Energy Union Choices

Cleaner, Smarter, Cheaper

Responding to opportunities in Europe's changing energy system

In-depth overview of the methodological approach and assumptions

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Annex 1 – Methodology and scenarios

Application of Artelys Crystal Super Grid for this report

For this study, Artelys Crystal Super Grid was used to determine the least-cost deployment of renewable capacities (i.e. solar PV, wind onshore, wind offshore) and the necessary accompanying flexibility solutions (namely investments in storage, gas-fired generation capacities, interconnectors or load shedding). Coal, lignite and nuclear as well as waste, biomass and hydro capacities are exogenous inputs to the model.

The capacity investment are jointly optimised with a year-long[1], hour-by-hour dispatch of all generation, storage, transmission assets and flexible consumers (i.e. demand side response, DSR)[2]. The analysis focusses on a single year (2030) and exclusively on the power sector (i.e. neither the ETS, nor the gas and heat sectors are explicitly represented). When optimising the investments, the model ensures a sufficient amount of capacity is available for reserve procurement. Grid modelling relies on a Net Transfer Capacity (NTC) approach, considering only the links between the core countries and the regions. Infra-national grids (distribution or transmission grids) are not explicitly modelled.

Artelys Crystal Super Grid includes a rich portfolio of technologies. In particular with respect to Demand Side Response (DSR), the applied approach goes beyond the prevailing state of the art in power system modelling as it distinguishes a large range of flexible consumers: electric vehicles (incl. Vehicle-to-Grid, V2G), heat pumps, industrial and commercial consumers, boilers. For an exogenously given capacity[3], the hourly consumption pattern of these end-uses in response to the wholesale market price is optimised, taking into account the techno-economic constraints of each type of consumer:

[1]Given the complexity of the optimisation problem, only a single a year of weather data is taken into account (hourly temperature, wind and irradiance time series).
[2]The optimisation carried out in this study aims at maximising the European social welfare. Since Member States can benefit from investments in other countries, one can imagine that the costs could also be distributed among Member States. Such cross-border re-allocations of costs and benefits are not studied here.
[3]Based on Gils (2015).

Table 1: Overview of flexible consumers[4] and selected parameters

Residential		Commercial		Industry	
Technologies	Parameters	Technologies	Parameters	Technologies	Parameters
Heat pumps	- temperature dependent load profile - max. load shifting capacity	Short-term load *shifting*: cooling in retail business, hotels/ restaurants, commercial ventilation, water supply	- daily/weekly demand profile - max. load shifting potential	Load shedding: aluminium, copper, zinc, chlorine, steel production	Demand profile Activation costs
Electric vehicles	- arrival and departure time series - charging capacity - available storage volume			Short-term load *shifting*: industrial ventilation, water supply	- daily demand profile - max. load shifting potential
Boilers for domestic hot water	- daily load profile - capacity			Long-term load *shifting*: paper, cement production, processes, industrial cooling	- daily demand profile - max. load shifting potential

General functioning of Artelys Crystal Super Grid

Artelys Crystal Super Grid is a software solution developed and distributed by Artelys to generate and analyse prospective scenarios. It includes its own power and gas system models, based on public data.

Artelys Crystal Super Grid, based on a fundamentals model, jointly optimises the dispatch of generation to meet the energy and reserves demands, and investments to ensure that a given security of supply criterion is met. The software has the ability to simulate several energy vectors and their interactions: electricity, gas, heat and other resources (e.g. water, hydrogen, etc.) can be included in the modelling so as to identify synergies between these sectors.

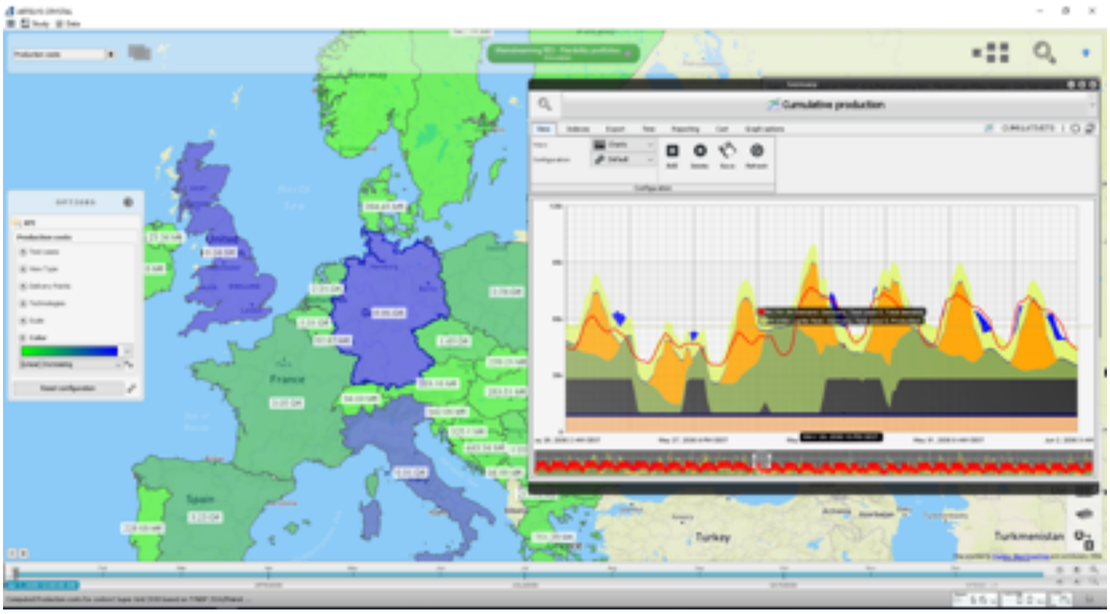
The refinement of the modelling can be adapted to the situation at hand. In particular, the description of generation technologies can be set at the fleet level (all similar units are grouped into a single asset), the cluster level (allowing to take into account start-up costs and the reserve procurement constraints), or the unit level. Similarly, the description of the network constraints can be based either

[4] End uses listed within the same cell of the table are simulated as aggregate.

on the net transfer capacity (NTCs) between countries or bidding zones, or on an approximation of an AC optimal power flow (DC linear optimal power flow). In this study, we have worked at the cluster level, with an NTC-based power flow.

