A. UNIT COMMITMENT AND ECONOMIC DISPATCH

As TSO, Elia must answer complex questions about the electricity market and, in a wider scope, the energy system.

To answer these questions, one of the main analyses consists in modelling the whole electricity market for future years.

In this appendix, the model and different elements of the problem (the inputs, outputs, and constraints) are described. The software used (Antares Simulator) is also detailed and his formulation shortly described. Finally, the modelling approach of the main elements of the model is detailed.

A.1. DESCRIPTION OF THE PROBLEM

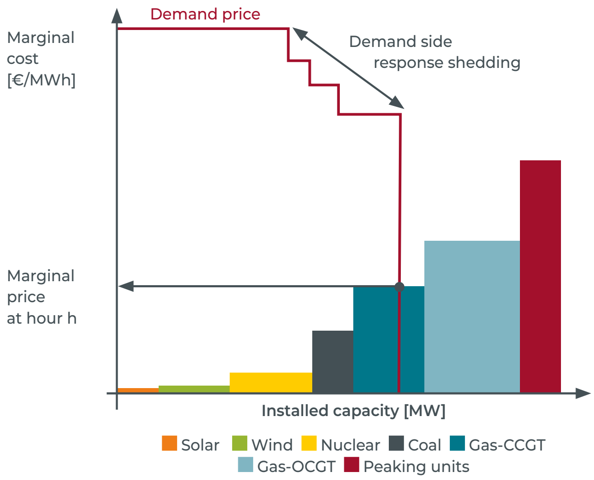
At any time, supply must meet demand. Modelling this happens to be challenging as the system is greatly interconnected in Europe, meaning one must model all market zones/countries in Europe, with their interconnections, composed of a large number of units (generation, storage, demand flexibility...); made of different type of units with significant different costs and constraints on the way they produce or store power and penetrated more and more with renewables whose production depends on the weather.

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 methods [KUL-2] 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 and 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 A-1 gives a visual representation of the merit order and demand curves although such representation is a simplification of the problem for one area (without interconnections). Indeed, the model takes also into account storage or hydro units which are not easily represented in the figure, since their placement in the merit order is defined during the simulation as their output will be optimised by the model to minimise the costs of the system.

FIGURE A-1 — DIDACTIC ILLUSTRATION OF THE SUPPLY AND DEMAND CURVES



Regarding the supply side, the decision variables of this optimisation problem are the dispatchable generation (including both centralised thermal production facilities and dispatchable hydro reservoirs) and the storage technologies (including batteries and pumped-storage plants). The interconnections (represented either with a Net Transfer 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 5 below.

Regarding the demand side, the model takes into account different kinds of demand flexibility (demand shedding, demand shifting) or can also optimise 'power-to-X' consumption based on a predefined strike price or other constraints.

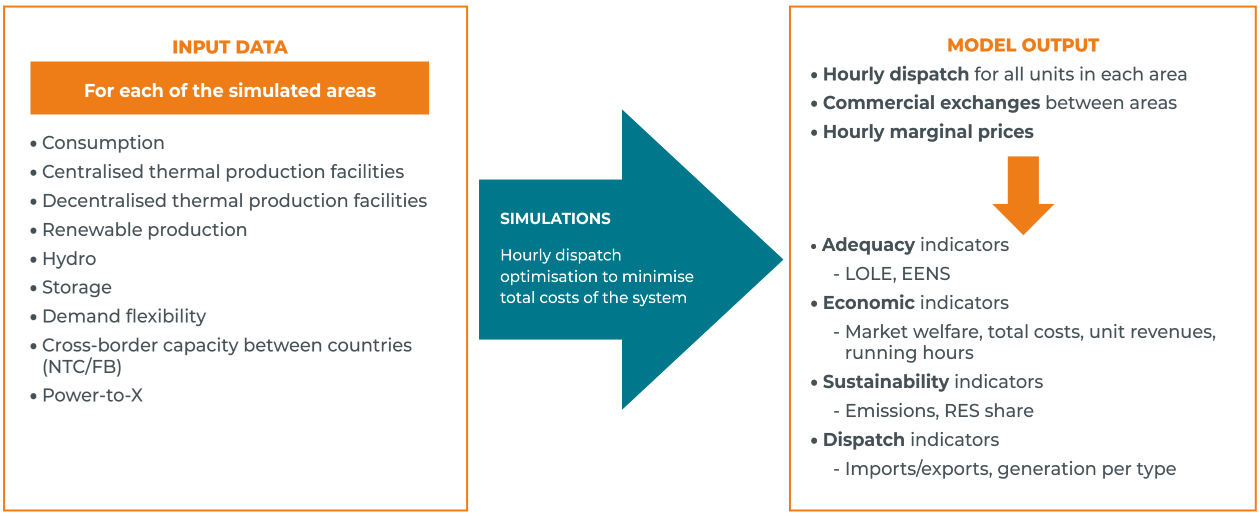
The resulting price of the model for a given node (also called 'marginal cost of the system') is the cost resulting from an additional MW consumption that would be added to the system node. The resulting price takes into account the merit order and the grid constraints. An example is given in BOX A-2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

