	0
LY	0	0
MA	0	0
SA	0	0
TN	0	0
JO	0	0
SY	0	0
TR	43800	10500

Another storage opportunity in the model is heat storing in CSP plants. Information about thermal storage is given in chapter 2.2.3.

6.5 Weather data

In order to model the hourly production of wind and solar power, weather data is needed. Table 21 shows the method and sources for the weather data used in this model. Each time series is from the year 2007.

Table 21: Costs assumptions for transmission technologies

Resource	Method	Source EU+2	Source MENA + Turkey
Wind	Wind speeds and characteristic power curve	ISET [2]	MERRA
PV	Global Irradiation	ISET [2]	Surface Solar Irradiation Data Set (SSIDS)
CSP	Collector heat calculated with SAM	Proprietary TMY for each country[2]	Proprietary TMY for each country2
Hydro	Scale historic data to installed capacity	ENTSO-E [3]	Constant value

[2] Countries not available are substituted (by neighbors) and scaled according to annual DNI. This is done in countries IT (ES), GR (TR), FR (ES) and SA (JO).

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A 1. Electricity production

The following tables contain annual electricity production per country by process for the four main scenarios.

A 1.1 Scenario 01 Base — Electricity production (GWh)

Produced electricity (GWh)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total	Overprod
AT	6'713	0	0	70	0	32'061	9'941	70	595	0	0	3'494	8'732	0	61'676	0
BE	3'330	0	40'459	0	0	532	0	0	235	0	5'811	2'338	3'408	0	56'114	0
BG	12'201	0	0	193	0	1'044	2'892	193	210	0	331	2'308	5'767	0	25'137	0
CH	2'328	0	3'111	0	0	19'304	20'680	0	498	0	0	900	0	0	46'821	0
CZ	4'448	0	8'852	0	0	984	586	0	231	0	0	18'497	46'224	2'351	82'172	9
DE	42'869	0	63'640	1'489	0	15'921	3'994	1'489	24'895	0	46'711	34'975	87'403	15'799	339'185	12
DK	3'005	0	0	0	0	31	0	0	139	0	9'416	27'917	69'764	18'704	128'976	64
EE	3'235	0	442	0	0	9	0	0	15	0	669	10'584	0	0	14'953	0
ES-E	5'508	0	0	2'079	0	3'514	6'486	2'042	10'579	0	1'487	24'929	12'022	0	68'646	7
ES-NW	6'429	0	4'192	2'193	0	3'514	6'487	2'374	3'120	0	19	26'126	9'414	0	63'868	21
ES-S	1'296	0	0	651	0	0	0	515	4'922	0	3'057	6'307	5'045	0	21'793	50
FI	8'622	0	10'945	0	0	13'944	0	0	116	0	1'941	8'142	0	0	43'710	0
FR	42'468	0	37'394	3'215	1'062	39'777	31'553	15'137	11'884	0	19'438	86'700	0	0	288'628	0
GB	41'598	0	70'503	79	0	6'450	0	36'845	512	0	86'548	136'725	0	0	379'259	2'285
GR	2'807	0	0	604	0	0	6'612	604	3'048	0	470	5'333	13'326	3'573	36'377	0
HU	5'784	0	11'453	850	0	210	0	850	247	0	0	1'041	2'602	0	23'036	0
IE	1'461	17	9'228	0	0	772	0	6'815	59	0	2'043	12'400	0	0	32'795	341
IT-N	13'465	0	24'849	877	0	9'876	13'881	8'293	2'773	0	285	6'769	16'916	0	97'983	0
IT-S	2'422	0	0	8'943	1'800	1'097	1'542	1'527	5'956	0	2'914	1'412	3'529	946	32'090	0
LT	17'017	0	0	0	0	397	0	0	83	0	295	2'434	0	0	20'225	0
LU	283	0	3'046	0	0	75	50	0	100	0	0	345	861	0	4'761	0
LV	3'830	0	0	0	0	3'621	0	0	19	0	609	1'015	0	0	9'093	0
NL	5'792	0	42'310	368	0	101	0	1'200	203	0	16'876	10'705	2'772	0	80'327	1
NO	672	0	0	0	0	0	136'968	2'190	159	0	1'070	48'727	121'770	0	311'556	523
PL	95'448	0	11'449	158	0	2'641	505	158	56	0	375	16'761	0	0	127'552	0
PT	5'615	0	0	219	0	6'812	7'542	5'904	4'223	0	0	12'503	0	0	42'818	31
RO	13'249	0	1'840	158	0	14'106	5'425	158	355	1'149	183	4'450	11'121	0	52'193	0
SE	16'583	0	0	0	0	0	68'326	0	128	0	5'621	38'955	0	0	129'613	2
SI	4'426	0	1'139	35	0	5'162	0	35	135	0	0	179	448	120	11'680	0
SK	8'742	0	7'219	114	0	4'446	0	114	83	0	0	1'985	4'961	0	27'663	0
TR	0	0	30'942	0	0	0	126'007	0	0	0	0	119'662	0	0	276'611	65
DZ	0	0	0	0	0	173	0	0	0	99'959	0	344'262	90'015	0	534'409	7'392
EG	0	0	0	0	23'935	50'000	0	0	0	34'727	0	28'877	211'681	0	349'221	3'014
JO	0	0	0	0	20'587	0	0	0	0	0	0	802	12'901	0	34'290	5
LY	0	0	0	0	9'505	0	0	0	0	11'155	0	32'143	66'906	0	119'710	518
MA	0	0	0	0	45	3'963	0	0	0	23'647	0	140'450	0	0	168'105	4'025
SA	0	2'851	56'376	0	93'710	0	0	0	0	95'833	0	15'792	270'635	0	535'197	3'460
SY	1'264	0	0	0	0	2'604	0	0	0	79'989	0	0	228'653	0	312'509	4'893
TN	0	0	0	0	9'390	160	0	0	0	0	0	1'566	32'993	0	44'109	234

A 1.2Scenario 02 High demand — Electricity production (GWh)

