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The potential of sector coupling in future European energy systems: soft linking between the Dispa-SET and JRC-EU-TIMES models

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ABSTRACT

The relevance of sector coupling is increasing when shifting from the current highly centralised and mainly fossil fuel-based energy system to a more decentralized and renewable energy system. Cross-sectoral linkages are already recognized as a cost-effective decarbonisation strategy that provides significant flexibility to the system. Modelling such cross-sectoral interconnections is thus highly relevant. In this work, these interactions are considered in a long-term perspective by uni-directional soft-linking of two models: JRC-EU-TIMES, a long term planning multisectoral model, and Dispa-SET, a unit commitment and optimal dispatch model covering multiple energy sectors such as power, heating & cooling, transportation etc. The impact of sector coupling in future Europe-wide energy systems with high shares of renewables is evaluated through five scenarios. Results show that the contributions of individual sectors are quite diverse. The transport sector provides the highest flexibility potential in terms of power curtailment, load shedding, congestion in the interconnection lines

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and resulting greenhouse gas emissions reduction. Nevertheless, allowing combinations of multiple flexibility options such as hydro for the long-term, electric vehicles and flexible thermal units for the short-term provides the best solution in terms of system adequacy, greenhouse gas emissions and operational costs.

KEYWORDS

Dispa-SET, Sector Coupling, High RES Europe, Electric vehicles, Thermal storage, Hydropower

1. INTRODUCTION

In recent years, significant effort has been devoted to the research and analysis of integration of high shares of renewable energy sources (RES). Two examples are the ambitious ProRES scenario from the JRC-EU-TIMES modelling of deployment of low carbon energy technologies [1] and PyPSA Europe 30: Scenarios for Europe with 95% renewable electricity [2]. These scenarios have already proven that, compared to 1990, it is possible to reduce CO_2 emissions from the electricity sector by more than 95%. In order to achieve these high RES or low carbon targets certain flexibility criteria must be met. One of the main drivers allowing high RES in electricity systems is the optimal balance between expansion of the pan-continental transmission network, that enables the utilisation and trading of variable renewable energy sources (VRES) [3] and storage solutions [4]. Some studies have gone even one step further by proposing a 100% RES powered Europe-wide electricity system. They demonstrate that such last step is achievable by means of a significantly higher storage deployment [5], an EU-wide market coupling [6], high utilization of bioenergy [7] and/or carbon capture and storage technologies [8]. All these technological options are frequently grouped in the literature under the so-called "Smart Energy Europe" concept [9].

Furthermore, most studies agree that focusing on the electricity sector only is not enough. In fact, a single-sector approach neglects the further significant greenhouse gas emissions reductions and the flexibility potential that can be unlocked by other energy sectors, such as domestic and industrial heating, hydro basins and electrified transportation. According to Jiménez Navarro et al. [10], the coupling of the heating and the electricity sectors is of utmost importance when it comes to the achievement of the decarbonisation and the energy efficiency targets set for 2030 in the EU, and centralised cogeneration plants connected to district heating networks are fundamental elements of this coupling. A study on the water-power nexus [11] has shown that water pricing will be an issue in forthcoming water-constrained power systems, especially when water shortages and/or policy decisions could impact the available maximum capacity of certain water-stressed hydro power plants, leading to system-wide generation cost increases or even shifting the water stress index to other power plants. Another study [12] has proven that using battery electric vehicles (BEVS) for vehicle to grid (V2G) services can positively impact the power system by increasing system flexibility and by significantly reducing the level of curtailment and electricity generation costs in case of high penetrations of VRES. Assessment of flexible electric vehicle charging in a sector coupling energy system model [13] concluded that energy system costs can be reduced by applying V2G technology. Taking all these aspects (electricity, heating, hydro basins and transportation) into account is commonly referred to as "sector integration" and these systems are sometimes referred to as "Smart energy systems"[14]. Other studies, investigating the synergies between different sectors such as: electricity and transportation [15], electricity and heating [16], electricity and gas [17] and electricity and heating, cooling, gas and transportation [1][3], have been also carried out and demonstrate the importance of these cross-sectoral links. For example, Pensini et al. [18] considered the possibility of using excess renewable electricity in the heating sector, but no requirements are set to de-carbonize all heating end uses, or to couple it to other demand sectors. Another study [19]analysed a simplified investment and dispatch scheme for a one-node-per-country model of Europe to study electricity-heat coupling. Clegg and Mancarella [20] demonstrated that the coupling of heat and electricity in Great Britain can ensure up to 75% savings in greenhouse gas emissions. For the case of Germany, Bloess [21] highlighted how the benefits in terms of primary energy savings ensured by heat-electricity integration also entail important increases in the electricity peak demand, with operational repercussions on dispatchable power plants. To this regard, Lombardi et al. [22] showed that the deep electrification of residential cooking heat alone could lead to an increase of the electricity peak demand of about 7.5%. Electric vehicles as a new power source for electric utilities were analysed by Kempron et al. [23], and Schill et al. [24] analysed power system impacts of electric vehicles on a German case study. A similar analysis has been performed for the case of Italy, showing that the flexibility ensured by electric vehicles and battery storage reduces the need for VRES capacity expansion by 24–44% [25]. Technological overview, systems analysis and economic assessment of the power-to-gas technologies were analysed by Robinius et al. [26] while energy system analysis for evaluation of sector coupling technologies was analysed by Boblenz et al. [27]. Nevertheless, all these studies focused on specific sectoral interactions, failing to analyse and compare the individual contributions of each sector-coupling option to the system as a whole.

According to Collins et al. [28], modelling all energy sectors in high spatial and temporal detail is computationally demanding. A common solution is to reduce the temporal resolution or focus on a few representative days, which can lead to significant biases when determining the optimal generation portfolio [29]. In order to avoid generating computationally intractable problems some studies took a different approach, commonly known as model coupling. This approach consists of two slightly different linking procedures: soft-linking and hard-linking between long-term energy system planning (ESOM) and short-term unit-commitment and power dispatch models (UCM). For example, TIMES, a well-known ESOM model, also used in this study, has been coupled with several models. Soft-linking between EMEC and TIMES-Sweden was done in [30], coupling between TIMES and housing stock models in [31], Asian-Pacific Integrated assessment Model and TIMES Integrated assessment Model in [32], a behavioural model for transport and JRC-EU-TIMES in [33], EnergyPlan and JRC-EU-TIMES in [34] and stochastic coupling between JRC-EU-TIMES and Dispa-SET model in [35]. The TIMES-PLEXOS and OSeMOSYS model coupling, for the Irish case [36] demonstrated that long-term energy models may clearly underestimate the importance of flexibility within the power system if short-term operating requirements are not considered. This was shown in several studies where EnergyPLAN was first coupled with GenOpt (a genetic optimization framework also known as EPOPT) [37]; EPLANopt, a hourly temporal resolution and a multi-objective investment optimization method [38] and Oemof-moea [39], a multi-objective investment optimization, both applied to the Italian case study in year 2050. Soft-linking energy demand and optimisation models for local long-term electricity planning has also been tested with success in [40] using the OSeMOSYS model.

The above studies can be referred to as unidirectional soft-linking, i.e. the outputs from one model are used to generated the inputs of another model. According to [28], the main advantage of this methodology is a detailed insight into the operation of the energy system as a whole. The approach allows modellers to assess power system reliability, provision of flexibility and the role that individual technologies play in balancing complex interactions between supply and demand. Furthermore, it also provides accurate estimates of the fuel consumption, total system costs and greenhouse gas emissions of operating the system. As such, this methodology provides a robust check on the results provided by the ESOM model. It should however be noted that the interaction between the UCM and ESOM model is limited to a single direction (usually ESOM to UCM). This linking does not impact the investment decisions of the ESOM model and thus does not guarantee a globally optimal solution.

The aim of this work is twofold. The first goal is to develop a cross-sectoral UCM model formulation including detailed representation of the hydro, heating & cooling and electromobility sectors. The second goal is to investigate the individual contributions to the system flexibility of these different cross-sectoral interactions on the future European system, as projected by the JRC-EU-TIMES ProRES scenario for the year 2050.

This paper improves the state-of-the-art with the following four novelties:

- It provides a detailed analysis of different sector-coupling options and of their individual as well as combined contributions to the flexibility of the system as a whole;
- It proves that greenhouse gas emission reduction and integration of higher shares of VRES that would otherwise have to be curtailed is not possible without sector coupling;
- It demonstrates that the flexibility provided by individual sector-coupling options is cumulative;
- It provides an open-source uni-directional soft linking framework between the JRC-EU-TIMES and the Dispa-SET model, representing first validation of results from the JRC-EU-TIMES ProRES scenario [1] performed with a highly-detailed large-scale multi-sector unit commitment and power dispatch model.

This paper is structured as follows: Section 2 discusses the methods adopted for the modelling of the European energy system within Dispa-SET, including model formulation and metrics of system performance; Section 3 discusses the considered flexibility scenarios; Section 4 presents the inputs (time series, costs, capacities) adopted for the present study; Section 5 reports the modelling results and discusses them; Section 6 provides concluding remarks.

2. METHODS

This section covers the different tools, methods and techniques used within this paper. The main focus is on the techniques used in the pre-processing, simulation and outputs of the proposed modelling framework.

2.1. Soft-linking methodology

All possible links and data flows within the proposed modelling framework are shown in Figure 1. They consist of five main elements: Sources, Inputs, Pre-processing, Simulation and Outputs. In addition to the usual measured or simulated input data (e.g. in the form of hourly timeseries), the outputs from the JRC-EU-TIMES are taken as inputs to the Dispa-SET model. These inputs include descriptions and characteristics of commodities, zones, generation capacities, prices and available technologies. They also provide yearly energy flows, from which timeseries are generated e.g. for unit availabilities, energy flow limits and demand profiles. A key feature of the modelling framework is related to the pre-processing (e.a. uni-directional soft-linking) of the input files. It consists of two models: the first is a transition model between the JRC-EU-TIMES outputs formatted into Dispa-SET readable format (included in the Dispa-SET SideTools toolbox[2]); while the second is the Dispa-SET mid-term scheduling (MTS) module

[2] DispaSET-SideTools: https://github.com/MPavicevic/DispaSET-SideTools/tree/master

used for pre-allocation of large storage units, such as hydro dams (HDAM) and pumped hydro reservoirs (HPHS). Reservoir levels computed by this module are then used as guidance curves, i.e. minimum-level constraints in the main Dispa-SET UCM model. Results from the Dispa-SET UCM model are the main outputs from where the main conclusions of this study are drawn.

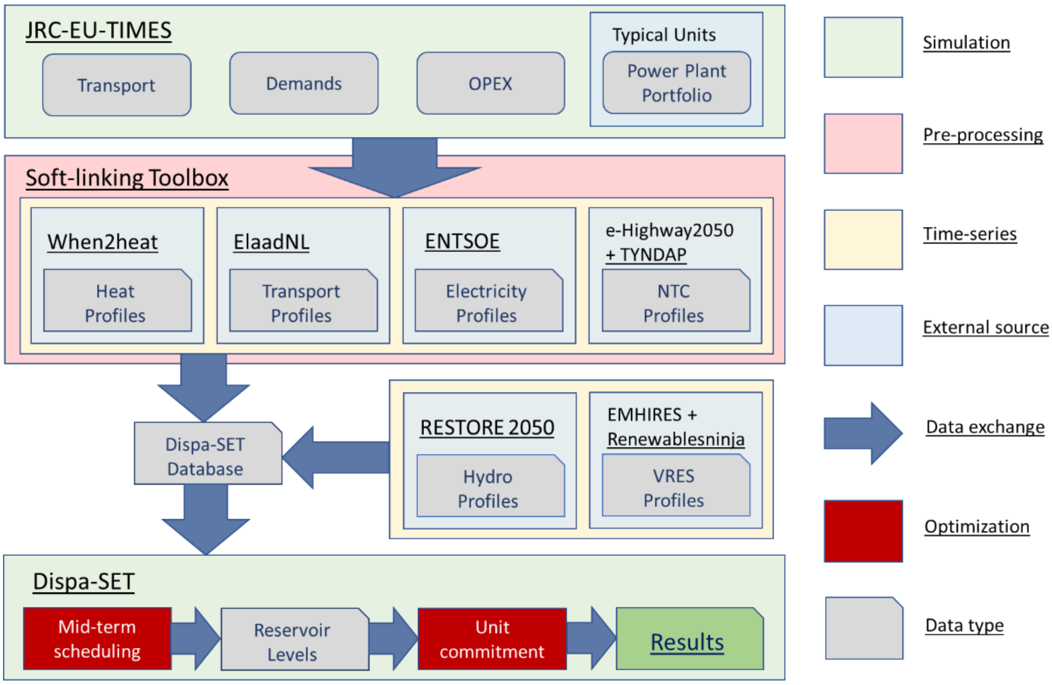


Figure 1. Relational block-diagram between models and various data sources used with this study. JRC-EU-TIMES outputs (top) are complemented with different hourly timeseries and profiles through soft-linking toolbox (middle) and then solved with a two stage Dispa-SET model (bottom)..

The uni-directional soft-linking between the JRC-EU-TIMES model and the Dispa-SET model is done through several intersecting variables:

- Total annual demands per country: power, heating and transport.
- Total installed capacities per country: RES, Conventional, CHP, hydro, P2HT and CSP units.
- Commodity prices (OPEX): fuels and carbon emissions.

The variables are used within a "Translation model" (soft-linking toolbox[2]) to generate realistic Dispa-SET inputs, such as scaled time series for all types of demands, or realistic power plant fleet according to the projected capacities.