Artelys Crystal Super Grid includes a library of assets (generation technologies, storage technologies, demand-response technologies, interconnectors, etc.).

Figure 1: Artelys Crystal Super Grid



Artelys Crystal Super Grid is regularly used, including by academics, to evaluate the impacts of infrastructure projects (e.g. interconnectors) in terms of social welfare, GHG emissions, RES integration, etc., to analyse the impacts of policy measures, to conduct cost-benefit analyses, or to find the optimal set of investments to ensure that a given security of supply constraint is met and/or that a given decarbonisation target is reached.

Overview of scenario configuration

The following table gives an overall view of common and distinctive features of all the scenarios and sensitivities introduced in Section 1.1.

Table 2: Overview of the scenario configuration

<table>
<tr><th colspan="2">Distinctive features</th><th>IPS</th><th>CPS</th><th>DSR only</th><th>RETIRE only</th><th>OPS</th></tr>
<tr><td colspan="7">Scenario description</td></tr>
<tr><td colspan="2">Regional cooperation for generation adequacy, exploitation of RES potentials</td><td>No</td><td colspan="4">Yes</td></tr>
<tr><td colspan="2">DSR/RES have access to balancing markets</td><td>No</td><td colspan="4">Yes</td></tr>
<tr><td colspan="2">DSR available in all countries</td><td>No</td><td colspan="4">Yes</td></tr>
<tr><td colspan="2">Enhanced DSR policies
Anticipatory distribution grid planning</td><td colspan="2">No</td><td>Yes</td><td>No</td><td>Yes</td></tr>
<tr><td colspan="2">Smart coal & nuclear retirement</td><td colspan="3">No</td><td>Yes</td><td>Yes</td></tr>
<tr><td colspan="7">Related modelling inputs and constraints</td></tr>
<tr><td rowspan="4">Input data</td><td>Data used from EUCO30</td><td colspan="5">RES capacities set as minimum, annual power demand (incl. EV demand), CO2 and fuel price</td></tr>
<tr><td>Other common data across all scenarios</td><td colspan="5">Residual gas capacities, CAPEX for wind (onshore, offshore), gas, NTC, load shedding and storage, WACC, wind capacity factors</td></tr>
<tr><td rowspan="2">Varying input data</td><td colspan="3">Coal, lignite, nuclear capacities based on EUCO30</td><td colspan="2">EUCO30 capacities reduced by 57 GW</td></tr>
<tr><td colspan="2">PV capacity factor (based on EUCO30)
PV CAPEX</td><td>Same as OPS</td><td>Same as CPS</td><td>PV CAPEX lowered by7%; 2% of grid-related curtailment</td></tr>
<tr><td rowspan="2">Capacity and dispatch optimisation</td><td>DSR characteristics</td><td>Industrial load shedding (limited to countries with existing schemes)</td><td>Explicit DSR of 25% of ind./comm. potential (TOU for other end uses)</td><td>Same as OPS</td><td>Same as CPS</td><td>Explicit DSR of 50% of ind./comm. potential; 50% of all EVs (V2G), 60% of HPs and boilers</td></tr>
<tr><td>Reserve procurement</td><td>Only thermal &hydro plants, ind. load shifting; no reserve sharing</td><td>IPS + batteries, reserve sharing</td><td>Same as OPS</td><td>Same as CPS</td><td>Same as CPS (2x load shifting potential)</td></tr>
</table>

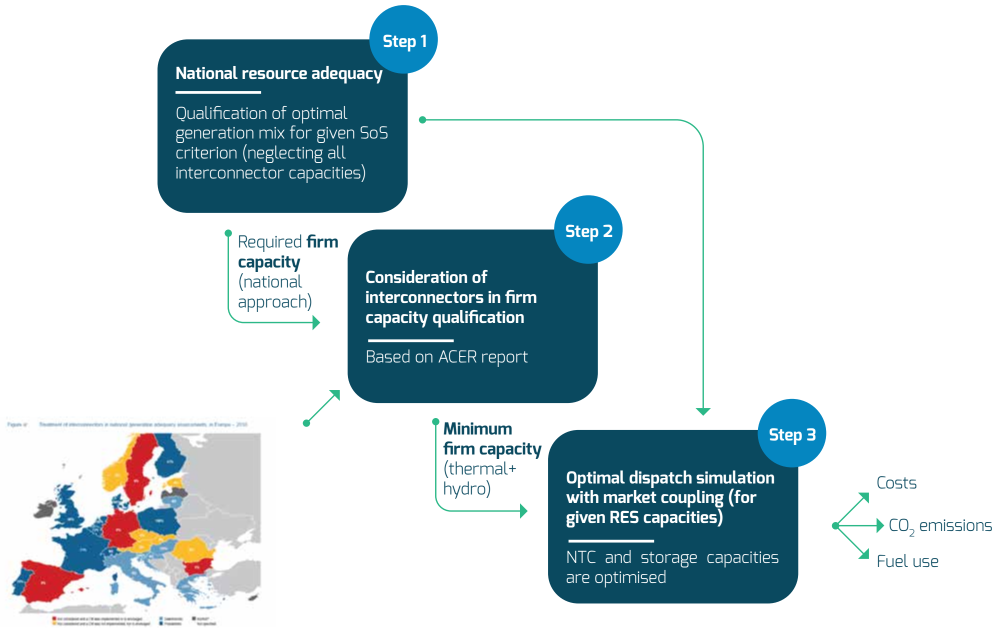
Calculation approach for the Incomplete Plans Scenario

Under the *Incomplete Plans Scenario*, it is assumed that the incomplete implementation of the CEP leads to restricted regional cooperation, implying that Member States apply national approaches to generation adequacy, reserve procurement and planning of RES investments.

