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Version of Record: https://www.sciencedirect.com/science/article/pii/S0360544223008095
Manuscript_373e845dab1dee8236825eef119148f1

Assessment of the marginal technologies reacting to demand response events: a French case-study

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Nomenclature

Abbreviations	
CCGT	Combined Cycle Gas Turbine
DR	Demand Response
DSM	Demand Side Management
OCGT	Open Cycle Gas Turbine
R	Correlation coefficient
RMSE	Root Mean Square Error
TSO	Transmission System Operator
UCED	Unit-Commitment and Economic Dispatch
Lists	
d_{gr}	List of days when the group *gr* is producing electricity
L_{gr}	List of groups *gr* after discretization of the technologies from the list L_{tech}
L_{tech}	List of technologies considered in the model (including electricity exchanges)
$MO1$	Merit-order for the unit commitment, corresponding to a sorted version of L_{gr}
$MO2$	Merit-order for the dispatch, corresponding to a sorted version of L_{gr}
Parameters	
α_1	Coefficient compensating the half- hourly variations of the hydroelectric units generation
α_2	Coefficient compensating the half-daily variations of the hydroelectric units generation
$Indic_1(gr)$	Indicator setting the position of the group *gr* in the merit-order MO1
$Indic_2(gr)$	Indicator setting the position of the group *gr* in the merit-order MO2
n_{gr}	Length of the list L_{gr}
Variables	
$E_{TSO}(hydro, w)$	Hydroelectric energy generation during the week *w* [J]
mix_{elec}	Electricity mix (vector of the generation level *P* of each technology) [W]
NTC	Net Transfer Capacity [W]
P	Generated power [W]

RC	Residual consumption [W]
$\overline{RC}$	Average residual consumption [W]
RC_{remain}	Remaining power to dispatch or commit during UCED [W]
Indices	
$1/2d$	Half-day
d	Day
exch	Electricity exchanges (considered as a technology)
gr	Group (elements from L_{gr})
hydro	dispatchable hydroelectric powerplants
t	time step (with a half-hourly resolution)
tech	Technology (elements from L_{tech})
vpp_{exch}	Virtual powerplant representing electricity exchanges (included in groups)
y	Year
w	Week
Subscripts	
avail	Availability of the powerplants
exp	export
imp	Import
i, j	ranks in the merit-orders
max	Maximum level (resulting from the unit-commitment)
min	Minimum level (must-run and minimum generation outputs)
remain	Remaining groups to dispatch or commit during UCED
TSO	Input data from the TSO

1. Introduction

Consequent to the Paris agreement, objectives for carbon neutrality by 2050 were defined for many countries over the world. A key lever to reduce the greenhouse gas (GHG) emissions resulting from energy consumption is the decarbonization of the energy sectors, mainly by increasing the renewable share of electricity generation [1]. Renewable powerplants flexibility being poor, relying on new sources of flexibility from the demand-side is a critical issue. Such approaches require an investigation of the impact of demand response (DR) on the power system. This means identifying the set of generation units, referred to here as the “marginal mix”, that will adapt their generation consequent to this variation in demand. In [2] the evaluation of the marginal mix was used to operate a demand side management strategy reducing the GHG emissions. In [3] the impact of DR and energy storage was compared in terms of both marginal costs and emissions. In addition, many studies investigate the impact of smart charging for electric vehicles [4] or control strategies for heating systems [5] on power systems. These results can then be used by utilities or system operators to design DR programmes, by policy makers to evaluate the environmental benefits of DR or by aggregators to maximize revenues in the markets. A good knowledge of the power system response is thus required to evaluate this marginal mix. As electricity generation is mainly planned to minimize the total production costs, power systems are generally described using an economic merit-order based on variable costs only (meaning that powerplants are activated successively in order of increasing variable cost) as illustrated Figure 1.

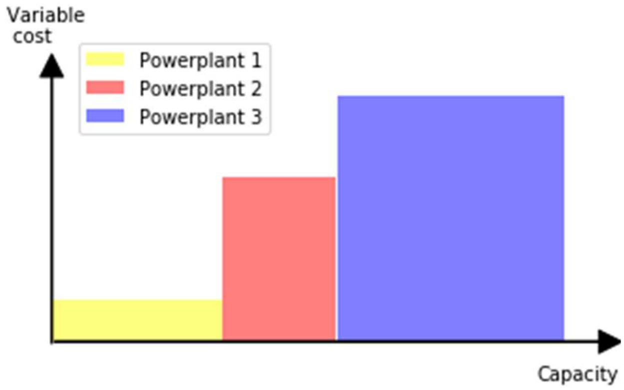


Figure 1: Simplified representation of an economic merit-order

However, other constraints interfere with this ideal merit-order. The following characteristics should be accounted for to properly evaluate the power system flexibility:

- Daily and intra-daily dynamics: the ratio between combustible and start-up costs varying for the different types of powerplants (nuclear, gas-, coal- or oil- fired power plants), the flexibility they provide depends on the considered timeframe (intra day or daily flexibility), as illustrated in [6].
- Limited water reserves: Dispatchable hydroelectric powerplants provide a large part of the flexibility, but their water reserves are limited. The total energy generated during the year can only be displaced and not increased or decreased.
- Electricity exchange with interconnected countries: The balance between electricity demand and generation is ensured through national electricity generation and exchanges. Countries being increasingly interconnected, it has become crucial to take into account the interaction with neighboring power systems in order to assess properly the flexibility of a national power system.

The scope of this article is the assessment of the impact of demand-side management strategies on power systems. Beforehand existing methods for determining the marginal mix of the electricity consumption will be investigated to evaluate how the three previous listed constraints are addressed.

Various approaches evaluating the marginal mix are available in the literature. A first type of approach avoids modelling the entire power system using different methods. Among them, the following can be listed. Firstly, the current market price of electricity can be used to identify the marginal powerplant by comparison with the variable cost of powerplants [7]. Alternatively, an economic merit order can be reconstructed and the marginal powerplant is assumed to be the last unit activated at current load [8]. The GHG protocol suggests that power plants from the highest tenth of the merit-order are marginal [9]. Finally, machine learning methods can be used to analyze the variation of the power plants generation level consequently to variations in the electricity consumption [10]. McKenna and Darby [11] illustrated the interest to study the impact of DR on power system using the merit-order method. However, they also expressed that such methods without models of the power system are insufficiently robust for this type of application. They usually do not take into account the dynamics of the variation in demand and the limited water reserves. In addition, the exchange of electricity is generally not considered in the methods mentioned above.

In a second approach, the marginal electrical mix can be deduced from the difference between the electricity mix with and without marginal consumption, both mixes being obtained using a Unit Commitment and Economic Dispatch (UCED) model. The Unit-Commitment problem aims to determine which power plants are switched on or off (defined as a discrete variable), while the economic dispatch problem sets the production level of each unit (defined as a continuous variable). The UCED problem is generally solved in order to minimize costs or maximize profits. These models can be used to evaluate the impact of different DR strategies. In [12] several energy models are proposed to model the demand response of power systems. However, these models are explicit power system optimization tools such as Balmorel [13] (a partial equilibrium model combining the electricity and heat sectors in an international perspective), EnergyPLAN [14] (a national multi-energy model including electricity, heating, cooling, industry and transport sectors), or Antares-Simulator [15] (a model from the French Transmission System Operator evaluating the adequacy or economic performance of power systems). In these models, many parameters are required such as the start-up and shutdown costs or the minimum on- and off-time of power plants though they are not readily available. Semi-physical models are a good compromise between model complexity and accuracy. They are based on a minimization (optimal or not) of the costs combined with one or more constraints. Intra-day dynamics of demand and interconnections are frequently neglected, whereas the conservation of the hydroelectric powerplants is integrated into most of the models. Neglecting any of these three constraints would strongly modify the obtained marginal mix and then reduce the accuracy of the model. However, the validation of the marginal mix obtained with such approaches is rarely addressed as many models (e.g. [16] or [17]) are evaluated according to their performances (cost minimization and computational speed) without verifying that the model output is realistic. Consequently, an original UCED model based on a semi-physical approach and considering the three constraints listed above need to be developed and validated for marginal evaluations.

The aim of the current work is to develop a UCED model that can be used to evaluate the short-term marginal mix of electricity consumption in order to assess the impact of DR strategies from one hour to a few days. The output of the model should then be the electricity generation of the different units with a 30-minute resolution. This UCED should take into account the daily and intra-daily dynamics, the water reservoir conservation and interconnections. This article focuses on the French use case. The French power system is an atypical power system based on large nuclear fleet. As nuclear powerplants have a low variable cost and a limited flexibility, the French power system has interesting characteristics:

- The order of the French power plants considering ascending variable cost and ascending emission factor is the same, contrary to most power systems;
- Due to economic and technical constraints, a significant part of the power system flexibility is not provided by the national power plants.

Although the French use case is currently marginal, , most of the power systems will have to deal with these issues in the future, with the transformation of power systems to reach carbon neutrality. The methodology proposed in this article will then be even more relevant for other countries.

A detailed state-of the art (Section 2) is necessary to define the methodology. The proposed method and the material for the French use case are described in Section 3. The developed model is validated section 4.1. Finally, this model is applied to assess the impact of three typical demand-response strategies section 4.2.

2. Literature overview

The marginal electricity mix can be determined by running a power system model twice, as illustrated in Figure 2. First the actual national consumption is used as input in the model to obtain the generation level for each type of power plant, in blue on Figure 2. Then the marginal demand (positive or negative) is added to the consumption to obtain the adapted generation levels, which is represented in red in the Figure. The marginal mix (in purple) is then identified as the adaptation of generation for each type of power plant, as well as the adaptation of electricity exchange by comparing the results with and without the marginal demand.

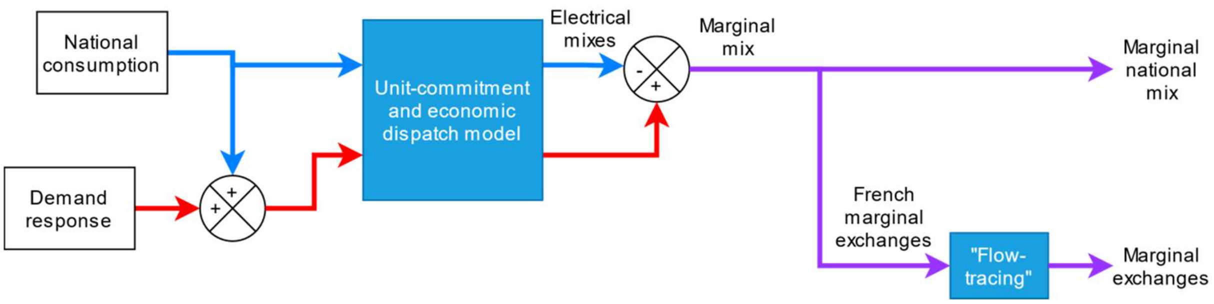


Figure 2: Method for the assessment of the marginal mix.