Other parameters such as renewable availability factors (AF) (a non-dimensional timeseries), outside temperatures and river inflows are assumed unchanged from their historical values from 2016. Re-forecasting of AF due to technological advancements, climate change, wake effects etc. are out of the scope of this paper.

2.2. Dispa-SET

Dispa-SET is a multi-sectoral energy modelling tool designed to assess the flexibility needs in smart energy systems with high shares of VRES. The core of the model is formulated as a mixed-integer linear programming problem. All the formulations are based on publicly available modelling approaches, such as computationally efficient Mixed integer linear programming (MILP) formulations for UCM problems [41], and tight and compact MILP formulation for the thermal UCM problem [42]. As mentioned before, simplified hydro-thermal allocation, also called MTS, is a linear programming approximation (i.e. integer variables are relaxed) of the above-mentioned modelling approaches, used to pre-allocate reservoir levels of large storage units. The main purpose of using the Dispa-SET model is the possibility of analysing large interconnected power systems with a high level of detail. Example of all available fuel types and technologies within one zone is presented in Figure 2 Figure 2.

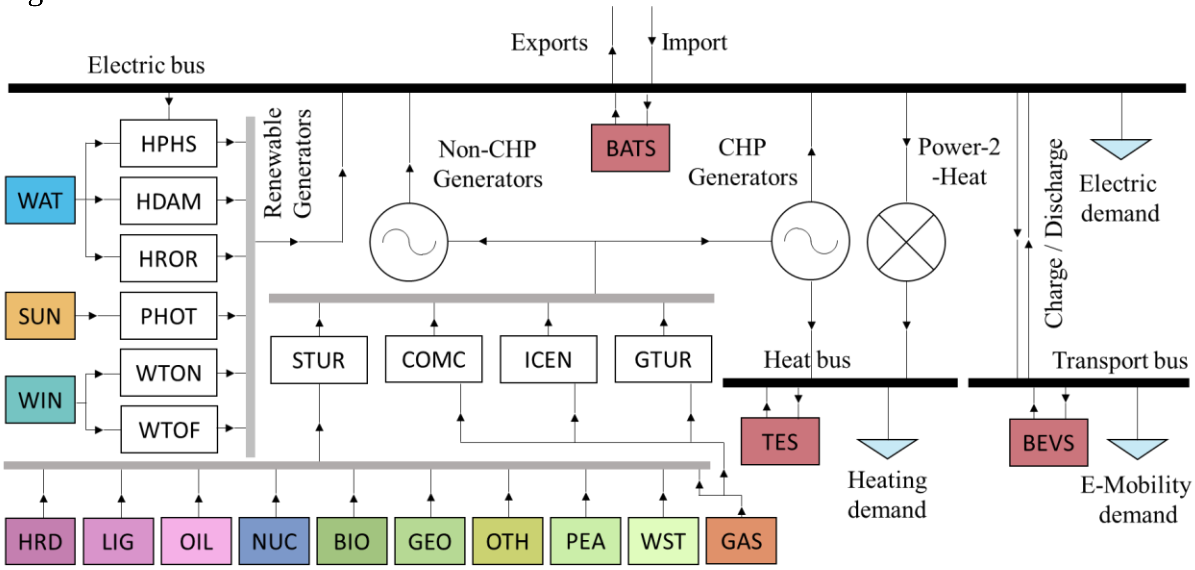


Figure 2. System structure for a single node. Each node represents a whole country. Each object represents fuels, storage and generation technologies (boxes), buses (tick black lines) or demands (triangles). Fuels are coloured according to the Dispa-SET colour scheme.

A detailed formulation of the Dispa-SET model is out of the scope of this paper. All relevant equations and constraints can be found in [43]. The main constraints of the model are:

- Technical limits on minimum and maximum power generation for individual units,
- Ramping limits, start-up and shut down times and minimum on and off times,
- Shed load as the main measure of the adequacy of the system,
- Up and down reserve requirements (Primary, secondary and tertiary),
- VRES Curtailment,
- Multiple storage technologies (hydro, chemical, thermal…)
- Non-dispatchable units (e.g. wind turbines, solar photovoltaics (PHOT), hydro run-of-river (HROR), etc.)
- Detailed representation of fixed and variable costs
- Multiple nodes with constrained interconnection capacities (congestion management)
- Renewables targets and/or emission constraints
- Flexible extraction and inflexible back-pressure combined heat and power (CHP) units
- Satisfaction of heating demands through power to heat (P2HT), CHP or backup heaters.
- Satisfaction of electric vehicle (EV) driving cycle requirements in limits of the battery capacities. Yearly schedules for forced and planned outages for individual units.

In the following chapters, the equations relevant for this study are presented and discussed in more detail.

2.2.1. Objective function

The goal of the unit commitment problem is to minimize the total power, heating and transportation system operational costs (expressed in EUR in equation 1). The demands are assumed to be inelastic to the price signal. The MILP objective function is, therefore, the total generation cost over the optimization period and can be summarized in the following equation:

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

Here $TotalSystemCost$, in EUR, are defined as the sum of different cost items such as: start-up and shut-down, fixed, variable, ramping, transmission-related and load shedding (voluntary and involuntary) costs.

2.2.2. Demand balance

The main constraint to be met is the power supply-demand balance, for each period and each zone, in the day-ahead market as proposed in the following equation:

$$\begin{aligned} \sum_{u} \left(\mathrm{Power}_{u,i} \cdot Location_{u,n} \right) + \sum_{l} \left(\mathrm{Flow}_{l,i} \cdot LineNode_{l,n} \right) &= Demand_{DA,n,h} \\ &+ \sum_{r} \left(\mathrm{PowerConsumption}_{p2h,h} \cdot Location_{p2h,n} \right) + \\ &+ \sum_{r} \left(\mathrm{StorageInput}_{s,h} \cdot Location_{s,n} \right) - ShedLoad_{n,i} - LL_{MaxPower\,n,i} \\ &+ LL_{MinPower\,n,i} \end{aligned} \quad (2)$$

According to this restriction, the sum of the power generated by all the units present in the node (including the power generated by the storage units), the power injected from neighbouring nodes, and the curtailed power from intermittent sources is equal to the day ahead load in that node, plus the power consumed for heat generation through P2HT units and power consumed for energy storage, minus the shed load.

2.3. Mid-term scheduling

Since simulations in Dispa-SET UCM are 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 at once. Therefore, the problem is split into smaller optimization problems that are run recursively throughout the year. The initial values of the optimization for any given day are the final values of the optimization of the previous day. A look-ahead period is included and then discarded to avoid issues linked to the end of the optimization period such as emptying the storage units or starting low cost but non-flexible power plants. Because of this relatively short optimization horizon, a pre-optimization must be run with a horizon of one year to optimize the minimum state of charge of long-term storage units. This pre-optimization is referred to as MTS.

This is particularly relevant in systems with high shares of HDAM and HPHS units (e.a. Norway and Switzerland). MTS is achieved by relaxing the integer variables and removing the following constraints, thus transforming the MILP problem into a linear programming formulation:

- Parameters and variables linked to the thermal sector such as heating demands, CHP units and thermal storage;
- Parameters and variables linked to power plant cycling such as start-up and shut-down time, ramping rates, minimum up and down time, must run power and unit commitment
- And costs associated to the above-mentioned constraints.

2.4. Data sources and preprocessing

2.4.1. Power plant fleet

Due to vast amount of generation units in the EU system, some clustering techniques are applied to ensure computational tractability. The clustering techniques used within this study have been discussed in more detail in a previous publication [44], where an optimal level of clustering was determined as a trade-off between accuracy and computation time. This clustering is referred to as “Per-typical technology” clustering and consists of grouping similar individual units into clusters of N units which share the same characteristics. This method allows efficient model reduction with scaling factor between 10-30 (from several tens of thousands of units down to few hundreds).

2.4.2. Heat demand

Extensive analysis and mathematical formulation of CHP and thermal energy storage (TES) units from the Dispa-SET model has already been covered by Jiménez Navarro et al. [10] previously and is thus out of the scope of this paper. For the purpose of this work, a new unit type (P2HT) is added, referring to distributed technologies converting electricity into domestic hot water and/or space heating – in this study, air-source heat pumps (HPs) and electric heaters (EHs). Such P2HT units are assumed to be subject to *direct load control* (DLC) [45], i.e. they can be managed by an aggregator as a virtual power plant and operated flexibly in order to minimise system costs. The main constraint characterising P2HT units is an energy balance formulated as follows:

$$StorageInput_{p2h,i} = PowerConsumption_{p2h,i} \cdot COP_{p2h,i} \tag{3}$$

The main hypothesis is that all heat suppliers are connected to a TES unit thus providing flexibility to the system. The heat generated by CHP and P2HT units is first being imported into the TES and then released to meet the demand. The maximum power consumption of these

P2HT units is also subject to maximum installed electrical power and total number of units available at any given time which translates into the following relation:

$$PowerConsumption_{p2h,i} = PowerCapacity_{p2h} \cdot Nunits_{p2h} \tag{4}$$

In this study, HPs and EHs are treated as a single P2HT technology group. Considering their different energy conversion efficiencies, a nominal efficiency (COP_{nom}) is computed for the group, on a per-country basis, as a weighted average of the nominal efficiencies of HPs and EHs (as given by JRC-EU-TIMES [46]) and of the country-specific shares of penetration of those. Hence, the dependency of the COP on hourly-variable ambient temperature is modelled by Equation 5, consisting in a parametrisation around COP_{nom} and the nominal ambient temperature (T_{nom}) for which COP_{nom} is calculated, namely 5°C. The coefficients C_1 and C_2 are computed, for each country, by ensuring that the COP_{nom} equals 1 for the hourly ambient temperature ($T_{amb,t}$) reaching -10°C (the value under which HPs would normally not operate and be substituted by auxiliary heaters with unitary efficiency), and that concavity of the curve is positive [47].

$$COP_{p2h,i}(T_{amb,i}) = COP_{nom} + C_1(T_{amb,i} - T_{nom}) + C_2(T_{amb,i} - T_{nom})^2 \tag{5}$$

In this work the useful heat demand for space heating is assumed to be 40% lower compared to 2010, the base year of JRC-EU-TIMES. This translates into an annual demand for useful space heat of around 1 500 TWh in 2050, compared to 2 500 TWh in 2010.

2.4.3. Power demand for transport

Modelling techniques and hypothesis used for computing total available storage capacity at any given time throughout the year can be summarized as follows:

- Limited battery availability: The total available storage capacity cannot be computed as the sum of all individually connected BEVS capacities. Minimum state of charge must be taken into account since battery charge should always ensure that customers have sufficient energy for the upcoming trips.
- Perfect foresight: BEVS users are fully aware of the time, duration and battery displacement of all future trips. They also deploy "just-in-time charging", where the minimum state of charge constraint is defined just before the time of departure. This value is the minimum required energy for the upcoming trip.

These constraints are summarized in Figure 3. The minimum level of charge is defined for each vehicle, by the energy consumed in the subsequent time interval (assumed to be equal to the energy spent during the trip plus the losses), and by the charging time to satisfy the constraint. Because of the perfect foresight hypothesis, the computed battery capacity using the methodology is too optimistic and a security margin is therefore defined as follows:

$$E_{s,i} = (E_{max_s} - SOC_{min_i}) \cdot (1 - \xi) \tag{6}$$

where $E_{s,i}$ stands for battery capacity available to the system, in MWh; E_{max_s} is the total battery capacity, SOC_{min_i} is the minimum state of charge and ξ is the security margin. Aggregate capacity is computed as the sum of the individual available capacities.

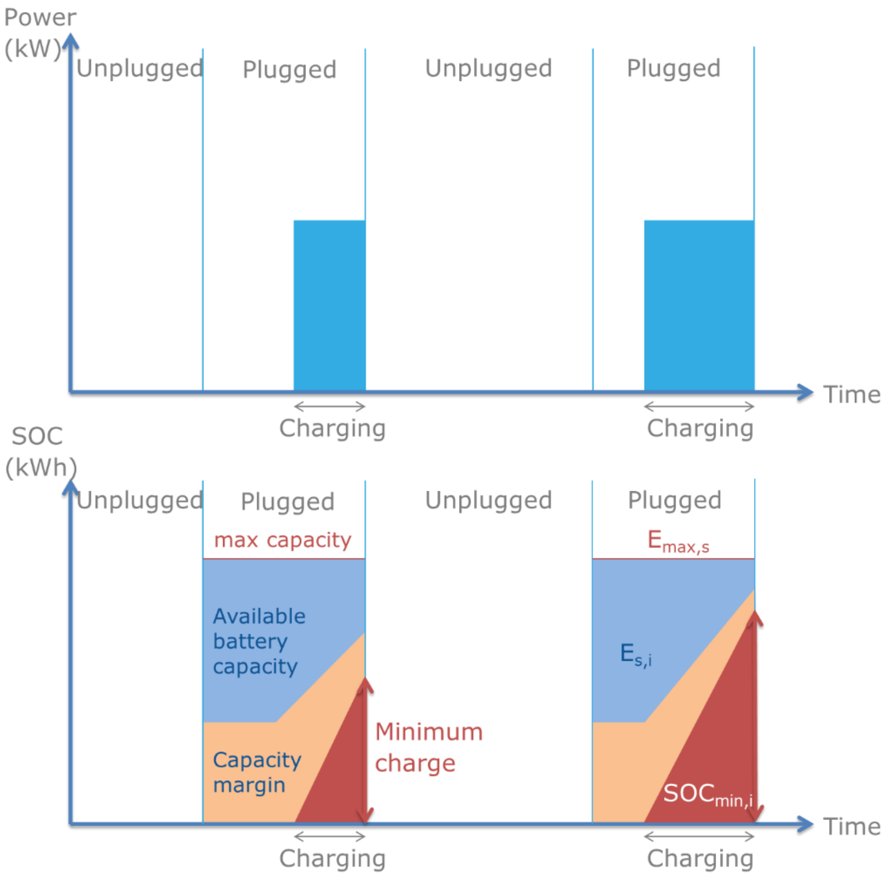


Figure 3. Optimal charging strategy, and computation of the battery capacity of a single BEVS unit made available for the system. Battery capacity available for V2G is constrained by the minimum state of charge and corresponding capacity margin.