In the scenario assessment, these assumptions are reflected via a three-step approach (cf. Figure 2):

1. Initially, the capacity optimisation is carried out disregarding all interconnectors between core countries and regions, reflecting the national approach of generation adequacy and exploration of RES potentials. The resulting RES investments are fixed.
2. Subsequently, the treatment of interconnectors in national generation adequacy assessments of all Member States (as stated in the latest ACER Market Monitoring Report[5]) is taken into account: the investments in additional gas capacities from Step 1 are compared to the market-based optimization solution from the Current Plans Scenario. The surplus in capacity is reduced to the extent to which a country considers interconnectors for generation adequacy.
3. In the last step, a dispatch simulation with market coupling is carried out, taking into account the RES capacities from Step 1 and the (potentially adapted) gas capacities from Step 2. The results include investments in load shedding, NTC and storage capacities, if it is deemed profitable from a market point of view.

Figure 2: Calculation approach for the Incomplete Plans Scenario, considering limited regional cooperation



[5] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf

Definition and quantification of flexibility needs

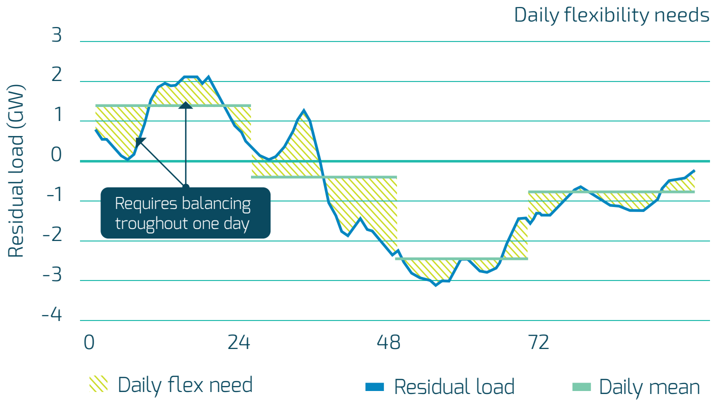
The French TSO RTE has introduced a number of metrics to measure national flexibility requirements on various timescales based on the MS's residual load.[6]

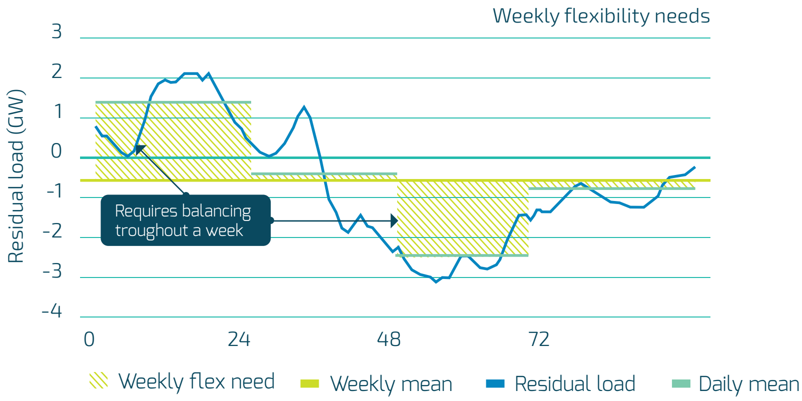
These metrics can be used to quantify the rising need for flexibility triggered by the further deployment of RES by 2030. In addition, we applied these metrics to determine the extent to which the different flexibility options (DSR, storage, flexible generation, interconnectors) help cover the identified needs. As these options feature different technical capabilities in terms of demand provision, we distinguish daily and weekly flexibility needs.

The **daily flexibility needs** equal the difference between the residual load and its daily average (sum of coloured areas in upper part of Figure 3). The sum of all daily flexibility needs over the year gives the annual need for flexibility to obtain a smoothened residual load for each day.

A similar calculation is realised for weekly flexibility needs, contrasting the daily averages with the overall average across each week. The weekly flexibility needs quoted herein correspond to the sum over all weeks of the year of the calculation represented on the lower part of Figure 3.

Figure 3: Schematic explanation of daily and weekly flexibility needs





[6] See RTE's 2015 Bilan prévisionel: http://www.rte-france.com/sites/default/files/bp2015.pdf

The daily and weekly flexibility needs metrics only depend on the demand and RES generation (since they are based on the residual load). In order to understand how these needs are met, a simulation of the dispatch is necessary so as to identify the role of each of the flexibility solutions.

In order to identify the contribution of a given technology in the provision of flexibility, we compute the two previously introduced metrics in two cases: (a) using the residual load without demand response activation and (b) using the residual load from which the generation or demand response activation time-series of the considered technology is subtracted. The resulting impacts on daily and weekly flexibility needs allow one to compare the contribution of a given technology on the daily and weekly timescales.

Annex 2 – Key assumptions

Additional data integrated from the EUCO30 scenario

A number of assumptions for the analysis are based on the EUCO30 scenario (see Section 1.1). In addition to that, also coal, lignite, hydro (excl. pumped-hydro storage), biomass and nuclear capacities are fixed at the level given by EUCO30. Yet, for the *Opportunity Scenario* and the *RETIRE-only* Sensitivity, these capacities are adapted.

For CCGTs, the 2030 residual capacities under the EUCO30 scenario have been evaluated, while investments in new CCGTs and OCGTs are decided endogenously through the optimisation. The EUCO30 power generation for each RES technology is transformed into generation capacities assumptions (by applying updated capacity factors, see Section 1.1), on top of which the model can decide to invest in additional RES capacities. Pumped hydro storage capacities are flexibility solutions in which the model can invest.

