Modelling flexible power demand and supply in the EU power system: soft-linking between JRC-EU-TIMES and the open-source Dispa-SET model

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Modelling flexible power demand and supply in the EU power system: soft-linking between JRC-EU-TIMES and the open-source Dispa-SET model

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Abstract:

Modelling the variability of renewable energy sources together with flexible and/or storage technologies is highly relevant for the current EU power system. Dispa-SET is an open-source unit commitment and optimal dispatch model that covers various energy sectors (power systems, heating & cooling, transportation) and the 26 European countries plus Switzerland and Norway. It uses high-resolution time series for the demands, renewable generation and outages to optimize the system operation under technical constraints (e.g. maximum ramping rates of power plants, interconnection capacities, heating & cooling constraints, etc.). This work evaluates the application of the model on the ENTSOE EU28 open-dataset and calibrates critical inputs such as renewables availability, power plant outages, hydro levels and power demands to match historic data for the year 2016. The calibrated model is finally used to assess the implementation of future low carbon EU strategies and policies through several “what if” scenarios and soft linking with the JRC-EU-TIMES model.

Keywords:

Power system modelling, Unit commitment and power dispatch, Dispa-SET, JRC-EU-TIMES, Soft-linking.

1. Introduction

Long-term energy system planning models such as MARKAL/TIMES, PRIMES, IKARUS and PERSEUS are frequently used to analyse transition pathways to a sustainable and carbon-free future [1]. Their main purpose is to analyse policy instruments and role of specific technologies, check the feasibility of realizing ambitious renewable energy sources (RES) targets and reduction of greenhouse gas (GHG) emissions [2][3]. They typically use a stylized temporal representation, e.g. using a limited number of time slices and mostly operate at technology-/fuel-type level. In most cases, technical power flow constraints and cycling costs are either simplified or completely neglected [4]. This can consequently lead to the suboptimal system configurations where high shares of RES can have a significant impact on the operation of the power system. Large penetration of RES increases the need for cycling of conventional powerplant and sufficient back-up capacity has to be available in case of low RES generation. The second category of models includes the so-called operational or power dispatch models, such as PLEXOS, PyPSA or Dispa-SET. These models incorporate most short-term constraints such as ramping rates, start-up and shut-down times and reserve requirements on the individual unit level. Breaching the gap between these two approaches can be done through soft linking [4], where results from the long term models are used as inputs in power dispatch models.

The aim of this work is twofold. The first goal is to validate the Dispa-SET model against real-world and open datasets. The second goal is to soft-link the long term planning JRC-EU-TIMES model with the power dispatch Dispa-SET model that allows analysing the operational feasibility of ProRES scenario [3].

2. Model description

The aim of the Dispa-SET model [5] is to represent, with a high level of detail, the short-term operation of large-scale power systems, solving the unit commitment problem. Hence, it is considered that the system is managed by a central operator or within a perfect market with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network.

The unit commitment problem consists of two parts: i) scheduling the start-up, operation, and shut down of the available generation units, and ii) allocating (for each period of the simulation horizon of the model) the total power demand among the available generation units in such a way that the overall power system costs are minimized.

The problem mentioned above can be formulated as a MILP problem. The formulation is based on publicly available modelling approaches [6][7][8]. The goal of the model being the simulation of a large interconnected power system with actual power flows (Kirchoff laws) between the zones, a tight and compact formulation has been implemented, in order to simultaneously reduce the region where the solver searches for the solution and increase the speed at which the solver carries out that search.

Since the simulation is performed for a whole year with a time step of one hour, the problem dimensions are not computationally tractable if the whole time-horizon is optimized. Therefore, the problem is split into smaller optimization problems that are run recursively throughout the year. Figure 1 shows an example of such an approach, in which the optimization horizon is one day, with a look-ahead (or overlap) period of one day. The initial values of the optimization for day j are the final values of the optimization of the previous day. The look-ahead period is modelled to avoid issues linked to the end of the optimization period such as emptying the hydro reservoirs or starting low cost but non-flexible power plants.

