Modelling the long-term deployment of electricity storage in the global energy system

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D'où qu'il vienne, le génie sera toujours un émerveillement.

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Introduction

The transformation of the energy system is a major challenge of the twenty-first century, being faced to the following heavy trends. The global population growth boosts the demand for basic goods such as water, food or energy. Developing countries are also seeing a surge in per capita energy consumption (China, India, Brazil, Africa) correlated to their Gross Domestic Product (GDP) and the access of poor populations to energy. This trend is not offset by the situation of developed countries (Europe or the United States of America - USA), although it is very different, with a downwards impact of deindustrialisation, the long lasting energy efficiency efforts and the financial crisis.

Simultaneously, human impacts on the environment are more and more alarming. In particular, it is now clear that anthropogenic Greenhouse Gas (GHG) emissions, mainly from fossil energy combustion, are causing a global climate change [1,2]. Energy production is the most important source of GHG emissions (25.9% for the 1990-2004 period) [3], but the industry, transport and buildings (residential or tertiary) are also using energy and add up to another 40.4% of GHG emissions.

A changing energy system

The energy system is complex and interacts with the entire economy. There are multiple sources of energy and several markets for energy. For example, the oil price is a crucial determinant of the global economy and geopolitics. It also impacts the prices of other energies (in particular gas) and of raw materials (including food). Electricity is not a global good, since physical grids are necessary to connect the market places. It is only traded at the regional scale, for example in the European grid. We observe a real change in the energy paradigm, pushed by the following drivers.

First, climate concerns are spurring governments towards sustainable energy policies, aiming at a strong reduction of CO_2 emissions. These policies are subject to multilateral discussions, e.g. at the annual United Nation’s Conference Of Parties (COP).

The second trend, on the supply side, is a relative scarcity of fossil resources, with increasing exploration expenses and decreasing yields. The recent development of unconventional oil and gas resources does not seem to be able to compensate in the long run for the losses of conventional resources. On the other hand, there is also a strong development of renewable energy sources, especially solar (photovoltaic) and wind power.

A third driver is the liberalization of the power system, particularly in Europe and North America. In Europe, it is promoted by the European Commission as a way to avoid monopolistic behaviours and facilitate the international market integration. However, the management of the power systems is made more complex, involving multiple markets and actors.

Furthermore, there is a global evolution of public opinions. In developing countries, local pollution (e.g. in China) and access to affordable energy are the main concerns. In isolated areas (rural areas in Africa, islands), renewable-based solutions can be more affordable than imported fossil fuels. In the developed countries, people are becoming more and more aware of the impacts of energy production on the climate and of the nuclear accident risks (especially since the Fukushima accident).

Finally, the power system has historically been developed as a vertical system, with centralized electricity production, transported to the final customers through extensive transmission and distribution grid infrastructures. The tendency is pushing towards a more decentralized system, where small-scale renewable generation is developed (mainly small consumer-owned solar panels) and where some consumers become “prosumers” (simultaneously producers and consumers). This desire to develop local renewable production reflects a mind-set change. The paradigm shift is already visible in the European electricity market, which decreasing prices are impacted by a lower demand, a higher renewable production and the resulting over-capacities. However, centralized production will still be necessary in the future, for instance as a complement to uncertain and variable renewable resources (such as wind and solar power). Indeed, a main challenge of the power system is its security and reliability, as electricity shortages have a huge impact on society.

Fighting climate change

The impact of the energy system on the global climate can be moderated by a reduction of the energy demand and by a less CO_2-intensive energy system. Energy efficiency programs are promising; for example energy retrofitting of buildings or electrical home appliances can significantly reduce a household’s electricity and heat consumption. For the industry, although significant advances have been accomplished, the margins for increased energy efficiency in the industrial sector are still large.

Nowadays, it is commonly admitted that a less CO_2-intensive energy supply is achievable through renewable energy sources, nuclear energy and coupling thermal power plants with Carbon Capture and Storage (CCS), or, alternatively, Carbon Capture and Utilization (CCU). Nuclear energy carries a risk of a major accident and concerns on nuclear waste disposal. CCS technologies remain to be developed, and also have some risks of accident (another drawback is the enormous volume of CO_2 to store). Renewable energy sources include hydro power, biomass, geothermal, marine energy (thermal, wave or tidal), but most of all we notice a strong expansion of wind and solar power generation. The huge potential of these sources of renewable electricity makes them a crucial option to decarbonise the energy system. Thus, the power system is bound to play a greater role in the total energy consumed. For instance, it could supply renewable energy to the transport sector (replacement of thermal vehicles with hybrid or full-electric vehicles) or for heating applications. This trend could outweigh the demand reduction efforts.

Modelling the power sector

Such evolutions of the power system, in terms of technological developments and economic investments, are very dependent on the energy policies enacted by governments. As a matter of fact, ambitious medium- to long-term energy policies were launched in several countries, such as the French energy transition or the German "*Energiewende*". However, energy policy has implications on energy dependency, trade balance, economic competitiveness, or local jobs. For that reason, policymakers need a global and long-term overview of the energy system, with an analysis of the different decarbonisation options (renewable energy sources, nuclear power and CCS technologies).

Long-term energy scenarios are used for this analysis purpose. A scenario is not a prediction of the future, but rather a description of one plausible pathway among others, corresponding to a set of policy-relevant assumptions. Taking the best decisions today requires a long-term foresight [4]. Energy scenarios can inform the discussion and add to the ongoing public debate, either with a qualitative or a quantitative approach. Narrative scenarios are more adapted to multi-disciplinary studies, showing the interactions between disciplines. Quantitative scenarios, most often produced with assessment models, are more explicit and more useful to policy makers, who need figures and time horizons. For example, quantitative scenarios can investigate the size of a future market (prices and quantities). However, one should not forget that this apparent precision is only valid as a way of exploring uncertainties, by making them more explicit.

Integrating renewable sources to the power sector

The background of our work is dominated by the important development of renewable energy sources in the power sector. The first historical electricity production was renewable, with hydro dams and hydro run-of-river. Today, a further deployment of renewable resources mostly relies on other renewable energy sources. Some of them can be controlled by the operator (dispatchable), such as geothermal or biomass (in thermal power plants); others have an uncontrolled output (non-dispatchable), such as wind and solar power, but also ocean thermal energy, tidal or wave power. The main possible regulation is downward (production curtailment), by reducing their output or switching them off at times of production.

Although they are still small in the world power supply, we observe a strong development of wind and solar power [5]. They are variable across several time-scales (very short-term: seconds, to very long-term: years), non-dispatchable (one cannot entirely control their output), and imperfectly predictable (as they depend on meteorological forecasts). These particularities make their integration at large scale in the power system difficult; some flexibility options are necessary.

Electricity storage comes as an important solution for shifting the renewable production in order to minimise the cost of the supply and demand balance. There are also very promising perspectives for demand response (better controlling the demand and adapting it to the supply) and decentralised, smarter grids. In addition, Supergrids for large interconnected AC-DC grids allow a better balancing of the local and regional variations of renewable production and power consumption. A relatively less innovative approach is to use fast-reacting thermal power plants to back up the variations of renewable output, but it harms the CO_2 emission reduction objective.

Objective of this work

For long-term foresight energy models, the development of these different flexibility options is a major challenge. In particular, the long-term technical and economic perspectives of the electricity storage, when correlated with various assumptions for renewable energy sources' development, have been little studied to date; this leads us to formulate the following question:

What role could electricity storage play in systems with high shares of variable renewable energy sources?

The first scientific challenge is related to the modelling of long-term impacts of renewable energy sources. Indeed, the variability and non-dispatchability of wind and solar power have crucial consequences in the long-term planning of power systems, which are not well represented in current long-term foresight energy models. Our first objective is thus to take into account the system effects of renewable energy sources in long-term technical and economic scenarios. Based on this objective we study scenarios with high shares of renewable energies, focusing on the impacts of renewable energy sources on the system.

A wide range of electricity storage technologies already exists, but today's market is still small, with little incentive to invest. The technologies are still too expensive and lack a viable business model. Still, energy storage is a key facilitator of renewable energy sources' integration in the energy sector. Therefore, the second objective of our work is to evaluate the potential for storage development. We consider the interactions of electricity storage with the entire power system, including the other flexibility options already mentioned (electric grid, demand response and more flexible power plants). Since existing long-term models do not account for a satisfactory representation of storage nor interconnected grids, we have to develop new approaches that take them into account and propose significant improvements.

Outline

Our research work is organized in four chapters. First, we review the current knowledge on the evolution of the power system and its modelling. The models of interest to us are the ones dealing either with the entire energy system or with the power sector sub-system only. Some models have a long-term foresight approach of the energy system; others have shorter-term ambitions – with a more accurate spatial and temporal representation. We focus on the impacts of variable renewable energy sources and on the representation of flexibility options, in particular electricity storage. In order to provide a consistent analysis of both power and energy modelling tools, we develop a typology to better understand and compare power sector modelling choices.

Second, we present our modelling developments of a long-term energy model, POLES (Prospective Outlook on Long-term Energy Systems). The operation and planning of the power system is modified to take into account the variability of renewable energy sources. Storage technologies are also introduced in POLES.

Third, we detail our new develop a power system optimisation model, EUCAD (European Unit Commitment And Dispatch). EUCAD can account for all system constraints and flexibility options. The variability of renewable energy sources is captured by using European-wide representative days of wind and solar production. In order to benefit from its technical detail in a long-term approach, we directly couple it to POLES. The information flows between models are bi-directional, which is a substantial improvement to the state-of-the-art. The long-term horizon of POLES is the basis for a coherent set of inputs to EUCAD, and the insights gained from EUCAD computation, such as storage operation or European international exchanges, are sent back to POLES and used in the capacity planning.

Fourth, the increased level of detail and new structure allow us to set up energy scenarios with a strong development of renewable resources. The impacts of renewable resources on the power system are assessed, with a focus on storage development. A sensitivity analysis is carried out in order to assess the impacts of a higher technical and economic performance of storage or a higher penetration of variable renewable resources in the power sector.

I. The long-term evolution of the power system and its modelling

I.1. The power system evolution

The energy system is expected to incur a drastic transformation in the coming years and decades, driven by decarbonisation objectives. The main levers to achieve this objective are mainly increased energy efficiency and use of renewable energy sources. Efficiency reduces (or avoids a strong increase of) energy demand. Some examples include increasing the efficiency standards in energy consuming appliances, better insulation of dwellings and public buildings, or using local sources of wasted heat or cold by increasing local synergies. Renewable energy sources include solar and wind power, the two sources with strongest potential, but other renewable sources are also expected to play a role: marine renewable energies (wave or tidal power, ocean thermal energy), geothermal energy, biomass and hydraulic energy. Renewable energy sources are mainly integrated in the power sector since they usually produce electricity, an energy carrier relatively easy to transport and use over long distances. Therefore the power sector is expected to play an important role by participating in the decarbonisation of other sectors: an increase of electrical uses is expected in the transport sector (development of hybrid or full-electric vehicles) and the heating sector (heat pumps). The power sector will undertake tremendous transformations, related to the increase of the share of renewable energy sources, as discussed below.

I.1.1. Impacts of renewable energy sources on the power system

Wind and solar energy sources are characterized by a fast development, as can be seen in Figure 1.

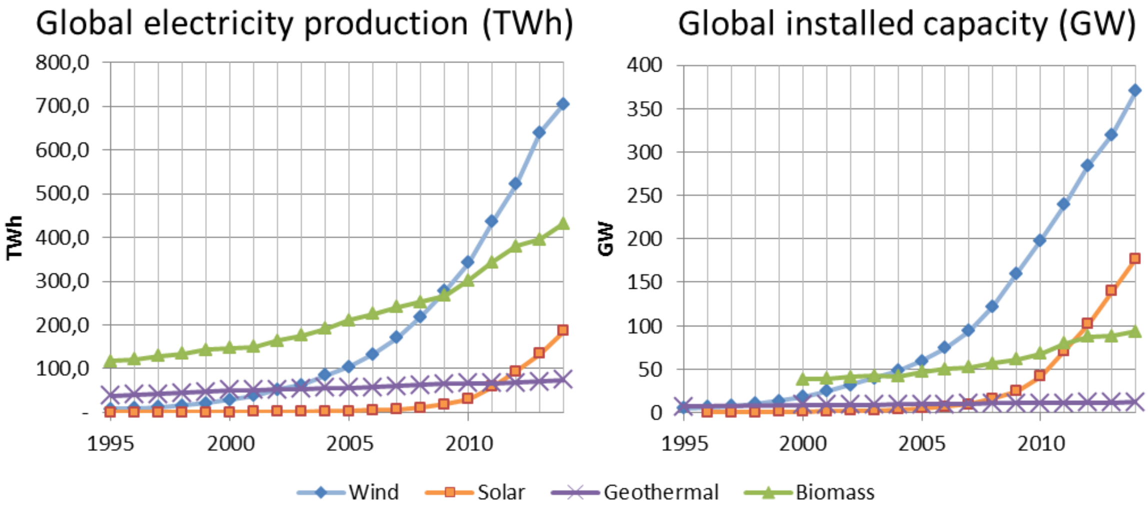

Figure 1: Development of the main non-hydro renewable energy sources worldwide (sources: [6–9]).

However, wind and solar energy sources can become an issue for the management of the power sector. They are variable across several time-scales: years, seasons, days, and hours. They are mainly not dispatchable, as a system operator or a producer cannot control their output, other than switching them off or voluntarily reducing their output (at times of production). Finally, their production forecast is based on meteorological forecasts, which implies that they are imperfectly predictable. The error margin decreases with the time horizon of the prediction. These specificities are implied by the term “Variable Renewable Energy Sources” (VRES) that we will use in this thesis.

* * *

VRES raise challenges for the power system management that have been extensively analysed in the last decade, e.g. [10–16]. The power generation capacities need to be adapted to the VRES development. Indeed, VRES have a quasi-zero marginal cost, since their production depends on the wind speed or on the solar irradiation; there are no fuel costs. This implies that, economically, they are always preferred to fossil fuel-fired power plants. Hydro lakes also have a “free fuel”: the water arriving in the dam storage. However this water acquires a value because its use can be displaced in time and can later replace an (expensive) fossil fuel generation. The non-dispatchability of VRES gives them a priority in the market. All other dispatchable productions have to be adapted to what is left of the demand, which is designated by the term “residual load” in the rest of this work.

The structure of this residual load is visible in the load duration curve of the following Figure 2, which is an ordered accumulation of the 8760 hours of consumption of a year. However, this type of curve hides the variability of VRES between two consecutive hours.

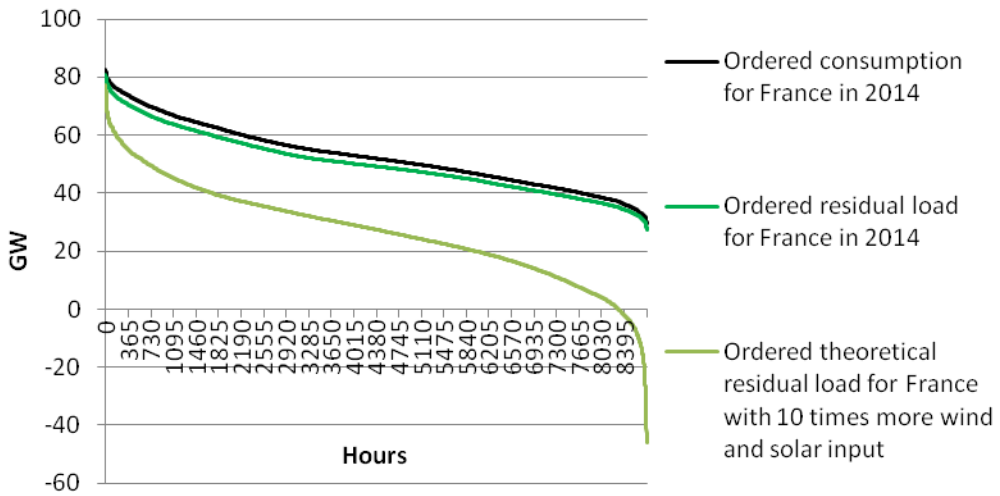

Figure 2: Load duration curve and residual load duration curves for two levels of wind and solar penetration in the French system (2.4% and 24.6%). Source: RTE data for 2014 [17].

Long-term impacts of VRES on producing capacities

The residual load duration curve shows the long-term impact of VRES on the capacity needs in order to maintain capacity adequacy. Compared to the development of a dispatchable capacity, the development of VRES increases the need for peaking capacities; the guaranteed VRES capacity available in periods of high demand is measured by the capacity credit [18]. Peaking capacities have to compensate for a lack of VRES production and can be switched off in periods of high wind or solar production. VRES cause a reduction of the need of base load capacities, because of their periods of strong production. VRES will replace very little capacities but will significantly reduce their equivalent full-load hours of operation. Some non-dispatchable VRES production can even be lost in case of over-production. These impacts represent an additional system-level cost, called “profile cost”, “adequacy cost” [19,20] or “compression cost” [21]. The market price structure is impacted, with periods of excess renewable power showing very low prices (even temporarily negative) and periods of high residual load showing very high prices, which are supposed to cover the costs of peaking capacities.

Short-term impacts of VRES on producing capacities

VRES also have a short-term impact on the power system: other power plants have to compensate for their variations (illustrated in Figure 3 for two different levels of wind and solar penetration).

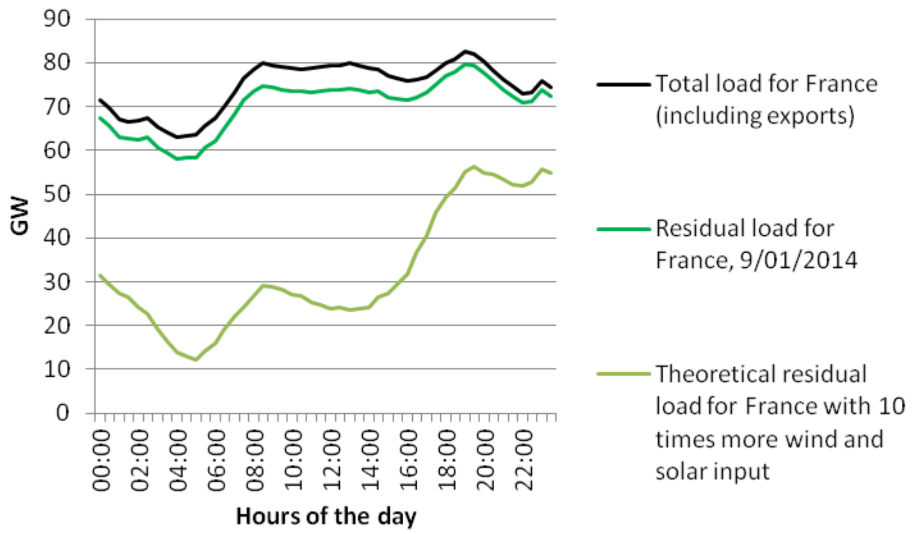

Figure 3: Temporal representation of the residual load for a winter day for two levels of wind and solar penetration in the French system (2.4% and 24.6%). Source: RTE data for January 9th, 2014 [17].

The fluctuations in demand and VRES production at an hourly time-scale can be covered by load-following capacities. This is currently planned in the day-ahead market and adjusted in the intra-day markets. On a shorter time-scale, fast variations of 15 to 30 minutes (mainly forecast errors) are compensated with balancing capacities, exchanged in the balancing markets. A higher penetration of VRES will increase system-level “balancing costs” [19,20]. The hourly market prices will become more volatile and shorter-term price signals could appear (15-minute markets already exist in Germany) in order to integrate better weather forecasts and send more dynamic market signals to plant operators [22,23].

The variability impacts of VRES, at all time-scales, support the development of flexible capacities (including electricity storage or demand-side management). Inflexible base-load capacities suffer from part-load efficiency losses and ramping limitations. VRES increase the wear and tear of thermal capacities, their Operation and Maintenance (O&M) costs, their polluting emissions, and the risk of unexpected failure (decreased reliability) [23,24].

Impacts of VRES on grid capacities

VRES have an impact on grid development because of their spatial distribution. Decentralized renewable productions have to be connected to the distribution network, thus often creating a need for new investment in the grid. The concept of smarter distribution grid (for better monitoring and control of the grid with large scale penetration of distributed generation) is emerging for coping securely and optimally with this situation. On the other hand, large renewable farms are usually far from load areas and need to be connected to the transmission grid with grid extensions. Other impacts on the grid management include risks of over-voltage in distribution networks or a loss of inertial reserve in the bulk system that can decrease the power supply reliability [25–27]. These grid-related costs are the third component of the “system costs” or “full LCOE” (Levelized Cost Of Electricity) of VRES [19–21].