2.4.4. Power demand

The proposed modelling framework links two models with different time scales and resolutions. The power demand in JRC-EU-TIMES is projected based on equations that divide each of its 12 timeslices in two sub-periods [48]. However, for this analysis, only the aggregated annual power demand for each country was used. In contrast, the Dispa-SET power demand needs to be in the form of hourly power curves. These hourly power curves are computed based on multiple sources, a detailed representation of the steps performed to compute the final power curve are shown in Figure 5. Power curves from ENTSO-E are reduced by the electrical heating needs, then multiplied by the JRC-EU-TIMES demand projection multiplier and increased by the power demand for transport purposes in a following way:

$$P_{n,i} = P_{n,i,2016}^{ENTSOE} \cdot \left(\frac{P_{n,2050}^{TIMES} - P_{ev,n,2050}^{TIMES} - \dfrac{Q_{p2h,n,i,2050}^{TIMES} - Q_{p2h,n,i,2016}^{TIMES}}{COP_{p2h,i,2016}}}{P_{n,2050}^{TIMES}} \right) + P_{ev,n,i,2050}^{TIMES} \qquad (7)$$

2.5. Metrics of energy system performance

2.5.1. Costs

Total costs of running the system are the values obtained by the optimization objective function and include all fixed and variable operation costs. When comparing several scenarios, the percentage difference is computed as follows:

$$\Delta TotalSystemCost = \frac{TotalSystemCost_{alternative} - TotalSystemCost_{base}}{TotalSystemCost_{base}} \tag{8}$$

Marginal prices are computed as the dual values of the energy balance equations.

2.5.2. Generated energy per technology

Energy mixes for both electricity and heating are based on total annual generation aggregated by fuel and technology type and divided by the total energy production of the sector. For electricity:

$$\mathrm{EnergyMix}_{Electricity} = \frac{\sum_{t,i} \mathrm{Power}_{u,i} \cdot Technology_u}{\sum_i \begin{pmatrix} Demand_{DA,n,h} + \mathrm{PowerConsumption}_{p2h,h} + \mathrm{StorageInput}_{s,h} \\ -ShedLoad_{n,i} - LL_{MaxPower\,n,i} + LL_{MinPower\,n,i} \end{pmatrix}} \tag{9}$$

and for heating:

$$\mathrm{EnergyMix}_{Heat} = \frac{\sum_{t,i} \mathrm{Heat}_{u,i} \cdot Technology_u}{\sum_i \left(HeatDemand_{u,i} - HeatSlack_{u,i} \right)} \tag{10}$$

Differences between computed results and the baseline are given as a mean absolute difference and are formulated as follows:

$$\Delta EnergyMix = \left| EnergyMix_{alternative} - EnergyMix_{base} \right| \tag{11}$$

2.5.3. Storage utilisation

The shifted load essentially moves electricity consumption from one time period to another. It occurs if the returns generated through energy cost savings or participation in reserves are greater than the cost of the related energy losses. It is important to note that load shifting does not result in a reduction in net quantity of energy consumed. In this work, shifted load is computed as the sum of energy inflows into the storage units. It is disaggregated by technology and fuel type.

2.5.4. RES Curtailment

In the context of this work, RES curtailment refers to the reduction of renewable generation due to grid constraints. The total curtailed energy and the maximum hourly curtailed energy are computed within this study to assess the adequacy of the proposed system. Too much curtailed power is an indication of poorly optimized system with excess generation capacity and lack of flexibility. It is worthwhile to note that curtailment in the Dispa-SET model does not necessarily reflect a waste of energy in JRC-EU-TIMES. This can be explained by the multi-sectoral formulation in the latter model, which partly allows using this excess for other purposes. The metrics however remains pertinent to assess the flexibility of the power system only.

2.5.5. Shed load and Lost load

The amount of shed load highlights adequacy of the system. It is defined as the demand of the system that must be reduced to match the available generation supply. The process of load shedding is used to prevent an imbalance and subsequent blackout of the system. A maximum value to load shedding is defined as follows:

$$ShedLoad_{n,i} \leq LoadShedding_n \tag{12}$$

which might correspond to the load-shedding plans of the Transmission System Operator (TSO) or to the contracted sheddable load in large industries. In case load shedding does not allow to match generation and demand, an additional Lost Load (LL) relaxing variable is added to the market clearing equation. LL is given a very high price and ensures that no infeasibility occurs in the optimization problem. It should however never be activated (optimizations with LL > 0 are discarded). The total count of time intervals with non-null LL is recorded and compared between the different scenarios.

2.5.6. Shadow price

Shadow prices, expressed as EUR/MWh, are computed for each time step *i*, and for each zone *n*. The shadow price of electricity is the dual value of the energy balance equation. Similarly, the shadow price of heat is the dual value of heat balance equation.

2.5.7. Congestion

Congestion in the interconnection lines is computed as the number of congestion hours in each line and in each direction. For the sake of comparison, the normalized difference in number of hours is computed with respect to the baseline scenario.

2.5.8. Carbon emissions

In this study, carbon footprint is computed with standard emission factors of different fuel-types. It relates to emissions from power generation and operation of thermal units (non-CHP and CHP) only (life cycle emissions are not considered) and is disaggregated per country.

2.5.9. Start-ups

Start-up events are only computed when committed status at time period *i* is greater than committed status at time period *i*-1.

3. SCENARIOS

In order to evaluate the potential system flexibility in each cross-sectoral links (power-hydro, power-heat, power-transportation), extreme scenarios are defined: one scenario with zero flexibility and various scenarios in which the full flexibility of each sector is exploited. The simulation results should therefore be seen as an upper boundary of the amount of flexibility available in each considered sector. In addition, specific attention is paid to the capacity of the system to accommodate high shares of VRES generation from wind and sun. In total there are five scenarios: NOFLEX, THFLEX, HYFLEX, EVHLEX and ALLFLEX. Each one focusing on one or more sectors at a time. A summary of scenario definitions is presented in Table 1. A more detailed scenario description is presented in Table 9, provided as supplementary material in Annex A of this paper.

Table 1 Scenario definitions and technology hypothesis. Demands

Scenario definition												
	Demand			Supply technologies								
Scenarios	Electricity	Heating	Transport	Hydro Storage (HPHS + HDAM)	CHP (Back-pressure)	CHP (Extraction)	P2HT	TES (DH & Residential)	BEVS (V2G)	CSP	CSP + Overnight TES	VRES
NOFLEX	•	•	•		•					•		•
HYFLEX	•	•	•	•	•					•		•
EVFLEX	•	•	•		•				•	•		•
THFLEX	•	•	•		•	•	•	•			•	•
ALLFLEX	•	•	•	•	•	•	•	•	•		•	•

3.1. NOFLEX

The NOFLEX scenario is the starting point of this analysis and serves as a benchmark for the other scenarios. No flexibility options are included:

- The district heating (DH) demand is covered by back-pressure CHP units (i.e. with a fixed power-to-heat ratio) and no thermal storage is installed.
- Thermal demand for P2HT technologies is fixed, but no thermal storage is installed.
- EVs do not have any smart charging or V2G features.
- Concentrated solar power (CSP) without thermal storage.
- All hydro power plants are run as HROR, thus neglecting the storage capacities in their reservoirs. It should be noted that this hypothesis is more pessimistic than the current energy system, in which the flexibility brought e.g. by hydro dams is already exploited but is assumed in order to be able to quantify the value of the flexibility that the hydro storage can provide.

Such system configuration is relatively inflexible and does not possess any load shifting possibilities. Load shifting options, provided in form of hydro, electric vehicle (EV) and thermal storage are investigated in more detail in other scenarios.

3.2. THFLEX

The THFLEX scenario introduces flexible heating demand to the system. The flexibility in this scenario is provided by three technologies:

- Extraction CHP units (vs back-pressure units in the NOFLEX scenario) coupled with the 12 hour thermal storage unit as proposed in [49].
- P2HT units coupled with 5 hours thermal storage (500 – 600 litres water tank for a single-family house).
- CSP with overnight storage (12 h of storage).

Several impacts of heating on the power sector occur:

- An endogenously-modified load curve due to the electrification of the heating & cooling sector (DLC of heat pump, generation of CHP units).

- Increased flexibility related to the flexible operation of extraction CHP units and to the possibility to include thermal storage, which is several orders of magnitude more cost-effective than electrical storage [50].
- Flexibility of P2HT units is also increased due to heat load shifting possibility with TES.
- Introduction of CSP units increases the flexibility of solar generation by introduction of overnight molten salt storage, which is connected to a heat engine, in this case a steam turbine (STUR) unit, allowing power generation also during the night and time periods with limited sun availability.

3.3. HYFLEX

The HYFLEX scenario investigates the impact of constrained hydro reservoirs on the flexibility of the system as a whole. These units are modelled either as HDAM, HPHS or combination of both units. Total available reservoir capacities and maximum allowed water stress limits [11] are discussed in more detail in previous publications [51,52]. The share of HROR, HDAM and HPHS capacities in the HYFLEX scenario is based on the JRC-EU-TIMES ProRES scenario. In order to investigate the total flexibility that can be provided by hydro units, the following characteristics have to be considered:

- Load shifting capability is high but not unlimited, mainly because of the losses that occur due to water evaporation when reservoirs are used as seasonal storage, and upstream pumping in HPHS units.
- Reservoirs cannot be entirely emptied at any given time without having huge impact on agriculture or downstream flooding.

3.4. EVFLEX

The EVFLEX scenario investigates the impact of EV, more specifically the portion of the EV fleet that can be used as V2G, on the flexibility of the system. In V2G technology batteries inside the EV's are used for load shifting. Although such storage is limited to only a couple of hours, due to large numbers of vehicles it becomes quite significant. The expected impact of the transportation sector on the power sector can be characterized by two components:

- Increase of the base load due to charging of the whole transport fleet.
- Increased storage and load shifting capacity that is directly proportional to the share of the connected V2G vehicles which are at a given time period available to provide additional flexibility to the power sector, without impacting or sacrificing driving patterns of the V2G owners.

3.5. ALLFLEX

Finally, in the ALFLEX scenario all flexibility and sector coupling options from previous scenarios are available. In addition, technologies that provide certain flexibility are also considered (i.e. concentrated solar power units with overnight storage). This scenario incorporates and explores the full idea of smart energy systems where multiple sectors are coupled together.

4. INPUTS

The main model inputs are in form of hourly times series. This include total electricity, heating, transport demands and minimum hydro-levels, VRES availability, power plant outages, net transfer capacities (NTC) and generation curves. Since this model focuses on the available technical flexibility and not on accurate market modelling, it is run deterministically using the measured historical data, and exogenous reserve requirements are defined.

Power plant 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 units such as the gas turbines (GTUR), combined cycle units (COMC) and internal combustion engine units (ICEN) with low capacity and/or high flexibility and 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. For the sake of conciseness, all inputs and parameters are not described in this paper. The interested reader can however refer to the source code and input data (both released with open licences) [53] for a comprehensive description.

4.1. JRC-EU-TIMES scenario

The goal of this work is to assess the sector coupling potential in a future energy system characterized by high penetration of variable renewable energy since it corresponds to high flexibility requirements. To that aim, a long-term planning model (JRC-EU-TIMES) is first run until 2050 with a specific target for CO_2 emissions. The simulated 2050 energy system is then used as input for the high time-resolution Dispa-SET model. The selected long-term objectives include an energy-related CO_2 emission reduction of 80% by 2050, compared to the 1990 levels together with relatively optimistic hypotheses regarding the deployment of renewables. More details regarding the inputs and constraints of the simulated ProRES scenario are available in [54].

In the simulated energy system [1] for the year 2050, electricity is almost exclusively produced by renewables and covers about 50% of the final energy demand in the EU. EU shifts towards decarbonisation by significantly reducing fossil fuel use, while also experiencing a rapid phase out of nuclear power in accordance with existing plans. Carbon capture and storage does not play a significant role because underground storage of CO_2 is not available by scenario design. Deep emissions reductions are achieved with high deployment of RES, electrification of transport and heat and high efficiency gains. Primary energy consumption is about 430 EJ, renewables supply 93% of electricity demand and CO_2 emissions are about 4.5 Gt_{CO_2} in 2050.

4.2. Countries

This study covers 28 European Network of Transmission System Operators for Electricity (ENTSO-E) synchronous zones, the EU-27 minus Cyprus and Malta plus UK, Norway and Switzerland. The Dispa-SET EU model was previously validated with historical data from the year 2016 [52]. In the present study, however, a scenario for 2050 is selected to assess potential impact of sector coupling options in energy system with extremely high shares of VRES. Commodity prices and technical parameters such as power plant capacities and total annual generation from all fuel types and technologies within this scenario analysis correspond to the ones from the ProRES scenario computed by the JRC-EU-TIMES model [52].

4.3. Fuel prices

A summary of commodity prices is presented in Table 2. All fuel prices and carbon emission allowances are obtained from the output of the JRC-EU-TIMES model in 2050.

Table 2 List of commodity prices as in the JRC-EU-TIMES model and the assumed CO_2 price. As no differentiation is available for the price of lignite, its price is assumed to be 25% lower than coal, matching the 2019 price ratio.