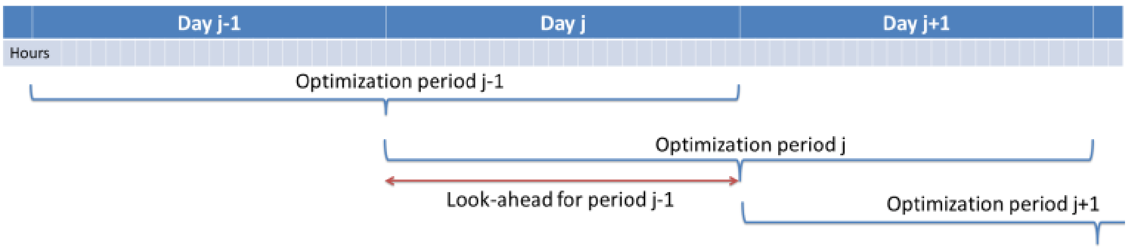


Figure 1 Time horizons of the optimization with the look-ahead period

2.1. Objective function

The goal of the unit commitment problem is to minimize the total power system costs (expressed in EUR), which are defined as the sum of different cost items, namely: start-up and shut-down events (self-consumption during synchronization with the grid), fixed costs of operating a unit (staf and maintenance), variable costs (fuel consumption), ramping costs (aging of powerplants due to thermal stress and cycling), transmission costs, load shedding costs (flexibility provided by not operating large industrial facilities), heat slack costs (heat generation by other means, non CHP units), variable CHP related costs (power loss due to heat extraction from the turbine) and value of lost load costs (mainly reserve requirements and balancing). The demand is assumed to be inelastic to the price signal. The MILP objective function is, therefore, the total generation cost over the optimization period.

$$
\text{Min}\, SystemCost = \sum_{\forall u,i} \left(\begin{array}{c} CostStartUp_{i,u} + CostShutDown_{i,u} + \\ CostFixed_{u} \cdot Committed_{i,u} + \\ CostVariable_{i,u} \cdot Power_{i,u} + \\ CostRampUp_{i,u} + CostRampDown_{i,u} + \\ PriceTransmission_{i,l} \cdot Flow_{i,l} + \\ \sum_{n} \left(CostLoadShedding_{i,n} \cdot ShedLoad_{i,n} \right) + \\ \sum_{chp} \left(CostHeatSlack_{chp,i} \cdot HeatSlack_{chp,i} \right) + \\ \sum_{chp} \left(CostVariable_{chp,i} \cdot CHPPowerLossFactor_{chp} \cdot Heat_{chp,i} \right) + \\ VOLL_{Power} \cdot \left(LL_{MaxPower,i,n} + LL_{MinPower,i,n} \right) + \\ VOLL_{Reserve} \cdot \left(LL_{2U,i,n} + LL_{2D,i,n} + LL_{3U,i,n} \right) + \\ VOLL_{Ramp} \cdot \left(LL_{RampUp,u,i} + LL_{RampDown,u,i} \right) \end{array} \right) \quad (1)
$$

2.2. Constraints

A formulation of the Dispa-SET model is out of the scope of this paper. A detailed description of all equations and constraints is available in [5]. The main model features and constraints can, however, be summarized by:

- Minimum and maximum power for each unit
- Power plant ramping limits
- Reserves up and down
- Minimum up/down times
- Load Shedding
- Curtailment
- Pumped-hydro, battery and thermal storage
- Non-dispatchable units (e.g. wind turbines, run-of-river, etc.)
- Start-up, ramping and no-load costs
- Multi-nodes with capacity constraints on the lines (congestion)
- Constraints on the targets for renewables and/or CO_2 emissions
- CHP min/max power and heat outputs
- Yearly schedules for the outages (forced and planned) of each unit.

2.3. Inputs and parameters

The main model inputs are the load and the variable renewable energy (VRE) generation curves. The model can indifferently operate with two different approaches: integrating the VRE into a residual load curve or considering VRE as power plants with must run constraints.

Since this model focuses on the available technical flexibility and not on accurate market modelling, it is run using the measured historical data, and not the day-ahead forecasted load and VRE production. This can be partly justified by the fact that a fraction of the forecast errors can be solved on the intra-day market. This perfect foresight hypothesis is however optimistic, and a more detailed stochastic simulation should be performed to refine the results.

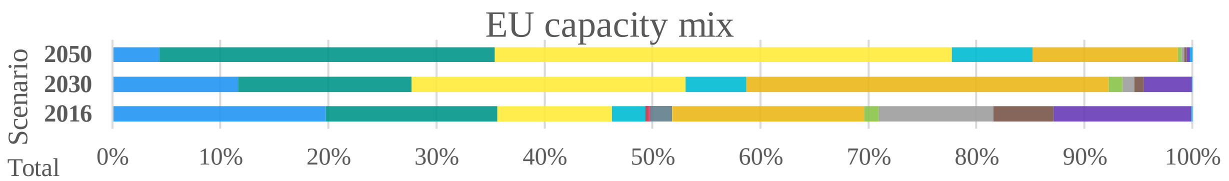
Powerplant data includes min/max capacity, ramping rates, min up/down times, start-up times, efficiency, variable cost (fuel prices are historical fuel prices for the considered period). It is worthwhile to note that some of the units such as the turbojets present a low capacity and/or high flexibility, such as the turbojets whose output power does not exceed a few MW, and which can reach full power in less than 15 minutes. For these units, a unit commitment model with a time step of 1 hour is unnecessary and computationally inefficient. Therefore, these units are clustered into one single, highly flexible unit with averaged characteristics.

