APPENDIX ON UNIT COMMITMENT & ECONOMIC DISPATCH

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As TSO, Elia must answer complex questions about the electricity market &, in a wider scope, the energy system. Will there be enough supply to meet demand? How much CO_2 will be emitted through electricity generation? What are the expected imports & exports in the coming decade?

To answer these questions, the whole electricity market is modelled for several future years. The type of model used is called a Unit Commitment & Economic Dispatch (UCED) model, which is described in this Appendix.

Firstly, the appendix describes the Unit Commitment & Economic Dispatch problem. Then, the elements of the problem (the inputs, outputs & constraints) are described. Finally, the software used (ANTARES) is presented.

1. Description of the problem

At any time, supply must meet demand. Modelling this happens to be quite a challenge as the system is:

- greatly interconnected in Europe, meaning one must model all countries in Europe, with their interconnections;
- composed of a large number of units;
- made of different type of units with significantly different costs & constraints on the way they produce power;
- penetrated more and more with renewables whose production depends on the weather.

To model these complex systems and represent the electricity market, there are two problems to be solved:

- **Unit Commitment**: fixing for each hour the units turned on to supply demand while respecting technical constraints (e.g.: ramp constraints or outages of thermal units);
- **Economic Dispatch**: with a given dispatch, determining the power output of each generator to meet demand at the lowest cost, all the while respecting network constraints.

Hence, there is a need to use a Unit Commitment & Economic Dispatch (UCED) model. The Unit commitment problem is very technical as it contains non-convexities (e.g.: startup costs) as well as some binary variables (e.g.: whether a unit is in use or not). Several method [KUL-1] could be used to solve the latter, but these being very complex they will not be described here.

The Economic Dispatch can however be more intuitively approached as the decision making of the power plants production is based on well-known concepts in the electricity market: the merit-order and the demand curve.

The problem is defined as a grid with different areas & links. Each area is defined as a bidding zone. In these, the demand curve is extracted from the consumption profiles and the supply merit order is determined based on the hourly marginal cost of each unit.

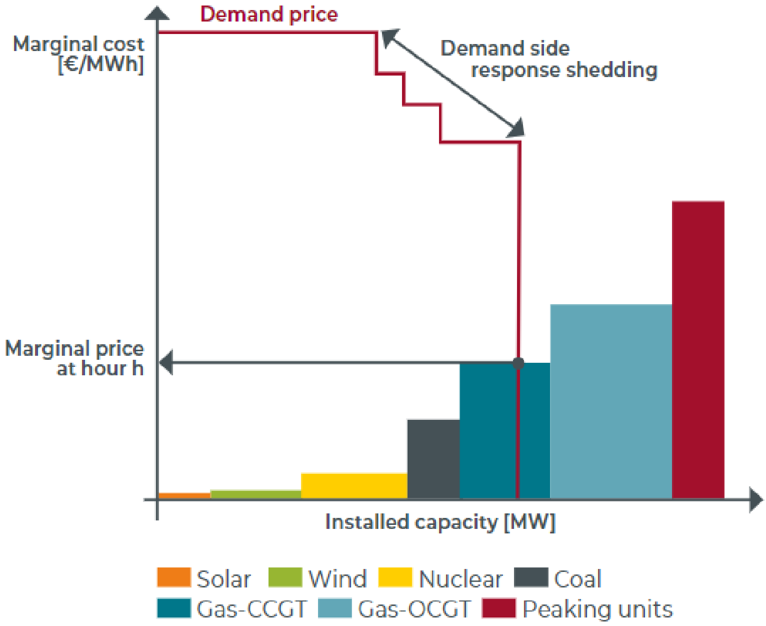

Figure 1 : Illustration of the supply and demand curves. Power plants deliver power by order of increasing marginal cost.

Regarding the supply side, the decision variables of this optimisation problem are the dispatchable generation (including both centralised thermal production facilities and hydro generation modelled as reservoir), the storage technologies (including batteries and pumped-storage plants) and the demand response capacities. The interconnections (represented either with a Net Transmission Capacity (NTC) or with Flow-Based constraints) are also key constraints of the problem. Wind, solar, run-of-river hydro and decentralised thermal production facilities are considered as non-dispatchable and 'must-run'. The modelling of the problem is more extensively described in Section 3.1.