A.2. INPUTS AND 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. Figure A-2 gives an overview of the input and output data of the model:

- the **hourly consumption profiles** for each climate year (see dedicated Appendix B 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 **renewable energy sources (RES)** supply;
- the hourly generation profiles of **out-of-market devices** that are optimised on the residual load (computed based on consumption profile and RES generation profile for each climate year), such as residential out-of-market batteries;
- the **hydro** facilities type, installed capacity and their associated technical and economic parameters;
- the installed capacity of **storage** facilities with their associated round-trip efficiency and reservoir constraints;
- the installed **demand flexibility** capacity, its type (e.g. demand response, batteries, vehicle-to-grid...) and their associated constraints (if any);
- the **'power-to-X'** capacities (e.g. power-to-gas, power-to-heat...) with their associated constraints.
- the **cross-border** capacity between countries. These constraints can be modelled in two ways: (i) flow-based constraints (with Standard or Advanced hybrid coupling and with flexibility devices if any) or through fixed bilateral exchange capacities between countries (NTC method) – see Appendix L;

FIGURE A-2 — INPUT AND OUTPUT DATA FOR THE UNIT COMMITMENT/ECONOMIC DISPATCH MODEL



Based on the inputs provided to the model, market simulations provide the results of the hourly dispatch optimisation, which aims 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 (locations are usually market zones);
- hourly dispatch of all the units in each market zone;
- 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 (e.g. market welfare, total costs, unit revenues, running hours);
- sustainability indicators (e.g. emissions, RES shares);
- dispatch indicators (e.g. imports/exports, generated energy per fuel/technology).

A.3. SOFTWARE ANTARES SIMULATOR

The Antares Simulator (herein after 'Antares') is an open-source hourly electricity market simulator developed by RTE [ANT-1], and used by Elia to perform the simulations for both adequacy and economic assessments. In addition, the output of the tool is also used as input to assess the flexibility means. Antares is a UC/ED 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 and hydro generation, storage facilities and demand side response) and the resulting cross-border market exchanges constitute the decision variables of the optimisation problem.

BOX A-1 — 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.

Elia is using the software for more than 10 years and it is the tool used for performing the simulations used in the framework of capacity mechanisms calibration in Belgium (Strategic Reserves and more recently the market-wide CRM) but also for the Adequacy and Flexibility studies since the first edition in 2016.

Antares has been used in several studies across Europe, including studies undertaken by ENTSO-E, which uses it as one of the market modelling softwares. These ENTSO-E studies include:

- the pan-European Resource Adequacy Assessment (ERAA) that ENTSO-E publishes every year [ENT-4];
- the assessment related to the 10-year network development plan (TYNDP, [ENT-2]) that ENTSO-E publishes every two years.