3. Case study

A reference scenario and two alternative ones representing the power system of 26 EU member states, Switzerland and Norway for the years 2030 and 2050 have been developed. In addition, the model has been validated against the ENTSO-E time-series [9] containing aggregated load values by country, fuel-based load duration curves (LDC), net generating capacities (NGC), net transfer capacities (NTC) and reservoir levels (RL). The power outputs of solar photovoltaics (PV), wind energy and hydropower are defined through the availability factors (AF). These hourly time series represent the fraction of the nominal power capacity that an RES-E powered power plant can produce at each hour.

Wind and PV AF are obtained from the "*Renewables.ninja*" database [10][11]. Hydro inflows are obtained from the RESTORE 2050 hydro energy inflow dataset [12]. Outage factors are obtained from the ENTSO-E platform [9], and EDF [13] and RTE [14] unavailability of generation resources databases. Other data sources used in this study are JRC-IDEES [15] and Bundesnetzagentur [16].

A summary of aggregated capacity mixes from all three scenarios is presented in Figure 2. RES amount to 60% of total NGC in 2030 and 85% in 2050 scenarios. Other fuel sources highlight the installed capacities of electric vehicles and other non-identifiable thermal and renewable capacities. Electric vehicle storage availability and charge/discharge rates, as well as power to capacity ratio, are modelled as proposed in [17][18]. Combined heat and power units are only used in the reference scenario and are modelled as proposed in [19].



Total NGC [TW]	2016	2030	2050
WAT	189	212	221
WIN	152	293	1,578
SUN	102	463	2,150
OTH	30	103	378
WST	3	0	0
PEA	1	0	0
OIL	19	0	0
GAS	170	613	685
BIO	13	24	18
HRD	101	19	12
LIG	54	16	11
NUC	122	81	16
GEO	1	1	10
Total	955	1,825	5,080

Figure 2 Europe 28 capacity mix in all three scenarios

Net generation capacities in the two alternative scenarios, one for 2030 and one for 2050, are inspired by the ProRES scenario from the JRC-EU-TIMES model [3] and expanded for the non-EU member states Norway and Switzerland. The ProRES scenario was chosen over the Diversified scenario because it has higher shares of variable renewable energy. The ProRES scenario was produced with a version of JRC-EU-TIMES that estimates negative residual loads (power surpluses) endogenously based on the amount of VRE and demand within each of the 12 timeslices of the model. The equations that are used for this estimation divides each timeslice into two sub-periods: one with and one without surplus. As shown in [20][21], these surpluses can be transformed into hydrogen for direct uses or into e-fuels. Different from [20], these equations are based on a country-specific analysis with an hourly model outside JRC-EU-TIMES that includes hundreds of possible combinations of wind and solar capacities, using EMHIRES data, based on 30 years of meteodata. For this parametrization, it is assumed that each country has a storage capacity equal to 5 hours of average power demand which is equivalent to 40% of the full storage capacity if all cars would have a 30kWh battery. One result of the statistical analysis was that in each country, the error of parametrising the average surplus is smaller than the annual variations of the surpluses. Furthermore, the NTC capacities between all simulated zones in the year 2050 are multiplied by the factor of $\times 3$ in order to ensure enough interconnection capacities for the integration of high-shares of VRES. This scenario analysis helps to understand how GHG emissions could be reduced, energy independence increased and how the stability of the European power system and its security of supply could be improved.

4. Results

The section presents results from the three analysed scenarios. Important indicators from the simulations include the average electricity generation cost (during the period of one year), the amount of curtailed RES-E, the amount of congestion in the transmission lines and the power output of each unit or cluster of units.

4.1. Reference scenario

In order to validate the accuracy of the model, simulated results from the reference scenario have been compared to the historical data (the period between 2015 – 2017) obtained from ENTSOE open dataset. A detailed comparison of load duration curves (LDC) from all analysed energy carriers is presented in Figure 3. A load duration curve can describe the peakiness (slope), maximum power (max value in y-axis) and the amount of energy generated (area under the curve). There is a clear match between the RES LDC. The reason for this lies in the nature of RES technologies. Their production highly depends on the availability of intermittent sources such as wind, sun and hydro. Correlation between LDC of dispatchable powerplants is lower due to a couple of reasons. Accurate modelling of overwhelming numbers of units in the European power system is a difficult task. Every unit has its own techno-economical specifications, fuel prices and operation of units depend on outside factors such as geography, market conditions and politics and actual starting-up and shutting-down is still managed by humans and isn't entirely automatized.