UCED models are chosen for their capability to replicate the dynamics of power systems. Furthermore, considering the data available for most of the power systems, this article focuses on semi-physical approaches. This model will be used to assess the impact of DR events ranging from a few hours to a few days. A time-step of 30 minutes, consistent with the data available is then chosen for the output of the model. This section presents a detailed state of the art of such models with a focus on their overall structures, the consideration of daily and intra-daily dynamics and the incorporation of hydro energy conservation and the interconnections.

2.1. Overview of the methodologies

Semi-physical UCED models can be cost- or utilization-based. Models explicitly using the known costs [18–27] will be referred to as cost-based. However, when the information relative to cost is not known with sufficient quality, such models can be calibrated with historical data [27–29] and are referred to as utilization-based. Although cost- and utilization-based models are presented as two distinct categories, some cost-based models use historical data in order to define the constraints of the model [27].

Two main methodologies for modelling the activation of power plants and solve the UCED problem can usually be found in the literature:

- **Optimization of a cost function:** Most models of electrical systems are based on a cost function minimized using an optimization algorithm constrained by the supply-demand balance [18–22,28]. The methodologies used to solve this problem are various (dynamic programming, Lagrangian relaxation, mixed integer linear programming, etc.) as are the cost-function definitions. Cost-function may contain only the variable cost of the technologies [22,28] or be more complex and generally completed with additional constraints for thermal units.
- **Priority-list models:** In priority-list (or merit-order) models, reviewed in [27], the units or groups of units are started successively in ascending order of variable cost (when cost-based) [24,26,27] or calibrated indicator (when utilization-based) [27,29] and constrained with additional rules. These models do not guarantee the economic optimum. In [29], data were grouped according to the weekday/weekend type for the four seasons and the generators were then ranked in height lists according to their percentage of full load operation.

Merit-orders have a quicker calculation time in comparison with models minimizing a cost function [30], especially in the case of a high proportion of renewable energy in the electricity production [31]. In [32] the UCED is solved using a stochastic priority-list method with better computation time compared to genetic algorithms. In [16] the priority-list is also applied, with additional procedure to include minimum up/down times and ramp rates to solve the UCED problem with competitive computation time and results. In [17] a method based on a simple merit-order and a second model based on a merit-order considering start-up costs and the minimum operating point of the units were compared with a model of full constrained minimization of a cost function. The constrained merit-order model and the model based on the minimization had similar results. Hybrid approaches combines the advantages of the two methods as in [33], where a model based on a priority list, was used as a complement to a cost-function optimization model in order to improve the simulation performance.

2.2. Daily and intra-daily dynamics

If only the variable costs and the availability of the powerplants are considered, both methodologies are similar and don't consider the daily and intra-daily dynamics. In most of the models reviewed, it is indeed possible to distinguish the constraints added to consider the intra-daily dynamics of the production in the model strategy. The implementation differs according to the type of model:

- **In models based on optimization of a cost function:** They use various techniques to model the intra-daily dynamics. One can use constraints on the ramp, constraints on the minimum up- and down-time, or start-up or ramping costs [18–20,23].

- **In priority-list models:** unit-commitment is generally implemented through additional constraints, such as minimum operating point and minimum up- and down-time [24,26] or maximum ramp-rate [27].

Each technology actually has different power ramp restrictions. However, for each technology, these ramp limits are higher than the nominal power of the plants for a time step of 30 minutes [34]. The ramping constraints observed in the data are thus related to economic rather than technical limitations. Using start-up costs (for models with detailed units) or ramping-costs (for models with aggregated technologies) seems then to be the best way to model the intra-day constraints for models based on the optimization of a cost function.

In both types of models, electricity production can be dispatched at the level of individual generation units [18,19,22,23,25,27,29], but generation units can also be aggregated per technology [21,28]. This simplification makes the model faster, but some parameters such as start-up cost cannot be defined or are more complicated to evaluate for an aggregated group of units. A third approach is to aggregate some units with very similar properties, such as type, fuel and efficiency [24].

2.3. Hydroelectric powerplants

Hydroelectric powerplants play an important role in regulating power systems and their specificity should be accounted for in UCED problems. However, the fact that their marginal production cost is near-zero and that the water reserves are limited requires a specific approach compared to the other technologies. Some authors modeled the hydroelectric power plant fleet as a real-world hydro-power unit-commitment [35,36]. In this case, the different turbines, pumps and reservoirs were explicitly modeled and interconnected and the water usage was optimized. The models took into account the market price of electricity, the residual consumption, the water level objectives, the rainfall and water runoff. However, most models use a unique water reservoir volume whether power plants are aggregated [28] or modeled independently [37].

Hydroelectric powerplant models are commonly incorporated into complete power system models: interactions between hydroelectric powerplants and thermal powerplants are then analyzed. In models minimizing cost-function, the variable cost of the hydroelectric power plants is generally set to zero and the minimization algorithm is usually constrained on a weekly basis, with a water reservoir conservation condition [28,35,37].

However, to the best of the authors' knowledge, the conservation of the water reserves is rarely addressed in empirical [10] or merit-order models [27,29]. One solution, as in [17], is to model hydroelectricity generation before applying the merit-order and then neglecting the interaction with the other dispatchable power plants without a significant degradation in accuracy. This also facilitates the implementation of a hydroelectric unit model with the conservation of energy.

2.4. Electricity exchange

Models can also be sorted according to the geographical area they consider. In this section single-country models refer to models considering the electricity generation of only one country. These models rarely address electricity exchanges.

In contrast, models that take into account electricity exchange generally model each interconnected country with a similar level of detail [24,38]. Electricity generation is committed for each country with a profit maximization algorithm or a merit-order, importing electricity from interconnected countries when the local generation is more expensive and when the network is not saturated.

Few single-country models consider the flexibility provided by electricity exchanges. In [28], Roux and al. developed a model of the French power system, which assesses the balance of the electricity exchanges using a black-box model, based on a two-layer neural network. In this model, only domestic parameters influenced the electricity exchange, namely: the domestic residual consumption, the domestic solar and wind generation, the availability of the French nuclear powerplants and the average French temperature. Such an approach only allows the calculation of aggregated electricity exchange over all borders. To assess the impact of the DSM strategies on power systems, it is also necessary identify the countries exchanging electricity and then trace back the electricity flow. The method described in [39] and [40] can be used to identify the origin of the imported electricity and the destination of the exported electricity.

2.5.Choice of the methodology

In conclusion, to describe the UCED problem of a power system, a model with the following features was chosen:

- single-zone model (such models being sufficient to consider electricity exchanges [28]);
- utilization-based (cost-based merit-order model would require the detailed costs and minimum up- and down-time for each power generation, which is a complex task given the level of public information available);
- based on two priority-lists representing respectively the unit-commitment and the dispatch. A model based on the minimization of a cost-function would require the calibration of both the variable and the ramp costs. However, given the number of powerplants constituting the French power system, it seems difficult to calibrate so many parameters. Moreover, as the priority-list method is a good compromise between computation time and accuracy [17], such a method seems to be the most appropriate;
- and applied on aggregated technologies, which are then discretize to reproduce correctly the daily and intra-daily dynamics. Indeed it was observed from the French Transmission System Operator (TSO) data that aggregated technology groups can generally be split into “must-run” and “flexible” parts. The flexibility of an aggregated technology was provided by different powerplants during the year, but the flexible capacity was almost always similar. Therefore, it would have been counterproductive to discretize per powerplant.

These choices ensure that the model can reproduce daily and intra-daily dynamics with a reasonable computation time. In addition:

- national electricity exchanges are considered as virtual power plants integrated in the priority lists;
- Hydroelectric dispatch is solved in preprocessing as in [24].

Additionally, after calculating the marginal mix, a method to trace back the electricity flow through Europe is used to identify which countries adapt their power generation to compensate for the variations in French electricity exchange.

3. Method and materials

This section describes the methodology used to model the French power system and to identify the interconnected countries impacted by changes in the French power consumption, as well as the data used for the study and the limitations of the methodology.

3.1. Structure of the model

The input of the model is the French national consumption, from which is subtracted the non-dispatchable production. This input is called the residual consumption (RC). The input of the model can be defined either using historical data (e.g. from the French TSO [41]) or with user-defined time series, at a 30-minute time-step. Renewable generation units such as solar, wind and run-of-river power plants can only be adjusted downward, which is rare as they provide electricity for a very low variable cost. In general and as of today, electricity generation from these plants is not driven by demand and per definition cannot be part of the marginal mix. Consequently, solar, wind and run-of-river power plants were considered to be non-dispatchable and thus were not included in the model.

Furthermore, other time series were needed for the simulation:

- The Net Transfer Capacities (NTC) in the hourly resolution (RTE [42]), which corresponds to the maximum power that can be exchanged across a border in both export *(*NTC_{exp}*)* and import *(*NTC_{imp}*)* directions (NTC_{exp} and NTC_{imp} both being positive) in the hourly resolution;
- The availability of the powerplants (P_{avail}) in the half-hourly resolution (ENTSO-E Transparency Platform [43]);
- The weekly energy produced by the hydroelectric powerplants $E_{\text{TSO}}(hydro, w)$, as it is assumed that hydroelectric energy can only be shifted over the week. From the French TSO data, the following types of hydroelectric units were considered “dispatchable” for our study:
  - storage hydroelectric plants (capacity of storage over 400 hours to exclude run-of-river plants);
  - pumped-storage hydroelectric (PSH) units, which are fitted with reversible turbines located between two water tanks at different levels;
  - non-reversible pumps, used to pump water to reservoirs fitted with non-reversible turbines.
- In some cases, data were not provided, such as the availability of a category of powerplant labeled “Fuel – Others”; this parameter is conventionally set at 460 MW. For a similar reason, the pumping capacity of the pumped storage hydroelectric units was set at 85% of the available

capacity for the electricity generation of these units, based on the fact that the installed capacities for electricity generation and for pumping were 5 029 and 4 291 MW respectively in 2015 [44].

The half-hourly electricity mix mix_{elec} (the vector of the generation level of each technology) is the output of the model. The generation level P was calculated for each time-step, for each type of powerplant (hydroelectric, nuclear, combined-cycle gas turbine (CCGT), coal-fired, open-cycle gas turbine (OCGT) and fuel-fired power plants), and for the electricity exchange.

Figure 3 represents the structure of UCED model. The time-step was set to 30 minutes, which fits the resolution of the TSO data. The following notations are used: weeks w and days d that refer to periods starting and ending at weekly (resp. daily) minimum residual consumption. The daily minimum residual consumption generally occurs during a time-step between midnight and 6am. Thus, a week w indicates a period of time beginning on Monday after this time-step until the following Monday at the daily minimum. A day d indicates a period of time between two consecutive daily minima. A less deep off-peak can be also noticed daily between 12am and 6pm. Half-days, denoted $1/2d$, correspond to the first or second part of the day before or after this mid-day off-peak. Examples of week w, day d and half-day $1/2d$ are illustrated on Figure 4.

It is necessary to use this method to separate the days as there are large variations in residual consumption from day to day, either due to changes in weather conditions, renewable production or type of day (weekdays vs. weekends). For example, at midnight on 10 February the residual consumption is higher than during the rest of the day. Consequently, considering days from midnight to midnight would result in an excessive number of units being committed for the 10 february.