* * *

The market design plays a crucial role in the integration of VRES in the power system. For example, with the current feed-in tariffs and priority grid access, even at null or negative market prices, VRES have no incentive to curtail their output (as long as the negative prices don’t exceed the feed-in tariff level). However, the market design is constantly evolving [28] and a long-term prediction of its operating rules is impossible. Competitive bidding (auctions) and direct-marketing (renewable producers selling their energy in the whole-sale market, complemented by a premium; this implies more price responsiveness) are expected to be the new European rule for large-scale renewable capacities [29,30]. In order to maintain the capacity adequacy, capacity markets are appearing in Great Britain and in France. Other market segments could also arise in the future, such as flexibility markets that would remunerate short-term output variations [31,32].

I.1.2. Different flexibility options for integrating VRES

Several solutions exist to integrate more VRES in the power system [33]. We present here shortly the technologies used as well as the market valuation mechanisms for these flexibility options.

Electricity storage

Electricity storage is a straightforward way of managing the variability of VRES, displacing the electricity production from hours of low residual load to hours of high residual load. It corresponds to an inter-temporal arbitrage between electricity prices. Efficiency losses during the process limit storage use to the highest price spreads. We detail all the economic values of storage in the next sub-section.

Many storage technologies exist, in many different forms [34,35]. They are usually separated in three categories: high-capacity energy storage, intermediary storage and high-power energy storage. The most used technology today (99% of the worldwide storage capacity) is Pumped Hydro Storage (PHS), which stores the gravitational energy of a volume of water by transferring it between a lower and a higher reservoir (or river). Another high-capacity energy storage is Compressed Air Energy Storage (CAES), which stores the mechanical energy of compressed air in caverns or pipelines, before expanding it in turbines – usually co-fired with a gas turbine[1]. Adiabatic CAES does not use the gas complement, storing the compression heat instead. The efficiency is better but the technology is not mature yet. Hydrogen has also a massive storing capacity potential, in solid (metal hydrates), liquid or gas state (tanks or pipelines). Production of hydrogen from electricity usually uses water electrolysis (but as of today, gas reforming is the main source of hydrogen production), and hydrogen fuel cells (or even gas turbines) are used for producing electricity from hydrogen. Intermediary storage mainly includes electrochemical batteries: lead-acid, lithium-ion, and nickel batteries (coupled with cadmium, iron, zinc or metal hydride). This category also includes sodium sulphur (NaS) and redox-flow batteries such as Vanadium batteries. High-power storage includes flywheels, Superconducting Magnetic Energy Storage (SMES) and supercapacitors.

Demand Response

Another possibility that can be used to compensate the variable production consists in controlling the load through Demand Response programs (DR) [36]. It is one of the two types of Demand-Side Management programs, along with energy efficiency programs. Yet, increasing overall efficiency on a constant basis does not contribute to variable production integration, while DR does so by reducing or displacing demand at certain times only (typically, times of high demand and expensive supply). This demand curtailment can have impacts on the rest of the demand curve by shifting consumption to another time-period, before or after the time of load reduction (time-shifting effect). The rebound effect characterises the impact on consumption that directly follows a load-shedding [37–40]. Depending on the electrical appliance, the rebound effect can be lower or higher than the curtailed load. A particularly important electrical load that could be controlled is the charging of Electric Vehicles (EV).

DR actions can be obtained locally through voluntary actions or remote-controlled by an operator (e.g. an aggregator). The financial incentive can consist in fixed contracts or dynamic pricing (e.g. time-of-use pricing, peak pricing or real-time pricing) [41]. Historically it was mainly based on binary tariffs (peak and off-peak prices), with peaking tariff periods ranging from a few hours to several days. The load shifting was either based on

[1] The gas turbine is used to heat up the expanding air (which naturally tends to cool down with expansion) and avoids a weakening of the turbine's blades.

(incentivized) voluntary and manual actions or on automatic control of the load (e.g. electric water heating in France). Private contracts between a Transmission System Operator (TSO) and industrial consumers (individually or through aggregators) allow the TSO to control their consumption in exchange for financial compensations. Distributed load-shedding is appearing, pushed by increasingly more dynamic prices (enabled by the development of new information and communication technologies as well as smart meters). Load-shedding aggregators sell the reduction of consumption to the market[2]. In the supply and demand balance modelling, DR is similar to electricity storage: both displace an electric load between two time-periods, although their technical operating constraints differ.

Grid interconnections

A third option to support the integration of VRES in the power system is the development of interconnected transmission grid infrastructures. A better international integration of the electric grids flattens the total wind production and smoothens the solar production to a bell curve [42,43]. An international market also shares the reserves, thereby reducing the total capacity requirements and the integration cost of VRES. This international approach is promoted in super-grid projects such as Ocean grid in the North Sea, Desertec [44] or MedGrid [45]. The High Voltage Direct Current (HVDC) lines allow transporting energy at very long distances with lower transmission losses than traditional Alternative Current (AC) lines. HVDC lines are developing fast in large countries such as China or Brazil, in order to connect remote and isolated areas (renewable resources can be abundant in isolated areas, such as wind in North-Western China or hydro in Amazonia). In Europe, the coupling of national markets is facilitating the international exchanges, especially with the new flow-based coupling. In the USA, nodal pricing between regions gives a market value to network extensions, whereas in Europe the local congestions are supported by the TSO and pass on to all the consumers.

Very flexible production capacities

Finally, dispatchable reserve capacities (“back-up”) can compensate the variability of wind or solar in the long- and short-term. These capacities have a low number of full load hours because their main use is during periods of low VRES production. In a long-term approach, peaking capacities, together with the other flexibility options, should meet the peak of residual load. Their economic profitability in an energy-only market is questionable; some other forms of remuneration (e.g. a capacity market) may be required. In the shorter-term, they should have fast-ramping capabilities in order to compensate quick changes in VRES output (e.g. gas turbines [46,47]). This flexibility could also be valued by specific market rules, similarly to spinning and non-spinning reserves in the balancing markets [48,49].

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[2] Contrary to storage operators, the DR aggregator does not have to “store” any energy, although it is (usually) still consumed at another time of the day.

I.1.3. Electricity storage value to the system

In addition from price arbitrage mentioned above, storage has multiple other values for the power system [35,50–55]. It can address short- and long-term impacts of VRES on the power system (including the grid impacts).

First, storage can be useful in isolated systems with intermittent production. It allows an autonomous operation of a small isolated power system by compensating the temporary variations of other capacities (renewable or not). For example, the application can be an isolated renewable + storage system such as the Spanish island of El Hierro [56].

When connected to a power system, storage can provide technical functions that we present now. Some allow the smooth running of the system with a perfect grid, connecting all its components; others are used to maintain the system stability in situations of imperfect grid.

First, given a perfect grid, we consider the technical roles of storage in perfectly predicted situations.

For a given set of production capacities and a given load curve, storage can optimize the balance between production and consumption. It can store excess electricity from the cheapest production capacities, avoiding a later expensive (and highly polluting) production. This is used at different time-scales, up to a seasonal or weekly storage, to compensate for load and VRES annual or weekly variations. The daily storage is frequent, displacing load between several hours (time shifting, load levelling) or offsetting the daily peak (peak shaving). Storage can also have a capacity firming role for uncertain production capacities, e.g. an intermittent renewable capacity. Finally, storage can participate in the security reserve of the system.

Depending on the storage location, the production optimisation role can have side-benefits, such as reducing the total Joule losses in the grid infrastructure.

Storage can provide not only active power but also reactive power, thanks to its power electronic interface. In this way it can participate in maintaining the voltage profile.

Similarly, high-power storage technologies can minimize harmonic distortions in the electrical signal, caused by power electronics or some polluting loads such as electric arc furnaces. Likewise, storage can help production capacities staying synchronized to the grid in cases of low voltage dips (Low Voltage Ride Through capacities, LVRT) or frequency oscillations (flicker).

The last technical value of storage in a perfect grid and perfectly predictable situation is to optimize the power electronics and grid investments in the case of an intermittent production. Indeed, the sizing of grid and power electronics infrastructure is dependent on the maximum power to absorb. Storing the infrequent peaks of production can reduce the need for investment.

In cases with a perfect grid but imperfect prediction of the situation of the system, storage can participate in the frequency and voltage control. Storage can participate in the primary frequency reserve, or frequency containment reserve. It can also be activated as part of the secondary frequency reserve, or frequency restoring reserve, and as part of the tertiary reserve, also known as balancing reserve or replacement reserve. The speed, amplitude and duration of the response are specific to each type of reserve. Similarly, storage can participate in the primary, secondary or tertiary voltage reserve.

Second, we analyze the technical values of storage in a system with an imperfect grid (forecasted or not).

When it is well located, storage can alleviate grid congestions by flattening the power flows. The side-benefits are a decreased wear and tear of power lines and transformers, which may postpone the replacement investment. The congestions can be forecasted, for example at an expected, occasional peak of power flow, or because of a grid weakness or delay in grid reinforcement. For example, the grid extension delays between North and South Germany cause congestions and wind power curtailment in the North. Many Chinese and US wind power plants also suffer from low grid availability and lose a considerable amount of energy [57,58]. The congestions can also be unplanned, in case of a short circuit or an outage of a line, transformer or production capacity. The grid operator can redispatch the production capacities, causing some production curtailment. Storage can avoid such curtailment losses by storing this energy locally in excess.

Current overflows or over-voltage can be addressed with electricity storage. Storage also allows a deferral of investments in transmission and distribution (T&D) lines or transformers. It is more modular than T&D investments and brings a degree of freedom to the voltage plan [59].

Finally, in case of an unexpected power shortfall (e.g. a local grid failure or production outage), storage can substitute fossil-fuelled reserve capacities. This application is called Uninterruptible Power supply (UPS). The storage can also assist the black-start of a thermal power plant, providing the necessary power for its auxiliaries while it starts.

* * *

Most of the listed values of storage are not monetized (they remain positive externalities), by lack of an appropriate market design. Therefore, the financial perspectives that we identify for storage are mainly price arbitrage, which has been the main income for storage up to now, and the ancillary services that are valued by a given market design (mainly frequency and voltage reserve). With the upcoming capacity markets, storage could gain another type of economic value. In some specific situations, a storage owner could also sign an agreement for other specific services, e.g. T&D deferral (if the grid regulation allows it) [60].

The long-term development of electricity storage is the subject of this work. Future energy system trajectories, based on long-term energy scenarios, can consider the evolution of storage in relation with the rest of the energy system. These scenarios require long-term foresight models of the energy system, which we present in the next section.

I.2. Long-term foresight energy models

Long-term models of the energy system provide a comprehensive economic approach of all energy sectors, as well as the interactions between sectors. We present here the different energy modelling families. First, it should be recalled that a model is a representation of the physical behaviour of a defined system, with inputs, parameters and outputs (which are the observed variables). Here we look at the energy system, and especially the power sector.

Long-term energy models portray possible futures of the energy system, with all sources, vectors and exchanges of energy between regions or countries. Some macroeconomic and demographic factors can be exogenous, but the main parameters monitored (like energy production or costs) have an endogenous evolution over time [61]. These models can analyse long-term energy policy decisions with a coherent long-term vision of the whole energy sector.

However, the technical description of energy flows and of the main technologies remains simple in these models. For example, in the power sector, the supply and demand balance generally uses a few aggregated time-slices that group similar hours. Other electricity-only models have the ability to describe more accurately the power system dynamics (e.g. the constant balance between supply and demand, the voltage and current regulation). These power sector models are usually shorter-term models, with a modelling horizon of up to one year. They allow a detailed study of the impacts of systems with high VRES penetration (control and stability of the system, operation, planning).

I.2.1. Top-down and bottom-up models

An important categorization of energy modelling tools is the distinction between top-down and bottom-up. A top-down model describes the macro-economic relationships between the components, while a bottom-up model focuses more on the detailed description of technologies for energy supply and demand [62–64]. Examples of top-down models are DICE (Dynamic Integrated Climate-Economy) [65], an optimal growth pathway model, or GREEN (General Equilibrium Environmental model) [66], a recursive general equilibrium model (it considers the whole economy). Examples of bottom-up models include MARKAL (Market Allocation) [67–71] or POLES (Prospective Outlook on Long-term Energy Systems) [72,73], which are sectoral models (they only consider the energy sector). Top-down and bottom-up can in some cases be combined, resulting in “hybrid models” [74] that add technological description to top-down models or a macro-economic loop to bottom-up models. Examples include MERGE (Model for Estimating the Regional and Global Effects of greenhouse gas reductions) [75] or Imaclim [76,77].

The models dealing with VRES integration challenges, grid and storage are mainly of the “bottom-up” type because of the necessary technical detail. They combine a representation of the technical characteristics of energy technologies with economic considerations.

I.2.2. Simulation and optimisation models

Another dimension of energy modelling tools is the simulation or optimisation nature of the algorithm. Simulation models provide a stylized representation of reality. In economics, they are usually recursive models: they run period by period, with evolving hypotheses and parameters. On the other hand, optimisation models are based on criteria and parameters used to optimize a solution. The modelling objectives are different; simulation models try to represent plausible future trajectories, and optimisation models provide an image of what would be an optimal trajectory (potentially a second best optimal). Examples of long-term bottom-up energy models of each category are shown in Table 1.

Typology	Model
Optimisation	EFOM (Energy Flow Optimisation Model) [78–80]
	MARKAL (Market Allocation) [67–71]
	TIMES (The Integrated MARKAL-EFOM System) [81,82]
	MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental impact) [83]
	OSeMOSYS (Open Source Energy Modelling System) [38,84]
Simulation	MEDEE [85]
	POLES (Prospective Outlook on Long-term Energy Systems) [72,73]
	PRIMES [86–88]
	WEM (World Energy Model) [89,90]
	Prometheus [91]

Table 1: Examples of optimisation and simulation long-term bottom-up models [92]

Remarks:

- In the early 1970’s, the first optimisation models were EFOM and the MARKAL family, which is now widely used (37 countries and 77 institutions). The main simulation models were developed in the 90’s.
- MARKAL is at the origin of TIMES and its derivatives, PET (Pan European TIMES) [93], TIAM (TIMES Integrated Assessment Model) and the ETP-TIMES (Energy Technology Perspectives).
- MESSAGE is also among the first optimisation models, later enhanced with MESSAGE II and MESSAGE III.
- OSeMOSYS is an open-source model structured in blocks, which allows easy modifications to the code.
- The WEM is used for the World Energy Outlooks of the International Energy Agency.
- Prometheus (based on POLES) uses generalised stochastic variables.

A number of studies have proposed further comparisons of energy models [92,94–96]. It is quite a difficult task, as each model is different in its approach and peculiarities. We will first present the fundamental economic concepts supporting long-term energy models.

I.2.3. General Equilibrium Models

An interesting distinction, introduced for example in [94], separates General equilibrium models (GEM) and partial equilibrium models. General equilibrium models consider the whole economy with endogenous economic parameters (capital cost, GDP, workforce, etc.). They were first implemented in Computable General Equilibriums (CGE). They are top-down models, but sometimes some technology description makes them hybrid models. The partial equilibrium models focus on one sector (here the energy sector), leaving apart the rest of the economy (for example, the impacts on GDP of energy policies are not considered). This allows a better level of detail for the energy sector but loses the inter-links with the rest of the economy and of the society. Table 2 presents some GEMs, with an indication on their simulation or optimisation nature.

Typology	Models	Characteristics
General equilibrium models	Edmond-Reilly-Barns, SGM (Second Generation Model) [97,98], Phoenix	Top-down / hybrid, simulation
	GREEN (General Equilibrium Environmental model) [66]	Top-down, simulation
	EPPA (Emissions Prediction and Policy Analysis, from the MIT) [99,100]	Top-down, simulation
	MARKAL-MACRO [101], MARKAL-EPPA [102]	Hybrid, optimisation
	NEMS (National Energy Modelling System) [103]	Hybrid, simulation
	AMIGA (All Modular Industry Growth Assessment) [104]	Hybrid, simulation
	CIMS (Canadian Integrated Modelling System) [105]	Hybrid, simulation
	Imaclim [76]	Hybrid, simulation
	NEMESIS (New Econometric Model of Evaluation by Sectoral Interdependency and Supply) [106]	Top-down / Hybrid, simulation

Table 2: Examples of General Equilibrium Models [92]

Remarks:

- The origin of GEM is the Edmond-Reilly-Barns model family, from the 1980's. It gave birth to the Second Generation Model (1991), now updated to Phoenix.
- Another family of GEM emerged from the OECD (Organization for Economic Co-operation and Development), with GREEN and EPPA.
- The bottom-up MARKAL model was coupled with macro-economic modules (MARKAL-MACRO, MARKAL-EPPA).
- The dynamic simulation frameworks of CIMS, IMACLIM and NEMESIS all include a macro-economic loop with elements of a Keynesian economic thinking.

I.2.4. Energy – Environment – Economy (E3) models

Some models focus on the interactions between these three sectors: energy, environment and economy [107]. These modules are useful for energy policy advice. E3 models are usually top-down simulation models.

The models presented in Table 3 are Energy – Environment – Economy (E3) models.

Typology	Models	Characteristics
Energy-environment-economy	GEM-E3 (General Equilibrium Model for Energy, Economy and Environment) [108,109]	Top-down, simulation
	GEMINI-E3 (General National - International Economy, Energy and Environmental Equilibrium Model) [110]	Top-down, simulation
	E3ME, E3MG (Energy Environment Economy Model, at the European or Global level) [111]	Top-down, simulation
	Three-ME (Multi-sector Macroeconomic Model for the Evaluation of Environmental and Energy policy) [112]	Top-down, simulation

Table 3: Examples of Energy – Environment – Economy models [92]

I.2.5. Integrated Assessment Models (IAM)

The integrated assessment models (IAM) are designed to analyse the interactions between human and natural systems [113,114]. When they focus on climate change, they combine GHG emissions and environmental considerations with energy and economy, which also qualifies them as E3 models. Table 4 shows a summary of some IAM.

Typology	Models	Characteristics
Integrated Assessment Models	DICE (Dynamic Integrated Climate-Economy) [65], RICE (Regional DICE)	Top-down, optimisation
	MERGE (Model for Estimating the Regional and Global Effects of greenhouse gas reductions) [75]	Hybrid, optimisation
	MESSAGE-MACRO [115]	Hybrid, optimisation
	IMAGE (Integrated Model to Assess the Greenhouse Effect)	Hybrid, simulation
	IMAGE/TIMER (Targets IMage Energy Regional).	Hybrid, simulation
	MiniCAM (Mini Climate Assessment Model) [116,117]	Hybrid, simulation
	GCAM (Global Change Assessment Model) [118]	Hybrid, simulation
	WITCH (a World Induced Technical Change Hybrid System) [119,120]	Hybrid, optimisation
	DNE21 (Dynamic New Earth 21) [121]	Hybrid, optimisation
	MIND, ReMIND (Regional Model of Investments and Development) [122]	Hybrid, optimisation
	AIM/CGE (Asian Pacific Integrated Model) [123]	Hybrid, simulation

Table 4: Examples of Integrated Assessment Models [92]

Remarks:

- DICE was the first to appear, in the 1980's, later followed by RICE.
- MESSAGE was developed and latter coupled with MERGE to give MESSAGE-MACRO.
- As for simulation models, IMAGE was also early developed, with a high level of technological detail. It later developed into TIMER (Targets IMage Energy Regional).
- Another family of IAM adopted the ObjECTS structure (Object-oriented Energy, Climate, and Technology Systems) [124], with the partial equilibrium models MiniCAM and GCAM.
- AIM/CGE is focusing on the Asia-Pacific region (42 countries).

Additional top-down models categories are the ***econometric models***, ***input/output energy-economy models*** [63,64,125], or ***accounting models*** such as LEAP (Long range Energy

Alternatives Planning system) [126,127]. LEAP is widely used thanks to its relatively little necessary input data. Other criteria exist, such as the programming technique (e.g. linear or nonlinear, mixed integer, neural networks) [128].

* * *

Despite a precise description of particular models in some studies (e.g. [95,96]), a general approach for categorising any model is lacking. In particular, studying VRES impacts on the power system needs a typology focusing on the power sector. Foley et al. [129] distinguish only two power sector model families: stochastic optimisation and dynamic programming. Another study by Connolly et al. [130] reviews 37 modelling tools that can study the integration of renewable energy sources. The tool-developers' survey helps understanding and choosing the appropriate tool for analysing the integration of VRES in the energy system. The models are categorised according to their scopes, from long-term energy scenarios to single project optimisations; from global and national energy tools to stand-alone-only systems. Another comparison criterion is the optimisation of the operation or of the investment. The models' components are also studied: regions, energy sectors, costs, thermal and renewable generation, storage and conversion, transport. These categories are adapted, but our structured approach [92] is preferred, being a more general typology, valid both for long-term energy models and power sector models. Qualitative criteria are suggested for understanding each component of the power system, both on technical and economic aspects. We present in the next section our new typology, focusing on the modelling choices of the VRES, grid and storage representation in the power sector.