Produced electricity (GWh)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total	Overprod
AT	6'593	0	1'677	70	0	32'061	9'941	70	595	0	0	3'494	8'732	2'341	65'573	0
BE	3'253	0	35'966	0	0	532	0	0	235	0	5'811	2'338	5'843	0	53'979	0
BG	11'692	0	3'123	193	0	1'044	2'892	193	210	0	331	2'308	5'767	0	27'750	0
CH	2'276	0	5'875	0	0	19'304	20'680	0	498	0	0	3'012	0	0	51'645	0
CZ	4'512	0	21'048	0	0	984	586	0	231	0	0	18'497	46'224	12'393	104'474	6
DE	43'549	0	147'367	1'489	0	15'921	3'994	1'489	24'895	0	46'711	34'975	87'403	15'799	423'593	0
DK	3'093	0	0	0	0	31	0	0	139	0	9'416	27'917	69'764	18'704	129'064	36
EE	3'072	117	1'255	0	0	9	0	0	15	0	669	12'853	0	0	17'990	59
ES-E	5'219	0	0	2'079	0	3'514	6'486	2'042	10'579	0	1'487	24'929	12'022	0	68'357	18
ES-NW	6'317	0	13'357	2'193	0	3'514	6'487	2'374	3'120	0	19	26'126	9'414	0	72'921	8
ES-S	1'276	0	0	651	0	0	0	515	4'922	0	3'057	6'307	5'045	0	21'773	23
FI	8'017	372	11'005	0	0	13'944	0	0	116	0	1'941	8'142	0	0	43'537	3
FR	40'207	0	39'321	3'215	1'127	39'777	31'553	15'137	11'884	0	19'438	86'700	7'306	0	295'665	1
GB	40'894	1'934	117'284	79	0	6'450	0	36'845	512	0	86'548	136'725	205'496	0	632'766	7'743
GR	2'652	0	0	604	4'176	0	6'612	604	3'048	0	470	5'333	13'326	3'573	40'399	0
HU	5'726	0	20'606	850	0	210	0	850	247	0	0	1'041	2'602	698	32'829	0
IE	1'427	76	14'350	0	0	772	0	6'815	59	0	2'043	23'499	0	0	49'041	887
IT-N	12'908	0	25'657	877	0	9'876	13'881	8'293	2'773	0	285	6'769	16'916	0	98'235	0
IT-S	2'317	0	0	8'943	1'958	1'097	1'542	1'527	5'956	0	2'914	1'412	3'529	946	32'143	3
LT	17'243	0	0	0	0	397	0	0	83	0	295	2'982	0	0	21'001	0
LU	292	0	5'319	0	0	75	50	0	100	0	0	345	861	231	7'274	0
LV	3'741	0	35	0	0	3'621	0	0	19	0	609	4'625	0	0	12'649	28
NL	5'659	0	53'044	368	0	101	0	1'200	203	0	16'876	10'705	26'751	0	114'906	33
NO	798	0	0	0	0	0	135'178	2'190	159	0	287'235	48'727	121'770	32'647	628'704	2'027
PL	93'696	891	45'893	158	0	2'641	505	158	56	0	375	37'282	0	0	181'654	0
PT	5'733	0	838	219	0	6'812	7'542	5'904	4'223	0	0	12'503	0	0	43'773	10
RO	13'253	0	12'785	158	0	14'106	5'425	158	355	11'121	333	4'450	11'121	2'982	76'246	0
SE	16'314	0	0	0	0	0	67'957	0	128	0	5'621	99'968	0	0	189'988	92
SI	4'307	57	4'520	35	0	5'162	0	35	135	0	0	179	448	120	15'000	0
SK	8'716	0	18'076	114	0	4'446	0	114	83	0	0	1'985	4'961	0	38'494	0
TR	0	0	74'040	0	0	0	126'007	0	0	0	0	119'662	99'340	0	419'049	82
DZ	0	0	0	0	27'676	173	0	0	0	177'561	0	344'262	639'489	0	1'189'160	15'895
EG	0	0	0	0	183'042	50'000	0	0	0	130'547	0	28'877	651'246	0	1'043'713	6'208
JO	0	0	0	0	61'043	0	0	0	0	0	0	802	29'314	0	91'159	2
LY	0	0	0	0	8'516	0	0	0	0	4'388	0	32'143	309'980	0	355'028	2'240
MA	0	0	0	0	109'648	3'963	0	0	0	41'656	0	156'519	0	0	311'786	1'047
SA	0	2'789	71'873	0	147'292	0	0	0	0	135'386	0	15'792	393'730	0	766'862	4'350
SY	1'240	0	15'745	0	27'720	2'604	0	0	0	109'847	0	0	375'603	0	532'759	6'154
TN	0	0	0	0	28'726	160	0	0	0	0	0	1'566	52'694	0	83'146	176

A 1.3Scenario 03 Disconnected — Electricity production (GWh)

Produced electricity (GWh)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total	Overprod
AT	5'854	0	0	70	0	32'061	9'941	70	595	0	0	3'494	8'732	2'341	63'158	0
BE	2'977	0	32'597	0	0	532	0	0	235	0	5'811	2'338	3'408	0	47'899	0
BG	11'782	0	550	193	0	1'044	2'892	193	210	0	331	2'308	5'767	0	25'268	0
CH	2'014	0	0	0	0	19'304	20'680	0	498	0	0	3'012	0	0	45'508	0
CZ	3'900	0	7'032	0	0	984	586	0	231	0	0	18'497	46'224	12'393	89'845	0
DE	38'864	0	40'521	1'489	0	15'921	3'926	1'489	24'895	0	46'711	34'975	87'403	15'799	311'993	31
DK	2'827	0	0	0	0	31	0	0	139	0	9'416	27'917	69'764	18'704	128'798	57
EE	2'919	0	371	0	0	9	0	0	15	0	669	11'286	0	0	15'269	16
ES-E	5'543	0	10'819	2'079	0	3'514	6'486	2'042	10'579	24'173	1'487	24'929	46'543	0	138'195	379
ES-NW	6'501	0	16'135	2'193	0	3'514	6'487	2'374	3'120	57'722	19	26'126	9'414	0	133'605	593
ES-S	1'370	0	0	651	14'294	0	0	515	4'922	0	3'057	6'307	15'760	0	46'876	212
FI	7'810	0	8'619	0	0	13'944	0	0	116	0	1'941	8'142	0	0	40'572	1
FR	38'837	0	73'100	3'215	1'188	39'777	31'553	15'137	11'884	36'402	19'438	86'700	31'457	0	388'687	11
GB	38'551	0	47'528	79	0	6'450	0	36'845	512	0	86'548	136'725	134'107	0	487'343	6'300
GR	2'753	0	0	604	37'499	0	6'612	604	3'048	0	6'746	5'333	13'326	3'573	80'097	0
HU	5'671	0	9'048	850	0	210	0	850	247	0	0	1'041	2'602	362	20'880	0
IE	1'373	0	7'286	0	0	772	0	6'815	59	0	2'043	14'023	0	0	32'371	571
IT-N	13'196	0	33'201	877	0	9'876	13'881	8'293	2'773	64'599	285	6'769	16'916	4'535	175'200	0
IT-S	2'333	0	1'458	8'943	1'911	1'097	1'542	1'527	5'956	29'345	2'914	1'412	3'529	946	62'915	37
LT	15'333	0	0	0	0	397	0	0	83	0	295	2'434	0	0	18'542	0
LU	262	0	2'166	0	0	75	50	0	100	0	0	345	861	0	3'860	1
LV	3'435	0	100	0	0	3'621	0	0	19	0	609	1'015	0	0	8'798	6
NL	5'197	0	29'099	368	0	101	0	1'200	203	0	16'876	10'705	2'772	0	66'521	35
NO	667	0	0	0	0	0	134'422	2'190	159	0	98'011	48'727	121'770	32'647	438'593	1'245
PL	86'974	0	8'436	158	0	2'641	505	158	56	0	375	23'817	0	0	123'120	0
PT	5'795	0	1'170	219	0	6'812	7'542	5'904	4'223	6'343	0	16'360	0	0	54'368	49
RO	12'756	0	615	158	0	14'106	5'425	158	355	3'522	333	4'450	11'121	1'527	54'526	0
SE	14'256	0	0	0	0	0	67'897	0	128	0	5'621	67'539	0	0	155'441	36
SI	4'205	0	970	35	0	5'162	0	35	135	0	0	179	448	120	11'290	0
SK	8'449	0	6'220	114	0	4'446	0	114	83	0	0	1'985	4'961	0	26'372	0
TR	0	0	20'823	0	31'352	0	125'056	0	0	107'378	0	119'662	185'189	0	589'459	2'613
DZ	0	0	1'761	0	0	173	0	0	0	4'032	0	89'290	0	0	95'256	2'620
EG	0	471	3'436	0	75'988	50'000	0	0	0	16'935	0	28'877	99'276	0	274'983	522
JO	0	0	0	0	16'286	0	0	0	0	0	0	802	24'717	0	41'805	42
LY	0	27	2'561	0	8'108	0	0	0	0	0	0	32'143	10'088	0	52'927	326
MA	0	135	2'401	0	8'974	3'963	0	0	0	2'481	0	31'680	0	0	49'634	564
SA	0	2'281	54'842	0	126'675	0	0	0	0	82'688	0	15'792	198'967	0	481'245	2'512
SY	1'041	0	14'625	0	5'302	2'604	0	0	0	3'110	0	0	47'281	0	73'961	705
TN	0	0	1'829	0	6'121	160	0	0	0	0	0	1'566	11'616	0	21'293	49