The capacity investment optimisation depends primarily on the fixed (CAPEX and FOC) and variable costs of the different technology options, along with the technology technical characteristics (availability, generation gradients, start-up constraints…).

Energy technology cost data

The capacity optimisation carried out in the analysis is a system cost minimisation. Hence, technology-specific cost data represent an essential input for the optimisation.

Major cost components include capital expenditures or investment costs (CAPEX), fixed operation costs (FOC) and variable operation costs, which usually include costs for fuel purchase and potentially carbon emissions.

As renewable technologies are assumed to have zero marginal generation costs, the investments costs can be translated into levelised costs of electricity generation (LCOE), in order to make them comparable with conventional power generation technologies for the purpose of illustration. The LCOE is calculated as the annualised CAPEX (which depends on the Weighted Average of Capital Costs, WACC) divided by the annual power production per unit of installed capacity, taking into account the mean availability (i.e. the capacity factor).

In the following the respective cost components are listed (if not stated in Section 1.1).

CAPEX data

Flexible generation technologies

CAPEX data for OCGT and CCGT is based upon the ETRI report, equalling 550 and 850 €/kW, respectively. FOC equal to 3% and 2.5%, respectively, of the CAPEX.

Renewable generation technologies

- PV: 550€/kW (based on ETIP-PV estimate[7] for industrial PV in 2025)
- Wind onshore: 1,350 €/kW (based on JRC's ETRI report[8])
- Wind offshore: 2,150 €/kW (based on Danish Energy Agency's estimate[9] for 2020/2030)

Storage data

Potential options for storage investments include pumped hydro storage (PHS, with one or two existing reservoirs) and battery storage:

	PHS – 2 reservoirs	PHS – 1 reservoir	Batteries
CAPEX (€/kW)	800	1,500	100
FOC (% of CAPEX)	1	1	1.4

Load shedding

Load shedding represents short-term load reduction of industrial processes to help solve situations of insufficient generation and avoid drops in grid frequency. In the present assessment, load shedding capacities are determined by means of optimisation.

The CAPEX for investing in infrastructure to enable load shedding is assumed to be 26 k€/MW/year, based on the current maximum remuneration on German reserve market for keeping capacities ready for load shedding. The fixed operation costs are assumed to be 2.5% of the CAPEX.

Activation costs for load shedding are set at 300 €/MWh based on the RTE Smart Grid report. These costs are assumed to be sufficient to compensate the losses caused by the supply interruption.

Load shifting

Load shifting capacities of industrial and commercial consumers, residential boilers, heat pumps and electric vehicles are not optimised but are an exogenous input. The study assumes that the roll-out of smart infrastructure for communication and automation of residential, industrial and commercial consumers is included in all scenarios. As the model uses a cost-optimization approach, the potential remuneration DSR providers may obtain from the market is not included.

WACC data

Renewable energy investments are capital intensive. As a result, the cost of capital plays a key role in determining the competitiveness of renewable energy investments. Capital expenditures for wind energy projects can represent more than 80% of total costs, compared with about 15% for some gas projects. This higher share of capital expenditures generally makes wind energy investments less volatile than energy projects dependent on volatile commodity prices, but also dramatically increases the role of financing as a share of total project costs.

[7] http://www.etip-pv.eu/fileadmin/Documents/ETIP_PV_Publications_2017-2018/LCOE_Report_March_2017.pdf
[8] https://setis.ec.europa.eu/system/files/ETRI_2014.pdf
[9] https://ens.dk/en/our-services/projections-and-models/technology-data

Both the PRIMES model[10] and IRENA[11] use a flat-rate WACC approach for their input assumptions on the cost of capital. As such, cost of capital is assumed to remain constant across space (i.e. no differentiation between Member States) and time (i.e. no differentiation over time), a gross simplification from real world conditions today. The modelling done for this report, on the other hand, uses a WACC Scenario for 2030 that takes a differentiated approach that more accurately reflects the regional variations in cost of financing for renewable energy projects seen today, while also taking into account potential changes in the framework for renewable energy investments in Europe. In developing the study's 2030 WACC Scenario, these figures were benchmarked against the figures for current WACCs for Onshore Wind and Solar PV found in the DiaCore (2015), Pricetag (2017), and RE-FRAME (2017) studies, while also taking into account estimates for 2030 found in CEPA 2017[12], NERA (2015)[13], Örtner & Heisl (2016)[14] and Toward2030 (2017)[15]. Potential factors/developments taken into consideration in developing the scenario include:

- (⇑) increased market/revenue risk driven by the increased market integration of renewable energy,
- (⇑) rising European Central Bank interest rates in the medium-term,
- (⇓) a gradual harmonization of support scheme and market design across Europe in line with best practices,
- (⇓) improved access to favorable financing for renewables projects due to the involvement of new financial actors, the further development of markets with low renewable investments today and potentially and potentially the introduction of cost of capital interventions on European level[16].

For all other investments into power sector technologies (e.g. storage, conventional generation), a +1% discount rate/WACC assumption was made in line with the modelling assumptions in PRIMES[17]. An overview of the country specific WACC values used for the study can be seen below in Table 3.

[10]Flatrate 7.5%
[11]Flatrate of 4% in the RE-map proces
[12]https://ec.europa.eu/energy/sites/ener/files/documents/cepa_final_report_ener_c1_2015-394.pdf
[13]http://www.nera.com/content/dam/nera/publications/2016/NERA_Hurdle_Rates_for_Electricity_Generation_Technologies.pdf
[14]http://towards2030.eu/sites/default/files/Impacts%20of%20electricity%20design%20trends%20on%20RES%20pathways.pdf
[15]http://towards2030.eu/sites/default/files/Towards2030-dialogue%20Scenario%20Report.pdf
[16]See Agora (2016) – RES CRF Proposal
[17]PRIMES assumes a basic discount rate in competitive power, gas, coal and gas markets used of 8.5%, which is +1% relative to the 7.5% assumed for renewable energy technologies for the EUCO30 scenario and certain renewable energy investment frameworks (e.g. feed in tariffs/contract for difference). Further information on the assumptions surrounding discount rates in PRIMES can be found in the documentation accompanying the 2016 Reference Scenario of the European Commission (EC 2016).