I.3. A new typology for energy and power sector modelling tools

The impacts of increasing VRES are more and more accounted for in power sector models, but they remain difficult to take into account in long-term energy models. In order to assess the modelling choices concerning VRES impacts, grid and storage, we need a clear description and categorization of their technical and economic choices [92].

I.3.1. A new approach for the characterisation of energy modelling tools

We analyse three complementary aspects of an energy modelling tool. First, one needs to understand the general context and positioning of a modelling tool. Then, the spatio-temporal characteristics are in general easy to identify. Finally, to go in deeper detail, the technical and economic features of the tool are described, as they influence the modelling capabilities.

The **modelling objectives** *of a tool could be analysed from two perspectives.*

The first one defines the underlying logical process. It can focus only on the power system or also consider other energy carriers (e.g. heat, hydrogen, gas, oil, gas, coal or biomass). The system can be a snapshot of the system, with fixed inputs, or it can be dynamic, with parameters evolving over time (e.g. installed capacities, prices of the technologies). The model can have a simulation or an optimisation approach (in which case the criterion and parameter(s) of optimisation must be identified).

The second one concerns the power system itself. It can follow a system approach or look at a specific project (agent-based logic). In the first case, the tool considers the system as a whole and pursues objectives based on the social perspective (total social surplus, minimisation of total system cost). An agent-based approach follows the point of view of an individual actor, with consideration of its own interests. The last criterion is whether the tool schedules the operation of the system, plans the investments or combines both (for example [131]). All these criteria have been summarized in Figure 4.

Next, the **spatio-temporal resolution** *is another useful criterion in the process of choosing a modelling tool (see Figure 4).*

The time-step can go from less than one second to more than a year, while the study can cover a modelling horizon from less than one hour up to several decades. These characteristics are usually within a range, limited by the computation time (and the fact that the time-step must be lower than the time horizon).

The spatial resolution is also important for taking into account local phenomena (electricity grid, situation of the production and demand areas) [132]. The spatio-temporal resolution depends on the data availability, the intended accuracy, and the computation time [133,134].

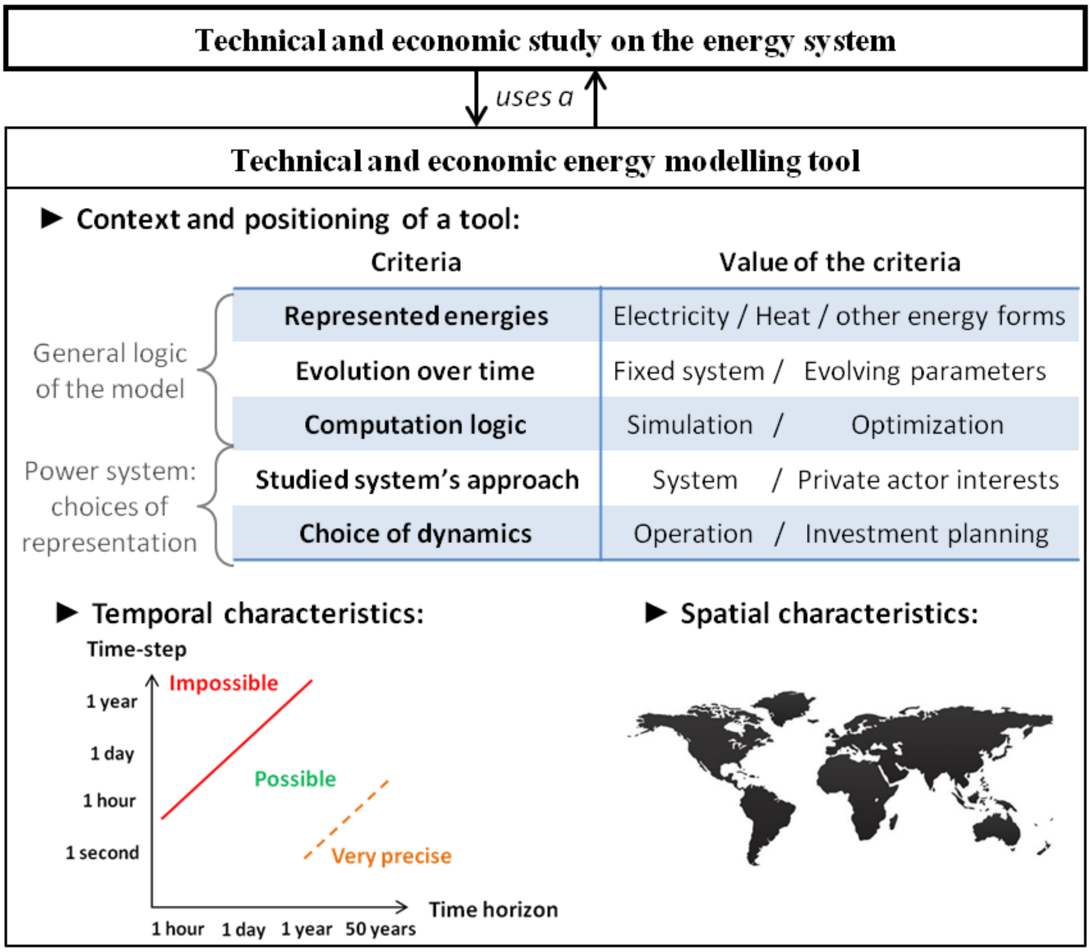

Figure 4: Criteria for the classification of energy modelling tools that include the power sector.

Finally, one may need to describe a modelling tool in a more descriptive way; here we emphasise the **power system components**.

Some qualitative comparison scales, from the least detailed to the most complex, are developed in [50,135]. In some cases, minimum levels of description of some components (supply, demand, storage, electricity grid) are necessary to carry out specific technical and economic studies, e.g. [136].

Power generation. Conventional generating units can be described at the power plant level or aggregated by technology types. On the technical side, the power plants can be represented at different levels: description of the energy inputs and flows, operational constraints (e.g. minimum output, ramping constraints), maintenance strategy or ageing of the power plant. The operation of the different technologies can be based on historical observations and heuristics rules, or computed as a merit-order (priority listing based on the variable cost) or as a constrained unit commitment and economic dispatch (e.g. a dispatch robust to wind power uncertainties and forecast errors [137]). Some models describe the market, sometimes with agent-based simulations or market power considerations [138–140]. The investment mechanisms in new capacities can also be simulated in different ways (e.g. the wind power production and electricity demand correlation can be considered in investment decisions [141]). Technical and economic characteristics of power generation technologies are linked to each other.

Variable renewable energy. Their production depends on meteorological conditions, explicitly or not. The production profile can be set to a constant, derived from historical data, statistically defined or generated stochastically [142]. Despite the zero marginal cost, a production curtailment may occur, depending on the profile of the demand, the multiple constraints of the conventional production and the transmission grid constraints. Combined uses (e.g. combined heat and power or bio-fuels) of renewable energy sources (power, heat, transport) need to link several sectors with an economic optimisation criteria [143].

Electricity storage. It is similar to electricity production in its technical considerations but it also has to consider a state of charge. Its economic modelling can consider several values, for example arbitrage, ancillary services, support to renewable production or to the available reserve capacity. Several sources of revenue could cumulate if it is technically possible and allowed by the market design [144].

Electricity demand. Its economic representation can be fixed, or elastic if it reacts to the electricity price changes. Electricity demand can be affected by the activation of a demand response program. Geographically, the demand can be aggregated to a unique regional load or more detailed if there is a sufficient spatial resolution (and an electric grid representation). On the temporal aspect, it can be aggregated to an annual energy demand, divided into blocks of consumption or into time slices of several hours. A more detailed representation is an hourly demand profile over a year. The models of interest to us often don't account for the reactive power.

Electric grid. Its representation is only useful if the corresponding level of detail is available for electricity demand and production capacities. If not, it has to be considered as a "copper plate” (no grid restrictions between all productions and loads). One node per country is usually not a problem for data availability. A higher meshing needs more data (or assumptions) on the renewable production and on the regional consumption (e.g. the economic activity). The grid considered can be of low, medium, high or very high voltage, and can be of alternative or continuous current. The power flow computation can be a “transport model”, with net transfer capacities (NTC), i.e. fixed physical limitations to the power transfers between regions. The power flows are directly attributed to the lines between the source and the load. It represents the commercial contracts but not the grid reality, which depends on Kirchhoff’s laws. An AC load flow takes them into account precisely, usually linearized as a DC load flow. Economically, the grid costs correspond to the investment (including social acceptance) and operation costs (including losses, congestions, ancillary services, balancing). The grid can cause local marginal pricing (nodal prices) if the connections are too weak.

I.3.2. Application of the new typology

We first illustrate this new typology by giving the main features of typical long-term energy models.

They usually consider several energy sources and carriers (oil, gas, coal, biomass, hydrogen), not just electricity. Their modelling logic can be an optimisation, a simulation or a combination of the two (hybrid models). They always adopt a system-wide approach. Being long-term models, their parameters change over time and they have to represent the investment decisions in the energy and power system. They have multiple timescales since the investment decisions are based on annual energy balances (the main time step) and each year is usually divided into several hour blocks (“time-slices”, for the operation decisions). The energy flows between components and countries are considered (e.g. the international fuel exchanges), but the representation of the individual components is simplified. Indeed, the geographical coverage and temporal horizon are large (world regions or countries, from 2000 to 2050, sometimes 2100).

Each long-term energy model has different modelling priorities for the power system components, with different levels of technical accuracy. Power generation is based on the type of fuel used, with fuel costs determined in some cases by the rest of the model. The technical constraints are usually not represented or very aggregated. The temporal detail is small; therefore the representation of VRES has to be averaged out. Some impacts of VRES on the system can be taken into account with a hard limit on the penetration of VRES, or with standardized constraints; for example the low capacity credit of VRES has impacts on the capacity planning. These general rules are computed in more detailed power sector models, e.g. ReMIX [145] for ReMIND or REFLEX for ReEDS (Regional Energy Deployment System) [146]. As an example, ReMIND attributes a pre-computed requirement of storage and grid extension for each VRES penetration in the energy mix. Storage is decomposed between short-term with redox-flow batteries (12 hours of stored energy), and medium-term with hydrogen (weekly variations). The seasonal adequacy of VRES is enforced by an over-capacity penalty, in order to meet demand in all seasons of the year [147]. This approach is parameterized, without taking into account the interactions between the power sector components (e.g. international exchanges).

Very few long-term foresight models actually include an endogenous dispatch of electricity storage or grid. They have intrinsic difficulties in representing storage and grid because of their technical constraints (temporal management of the storage state-of-charge, geographical representation for grid congestions). Nevertheless, the power system representation in TIMES or PRIMES are worth mentioning; in some versions, they can include storage (pumped hydro, hydrogen) or the European grid (interconnections between countries) in their optimisation logic. However, dedicated power sector modelling tools offer more detail[3].

We show in Figure 5 a summary of the general approach and temporal characteristics of classical long-term energy models (in blue) and power sector modelling tools (in red).

[3] EnergyPlan [148] offers a hybrid approach, compared to long-term energy models or detailed power sector models. It is a widely-used energy model, simulating several energy sectors relative to renewable energy (electricity, transport, heat, industry). Contrary to long-term foresight models, it has a one year time horizon and an hourly time-step, useful to study the integration of VRES in the energy system (e.g. [149]). This input/output tool optimises the operation of the power sector; however, the investment decisions are not represented.

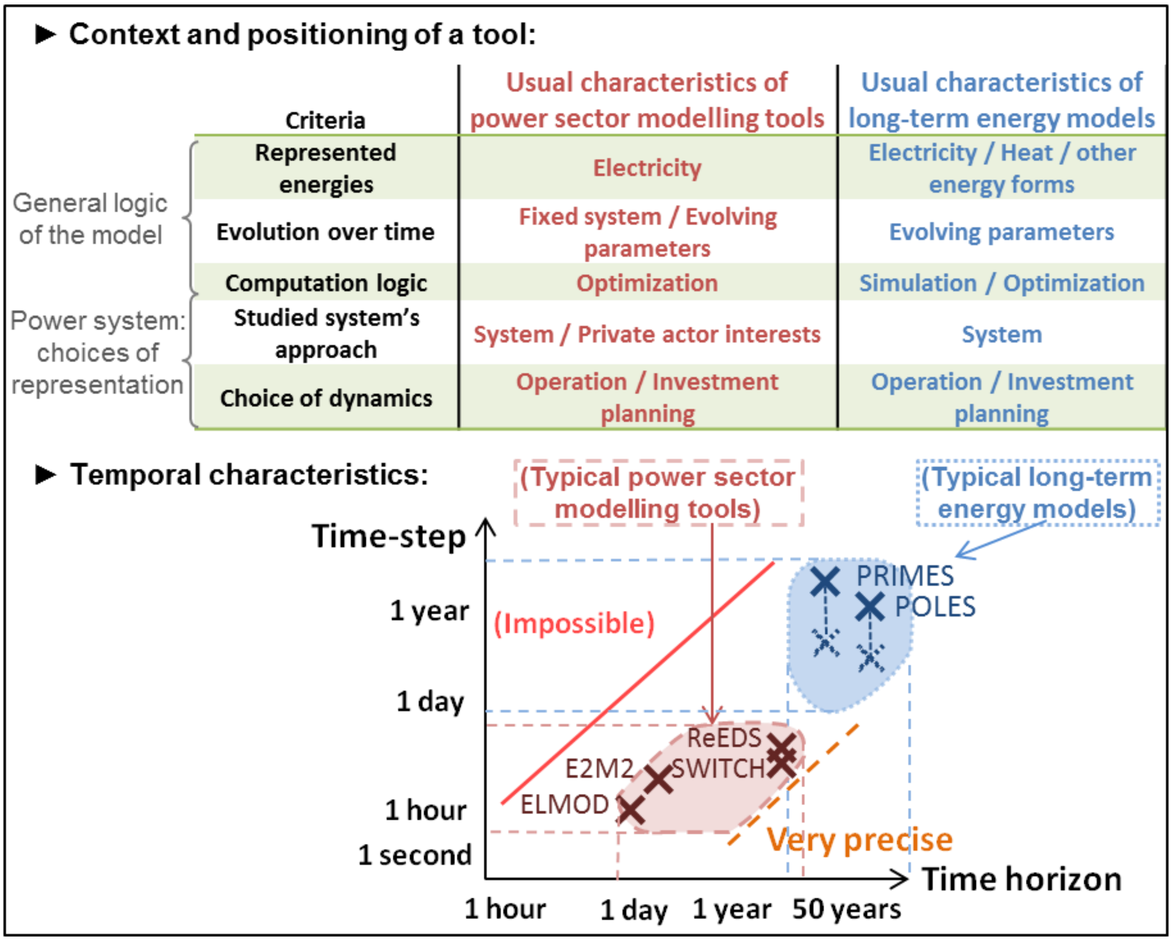

Figure 5: Summary of the main characteristics of typical power sector modelling tools and long-term energy models.

The graphical representation in figure 5 shows the main differences between long-term energy modelling tools and power sector tools, in terms of the usual positioning of the different models. Compared to power sector modelling tools, the long-term energy models include more energy sectors and can have a simulation approach, but they cannot study private interests. The temporal characteristics are also very different; no model exists that combines the long-term perspective with an hourly time-step, because the computation time and complexity are seen as unachievable. The longest time horizon in detailed power sector models is 2050; however these models still do not include a comprehensive economic approach in energy scenarios.

As an illustration, we now analyse in detail the modelling choices of two long-term foresight energy models (POLES and PRIMES), and of four power sector modelling tools. Two of them are rather short-term: ELMOD (Electricity Model) [150,151] and E2M2 (European Electricity Market Model) [21,152,153]; the other two also show a long-term evolution: SWITCH (Solar, Wind, Hydro, and Conventional generators and Transmission) [154–156] and ReEDS (Regional Energy Deployment System) [157,158]. We choose those models as examples because they form an interesting panel of diverse modelling choices[4]:

- POLES and PRIMES are simulation models of the energy sector, with a representation of other energy carriers than electricity. The others only look at the power sector.
- POLES, PRIMES, SWITCH and REEDS have an endogenous evolution of the parameters (until 2050 or more) with long-term investments mechanisms, while E2M2 and ELMOD only focus on an exogenous system, so they only consider the power system operation in a fixed year.
- Except for POLES, they minimize the total system cost[5]. On the other hand, POLES has a simulation approach and the choice of electricity production technologies is simulated based on total production costs, maturity factors, price elasticity and maximum potentials. This approach allows some inertia in the system across time.
- They all use a system approach, i.e. the point of view of a central authority or decision-maker.
- They all deal with operation and investment planning, except ELMOD which is limited to the operation.

The six tools are included in Figure 5, with their characteristics more detailed in Table 5.

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[4] Many other power system tools exist that have somehow similar levels of description as ELMOD or E2M2. Among them we can mention WILMAR [159], LTS [140], EUPowerDispatch [160], URBS-EU [143], PowerACE-Europe [161], the European Climate Foundation model [162], COMPETES [163] or the agent-based models HOMER [164] and HYDROGEMS [165]. PLEXOS (by EnergyExemplar) [166] and ProMod (from Ventyx, ABB) [167] are commercial power sector tools (as well as Artelys Crystal [168], from Artelys, which offers several models for different spatial scales), with many features that make them very flexible to the customer’s need (short- or long-term modelling, hydro resource planning, grid studies, renewable generation integration, etc.). Computation time being the main limitation, each modeller makes choices when using these tools. This makes it difficult to categorize and compare them to other power sector tools. Moreover, these models are not publicly available and do not offer the economic coherence of energy scenarios.

[5] Although PRIMES is a simulation model, its power sector uses optimisation.

<table>
<tr><th>Modelling tools</th><th>POLES</th><th>PRIMES</th><th>SWITCH</th><th>ReEDS</th><th>E2M2</th><th>ELMOD</th></tr>
<tr><td rowspan="3">General logic of the model</td><td colspan="2">Electricity, gas, oil, coal, biomass, etc.</td><td colspan="4">Electricity</td></tr>
<tr><td colspan="4">Evolving parameters</td><td colspan="2">Fixed system</td></tr>
<tr><td>Simulation</td><td>Sim.+Optim.</td><td colspan="4">Optimisation</td></tr>
<tr><td rowspan="2">Power system choices of representation</td><td colspan="6">System approach</td></tr>
<tr><td colspan="2">Operation (simplified),
Investment planning</td><td colspan="3">Operation,
Investment planning</td><td>Operation
No
investment</td></tr>
<tr><td>Time horizon</td><td>2100 (every year)</td><td>2050 (every 5 years)</td><td>2050 (every 4 years)</td><td>2050 (every 2 years)</td><td colspan="2">1 year</td></tr>
<tr><td>Time step (occurrences per year)</td><td>2 hours
(2 days per year)</td><td>none
(11 blocks per year)</td><td>1 to 4 hours
(12 to 24 days per 4 years)</td><td>4 to 8 hours
(17 blocks per year)</td><td>2 h
(12 days per year)</td><td>Hourly
(1 day per year)</td></tr>
<tr><td>Spatial representation</td><td>57 regions in the world</td><td>Europe</td><td>USA (multi-scale)</td><td>Region of the USA</td><td>Europe</td><td>Germany and Europe</td></tr>
</table>

Table 5: General and temporal characteristics of the main models studied.

POLES and PRIMES are shown with two time-steps because they have an annual logic for the energy balance and the investments decisions, but the year is also divided in several blocks for a better accuracy of the system operation. For example, POLES is subdivided in two seasons (summer and winter), each being represented with a day of 12 two-hour blocks. PRIMES' computed years are also divided in summer and winter, with a total of 11 blocks for the entire year[6]. ReEDS and SWITCH are not foresight models but still offer a long-term vision of the power sector with an interesting accuracy.

We now compare the tools along technical and economic criteria. First we describe the constraints that they respect; then for all five optimisation models, we analyse the minimisation objective (i.e. the cost components). Next, we compare the representation of the production from VRES and VRES impacts on the rest of the system. Finally we examine the electricity storage and the grid in all six models.