A 1.4Scenario 04 Disconnected/High demand — Electricity production (GWh)

Produced electricity (GWh)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total	Overprod
AT	6'051	0	2'832	70	0	32'061	9'941	70	595	0	0	3'494	8'732	2'341	66'186	0
BE	2'864	0	48'997	0	0	532	0	0	235	0	5'811	2'338	3'408	0	64'187	0
BG	11'058	0	0	193	0	1'044	2'892	193	210	0	331	2'308	5'767	1'546	25'540	0
CH	2'034	0	2'804	0	0	19'304	20'680	0	498	0	0	3'012	7'527	0	55'859	0
CZ	4'070	0	21'073	0	0	984	586	0	231	0	0	18'497	46'224	12'393	104'057	29
DE	38'339	0	123'708	1'489	0	15'921	3'994	1'489	24'895	0	46'711	34'975	87'403	15'799	394'723	1
DK	2'805	0	0	0	0	31	0	0	139	0	100'078	27'917	69'764	18'704	219'438	143
EE	2'842	0	1'157	0	0	9	0	0	15	0	669	12'853	0	0	17'545	132
ES-E	4'938	0	9'395	2'079	0	3'514	6'486	2'042	10'579	35'502	16'747	24'929	62'298	0	178'510	101
ES-NW	5'743	0	0	2'193	0	3'514	6'487	2'374	3'120	82'063	11'881	26'126	65'290	0	208'792	2'246
ES-S	1'228	0	0	651	129'362	0	0	515	4'922	0	6'786	6'307	15'760	0	165'532	246
FI	7'088	125	10'413	0	0	13'944	0	0	116	0	1'941	8'142	20'347	0	62'116	8
FR	35'841	0	99'798	3'215	1'116	39'777	31'553	15'137	11'884	156'675	99'072	86'700	120'611	0	701'380	247
GB	37'061	291	96'381	79	0	6'450	0	36'845	512	0	86'548	136'725	341'676	0	742'567	14'547
GR	2'624	0	0	604	53'073	0	6'612	604	3'048	0	7'923	5'333	13'326	3'573	96'720	8
HU	5'316	0	14'283	850	0	210	0	850	247	20'855	0	1'041	2'602	698	46'951	40
IE	1'280	0	12'350	0	0	772	0	6'815	59	0	2'043	29'793	0	0	53'112	1'732
IT-N	12'437	0	71'355	877	0	9'876	13'881	8'293	2'773	71'883	33'608	6'769	16'916	4'535	253'202	0
IT-S	2'183	0	6'647	8'943	1'857	1'097	1'542	1'527	5'956	65'505	6'198	1'412	3'529	946	107'345	524
LT	15'188	0	0	0	0	397	0	0	83	0	295	2'982	0	0	18'945	0
LU	256	0	3'609	0	0	75	50	0	100	2'486	0	345	861	231	8'013	0
LV	3'354	0	0	0	0	3'621	0	0	19	0	609	9'440	0	0	17'043	246
NL	5'015	0	46'156	368	0	101	0	1'200	203	0	16'876	10'705	26'751	0	107'374	71
NO	705	0	0	0	0	0	133'675	2'190	159	0	299'666	48'727	121'770	32'647	639'538	3'644
PL	82'611	0	36'767	158	0	2'641	505	158	56	0	26'052	37'282	13'226	0	199'454	4
PT	5'385	0	0	219	0	6'812	7'542	5'904	4'223	23'826	0	16'360	0	0	70'272	305
RO	12'410	0	7'694	158	0	14'106	5'425	158	355	16'361	333	4'450	11'121	2'982	75'553	51
SE	14'947	0	0	0	0	0	66'805	0	128	0	5'621	99'968	5'053	0	192'523	520
SI	4'090	0	4'085	35	0	5'162	0	35	135	0	0	179	448	120	14'290	1
SK	8'181	0	13'948	114	0	4'446	0	114	83	0	0	1'985	4'961	1'330	35'161	3
TR	0	0	0	0	133'421	0	126'007	0	0	141'597	0	119'662	442'894	0	963'582	4'476
DZ	0	176	6'705	0	195	173	0	0	0	8'979	0	281'065	0	0	297'293	9'052
EG	0	1'315	20'347	0	270'015	50'000	0	0	0	85'237	0	28'877	388'184	0	843'975	2'132
JO	0	0	0	0	71'610	0	0	0	0	0	0	802	27'928	0	100'340	22
LY	0	0	264	0	0	0	0	0	0	0	0	32'143	60'321	0	92'728	2'308
MA	0	419	5'104	0	28'782	3'963	0	0	0	6'943	0	80'089	0	0	125'300	1'248
SA	0	2'282	62'563	0	144'895	0	0	0	0	136'604	0	15'792	364'466	0	726'601	5'479
SY	917	0	32'223	0	24'955	2'604	0	0	0	9'808	0	0	144'633	0	215'140	2'068
TN	0	0	1'925	0	9'379	160	0	0	0	0	0	1'566	14'041	0	27'071	50

A 2. Production capacities

The following tables contain installed production capacities in MW (and in ha for CSP collector) per country and process in the four main scenarios.