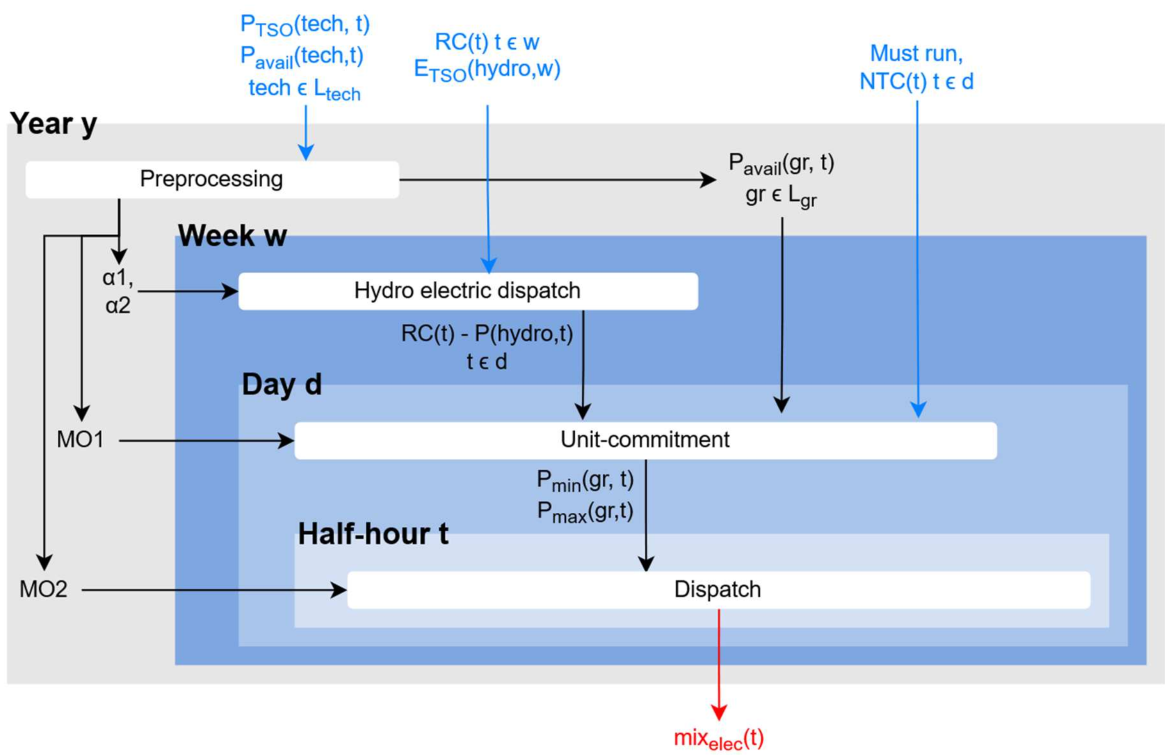


Figure 3: General overview of the French power system model

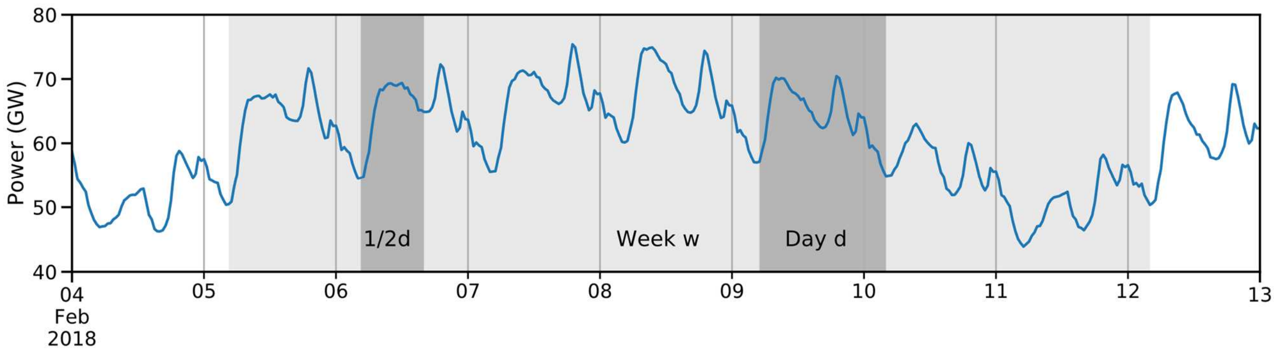


Figure 4: Residual consumption between the 4th and 12th of February 2018 and definition of the various time-frames

The first step of the model is data pre-processing which is necessary to:

- Adapt the data related to electricity exchange in order to include them as virtual power plants in the merit-orders;
- Discretize the domestic production technologies and the virtual power plants (referred to as $tech$ and listed in L_{tech}) into groups (referred to as gr and listed in L_{gr}), calculate the generation capacity and availability of each group and define the minimum activation power of each group ($P_{\min}$);
- Generate the two merit-orders $MO1$ and $MO2$;
- Calibrate the hydro electric dispatch model.

Once the data are preprocessed, the units can be committed using the three following sub-models:

- In the hydroelectricity dispatch sub-model, the generation level of the hydroelectric powerplants is evaluated;
- In the unit-commitment sub-model, the committed capacity P_{max} of each group is evaluated daily;
- In the dispatch sub-model, the generation level of each group P is defined considering the commitment of the group.

3.2. Unit commitment and Economic Dispatch

In the following paragraph, the methodologies applied in the different sub-models presented in Figure 3 (the data pre-processing, the hydroelectric powerplants, the unit-commitment and the dispatch) are described.

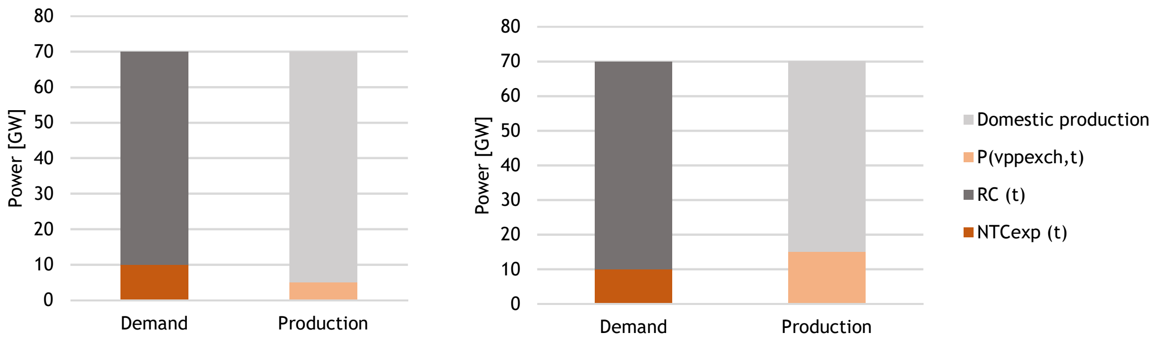
3.2.1.Data pre-processing

Including interconnections as virtual dispatchable powerplants

As stated in section 2.4, the national data were considered sufficient to determine the electricity exchange level and it was thus integrated directly into the unit-commitment- and dispatch- sub-models. This modelling strategy was chosen to reflect the high correlation between the export and the residual consumption, which is typical of the French power system due to the high capacity of nuclear power plants. Consequently, cross-border exchanges were modelled as a production from virtual powerplants (named vpp_{exch}) representing the level of exchange between the other EU countries and France. Thus, to be part of the merit orders, the electricity generation of the corresponding technology must be positive. To achieve this, the residual consumption and the level of the electricity exchanges were rescaled:

- this model assumes that the power to be dispatched between the French power plants and the borders is equal to the sum of the residual consumption and the NTC for exports.
- the production level of this virtual powerplant ranged between 0 and the sum of both transfer capacities ($NTC_{\text{exp}}(t) + NTC_{\text{imp}}(t)$): France is a net exporter if $P(vpp_{\text{exch}}, t)$ is below $NTC_{\text{exp}}(t)$, whereas France is a net importer if $P(vpp_{\text{exch}}, t)$ is above $NTC_{\text{exp}}(t)$. This is illustrated in Figure 5.

This modelling procedure ensures that the production level of exchanges will always be above zero in the merit-order and avoid distinguishing imports from exports.



To calculate the indicators relative to the merit-orders MO1 and MO2 and then generate the two merit orders, the equivalent generation ($P_{\text{TSO}}(vpp_{\text{exch}}, t)$) and availability ($P_{\text{avail}}(vpp_{\text{exch}}, t)$) of the virtual powerplants have to be calculated with Equations 1 and 2 from the net transfer capacity for exports and imports and from the electricity exchanges summed over the borders. $P_{\text{TSO}}(exch, t)$ is positive for imports and negative for exports. $P_{\text{TSO}}(vpp_{\text{exch}}, t)$ is thus always positive.

$$P_{\text{TSO}}(vpp_{\text{exch}}, t) = P_{\text{TSO}}(exch, t) + NTC_{\text{exp}}(t) \qquad 1$$

Figure 1: Dispatching principle for exchanges in the case of net exporter (left) and net importer (right)

$$P_{\text{avail}}(vpp_{\text{exch}}, t) = NTC_{\text{exp}}(t) + NTC_{\text{imp}}(t) \qquad 2$$

Consequent to this approach, the residual consumption in the input of the model has also to be adapted by adding $NTC_{\text{exp}}(t)$ to it. The level of electricity exchange, obtained in the output of the model, is transformed by subtracting the NTC for export (Equation *3*).

$$P(exch, t) = P(vpp_{\text{exch}}, t) - NTC_{\text{exp}}(t) \qquad 3$$

During national holidays in France and Germany (only a few days per year), the correlation between the French residual consumption and electricity exchange seemed to be reduced. Comparing the French exchanges with the German residual consumption showed that the French exports are generally lower when the German residual consumption remains low. As a result, the French exports were limited as a function of the German residual consumption. Indeed, a large part of the variation in electricity exchanges from France has an impact on the German power system. This means that when the German grid is already exporting to the European grid, the European market becomes saturated, leading to limited French exports. Such an assumption should be discussed for the modelling of a future power system with different commercial behavior and installed capacities in Europe.

Discretization

Parametrization and calibration of the model would not be possible for individual powerplants. This is why dispatchable units of similar technologies were aggregated. However, in order to improve the dynamics of the model, the virtual powerplant and all the technologies have to be discretized. The virtual power plant obtained from electricity exchange represents indeed a wide span of power variation. Different discretization strategies were used for each technology in order to constitute groups with properties as homogeneous as possible for daily and intra-day flexibility. The size of each group (from 200 up to 10 000 MW) was defined based on observation and parametric analysis. The groups obtained after discretization, (10 for the virtual powerplants, 5 for the coal-fired powerplants, 10 for the CCGT, 6 for the nuclear powerplants) do not represent real powerplants. The discretization of the French case is presented in Annex.

Calibration of the use of powerplants

Two merit-orders were used to reproduce the unit-commitment and dispatch of the electricity generated and thus two priority indicators were developed and calibrated for France with data from the TSO of 2018 [41]. In this study, the merit-orders were calibrated before the simulation and the orders remained constant during the entire simulation.