The resulting price of the model (also called 'marginal cost of the system') is the cost resulting from an additional MW consumption that would be added to the system node. The resulting price takes into account the merit order and the grid constraints. An example is given in BOX-2 for the specific software used at Elia, where the price formation in a 'flow-based' context is explained.

2. Elements of the problem

2.1. Assumptions and limits

It is important to highlight several modelling assumptions to correctly interpret the results. These are outlined below.

- **Perfect weekly foresight** is considered for renewable generation, consumption and unit availability (known one week in advance following an ex-ante draw). This also means that storage, hydro reservoirs and thermal dispatch are optimised knowing all this in advance. In reality, this is not the case, as forecasting deviations and unexpected unit and interconnection outages can happen and need to be covered by the system. In line with the ERAA methodology, for each market zone, in order to cope with such events, a part of the capacity is therefore reserved for balancing purposes and could not be dispatched by the model.
- Simulations of the market are performed on the basis that **all the energy is sold and bought on an hourly basis**. Integrating long (I.e.: capacity markets) and/or real-time markets (I.e.: balancing market) in such a model is not straightforward. Forward markets are assumed to act as financial instruments anticipating day-ahead/real-time prices. Depending on the trading strategy and actual market conditions, an arbitrage value may exist between different time frames.
- The model **minimises the total cost of generation (including energy not served)** of the whole simulated system.
- A **perfect market is assumed** (no market power, bidding strategies...) in the scope of the model.
- Pumped storage units, batteries and market response are dispatched/activated in order to minimise the total cost of operation of the system. In fact, they could be used to net a certain load in a smaller zone or to react to other signals. The modelling approach also assumed that price signals are driving the economic dispatch of those technologies.

- Prices calculated in the model are based on the marginal cost/activation of each unit/technology while considering the modelled network constraints.
- The efficiency of each thermal unit is considered as fixed and independent of the loading of the unit. Actually, efficiency is a function of the generated power.
- Each bidding zone is considered a copper plate. Meaning, internal grid limitations within a bidding zone are not considered. In practice, some units can be re-dispatched in order to limit congestion on a grid.

2.2. Inputs & outputs

The model requires a set of specific information for each country within the simulated perimeter. These are either input parameters or constraint to the problem to solve:

- the hourly consumption profiles for each climate year (see dedicated Appendix on the subject),consisting of hourly/daily temperature;
- the centralised thermal production facilities with their technical parameters and costs;
- the hourly generation profiles associated with decentralised thermal production facilities;
- the hourly generation profiles related to each climate year (consisting of hourly load factors) for RES supply;
- the hydro facilities type, installed capacity and their associated technical parameters;
- the installed capacity of storage facilities with their associated efficiency and reservoir constraints;
- the installed demand flexibility/market response capacity and their associated constraints (if any).

Figure 2 gives an overview of the input and output data of the model.