A 2.1 Scenario 01 Base

Production capacity (MW)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	CSP (coll, ha)	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total
AT	785	0	0	8	0	6'579	5'418	8	0	613	0	0	1'455	4'365	0	19'231
BE	407	0	10'289	0	0	111	0	0	0	277	0	2'208	1'004	1'757	0	16'053
BG	1'496	0	0	22	0	260	2'462	22	0	192	0	116	1'061	3'182	0	8'813
CH	273	0	1'289	0	0	6'553	7'547	0	0	500	0	0	500	0	0	16'662
CZ	538	0	3'548	0	0	252	729	0	0	288	0	0	6'230	18'691	1'182	31'457
DE	5'541	0	23'492	170	0	3'946	1'400	170	0	29'932	0	14'543	13'068	39'204	8'811	140'277
DK	431	0	0	0	0	11	0	0	0	156	0	2'512	6'114	18'343	6'114	33'681
EE	433	0	326	0	0	5	0	0	0	20	0	217	3'913	0	0	4'914
ES-E	757	0	0	237	0	2'313	8'868	233	0	8'187	0	532	11'717	6'783	0	39'627
ES-NW	880	0	2'323	250	0	2'313	8'868	271	0	2'276	0	7	13'619	5'891	0	36'699
ES-S	191	0	0	74	0	0	0	59	0	3'614	0	1'064	2'956	2'839	0	10'797
FI	1'027	0	4'801	0	0	3'133	0	0	0	149	0	662	3'733	0	0	13'506
FR	5'191	0	19'144	367	370	7'766	13'734	1'728	332	11'069	0	6'435	38'000	0	0	104'137
GB	6'221	0	20'157	9	0	2'130	0	4'206	0	570	0	23'389	40'280	0	0	96'963
GR	362	0	0	69	0	0	4'531	69	0	2'485	0	169	2'078	6'233	2'078	18'073
HU	661	0	3'475	97	0	47	0	97	0	250	0	0	499	1'496	0	6'622
IE	220	49	2'366	0	0	216	0	778	0	64	0	563	3'988	0	0	8'244
IT-N	1'619	0	11'909	100	0	4'482	8'868	947	0	2'603	0	121	2'984	8'953	0	42'586
IT-S	298	0	0	1'021	477	1'494	2'956	174	560	4'600	0	1'235	550	1'649	550	15'562
LT	2'142	0	0	0	0	122	0	0	0	111	0	96	959	0	0	3'430
LU	35	0	827	0	0	15	17	0	0	108	0	0	136	407	0	1'546
LV	512	0	0	0	0	1'520	0	0	0	24	0	198	395	0	0	2'649
NL	732	0	10'145	42	0	37	0	137	0	241	0	5'891	4'044	1'257	0	22'526
NO	122	0	0	0	0	0	30'700	250	0	200	0	250	13'482	40'446	0	85'450
PL	11'062	0	4'209	18	0	680	167	18	0	74	0	108	7'047	0	0	23'383
PT	814	0	0	25	0	5'211	4'337	674	0	3'044	0	0	6'687	0	0	20'792
RO	1'529	0	617	18	0	2'964	4'765	18	0	315	1'021	64	1'833	5'500	0	18'645
SE	2'408	0	0	0	0	0	16'317	0	0	159	0	1'713	14'300	0	0	34'897
SI	513	0	447	4	0	1'354	0	4	0	140	0	0	75	226	75	2'839
SK	999	0	2'131	13	0	1'686	0	13	0	93	0	0	935	2'806	0	8'676
TR	0	0	12'340	0	0	0	43'800	0	0	0	0	0	51'337	0	0	107'477
DZ	0	0	0	0	0	228	0	0	0	0	47'994	0	121'725	39'268	0	209'216
EG	0	0	0	0	5'556	11'624	0	0	6'084	0	14'888	0	10'027	86'361	0	134'540
JO	0	0	0	0	4'048	0	0	0	4'731	0	0	0	315	5'964	0	15'058
LY	0	0	0	0	1'834	0	0	0	2'289	0	5'473	0	11'573	29'094	0	50'263
MA	0	0	0	0	12	1'518	0	0	11	0	11'785	0	52'199	0	0	65'526
SA	0	5'972	22'527	0	21'078	0	0	0	23'525	0	43'253	0	6'027	126'090	0	248'472
SY	188	0	0	0	0	1'250	0	0	0	0	41'039	0	0	93'866	0	136'343
TN	0	0	0	0	2'170	62	0	0	2'370	0	0	0	602	14'687	0	19'890

A 2.2Scenario 02 High demand

Production capacity (MW)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	CSP (coll, ha)	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total
AT	785	0	615	8	0	6'579	5'418	8	0	613	0	0	1'455	4'365	1'455	21'301
BE	407	0	11'671	0	0	111	0	0	0	277	0	2'208	1'004	3'011	0	18'690
BG	1'496	0	1'201	22	0	260	2'462	22	0	192	0	116	1'061	3'182	0	10'014
CH	273	0	2'654	0	0	6'553	7'547	0	0	500	0	0	1'673	0	0	19'200
CZ	538	0	8'217	0	0	252	729	0	0	288	0	0	6'230	18'691	6'230	41'174
DE	5'541	0	47'420	170	0	3'946	1'400	170	0	29'932	0	14'543	13'068	39'204	8'811	164'205
DK	431	0	0	0	0	11	0	0	0	156	0	2'512	6'114	18'343	6'114	33'681
EE	433	549	558	0	0	5	0	0	0	20	0	217	4'752	0	0	6'535
ES-E	757	0	0	237	0	2'313	8'868	233	0	8'187	0	532	11'717	6'783	0	39'627
ES-NW	880	0	7'214	250	0	2'313	8'868	271	0	2'276	0	7	13'619	5'891	0	41'590
ES-S	191	0	0	74	0	0	0	59	0	3'614	0	1'064	2'956	2'839	0	10'797
FI	1'027	1'910	4'788	0	0	3'133	0	0	0	149	0	662	3'733	0	0	15'402
FR	5'191	0	20'582	367	370	7'766	13'734	1'728	366	11'069	0	6'435	38'000	3'844	0	109'452
GB	6'221	17'124	33'925	9	0	2'130	0	4'206	0	570	0	23'389	40'280	72'678	0	200'533
GR	362	0	0	69	1'282	0	4'531	69	1'194	2'485	0	169	2'078	6'233	2'078	20'549
HU	661	0	5'676	97	0	47	0	97	0	250	0	0	499	1'496	499	9'322
IE	220	646	3'580	0	0	216	0	778	0	64	0	563	7'558	0	0	13'625
IT-N	1'619	0	11'657	100	0	4'482	8'868	947	0	2'603	0	121	2'984	8'953	0	42'335
IT-S	298	0	0	1'021	573	1'494	2'956	174	614	4'600	0	1'235	550	1'649	550	15'714
LT	2'142	0	0	0	0	122	0	0	0	111	0	96	1'175	0	0	3'646
LU	35	0	1'311	0	0	15	17	0	0	108	0	0	136	407	136	2'165
LV	512	0	22	0	0	1'520	0	0	0	24	0	198	1'802	0	0	4'078
NL	732	0	13'328	42	0	37	0	137	0	241	0	5'891	4'044	12'133	0	36'584
NO	122	0	0	0	0	0	30'700	250	0	200	0	67'096	13'482	40'446	13'482	165'778
PL	11'062	3'055	13'506	18	0	680	167	18	0	74	0	108	15'675	0	0	44'363
PT	814	0	464	25	0	5'211	4'337	674	0	3'044	0	0	6'687	0	0	21'256
RO	1'529	0	2'421	18	0	2'964	4'765	18	0	315	9'879	116	1'833	5'500	1'833	31'192
SE	2'408	0	0	0	0	0	16'317	0	0	159	0	1'713	36'697	0	0	57'294
SI	513	248	1'649	4	0	1'354	0	4	0	140	0	0	75	226	75	4'288
SK	999	0	4'094	13	0	1'686	0	13	0	93	0	0	935	2'806	0	10'639
TR	0	0	28'434	0	0	0	43'800	0	0	0	0	0	51'337	58'914	0	182'485
DZ	0	0	0	0	7'313	228	0	0	7'816	0	85'254	0	121'725	278'971	0	501'307
EG	0	0	0	0	45'494	11'624	0	0	47'216	0	55'967	0	10'027	265'694	0	436'021
JO	0	0	0	0	12'221	0	0	0	14'204	0	0	0	315	13'551	0	40'291
LY	0	0	0	0	1'928	0	0	0	2'160	0	2'153	0	11'573	134'795	0	152'607
MA	0	0	0	0	22'259	1'518	0	0	24'467	0	20'761	0	58'171	0	0	127'176
SA	0	15'960	26'222	0	34'797	0	0	0	37'380	0	61'105	0	6'027	183'441	0	364'932
SY	188	0	6'657	0	8'614	1'250	0	0	7'985	0	56'358	0	0	154'192	0	235'244
TN	0	0	0	0	6'914	62	0	0	7'217	0	0	0	602	23'457	0	38'251