The unit-commitment merit-order (MO1) was based on a first indicator (Equation 4) that was evaluated on a daily basis and quantifies the activation frequency of the units of a group. The closer the indicator is to 1, the more often the units are activated. The second indicator related to dispatch defines the second merit-order (MO2) (Equation 5) and represents the reactivity of the units. A value close to 1 corresponds to the base units and close to 0 to peak units. The d_{gr} list indicates the days of the year 2018 when the group gr was activated (meaning a daily maximum generation power higher than 20 MW) and $\mathrm{len}(d_{gr})$ the length of the list d_{gr}.

$$Indic_1(gr) = \frac{1}{365} \cdot \sum_{d \epsilon 2018} \frac{\max_{t \in d}(P_{\mathrm{TSO}}(gr,t))}{\max_{\mathrm{t \in d}}(P_{\mathrm{avail}}(gr,t))} \qquad 4$$

$$Indic_2(gr) = \frac{1}{24 \cdot \mathrm{len}(d_{gr})} \sum_{d \epsilon d_{gr}} \int_{t \epsilon d} \frac{P_{\mathrm{TSO}}(gr,t)}{\max_{t \in d}(P_{\mathrm{TSO}}(gr,t))} \qquad 5$$

The two calibrated merit-orders, respectively for the unit commitment and the dispatch of the electricity, are presented in Figure 6 for the French power system in 2018. This can be compared with the parameters usually employed in cost-based methods. The value $1 - Indic_1(gr)$ corresponds indeed to the relative fuel cost for each type of power plants and the value $Indic_2(gr)$ to the relative ramping cost. The constraints on must-run units can also be identified on the merit-order for unit-commitment and the reserves on the merit-order for dispatch.

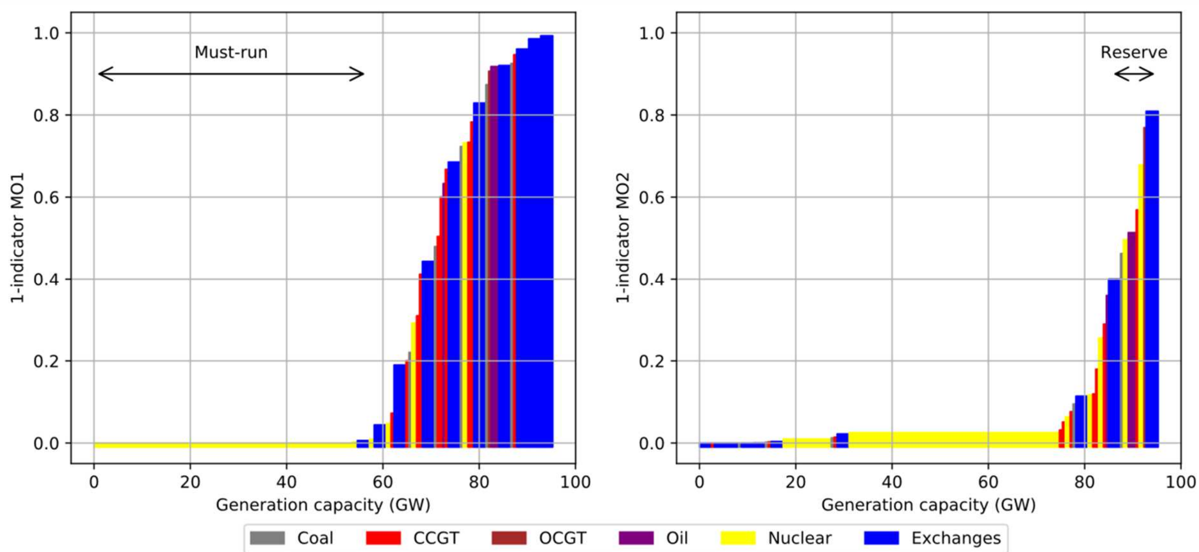


Figure 6: Merit-orders for unit-commitment and dispatch evaluated for the French power system for 2018

3.2.2. Hydroelectric powerplants (week $\boldsymbol{w}$)

In this study, hydroelectric powerplants were considered as one group of technologies whose generation level was summed over the consumption of the pumps for water storage and the generation of the turbines. The generation level of the hydroelectric group was thus either negative (more pumping for water storage than electricity generation by the turbines) or positive (in the opposite situation).

The use of hydroelectric powerplants being mainly driven by the residual consumption, their activation is processed first in the model. The developed model for the hydroelectric dispatch supposes that:

- hydroelectric energy generation $E_{\mathrm{TSO}}(hydro, w)$ is conserved weekly as in [15,28];
- the half-daily and half-hourly variation in residual consumption are partially compensated for by hydroelectric power plants.

Indeed, in [6], the authors showed that in Germany pumped storage hydroelectric power plants mostly modulate on the daily and half-daily timescales. Consequently, the hydroelectric dispatch model should compensate for half-daily energy demand variation in addition to half-hourly variation and to weekly energy conservation.

Figure 7 illustrates the breakdown of the residual consumption to isolate the weekly mean (orange in plot a) , a half-daily component (orange in plot b, which corresponds to the half daily mean of the residual consumption less the weekly mean) and a half-hourly component (blue in plot b, which corresponds to the residual consumption less the two previous components). In order to account for the half-daily and half-hourly compensations in the UCED model, a function to dispatch the hydroelectric energy is defined in Equation 6 and applied first. α_2 is constant over the year, while α_1 has a specific value at the end of winter when the water reserves are discharged in preparation for spring. α_1 and α_2 are evaluated using a linear regression. $\overline{RC}(1/2d)$ and $\overline{RC}(w)$ corresponds to the half-daily and weekly means of residual consumption, respectively.

For $1/2d \in w$, for $t \in 1/2d$, 6

$$f_{\text{hydro dis}}(t) = \alpha_1\big(RC(t) - \overline{RC}(1/2d)\big) + \alpha_2\big(\overline{RC}(1/2d) - \overline{RC}(w)\big) + \frac{E_{\text{TSO}}(hydro, w)}{\text{len}(w)}$$

However, this function does not guarantee that pumping never exceeds the availability of the pumps. Therefore, in a second step, the output power is saturated with the pumping capacity. Then, another saturation is applied to curtail the extreme low values, which are not consistent with the observed behavior of the hydroelectric fleet. Finally, the curtailed hydroelectric power generation has to be shifted to ensure the conservation of the energy produced. The curtailed energy is allocated between the half-day of the curtailment and the week. Once the hydroelectric dispatch is applied for a week, the different groups of technologies have to be dispatched each day of the week.

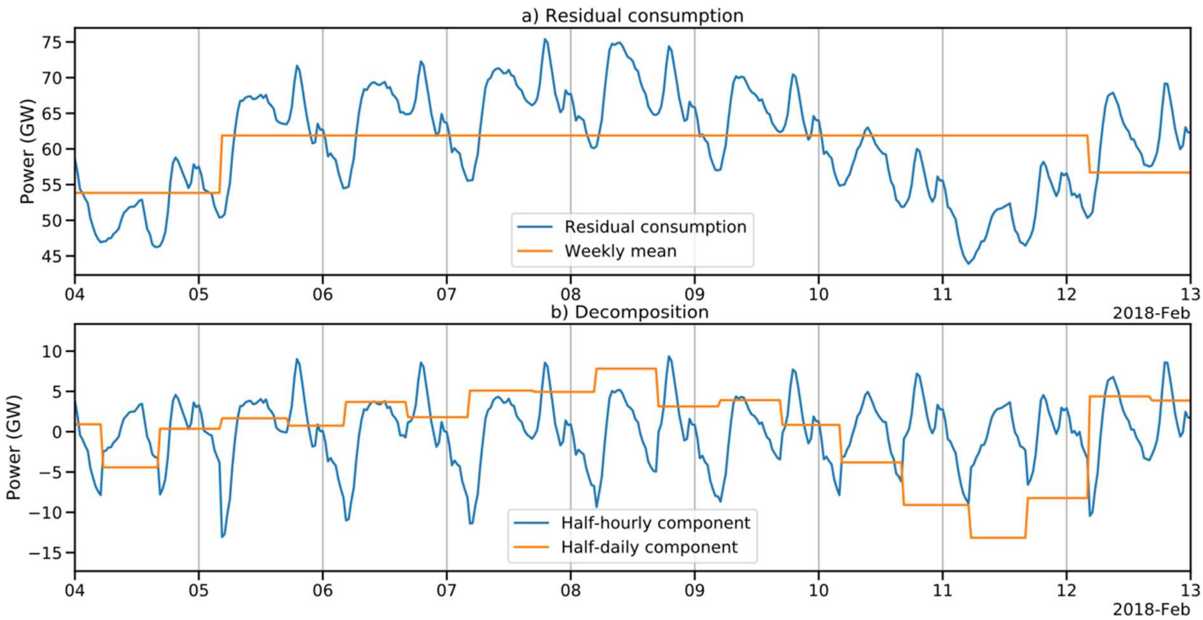


Figure 7: Breakdown of residual consumption into weekly, half-daily and half-hourly components.

3.2.3.Unit Commitment (day d): turning on or off the groups for each day

The different groups i of power plants were committed everyday, meaning that the daily maximum activable power for each group ($P_{\max}(MO1[i], t)$) was calculated by activating successively the different groups in the order of the first merit-order (MO1). The merit-order method is applied with the following characteristics:

- Ranking: MO1 order defined using the indicator defined in section 3.2.1 (equation 4).
- Upper boundary: availability of each group
- Lower boundary: must runs

1. The following sequence (steps 1 to 3) was applied successively for each group i of power plants following the ranking of the first merit-order (MO1) of length n_{gr}:Calculation of the remaining capacity to commit $RC_{\text{remain}}(i,t)$ with equation 7 for each time step of the day. At each time step, the daily maximum activable power of each already committed group and the minimum activation power $P_{\min}$ (which correspond to must-run units) of each not-yet committed group have to be subtracted from the power to be provided.

for $t \in d$, 7

$$RC_{\text{remain}}(i,t) = RC(t) + NTC_{\exp}(t) - P(hydro,t) - \sum_{j\,\in[1,i-1]} P_{\max}(MO1[j],t) - \sum_{j\,\in[i+1,n_{gr}]} P_{\min}(MO1[j],t)$$

2. The remaning capacity to be provided is the daily maximum of the time series $RC_{\text{remain}}(i,t)$.
3. $P_{max}(MO1[i],t)$ is then obtained by saturating this value between 0 and the available capacity of the group $P_{avail}(MO1[i],t)$. As the available capacity varies during the day, $P_{\max}(MO1[i],t)$ also varies during the day.

All the $P_{max}(MO1[i],t)$are thus obtained for each group i. After the unit commitment is performed, the value of $P_{\min}$ is set for the groups, whose value depend on the commitment (e.g. coal-fired powerplants in the French context).