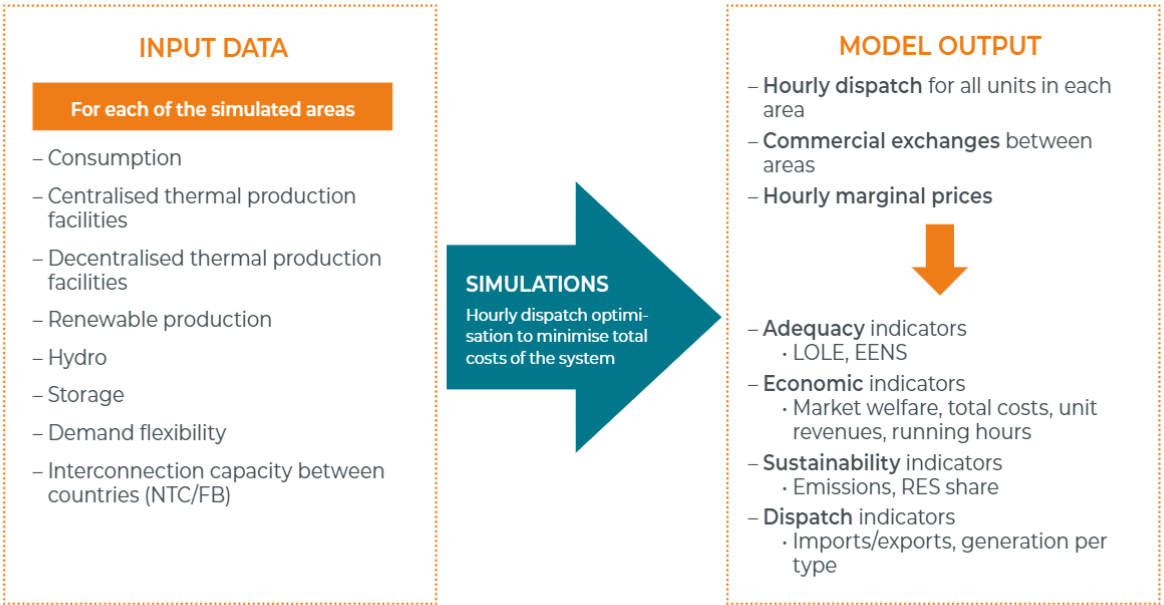

Figure 2: input & output data for the Unit Commitment & Economic Dispatch model.

In addition, it is possible to integrate other types of technologies within the model. For instance, the simulation of 'Power to X' by means of electrolysers reacting to prices can be considered, as well as time-constrained Vehicle-to-grid (V2G) technology.

A key input to be provided is the interconnection capacity between countries. This can be modelled either through flow-based constraints or through fixed bilateral exchange capacities between countries (NTC method).

Based on the inputs provided to the model, market simulations provide the results of the hourly dispatch optimisation, which aim to minimise the total cost of operation of the whole simulated perimeter. When this optimum cost is found, the following output can be extracted:

- locational marginal prices based on market bids (in this study locations are market zones);
- hourly dispatch of all the units in each country;
- hourly commercial exchanges between market zones.

This output data provided by the model allows a large range of indicators to be analysed:

- adequacy indicators (LOLE – Loss of Load Expectation, EENS – Expected Energy Not Served);
- economic indicators (market welfare, total costs, unit revenues, running hours...);
- sustainability indicators (emissions, RES shares);
- dispatch indicators (imports/exports, generated energy per fuel/technology).

3. Tool used

At Elia we use the electricity market simulator developed by RTE, called ANTARES [ANT-1], to perform the simulations for both adequacy and economic assessments. In addition, the output of the tool is also used to assess the flexibility means. ANTARES is a UCED model as it calculates the optimal unit commitment and generation dispatch from an economical perspective, i.e. minimising the generation costs of the system while respecting the technical constraints of each generation unit. The dispatchable generation (including thermal & hydro generation, storage facilities and demand side response) and the resulting cross-border market exchanges constitute the decision variables of the optimisation problem.

BOX 1: ANTARES market modelling tool

antares simulator

Antares-Simulator is an Open Source software developed by RTE. It is a sequential Monte Carlo simulator designed for short- to long-term studies related to large interconnected power grids. It simulates the economic behaviour of a given transmission-generation system, across the period of one year and on an hourly basis.

ANTARES has been used in several studies, including studies undertaken by ENTSO-E, which uses it as (one of the) market modelling softwares. These ENTSO-E studies include:
- the future European Resource Adequacy Assessment (ERAA) that will replace the MAF as from 2021;
- the assessment related to the 10-year network development plan (TYNDP, [ENT-1]) that ENTSO-E publishes every two years.

Moreover, ANTARES is used as the reference market modelling software in many other European projects and national assessments. Besides adequacy studies performed by Elia and the Belgian federal grid development plan, the tool has been used for:
- the Pentalateral Generation Adequacy Assessment (PLEF GAA 3.0), the third regional generation adequacy assessment report which is published in 2020 [PLE-1];
- French Generation Adequacy Reports by RTE [RTE-1] including long-term, mid-term and seasonal analyses;
- RTE's analysis of trends and perspectives in the energy sector (transition to low-carbon hydrogen in France or integration of electric vehicles into the power system) [RTE-2];
- the OSMOSE project [OSM-1];
- the Cigré Working Group C1.35: Global Electricity Network Feasibility Study [GLO-1].