Commodity	Unit	Value
Nuclear	EUR/MWh	4
Lignite	EUR/MWh	15
Black coal	EUR/MWh	20
Gas	EUR/MWh	60
Fuel-Oil	EUR/MWh	78
Biomass	EUR/MWh	30
RES	EUR/MWh	-
CO_2	EUR/t_CO_2	100

4.4. Sectors

Four sectors are considered in this study. In the transport sector, only road and train are taken into account; marine and air sectors are not considered due to the lack of direct link with the power sector. The heating sector covers only heating demands for space heating, domestic hot water and industrial heat connected to the CHP and P2HT units. The electricity sector is the main intersection point between all others. Electricity demand curves are directly impacted by the EV charging patterns and heating needs covered by P2HT units, while reservoir levels directly impact the electricity prices. Breakdown of heating and mobility demand curves is presented in Figure 4. A more detailed explanation of each one is discussed in the upcoming chapters.

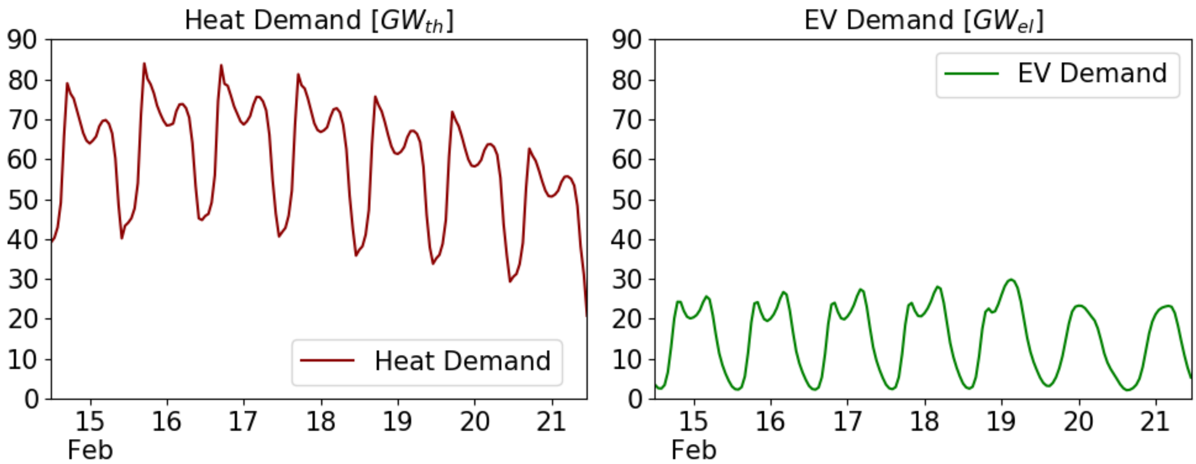


Figure 4. Aggregated EU-wide demand breakdown of heating and transport sectors for one week in February

4.4.1. Electricity

Hourly demand profiles are constructed based on the ENTSO-E dataset for the year 2016 and scaled up to align the total annual demands in both Dispa-SET and JRC-EU-TIMES. In order to avoid double counting of P2HT technologies, the proportion of the P2HT demand from 2016 has been subtracted from the power curves. Additionally, charging demand for electric vehicles has been added on top of the newly computed power curve. Electricity demand hypotheses are presented in equation (7), for consistency the same nomenclature has been used in Figure 5. Maximum hourly demand in the analysed region amounts to 1 521 334 MW. The total spinning reserve requirements in this study sum up to 14 215 MW for upward, and 7 107 MW for downward reserve.

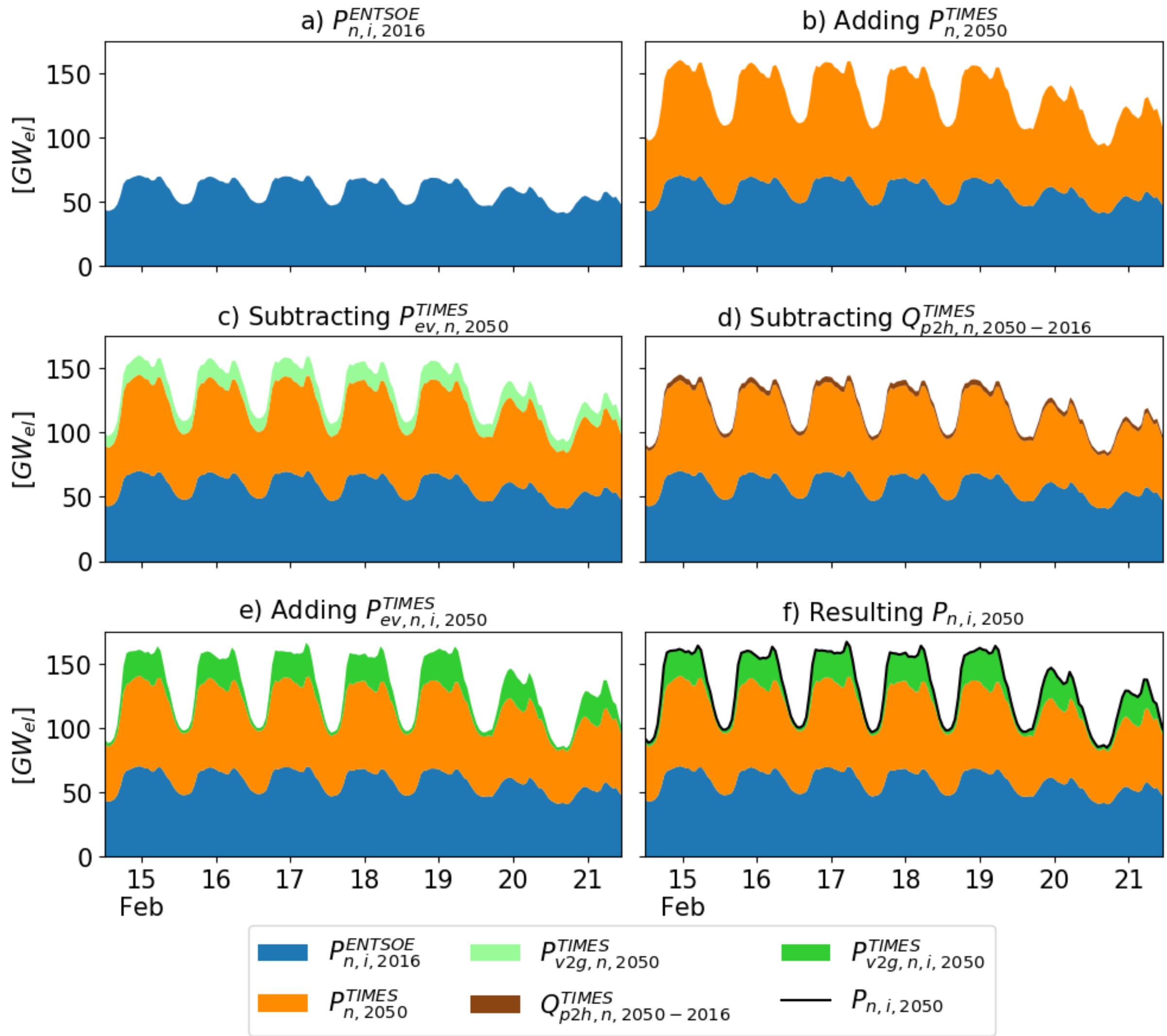


Figure 5 Electricity demand modelling steps for one week in February. Resulting hourly demand curve is composed of ENTSO-E 2016 dataset increased to match annual demand from JRC-EU-TIMES model, adjusted electric vehicle charging demand and decreased by the P2H demand in 2016.

In case there is not enough generation capacity available to meet all of the demands within one zone, load shedding (i.e. a reduction of the load also known as interruptible load) occurs. The cost of shed load is set to 400 EUR/MWh and its maximal value is set to 25% of the demand. Hourly wind [17] and PHOT [18] time series are obtained from the "*Renewables.ninja*" and EMHIRES datasets, while hydro inflows are obtained from the RESTORE 2050 project [54] for the year 2016. The main technical and cost parameters for typical thermal units used in this work are presented in Table 3.

Table 3 Technical and costs parameters for typical power generation units

Fuel	Technology	Power	Efficiency	Min Up Time	Min Down Time	Ramp Rate	Start Up Cost	No Load Cost	Ramping Cost	Part Load Min	Start Up Time	CO_2 Intensity
BIO	**STUR**	180	0.40	4	6	0.020	120	12.5	1.30	0.4	1	0.42
BIO	**GTUR**	64	0.33	1	1	0.167	25	2.9	0.25	0.2	0.167	0.32
BIO	**COMC**	420	0.51	3	3	0.070	55	2.9	0.25	0.06	1	0.22
BIO	**ICEN**	25	0.36	1	1	0.040	24	0	0.63	0.25	1	0.27
GAS	**COMC**	420	0.51	3	3	0.070	55	2.9	0.25	0.06	1	0.36
GAS	**GTUR**	64	0.33	1	1	0.167	25	2.9	0.25	0.2	0.167	0.68
GAS	**STUR**	120	0.37	1	1	0.020	25	2.9	0.25	0.4	0.167	0.53
GAS	**ICEN**	10	0.36	0	0	1	0	0	0	0.3	0	0.01
GEO	**STUR**	40	0.10	2	2	0.020	0	0	0	0	0	0
HRD	**STUR**	764	0.42	6	6	0.040	65	12.5	1.80	0.18	2	0.47
LIG	**STUR**	604	0.40	8	8	0.008	65	8	2.20	0.43	7	1.15
NUC	**STUR**	1008	0.34	24	48	0.050	300	12.5	2.20	0.25	12	0
OIL	**STUR**	386	0.33	5	5	0.020	120	0	1.80	0.4	1	0.73
OIL	**GTUR**	70	0.33	0	0	0.167	0	0	0	0.2	0.167	1.08
OTH	**BEVS**	-	0.95	0	0	1	0	0	0	0	0	0
OTH	**STUR**	70	0.33	0	0	0.167	0	0	0	0.2	0.167	0.80
OTH	**P2HT**	100	1	0	0	1	0	0	0	0	0	0
SUN	**STUR**	150	0.25	0	0	0.020	0	0	0	0	1	0
WAT	**HROR**	*	1	0	0	0.076	0	0	0	0	0	0
WAT	**HDAM**	*	0.80	0	0	0.067	0	0	0	0	0	0
WAT	**HPHS**	*	0.80	0	0	0.067	0	0	0	0	0	0

4.4.2. Transport

The aggregated connected battery capacities and charging time series are computed in a bottom-up approach based on historical data provided in [12]. It consists of two different datasets for EVs charging transactions, recorded from January 2012 until May 2016. The dataset consists of more than one million records from 1747 charging stations managed by EVnetNL in the Netherlands. A similar approach was also proposed in [24], where the impacts of BEVS on the German power system was analysed with high level of detail. Similar charging patterns were also observed in [55], where the day-ahead probabilistic forecasting of the availability and the charging rate at charging stations for plug-in electric vehicles were analysed. Total installed BEVS charging / discharging power in this study amounts to 501 184 GW maximal hourly storage capacity to 2 245 GWh.

Potential storage capacity of BEVS is computed from historical monitoring data regarding the charging patterns of a large number of EVs. To separate charging transactions pertaining to BEVS from those related to Plug-in Hybrid EV, the usable energy and charging power battery characteristics of the main EV models sold in the Netherlands between years 2010 and 2015 are considered [12]. Two clusters are identified for BEVS, based on the maximum values of total energy and charging power recorded for each ID:

- Maximum Charging Power ≤ 4 kW and Maximum Total Energy charged > 12 kWh;
- Maximum Charging Power > 4 kW.

In addition, the selected data are further refined by considering only IDs with more than 10 transactions recorded at ElaadNL charging points over the entire year. This aims at identifying frequent users that are more representative of realistic charging patterns. The aggregate load is scaled up according to the reference input data used to characterize the BEVS technology in the JRC-EU-TIMES model. The total aggregate charging demand D is calculated as follows:

$$D = \frac{d}{\varepsilon} \cdot v_{tot} \quad (13)$$

where d is the average distance travelled by car, 13 201.69 km/veh, year, ε is the average energy consumption of EVs, 1.43 Bkm/PJ, year, v_{tot} is the total number of passenger cars, 6 188 729.6 vehicles. The corresponding scaled charging curve L is obtained through a proportion with the aggregate curve λ computed out of the 2015 data for each time step in the optimization period as follows:

$$L_i = \frac{D}{\delta} \cdot \lambda_i \quad (14)$$

where δ is the 2015 total aggregate charging demand.

4.4.3. Heating

Space heating non-dimensional demand time series for all European countries are obtained using the empirical methodology proposed by Ruhnau et al. [56]. Subsequently, these non-dimensional and country-specific time series are rescaled to the total amount of each country's heat demand (residential and commercial) that is met by either P2HT or DH-CHP technologies, according to the ProRES scenario. Low-temperature industrial heat covered by DH-CHP is also considered as part of such heat demand, whilst process heat met by electricity is not considered here, but already included within the electricity demand. Cooling is also only considered in the aggregated electricity demand.

The total annual useful space heating demand to be covered by P2HT amounts to 1 009 TWh. This corresponds to 53.9% of commercial and 34.5% of residential heat end uses. Peak heat demand is around 315 GW. Following the methodology outlined in paragraph 2.4.2., the nominal conversion efficiency of the P2HT technology group (COP_{nom}) and the coefficients for its parametrisation as a function of hourly ambient temperature are computed. The results for each country are shown as supplementary material in Table 10 (Annex A).
The total annual heating demand that should be covered by CHP units amounts to 564 TWh. This corresponds to about 24.2% of commercial, 8.9% of residential and 19.8% of (low-temperature) industrial heat demand types. Maximum hourly heating demand amounts to 183 GW.