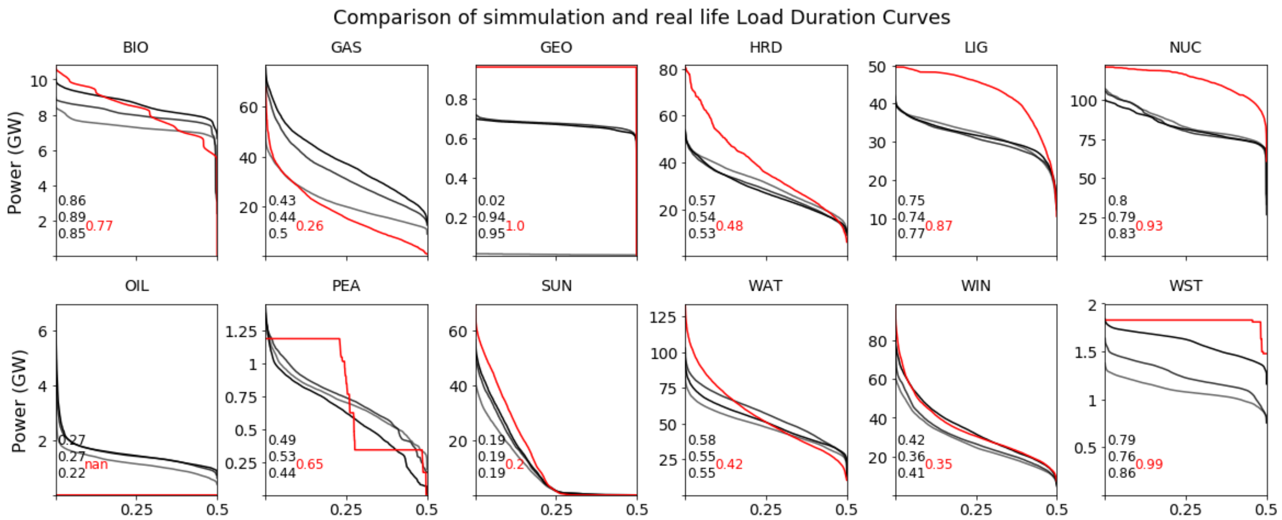


Figure 3 Validation of the Dispa-SET model (red lines) on the ENTSOE dataset (black/grey lines). The annotated factors correspond to the capacity factor of each technology/year.

Other factors such as industrial heat demand in combined heat and power units, and unscheduled malfunctions and outages can also impact the real-life dispatch. The main reason for the overproduction from nuclear units is the lack of reported outages in the UK, Spain and Sweden.

Simulated weekly power dispatch curves from the largest European countries for the year 2016 are presented in Figure 4. Each diagram represents a different fuel and technology dispatch mix. In the period between 13th – 20th May Spain is dominated by RES-E from wind and hydro, France by nuclear energy, while UK and Germany have a mix of different RES and non-RES technologies. It is clear that, in all six countries, RES-E dispatch does not cause any major problems and can easily be integrated into the system. During the whole year, UK is the only country that had to curtail RES-E. This is mainly caused by lower demand during the weekend and favourable RES conditions with high amounts of hydro run-of-river, wind and sun.