The first constraint to ensure is the balance between supply and demand. The demand curve can be endogenously produced in several ways. In POLES and PRIMES, the annual electricity demand is the aggregation of all sectoral load curves and depends on macro-economic drivers (e.g. GDP, energy prices). PRIMES can represent the interactions with the rest of the economy when it is coupled to macro-economic models such as GEM-E3. POLES includes considerations of price elasticity for each demand sector. SWITCH uses the demand of a historical year. The three other models proceed by aggregating demand into typical time-slices or typical days. ReEDS and ELMOD also link the demand to a price-

[6] The slight advantage of POLES in terms of time step precision is a trade off with the technical detail of PRIMES' power sector.

elasticity. There are also some reliability constraints, expressed with frequency reserves for the short-term operation (PRIMES, SWITCH) and capacity reserves (for the long-term investments). ELMOD and E2M2 add constraints for thermal power plants (start-up time, part-load efficiency).

Then we look at the different components of the total cost of the system, which is the objective to be minimised for the optimisation models. On one side, ELMOD is a short-term model and only considers the system over one day, therefore not accounting for the fixed costs (investment in capacities or in grid infrastructure, capital costs). At the other extreme, PRIMES is oriented towards economic considerations, using Ramsey-Boiteux pricing, which incorporates the whole system costs (including investment and operation costs or weighted average capital costs). PRIMES also includes mark-up costs, reflecting market imperfections such as market power when some agents charge prices above marginal costs. E2M2 and ELMOD take into account the start-up costs and some other inter-temporal constraints typical of unit commitment models (reliability, start-up time, ramping capabilities or grid constraints). However, these two models do not consider renewable subsidies, CO_2 taxes or mark-up costs; they are not designed to evaluate public policies but are more technically detailed. ReEDS and SWITCH are in between the two approaches, they show some characteristics of both approaches.

The modelling choices of the VRES production rely on historical data. The easiest way is to directly use the historical production profile (SWITCH). Based on a statistical analysis of the historical data, POLES, PRIMES and ELMOD choose to use a capacity factor by region and hour of the day, while ReEDS generates its own production profile. E2M2 uses a stochastic approach: a probabilistic tree is used to represent the probabilities of variation between a low, a medium and a high wind resource, over three rolling time steps. This approach takes into account the uncertainties and variations of the production.

The POLES electricity module cannot represent accurately storage because it does not have inter-temporal correlation between time windows. PRIMES takes into account storage (hydraulic and hydrogen) in its optimisation process across the few time-slices it has (11). Storage reduces the spread of prices and decreases the production curtailment of excess energy. For the other tools, the value of storage is represented in the optimisation of the unit commitment (and so, avoiding the curtailment of excess renewable energy production) or in providing ancillary services.

Finally, the electricity grid is represented at different levels in the studied modelling tools. E2M2 has no grid representation; PRIMES and POLES use one node per country; SWITCH, ReEDS and ELMOD have hundreds of nodes and lines. E2M2 has a copper plate representation (for the only country represented). In POLES the international exchanges are historical and kept constant in the future. The other models use a DC load flow.

The comparison between these six models (summarized in Table 6) shows different methodologies, particularly concerning the specific constraints imposed by VRES.

Modelling tools	POLES	PRIMES	SWITCH	ReEDS	E2M2	ELMOD
Optimisation constraints:						
Demand	By sector	By sector	Historical	Elastic	Aggregated	Elastic
Operating reserves	Y	Y	Y	Y	Y	N
Capacity reserves	Y	Y	Y	Y	Y	N
Grid	N	(Y)	Y	Y	N	Y
Minimum renewable penetration	N	N	Y	Y	N	N
Start-up time	N	N	N	N	Y	Y
Costs:						
Fixed (O&M, investment)	Y	Y	Y	Y	Y	N
Variable (O&M, fuel)	Y	Y	Y	Y	Y	Y
Variable fuel efficiency	N	N	N	Y	Y	Y
Start-up	N	N	N	N	Y	Y
Reserves, ancillary services	N	N	N	Y	Y	N
Grid	N	Y	Y	Y	N	N
Renewable subsidies, CO_2 taxes	Y	Y	Y	Y	N	Y
Capital	Y	Y	Y	N	Y	N
Risk premium, mark-up	Y	Y	N	N	N	N
Renewable energy sources:						
Hydraulic resource	Historical	(Unclear)	Historical	Historical	(Unclear)	(Unclear)
VRES production profile	Statistically determined	Statistically determined	Historical	Statistically determined	Stochastic	Deterministic
Curtailment of excess energy	N	N	Y	Y	Y	N
Impacts of VRES on:						
Operating reserve	N	Y	Y	Y	Y	N
Capacity reserve	Y	Y	Y	Y	Y	N
Grid costs	N	Y	Y	Y	N	Y
Storage economic value:						
Optimisation of the system	None	Y	Y	Y	Y	Y
Ancillary services		Y	Y	Y	Y	N
Grid:						
Nodes and lines	57 nodes (world)	35 nodes, 240 lines	50 nodes, 104 lines	134 nodes, 300 lines	None (only one country)	Entire Europe
Type of computation	None (historical)	DC load flow	NTC	DC load flow or NTC	Copper plate	DC load flow

Table 6: Main characteristics of six electricity modelling tools.

This analysis highlights the differences in objectives of long-term energy system and power sector tools. The accuracy level is adapted to the application targeted. Power sector tools have a good description of the technical constraints; their sequential dispatch can incorporate storage options, thanks to inter-temporal constraints. On the other hand, long-term energy models can represent broader economic assumptions and provide economic scenarios, at the expense of an aggregated power system description.

I.3.3. The need for a better representation of the power sector in long-term energy models

In order to study the power system evolution, energy models are used. They classically estimate the evolution of supply and demand of an energy carrier, but the power system is special in this respect: the balance between supply and demand has to be perfect at all times while considering grid constraints. Indeed, unlike oil, gas or coal, there is no easy way to store large amounts of electricity without expensive infrastructures and important round-trip losses.

Considering the increasing share of non-dispatchable VRES in electricity grids, a new long-term approach is necessary that takes into account the VRES integration challenges. For example, storage modelling is very different from the classical modelling of electricity technologies. The operation and investment of storage cannot rely on a comparison of its Levelized Cost Of Electricity (LCOE) with the ones of other electricity producing technologies. Indeed, electricity storage is a net consumer and not a net producer. A storage power plant cannot simply sell energy; it has to store it beforehand. The arbitrage value, for example, takes advantage of a spread in prices by buying at low prices and, only then, selling at high prices. The production cost depends on the buying price, a major determinant of the total cost of production from storage. Therefore, the operation of storage requires inter-temporal constraints, in order to check that the produced and stored energy are balanced (including round-trip efficiency losses). The planning of new storage capacities needs to take into account at least some of the technical or economic values of storage, instead of considering the mere energy sales and the meeting of anticipated demand.

Our overview of the long-term energy models shows that their technical and economic representation of the power system is usually kept simple (time-slices instead of a sequential time, big regions and low geographical detail). On the other hand, power system modelling tools are more technical but usually only consider the power sector, with no interactions with the rest of the energy system. They don't have the large scope of the entire energy system, useful to evaluate the long-term implications of energy policies. The developed typology clearly shows that up to now energy modelling tools and power sector tools respond to different objectives and do not merge the advantages of their approaches, namely:

- For power sector modelling tools:
    - detailed assessment of VRES variability and intermittency impacts;
    - detailed temporal representations for the electricity storage;

- detailed spatial representation for the electricity grid;

- For long-term energy system models:
  - interactions between energy sectors;
  - long-term consistency of technical and economic hypotheses;
  - possibility to evaluate energy policies in long-term energy scenarios.

In a complementary approach, the outputs of detailed power sector models can serve the calibration of long-term models by providing insights on the interactions between VRES and the rest of the system (e.g. storage, grid, dispatchable capacities, or production curtailment). In turn, long-term energy models can bring a coherent estimation of the long-term evolution of the technical and economic parameters necessary for the short-term analysis (e.g. electricity demand, cost assumptions).

Many efforts are currently pushing towards more coupling between the different approaches [169,170]. By using a comparison with a detailed unit commitment model, [169] shows that a long-term model such as TIMES can miss some integration costs of VRES. Representing the temporal variability of VRES requires a careful choice of the time-step used [133,134].

These articulations are often a soft-linking, in the sense that the data from a model are sent to a more detailed model, with no feedback. For example, the outputs of the optimisation models TIMES or ReEDS can be fed into a separate optimisation of the power system (PLEXOS) [171]. The coupling can also consist of iterations, for example between the CGE EMEC (Environmental Medium-term EConomic model) and a bottom-up model (TIMES-Sweden) [172,173] or between GEMINI-E3 and TIAM-world [174].

Another approach is to derive some general rules (heuristics) from a detailed power sector model, and use this understanding in the long-term energy model. This is the case for the implementation of flexibility requirements in OSeMOSYS [38,175,176] or in MESSAGE [177]. In [176], Welsch improves OSeMOSYS, a long-term model with few time-slices, by including some stylized short-term constraints (wind capacity credit, balancing requirements) and in [175] he uses a calibration from TIMES-PLEXOS. OSeMOSYS' results are closer to those of a soft-linking approach while keeping a low temporal resolution and a small computation burden. However, some differences in the investments remain, by lack of technical detail, and the role of storage cannot be truly appreciated with this tool because the time-slices cannot represent the hourly solicitation of storage.

Some recent improvements on TIMES include a representation of storage [178] and of the grid investment decisions [132,179] – in which case there is a soft-coupling with a short-term modelling tool, ProPSim (Probabilistic Production Simulation). Other works have focused on a very short-term indicator of the reliability of the power system and implemented it in TIMES [26,37,180].

From what we gathered, only PRIMES – and recently, TIMES – include technical constraints of storage and grid in a long-term perspective. However, the time-steps for storage and international exchanges are aggregated to respectively only 11 and 12 time-slices per year. Moreover, PRIMES is limited to Europe and only has a five-year computation time-step, with a 2050 time horizon. Furthermore, the computation times become very long with this level of detail (several hours) and the model is little documented (it is not publicly available).

Therefore, for enhancing the long-term forecasts and representing the VRES impacts, we recommend a more precise power sector module within long-term energy models. The electricity module needs to include short-term inter-temporal constraints in order to determine the value of electricity storage. The optimisation logic seems unavoidable.

Conclusion of chapter 1

In a long-term perspective, the energy system is undertaking a transition towards a more sustainable future with lower emissions. The expected high shares of VRES in the electricity mix are challenging for the power sector. Indeed, VRES bring long-term constraints to the power system (adequacy of capacities), as well as short-term balancing impacts and electric grid implications. To address these challenges, the power system will need a further development of flexibility options, which are electricity storage, a development of the electric grid at the local and international level, a better control on the demand-side, and an increase in highly flexible production capacities. As shown, electricity storage has the advantage of representing multiple values for the system, but it also represents additional modelling difficulties.

In order to analyse the long-term impacts of VRES and the development of the different flexibility options, we looked at long-term energy models and their main categories. We completed this approach with our own typology of energy modelling tools, applicable either to power sector tools or to long-term energy modelling tools. It considers three angles of approach for a modelling tool: the general objectives of the model, the spatial and temporal description, and the technical and economic description of the power system components (especially the VRES and flexibility options). We then applied this typology to six different energy modelling tools.

The diverse modelling choices for VRES integration challenges emphasized the discrepancies of objectives between short-term power sector tools and the long-term energy system models. Long-term energy models can generate studies on power systems with high shares of renewable energy sources, but they don't have the necessary detail for representing the challenges of VRES integration and the value of flexibility options (e.g. the inter-temporal constraints associated to VRES and electricity storage). Power sector modelling tools, on the other hand, can provide such details but lack the overall coherence of long-term economic scenarios (e.g. interactions between energy sectors; economic assumptions), which forces them to use exogenous economic assumptions.

As a result, it is decisive to combine the benefits of long-term energy system and power sector modelling tools. Long-term energy forecasting models would draw huge benefits from an effective coupling with a detailed power sector tool, particularly for the representation of the variable renewable energy sources and their impacts on the power sector.

In the next chapter we present the model POLES – the reasons for choosing it and its previous modelling state. We highlight the improvements we made on its power sector module: the introduction of the impacts of VRES as well as a first representation of electricity storage. We present the new modelling of the power system operation. The capacity planning has received special attention and has been extended with an electricity storage investment mechanism.

II. Integrating variable renewable energy sources in a long-term energy model

The scientific challenges addressed in this thesis, already presented in the previous chapter, concern the impacts of VRES on the power sector, considering the particular role of storage in a long-term energy system model. The improvements presented in this chapter bring a first representation of the operation and planning of the power sector. In the first section we present the long-term energy model POLES, with a focus on its power sector (all the corresponding figures are labelled “former modelling” since they do not take into account our improvements). Then, we expose our improvements of the representation of the power system operation, and the way we introduced different forms of storage in a POLES. Finally, we introduce a new capacity planning, with a separate investment mechanism for electricity storage and demand response.

II.1. Description of the model POLES

We choose to work with POLES because it has some key characteristics for our research work:

- The model covers the global energy system, divided into 57 regions (some regions include several countries), with a time horizon up to 2100.
- The simulation logic generates output scenarios closer to plausible developments of the energy system than optimisation scenarios.
- The electricity module of this technology-oriented, bottom-up model is one of the most detailed among long-term foresight energy models.
- Many energy sources or carriers are represented, namely coal, oil, gas, but also uranium, biomass, hydrogen, and of course electricity.
- POLES is widely used, by the European Commission (Joint Research Center - Institute for Prospective Technological Studies) and by Enerdata and its industrial customers. The model is also co-developed by the EDDEN (Economie du Développement Durable et de l’Energie) laboratory in Grenoble, France.

As described in POLES’ manual from 2010 [72], POLES contains several modules, describing energy demand, prices and transformation processes. The remaining natural resources (including uranium) are also monitored, impacting the energy prices. There is one global market for oil (tracking prices and quantities), three separate markets for gas, and three for coal. The exogenous inputs are the GDP, the population, and the carbon constraints. The technologies are described as of today, but their characteristics can evolve along the simulation. The diagram of the energy system is presented in Figure 6.

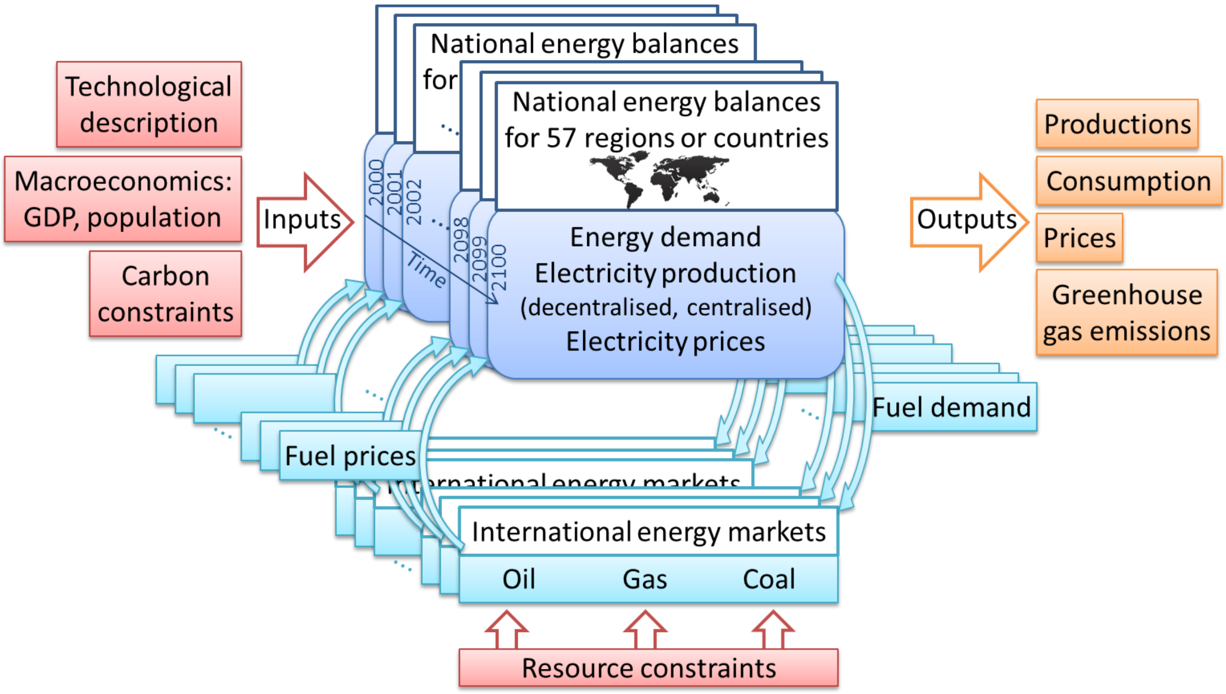

Figure 6: POLES energy system diagram

II.1.1. Description of the power system operation (former modelling)

The ***electricity demand*** is the sum of the national or regional load curves of the industry, residential, service, agriculture and transport sectors. Other miscellaneous consumptions are the auto-consumption of power plants, the grid losses, the consumption from water electrolysis (to produce hydrogen) and the net electricity exports. Each year, the level of the demand is determined based on the previous year's demand, the (exogenous) population and GDP, and the (endogenous) sector activity and fuel prices (indeed some electricity consumptions are substitutable by other fuels). Each sector has its own daily load shape for summer and winter typical days, at a two-hour time-step. The electricity demand by sector is resulting from the energy demand in each sector and the share of electricity in this total demand, which partly depends on the relative fuel prices. For example, the mobility needs and the share of hybrid or full-electric vehicles define the electricity demand of the transport sector. Therefore, the load curves vary with time (year of the simulation) and place (country). The Figure 7 shows an example of the decomposition of the demand.

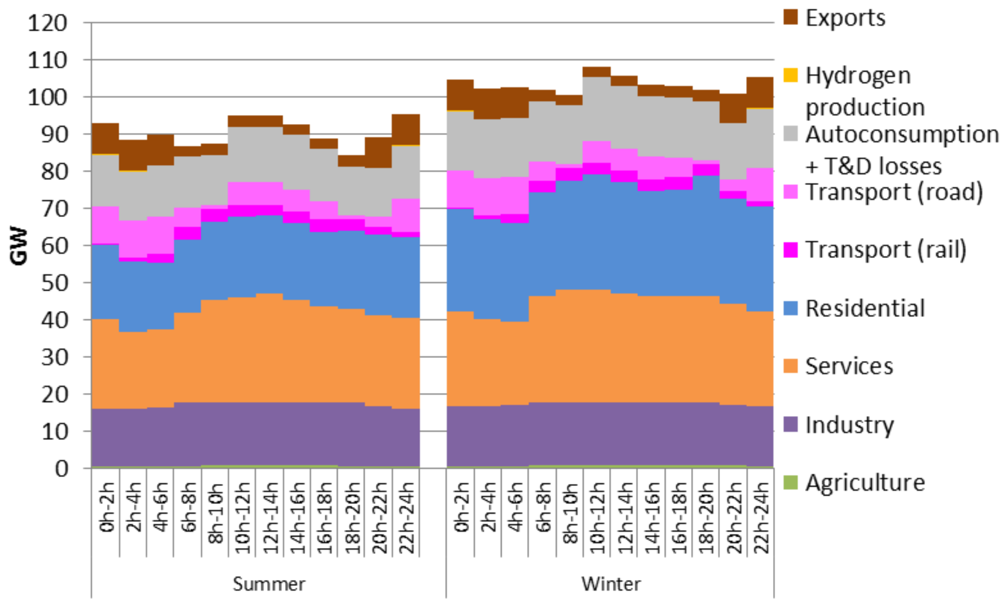

Figure 7: National demand breakdown in consumption sectors. France 2050, baseline scenario (former modelling).

The ***electricity supply*** is divided into 41 generation technologies, described in appendix A. They cover nuclear, coal, gas, oil and renewable technologies: hydraulic, biomass and waste, several wind power technologies (describing several wind resources), several solar technologies (photovoltaic, thermodynamic), geothermal, marine and tidal power. There is also a hydrogen (H_2) module: water electrolysis for H_2 production, and decentralised fuel cells for electricity production from H_2.

The general diagram of the power sector is presented in Figure 8.