Heat can be supplied either through back-pressure or extraction CHP units or using a backup gas heater. The CHP technical parameters are presented in Table 4. The cost of heat generated by the backup heaters is set to 112 EUR/MWh. This number is evaluated based on a gas price of 60 EUR/MWh and a CO_2 price of 100EUR/t as proposed in [34]. In THFLEX and ALLFLEX scenarios, all CHP units are defined according to Table 4, while in the other scenarios, the CHP

Type for all units is set to back-pressure and the CHP Power Loss Factor to 0. All other cost and technical parameters remain unchanged from Table 3.

Table 4 Technical parameters for CHP units

Fuel	Technology	CHP Type	CHP Power To Heat Ratio	CHP Power Loss Factor
STUR	BIO	Extraction	0.45	0.238
GTUR	BIO	back-pressure	0.55	0
COMC	BIO	Extraction	0.95	0.213
ICEN	BIO	back-pressure	0.75	0
COMC	GAS	Extraction	0.95	0.213
GTUR	GAS	back-pressure	0.55	0
STUR	GAS	Extraction	0.466	0.23
ICEN	GAS	back-pressure	0.75	0
STUR	GEO	Extraction	0.22	0.169
STUR	HRD	Extraction	0.45	0.256
STUR	LIG	Extraction	0.45	0.236
STUR	OIL	Extraction	0.45	0.11
GTUR	OIL	back-pressure	0.55	0
STUR	OTH	back-pressure	0.55	0

4.4.4. Hydro

The coupling between the power sector and the hydro sector is described by Fernandez Blanco Carramolino et al. [11]. HDAM, HPHS and HROR units are already considered in the Dispa-SET model together with the related inflow times series. In order to compute seasonal storage, the yearly reservoir levels are pre-optimized using the mid-term scheduling module of Dispa-SET. Comparison of historical and Dispa-SET-MTS computed aggregated reservoir levels is presented in Figure 6, with a very good agreement between both curves.

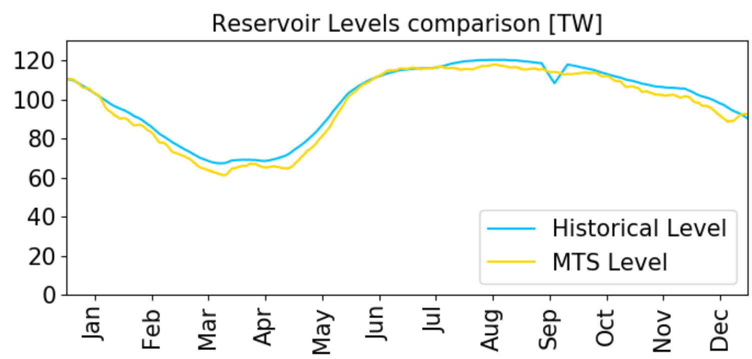


Figure 6 Comparison of historical and computed aggregated reservoir levels. Short-term variations are optimised, and long-term seasonal variation is preserved.

5. RESULTS AND DISCUSSION

Summary of important simulation results such as simulation time, memory usage, total system costs and average generation costs are presented in Table 5. From a computational point of view, considering certain cross-sectoral linkages significantly increase the size of the numerical problem. This has a direct impact on the simulation times which range from 3 h 39’ in the

NOFLEX to almost 30 hours in the ALLFLEX scenario, on a 8-core Intel(R) Core(TM) i7-5960x CPU @ 3GHz, 16 GB RAM computer.

Table 5 Summary of simulation results

Results					
Scenarios	**Simulation time [hh:mm:ss]**	**Memory [MB]**	**Total system cost [10^9 EUR]**	**Average generation cost [EUR/MWh]**	**System Feasibility**
NOFLEX	03:39:07	4,841	409.3	45.5	No
THFLEX	04:23:59	4,921	370.7	45.0	No
HYFLEX	07:13:24	5,657	386.0	44.1	No
EVFLEX	11:56:49	5,417	328.4	37.5	Yes
ALLFLEX	29:53:07	6,308	297.1	33.6	Yes

5.1. Total System Costs and Shadow Prices

A more detailed cost breakdown is presented in Figure 7. As expected, the lack of flexibility in the NOFLEX scenario significantly impacts the total system costs. With around EUR 80.7 bn in ALLFLEX and EUR 59 bn in NOFLEX, heat generation significantly contributes to the total system costs. It is however worth noting that a combination of all flexibility options in the ALLFLEX scenario is the most cost-effective. Other non-fuel related costs are lowest in ALLFLEX scenario and followed by EVFLEX and THFLEX. As expected, the most expensive scenario is the NOFLEX scenario due to forced operation of gas units. It is worthwhile to note that in the first three scenarios, costs are estimated based on time intervals with feasible solutions. System costs in under capacity periods (LL>0) are discarded and the average generation cost is computed only for the time intervals where feasible solutions are provided.

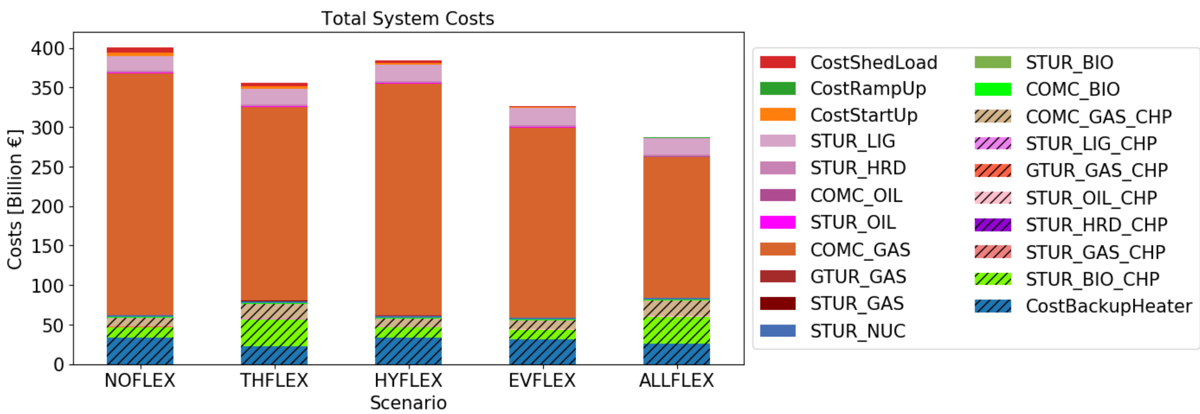


Figure 7. Costs breakdown in all five scenarios. Variable fuel costs are presented per fuel and per technology type and other costs represent backup heaters and shed load.

A summary of hourly shadow prices in all zones and all scenarios is presented in Figure 8. ALLFLEX is the scenario with the most uniform shadow prices around the year. Some exceptions are northern countries such as Estonia, Finland and Sweden, and isolated countries such as Bulgaria. Shadow price in Spain, Portugal and Greece is 0 EUR/MWh throughout the year, meaning that they are powered by zero marginal cost RES technologies almost 100% of the time.

Adequacy issues are detected in the other four scenarios, with lack of generation capacity during certain time periods, even after demand reduction due to load shedding. In the EVFLEX scenario, this occurs only on couple of hours per year, while in other three scenarios infeasibility of the system can be observed on multiple occasions, especially in January. This can be explained by the following reasons:

- A combination of low availability factors for VRES technologies.
- High heating demand due to relatively low outside temperatures.
- A lack of backup capacity and the scarcity of flexible thermal units.
- A lack of load shifting capability in form of TES, HPHS and BEVS technologies.

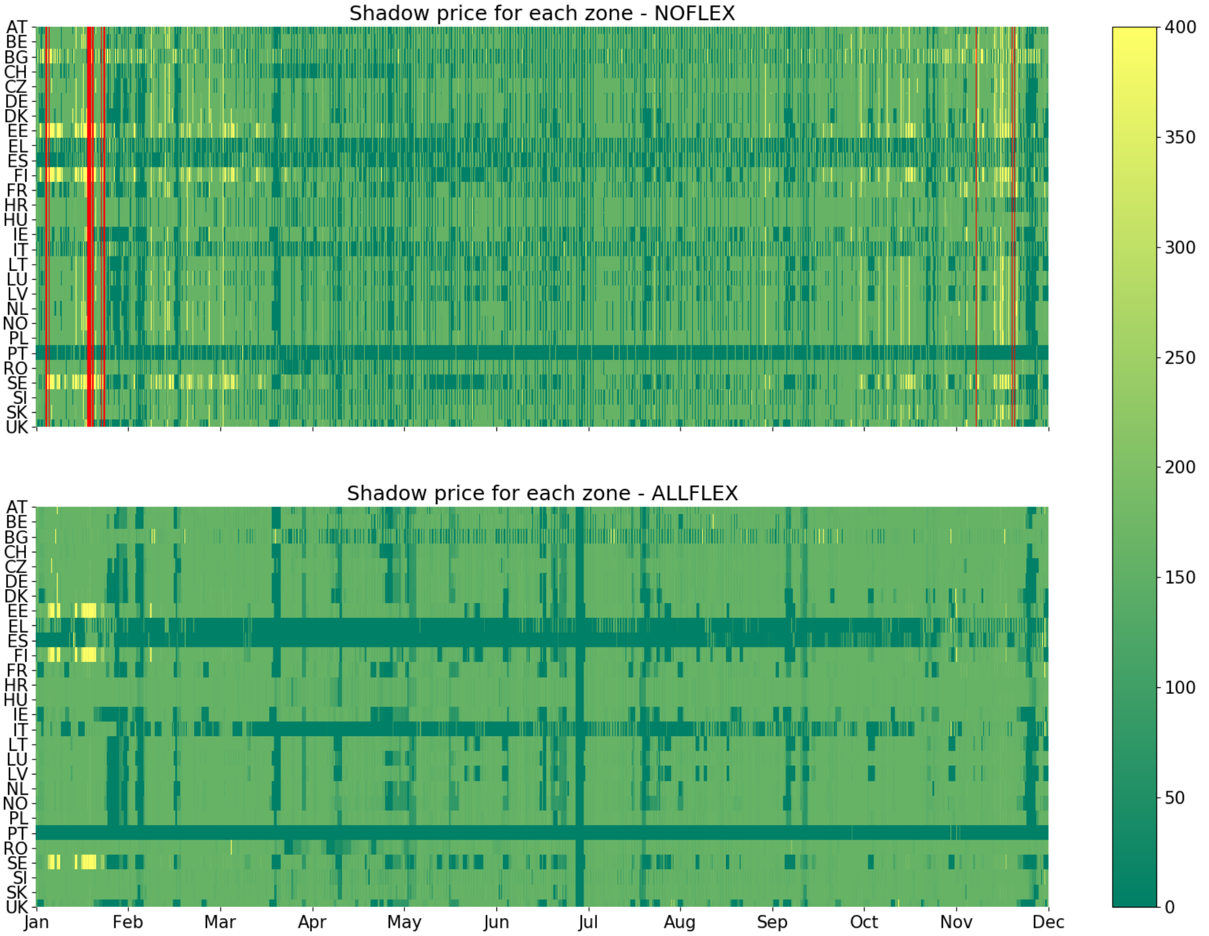


Figure 8. Heat map of computed shadow prices on hourly scale in each of the 28 countries. Values on the legend indicate shadow prices in EUR/MWh, green colours represent variable dispatch costs, yellow stands for shed load and red indicates disregarded time periods where lost load, resulting in infeasible solutions, is being computed.

5.2. Power and Heat Generation

Energy output per fuel and technology type is presented in Figure 9. The lowest electricity generation is observed in the NOFLEX and HYFLEX scenarios, amounting to 7741 TWh and 7871 TWh respectively. The highest electricity generation can be observed in ALLFLEX scenario, amounting to 8404 TWh. It is important to note that storage technologies in HYFLEX, EVFLEX and ALLFLEX scenarios have a significant impact on curtailment and thus on the generation from wind (WIN) and solar (SUN) (ALLFLEX: +15.3% SUN, +4.9% WIN; EVFLEX: +12.9% SUN, +3.2% WIN; HYFLEX: +2.2% SUN, +1.2% WIN). The total generation differences between scenarios are due to the presence of P2HT technologies, which are responsible for the increase of the endogenous electricity demand.

The low generation from hydro units can be attributed to relatively small increase in additional capacities when compared to other VRES and high demand projected by the JRC-EU-TIMES model. Contribution of HPHS and HDAM units amounts to 70 TWh and 300 TWh, respectively. This partly explains why the flexibility potential of the hydro sector is low compared to the other ones. Generation from gas units is significantly lower in THFLEX scenario, mainly due to higher RES integration which was shifted from hours with excess production to hours with RES scarcity. The power dispatch diagrams are provided as supplementary material in Figure 16 (Annex A).

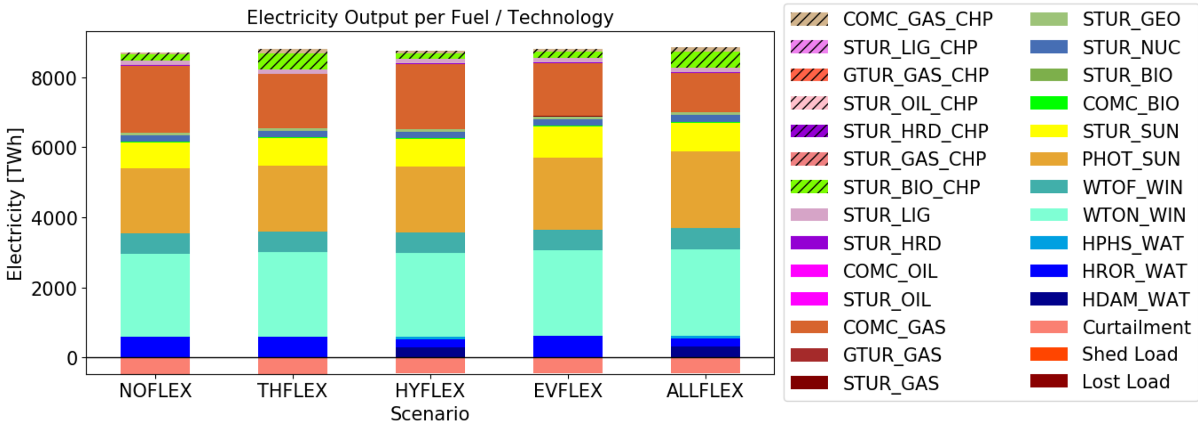


Figure 9. Electricity output per fuel and per technology type as computed in all five scenarios. Positive values on the y-axis indicate generation, while negative values indicate demand suppression in form of shed load and lost load and RES curtailment.