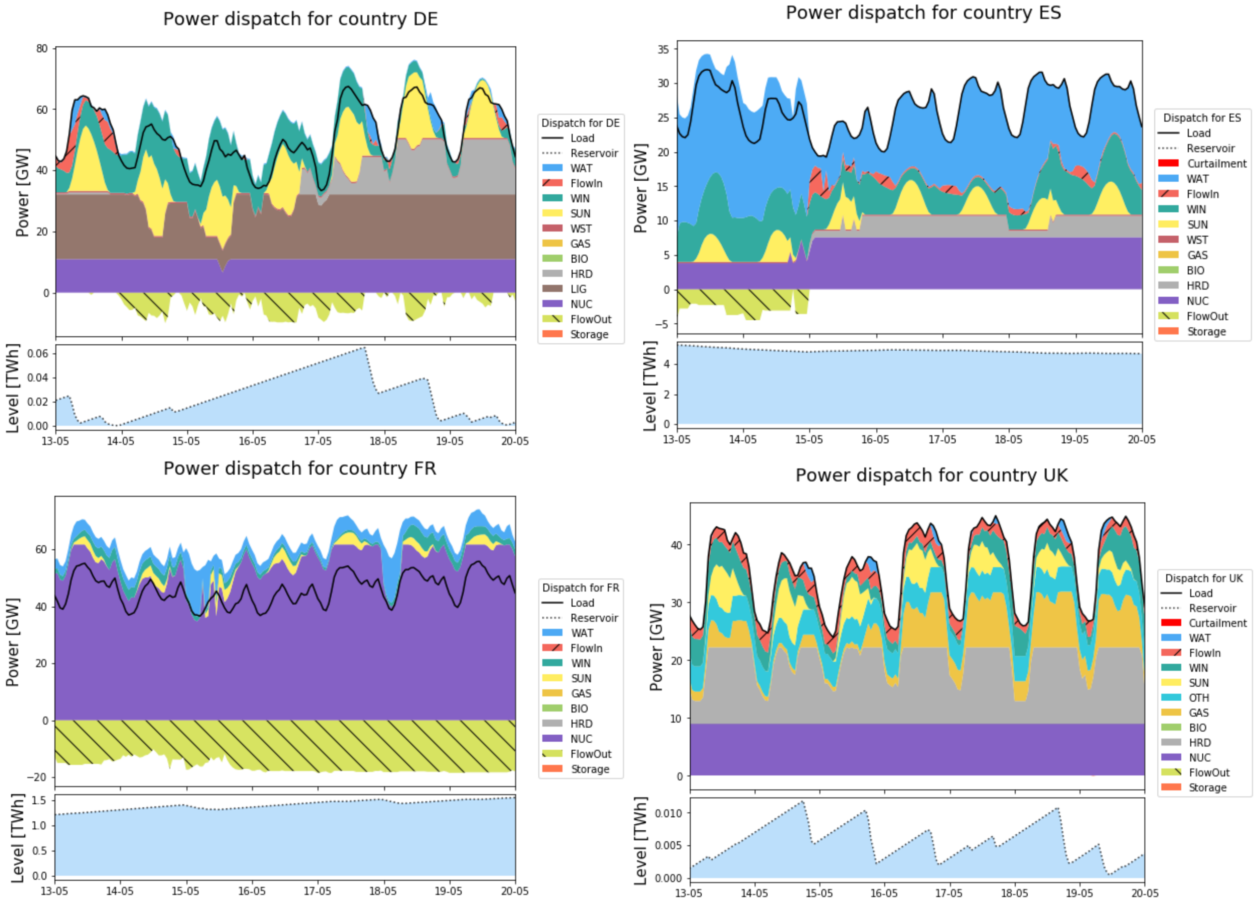


Figure 4 Weekly power dispatch curves and storage levels for four of the largest countries in 2016

4.2. Alternative JRC-EU-TIMES ProRES scenario

A summary of the results from both alternative scenarios is presented in Table 1. Computed average electricity generation cost is 29.7% higher in the year 2030 and 8.1% higher in the year 2050. The reason for this price increase is twofold. The amount of new RES capacities is not high enough to offset phaseout of nuclear powerplants, higher fuel prices and higher cycling costs in alternative scenarios. A more relevant comparison price is given in the brackets. These numbers represent the present value of the average annual price of electricity. This is a clear indication that high shares of RES-E have a positive impact on the production costs of the system. A number of start-up events, on the other hand, increases significantly with the higher penetrations of RES-E. This is especially true for storage technologies that have to compensate for large variations from PV and wind. In JRC-EU-TIMES, the excess electricity generation is partly used for the electrolysers to produce hydrogen and e-fuels. The current version of Dispa-SET does not yet support the modelling of electrolysers however curtailment can be considered “energy available for other non-considered uses”.

The expected amount of load shedding in both alternative scenarios is higher than in the base year. Average congestion in the interconnection lines is almost on the same level as in the reference scenario. It is important to note that the interconnection capacities in both scenarios are significantly higher (× 1.5 and × 3) than in 2016.

Table 1 Key results from the analysed scenarios

Parameter	Units	2016	2030	2050
Average electricity generation cost	EUR/MWh	10.56	13.70 (10.38)	11.42 (5.82)
Load shedding	TWh	0.01	0.14	0.17
Curtailment	TWh	3.94	0.90	594.56
Congestion	%	32.15	33.95	31.90
Start-ups	#	15 725	34 806	40 192
Fossil	#	5 397	3 953	7 380
Storage	#	2 988	21 954	23 913
Total consumption	TWh	3 076	3 506	7 075
Peak load	GW	501	571	1 152

Total annual generation per country from all three scenarios is presented in Figure 5. A switch from mostly fossil fuel powered technologies to almost entirely RES-E powered system would drastically change the energy mix of the European power sector. France, Italy and the UK will require significant capacity replacements to meet the ProRES switch to clean, sustainable and low carbon technologies.