3.2.4.Dispatch (hour h): setting the generation level of each generation group during the day

Once the maximum and minimum activable powers have been calculated during the Unit-Commitment, the generation level $P(MO2[i],t)$ of each group i is calculated successively for each time step of the day t following the ranking in the merit-order for the dispatch (MO2). The merit-order method is applied with the following characteristics:

- Ranking: MO2 order defined using the indicator defined in section 3.2.1 (equation 5).
- Upper boundary: committed capacity of each group
- Lower boundary: must-run or minimum output constraints of some units

The following sequence (steps 1 to 2) was applied successively for each group of power plants following the ranking of the second merit-order (MO2) of length n_{gr}:

1. For the group ranked i in the merit-order for the dispatch MO2, the remaining electricity to dispatch $RC_{\text{remain}}(i,t)$ is first calculated with equation 8. At each time step, the generation level P of each already dispatched group i and the minimum activation power $P_{\min}$ (which correspond to must-run units minimum output constraints of some units) of each not-yet dispatched group have to be subtracted from the power to be provided.

For $t \in d$, 8

$$RC_{\text{remain}}(i,t) = RC(t) + NTC_{\text{exp}}(t) - P(hydro,t) - \sum_{j \in [1,i-1]} P(MO2[j],t) - \sum_{j \in [i+1,n_{gr}]} P_{\min}(MO2[j],t)$$

2. The electricity generated at time step t by the group ranked i in the merit order for dispatch is then obtained by saturating RC_{remain} between the minimum output power $P_{\min}(MO2[i],t)$ and the committed capacity of the group $P_{\max}(MO2[i],t)$ at time step t.

3.3. Identification of the countries adapting their electricity generation

The aggregated electricity exchange over all the boundaries can be evaluated using the previous UCED model. However, this is not sufficient as the source/destination of electricity needs to be identified and, more importantly, the countries whose production will be impacted by DR events. It should be remembered that the real source countries are not necessarily neighboring countries as electricity can transit through many countries before reaching its final destination. For each time step, for the European grid, there is a balance between the total power produced, the transmission and distribution losses and the electricity consumption. Some countries (net exporters) thus produce more electricity than they consume, while others (net importers) produce less than they consume and need this excess power. Bialek [40] proposed an algorithm based on proportional sharing to trace back the flow of electricity in an electricity grid. In this article, it means that each country is considered as a "perfect mixer" for all the imported and exported flows. From this assumption, the amount of power consumed by each net importer country from the national production of each exporting country is estimated. This method uses for each time-step the physical exchange of electricity for each boundary of each country. These data are available for European countries in the ENTSO-E transparency platform [43] and already include the losses. The list of countries potentially impacted are constituted by including countries successively until the excluded countries have, on average, a total impact lower than 5% on the yearly French exchange.

This method indicates, for each time-step, the proportion of French exports consumed by each net importer country or the proportion of French imports produced by each net exporter country. 0However, in order to deduce the marginal mix at the border, it is crucial to identify the interconnected neighboring countries, whose power generation is actually modified consequent to the variation in French exchange. It is assumed that in net importing countries, the power system is either saturated or could produce more electricity but at a price higher than the market price and thus that they will not adapt their electricity generation. Consequently, for each time step, only the net exporters can adapt their electricity generation following a variation in French exchange that would be caused by DR events. At each time-step t, two situations can be distinguished:

1. If France is producing less electricity than its national consumption ($P_{\mathrm{TSO}}(\mathrm{exch}, t) > 0$), France is a net importer. The countries adapting their electricity generation are then the countries from which France is importing electricity.
2. If France is producing more electricity than its national consumption ($P_{\mathrm{TSO}}(\mathrm{exch}, t) < 0$), France is a net exporter. As it is considered that only net exporters can adapt their electricity generation, the countries adapting their generation consequent to a change in French exchange are the countries exporting electricity to the same countries as France.

3.4. Limitations

Various assumptions about the method developed limit the range of validity of the model and should be addressed. The first assumptions concern some of the inputs to the model:

- The unavailability of the power plants was considered as an input of the model, although planning of nuclear unavailability is known to follow electricity consumption on a monthly basis [45]. A large change in electricity consumption could then change the unavailability forecasts.
- The hydroelectric weekly generation was also considered as an input neglecting the possible impact of the demand response on seasonal storage.

However, the model was developed in order to evaluate the impact of DR events from a few hours to a few days. Such DR events should then have a limited impact on the planned outages of the power plants and on hydroelectric planning.

The second major limitation of the model is that it is based on the current French power system. The model can then be used as long as the change in electricity consumption does not modify the installed capacity of the power system, for example a historical situation in this study. Future power system models could be derived from a model calibrated with historical data considering a few changes:

- Modification of the capacity of the groups of power plants to reproduce changes in the installed capacities;
- Modification of the order of the groups in the first merit order (MO1) to reproduce evolution in the variable prices;
- Accounting for new thermal or electrical storages using the method applied for hydroelectric powerplants;
- Implementation of power-to-X strategies or electricity curtailment measures following the method for the integration of electricity exchanges in the merit-orders.

4. Validation and results

In the first section of this part, the validation of the French power system model is discussed with a focus on the accuracy of the marginal mix obtained. Then the impact of different DR events on the French power system is assessed using the previously validated model.

4.1. Validation for the year 2018

The model was validated using data from the French TSO [42] for 2018. The modeled generation level of each group of units was compared to the TSO data and evaluated using two indicators:

- The correlation coefficient (R), evaluating the linear dependence between two sets of data. A value near 1 means that the dynamics of the system are correctly modeled but does not give any information about the potential systematic bias between the results and the measured data.
- The root-mean-square error (RMSE), representing the difference between the simulation results and the TSO data. This value is absolute and has to be compared with the mean daily range of the residual consumption, which is around 14 GW.

The validation of the model is based on two steps:

- First, a yearly validation of the model in order to evaluate its overall behavior using the correlation coefficient and the RMSE over the whole year;
- A weekly validation in order to check the response of the model during periods corresponding to the marginal analysis.

4.1.1. First step: yearly validation

The correlation coefficient R and the RMSE were calculated for the different technologies using the data from the TSO and the simulation results for 2018 (Table 1). In this table, the different technologies were ranked according to the correlation coefficient. The observed operation time during 2018 is also indicated for each technology. It can be observed that the first powerplants of the merit-order MO1 (that are more often committed) have a higher correlation coefficient, while the peak units suffer from the accumulated errors of the units better ranked in the merit-order. The error on fossil fuel power plants can also be partly explained by the price of fossil combustibles, which varies continuously and is not explicitly accounted for in the model. The error on peak units can also be explained by the scope of the model, e.g. ancillary services and congestion are not explicitly taken into account.

Table 1: Validation of the French power system model for 2018

Technologies	**Operation time in 2018 (%)**	**R**	**RMSE (GW)**
Nuclear	100	0.99	1
Hydroelectric	100	0.90	1
Exchanges	100	0.89	1,9
CCGT	99	0.83	1
Coal	71	0.74	0,4
Oil	31	0.65	0,3
OCGT	3	0.48	0,1

For a more detailed overview of the model, Figure 8 presents the modeled and observed power generation for each type of power plant. The behavior of the model for nuclear, hydroelectric, CCGT powerplants and electricity exchanges fits well with the real power system. Regarding oil turbines and the OCGT, the error on these powerplants can be considered acceptable for the analysis as their activation time (31% and 3%, respectively, in 2018) and their energy generation level were small. Moreover, the values from Table 1 were compared with the validation of other unit commitment models [28,38,46] and the performances were similar to this model for a yearly validation.

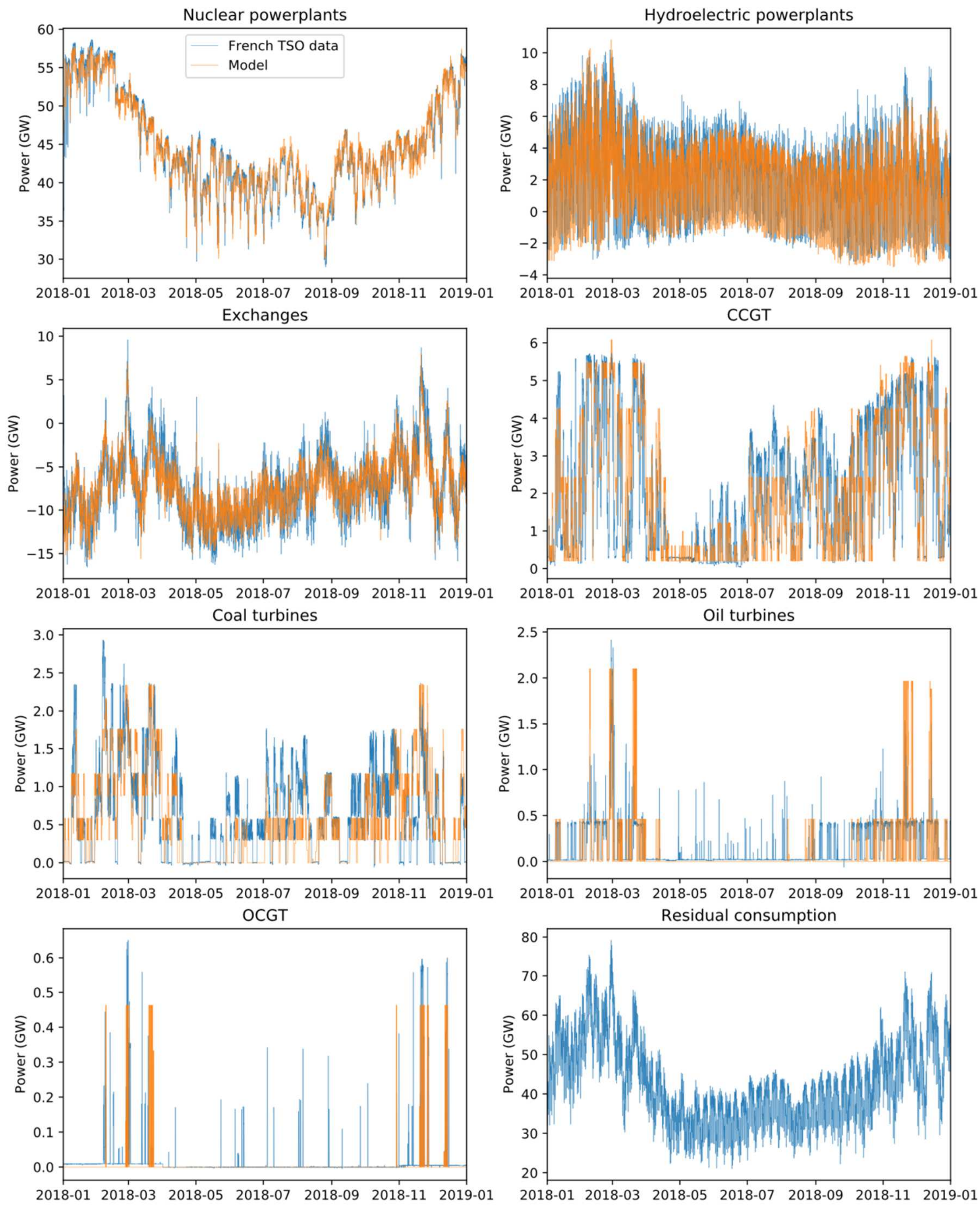


Figure 8: Modeled and observed power generation [41] *for each type of powerplant in 2018. The residual consumption at the bottom right is provided for information, being an input of the model.*

Such a validation protocol ensures that the model can predict the entire electricity mix, but, at this stage, does not validate its marginal behavior. Validating models designed for applications such as DR requires testing them against the dynamics of the duration of flexibility.