Table 3: 2030 WACC Scenario

Country/region	RES/NTC	Thermal/nuclear/NTC/storage
Belgium + Luxembourg	5.5%	6.5%
Baltic countries (EE, LT, LV)	6.0%	7.0%
Scandinavia (SE, DK, FI)	5.5%	6.5%
South-Eastern Europe	6.5%	7.5%
IT	6.0%	7.0%
FR	5.5%	6.5%
DE	5.0%	6.0%
UK	5.5%	6.5%
ES	6.5%	7.5%
PT	6.5%	7.5%
CZ	6.0%	7.0%
PL	6.5%	7.5%
CY	7.0%	8.0%
MT	6.0%	7.0%
IE	6.0%	7.0%
AT	5.5%	6.5%

Maximum potentials of flexibility solutions

In addition to cost data, data on potentials for each flexibility option represent key assumptions that drives the deployment of a technology or absence thereof.

Gas-based power generation is not subject to potential restrictions.

Short-sighted vs smart distribution grid planning and operation

Under the *Current Plans Scenario*, PV and onshore wind deployment speed in the core countries is limited to historical values in the core countries to reflect short-sighted distribution planning: capacity uptake is limited to +1.5 GW/year (equals to +21 GW until 2030) and +2.5 GW/year for British PV (based on steep growth rates in last two years). No constraint is applied for Germany, given the more important growth rates over the past years. The available potential for solar and wind under the *Current Plans Scenario* is given by the red dots in Figure 4.

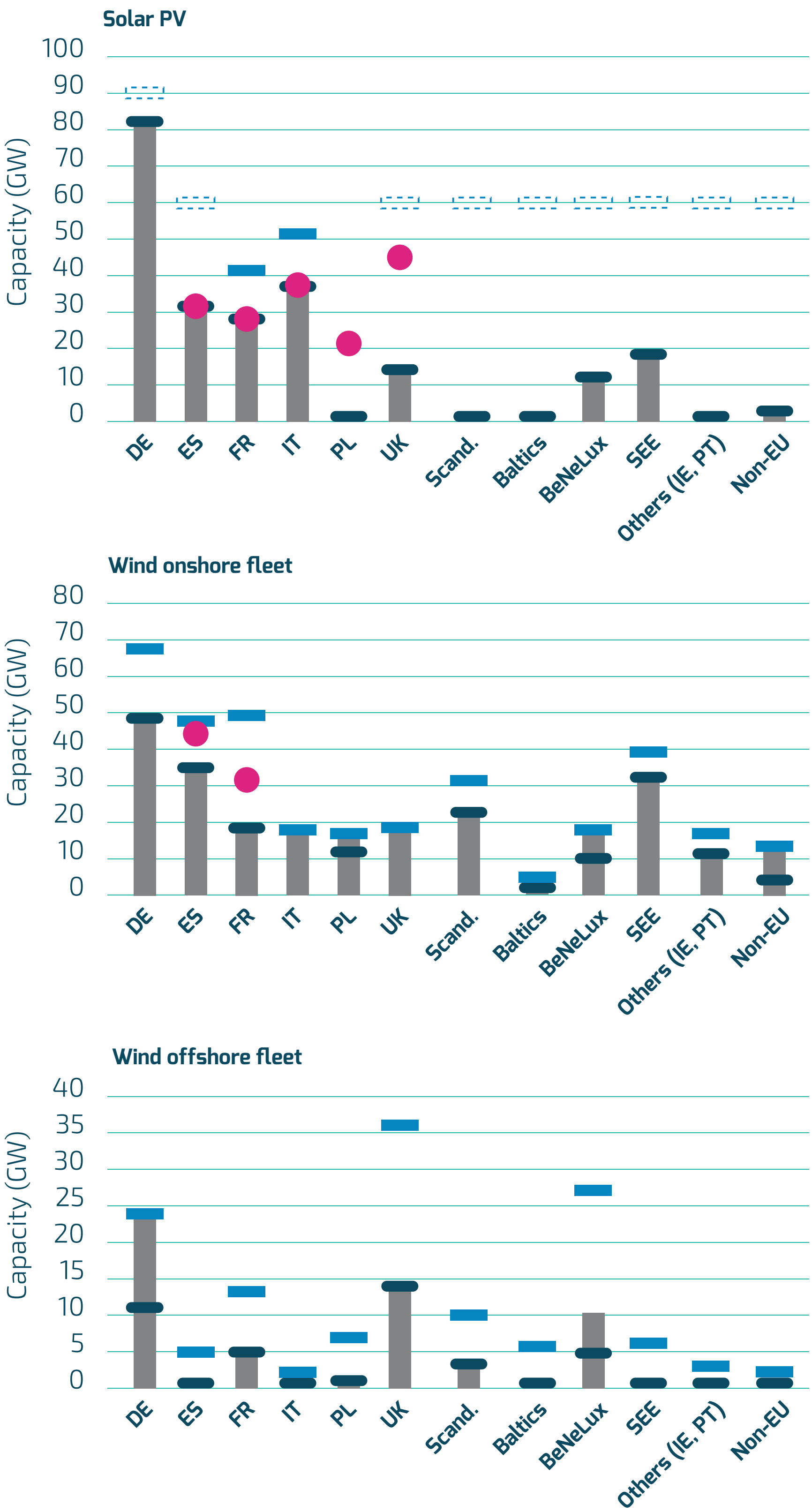
This constrained deployment speed is considered under the *Incomplete Plans Scenario* as well and in the *RETIRE-only* sensitivity. Under the *Opportunity Scenario* and the *DSR-only* sensitivity, the deployment speed is unconstrained in all countries.