As indicated in Figure 10 the heat output from CHP units is similar across all scenarios. However, heat supply from P2HT technologies vary significantly because of the competition with backup heaters: when the price of electricity is high, backup heat generation is preferred over P2HT. The presence of TES in THFLEX and ALLFLEX allows to balance VRES generation and therefore leads to a higher P2HT penetration in these scenarios.

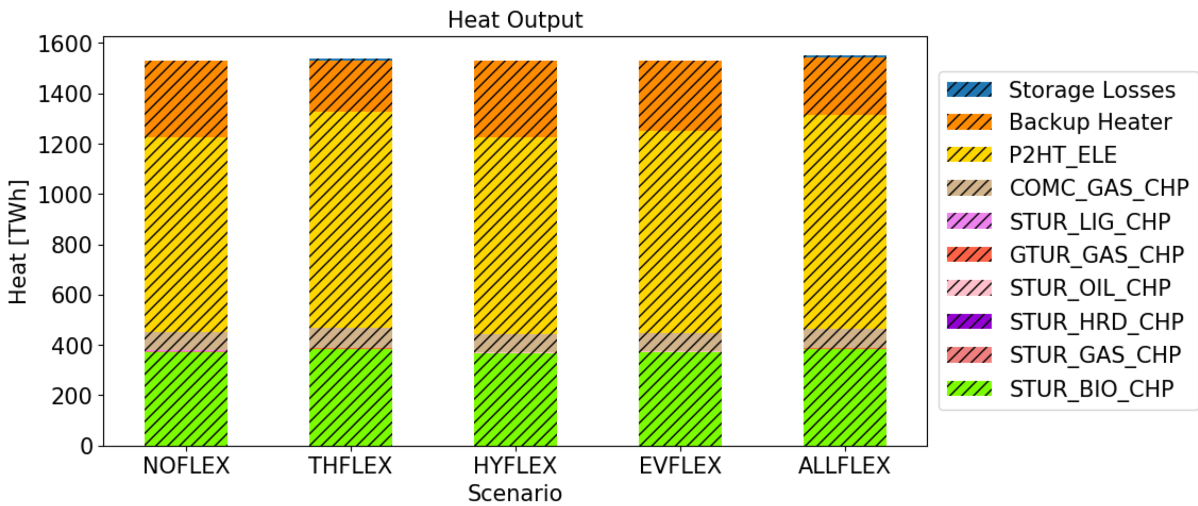


Figure 10. Heat output per fuel and per technology type as computed in all five scenarios. Generation from backup heaters indicates either lack of heat generation capacity or expensive electricity.

5.3. RES Curtailment

The major contributor in reducing curtailment form RES is the transport sector, followed by heat and hydro sectors as shown in Figure 11. When all sector coupling options are turned on at once (ALLFLEX), the total reduction of curtailed VRES is higher than the sum of the individual contributions. This is explained by multiple factors such as a higher total load shifting potential in time intervals with peeking energy from RES generation, additional flexibility provided by CSP units and increased overall flexibility due to higher synergies between groups of different technologies. Reduction of curtailment, load shedding, number of hours in which interconnection lines are congested and total CO_2 emissions with respect to NOFLEX scenario are provided in Table 6.

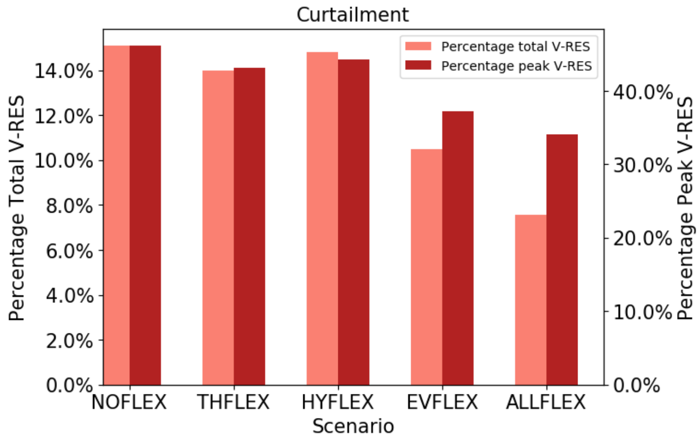


Figure 11. Total annual and maximum aggregated hourly curtailment as percentage of total and peak generation from VRES in all scenarios

Table 6 Summary of curtailment, load shedding, congestion and emissions reduction in respect to NOFLEX scenario

Scenario	THFLEX	HYFLEX	EVFLEX	ALLFLEX
Curtailment	-7.3 %	-8.3 %	-30.6 %	-53.0 %
Load shedding	-27.7 %	-57.0 %	-77.0 %	- 89.2 %
Congestion	-1.0 %	-2.3 %	-6.8 %	-8.3 %
CO_2	-16.4 %	-2.1 %	-14.5 %	-29.4 %

5.4. Load Shedding

Load shedding follows a similar pattern as VRES curtailment. The highest contribution to its reduction comes from the transport sector, followed by the hydro and thermal sectors. Although the total contribution to annual shed load reduction from thermal sector is higher than from the hydro sector, the highest maximal aggregated hourly shed load lower. The main reason for this is that hydro sector can provide flexibility throughout the year while the heating sector mostly contributes during the winter months. Load shedding values for each scenario are presented in Figure 12.

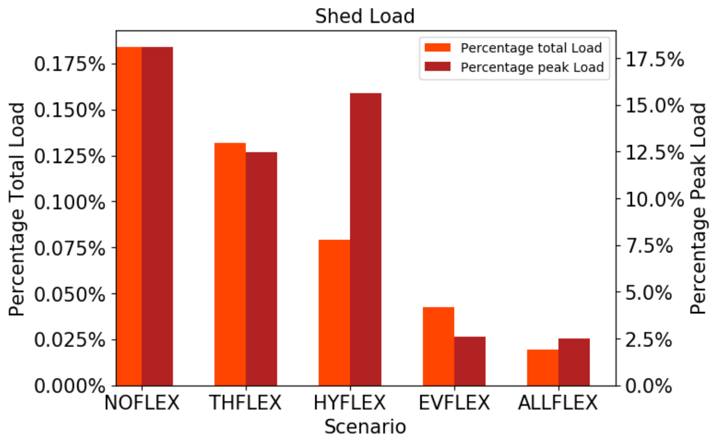


Figure 12. Total annual and maximum hourly shed load in all scenarios as a percentage of total and peak load

5.5. Storage Utilization

The amount of shifted load is in direct correlation with curtailment and load shedding. The shifted load breakdown per fuel and per technology type is presented in Figure 13. Individual flexibility potentials in HYFLEX, EVFLEX and THFLEX are clearly cumulative in the ALLFLEX scenario. The highest overall load shifting contribution is provided by short term P2HT-TES, and followed by BEVS

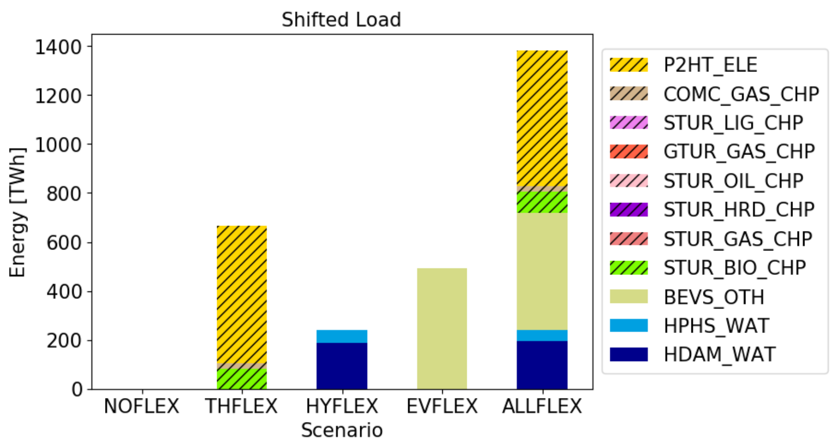


Figure 13. Shifted load per fuel and technology type in all five scenarios. Contoured labels indicate TES storage of CHP and P2HT units

5.6. Congestion

Figure 14 presents the number of hours of congestion in transmission lines in the ALLFLEX scenario. Some interconnection lines, especially from southern countries such as Portugal, Spain, Italy and Greece, are highly congested. This is directly related to the excess generation from VRES (mostly solar) installed in these countries. Moderately congested lines are also present between Norway and all its neighbours, mainly due to the high storage capacity provided by hydro units. In all five scenarios power grid significantly contributes to the overall flexibility of the system. As presented in Table 7, the highest total overall congestion is observed in the ALLFLEX, and the lowest one in the NOFLEX scenario. This can be attributed to high load shifting availability throughout the EU, which consequently reduces the curtailment and increases overall VRES absorption. Total flow in the cross-border lines is higher in NOFLEX, and lowest in ALLFLEX. In this case, local load shifting possibilities, especially in from of hydro units, reduce the need for utilization of NTC’s.

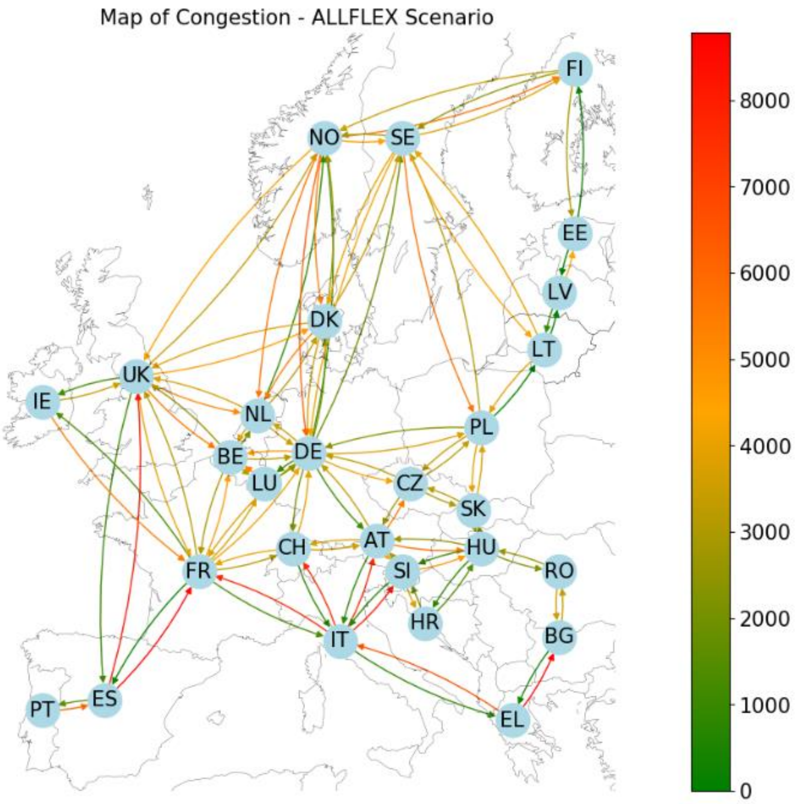


Figure 14. Number of hours of congestion in the cross-border lines. Red lines indicate high (lack of NTC capacity) and green values low congestion (adequate NTC capacity).

Table 7 Total flow and average congestion in all cross-border lines from all scenarios.

Parameter	Unit	NOFLEX	THFLEX	HYFLEX	EVFLEX	ALLFLEX
Total flow	TWh	1 479.5	1 465.7	1 424.4	1 494.2	1 424.7
Average Congestion	h	3 025.4	3 056.6	3 093.9	3 230.7	3 276.8

5.7. Environmental Impact

A summary of operational carbon emissions from thermal units (non-CHP and CHP) is finally presented in Figure 15 for each scenario. There is a clear downwards trend in carbon emissions as more flexibility and increased sector coupling are present in the system. As conventional units in the JRC-EU-TIMES ProRES 2050 scenario are mostly dominated by gas, the latter is the main source of carbon emissions in all scenarios. It is followed by emissions from lignite and hard coal units. The flexibility provided by TES in THFLEX and ALLFLEX reduces the need for backup heaters and thus the CO_2 emissions. The CO_2 emissions from power generation and operation of CHPs amount to 354 Mton in the results of the JRC-EU-TIMES model for the ProRES scenario [1]. However, the comparison with the original results from JRC-EU-TIMES are out of scope because the focus on the power sector in Dispa-SET does not allow an accurate quantification of the carbon contents of the fuel.