4.1.2. Second step: weekly validation

The scope of this article being the estimation of the marginal mix for DR events ranging between 30 minutes and a few days, the weekly scale also needed to be considered for validation. To that purpose, the correlation coefficient R and the RMSE for each type of power plant were calculated for each week, comparing the TSO data to the results with the model. Figure 9 and Figure 10 represent the distribution of the correlation coefficient and the RMSE, respectively. The RMSE cannot be calculated if one of the two time series is constant (e.g. equal to 0), which often occurs for the simulation of a power system for OCGT, coal and oil-fired turbines. These values have thus been removed from the analysis.

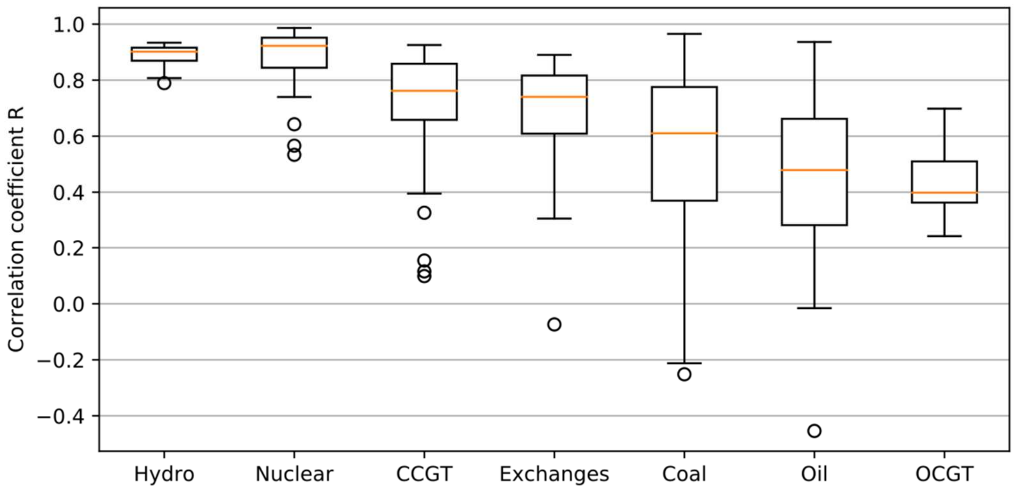


Figure 9: Distribution of the correlation coefficient calculated for each technology during each week of 2018, the orange line represents the median of the values, the box the values between the lower and the upper quartiles of the distribution, the circles the values under the lower quartile and above the upper quartile

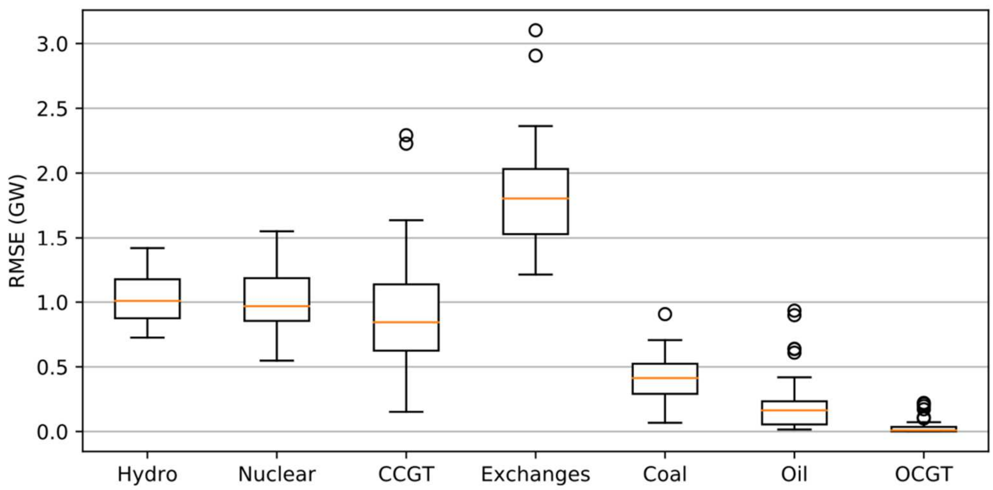


Figure 10: Distribution of the RMSE calculated for each technology during each week of 2018, the orange line represents the median of the values, the box the values between the lower and the upper quartiles of the distribution, the circles the values under the lower quartile and above the upper quartile

For a more detailed understanding of the model dynamics, Figure 11 presents the modeled and observed power generation for each type of power plant detailed for one week of February 2018.

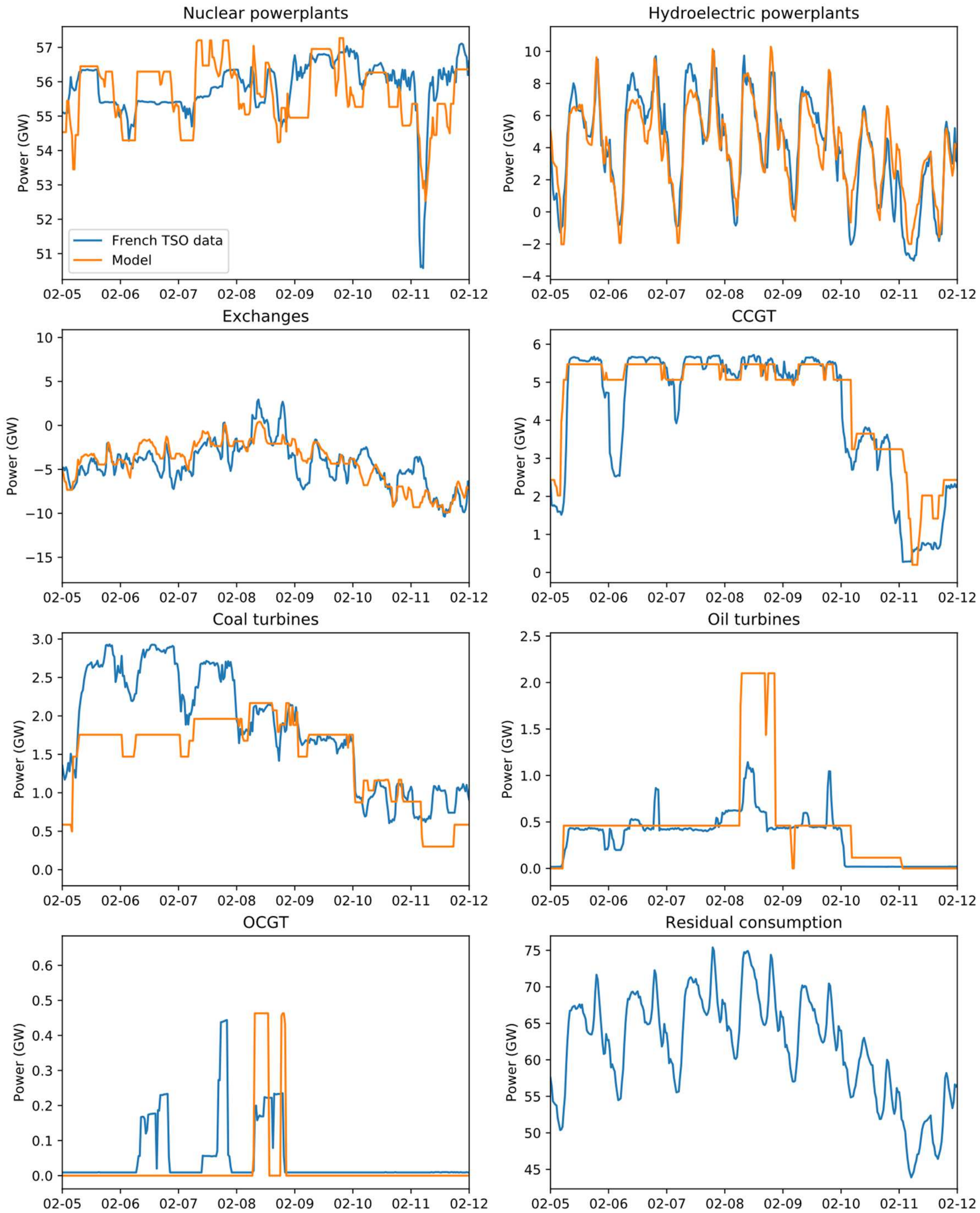


Figure 11: Modeled and observed power generation [41] *for each type of powerplant for one week of February 2018*

The weekly validation corroborated the yearly results since the correlation coefficient and the RSME were satisfactory for the frequently activated power plants and worse for the peak units. Although the weekly coefficients of the RMSE and the correlation were not as good as the annual validation, especially for electricity exchange and fossil fuel power plants, these indicators validate the model for a marginal usage. Weekly validations of power system models were not available in the literature to make a comparison with this model.

4.2. Impact of DR strategies on the French power system

In this article, three usual strategies of DR, illustrated Figure 12, are considered:

- Peak Clipping: the electricity consumption is decreased during the peak periods in order to reduce the peak demand (e.g. implementation of fuel switch strategies for space heating);
- Valley filling: the electricity consumption is increased during the off-peak periods (e.g. hydrogen production) ;
- Load shifting: the consumption is displaced from peak periods to off-peak periods, combining the two previous patterns (e.g. electricity storage in batteries or thermal storage in domestic hot water tank).

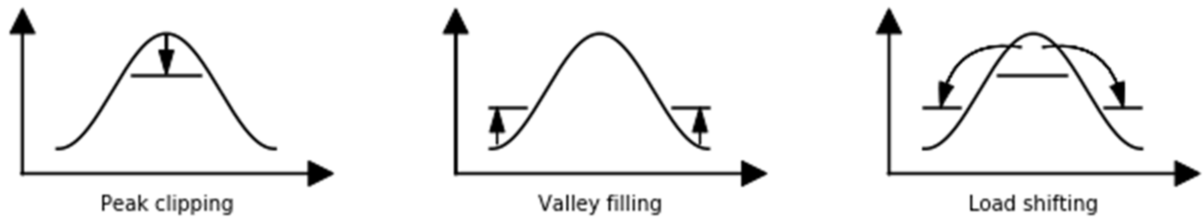


Figure 12: DR strategies addressed in this article

In this study, these DSM were turned into three patterns:

- Peak clipping: daily decrease of the consumption (-100 MW) during three hours applied at the daily maximum of the residual consumption;
- Valley filling: daily increase of the consumption (+100 MW) during three hours applied at the night minimum of the residual consumption;
- Load shifting: Addition of the two previous patterns.