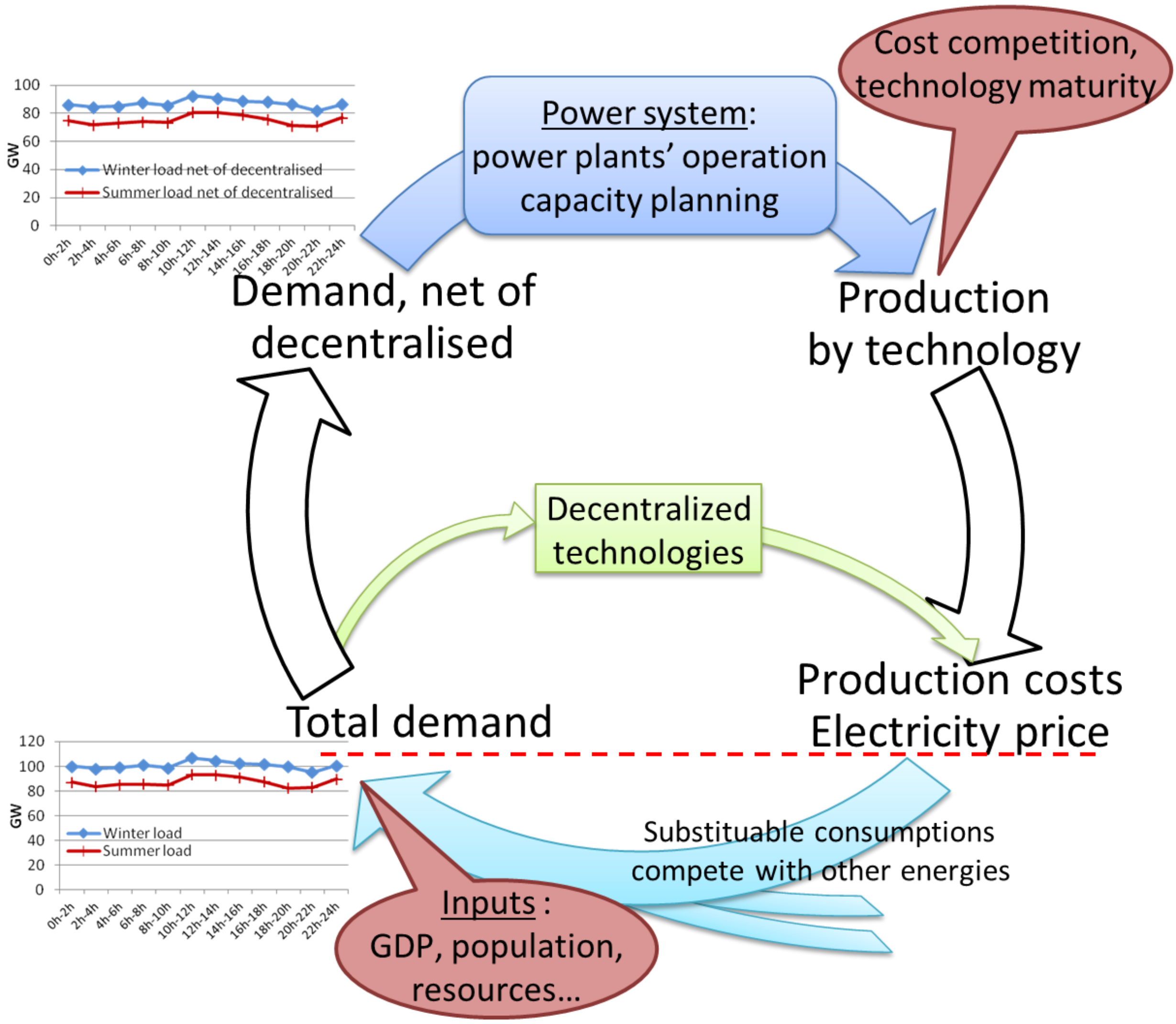

Figure 8: POLES power system diagram

The decentralised productions (hydrogen or gas fuel cells, combined heat and power, and decentralized photovoltaic) are handled separately from the other grid-scale productions: they compete with the end-consumer electricity price. Their two-hourly production is proportional to the total demand.

The other production technologies are supplying the remaining demand, whether they are VRES or dispatchable technologies. Feed-in-tariffs or other subsidising forms are taken into account in the variable and fixed costs.

The demand is met in priority by "must-run" power plants, which are (by order of preference): wind (onshore and offshore), solar, nuclear, hydraulic, geothermal, and nuclear with new design (4^{th} generation). These power plants are supposed to run at full potential at all times, i.e. the installed capacity multiplied by an availability factor, which can depend on the time of day and on the season. The production profiles per two-hour block are shown in Figure 9, for wind and solar (assumed identical for all countries).

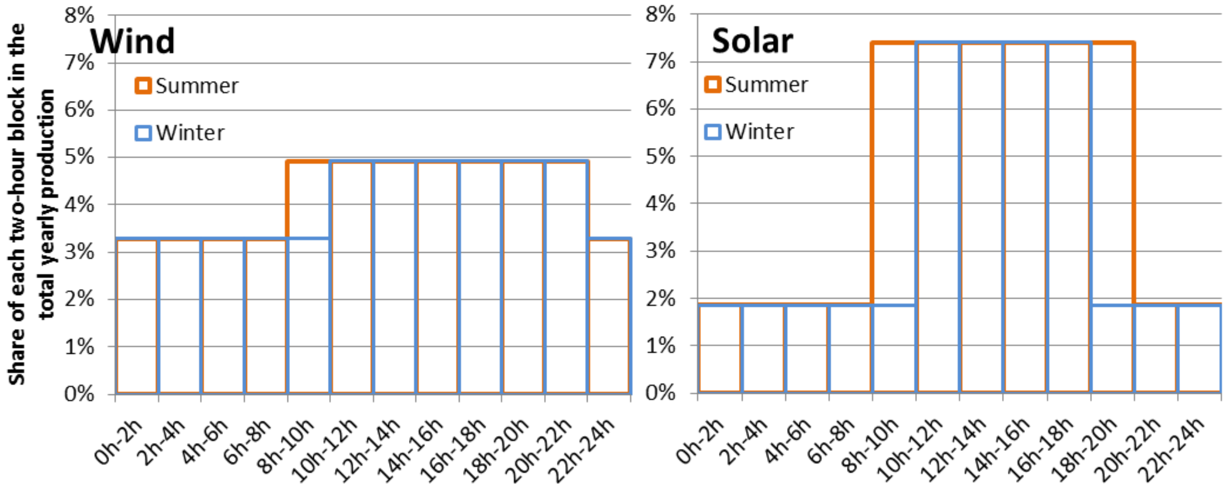

Figure 9: Distribution of wind and solar (centralised) productions across the 24 two-hour blocks (former modelling).

If the demand is not high enough, the output of “must-run” technologies is limited, by respecting the priority order.

The remaining demand is matched by all the other technologies, using a “merit-order” (competition on variable costs) and considerations of every technology’s maturity. The dispatch is constrained by the maximum available capacity of each technology, which is determined by the installed capacity and by an availability coefficient reflecting the forced outage rate and the maintenance downtimes (which depends on the season and hour of the day).

Another important component of the operation is the international electricity exchange through interconnections. Imports and exports are based on historical data; the last available data (2013) are maintained for the whole simulation (by lack of further information on its evolution). Inside a summer or winter day, they follow a fixed daily pattern.

POLES is not an optimisation model, and does not include explicit constraints such as inter-temporal constraints or temporal correlation: each two-hour time-slice is computed independently from the others. This means that the computation is equivalent to a load-duration curve of 24 blocks (see the bar chart of Figure 10, showing POLES’ operation of the power system with the former modelling).

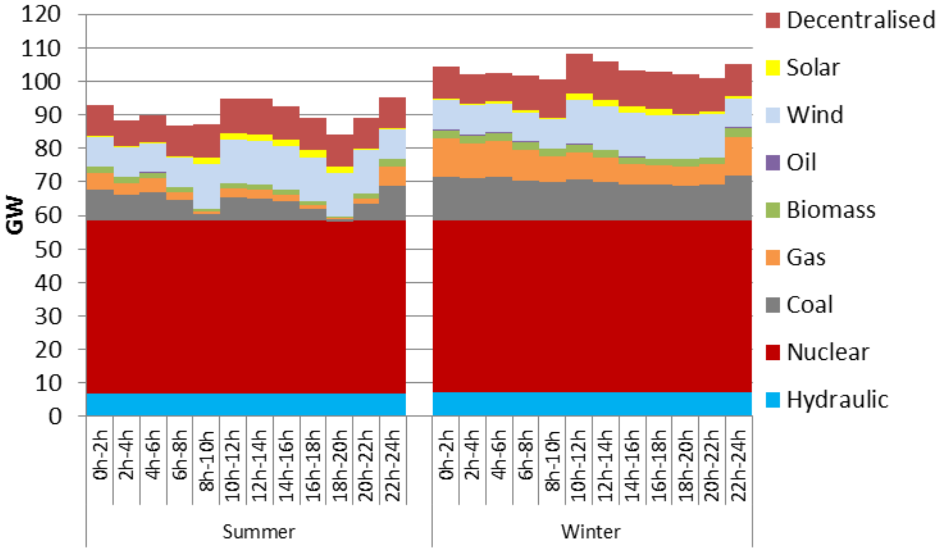

Figure 10: Power plant operation in POLES. The 41 technologies have been aggregated in the graphs in order to keep the representation simple. France, 2050, baseline scenario (former modelling).

The lack of temporal correlation makes it difficult to represent the variability of VRES or storage (as the state-of-charge depends on the previous time-step).

II.1.2. Description of the power system planning of investments (former modelling)

In order to forecast the investments, the future electricity demand is divided into seven blocks of load, which correspond to different expected capacity factors for the necessary power plants: 8760 h, 8030 h, 6570 h, 5110 h, 3650 h, 2190 h and 730 h. The Figure 11 illustrates the seven duration blocks.

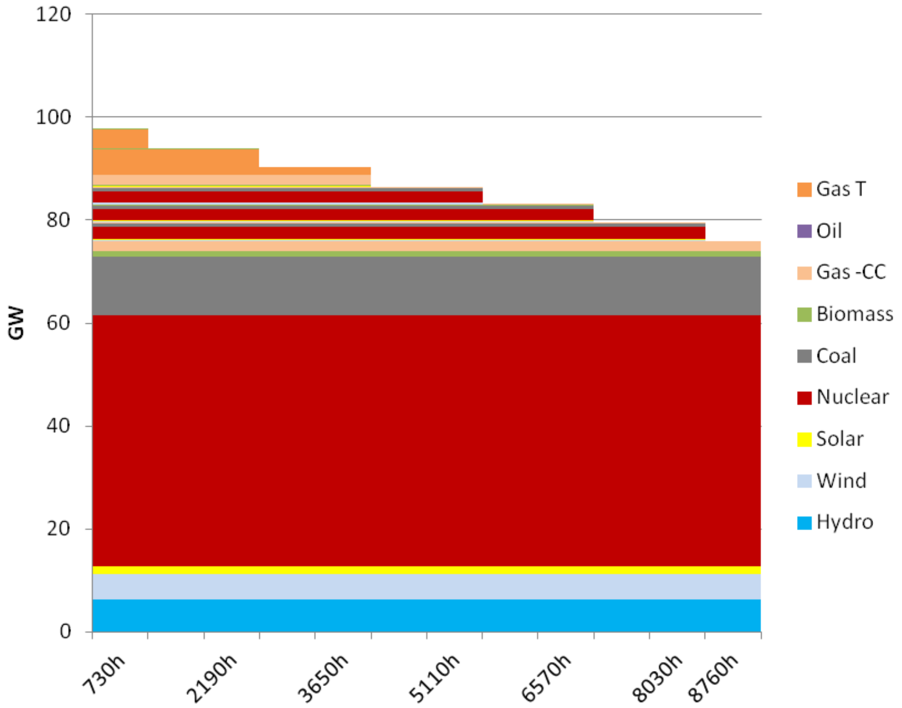

Figure 11: 10-year capacity expectations of the main technologies, split into seven duration blocks. France, 2050, baseline scenario (former modelling).

For each of those blocks, the demand is projected with “rolling myopic expectations”: using the past ten-year evolution of base and peak load as a trend, the base and peak demands are estimated ten years later. The five intermediary blocks are linearly interpolated between the 8760 h and the 730 h blocks (each block covers one sixth of the peak- base difference).

The hydro capacities are handled first. They follow an exogenous trend and are subtracted from the 8760 h block (i.e. considered as base load production only).

The other technologies’ expected capacities are then distributed for every duration block with POLES’ simulation process. The competition between technologies is based on their total cost of production (with the number of expected hours of production defined by each duration block) and their maturity (current share of the market, expectations of technology improvements). A maximum potential is limiting the investments in biomass, geothermal, marine, wind and solar technologies. The simulation equations avoid a “winner takes all” situation; investments are spread across several technologies, as can be seen in the illustration of Figure 11.

The sum of the different investment blocks gives the total expected installed capacity for each technology. Meanwhile, the technology lifetime implies that a fraction of them will be decommissioned within these ten years. For each of the seven blocks, a gap may appear between expected capacities and remaining capacities after decommissioning, indicating a need for new power plants. One tenth of these needs are installed in the following year.

II.1.3. Shortcomings of the pre-existing representation of the power system

Several assumptions of the pre-existing modelling of the power sector hinder an in-depth analysis of the impacts of high VRES scenarios.

Firstly, the former representation of the power system operation in POLES does not model any controllable consumption such as hydrogen production or electrical vehicle charging. The hydro production profile is also considered a constant, without any storage possibility. The import/export profile of each country is fixed exogenously. No storage technologies and no electric grid are represented.

Secondly, the representation of wind and solar variability is very simplified. Wind and solar power are averaged to capacity factors for each two-hour block of the summer and winter days, thus missing most of the variations across the year (e.g. no periods of over-production to curtail). This may be valid in systems with low penetration of VRES, but the scenarios of interest to us include a strong wind and solar development. The statistical mean (even subdivided in 24 time-slices) is not enough to describe the diversity of the situations of VRES production, and does not encompass the constraints on the system. Therefore, the VRES integration constraint is modelled with limits on the maximum VRES penetration in the electricity mix planning. These bounds depend on the ratio between VRES capacities and thermal and hydro capacities, which are seen as "back-ups" (they compensate for wind or solar variability).

For these reasons, some improvements are needed in order to integrate the impacts of VRES on the power system, both in the operation and the planning.

On the operation side, it is important to represent the impacts of VRES on the need for flexible power plants. Balancing requirements (including frequency reserves) and thermal power plants' ramping constraints (as well as start-up and shut-down constraints) should also be included in a more detailed modelling. This calls for a temporal representation of the (residual) demand; it is even more important for evaluating the potential role of storage, as the load-shifting value is crucial.

The planning of dispatchable capacities has to take into account the limited availability of VRES in times of high demand (low capacity credit of VRES) and the reduced number of full load hours for base load power plants (caused by periods of high VRES production and low demand). The planning of storage and demand response programs needs particular attention.

We present hereafter the improvements we made on the power system operation and capacity planning in POLES.

II.2. Improvements in the power system operation in POLES

A number of improvements have been carried out in POLES in collaboration with Alban Kitous and Silvana Mima. For example, in parallel with the thesis work, the production profile of wind and solar power plants has been better calibrated by using real data, as shown in

Figure 12 (the wind profile is the Spanish 2009 yearly average of each two-hour block; the solar profile is adapted to every country; the solar with thermal storage is an assumption which considers a storage efficiency of 80%).

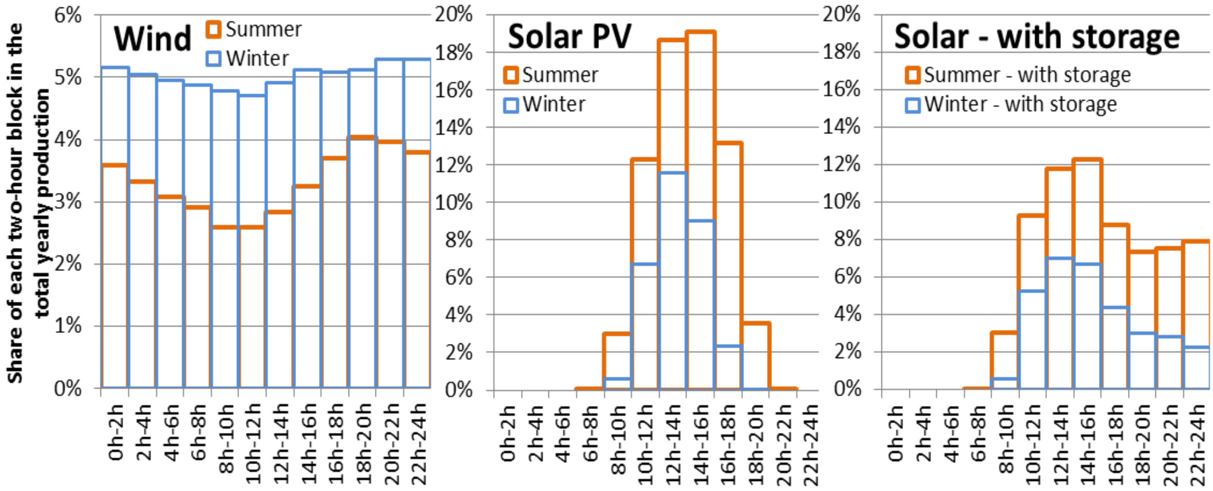

Figure 12: Distribution of wind and solar production (photovoltaic or thermodynamic with heat storage); first improvement of POLES' inputs.

The decentralised photovoltaic power is not constant anymore and follows the production profile of other photovoltaic (PV) plants. Hydraulic production is now split into run-of-river, lakes and pumped hydro. Their operation is not constant anymore; we include a new connection to the results of an environmental model, HadGEM2-ES [181]. Several climate change scenarios are considered for calibration (rcp 2.6, rcp 4.5, rcp 6.0, rcp 8.5) and the resulting seasonal water runoffs (for each POLES' region) are inputs in POLES scenarios.

We present in this subsequent section additional improvements we carried out in order to evaluate the interactions between non-dispatchable VRES and the rest of the power system, particularly electricity storage.

<u>II.2.1. Building a residual load duration curve</u>

We have first increased the temporal detail in order to cover more situations than the pre-existing 24 two-hour blocks. As the focus is the variability of the residual load, we have represented both the variations in the demand and in the VRES productions, reaching 648 time-slices:

- The 12 two-hour blocks for summer and winter days are kept
- Demand variability is increased with three levels of demand (lower 20%, medium 55% and higher 25%)
- Wind variability is increased with three levels of wind production (lower 10%, medium 80% and higher 10%)
- Solar variability is increased with three levels of solar production (lower 10%, medium 80% and higher 10%)

The "low" and "high" days for demand, wind and solar are calibrated with data from France in 2013 (RTE data [17]), by fitting the real residual load duration curve of 2013. The fixed coefficient that calibrates the "high demand" days corresponds to an increase of consumption in the residential and service sectors (+40%), while the “low demand” days have a decreased residential, service and industrial sectors consumption (-30%). This distorts the load profile according to the share of these sectors in the total demand. We assume here that every country has a similar structure for “high” and “low” days of consumption[7]. The “medium” demand day is calibrated such that the yearly average corresponds to the total electricity demand. For wind and solar, the production profiles (per two-hour block) of “high” and “low” days are adjusted with coefficients: for wind, the new production profiles correspond to real “high” and “low” production days for France in 2013 (the 10th and 90th percentile of RTE data [17]); for solar, the production profiles are already adapted to every country and are just up- or down-scaled (+30%/+0%/-30% in summer and +75%/-3.8%/-50% in winter, in order to maintain the capacity factor). The new production profiles are shown in Figure 13.

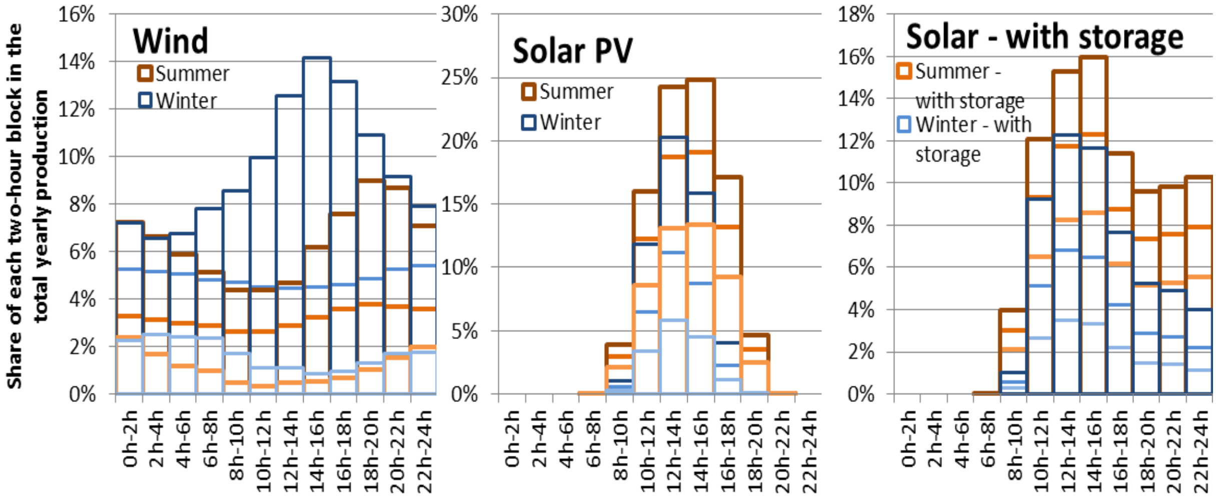

Figure 13: High, medium and low production profiles of wind and solar (photovoltaic or thermodynamic with heat storage); second improvement of POLES’ inputs.