Moreover, Antares Simulator is used as the reference market modelling software in many other European projects and national assessments. Besides adequacy studies performed by Elia and the economic assessment of the Belgian federal grid development plan, the tool has been used for (non-exhaustive list):

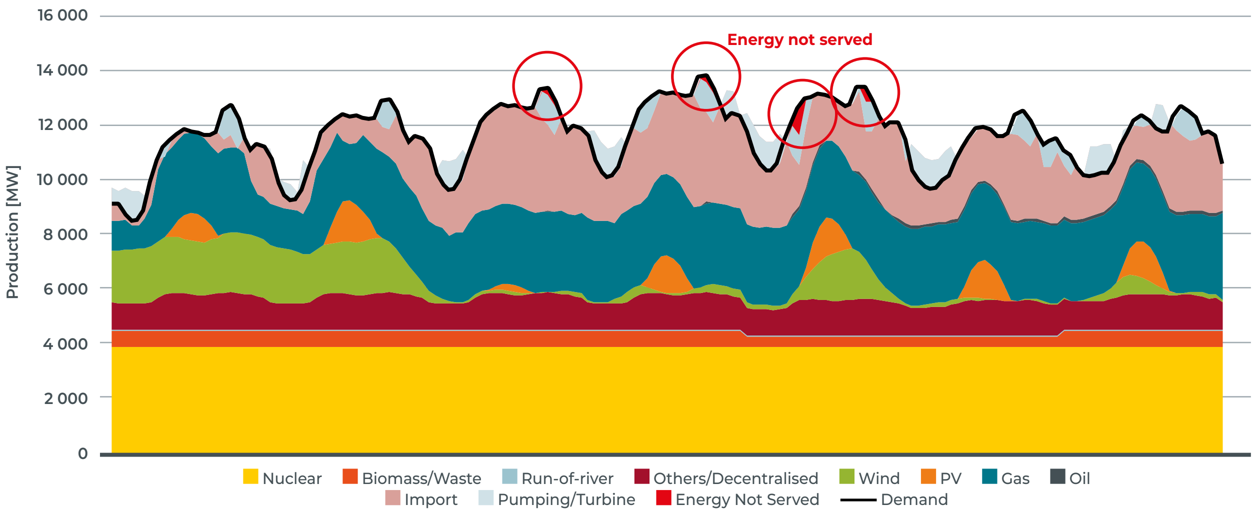
- The 'Bilan Prévisionnel' by RTE [RTE-2], assessing the adequacy for France covering the years from 2023 to 2035;
- RTE's analysis of trends and perspectives in the energy sector (transition to low-carbon hydrogen in France or integration of electric vehicles into the power system) [RTE-3];
- RTE's Energy pathways 2050 ('Futurs énergétiques 2050') [RTE-1];
- The OSMOSE project [OSM-1];
- The Cigré Working Group C1.35: Global Electricity Network Feasibility Study [GLO-1].
- E-Highway 2050, aiming at developing a grid planning methodology [ENT-7];
- MedTSO studies [MED-1];
- Litgrid Adequacy Assessment [LIT-1];
- APG (Austrian TSO): Electricity stress test for the security of supply in winter 2022-23 [APG-1]

For the creation of annual scenarios, Antares Simulator 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 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.

Finally, RTE international (RTE-i) has developed a collaborative approach around Antares Simulator, gathering different users to enhance the application, provide training, support, and development. TSOs amongst RTE-i Antares Simulator Users Club are: APG, Elia, EMS, Swissgrid, SEPS, IPTO, ELES, MAVIR, MEPSO, ESO, OST.

Antares simulates a year by solving fifty-two weekly optimisation 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 A-3 illustrates such a dispatch for every hour of a single week.

FIGURE A-3 — EXAMPLE OF A SIMULATION DISPATCH OUTPUT FOR A WEEK IN BELGIUM



A.4. FORMULATION OF THE PROBLEM

In Antares, the 'elementary' optimisation problem of the so-called Economic Dispatch (ED) problem is the minimisation of the overall system operation cost over a given period (e.g. a calendar year or winter period), taking into account all proportional and non-proportional generation costs, as well as transmission charges (i.e. hurdle costs) and other 'external' costs such as that of the unsupplied energy (generation shortage) or that of the spilled energy (generation excess).

The common rationale of the modeling used in Antares is to decompose the general problem into series of coupled standardised weekly optimisation problems.