The UCED model validated in the previous section was used to evaluate the influence of DR events on the French power system following the process described in Figure 2. The electrical mix was evaluated twice. The first evaluation takes the observed residual consumption as input, while the second evaluation is performed with a modified residual consumption according to the DSM pattern. The marginal mix corresponds to the difference between these two electrical mixes. The case-studies illustrate the capability of this model to assess the impact of DR events on a power system, and thus the necessity to consider daily and intra daily dynamics, electricity exchanges and the limited water reserves.

4.2.1. Influence of DR events during a critical week

For this case-study a week of February with a high residual consumption was chosen. Two simple DR events were first investigated (peak clipping and valley filling).

The duration of these two events during the week are represented in Figure 13 a. Figure 13 b and c show the influence of the two considered DR events on the power system. Figure 14 presents the two marginal mixes responding to the DR events considering the balance during the entire week. Several effects on the power system were noticed:

- Example 1 (peak clipping): Around 40% of the consumption reduction led to a simultaneous decrease of the hydroelectric generation. This consumption was mainly displaced during the same half-day and also during the rest of the week to a lower extent. The other 60% of the decrease led to a decrease of the coal-fired generation. As the decrease happened during the daily peak, the unit-commitment of the power system was modified: a part of the coal-fired power plants was decommited. Consequently, this resource was not available for the dispatch during the rest of the day. In the French power system, coal-fired power plants are one of the latest technology committed, but they are firstly dispatched when committed. The decommitment of the technology impacted then the whole day. The decrease of the coal fired generation was mainly compensated through a decrease of the electricity exports and an increase of the generation of the nuclear and CCGT power plants. In total, the decrease of the consumption seemed to have a positive impact on the greenhouse gas emissions of the power system: the coal-fired electricity generation decreased and the utilization rate of the nuclear powerplants increased. However, it is more complicated to evaluate the impact of the decrease of the French exports. In this model, it is assumed that the decrease of the French exports is compensated by the other countries exporting to the same countries as France. In this example, the decrease of the French exports mainly affected the German electricity generation, which is more carbon-intensive than the French.
- Example 2 (valley filling): Similarly to the previous example, the DR event affected partially the hydroelectric generation. The increase in the hydroelectric generation was mainly compensated during the half-day. The remaining increase in consumption is met mainly by nuclear power plants, which led to an increase of the utilization rate of the nuclear powerplants.

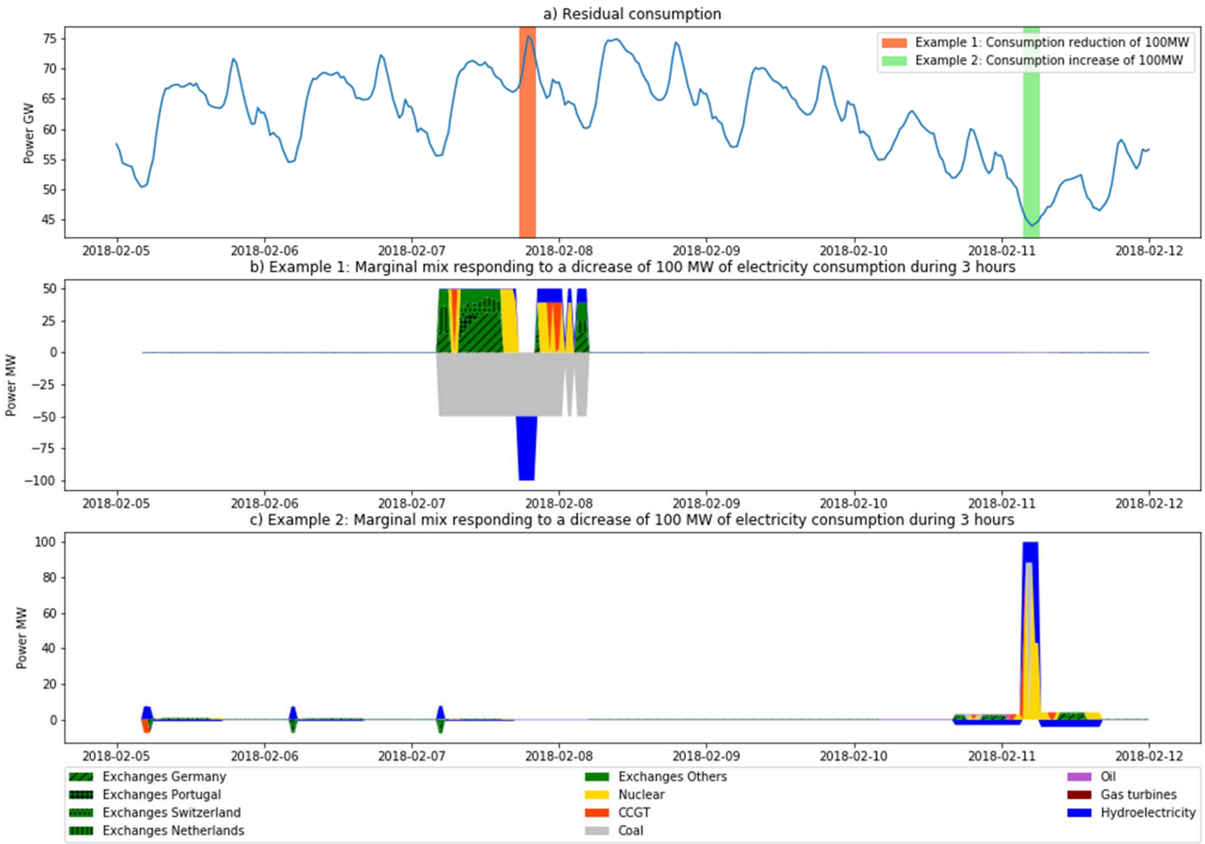


Figure 13: Influence on the French power system of two DR events during the week of the 5th February 2018

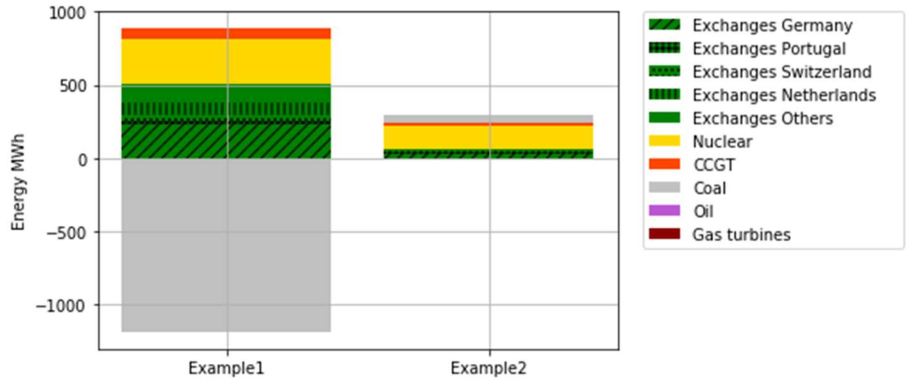


Figure 14: Marginal mixes consequent to the two DR events

4.2.2.Influence of recurrent DR events

Daily peak clipping, valley filling and load shifting were applied for each day of the year 2018, simulating a recurring DR event with an amplitude of 100 MW. Figure 15 represents the yearly impact on the French power system for these three patterns. The depicted results are represented in terms of a net balance and negative values indicate a decrease in production or an increase in export. Results of the flow tracing method showed that DR applied on the French power system impacted mainly the German, Portuguese, Swiss and Dutch power systems. The details of the yearly impact of the DR on the exchanges are detailed in Table 2.

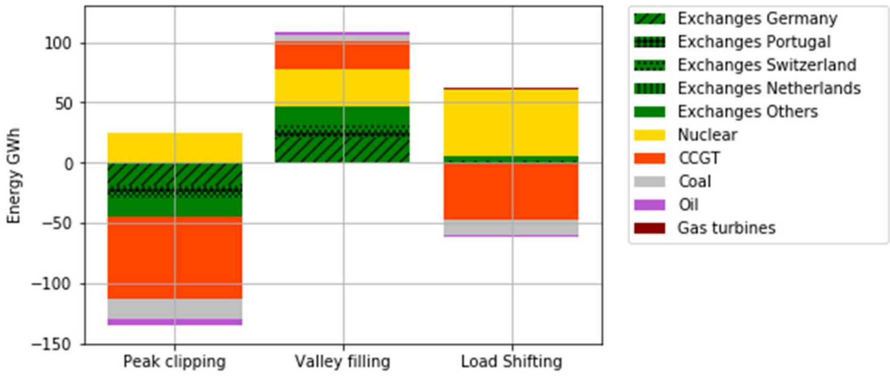


Figure 15: Marginal mixes of the impact of DR on the French Power system in 2018

The three DR strategies increased the nuclear electricity generation, leading to an increase of the utilization rate of the nuclear fleet. The peak clipping strategy also decreased the energy generated from fossil fuels such as natural gas, coal or oil. Moreover, this strategy increased the total amount of electricity exported and would reinforce the French position as net exporter on the European grid. The valley filling strategy increased the electricity generation from fossil fuels and decreased the total amount of electricity exported. Finally, the load shifting strategy seemed to be the most efficient way to increase the utilization rate of the nuclear fleet while decreasing the electricity generation from fossil fuels. The net balance of the exchanges was only slightly affected. It should be emphasized that this result presents the sum over the year of net imports and net exports occurring at different periods of the year. Table 2 details the net imports and exports for the three DR strategies, focusing on countries most affected. For example, the load shifting strategy only increased the net balance of the electricity exchanges by 4 GWh, but an increase of 47 GWh and a decrease of 44 GWh of the exports to Germany occurred during the year. While the net balance of the exchanges was slightly affected, the net imports and exports were widely impacted. It can be assumed that the technologies hidden behind these nets imports and exports varied also widely during the year.

Table 2: Details of the impact of the DR on the exchanges

Strategy	**Peak Clipping (-110 GWh)**		**Valley Filling (+110 GWh)**		**Load Shifting**	
Impact on the exchanges	**Decrease of the French exchanges (GWh)**	**Increase of the French exchanges (GWh)**	**Decrease of the French exchanges (GWh)**	**Increase of the French exchanges (GWh)**	**Decrease of the French exchanges (GWh)**	**Increase of the French exchanges (GWh)**
Germany	35	-54	22	-1	47	-44
Portugal	12	-16	4	0	13	-14
Switzerland	10	-12	4	0	12	-10
Netherlands	3	-7	3	0	5	-6

Others	19	-34	15	0	29	-28
Total	**79**	**-124**	**48**	**-1**	**106**	**-102**

As expected, most of the exchange marginality was in Germany, which is Europe's largest exporter along with France. Most of the time, France and Germany are competing to export to the same countries. When the French exports increased, German electricity production and exports decreased.

The power systems of Portugal also had a significant impact on the French marginal mix. Spain was a net importer most of the time, importing electricity from France and Portugal. Consequently, when the French exchange increased, the model often considered that Portuguese electricity generation and exchange would decrease with the French electricity exported to Spain.

Finally, the impact of the Swiss power system can be explained by the high installed capacity of hydroelectric powerplants associated with snow-melting, which increases hydroelectricity generation and decreases the generation cost of Swiss electricity between April and September.