This calibration of “high”, “low”, and “medium” days are considered to be a satisfying first approximation; yet, these assumptions should be improved and validated with further work (part of the perspectives of this work).

The 12*2*3*3*3=648 time-slices are reordered in a residual load duration curve and are shown in the Figure 14.

[7] Note that the French load duration curve is slightly different than in other countries because of its thermo-sensibility, due to the particularly high influence of electric heating.

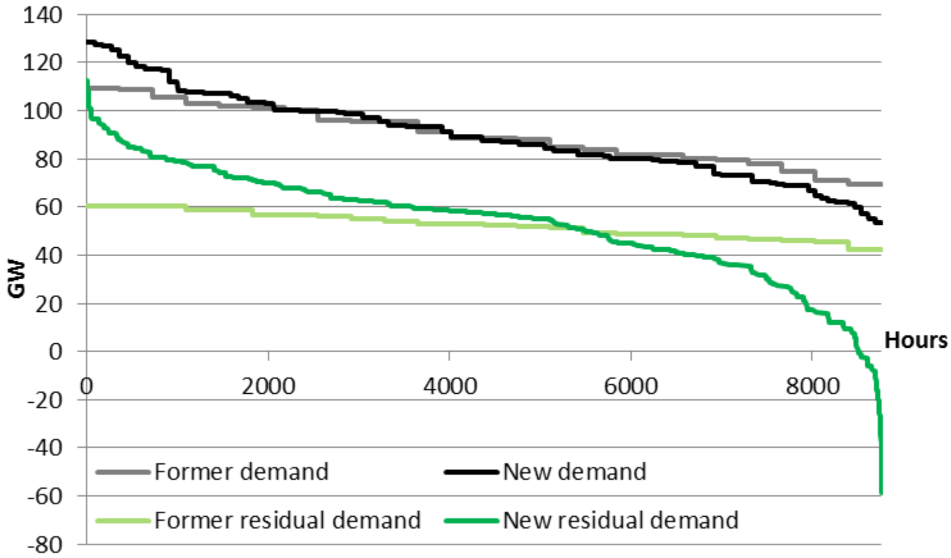

Figure 14: Load duration curve and residual load duration curve: former modelling (applied to the same scenario and year) and new modelling integrating the variability of demand and VRES. France, 2050, baseline scenario.

The new modelling has increased the steepness of the residual load duration curve. The extremes are now much better represented; in the example of Figure 14 (baseline scenario, France in 2050), the residual load even becomes negative on a few hours of the year.

This residual load duration curve is now the basis of the technology dispatch.

II.2.2. Dispatching the Electric Vehicle charging

A strong electrification of the transport sector is expected; for example the vision of the International Energy Agency is to achieve half of the vehicle sales from plug-in hybrid and full-electric cars in 2050 [182]. Therefore it is important to refine the representation of EV charging, which could be a huge lever for the integration of VRES. We present hereafter our modelling improvements in this sector.

For each of the 54 days computed (2 seasons * 3 demand levels * 3 solar levels * 3 wind levels), the daily consumption of EV has to be supplied. We consider a maximum charging level, determined by:

- the proportion of vehicles available for charging at a given time (taken from [183], see Figure 15),
- a charging power (set at 3.2 kW, which corresponds to a Nissan Leaf and is in the range of most current commercial EV [184])[8],
- the number of EV (hybrid and full-electric).

[8] We consider only slow-charging devices. Fast-charging is more expensive and constraining for the system.

This consumption can be controlled, thanks to the assumed high number of hours of connections to the grid (a reduction of this number of connection to the grid would decrease the controllability of the load [185]).

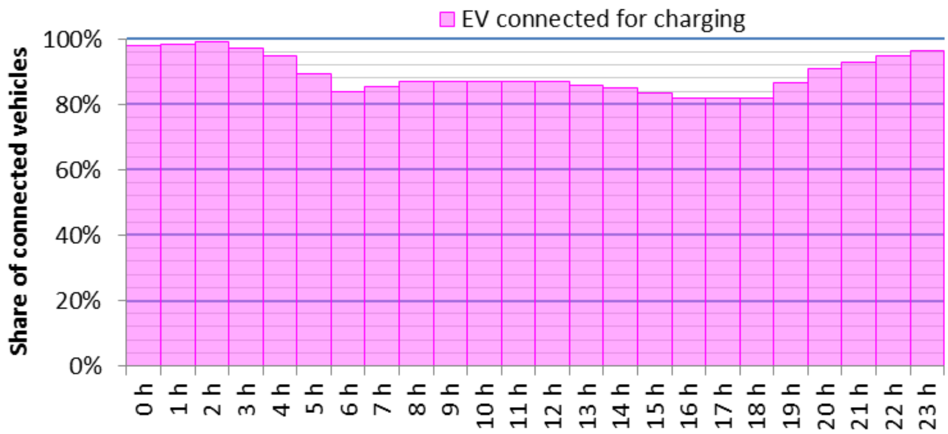

Figure 15: Assumed availability of EV for charging (based on [183]).

For each of the 54 days considered (each with 12 time-slices), the distribution of the EV charging is based on the ratio between the load on a given time-slice and the highest residual load of the day:

$$\forall h \in [1;12], Coef_{EV}(h) = 1.05 * RL_{max} - RL(h)$$

$Coef_{EV}$ is the coefficient for the EV charging happening at the two-hour block h; RL is the residual load and RL_{max} is the daily maximum of the residual load. The 1.05 factor ensures a minimum level of EV consumption at every time-slice. Some specific cases lead to exceptions:

- If RL_{max} is negative, we use 0.95 instead of 1.05;
- If the charging energy is higher than:

$$\sum_{h=1}^{12} \left(1.05 * RL_{max} - RL(h)\right)$$

  then the remaining energy is distributed equally on all two-hour blocks.

Then, the EV charging is split in daylight hours (up to 50% of the total charging), and night hours (at least 50% of the total charging). This assumption means that most of the trips are two-way, with a 'commuting' profile between 7am and 7pm [185]. We assume that the EV drivers will in any case charge their vehicle at home (and reach a full battery before leaving their home in the morning). If they want to charge also during daylight hours (possibly benefiting from attractive electricity prices, fostered by the appearance of excess solar production during daylight hours), only half of the daily consumption can be charged before filling the battery again, since they have only travelled half of their daily trip.

We ensured this 50% night-charging constraint and the maximum charging power constraint by a careful normalisation.

II.2.3. Representing storage technologies and demand response

Technology assumptions

We add four storage technologies to POLES (see appendix A): hydro pumping, adiabatic CAES (a-CAES), Lithium-ion stationary batteries and batteries for Vehicle-to-Grid applications (V2G). We choose these technologies because they have a significant potential of development: hydro pumping is already dominating the storage market today; a-CAES is another promising high-capacity storage; Li-ion batteries are already on the rise and a sharp decrease in their costs is expected (partly related to the industrial development of EV batteries); finally, EV could be used as V2G without any significant further investment. Because POLES uses two-hour blocks, it is not relevant to represent high-power (and low-energy) storage (flywheels, superconductors, SMES). Finally, long-term storage such as hydrogen is not explicitly represented with a storage cycle in POLES. Hydrogen fuel cells are developed as a distributed generation technology competing with other decentralised alternatives (decentralised combined heat and power, gas fuel cells, decentralised PV). Conversely, hydrogen can be produced from electricity, using water electrolysis, but in competition with other ways of supplying the demand for hydrogen; this hydrogen production does not necessarily correspond to electricity produced later. However, any other daily storage technology could be easily added with the new modelling framework in place. We also add a possibility for Demand Response (DR).

The important technical and economic parameters of each technology are described in Table 7: round-trip efficiency, maximum potential of deployment, investment and fixed O&M costs, life-time, discount rate and learning rate.

Baseline scenario	Hydro pumping	a-CAES	Batteries (Li-ion)	V2G (Li-ion)	DR
Efficiency	75%	65% [186]	80%	80%	100%
Potential	10% of the total hydro potential	20% of the maximum load	50% of the maximum load	60% of EV after 2050	5% of the maximum load
Investment costs	1000 $/kW or country-specific values from [187]	1075 $/kW + 43 $/kWh (2013) [186]	161 $/kW + 403 $/kWh (2013) [186]	100 $/kW	123 $/kW [188]
Fixed O&M costs ($/kW/year)	4.3 [186]	32.2 [186]	10.75 [186]	10.75	10
Variable O&M costs ($/MWh)	8.6 [186]	0 [186]	2.15 [186]	2.15	0
Life time (y)	55 [186]	35 [186]	12.5 [186]	10	20 [189,190]
Discount rate	4%	4%	8%	8%	5% [188]
Learning rate	0.61%	5%	8%	1%	1%

Table 7: Standard characteristics chosen for storage technologies and demand response for the baseline scenario. All costs are in $US of 2005.

The round-trip efficiency is a key parameter of the storage technologies and could evolve over time (user-defined evolution). We choose rather conservative assumptions from the literature (hydro pumping efficiency is based on real operational data [17]; a-CAES, stationary batteries and V2G efficiencies are based on [35,50] and DR overall "efficiency" is a personal assumption used to illustrate DR). The consequences of higher efficiencies for all four storage technologies are analysed in IV.2, with a focus on battery efficiency in IV.2.3.

The deployment potentials (necessary for the investment mechanism) are difficult to know, especially for each of the 57 world regions of POLES. Therefore we use the following working hypotheses; the result sensitivity, tested in appendix B, shows little influence of the potential of a technology on the development of the others (however, some technologies develop up to their potential, so they are very sensitive to this assumption). For V2G development, we consider that agreements of using an EV battery for V2G will develop progressively from 2020 on, reaching 60% of the existing EV in 2050 and after. For DR, in the baseline case-study we consider that the maximum capacity useable simultaneously represents 5% of the peak demand (this includes the effective activation rate of the contracted capacity).

The investments costs, fixed O&M costs and life-time are based on a wide study from an industrial consortium [186]. For V2G, we consider that the only cost is the remote control of the EV (same order of magnitude as the DR investment costs). We assume similar characteristics for batteries and V2G batteries (the lower life-time represents the ageing impacts of the driving cycles).

The discount rates are used to annualise the investment cost. We assume utility-wide investments for hydro pumping and CAES (low discount rate), and privately-owned business investments for batteries and V2G (higher discount rate).

The learning rate is the diminution of costs related to a multiplication by two of the global cumulated installed capacities ("learning by doing"). It is very low for hydro pumping, which is already a mature technology and doesn't show any diminution in the new plants' costs. DR and V2G also show low learning rates because their costs are already considered to be low; moreover, the communication and control devices are dependent on the chosen technology, which changes from a place to another and will change in time (thus restraining the learning effect). For CAES and Li-ion batteries, we choose rather high learning rates because these technologies could strongly develop and reduce costs. Batteries could particularly benefit from a mass-production effect, driving costs down.

A sensitivity analysis on the technological and economic assumptions is discussed in Chapter 4.

Dispatching assumptions

The electricity storage and DR technologies are dispatched based on the residual load, net of EV charging. Because POLES' software (Vensim) does not allow for any optimisation computation, we have to use simulation equations, which is much more complex and long than an optimisation approach. We give more details in the appendix C, but here are some indications on the modelling choices.

In the first step, storage technologies are allowed to produce electricity in the three two-hour blocks of highest residual load (net of EV) and store electricity in the three blocks of lowest residual load (net of EV). For each of these two-hour blocks, we fix the production or storage output value (see Table 8), depending on the assumed daily availability of the technology[9] (they cannot participate equally to the market). The modelling of DR is the same, the "production" of DR being in fact a load shedding, and the "storage" representing the rebound effect (no temporal constraint). More details on the limits of this analogy are presented in appendix D.

Theoretical output (% of the installed capacity)	Hydro pumping	a-CAES	Batteries	V2G	DR
1st block of highest consumption	+100%	+100%	+100%	+100%	+80%
2nd block of highest consumption	+87.5%	+30%	+90%	0%	0%
3rd block of highest consumption	+0%	0%	10%	0%	0%
4th to 9th block	0%	0%	0%	0%	0%
10th block of highest consumption	-50%	-60%	-50%	-25%	0%
11th block of highest consumption	-100%	-70%	-100%	-40%	-20%
12th block of highest consumption	-100%	-70%	-100%	-60%	-60%

Table 8: Output assumptions for storage and DR technologies for each of the ordered two-hour blocks of residual load, net of EV. A positive value indicates production; a negative value indicates storage.

In the second step, we modify the operation of the storage and DR capacities in order to remove the inconsistencies of the first step (too much storage used at a single two-hour block compared to the other blocks; too much or too few stored energy compared to the produced energy).

These two steps are illustrated in the Figure 16.

[9] These assumptions are fixed in POLES; they are an approximation of what could be the operation of storage (and DR) for the duration of the scenario. This leads to some over-estimation of storage operation (and investments) in the beginning of the scenario and under-estimation in the end.

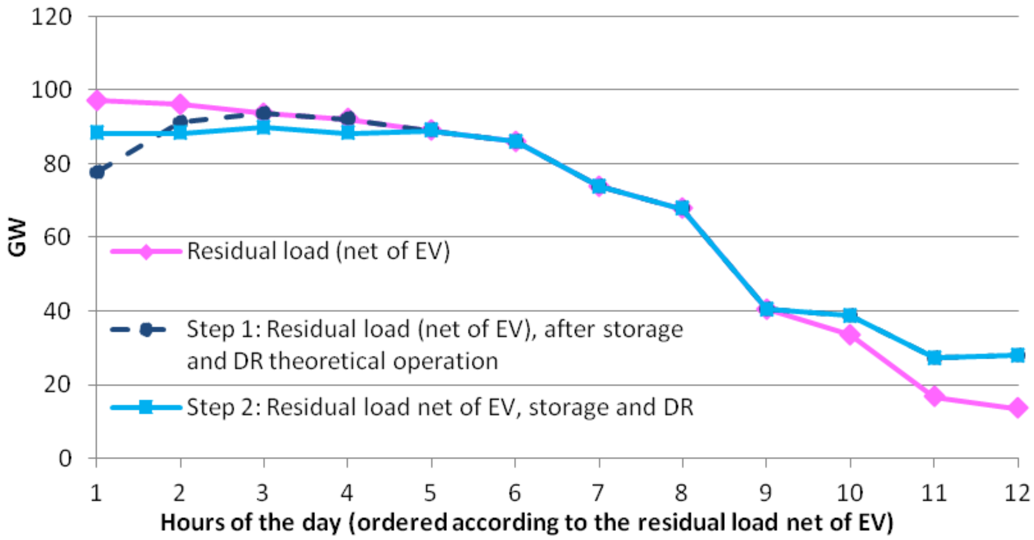

Figure 16: Storage and DR dispatching method, illustrated on a summer day of medium demand, low wind and high solar. France, 2050, baseline scenario (POLES only).

The example of figure 16 shows a case where the first dispatch step of storage and DR in POLES leads to dispatching storage and DR mostly on the highest and lowest block of the day of the residual load net of EV (number 1 and 12 when ordering them). The second step ensures that storage and DR show a more even distribution, thus flattening the residual load.

In Figure 17 we show the result of the different dispatch steps for an entire year: the load duration curve (in black), the residual load duration curve (in green), and the duration curves of the residual load net of EV (pink) and net of EV, storage and DR (blue).

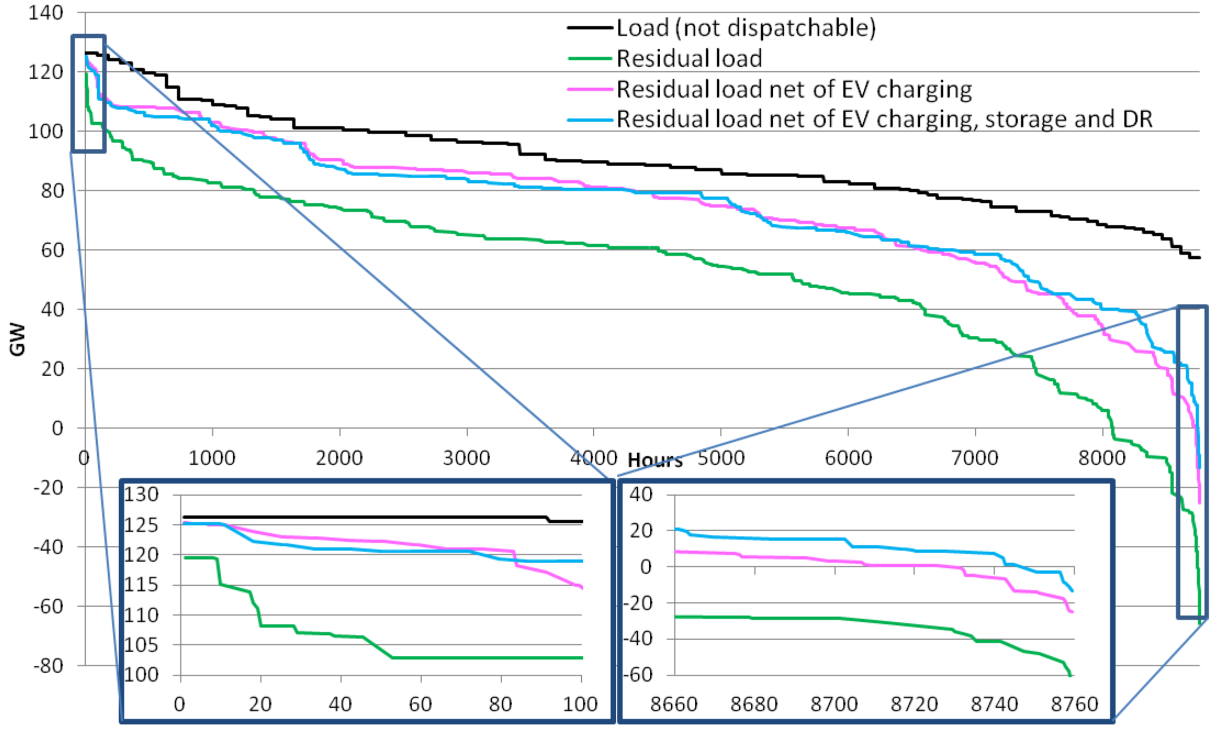

Figure 17: Effect of VRES, EV charging, storage and DR on the load duration curve, zooming on the 100 hours of highest (lower left) and lowest consumption (lower right). France, 2050, baseline scenario (POLES only).

We observe that the flexibility options considerably decrease the surplus renewable energy (negative residual load, in the lower right-hand focus). The negative residual load is a new feature for POLES, enabled by the improved level of detail on the VRES variability. This can lead to curtailed surplus energy, depending on the level of inflexible generation (25% of the installed nuclear capacities are considered entirely must-run) and on the installed hydro long-term storage (that participate up to its energy and power capacity).

There is mainly an impact of EV charging on the residual load; the effect of storage and DR remains relatively small despite a total of 15.8 GW of storage and 4.5 GW of DR installed in France in 2050. The Figure 18 is looking at specific days in order to visualise the roles of EV charging, storage and DR.