A 2.3Scenario 03 Disconnected systems

Production capacity (MW)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	CSP (coll, ha)	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total
AT	785	0	0	8	0	6'579	5'418	8	0	613	0	0	1'455	4'365	1'455	20'686
BE	407	0	10'112	0	0	111	0	0	0	277	0	2'208	1'004	1'757	0	15'876
BG	1'496	0	264	22	0	260	2'462	22	0	192	0	116	1'061	3'182	0	9'077
CH	273	0	0	0	0	6'553	7'547	0	0	500	0	0	1'673	0	0	16'546
CZ	538	0	3'760	0	0	252	729	0	0	288	0	0	6'230	18'691	6'230	36'717
DE	5'541	0	18'166	170	0	3'946	1'400	170	0	29'932	0	14'543	13'068	39'204	8'811	134'951
DK	431	0	0	0	0	11	0	0	0	156	0	2'512	6'114	18'343	6'114	33'681
EE	433	0	307	0	0	5	0	0	0	20	0	217	4'173	0	0	5'155
ES-E	757	0	3'865	237	0	2'313	8'868	233	0	8'187	18'707	532	11'717	26'261	0	81'677
ES-NW	880	0	5'953	250	0	2'313	8'868	271	0	2'276	42'106	7	13'619	5'891	0	82'435
ES-S	191	0	0	74	3'194	0	0	59	4'493	3'614	0	1'064	2'956	8'868	0	24'514
FI	1'027	0	4'278	0	0	3'133	0	0	0	149	0	662	3'733	0	0	12'982
FR	5'191	0	26'766	367	320	7'766	13'734	1'728	379	11'069	33'905	6'435	38'000	16'552	0	162'212
GB	6'221	0	18'529	9	0	2'130	0	4'206	0	570	0	23'389	40'280	47'430	0	142'764
GR	362	0	0	69	8'000	0	4'531	69	10'299	2'485	0	2'427	2'078	6'233	2'078	38'630
HU	661	0	3'437	97	0	47	0	97	0	250	0	0	499	1'496	258	6'843
IE	220	0	2'113	0	0	216	0	778	0	64	0	563	4'510	0	0	8'464
IT-N	1'619	0	14'173	100	0	4'482	8'868	947	0	2'603	60'632	121	2'984	8'953	2'984	108'467
IT-S	298	0	824	1'021	446	1'494	2'956	174	614	4'600	22'662	1'235	550	1'649	550	39'073
LT	2'142	0	0	0	0	122	0	0	0	111	0	96	959	0	0	3'430
LU	35	0	827	0	0	15	17	0	0	108	0	0	136	407	0	1'546
LV	512	0	86	0	0	1'520	0	0	0	24	0	198	395	0	0	2'735
NL	732	0	9'364	42	0	37	0	137	0	241	0	5'891	4'044	1'257	0	21'745
NO	122	0	0	0	0	0	30'700	250	0	200	0	22'895	13'482	40'446	13'482	121'576
PL	11'062	0	3'726	18	0	680	167	18	0	74	0	108	10'014	0	0	25'867
PT	814	0	532	25	0	5'211	4'337	674	0	3'044	4'572	0	8'750	0	0	27'959
RO	1'529	0	473	18	0	2'964	4'765	18	0	315	3'129	116	1'833	5'500	939	21'600
SE	2'408	0	0	0	0	0	16'317	0	0	159	0	1'713	24'793	0	0	45'390
SI	513	0	451	4	0	1'354	0	4	0	140	0	0	75	226	75	2'843
SK	999	0	2'155	13	0	1'686	0	13	0	93	0	0	935	2'806	0	8'700
TR	0	0	8'043	0	8'158	0	43'800	0	9'427	0	73'344	0	51'337	109'826	0	303'935
DZ	0	0	1'184	0	0	228	0	0	0	0	1'936	0	31'572	0	0	34'919
EG	0	4'766	2'291	0	17'038	11'624	0	0	20'302	0	7'260	0	10'027	40'502	0	113'809
JO	0	0	0	0	3'533	0	0	0	4'159	0	0	0	315	11'426	0	19'432
LY	0	301	1'604	0	2'058	0	0	0	2'276	0	0	0	11'573	4'387	0	22'198
MA	0	565	1'499	0	2'605	1'518	0	0	2'358	0	1'237	0	11'774	0	0	21'556
SA	0	13'403	18'792	0	30'132	0	0	0	32'220	0	37'320	0	6'027	92'700	0	230'593
SY	188	0	4'706	0	1'919	1'250	0	0	1'647	0	1'595	0	0	19'410	0	30'714
TN	0	0	814	0	1'811	62	0	0	1'617	0	0	0	602	5'171	0	10'076

A 2.4Scenario 04 Disconnected systems/High demand

Production capacity (MW)	Bio	Gas T	Gas CC	Geothermal	CSP (turb)	Hydro (RoR)	Hydro (dam)	Others	CSP (coll, ha)	PV (roof)	PV (util)	Wind-off (1)	Wind-on (1)	Wind-on (2)	Wind-on (3)	Total
AT	785	0	1'219	8	0	6'579	5'418	8	0	613	0	0	1'455	4'365	1'455	21'905
BE	407	0	15'302	0	0	111	0	0	0	277	0	2'208	1'004	1'757	0	21'067
BG	1'496	0	0	22	0	260	2'462	22	0	192	0	116	1'061	3'182	1'061	9'873
CH	273	0	1'191	0	0	6'553	7'547	0	0	500	0	0	1'673	5'018	0	22'754
CZ	538	0	7'841	0	0	252	729	0	0	288	0	0	6'230	18'691	6'230	40'799
DE	5'541	0	48'008	170	0	3'946	1'400	170	0	29'932	0	14'543	13'068	39'204	8'811	164'793
DK	431	0	0	0	0	11	0	0	0	156	0	26'694	6'114	18'343	6'114	57'863
EE	433	0	769	0	0	5	0	0	0	20	0	217	4'752	0	0	6'196
ES-E	757	0	6'252	237	0	2'313	8'868	233	0	8'187	27'475	5'990	11'717	35'150	0	107'180
ES-NW	880	0	0	250	0	2'313	8'868	271	0	2'276	59'862	4'549	13'619	40'857	0	133'746
ES-S	191	0	0	74	28'176	0	0	59	41'046	3'614	0	2'361	2'956	8'868	0	87'345
FI	1'027	2'534	4'992	0	0	3'133	0	0	0	149	0	662	3'733	11'198	0	27'428
FR	5'191	0	37'147	367	355	7'766	13'734	1'728	379	11'069	145'928	32'800	38'000	63'461	0	357'925
GB	6'221	7'294	36'513	9	0	2'130	0	4'206	0	570	0	23'389	40'280	120'841	0	241'454
GR	362	0	0	69	11'397	0	4'531	69	14'600	2'485	0	2'850	2'078	6'233	2'078	46'751
HU	661	0	4'383	97	0	47	0	97	0	250	21'136	0	499	1'496	499	29'165
IE	220	7	3'639	0	0	216	0	778	0	64	0	563	9'582	0	0	15'070
IT-N	1'619	0	25'986	100	0	4'482	8'868	947	0	2'603	67'469	14'272	2'984	8'953	2'984	141'268
IT-S	298	0	3'401	1'021	484	1'494	2'956	174	614	4'600	50'588	2'628	550	1'649	550	71'005
LT	2'142	0	0	0	0	122	0	0	0	111	0	96	1'175	0	0	3'646
LU	35	0	1'081	0	0	15	17	0	0	108	2'675	0	136	407	136	4'610
LV	512	0	0	0	0	1'520	0	0	0	24	0	198	3'677	0	0	5'932
NL	732	0	13'706	42	0	37	0	137	0	241	0	5'891	4'044	12'133	0	36'963
NO	122	0	0	0	0	0	30'700	250	0	200	0	70'000	13'482	40'446	13'482	168'682
PL	11'062	0	12'558	18	0	680	167	18	0	74	0	7'500	15'675	6'676	0	54'427
PT	814	0	0	25	0	5'211	4'337	674	0	3'044	17'174	0	8'750	0	0	40'029
RO	1'529	0	2'196	18	0	2'964	4'765	18	0	315	14'535	116	1'833	5'500	1'833	35'623
SE	2'408	0	0	0	0	0	16'317	0	0	159	0	1'713	36'697	2'227	0	59'520
SI	513	0	1'460	4	0	1'354	0	4	0	140	0	0	75	226	75	3'852
SK	999	0	3'670	13	0	1'686	0	13	0	93	0	0	935	2'806	935	11'150
TR	0	0	0	0	32'166	0	43'800	0	40'548	0	96'717	0	51'337	262'659	0	527'226
DZ	0	770	5'499	0	120	228	0	0	75	0	4'311	0	99'380	0	0	110'383
EG	0	15'330	13'634	0	66'305	11'624	0	0	76'096	0	36'542	0	10'027	158'371	0	387'928
JO	0	0	0	0	15'106	0	0	0	18'300	0	0	0	315	12'910	0	46'631
LY	0	0	215	0	0	0	0	0	0	0	0	0	11'573	26'230	0	38'018
MA	0	1'635	3'691	0	8'233	1'518	0	0	7'958	0	3'460	0	29'765	0	0	56'260
SA	0	12'011	24'138	0	40'648	0	0	0	37'813	0	61'654	0	6'027	169'806	0	352'098
SY	188	0	11'840	0	7'956	1'250	0	0	8'726	0	5'032	0	0	59'374	0	94'366
TN	0	0	1'072	0	2'882	62	0	0	2'507	0	0	0	602	6'250	0	13'374