For the creation of annual scenarios, ANTARES can be provided with ready-made time series or can generate those through a given set of parameters. Based on this input data, a panel of Monte Carlo years is generated through the association of different time series (randomly or as set by the user). Then, an assessment of the supply-demand balance for each hour of the simulated year is performed by subtracting wind and solar generation from the load, by managing hydro energy with a heuristic approach and by optimising the dispatch and unit-commitment of thermal generation clusters, storage and demand side response. The main goal is to minimise the total cost of generation on all interconnected areas.

ANTARES simulates a year by solving fifty-two weekly optimization problems in a row along the whole European perimeter for each 'Monte Carlo' year. This results in an hourly dispatch over the whole year for all technologies implemented in the model, considering all generation, storage and market response capacities as well as interconnection flows. Figure 3 illustrates such a dispatch for every hour of a single week.

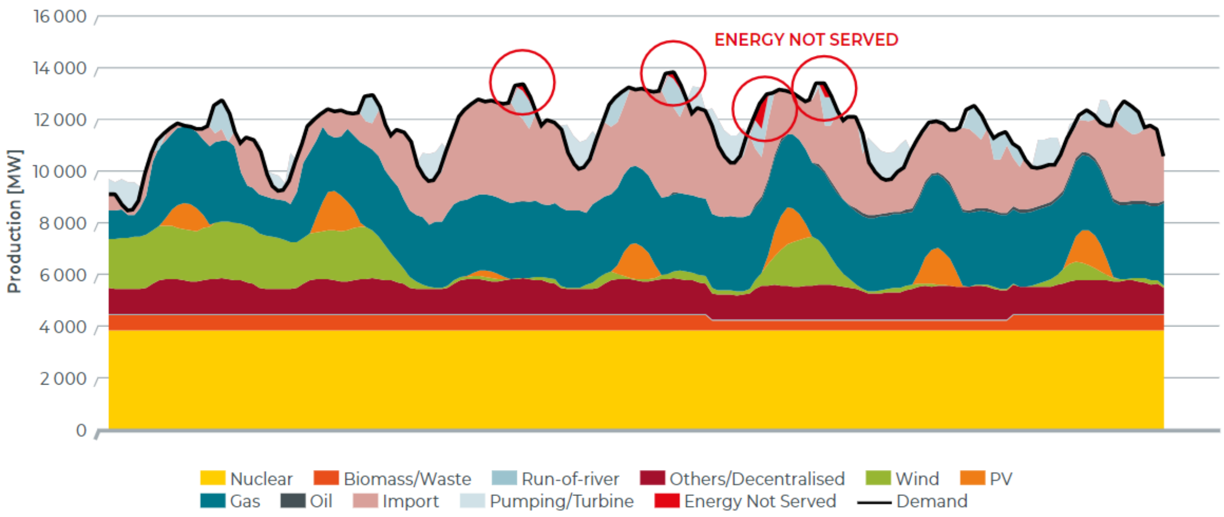

Figure 3 – example of a simulation dispatch output for a week in Belgium.

BOX 2: price formation

The market price calculated by ANTARES is based on the marginal cost of the different units but also on the flow-based constraints. Indeed, the different flow factors (if constraining) will impact the marginal price for each zone. In order to illustrate this, a simple example will be used as described below and in Figure 4.

Using an imaginary example with 3 zones as follows:

- Zone A: no supply, load of 100 MW;
- Zone B: 300 MW supply at 20 €/MWh, load of 100 MW;
- Zone C: 45 MW supply at 50 €/MWh, load of 100 MW.

The physical interconnection capacities are set as follows:

- Line A to B: 85 MW, impedance set to 1 Ohm;
- Line B to C: 85 MW, impedance set to 1 Ohm;
- Line A to C: 85 MW, impedance set to 1 Ohm.