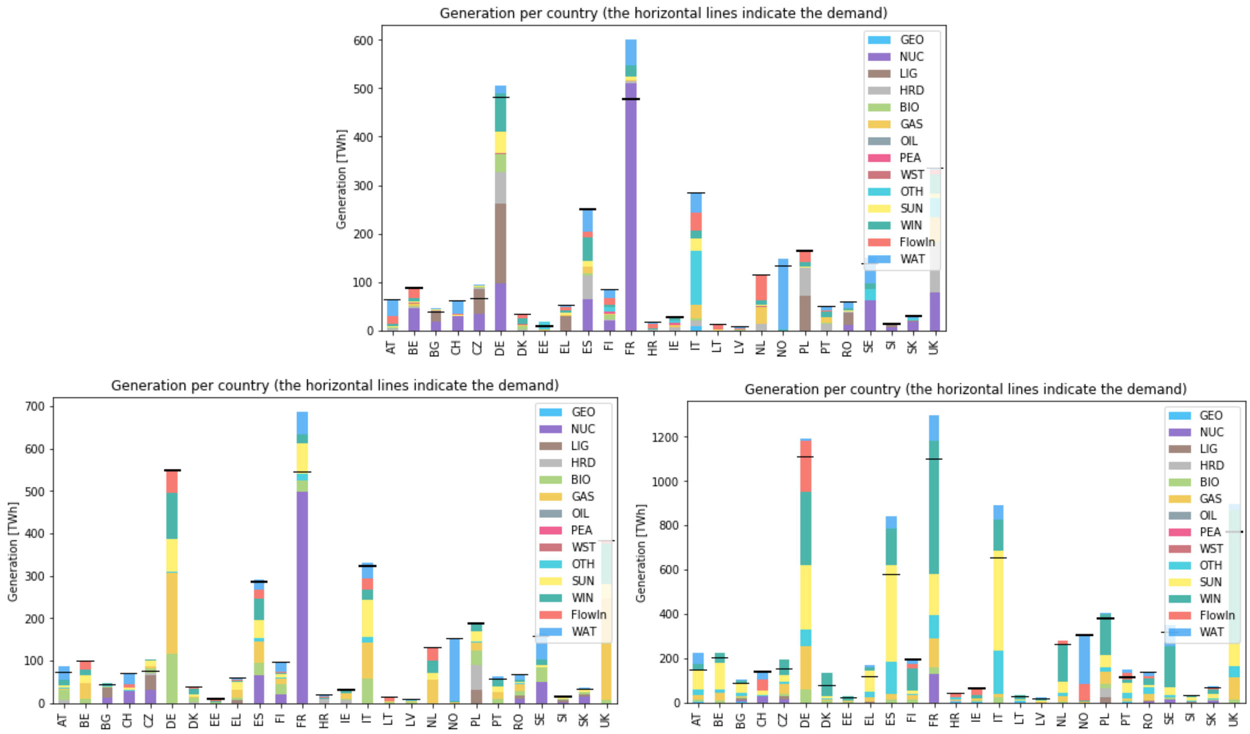


Figure 5 Annual generation per country in reference (top) and 2030 and 2050 alternative scenario (bottom).

A detailed comparison of load duration curves from all analysed energy carriers is presented in Figure 6. Higher penetration of RES-E in alternative scenarios clearly impacts the cycling of conventional units. Computed capacity factors of coal, lignite, gas and nuclear units in 2030 scenario are generally higher than in 2016. The main reason for this lies in the reduced capacity of conventional generation due to the phase-out of old and inefficient units. Such configuration is clearly better than the current one as the utilization rate of existing units is in most cases higher than 90%. In contrast, capacity factors of conventional units in the 2050 scenario are lower. Even higher shares of VRES clearly impact the cycling requirements as capacity factors are always below 75%.

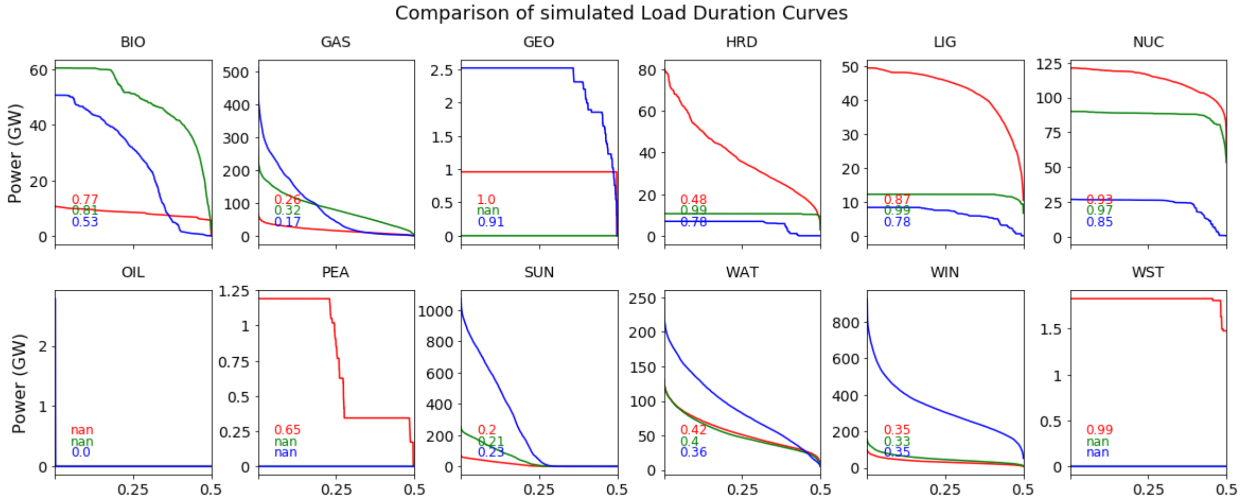


Figure 6 Comparison of LDC from all three scenarios. The annotated factors correspond to the capacity factor of each technology/year (red = 2016, green = 2030 and blue = 2050).