A 3. Transport capacities between regions

A 3.1 Scenario 01 Base

Transport capacity (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	6251	0	3568	13035	0	0	0	700	0	0	0	7649
Central Europe	0	16818	3000	14220	0	8132	0	0	4652	2843	0	0
France	3568	3000	0	8292	9975	2400	25842	0	0	0	0	5157
Germany	13035	14220	8292	0	0	0	0	44829	1200	0	0	0
Iberia	0	0	9975	0	54887	0	35717	0	0	0	0	0
Italy	0	8132	2400	0	0	8033	35997	0	0	4276	0	0
MENA	0	0	25842	0	35717	35997	70687	0	0	7985	82933	0
Nordic	700	0	0	44829	0	0	0	78925	5595	0	0	1328
Poland and Baltic	0	4652	0	1200	0	0	0	5595	8956	1150	0	0
South East Europe	0	2843	0	0	0	4276	7985	0	1150	4210	7211	0
Turkey	0	0	0	0	0	0	82933	0	0	7211	0	0
UK and Ireland	7649	0	5157	0	0	0	0	1328	0	0	0	2349

A 3.2 Scenario 02 High demand

Transport capacity (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	31189	0	14788	15690	0	0	0	700	0	0	0	21753
Central Europe	0	16581	5501	21808	0	21384	0	0	7036	5991	0	0
France	14788	5501	0	8450	10787	2400	73721	0	0	0	0	12465
Germany	15690	21808	8450	0	0	0	0	80323	1200	0	0	0
Iberia	0	0	10787	0	78578	0	62845	0	0	0	0	0
Italy	0	21384	2400	0	0	17299	73285	0	0	9585	0	0
MENA	0	0	73721	0	62845	73285	186665	0	0	14905	127533	0
Nordic	700	0	0	80323	0	0	0	188938	12136	0	0	0
Poland and Baltic	0	7036	0	1200	0	0	0	12136	9276	1150	0	0
South East Europe	0	5991	0	0	0	9585	14905	0	1150	8309	14823	0
Turkey	0	0	0	0	0	0	127533	0	0	14823	0	0
UK and Ireland	21753	0	12465	0	0	0	0	0	0	0	0	4189

A 3.3Scenario 03 Disconnected systems

Transport capacity (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	4600	0	2900	15682	0	0	0	700	0	0	0	10581
Central Europe	0	23216	3000	32307	0	27066	0	0	6945	3364	0	0
France	2900	3000	0	7748	13561	10232	0	0	0	0	0	26021
Germany	15682	32307	7748	0	0	0	0	67664	1200	0	0	0
Iberia	0	0	13561	0	37295	0	0	0	0	0	0	0
Italy	0	27066	10232	0	0	36001	0	0	0	16169	0	0
MENA	0	0	0	0	0	0	73466	0	0	0	0	0
Nordic	700	0	0	67664	0	0	0	124029	7089	0	0	3506
Poland and Baltic	0	6945	0	1200	0	0	0	7089	9582	1150	0	0
South East Europe	0	3364	0	0	0	16169	0	0	1150	4936	14579	0
Turkey	0	0	0	0	0	0	0	0	0	14579	0	0
UK and Ireland	10581	0	26021	0	0	0	0	3506	0	0	0	2956

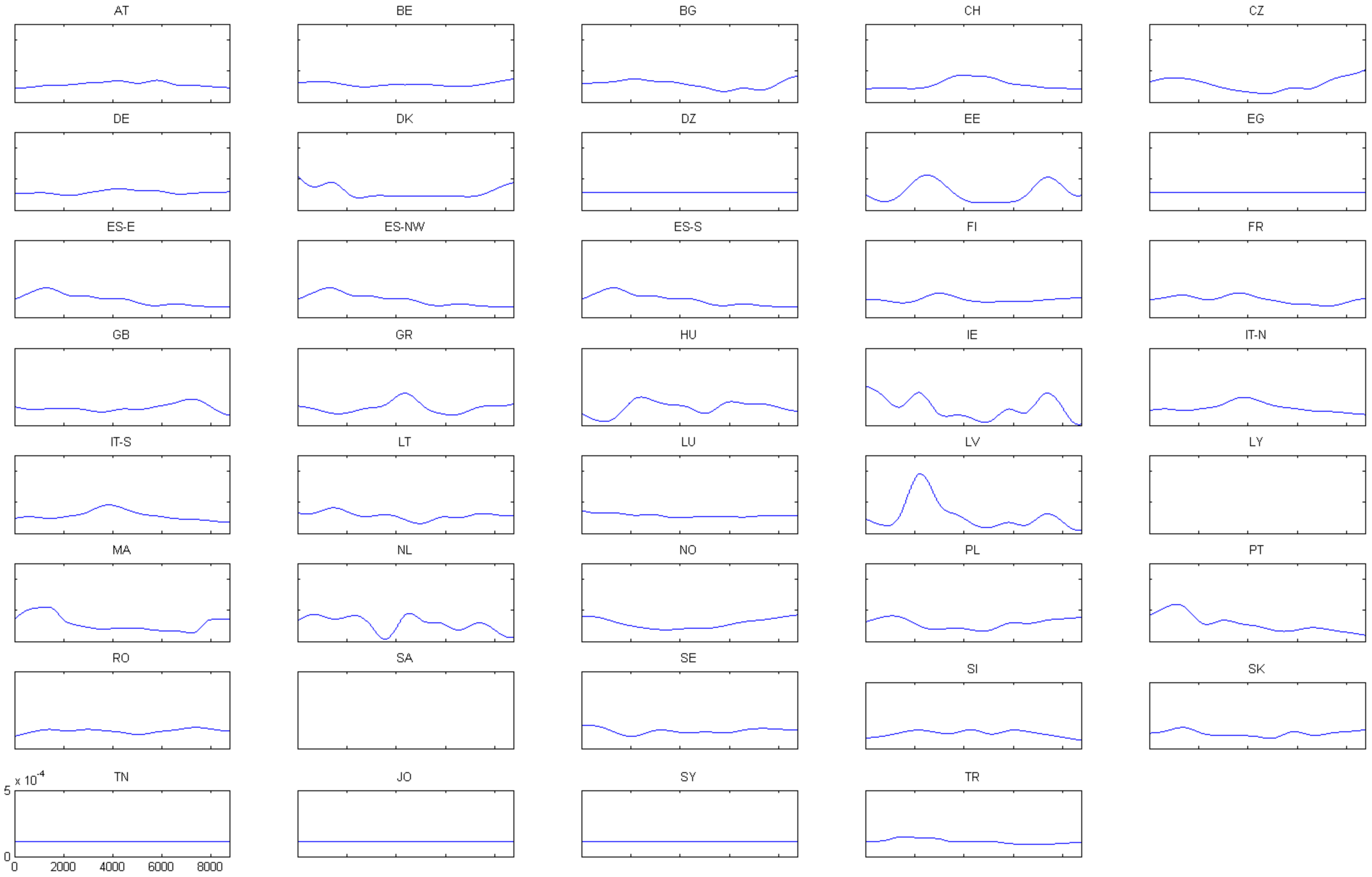
A 3.4Scenario 04 Disconnected systems/High demand