In many contexts, the different weekly problems are actually coupled, as a result of e.g. energy constraints (such as management of annual reservoirs of hydro resources). Therefore, the coupling of the different weekly problems needs to be also properly handled before the actual decomposition of the problem into several weekly problems, namely (depending on simulation options):

- By use of an economic signal (typically, a shadow 'water value') yielded by an external preliminary stochastic dynamic programming optimisation to define the strategy for the use of energy-constrained resources across weeks/annually.
- By use of heuristics that provide an assessment of the relevant energy credits that should be used for each period, fitted to accommodate with sufficient versatility the different operational and/or market rules.

In a very simplified way, each (weekly) optimisation problem can be stated mathematically as follows

$$\textit{minimise} \sum_j c_j \bullet x_j$$

$$\textit{subject to}$$
$$\boldsymbol{A\,x \leq b}$$
$$\boldsymbol{x \geq 0}$$

In this formulation the parameters c_j relate to ('marginal') cost associated e.g. to generation costs (thermal generation costs, hydro production costs, storage production costs, demand side response costs, flexibility assets costs), transmission charges (i.e. hurdle costs), unsupplied energy (generation shortage) costs and/or spilled energy (generation excess) costs and pumping of energy costs.

As an example, the total production cost c of a given area can be defined as the integral (sum) over the marginal costs c(x) of production for each available technology within the merit-order of that market area, as:

$$C(x^s) = \int_{x=0}^{x=x^s} c(x)dx = \sum_{s,t} c_s \bullet x_{s,t}$$

where the label t (time) represents the period chosen (e.g. each hour of within the weekly problem) and the label s represent the different supply technologies within that area.
The variables x_j relate to the so-called **decision variables** of the problem, i.e. variables to be optimised. These typically represent the dispatched energy, the amount of energy non-served or the amount of energy spillage. The label j above is rather general and refers to a variety of variables or level of detail such as time resolution, type of technologies, geographical area, etc.

Furthermore, the x_j decision variables are subject to equality and inequality constraints. E.g. the decision variables themselves can either be zero or have finite value. Furthermore, several constraints on the decision variables are defined by the matrix **A** and vector **b** on the vector of all decision variables **x**.

For illustration, two examples of constraints contained inside the expression **Ax ≤ b** are:

<u>Energy balance for area 'k' at each hour t:</u>

$$\sum_s x^k_{s,t} - \sum_a d^k_{a,t} = \sum_{l(k)} F_{l,t}$$

where $\sum_a d^k_{a,t}$ refers to the total 'inelastic' demand to be served in area 'k' at hour 't' and $\sum_s x_{s,t}$ denotes all the production and pumping, or charging of batteries, in the area 'k' as well as possible energy non-served and spilled energy in area 'k' at hour 't'. Finally $F_{l,t}$ refers to the total flow through each 'link' 'l' in the Antares simulation connected to the area 'k'.

<u>Flow based constraint corresponding to the grid element 'CNEC' at hour 't':</u>

$$\sum_k PTDF_k^{cnec}\,(P_s^k - P_L^k) \le \mathrm{RAM}_{cnec}$$

where $PTDF_k^{cnec}$ refers to the PTDF of the zone 'k' and the grid element 'CNEC', RAM_{cnec} refers to the Remaining Available Margin (RAM) of the grid element 'CNEC' at hour 't', and P_s^k, P_L^k denote the total supply and total 'inelastic' demand of the area 'k' at hour 't' (related to some of the variables $x_{s,t}$ and $d_{a,t}$ above) and reflecting the total balance of the area 'k'.

Several other constraints are defined inside the expression ***Ax ≤ b***.

For all technical details and a complete detailed description, the reader can refer to the 'optimisation problem formulation' of the Antares software simulator [ANT-2].

BOX A-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 A-4.