Maximum installable RES potentials

Even if the deployment speed is not constrained, overall renewable expansion in a country may be restricted for other reasons, such as land use and acceptability concerns. Thus, maximum installable potentials were introduced for wind deployment across all countries and solar PV deployment in France and Italy (see blue dash in Figure 4). Maximum installable wind capacities are based upon the High Scenario of the latest WindEurope market outlook for 2030[18], plus a mark-up of 20%. Maximum potentials for solar PV in France and Italy are based on national deployment projections +20%.

[20] https://windeurope.org/about-wind/reports/wind-energy-in-europe-scenarios-for-2030/

Figure 4: Installed capacities in EUCO30 and *Current Plans Scenario*, and available additional investment potentials



Interconnectors

The optimisation of investments in interconnector capacities between core countries and regions relies on the TYNDP 2016 project list. Yet, it was limited to projects with status "under planning" and only 50% of the available capacities of all projects being labelled "under consideration", in order to reflect potential acceptability constraints.

Load shedding potentials

The capacity expansion for load shedding is subject to national, technology-specific load shedding potentials, based on Gils (2014)[19].

Assumptions on baseload retirement

Retired capacities are determined based on current plans and ongoing discussions in the individual Member States and the assumption that no coal/lignite capacities are added after 2015.[20]

Table 4: assumptions on baseload retirement in the *Current Plans* (CPS) and *Opportunity Scenario* (OS)

(GW)	Coal			Lignite			Nuclear		
	2015	**CPS**	**OS**	**2015**	**CPS**	**OS**	**2015**	**CPS**	**OS**
DE	26	22	9	21	15	9	11	0	0
ES	10	4	0	1	0	0	8	7	7
FR	3	4	0	0	0	0	63	60	40
GB	18	1	0	0	0	0	9	13	13
IT	9	5	0	0	0	0	0	0	0
PL	17	11	11	9	9	8	0	0	0
Scand.	8	3	3	0	0	0	12	10	10
Baltics	n/a	1	1	n/a	0	0	n/a	1	1
Benelux	6	4	0	0	0	0	6	0	0
SEE	5	3	2	25	17	16	12	18	18
Others (IE, PT)	6	1	1	0	0	0	0	0	0
Non-EU	0	0	0	0	0	0	3	1	1
EU 28+2		**59**	**28**	**55**	**40**	**34**	**125**	**112**	**92**

[19] http://elib.dlr.de/104130/
[20] 2015 data is based on ENTSO-E's Statistical Fact Sheet 2015: https://www.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2015_web.pdf

Electric vehicles and heat pumps

The analysis maintained the annual electricity demand for electric road transport given by EUCO30 across all scenarios. This demand is subsequently transformed into an EV stock. We base our assumptions on a report prepared on behalf of the European Climate Foundation on low-carbon cars in Germany[21]. For 2030, the document suggests about 5M EVs and an overall electricity demand of 12 TWh. This would translate into an average electricity demand of 11.6 kWh/day/vehicle, considering that:

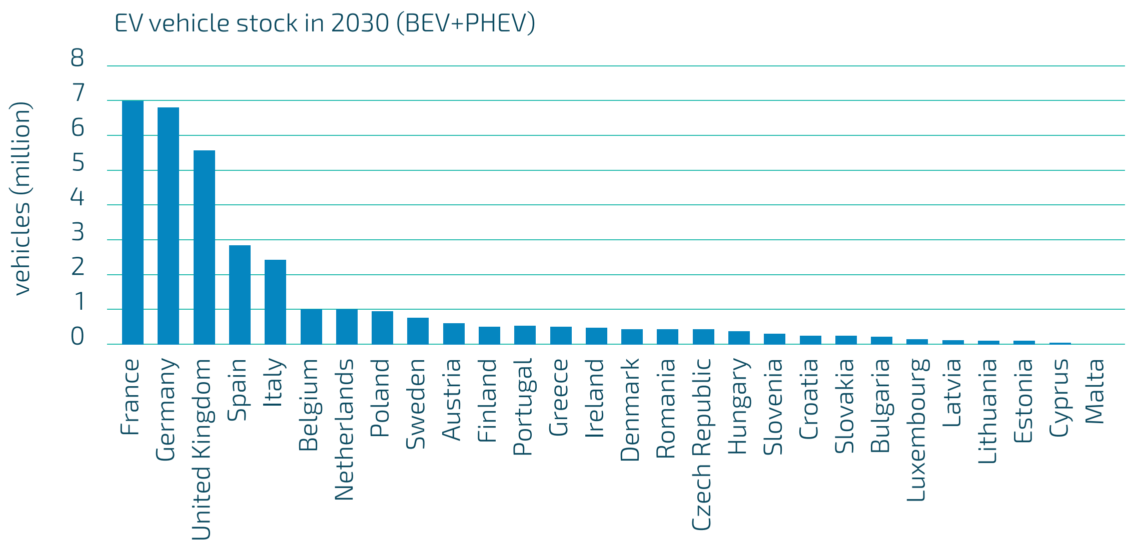
1. About 70% of all existing vehicles are on the road every day and;
2. on weekend days, driving activity is reduced by 2/3 (both assumptions are based on a study performed by the French Environment Ministry in 2011[22]).

Such a daily demand level is reasonable for pure battery electric vehicles (BEV). JRC assumes 0.13-0.2 kWh/km and the mean daily driving distance is in 80% of the cases below 80km.
However, we believe that the vehicle stock in 2030 will include BEV as well as plug-in hybrid EVs (PHEV), which feature a lower daily demand.

Assuming that the ratio between BEV and PHEV is 1:1 and that the daily demand of a PHEV is about 65% of a BEV[23], the annual electricity demand of 12 TWh (mentioned in the ECF study) would translate into 3 M of BEV and 3 M of PHEV in 2030, i.e. about 20% above the figure mentioned in the report. The German government has announced the objective of 6 M EVs in 2030.