Simulated weekly power dispatch curves from four of the largest European countries in alternative 2030 and 2050 scenarios are presented in *Figure 7* located in the appendix A of this paper. It is clear that the lack of interconnection and storage capacities together with no consideration of electrolysis and other sector coupling technologies in isolated countries such as Spain and Italy will lead to significant curtailment of RES-E. Well-interconnected countries such as Germany and France would experience such events only occasionally throughout the year.

5. Conclusion

This article describes the implementation of the Dispa-SET model on the 28 European countries and its validation with the ENTSOE and other open datasets. Furthermore, it also investigates the possibilities for soft-linking with the JRC-EU-TIMES model. This implementation of the Dispa-SET can be freely downloaded[1] and is released with an open-source license to ensure transparency and reproducibility of the work [22].

There are two main findings of this work. First, Dispa-SET has the capacity to accurately simulate the behaviour of all participants in the power sector. RES-E can be simulated with high precision and with the relatively small deviation (<5%) from the ENTSOE dataset. A more accurate input data would reduce the mismatch between the LDC from conventional powerplants and the real-world power dispatch reports. Second, soft linking between the JRC-EU-TIMES and Dispa-SET has been carried out successfully. Results from the ProRES scenario have been used as inputs to the Dispa-SET model, except the power conversion from electrolysis. This analysis has proven that a switch from current to ProRES scenarios is feasible as the amount of dispatchable and quick start units and storage technologies is sufficient to meet all the reserve requirements in the system. Furthermore, even without electrolysers the amount of curtailed RES-E in ProRES 2050 scenario amounts to 594 TWh and can be isolated to only a couple of not well-interconnected countries such as Spain, Italy and Greece. It is important to note that the available capacity of electrolysis is always higher than the curtailment, meaning that the system proposed by the JRC-EU-TIMES is justified. The inclusion of electrolysis technologies and better representation of sector coupling technologies in future systems is needed to check the feasibility of the ProRES scenario more accurately.