Using an imaginary example with 3 zones as follows:

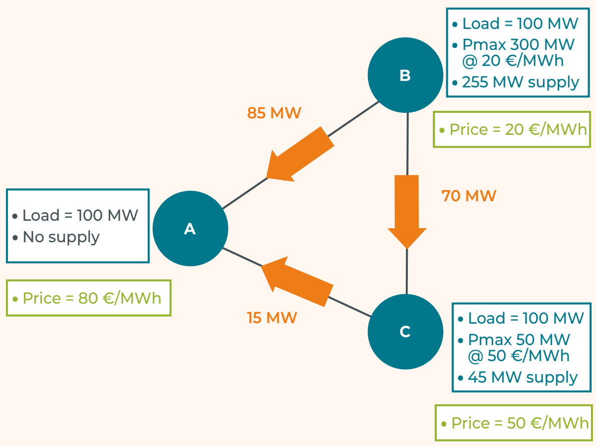
- Zone A: no supply, load of 100 MW;
- Zone B: 300 MW of Pmax at 20 €/MWh, 255MW of supply at 20 €/MWh, load of 100 MW;
- Zone C: 50MW of Pmax at 50 €/MWh, 45 MW supply at 50 €/MWh, load of 100 MW.

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.

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 behaviour as well.

FIGURE A-4 — SIMPLE EXAMPLE TO UNDERSTAND PRICE FORMATION IN THE ANTARES MODEL, IN A FLOW-BASED CONTEXT



A.5. MODELLING THE ELECTRICITY MARKET

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), non-dispatchable generation (including Renewable Energy Sources), storage technologies (including pumped-storage plant and batteries) and demand/market response. This section gives insights as to how every unit and decision variable is modelled.

Grid topology

The topology of the network is described with areas and links. In the next AdeqFlex'25 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 and some HVACs 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 are used to model flow-based domains in the Core market-coupling area (for more information, see Appendix L).

Wind and solar generation

Wind and solar generation depends on the climate. The projection of installed capacity for each simulated country are combined with climate years data (capacity factors based on e.g. speed of wind, solar radiation, etc.) to obtain production time series for onshore wind, offshore wind and photovoltaic production. More information on the synthetic climate years that will be used in the next AdeqFlex'25 study can be found in Appendix J.

Wind and solar generation are considered as non-dispatchable and come first in the merit order given their very low variable cost. 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

Regarding thermal generation, two modelling methods are applied:

- **Dispatchable thermal generation** – the unit will generate according to the most economical dispatch. Its final production is an output of the simulation;
- **Profiled thermal generation** – the production of the unit is fixed before the simulation (must-run).

Whether it is for dispatchable or profiled thermal generation, the thermal generation of each node in the model is divided into clusters. A cluster can be a single power plant or a group of power plants with similar characteristics.

The profiled thermal generation is used in the next AdeqFlex'25 study for the generation of smaller aggregated CHP, biomass and waste units (for instance units usually connected on the DSO grids). They are considered as full must-run according to a prede-fined profile, meaning that the production is to be consid-ered fixed whatever the most economic dispatch.

The dispatchable thermal generation is usually used to model units individually. Their dispatch can also be bounded to a partial must run in order to account for the production at low electricity prices related to the need of side processes.

More information on the general approach and the modelling for Belgium and other EU countries can be found in the dedicated Appendix C.

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, usually 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 possess 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. These plants often follow seasonal trends (i.e.: charging in summer and discharging in winter) which are not well represented by the unit commitment model. To that effect, the value of water ("water values") at each time of the year can be inputted and considered in the economic dispatch, to best represent reality.

In-the-market 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 85% 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.

Out-of-market batteries

A share of residential batteries can be considered to not be dispatched by the market but can be optimised based on a local signal, often linked to the domestic load of the house and a local production of solar panels. Hence, the production of these is defined ex-ante based on the residual load of each day.

Demand side Response Shedding

One way of modelling demand side response shedding in the tool is by using expensive generation units (mimicking a reduction of demand). Those will only be activated when prices are above a certain price (and usually 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 the next AdeqFlex'25 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.

Power to Molecules

The model can integrate the use of electricity to generate other energy carriers or heat. For instance, the consumption of electricity to produce hydrogen can be modelled. Different rules can be applied such as turning on electrolysers if (i) there is excess electricity (ii) the marginal unit is either a source of renewable energy or a nuclear power plant (iii) as baseload consumption. For the (i) and (ii), this is modelled via a dedicated node in the model. This node contains a load, which corresponds to the Hydrogen production. When the marginal price drops below the marginal price of nuclear units, the excess electricity is consumed by this node. Note that this is modelled for all countries in Europe with public plans to install electrolysers.