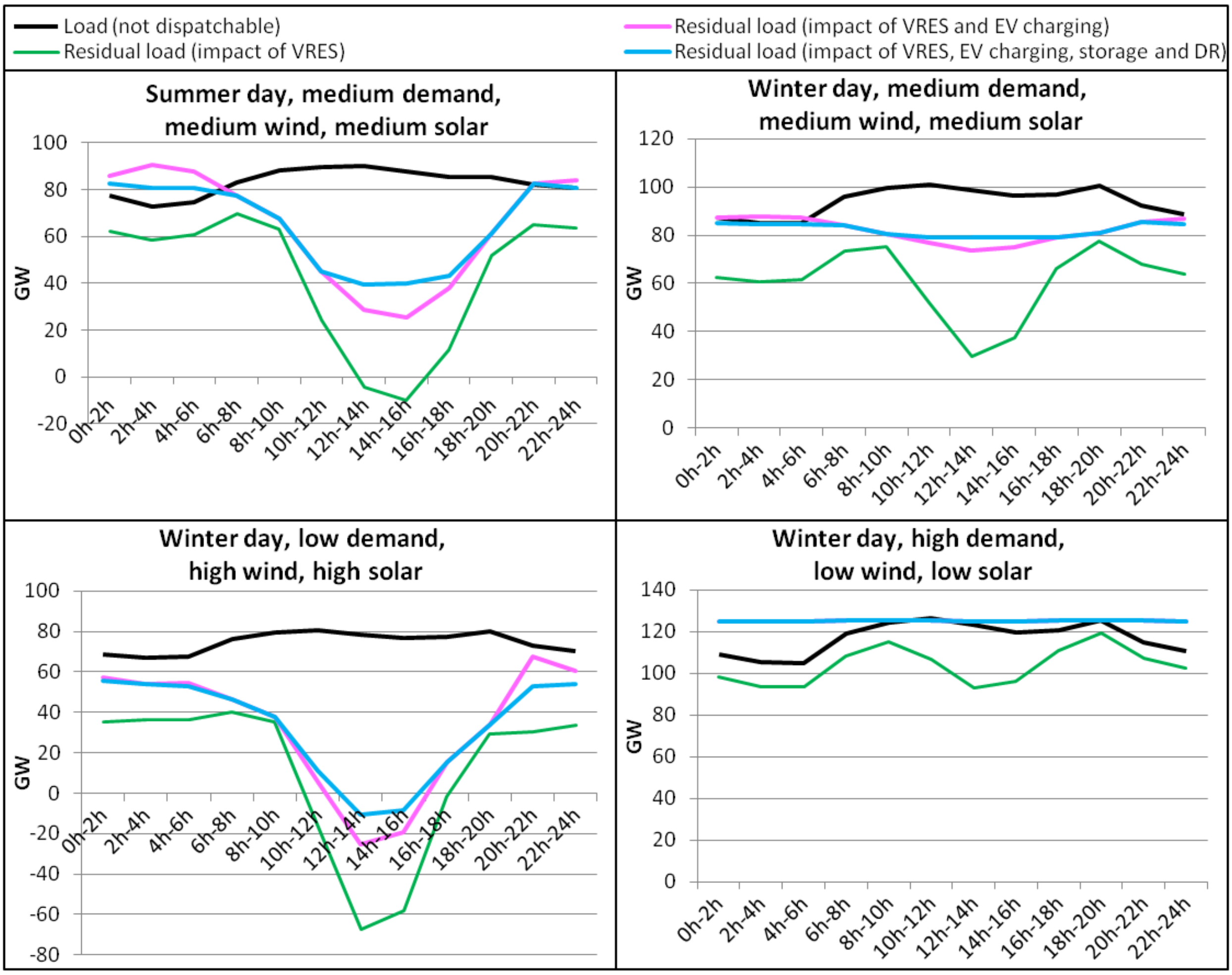

Figure 18: Effects of VRES, EV charging, storage and DR on the load on four different days. France, 2050, baseline scenario (POLES only).

It can be seen, given the constraints we imposed on storage, that the potential for storage is mostly absorbed by EV charging, especially in days with a low solar production (right side of Figure 18). Concerning the medium day (upper left for summer, upper right for winter), we see a good participation of storage and DR on the summer day (when solar production largely exceeds the difference between day and night consumption) but a small value in winter days, when EV charging is enough to compensate the smaller dip in residual load. Concerning the day with the lowest residual load (winter, low demand, high wind and high solar, at the lower left of Figure 18), we see that EV, storage and DR absorb almost entirely the over-production from solar generators (250 GWh of surplus energy avoided on this single day) and produce at night. Concerning the day with peak residual load (winter, high demand, low wind and low solar, at the lower right of Figure 18), storage and DR have little value to the system since they are only capable of daily cycles in POLES; yet the residual load net of EV charging is consistently high during the day and almost constant, leaving only a small window of opportunity for storage and DR (the reduction of peak load thanks to storage and DR is only 120 MW in this particular case).

II.2.4. Dispatching the other capacities

Once we have dispatched the EV charging, storage and demand response, the remaining load is aggregated into 24 two-hour blocks again (separated in summer and winter days).

The hydrogen production by water electrolysis is made more flexible. We use a load curve excluding electrolysis consumption. The repartition of water electrolysis is then based on the ratio between the demand on a given time-slice and the spread between high and low demand: more hydrogen production happens at times of low demand.

The representation of "must-run" technologies is improved. The hydro run-of-river is kept constant, but the hydro lake and nuclear production can partly decrease their consumption to adapt to energy surpluses from VRES. Hydro lakes have the possibility to reschedule this energy to another time, thanks to the storage capacity of the dams.

Then, a competition between merit-order technologies (with considerations of maximum potential) dispatches the remaining capacities in the former modelling fashion. The results of this new operation of the power system are illustrated in the Figure 19 (hydrogen production by water electrolysis is not visible because this demand is too small in this case).

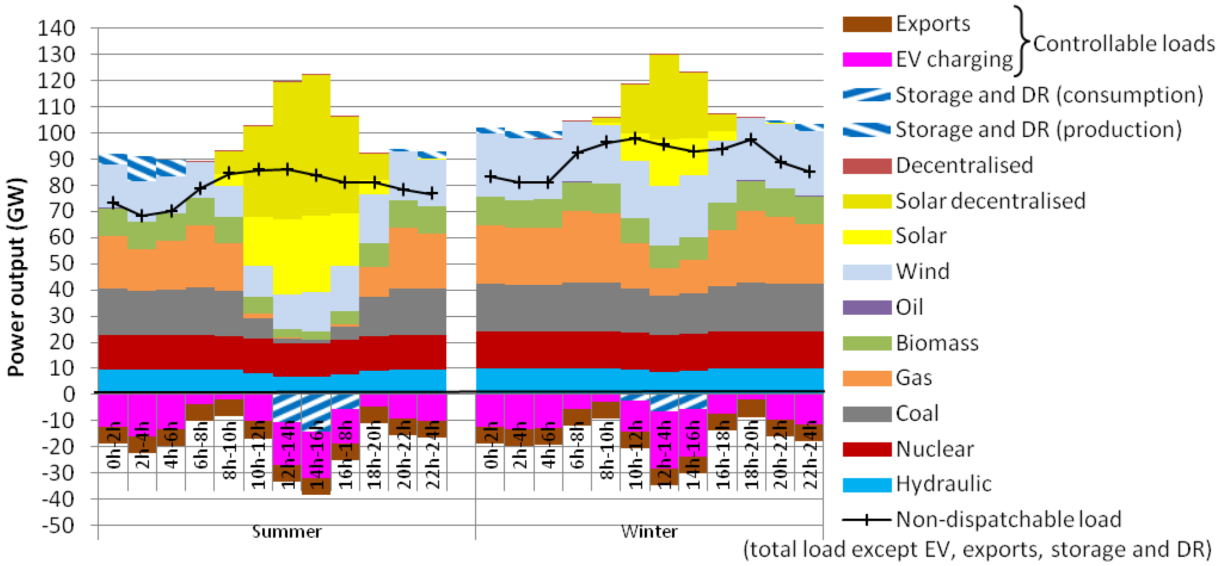

Figure 19: Operation of the power system in the improved POLES. France, 2050, baseline scenario (POLES only).

With this new simulation framework, we have a more flexible representation of hydrogen production from electricity, hydro production and nuclear production. There is also a new modelling of the EV charging, storage and DR flexibility. However, these modelling choices rely on hard constraints (Table 8), with no guarantee that the flexibility options will be used in an optimal system; the operation of storage may be over-estimated[10].

However, there is no guarantee that the importing or exporting situation of a country (fixed to the 2013 situation by lack of further information) remains the same until the end of the scenario. This could significantly impact the total energy produced in each country, leading to significant simulation inaccuracies.

These approximations on the operation of storage, DR, exports and capacity dispatch are necessary in a simulation approach such as POLES, but they are further improved in the Chapter 3, thanks to the coupling of a short-term optimisation model to POLES.

II.3. Improvements in the planning of investments

In addition to the progress in the operation of the power system, we also improved the production capacity planning. We added a brand new planning for storage and DR capacities. Both are based on the residual load duration curve net of EV, storage and DR, as explained above.

II.3.1. Planning of production technologies

Using the residual load duration curve

The planning of new power plants is computed with the following modelling steps, illustrated in Figure 20:

1. The residual load duration curve (net of EV, storage and DR, but without taking into account the grid interconnections) is sampled to eight points (see the stars in figure 20-left): 1 h, 730 h, 2190 h, 3650 h, 5110 h, 6570 h, 8030 h and 8760 h.
2. The base-load investments are based on the 8760 h block. The peak-load investments (730 h) ensure capacity adequacy: they cover the annual peak-load (with an occurrence of 1 hour). The intermediary duration blocks for investment are averages of two successive sampled points (e.g. the capacities operating 2190 h have to cover the average of the 2190 h and 730 h points). This ensures that duration

[10] Another modelling possibility would have been to first dispatch the production technologies on the residual load (net of EV), compute prices (short-term marginal costs), dispatch storage if it makes economic sense (see II.3.2 on storage “energy value” for more detail), and dispatch the power plants again afterwards, iteratively until prices converge. The number of additional equations to include in POLES would have been significantly higher, adding some complexity – and risks of errors in the code.

blocks for investment are close to the actual residual load duration curve (net of EV, storage and DR).

3. The future duration blocks for investments follow a 10-year trend. Their evolution is restricted to a range of -10% to +100% of the current installed capacities (while staying positive).
4. Hydro power plants still follow an investment trend, independent from the duration blocks. Run-of-river power plants are deduced from the 8760 h block and hydro lake power plants contribute to the 8760 h and 8030 h blocks (half of the expected power for each block): pumping hydro is already taken into account in the residual load duration curve and should not be double counted.
5. All investments of technologies with a maximum potential (VRES, biomass) are planned based on the remaining expected demand.

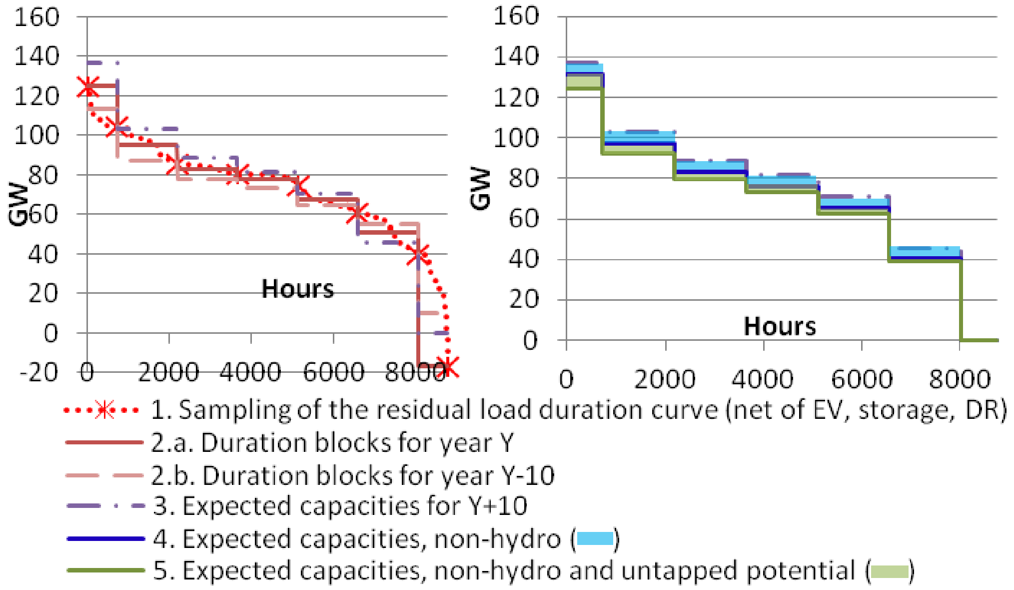

Figure 20: *left*: definition of the investment blocks based on the residual load duration curve (net of EV, storage and DR); *right*: the three steps of the investment mechanism (hydro, technologies with potential reached, others). France, 2050, baseline scenario (POLES only).

All non-hydro and non-VRES centralized power plants are handled by the remaining blocks of expected capacities. The actual investments are determined by the gap between the expected capacity needs and the expected remaining power plants after decommissioning.

This new way of computing the investments better shows the impacts of VRES on full load hours of base-load power plants and on the development of peaking power plants. This is visible in the comparison of the Figure 21.

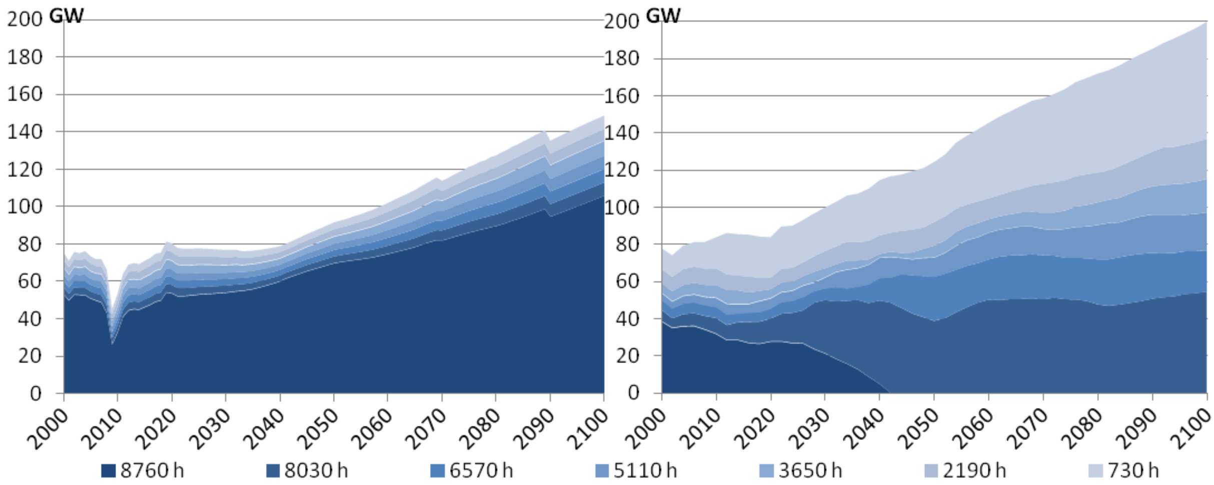

Figure 21: Duration blocks' evolution as expected by the former modelling (left) and the new modelling (right). France, baseline scenario (POLES only).

The new investment mechanism reveals that the need for peaking power plants increases with VRES development, in order to meet the peaks in the residual load (net of EV, storage and DR). Base load power plants are not as necessary as in the former capacity planning of POLES (there is an important shift of capacity needs from 8760 h to 8030 h). This means that POLES now represents the impact of VRES on the full load hours of conventional power plants.

Assessing the need for a flexibility constraint

As the power production mix is increasing its share of non-dispatchable VRES, it also needs an increased flexibility of the rest of the power system. In order to meet the demand at all times, the rest of the electricity mix must stay flexible enough and accommodate for the variations of the residual load. While Huber et al. [191] study the hourly and multi-hourly output variations, we choose to focus on half-hour output variations.

Using an approach similar to Sullivan et al. [177], we set a flexibility test for the system. Each power plant (as well as the demand) has a half-hour variability coefficient, either positive (if the capacity is dispatchable) or negative (if it is non-dispatchable). For conventional power plants, we choose the 30 min ramp-rates from [192] (possible variations that can be expected in 30 minutes). We also have to take into account the international interconnections, as they are very useful for mitigating the residual load variability. We tried two cases: a coefficient of 0 (which means they do not participate in the flexibility of the system at all) or 0.2 (interconnections provide 20% of their rated capacity in half an hour – independently from the situation of the neighbours). This is assumed to represent the international balancing market; however it does not explicitly take into account the situation of the neighbouring country.

For the wind, solar and demand variations, we analysed 2013 data for France [17] and used the maximum observed 30-minutes variations (up or down) for each two-hour block of POLES (summer and winter seasons). More details are available in appendix E.

When adding the contributions of all installed power plants and of the demand, the total flexibility of the system must remain positive [193]. Our computation shows that the flexibility indicator remains positive even in the long-term (see appendix E); this finding is confirmed in [194]. This means that the current investment mechanism already includes enough flexibility; there is no need for an additional constraint in the investment decisions process.

A more comprehensive approach of the flexibility metric is proposed by [195] and discussed by Ulbig and Andersson [196,197]; they add other metrics to the ramp-rate: the maximum power and energy available for balancing requirements (as well as a ramp duration, deduced from the other metrics). Indeed, the instantaneous ramping capabilities of the system are not enough to assess the impact of persistent deviations. This level of detail is incorporated in the operation of POLES coupled with EUCAD (thanks to the explicit constraints in EUCAD: ramping, minimum on- and off-time). The flexibility metric that we develop shows that the margin is enough and that the long-term investment mechanism does not need to add this kind of constraint.

II.3.2. Planning of storage and DR technologies

In the investment process, all electricity producing technologies are compared according to a LCOE, in €/MWh. This total cost depends on the number of hours of equivalent full load operation in a year (the "full load hours"), because the fixed costs are spread across these hours. Capacity planning models usually optimize the electricity portfolio by comparing these costs.

Electricity storage is not a net production power plant, which makes it difficult to compare to traditional producing technologies (an alternative indicator to LCOE can be the Levelized Cost Of Storage, which tracks the costs relative to the storage capacity but not the electricity input [198]). Another difference with producing technologies is the multiple source of economic values of storage; for example taking advantage of excess renewable energy that would otherwise be curtailed [199].

As for DR technologies, they usually have a low cost compared to storage technologies or producing technologies. DR aggregators can sell the load shedding capacity as an alternative to another production, and many other business models could appear in the future [40,200].

Storage and DR are not perfect substitutes for peaking capacities because here we only consider daily storage (or load shifting within a day), so they cannot supply a whole day or week of peak-demand. However, hydro pumping or CAES are high-energy technologies that could offer weekly storage, not modelled here. This is a future perspective of the current modelling.

We look below at the representation of the economic benefits of storage and DR technologies.

Energy value

We want to represent the economic value related to price arbitrage of an additional storage. To do this, we estimate shadow power market prices, based on the existing power system (including the existing storage and DR). We use the economic merit order, adding all power productions according to their variable cost in the ascending order. The marginal technology is the last one to supply the residual load, net of existing EV, storage and DR. Its variable cost defines the market price, for each of the two-hour blocks of the 54 summer and winter days computed.

The important variable for storage operation is the spread between high and low prices on a given day. However, this approach overlooks the smoothening effect of international exchanges on national prices (the residual demand and producing technologies are only considered at a national level here; the interconnections cannot be easily incorporated in a simulation model like POLES). In POLES, the end-user electricity prices are already combined with the European average (30% national, 70% European average). We use the same assumption for market prices: the highest prices are combined with peak-load average European prices and the lowest prices are combined with base-load average European prices.

If the price spread covers the efficiency losses, storage (or DR) operates – without any temporal representation of the state-of-charge or of the rebound effect of DR. The operation is bounded by the same maximum operating hours per day as in the power system operation (see Table 8). The round-trip efficiency is crucial to the potential profit of storage; DR is assumed to have a 100% efficiency (all load curtailment is displaced to another time), therefore it has a high energy value and develops quickly.

The price modelling includes the effects of existing storage or DR, thus decreasing the value of further investments. On the other hand, there is a possibility of negative prices at times of excess non-dispatchable and subsidised renewable generation (although we don't model the flexibility constraints of thermal power plants within POLES, which are a major cause of negative prices today). Our modelling of benefits from arbitrage is only valid for a marginal (small) additional storage or DR, meaning that they do not have any impact on the shadow market prices (which is the case here because the annual investments remain small). The existing storage and DR are not small and clearly affect the prices; this is the reason why the storage operation (see II.2.3) is not modelled by simulating prices (several iterations would be needed before stabilisation).

The storage and DR annual resulting profits represent their energy value (see Figure 22).

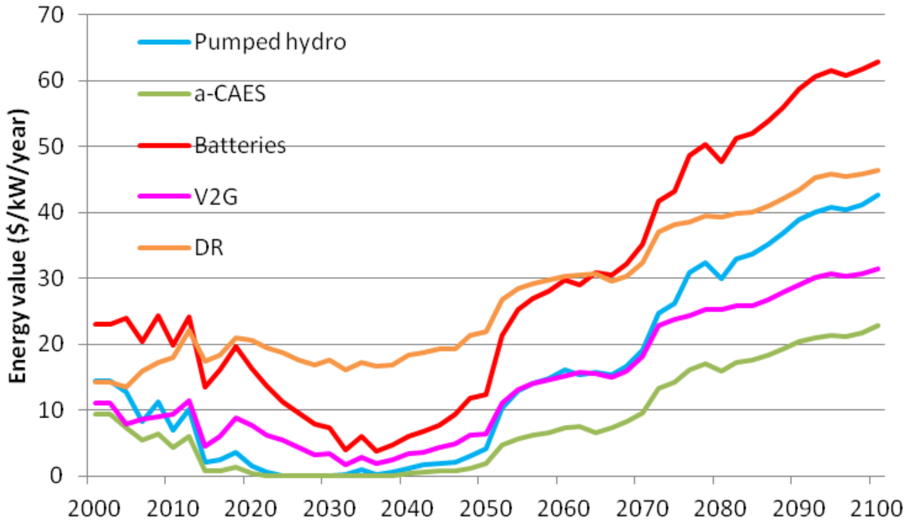

Figure 22: Energy value of a marginal storage as computed in the investment mechanism. France, baseline scenario (POLES only).