The three DR strategies tested previously were applied everyday of the year. However, a sensitivity analysis could be performed on this model to develop an optimal DR strategy. For example, Figure 16 presents the marginal mix consequently to the peak clipping strategy during each quarter of the year. The strategy was the most efficient to improve the utilization rate of the nuclear fleet, reduce the generation from fossil fuels and increase the exchange balance during the first quarter of the year. The electricity demand was high during this quarter and the power system was often saturated. On the contrary, the demand was lower during the second quarter and the electricity generated by hydroelectric powerplants was high due to snow melting. Consequently, the peak clipping strategy decreased the utilization rate of the nuclear fleet.

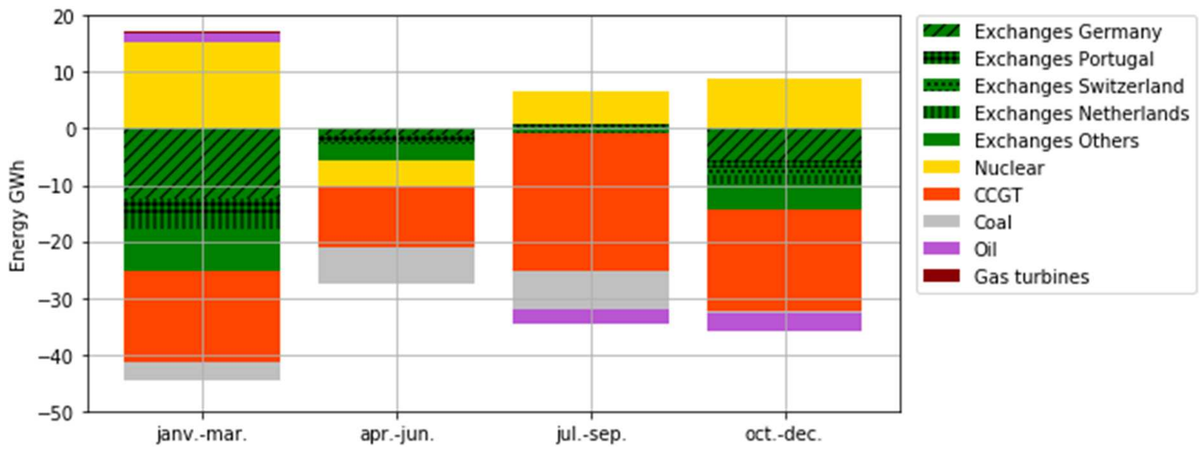


Figure 16: Marginal mix consequently to the peak clipping strategy during each trimester of year 2018

Figure 17 shows the marginal mix resulting from the peak clipping strategy applied only one day per week. Throughout this example the sensitivity of the marginal mix to the time of the week could be observed. For a similar reason as in the previous example, the peak clipping strategy seemed to be more favorable on weekdays than on weekends.

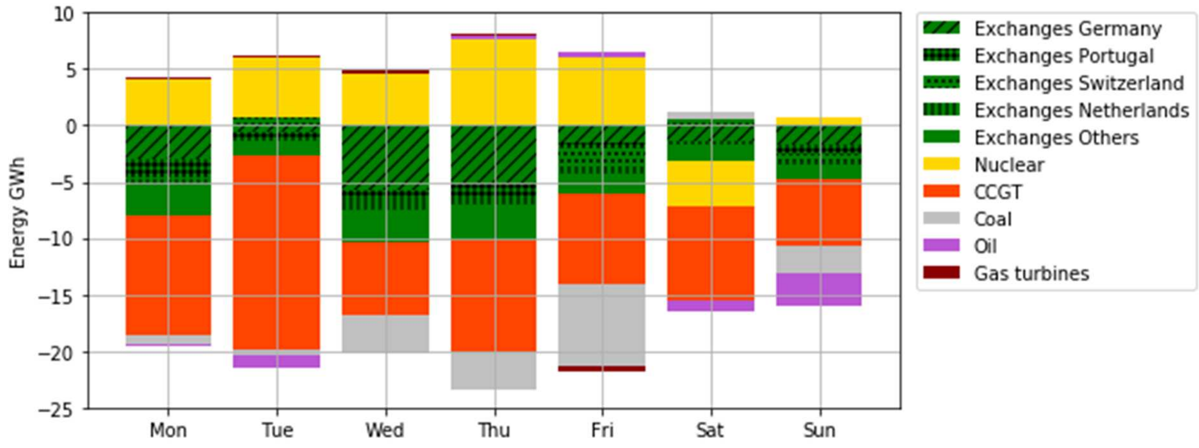


Figure 17: Marginal mix consequently to a peak clipping applied a day per week depending on the way of the week

In conclusion, the method presented in this article can be used to evaluate the influence of DR strategies on cost, GHG emission or cross-boarder exchanges.

5. Conclusions

The purpose of this study was to assess the marginal mix of DR events with an application to France, using a semi-physical power system model. First, a method to model the unit-commitment and economic dispatch problem was developed based on two calibrated merit-orders, the first one representing the unit commitment merit-order, the second the economic dispatch merit-order. Moreover, the model takes into account the specificities of hydroelectric production with its energy conservation, the availability of power plants and the electricity exchanges. This allows to reproduce the daily and intra-daily dynamics, which is an essential feature for evaluating DR events. The combination of all these characteristics makes it an original model as the literature shows that single-country models rarely address all these constraints. Moreover, incorporating the "flow-tracing" method that allows to identify the origin of the imports and the destination of the exports adds an essential aspect to such models.

The application of the method to France for the year 2018 is validated with historical data for the whole year and for each week. This ensures the validity of the model, an important point to stress in order to analyze the impact of DR events of a few hours. Sub-hourly DR events were not addressed in this article, and would require models with a much finer time step and, given the limited availability of calibration data at sub-hourly time step, a different approach. The validation showed that single-country models, including interconnections, are relevant to model power systems even though they are increasingly interconnected.

The marginal mix of the French power system was then evaluated for three DR strategies. The results showed that these strategies could increase the utilization rate of the nuclear power plants and decrease the French electricity generation from fossil fuels. Moreover, DR applied in France also affected the interconnected power systems, in particular Germany, Portugal, Switzerland and the Netherlands. This demonstrates the importance to model interconnections and to identify which countries adapt their electricity generation consequently to a change in national exchange. The limited water reserves also happened to be the key to capturing the displaced energy demand and its overall impact on the marginal mixes. Additionally the results showed how sensitive the marginal mix is to the time of the week as well as to the season .

From this study, it was observed that a large part of the variation in French electricity exchange is compensated by other countries, where a carbon-intensive marginal mix such as in Germany is expected. While the electrification of energy services will be part of the decarbonization process in France, its short-term consequences might be higher GHG emissions than expected. The evaluation of the marginal emission factor would require completing the model developed in this article with models evaluating the marginal emission factor from the different European countries and the national power plants.

One key limitation of the model is that it addressed a current power system (applied to France in this study) and can be used as long as the change of electricity consumption does not modify the installed capacity of the power system or the planned availability of powerplants. The variation in demand for such an analysis should then be restricted to the observed range of variation for a given installed capacity, for instance an historical situation in this study. As all calibrated models, exceptional circumstances could generate larger errors, strongly modifying the dynamics of the power system, such as those occurred during the lockdown in March 2020 or the current energy crisis.

Provided that the input data needed for the model are available for future configurations of the power system (e.g. from simulations), this model could also be used for a prospective study. The methodology developed in this work could also be applied, with a few modifications, to evaluate the marginal mix of other countries.

Data Availability

The model developed in Python is available to download at:

https://gitlab.univ-lr.fr/jledreau/french-marginal-mix

Acknowledgements

This work is supported by ANRT under contract CIFRE 2019/0629.

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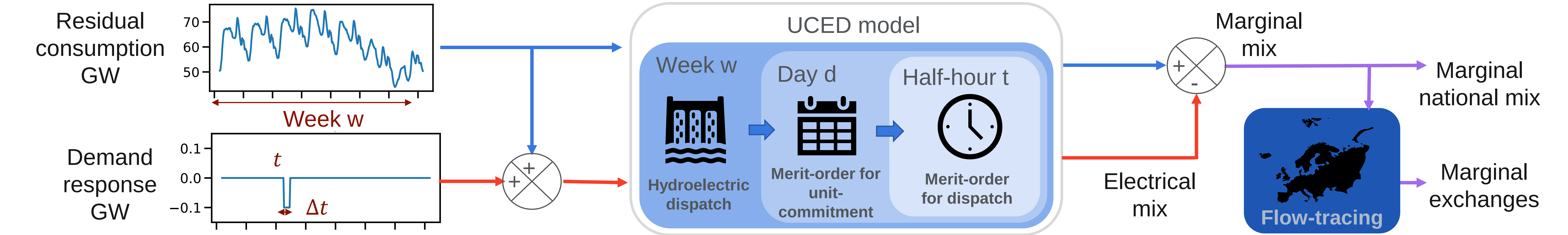
How to assess units reacting to a demand response event?

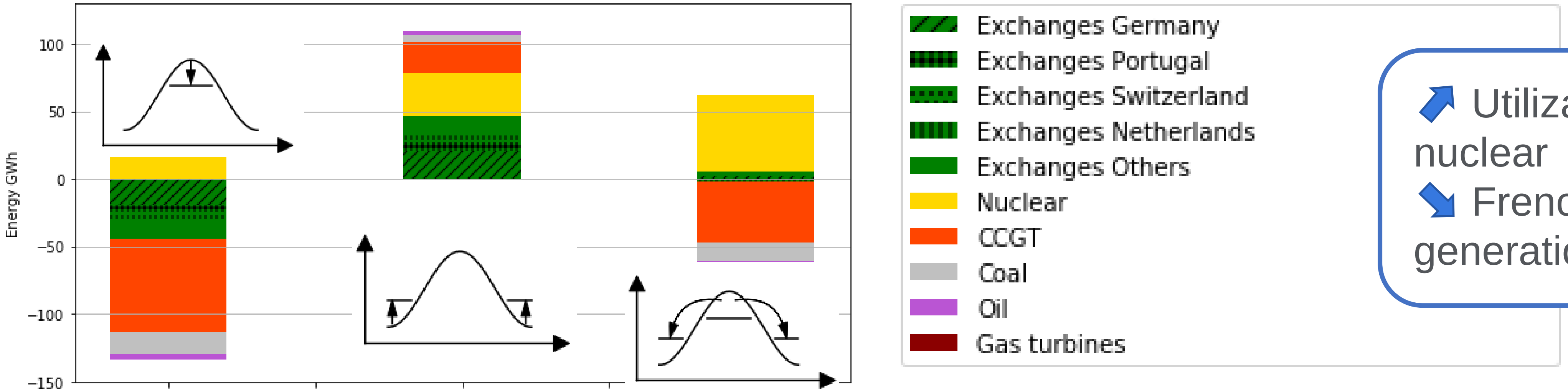
Development of a unit–commitment and economic dispatch model, validation and application to France

METHOD



RESULTS

Evaluation of three DR strategies for 2018:



↗ Utilization rate of French nuclear
↘ French electricity generation from fossil fuels

The model can help evaluating or designing DR strategies.