[1] https://github.com/energy-modelling-toolkit/Dispa-SET/tree/Dispa-SET_EU

Appendix A

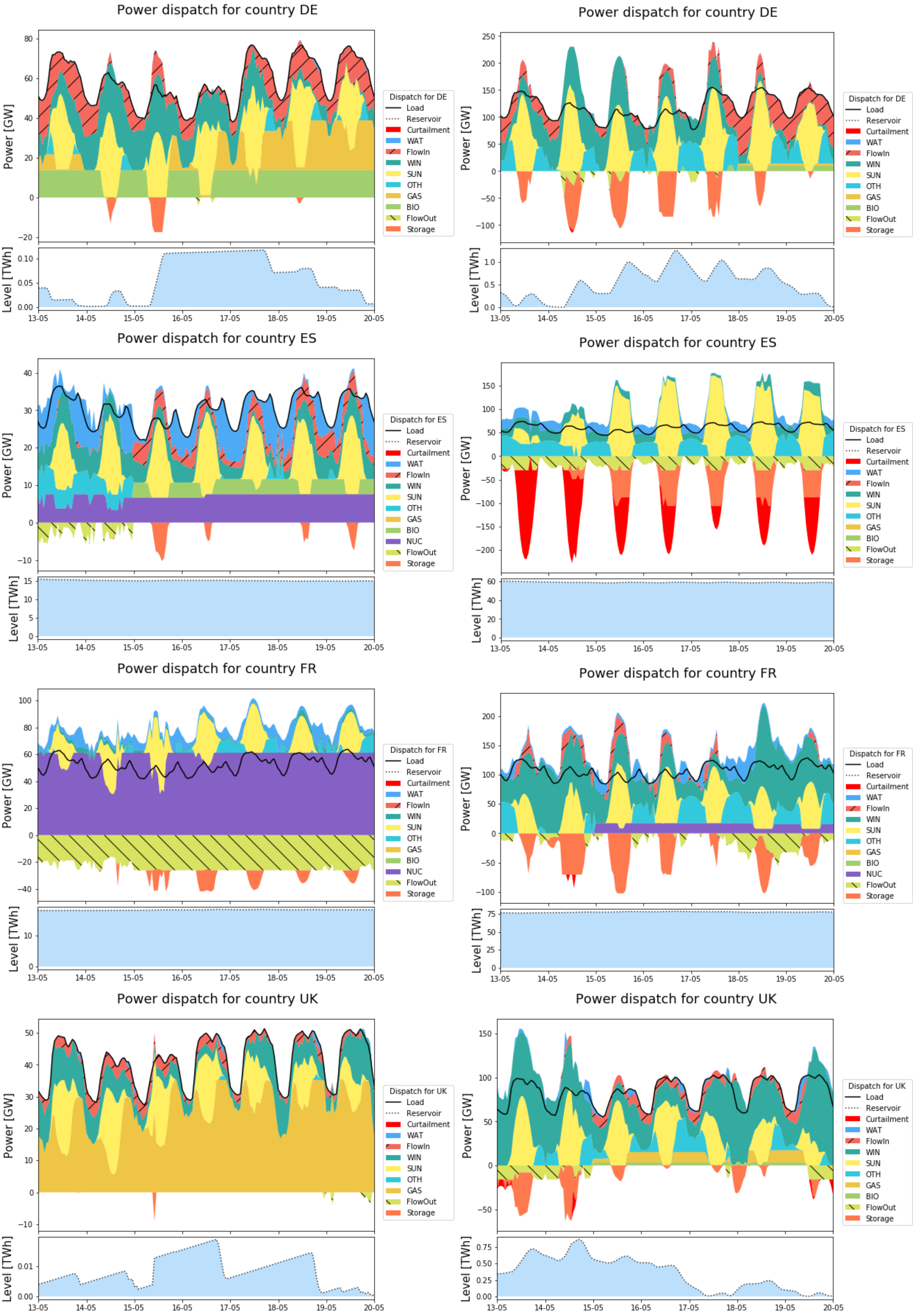


Figure 7 Weekly power dispatch curves and storage levels for four of the largest countries in alternative 2030 (left column) and 2050 (right column) scenarios

Nomenclature

Abbreviations	Description	Unit
AF	Availability factor	[-]
BIO	Biomass and biogas	[-]
GAS	Gas	[-]
GEO	Geothermal	[-]
GHG	Greenhouse gas	[-]
HRD	Hard coal	[-]
LDC	Load duration curve	[-]
LIG	Lignite	[-]
MILP	Mixed integer linear programming	[-]
NGC	Net generation capacity	[-]
NTC	Net transfer capacity	[-]
NUC	Nuclear	[-]
OIL	Oil	[-]
OTH	Other energy carriers including electric vehicles	[-]
PEA	Peat	[-]
PV	Photovoltaics	[-]
RES	Renewable energy sources	[-]
RES-E	Energy from renewable energy sources	[-]
SUN	Solar	[-]
VRES	Variable energy sources	[-]
WAT	Hydro	[-]
WIN	Wind	[-]
WST	Waste	[-]

Sets	Description	Unit
i	Time step in the current optimization horizon	[-]
l	Transmission lines between nodes	[-]
n	Zones	[-]
u	Units	[-]

Parameters	Description	Unit
$CHPPowerLossFactor_{chp}$	Power loss when generating heat	[%]
$CostFixed_{u}$	Fixed costs	[EUR/h]
$CostHeatSlack_{chp,i}$	Cost of supplying heat via other means	[EUR/MWh]
$CostLoadShedding_{i,n}$	Shedding costs	[EUR/MWh]
$CostRampDown_{i,u}$	Ramp-down costs	[EUR/MW]
$CostRampUp_{i,u}$	Ramp-up costs	[EUR/MW]
$CostShutDown_{i,u}$	Shut-down costs for one unit	[EUR/u]
$CostStartUp_{i,u}$	Start-up costs for one unit	[EUR/u]
$CostVariable_{chp,i}$	Variable costs	[EUR/MWh]
$CostVariable_{i,u}$	Variable costs	[EUR/MWh]

$PriceTransmission_{i,l}$	Price of transmission between zones	[EUR/MWh]
$VOLL_{Power}$	Value of lost load due to power output	[EUR/MWh]
$VOLL_{Ramp}$	Value of lost load due to ramping	[EUR/MWh]
$VOLL_{Reserve}$	Value of lost load due to lack of reserve capacities	[EUR/MWh]

Variables	Description	Unit
$Flow_{i,l}$	Flow through lines	[MW]
$HeatSlack_{chp,i}$	Heat satisfied by other sources	[MW]
$Heat_{chp,i}$	Heat output by CHP plant	[MW]
$LL_{2D,i,n}$	Deficit in reserve down	[MW]
$LL_{2U,i,n}$	Deficit in reserve up	[MW]
$LL_{3U,i,n}$	Deficit in reserve up - non spinning	[MW]
$LL_{MaxPower,i,n}$	Deficit in terms of maximum power	[MW]
$LL_{MinPower,i,n}$	Power exceeding the demand	[MW]
$LL_{RampDown,u,i}$	Deficit in terms of ramping down for each plant	[MW]
$LL_{RampUp,u,i}$	Deficit in terms of ramping up for each plant	[MW]
$Power_{i,u}$	Power output	[MW]
$ShedLoad_{i,n}$	Shed load	[MW]
$SystemCost$	Total system cost	[EUR]
$Committed_{i,u}$	Committed status of unit at hour h {1 0} or integer	[-]

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