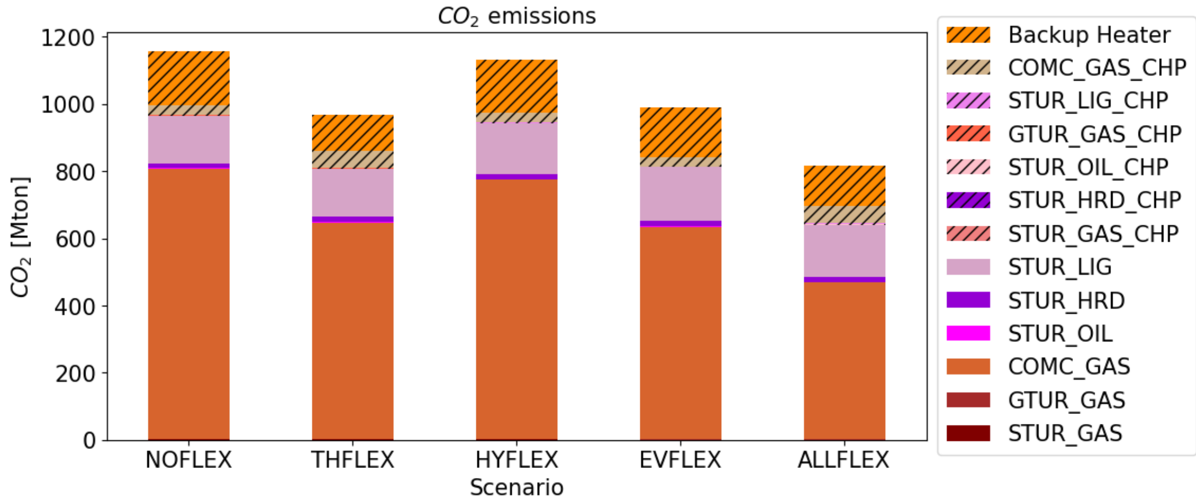


Figure 15. Summary of CO_2 emissions grouped per fuel and per technology type in all scenarios

5.8. Start-ups

Total number of start-up events in conventional units grouped by fuel type is presented in Table 8. Due to increased number of load-shifting technologies in flexible scenarios, the number of start-up events in conventional power plants is significantly reduced. This is clearly visible in Biogas (BIO), Gas (GAS), Geothermal (GEO), Hard Coal (HRD), Lignite (LIG) and Oil (OIL) units. The start-up events in storage technologies are directly corelated to the reduced curtailment, increased absorption of VRES and reduced number of start-ups in conventional power fleet.

Table 8 Total number of start-ups in conventional power plants, hydro units and BEVS as computed in all five scenarios.

	BEVS	BIO	GAS	GEO	HRD	LIG	NUC	OIL	WAT
NOFLEX	-	6 291	7 311	4 930	753	3 592	23	857	0
THFLEX	-	3 125	7 494	1 273	761	2 652	32	277	0
HYFLEX	-	6 699	7 272	2 685	635	3 195	15	612	24 034
EVFLEX	12 438	7 239	4 427	860	273	790	106	362	-
ALLFLEX	15 516	1 235	3 458	1 141	249	607	69	290	25 787

6. CONCLUSION

This article proposes a framework for the evaluation of sector coupling options in future energy systems. Because of the long-term perspective, a uni-directional soft-linking methodology is proposed, allowing to simulate the 2050 energy system with a high time-resolution and a cross-sectoral representation. All the proposed models, methods, and data are released with an open license to ensure transparency and reproducibility of the work; they can be freely downloaded[3][4][5]. In order to quantify the flexibility resources provided by each cross-sectoral

[3] https://github.com/energy-modelling-toolkit/Dispa-SET

[4] https://zenodo.org/record/3627259#.Xni803Io-Uk

[5] https://data.jrc.ec.europa.eu/dataset/8141a398-41a8-42fa-81a4-5b825a51761b

linkage, two scenarios were defined for each sector: a scenario with a non-flexible sector coupling and a scenario where the full potential flexibility for sector coupling is unlocked. In a last scenario, the flexibility potential of all three sectors (hydro, heating and transportation) is used simultaneously. It is important to note that the goal of this paper is to provide the upper boundaries for the flexibility potential of each sector, and not to simulate an in-between and more realistic, but highly uncertain scenario.

Simulation results indicate that the coupling of hydro, heating and transportation sectors to the power sector enables higher (5% more wind and 15% more sun) utilisation of renewable energy within the system. The analysis further shows that simultaneous integration and cross-sector coupling can reduce the potential carbon emissions by more than 30% compared to the scenario where no flexibility resources are present. Furthermore, congestion in the proposed interconnection lines might cause serious VRES curtailment by limiting the energy flows from south, RES abundant, countries. Three main conclusions can be drawn from this work.

First, since the primary energy generation in future low carbon scenarios is dominated by highly variable and intermittent energy sources such as wind and solar, lack of flexibility and load shifting options can lead to significant curtailment in time periods with high availability and significant load shedding in time periods with low renewable availability. This is the main reason why cross-sector coupling must be considered and analysed simultaneously, especially in a long-term planning perspective. Such load shifting options, especially flexible pumped hydro storage and storage provided by the electric vehicles connected to the grid can significantly contribute to the flexibility of the system as a whole.

Second, the power sector and the heating sector are expected to be more interlinked because of the increasing shares of P2HT and CHP units which are direct competitors of gas heating units. In such system configurations, thermal storage plays a crucial role as it prevents over-capacity of thermal units and provides load shifting possibilities. This consequently enables much higher and more efficient utilization of renewable resources.

Finally, results suggest that long term planning models such as JRC-EU-TIMES can be complemented by a more detailed dispatch model to ensure feasibility of the proposed scenarios. Also, the results suggest that Dispa-SET can be complemented with even more energy conversion pathways identified as promising by energy system models, such as the production and use of e-fuels. This will be the focus of future works, among others through a bi-directional soft-linking between JRC-EU-TIMES and Dispa-SET.

NOMENCLATURE

Abbreviations	Description	Unit
AF	Availability factor	[-]
BEVS	Electric vehicles available for V2G	[-]
BIO	Biomass and biogas	[-]
CHP	Combined heat and power	[-]
COMC	Combined cycle	[-]
CSP	Concentrated solar power	[-]
DH	District heating	[-]
DLC	Direct load control	[-]
EH	Electric heaters	[-]
ESOM	Long-term energy system planning	[-]
EV	Electric vehicle	[-]
GAS	Gas	[-]
GEO	Geothermal	[-]
GTUR	Gas turbine	[-]
HDAM	Hydro dam (turbine)	[-]
HPHS	Pumped hydro (pumped / turbine)	[-]
HRD	Hard coal	[-]
HP	Air-source heat pumps	[-]
HROR	Hydro run-of-river	[-]
ICEN	Internal combustion engine	[-]
LIG	Lignite	[-]
LL	Lost Load	[-]
MILP	Mixed integer linear programming	[-]
MTS	Mid-term scheduling	[-]
NTC	Net transfer capacity	[-]
NUC	Nuclear	[-]
OIL	Oil	[-]
OTH	Other energy carriers including electric vehicles	[-]
P2HT	Power to heat thermal	[-]
PHOT	Photovoltaics	[-]
RES	Renewable energy sources	[-]
STUR	Steam turbine	[-]
SUN	Solar	[-]
TES	Thermal energy storage	[-]
TSO	Transmission System Operator	[-]
UCM	Unit-commitment and power dispatch models	[-]
V2G	Vehicle to grid	[-]
VRES	Variable energy sources	[-]
WAT	Hydro	[-]
WIN	Wind	[-]

Sets	Description	Unit
chp	CHP units	[-]
i	Time step in the current optimization horizon	[-]
l	Transmission lines between nodes	[-]

n	Zones	[-]
$p2h$	P2HT units	[-]
u	Units	[-]
Parameters	Description	Unit
C_1, C_2	Coefficients for $COP_{p2h,i}$ equation	[-]
$CHPPowerLossFactor_{chp}$	Power loss when generating heat	[%]
$COP_{p2h,i}$	COP of the P2HT units	[-]
COP_{nom}	COP at nominal ambient temperature	[-]
$CostFixed_u$	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 un	[EUR/u]
$CostVariable_{chp,i}$	Variable costs	[EUR/MWh]
$CostVariable_{i,u}$	Variable costs	[EUR/MWh]
D	Total aggregate charging demand	[MJ]
d	Average distance travelled by car	[km/veh]
δ	2015 total aggregate charging demand	[MJ]
$Demand_{DA,n,h}$	Hourly demand in each zone	[MW]
E_{max_S}	Battery capacity available to the system	[MWh]
$E_{s,i}$	Total battery capacity	[MWh]
ε	Average energy consumption of EV	[Bkm/PJ]
$HeatDemand_{u,i}$	Heat Demand	[MW]
λ_i	Aggregate curve out of the 2015 data	[MW]
L_i	Scaled charging curve	[MW]
$LineNode_{l,n}$	Line-zone incidence matrix {-1,+1}	[-]
$LoadShedding_n$	Maximum value of load shedding	[MW]
$Location_{u,n}$	Location {binary: 1 u located in n}	[-]
$Nunits_{p2h}$	Number of P2HT units	[-]
ξ	Security margin	[-]
$P_{n,i}$	Power demand	[MW]
$P_{ev,n,2050}^{TIMES}$	Annual EV charging demand from JRC-EU-TIMES model	[MW]
$PowerCapacity_{p2h}$	Power capacity of P2HT units	[MW]
$PriceTransmission_{i,l}$	Price of transmission between zones	[EUR/MWh]
$Q_{p2h,n,i,2016}^{TIMES}$	Electric heating demand in JRC-EU-TIMES	[MW]
SOC_{min_i}	Minimum state of charge	[-]
$StorageInput_{s,h}$	Charging input for storage units	[-]
$T_{amb,i}$	Ambient temperature	[°C]
T_{nom}	Nominal temperature	[°C]
$Technology_u$	Technology type	[-]
v_{tot}	Total number of passenger cars	[veh]
$VOLL_{Power}$	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
$EnergyMix_{Electricity}$	Electricity production mix	[%]
$EnergyMix_{Heat}$	Heat production mix	[%]
$Flow_{i,l}$	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]
$PowerConsumption_{p2h,h}$	Power consumption of P2HT units	[MW]
$ShedLoad_{i,n}$	Shed load	[MW]
$TotalSystemCost$	Total system cost	[EUR]
Integer variables	Description	Unit
$Committed_{i,u}$	Committed status of unit at hour h {1 0} or integer	[-]

ANNEX A

A.1. Reserve requirements and Lost Load

To ensure that proper balancing and stability of the system can be guaranteed year-round, Dispa-SET has, besides supply-demand balance, certain reserve requirements (upwards and downwards) that must be meet in each node and each time interval. Three types of reserves are present in the model:

- Upward secondary reserve (2U): reserve that can only be covered by spinning units
- Downward secondary reserve (2D): reserve that can only be covered by spinning units
- Upward tertiary reserve (3U): reserve that can be covered either by spinning units or by non-spinning (supplemental) quick-start offline units

In case that the proposed system configuration cannot generate feasible solutions of the balancing equation and fails to meet the minimum reserve requirements, the system is considered infeasible. In the following sections certain reserve requirements are presented in more detail.

First the capacity margin between current and maximum power output is formulated as a hard constraint that limits the secondary upward reserve capability of committed units. Thus, hourly demand balance in the upwards spinning reserve market for each node equals:

$$Reserve_{2U_{u,i}} \leq PowerCapacity_{u} \cdot LoadMaximum_{u,i} \cdot Committed_{u,i} - Power_{u,i} \tag{15}$$

The same but reversed principle also applies to the downwards secondary reserve capability, with an additional term that also takes into account the downward reserve capability of pumping storage units. This then equals to:

$$\begin{aligned} Reserve_{2D_{u,i}} \leq\ & Power_{u,i} - PowerMustRun_{u,i} \cdot Committed_{u,i} \\ & + \left(StorageChargingCapacity_{u} \cdot Nunits_{u} - StorageInput_{u,i}\right) \end{aligned} \tag{16}$$

The quick start reserve capability represents extra generating capacity that isn't connected to the system but can be brought online after a short delay. The non-spinning (supplemental) reserve is than formulated as follows:

$$Reserve_{3U_{u,i}} \leq \left(Nunits_{u} - Committed_{u,i}\right) \cdot QuickStartPower_{u,i} \tag{17}$$

The reserve requirements should be fulfilled at all time steps within the optimization horizon. This can be done only by the power plants allowed to participate in the reserve market. Participation in the market is limited to technologies that are flexible enough to regulate their power output. Today this are usually gas and hydro units as well as battery storage. If the proposed capacity isn't sufficient, lost load (LL) indicating the lack of reserve capacity is being recorded. The secondary upward and downward demand balances are then given by the following equations:

$$Demand_{2U,n,i} \cdot (1 - K\_QuickStart_n) \leq \sum_{u,t} \Big(Reserve_{2U_{u,i}} \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}\Big) + LL_{2U_{n,i}} \tag{18}$$

$$Demand_{2D,n,i} \leq \sum_{u,t} \Big(Reserve_{2D_{u,i}} \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}\Big) + LL_{2D_{n,i}}$$

As tertiary reserve can also be provided by non-spinning units this inequality is then transformed into:

$$Demand_{3U,n,i} \leq \sum_{u,t} \Big[\Big(Reserve_{2U_{u,i}} + Reserve_{3U_{u,i}}\Big) \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}\Big] + LL_{3U_{n,i}} \tag{19}$$

The reserve requirements are provided as exogenous inputs to the model.