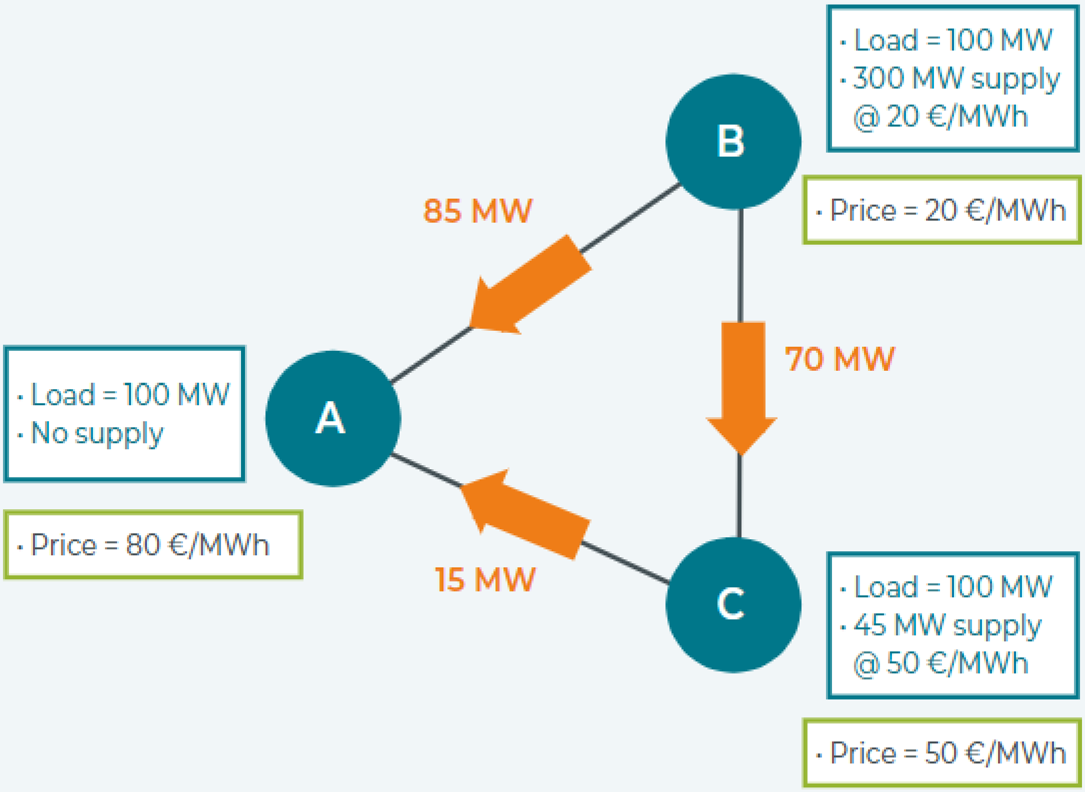

Figure 4 – example of a price formation in the ANTARES model, in a flow-based context.

Given that the branch [A,B] is limiting, the market clearing price in zone A is not only set by the marginal unit but also by the associated PTDF related to the branch. The price is therefore 80 €/MWh, which can be calculated based on the PTDF and other market prices. ANTARES replicates this behavior as well.

3.1. Model of electricity generation

A power system is made of different type of technologies with different set of technical characteristics setting the way they can operate (produce electricity). Technologies today include (not exhaustively) Dispatchable generation (including thermal and hydro generation), storage technologies (including pumped-storage plant and batteries) and demand/market response.

For each hour of each Monte Carlo year simulated (more information in dedicated Appendix), ANTARES calculates the most economical unit commitment and generation dispatch, i.e. the one that minimises generation costs while respecting the technical constraints of each generation unit. All units cited above constitute a part of the decision variables pf the unit commitment problem. This section gives a bit more insights as to how every unit / decision variable is modelled.

Grid topology

The topology of the network is described with areas and links. In this study, one area represents a bidding zone. It is assumed that there are no network congestions inside an area and that the load of an area can be satisfied by any local capacity.

Each link represents a set of interconnections between two areas. The power flow on each link is bound between two Net Transmission Capacity (NTC) values, one for each direction. Similarly to what is done by ENTSO-E, outages can also be modelled for chosen links. This is applied for HVDCs which are not in the meshed continental grid.

Moreover, in ANTARES, some binding constraints on power flows can be introduced. They take form of equalities or inequalities on a linear combination of flows. For instance, they have been used to model flow-based domains in the Core market-coupling area. (for more information, see dedicated appendix on Flow-based).

Wind and solar generation

Wind and solar generation depends on the climate Hourly wind energy production and solar generation data used are historical data for these production types. The forecasts of installed capacity for each simulated country are combined with this historical data to obtain production time series for onshore wind, offshore wind and photovoltaic production. This process is illustrated in Figure 2.