Transport capacity (MW)	BLX	CE	FR	DE	IB	IT	MENA	NORD	BLT	SEE	TR	UK
Benelux	25916	0	11894	21282	0	0	0	700	0	0	0	25756
Central Europe	0	31538	8646	41509	0	36630	0	0	10322	6401	0	0
France	11894	8646	0	8048	32053	31261	0	0	0	0	0	32245
Germany	21282	41509	8048	0	0	0	0	108949	3107	0	0	0
Iberia	0	0	32053	0	95315	0	0	0	0	0	0	0
Italy	0	36630	31261	0	0	85719	0	0	0	39633	0	0
MENA	0	0	0	0	0	0	194036	0	0	0	0	0
Nordic	700	0	0	108949	0	0	0	206253	9173	0	0	18
Poland and Baltic	0	10322	0	3107	0	0	0	9173	20276	1737	0	0
South East Europe	0	6401	0	0	0	39633	0	0	1737	9477	39713	0
Turkey	0	0	0	0	0	0	0	0	0	39713	0	0
UK and Ireland	25756	0	32245	0	0	0	0	18	0	0	0	6178

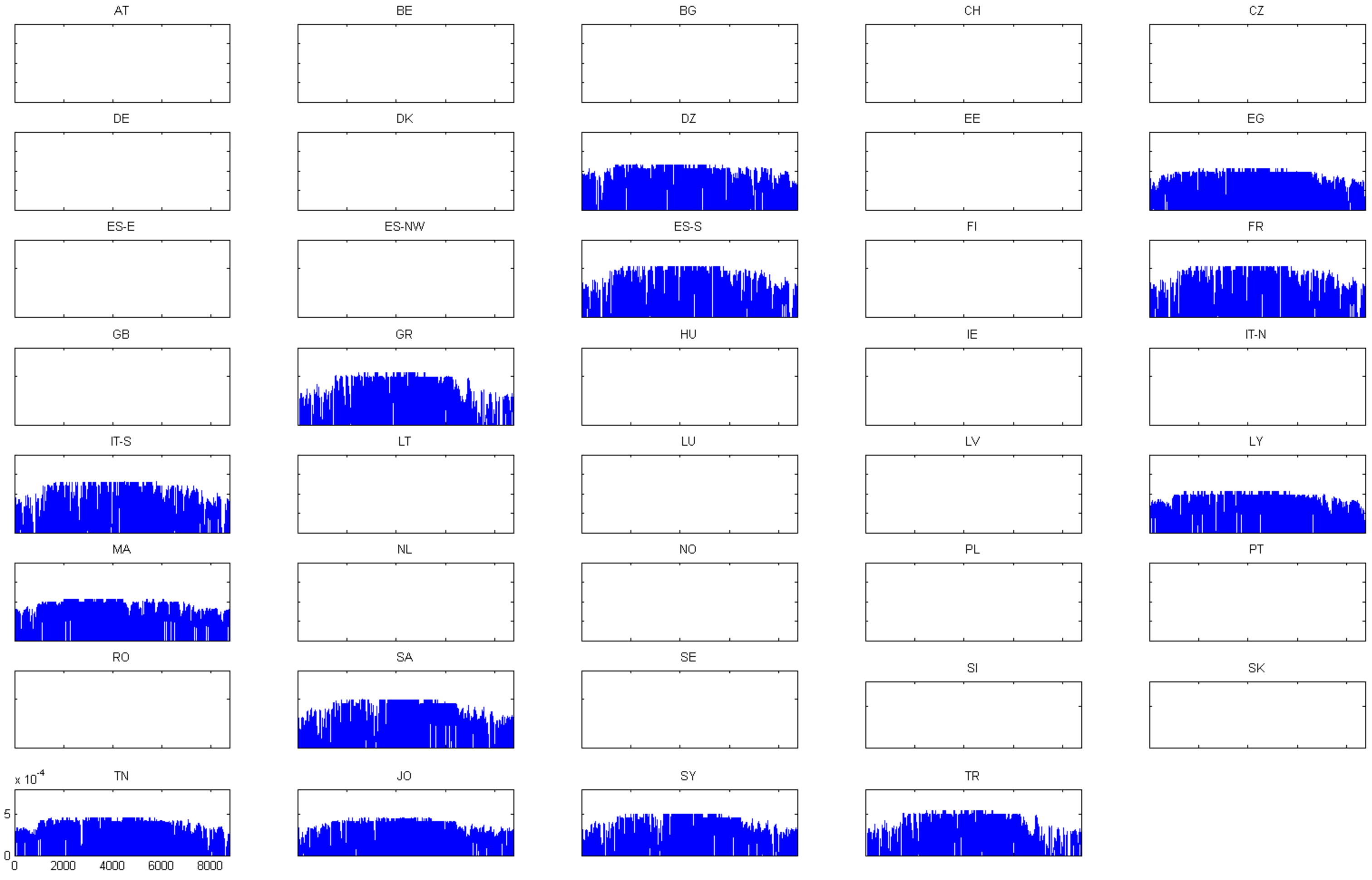
A 4. Capacity factors

The following pages show normalized hourly time series derived from measured weather data from the year 2007. They are used as input data for renewable energy power plants.