Power to Heat in industry

Similarly to hydrogen, generating heat in the industry most often happens through combustion of fossil fuels. To decarbonise the industry, more and more players plan to electrify their heat production. For this, industrial players will invest in either heat pump or e-boilers to produce respectively low (< 200°C) or high temperature heat (> 200 °C).

These power-to-heat units will likely run when it is financially more advantageous to use electricity than fossil fuels. In other words, if the marginal price of electricity falls under a certain threshold, any excess electricity will generate heat. This threshold price of activation depends on the gas price, the price for CO_2, as well as the expected efficiency of the appliance (which differs for a heat pump or an e-boiler). These units are modelled in the same way as the description of the electrolysers' modelling above. More information on this is given in the Appendix B on hourly electricity consumption and Section 3 on electrification of industry.

Electric Vehicle (EV)

There are different ways to model EVs to define their load on the grid, and all of them fall in two categories: (i) pre-defined load time series and (ii) dispatch it via the model. For the interested reader, more details are given on EV modelling in Appendix D.

Pre-defined time-series represent best natural EV charging, or in other words, a sub-optimal way to charge EVs for the electricity market. Other time-series can be defined to take into account a different network tariff (e.g. time-of-use tariff), or emulate PV self-consumption for consumers.

The other way to model EV consists of defining two constraint and let the model dispatch the load following these constraints. This way, the model ensures to dispatch the load in a way that minimises the system cost. These constraints concern (i) the maximum power at which EVs can charge and (ii) the energy needs that the EV needs to fulfill. For the latter, the energy needs can be defined either on a daily or weekly basis.

Note that with the proper technological and infrastructure developments, EVs are able to inject electricity back into the grid. This is also modelled for a share of the EV fleet, which size depends on the scenario.

Heat-Pump (HP)

Heat pumps can provide space heating as well as hot water. As for EVs, there are different ways to model HPs to define their load on the grid, and all of them fall in two categories: (i) pre-defined load time series and (ii) dispatch it via the model.

Pre-defined time-series represent best natural heating load. Other time-series can be defined to imitate a pre-heating period outside of electricity peak hours (i.e. 8 AM and 6 PM).

The other way to model HP consists of defining two constraint and let the model dispatch the load following these constraints. This way, the model ensures to dispatch the load in a way that minimises the system cost. These constraints concern (i) the maximum power at which HPs can heat and (ii) the energy needs that the HP needs to fulfill. For the former, comfort of the consumer needs to be taken into account in order to avoid having houses being heated beyond a reasonable set point (e.g. over 25°C). As for the energy constraint, this one has to be set daily and respect the energy needs defined for each day, of each climate year, based on Heating Degree Days (HDD).

For the interested reader, more details are given on Heat Pump modelling in Appendix E.

A.6. ASSUMPTIONS AND LIMITS

It is important to highlight several modelling assumptions to correctly interpret the results. These are outlined below and need to be kept in mind when analysing the results.

- **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. The optimisation solves all the system (i.e. the whole geographical perimeter) at once.
- **Energy Limited Resources (ELR)** such as pumped storage units, batteries and demand side response, modelled as 'in-the-market', are dispatched/activated in order to minimise the total cost of operation of the system. In reality, they could be used to net a certain load in a smaller zone or to react to other signals. The modelling approach assumes that price signals are driving the economic dispatch of those technologies.
- **During times of scarcity,** energy limited resources (such as storage or demand response) could be dispatched in different ways. In this respect, the default 'shedding policy' in Antares (i.e. 'shave peaks' see [ANT-1]), is used in the simulations. This 'shedding policy' aims at minimising the depth of the ENS, in line with the reliability standard calculation.
- **Prices** calculated in the model are based on the marginal cost/activation of each unit/technology while considering the modelled network constraints and their shadow prices.
- **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.
- **Offshore hybrid interconnectors** (i.e. interconnectors which combine both offshore wind and market-to-market connections) are modelled assuming that the wind farms connected to the interconnector are in a separate bidding zone.