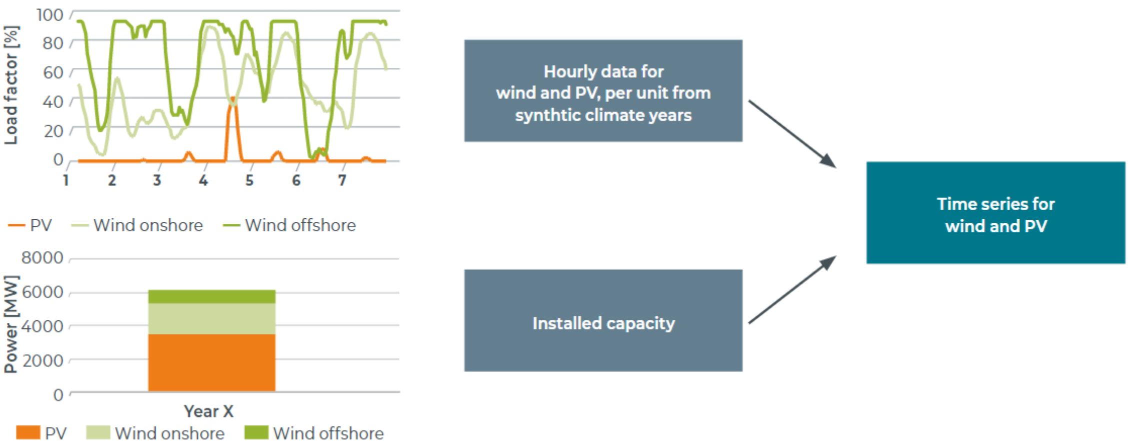

Figure 2 – production time series for wind & PV. Starting from hourly production for each climate year, these can be scaled up with a given installed capacity to create the production time series

Wind and solar generation are considered as non-dispatchable and come first in the merit order. More precisely, as other non-dispatchable generation, they are subtracted from the load to obtain a residual load. Then, ANTARES calculates which dispatchable units (thermal and hydraulic generation, storage and demand side response) and which interconnection flows can supply this residual load at a minimal cost.

Thermal generation

For each node, thermal generation can be divided into (i) profiled thermal generation and (ii) individually modelled. Meaning that either the generation of the thermal unit is fixed before the simulation, or that the unit will produce according to the most economical dispatch (as described in this appendix)

Thermal units whose production is profiled (who can also be referred to as 'must-run') represents either an aggregate of small units or units that do not have a CIPU contract. The small units represent either biomass or CHP units whose fixed time series directly take into account their unavailability, which will then be the same for all Monte Carlo simulations (see Appendix on Adequacy study for more details on Monte Carlo years). For the non-CIPU units, these can represent biomass, CHP and waste units. For each of these types, available power output measurement data is analysed. A correlation analysis on the relation between these units' output and the corresponding daily temperature, load and electricity price showed a clear seasonal trend. Furthermore, because no significant difference in aggregated behaviour between these categories is discovered, in terms of load factor or seasonal correlation, and to limit the upscaling error due to the ratio of installed capacity over measured capacity, it is decided to combine these three categories into a single generation profile. Based on historical data, this gives the hourly generation profile, displayed in Figure 3

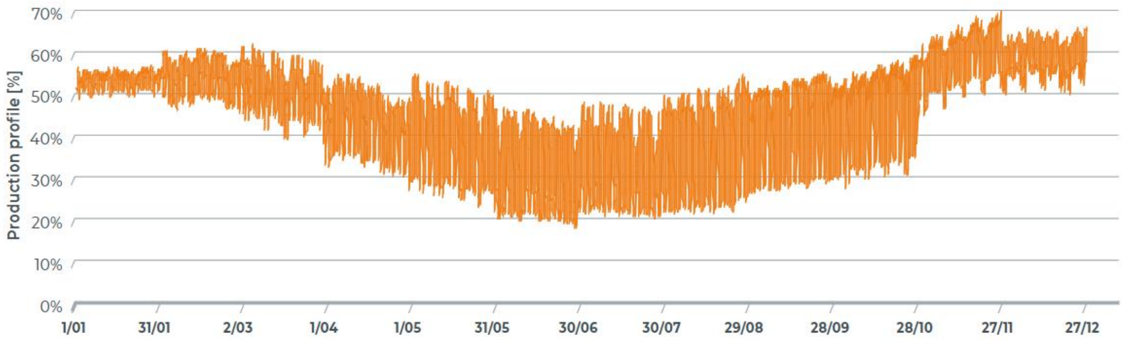

Figure 3 : hourly profiled thermal generation

Whether concerning an individually modelled or profiled thermal generation, in each node, the thermal generation is divided in clusters. A cluster is a single power plant or a group of power plants with similar characteristics. For each cluster, some parameters necessary for the unit commitment and dispatch calculation are taken into account by ANTARES. Some are needed for both individually modelled & profiled thermal generation:

- the number of units, the nominal capacities and a capacity modulation (if any), defining the installed capacities for each hour; the cost, including a variable cost (including modulation within the year) and a start-up cost; Some other parameters are only relevant for individually modelled plants:
- the parameters associated to the availability of units, including forced outage rate and duration, planned outage rate and duration and the planned outage minimum and maximum amounts for each day; the technical constraints for minimum stable power, (partial) must-run, minimum up and down durations.

Concerning the technical constraints for must-run (or profiled thermal generation), two values can be used: a value considered only if the plant is switched on (minimum stable power) and a value which, if higher than null, forbids the plant from being switched off in the dispatch (must-run). The latter is given on an hourly step time base, whereas the former is a single value for the whole simulation.

The variable cost of each unit is determined through a set of parameters including the efficiency, the variable and operating maintenance cost and prices (CO_2 price, fuel price, fuel price modulation). Moreover, the efficiency of each thermal unit is considered independent of the loading of the unit even though it depends on the generated power.

The installed capacity for each hour and the parameters associated to the availability of units are used to generate the time series of available capacity

Hydro generation

Three categories of hydro plants are defined:

- pumped storage;
- run-of-river;
- inflow reservoir power production.

The first two types of hydroelectric power production are present in Belgium, whilst the last type is more common in countries with more natural differences in elevation.

Pumped-storage plant (PSP) whose power depends only on economic data. Pumped-storage plants can pump water which is stored and turbined later. ANTARES optimises the operation of PSP alongside the other dispatchable units while making sure that the amount of energy stored (taking into account the roundtrip efficiency of the PSP, set at 75%) equals the amount of energy generated during the week. Pumped-storage plants are divided in two categories: **open-loop** and **closed-loop**. Open-loop pumped-storage plants have a reservoir associated with a free flowing water source whereas closed-loop pumped-storage plants have a reservoir independent from any free flowing water source. Dispatch of the pumped storage reservoirs can depend on the size of the units as well as their operating mode;

Run-of-river (**RoR**) plants which are non-dispatchable and whose power depends only on hydrological inflows. Run-of-river generation is considered as **non-dispatchable** and comes first in the merit order, alongside wind and solar generation. It is therefore subtracted from the load of each area in order to obtain a country-specific residual load;

Storage plants which possesses a **reservoir** to defer the use of water and whose generation depends on inflows and economic data. For storage plants, the annual or monthly inflows are first split into weekly amounts of energy. The use of this energy is then optimised over the week alongside the other dispatchable units. Each hydro unit can generate up to its maximum turbining capacity.

Storage

Storage includes the different technologies associated with batteries. Electricity can be stored in the batteries to be dispatched later. Batteries are defined by a set of parameters including loading and unloading capacity, a duration of availability related to the reservoir size and a roundtrip efficiency (set at 90% in the modelling). ANTARES optimises the operation of batteries the same way as pumped-storage plants, making sure that the amount of energy stored (taking into account the roundtrip efficiency of batteries) equals the amount of energy generated during the week. The different storage parameters for each country are collected through bilateral contacts or within the context of ENTSO-E.

Demand side Response

One way of modelling demand side response in the tool is by using expensive generation units. Those will only be activated when prices are above a certain price (and therefore after all the available generation capacity is dispatched). This makes it possible to replicate the impact of demand side response shedding, which is assumed to be mostly industrial load that can reduce part of its consumption when prices are above a certain activation price, as considered in this study. Duration of availability as well as activations per day and week can be set for this capacity as binding constraints.

These units are modelled in the same way as for individually modelled thermal production. Additional constraints are integrated in the tool to represent the limits of each category of market response shedding, such as the duration of availability or the number of activations per day or per week.

References

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