Applying this approach to all countries and the annual EV electricity demand from PRIMES EUCO30 as overall input leads to a total number of electric vehicles in the EU28 of 32 M. Figure 5 depicts the EV stock in 2030 across all EU Member States.

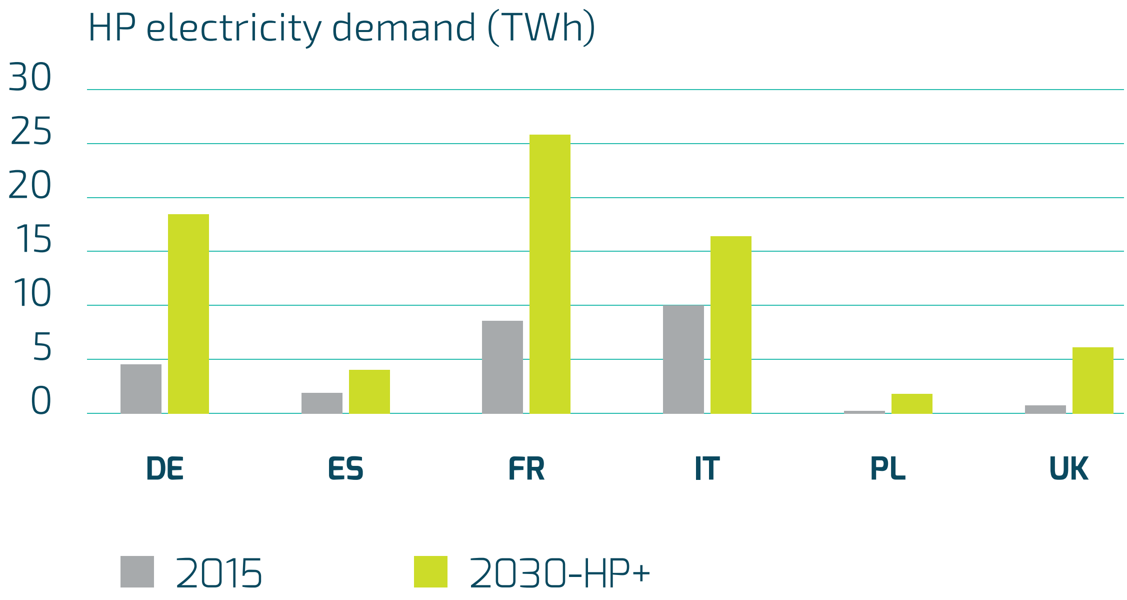
Figure 5: Assumed EV stock in 2030, by country



[21] https://www.camecon.com/wp-content/uploads/2017/10/ECF_EN_CARS_SCREEN_V1.2.pdf
[22] http://temis.documentation.developpement-durable.gouv.fr/docs/Temis/0069/Temis-0069678/19162.pdf
[23] http://onlinelibrary.wiley.com/doi/10.1111/jiec.12623/full

As the assumptions related to the deployment of heat pumps in the EUCO30 scenario are not publicly available, a separate assessment was performed to estimate heat pump stock in 2030, relying on the HP+ penetration scenario of Ecofys/EHPA[24]. For the EU28, 38 million heat pumps are assumed to be installed by 2030. The related electricity demand equals 109 TWh. Figure 6 illustrates the related electricity demand in the core countries.

Figure 6: Electricity demand from residential heat pumps in 2015 and 2030 (based on HP+ scenario of EHPA)



Consumption data for boilers is based upon the ENTRANZE database[25] and the PhD from Gils (2014)[26]. Boilers are only considered for load shifting only in France, Spain and the UK given their respective national shares in stock.

Load shifting potentials

Load shifting potentials represent an exogenous input, i.e. not the capacity but the hourly dispatch of load shifting is optimised. Load shifting potentials are based on national data by Gils (2014) and adapted according to the scenario-specific smart share, as indicated in Section 1.1.. Merely for electric vehicles, the overall capacity is calculated as the product of vehicle stock and charging capacity per vehicle.

In the *Current Plans Scenario*, only the industrial load shedding potential and 25% of the industrial and large scale commercial load shifting potentials are assumed to be accessible (considering the potentials given by Gils for 2030). Residential and small commercial consumers are assumed to manage their flexibility in response to a static time-of-use tariff.

[24] https://www.ecofys.com/en/publication/heat-pump-implementation-scenarios-until-2030/
[25] http://www.entranze.enerdata.eu/
[26] http://elib.dlr.de/104130/

By contrast, the *Opportunity Scenario* assumes that consumers react to time-varying electricity tariffs (real-time pricing, RTP, that reflects the hourly variation in wholesale market prices). Such explicit demand response participation is assumed for the following share of consumers:

- 50% of the industrial and commercial load shifting potential,
- 60% of all consumers with boilers, heat pumps having access to real-time pricing
- 50% of all EVs

The hourly DSR activation of the different types of consumers takes into account their hourly, year-long load profile, their maximum capacity and potentially additional technical constraints (e.g. maximal shifting duration).

The load profile of industrial consumers is assumed to reflect a constant load level, whereas commercial consumers feature a load pattern that exhibits the typical variation throughout the day and the week.[27]

For heat pumps, the load profile varies in function of the outdoor temperature and is consequently different for each Member State.

For electric vehicles, a charging capacity of 3.9 kW per vehicle is assumed (likewise for BEV and PHEV), implying an average daily charging duration of 3 and 2 hours, respectively. The same capacity is available and charging/discharging duration is available for the vehicle-to-grid functionality. Daily arrival and departure time series determine the number of cars being connected to charging infrastructure at a given point in time.

Employment factors

Labour impacts are calculated by applying employment factors to the change in renewable and thermal/nuclear capacity. We distinguish direct and indirect employment (see Table 5).