A.2. Supplementary scenario definitions

Table 9 Additional scenario definitions and assumptions

Scenario Definition					
Scenarios	CHP - CSP - P2HT Thermal Storage [h]	CHP Type	V2G Share	V2G Power to Energy ratio [MWh / MW]	Demands (Electricity, Heating, Transport)
NOFLEX	0 - 0 - 0	Back-Pressure	0	0	All
THFLEX	12 - 7.5 - 5	Extraction	0	0	All
HYFLEX	0 - 0 - 0	Back-Pressure	0	0	All
EVFLEX	0 - 0 - 0	Back-Pressure	50%	4.487	All
ALLFLEX	12 - 7.5 - 5	Extraction	50%	4.487	All

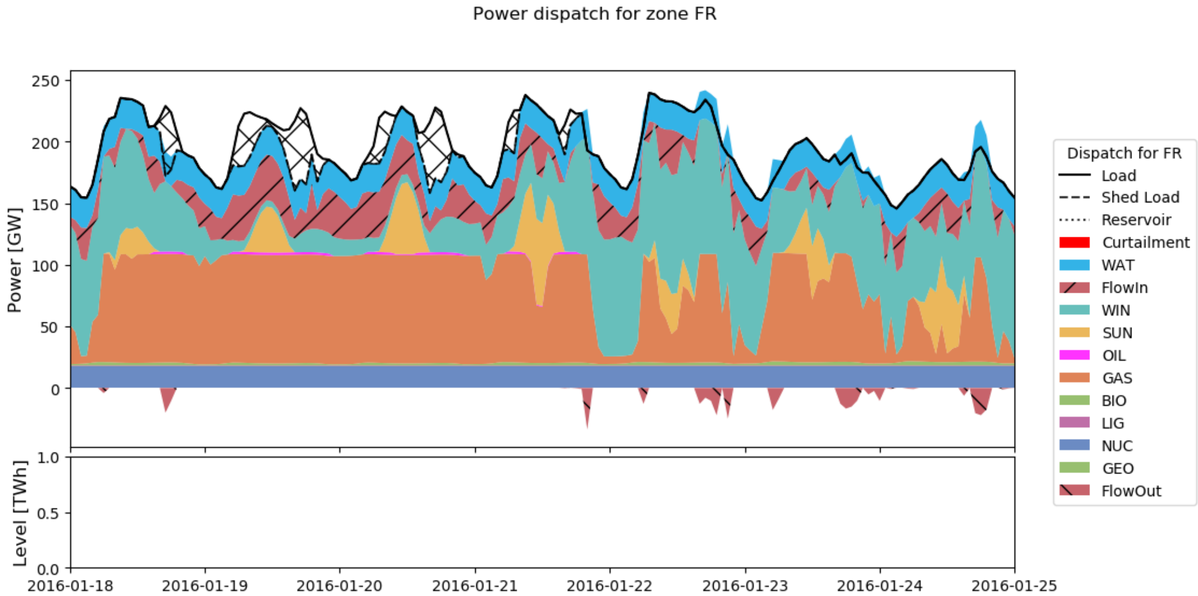
A.3. Temperature dependent aggregated coefficient of performance factors

Table 10 Aggregated COP assumptions for P2HT technologies. The temperature dependent variability of COP in different zones is ensured by coefficients C1 and C2, ensuring proper representation of climate and P2HT technology shares proposed by JRC-EU-TIMES

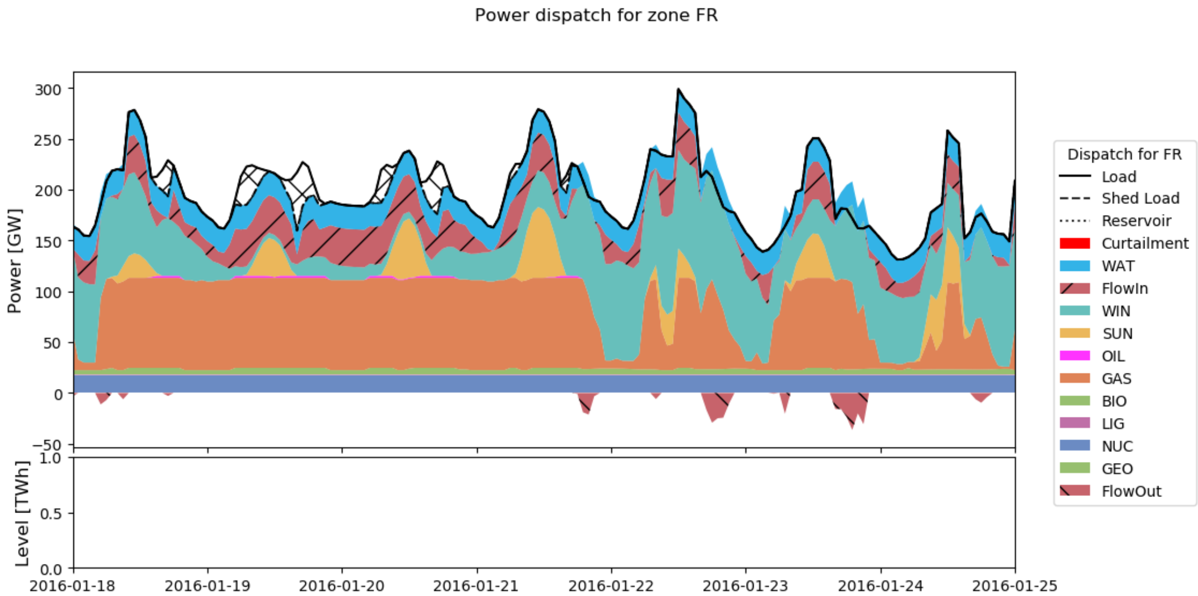
Zone	COP_{nom} [-]	T_{nom} [°C]	C_1 [$°C^{-1}$]	C_2 [$°C^{-2}$]
AT	1.701	5	0.048027	0.000084
BE	1.817	5	0.054492	0
BG	1.140	5	0.023426	0.000935
CH	2.126	5	0.075130	0
CZ	1.583	5	0.042839	0.000264
DE	2.487	5	0.099169	0
DK	1.086	5	0.014417	0.000577
EE	1.185	5	0.025376	0.000868
EL	1.177	5	0.025034	0.000880
ES	1.299	5	0.030407	0.000694
FI	1.113	5	0.018869	0.000755
FR	1.684	5	0.047302	0.000110
HR	1.490	5	0.038789	0.000404
HU	2.500	5	0.100052	0
IE	1.967	5	0.064517	0
IT	2.027	5	0.068525	0
LT	1.425	5	0.035919	0.000503
LU	1.973	5	0.064871	0
LV	2.099	5	0.073271	0
NL	2.457	5	0.097161	0
NO	1.044	5	0.007392	0.000296
PL	1.907	5	0.060528	0
PT	1.091	5	0.015247	0.000610
RO	2.293	5	0.086232	0
SE	1.001	5	0.000170	0.000007
SI	2.293	5	0.086206	0
SK	2.176	5	0.078440	0
UK	1.613	5	0.044170	0.000218

A.4. Dispatch plots

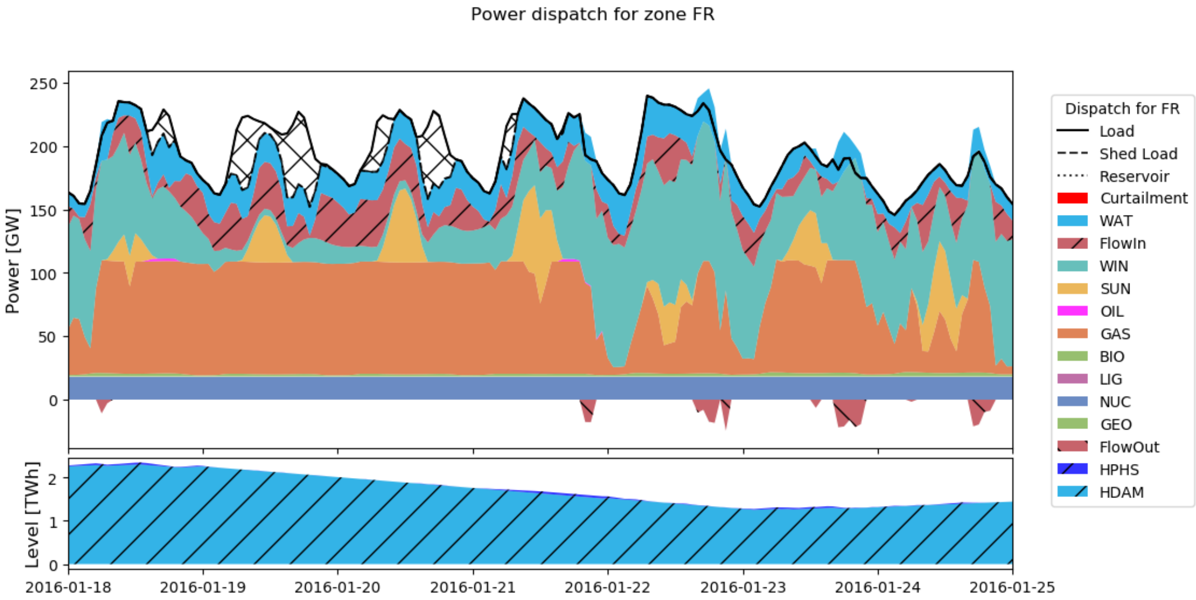
NOFLEX



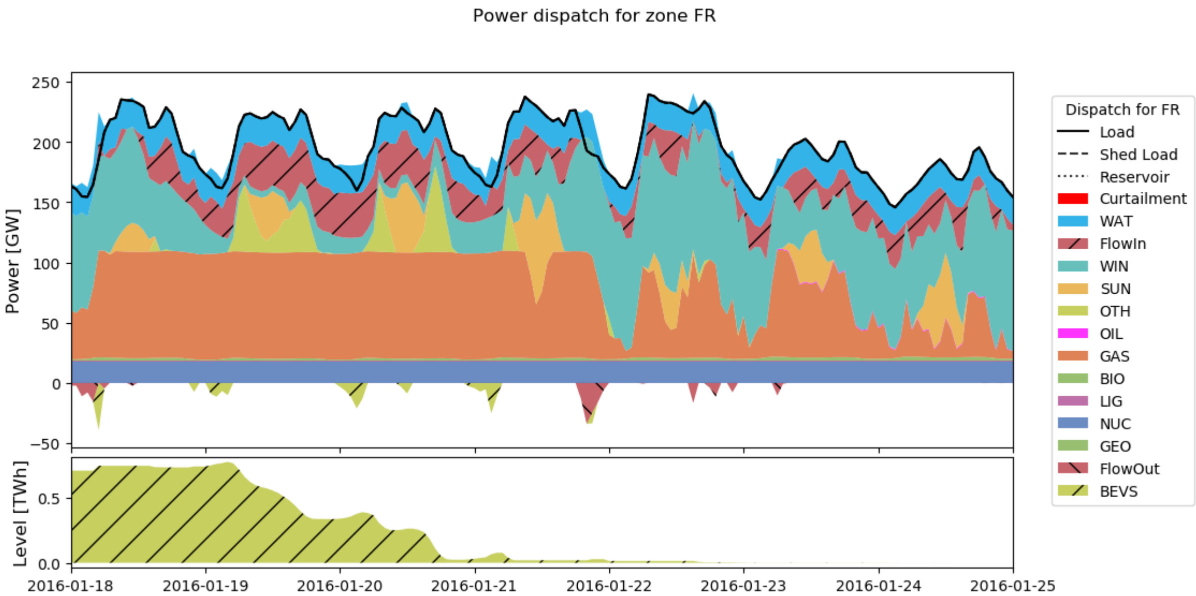
THFLEX



HYFLEX



EVFLEX



ALLFLEX

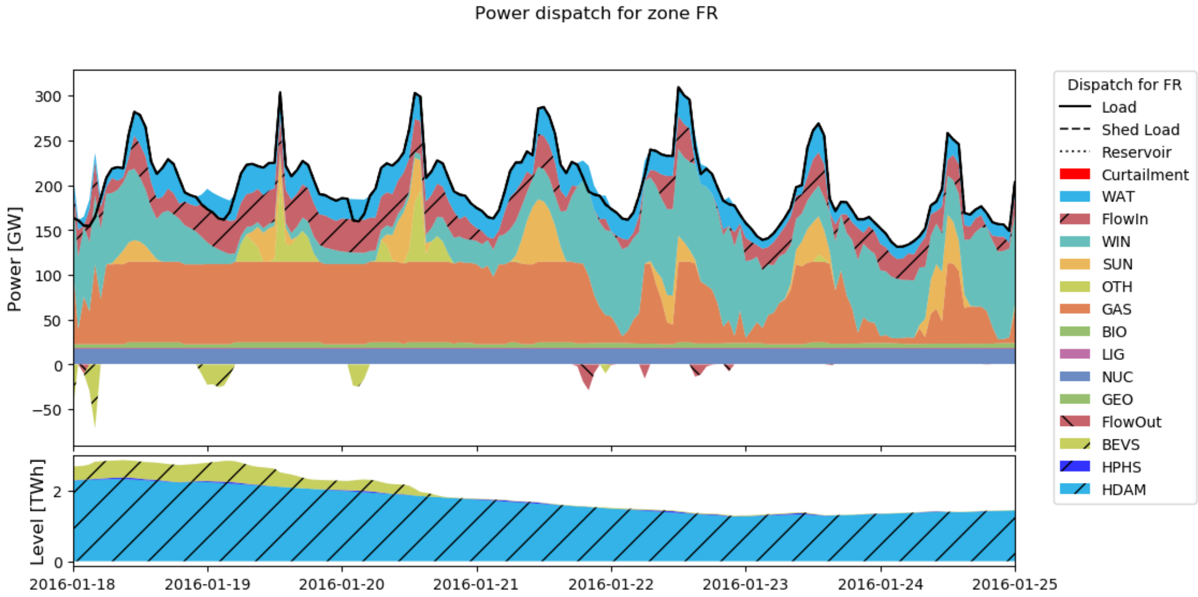


Figure 16 Dispatch plots for France in all scenarios. Same week in January is analysed to showcase how activation of different flexibility resources has a positive impact on shed load reduction.

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