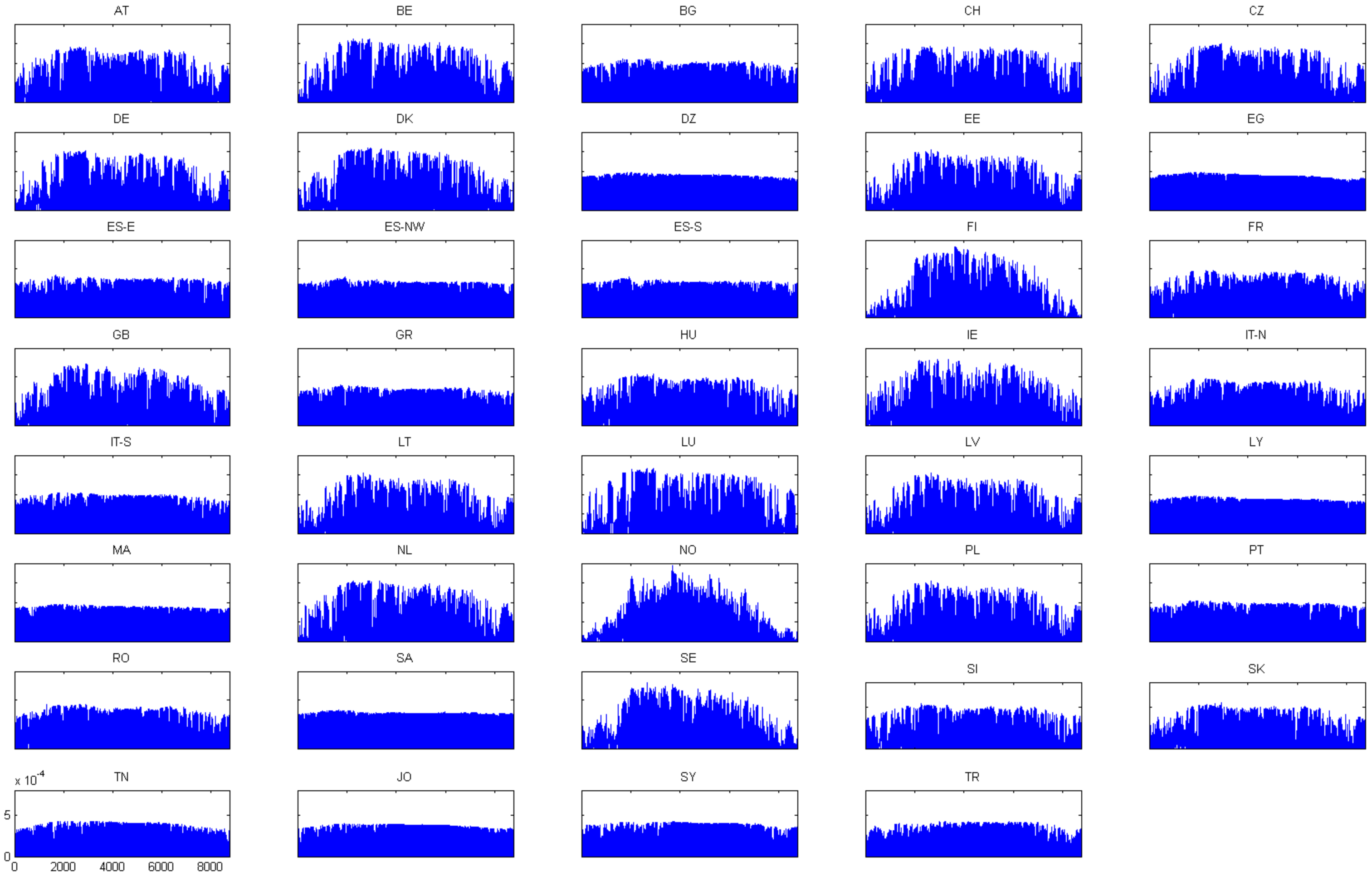
A 4.1 Hydro — energy input for dam storage hydro power plants



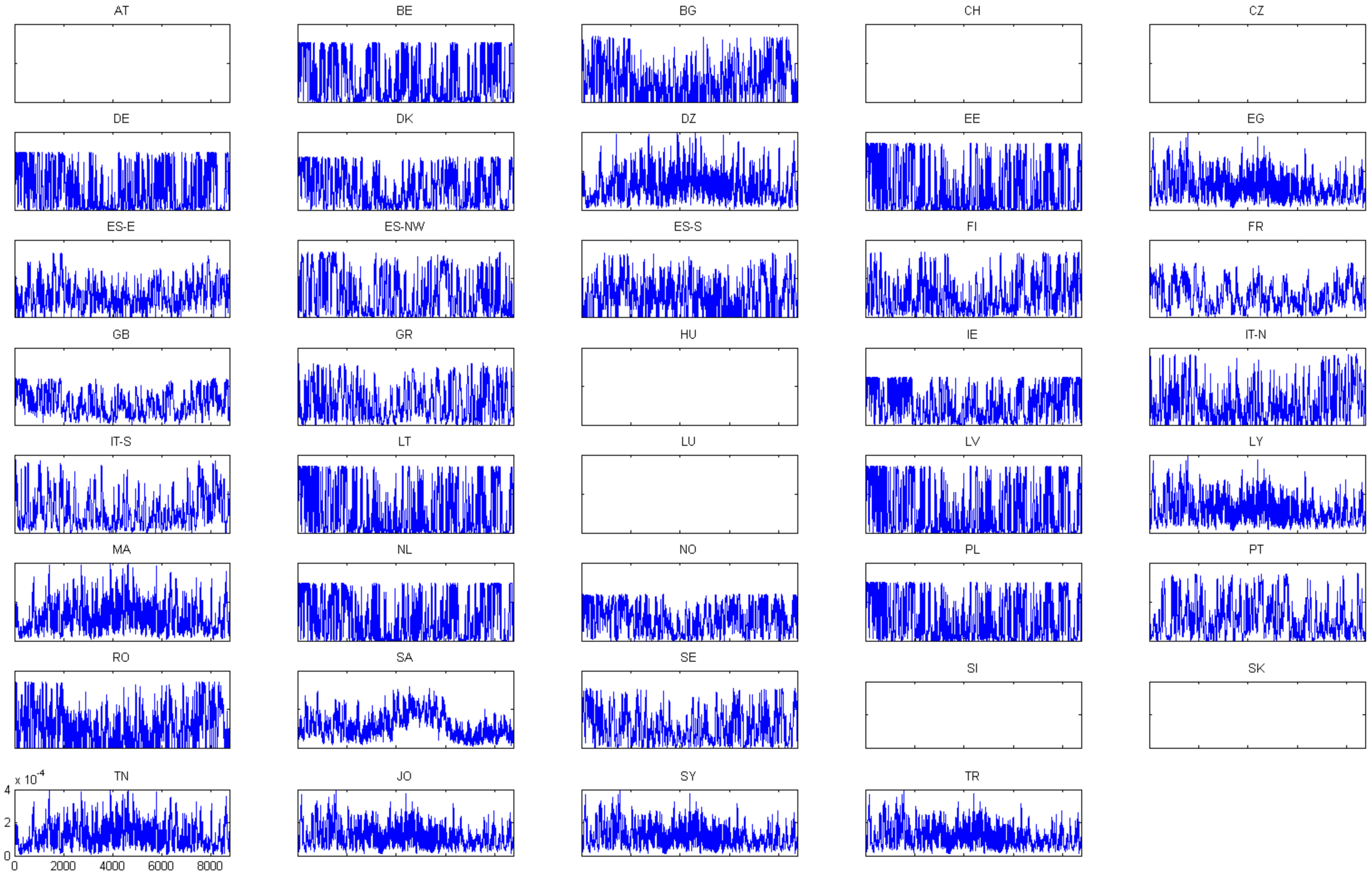
A 4.2SunDirect — energy input for CSP collectors



A 4.3SunGlobal — energy input for photovoltaic



A 4.4 Offshore wind — energy input for offshore wind turbines



A 4.5Onshore wind — energy input for onshore wind turbines