Table 5: Direct and indirect employment factors by technology.

Median	**Direct Employment Factor (jobs/MW)**	**Indirect Employment Factor (jobs/MW)**	Source
Coal fleet	0.8	1.2	Agora report[28]
Gas fleet	1	0.05	Cambridge Econometrics[29]
Lignite fleet	1	1.5	Agora report
Nuclear fleet	0.8	n/a	ADEME report[30]
Solar fleet	0.96	0.15	Lachlan et al. (2015)[31]
Wind offshore fleet	1.7	0.7	
Wind onshore fleet	0.8	0.40	

[27]Base on the hourly consumption profile published by RTE for its Bilan prévisionnel: https://rte-opendata.opendatasoft.com/explore/dataset/bp_2015_scenario_conso_horaire_brute/
[28]https://www.agora-energiewende.de/de/presse/agoranews/news-detail/news/die-deutsche-braunkohlenwirtschaft/News/detail/
[29]https://ec.europa.eu/energy/sites/ener/files/documents/2013_report_employment_effects_roadmap_2050.pdf
[30]http://www.ademe.fr/sites/default/files/assets/documents/mix-100-enre_evaluation-macro-economique-8891.pdf
[31]http://www.sciencedirect.com/science/article/pii/S1364032115000118

Non-CO2 emission factors

The calculation of non-CO2 emissions is realised by applying emission factors (see Table 6) to the overall power generation determined via the dispatch optimisation. The emission factors for coal are based on Dios et al. (2013)[32], whereas the factors for lignite and gas are based on entries from the European Pollutant and Release and Transfer Register (E-PRTR)[33].

Table 6: Emission factors for non-CO2 emissions

	NOx	SOx	Particulate matters
Lignite	0.6 kg/MWh_el	0.37 kg/MWh_el	25 g/MWh_el
Coal	0.71 kg/MWh_el	0.25 kg/MWh_el	16 g/MWh_el
Gas	0.05 kg/MWh_el		

[32] http://www.sciencedirect.com/science/article/pii/S0360544213001576
[33] http://prtr.ec.europa.eu/#/home

Annex 3 – Results

Overview of main results across all scenarios

Table 7: Overview of all results for the EU28

	2015	EUCO30*	Incomplete Plans Scenario	Current Plans Scenario	RETIRE -only sensitivity	DSR -only sensitivity	Opportunity Scenario
Renewables							
RES share (% of total net production)	29%	49%	54%	**55%**	60%	57%	**61%**
vRES share (% of total net production)	13%	30%	34%	**35%**	40%	36%	**41%**
Installed PV (GW)	97	241[a]	249	**242**	242	262	**280**
Installed wind-onshore (GW)	141	270[a]	241	**247**	258	261	276
Installed wind-offshore (GW)	13		56	**58**	85	54	**68**
Solar PV generation (TWh)	108	306	319	311	311	329	359
Wind-onshore generation (TWh)	302	691	548	570	600	614	656
Wind-offshore generation (TWh)			235	242	359	227	287
RES curtailment (TWh)	n/a	n/a	7	**6**	6	7	**10**

Flexibility (installed capacity, GW, determined via capacity optimisation)							
Load shedding	n/a	n/a	5	**4**	4	63	**65**
Batteries	n/a	n/a	2	**21**	24	5	**6**
Pumped hydro	35	n/a	39	**35**	39	39	**35**
Interconnectors (incl. NO, CHe)	66[f]	n/a	86	**92**	92	93	**92**
Gas (CCGT+OCGT)	≈183[b]	189[c]	216	**173**	208	164	**195**
Contribution to daily flexibility needs (energy, TWh)							
DSR	n/a	n/a	2	**4**	4	63	**65**
Batteries	n/a	n/a	0	**6**	8	0	**1**
Pumped hydro storage	n/a	n/a	39	**40**	39	23	**23**
Interconnectors	n/a	n/a	29	**32**	36	31	**36**
Hydro	n/a	n/a	21	**21**	23	17	**19**
Gas	n/a	n/a	39	**28**	41	14	**23**
Solids (coal + lignite)	n/a	n/a	38	**36**	21	23	**15**
Nuclear	n/a	n/a	10	**11**	9	9	**9**
Thermal power generation							
Net gas-based generation	514	396[d]	155	**133**	291	104	**259**
Net solid-based generation	792	456[d]	529	**511**	347	500	**347**
Net nuclear-based generation	814	730	791	**789**	648	778	**644**
CO_2 emissions							
CO2 emissions (Mt)	1060[g]	735[h]	584	**560**	483	538	**470**
Costs							
Δ production cost (bn€) vs Scen. 2[i]	n/a	n/a	+2.4	**-**	+1.4	-2.7	**-0.8**
Δ CAPEX + FOC (bn€) vs Scen. 2[i]	n/a	n/a	+1.0	**-**	+3.3	-1.5	**+0.2**
Net cost effect (bn€) vs Scen. 2[i]	n/a	n/a	+3.4	**-**	+4.7	-4.1	**-0.6**

a: RES capacities outlined here do not represent the capacities stated by PRIMES, but adapted capacities to meet the RES-based generation stated by PRIMES, considering deviating capacity factors
b: based on ENTSO-E transparency database
c: Official PRIMES value – not really comparable with data from the analysis as PRIMES builds upon typical days and different meteorological data, thus deviating dimensioning of the plant fleet
d: Public PRIMES data only contains gross power generation; for reasons of comparability these values were transformed into net generation and gas-based power generation was adapted to take into account weather-related differences in demand and hence power generation
e: NTC data only counts interconnections between individually modelled countries and regions; intra-regional NTCs are not taken into account
f: based on ENTSO-E 2016 MAF
g: based on UNFCCC GHG inventory (contains power and district heat generation)
h: based on technical report on EUCO scenarios (based on gross generation, contains power and district heat generation)
i: covers EU28 + NO, CH