We observe a period with low energy value for storage around 2030 – 2040, followed by an increase after 2050. This is due to the solar development: at first, solar power replaces the peaking power plants of the middle of the day, but then it begins to dig in the base-load power and even creates over-supply in a few hours of the day (mainly after 2070). This second period is particularly interesting for (daily) storage. DR is less affected by this effect.

The energy value is not enough to cover alone the annualised costs of storage [192,201,202]. However, storage has other values that could also contribute to its economic viability [52,203].

Capacity value

The price spread in the real market is influenced by the development of variable generation. Indeed, VRES decrease the number of full load hours of existing capacities, and a capacity with less utilisation will need higher prices when it is used in order to pay back the fixed costs. By construction, the “energy value” computed above does not take into account the highest market power prices, in periods of peak consumption. These prices (up to thousands of euros per MWh) are such that they cover the fixed costs of the extreme-peak power plants (and do not only follow the variable costs of the peaking capacities). Alternatively, or as a complement, a capacity market or capacity mechanism can also represent this hidden cost for the system.

Therefore, we define a “capacity value”, linked to the fixed cost of the extreme-peak power plant used during the year (i.e. the technology used at least during one time slice and with the highest variable cost). By building a storage power plant or contracting DR agreements, the system avoids the corresponding fixed cost. We assume that this value could instead be paid to the storage or DR capacities, but only when they actually produce, which is defined in the assumptions of Table 8. This means that each storage or DR technology does not have the same capacity value.

Balancing value

Finally, we account for a "balancing value" of storage and DR. This value includes several ancillary services such as frequency or voltage regulation. It is aggregated to an annualised economic profit ($/kW/year).

The balancing value is difficult to evaluate in its totality. An analysis of the French balancing markets in 2008 and 2013 gives a first approximation of 11 $/kW/year on average[11]. This corresponds to a VRES penetration in the electricity mix of approximately 2% (average of these two years). By lack of more indications on the value and evolution of this balancing value, we assume that the balancing value increases with the VRES development (by lack of references, we set 30 $/kW/year for a VRES penetration of 100%[12]). We consider that storage and DR can only supply ancillary services when they are not already producing or storing electricity (see Table 8). This creates some complementarities between energy and balancing values.

Sharing the total value with existing flexibility options

The market prices computed above are based on the variable cost of the marginal thermal power plants and take into account the existing EV charging, storage and DR. This ensures that the "energy value" of new storage or DR is fully competing with all the other flexibility options that already exist.

For the capacity and balancing values, we have take into account the existing storage and DR, as they reduce the remaining value. Note that we could not evaluate the size of each capacity or balancing market (which would then be allocated to the different market stakeholders, and not only to storage capacities), because we lack a country-specific analysis. Our modelling assumption is that, if storage and DR capacities add up to more than 10% of the maximum demand, their capacity and balancing values start to decrease linearly because their impact on the market increases (peaking capacities or ancillary services are already well supplied) and the value of an additional storage or DR capacity decreases. However, their value does not decrease to zero, and a minimum economic value is reached when storage and DR capacities represent more than 50% of the peak demand. These assumptions could be improved later if further knowledge becomes available on that matter.

The capacity value decreases because storage and DR cannot supply electricity for many hours in a row, which becomes more and more constraining at high penetration of VRES.

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[11] For this computation we used the volumes and prices of ancillary services (balancing supply and demand, managing congestions and reconstituting the used frequency reserves and margins); then we use the share of hydro in the balancing market, and the ratio of pumped hydro compared to lake and pumped hydro.

[12] For this evaluation, we applied the ratio (2.7) between the standard deviation of load (0% VRES) and the standard deviation of solar+wind (100% VRES, 50% wind and 50% solar). These standard deviation are computed with the half-hour variability of load, solar and wind in France in 2013 [17].

The assumed minimum value corresponds to the average availability on six hours per day, instead of four hours at low development of storage (see Table 8). As for the balancing value, the floor value (assumed to be a third of the initial balancing value) represents other ancillary services, e.g. localised ancillary services such as voltage regulation.

Figure 23 shows the assumptions on the recovered capacity and balancing values for a new storage or DR capacity, in percentage of the maximum computed value.

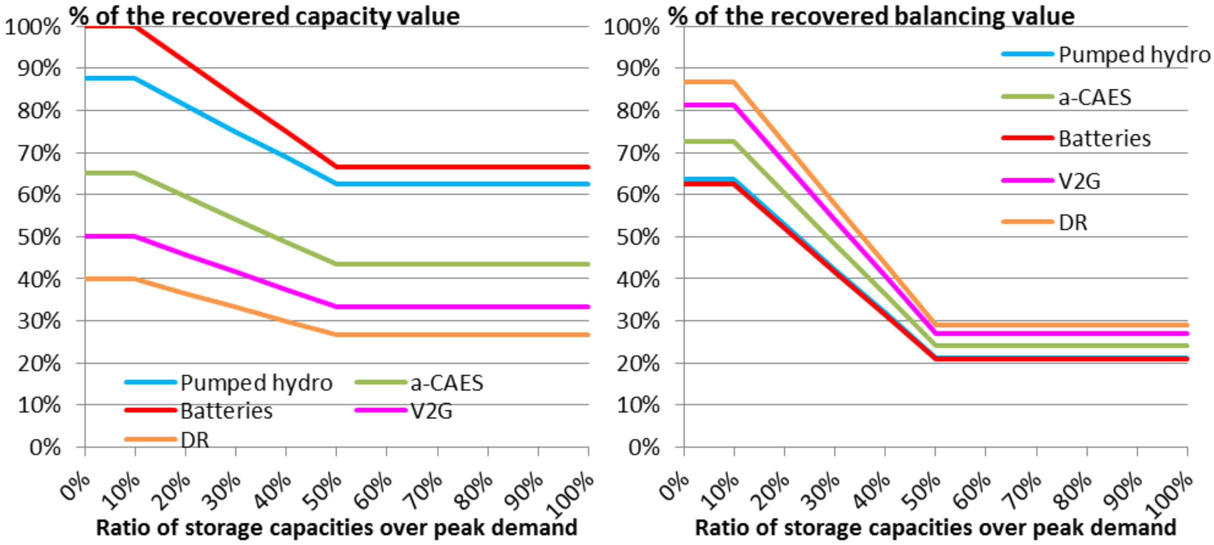

Figure 23: Proportion of capacity (left) and balancing values (right) that storage and DR could recover (modelling assumptions).

The capacity and balancing values actually applicable to new storage and DR capacities for the baseline scenario are shown in Figure 24.

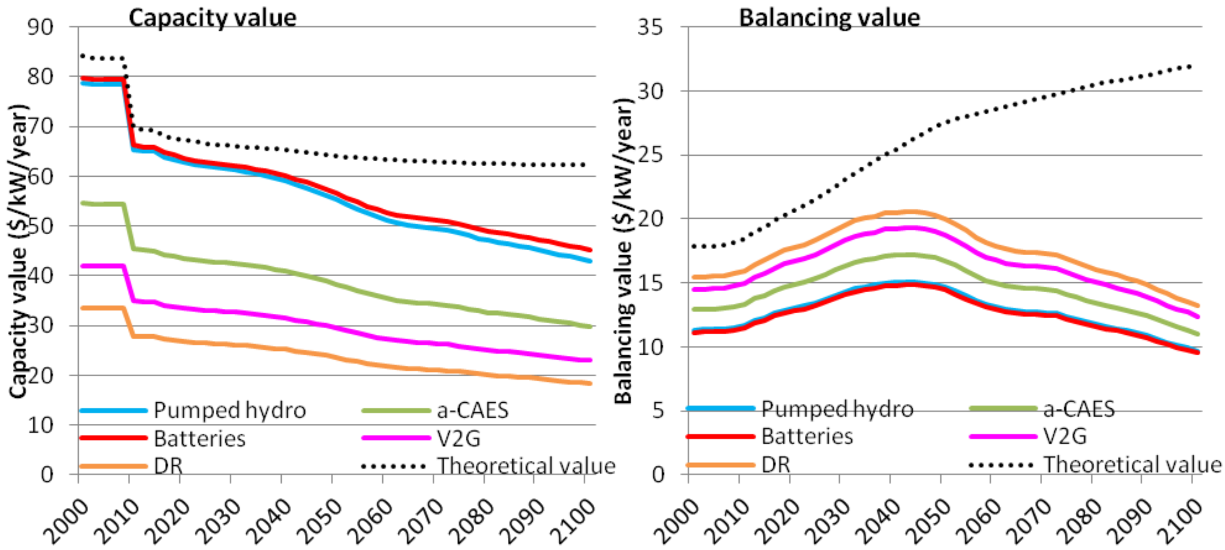

Figure 24: Capacity (left) and balancing value (right) of storage and DR technologies as computed in the investment mechanism. The dotted line indicates the total theoretical value. France, baseline scenario (POLES only).

We see that each storage or DR technology has a different capacity and balancing value. These values decrease after 2040 compare to the theoretical value because the storage capacity approximately reaches 10% of the peak demand at this moment in this scenario.

All these modelling choices could evolve as the knowledge in this domain expands.

Investment mechanisms for storage and DR

The total of these three values (energy, capacity and balancing) for storage and DR gives an indication of the total economic value of a new storage or DR capacity [203]. Here we don't check for the temporal consistency of using storage (or DR) for the three different applications. Some conflicts could appear in the energy management (state of charge for storage, rebound effect for DR) or in the available capacity at a given time for combining different commitments of energy selling, security reserve or regulation; using one of the services imposes constraints on the others [203].

The total economic value is compared to the annualized fixed costs. If the economic value is higher than the costs (ratio higher than 1), new storage capacities are built according to the following graph in Figure 25.

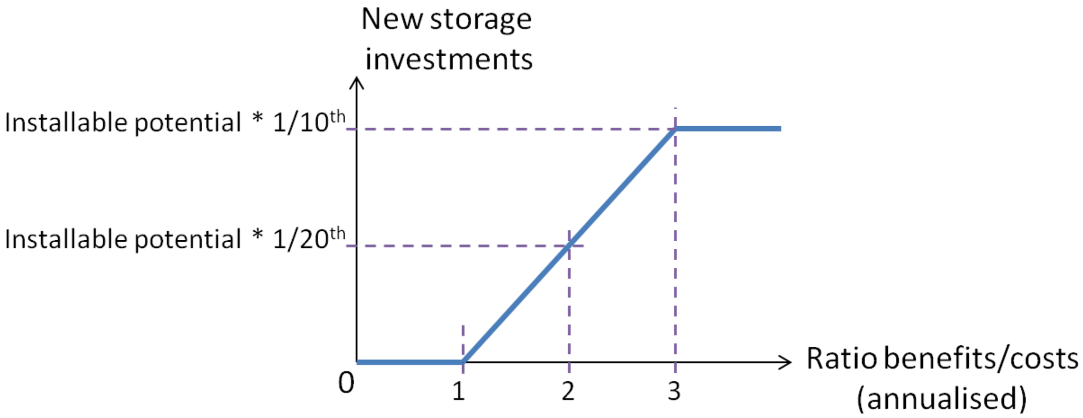

Figure 25: Graphical representation of the assumed equation of new investments in storage or DR.

The investments are inexistent if the anticipated benefits are lower than costs. If the benefits are enough, the investments are progressively made. New investments are assumed to be limited by the tenth of the installable potential for all countries or regions in POLES (this avoids the need for country-specific data). In any case, the existing storage capacities are slowly decommissioned, in relation to the lifetime of the technology. The only exception is for pumped hydro, which has lower investment costs for replacing decommissioned capacities (division by two) because the main infrastructure are already installed and it is assumed that investments for replacing are significantly cheaper than new investments: these pumped hydro will be kept in priority. Hydro dams and pumping stations are mature technologies with a rather high potential for reusing old facilities for refurbishment.

The resulting storage and DR investments in France are shown in Figure 26.

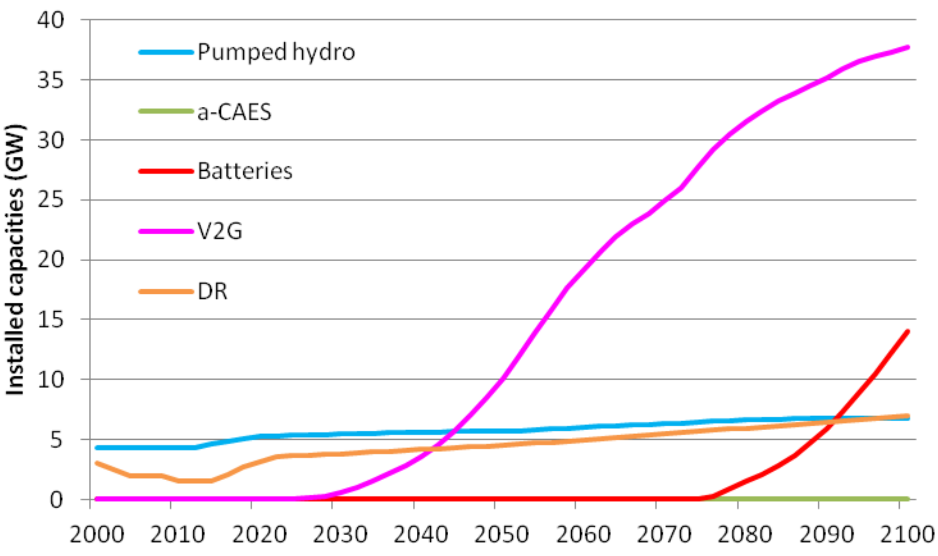

Figure 26: Investment mechanism applied to pumped hydro in France (top) and resulting installed storage and DR capacities (bottom). France, baseline scenario (POLES only).

In this baseline scenario, further described in chapter IV, the development of storage is driven by V2G batteries, thanks to their low investment cost (and rather optimistic life-time and efficiency assumptions). Pumped hydro storage develops mainly thanks to its capacity value until 2050; after 2070 it is also driven by an energy value. Demand response increases until 2025 and is then limited by its assumed potential; stationary batteries develop after 2080 and a-CAES is not developed. All these “baseline” results are shown as a working hypothesis and are discussed further in chapter IV. Besides, they do not benefit from the new representation of the power sytem operation presented in chapter III.

Conclusion of chapter 2

POLES is a long-term foresight energy model with a bottom-up, simulation approach. The electricity production technologies and consumption by sector are rather detailed (41 technologies, 9 demand sectors). However, the pre-existing modelling does not represent electricity storage or electric grids, which are essential to the integration of VRES in the power sector. Moreover, it does not specifically account for the variability of wind or solar energy sources (either in the operation or in the planning of new capacities).

Therefore we have introduced some improvements on the power sector operation of the model. We build a residual load duration curve of 648 time-slices by taking the variability of demand and VRES into account. Based on this description, we can compute a temporal dispatch of EV charging. We add storage and demand response technologies to POLES (hydro pumping, adiabatic CAES, lithium-ion batteries, V2G, and load shifting). They are dispatched after the EV charging. The assumptions on the EV charging, storage and DR operation are fixed by the user and could be enhanced if a better knowledge of a realistic development of these technologies becomes available. International electricity trade, hydrogen production from electricity and hydro and nuclear production are also made more flexible; they are not constant over time anymore, they partly adapt to the rest of the load (but their dispatch only depends on 24 aggregated time-slices, not 648 like EV charging, DR or storage).

The residual load duration curve (net of EV, storage and DR) is now the basis of the capacity planning (instead of directly using the load, as before). The development of new power production capacities and storage depends on it. Shadow prices are computed so that storage and DR are dispatched according to the price spread. This gives what we call the "energy value", which, along with the "capacity value" and "balancing value", gives the total expected benefits of storage or DR. A comparison with their costs defines the investments in storage and DR. A more realistic description of the capacity and balancing values could easily be implemented if a specific market design was represented or if more feedback on real operation of storage and (especially) DR was available. The new modelling enables the user to easily adapt these assumptions.

We consider that the investment mechanism for production or storage capacities is a reasonable approximation of a probable regulatory framework. A full representation of reality is impossible; indeed the investment decisions of private investors are always subject to many parameters, some of them being very difficult to predict (development strategy, public image, market failures – which themselves depend on the regulatory framework).

Unlike the investment decisions, the actual operation decisions for power plants, storage, interconnections and DR are much closer to the results of an optimisation method, which minimises the operational costs. In the presented modelling, storage and international exchanges of electricity are not rigorously checked across time (temporal correspondence) and across countries (geographical correspondence). POLES' software (Vensim) does not really allow such an approach. Therefore, we need a new tool for the power system operation, which we develop in chapter three.

III. Incorporating storage and grid operation with a unit commitment and dispatch at the European level

In the previous chapter we have incorporated electricity storage and demand response in a long-term foresight simulation model, POLES. However, such an approach reaches its limits when the power sector operation has to include highly-detailed spatial and temporal constraints, imposed by VRES, storage, DR and grid interconnections. Therefore we develop a new power sector optimisation tool for the operation of the system, with a focus on electricity storage. We then couple this tool with POLES and show the improvement it brings to the representation of electricity storage and other flexibility options (for example imports and exports). This new modelling overcomes the difficulties stressed in the first chapter, namely the gap between power sector tools (with hourly time-step and a detailed approach) and long-term foresight models (with only a few time-slices per year but a long-term coherence with the entire energy system).

III.1. A European Unit Commitment And Dispatch model (EUCAD)

As already mentioned, studying the impacts of the variability of renewable energy sources and the operation of storage requires inter-temporal constraints, which call for an optimisation model. Having this in mind, we developed EUCAD, a European Unit Commitment And Dispatch model. Like many other similar optimisation models of the power system operation (ReEDS [157,158], PRIMES [88], ELMOD [151,204], WILMAR [201,205,206], Van den Bergh et al. [207], EUPowerDispatch [160]), it is developed in the GAMS optimisation language and with the CPLEX solver.

III.1.1. Description

Many existing models study the operation of the power system with unit commitment and economic dispatch problems [208,209]. We present here the modelling choices and equations used in EUCAD (appendix F presents the whole EUCAD code).

Objective of the optimisation

The main equation of EUCAD is the minimisation of the power system total cost of operation, in a mixed integer, quadratically constrained problem (MIQCP). The total cost spans 24

European countries[13], over a 24-hour period. It includes the variable production costs of all European productions, as well as the cost of ramping up and down, proportional to the square of an hourly output variation, and the - very high – social and economic cost of unserved load (see appendix G).

$$TotCost = \sum_{Country\ \epsilon\ Europe} \sum_{t=1}^{24} \Bigg(SocioEcoCost(Country) * UnservedLoad(Country, t) + \sum_{\substack{DispTech \\ s.t. Pmax(Country, DispTech) > 0}} (VarCost(Country, DispTech) * P(Country, DispTech, t) + RampingCost(Country, DispTech) * R(Country, DispTech, t)^2) \Bigg)$$

The indices of the variables and parameters are:

- *Country* (for the 24 European countries considered in *Europe*),
- *t* (for the 24 hours of the computed day)
- *DispTech* (for 32 dispatchable technologies, including production from storage technologies).

The parameters are fixed inputs for GAMS:

- *VarCost*, the variable cost of production of a technology (in \$/MWh);
- *RampingCost*, the cost due to the ramping of thermal capacities (in $\$.MW^{-2}$), detailed in the section for ramping constraint (see below);
- *SocioEcoCost*, the social and economic cost of curtailing load[14] (in \$/MWh).

The variables are the outputs computed by GAMS:

- *TotCost*, the European variable cost of production for an entire day (in \$);
- *P* the production output (in MW);
- *R* the ramp between two consecutive hours (in MW);
- *UnservedLoad*, the lost load (in MW).

---

[13] Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxemburg, Netherland, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, United Kingdom.

[14] For most European countries we used 20000 \$/MWh, an approximation of the values found in [210–213]. We use more specific nation-wide data found in these reference for some countries: 14400 \$/MWh of Norway, 32500 \$/MWh for France and 16100 \$/MWh for Ireland. More detail in the appendix 4.

Power system balance

The main constraint is the balance between production and demand. It is expressed as the equality between the national production, and the national consumption (including storage), plus the net exports. The possibilities of unserved load or surplus energy are also represented.

$$\forall(Country, t)\epsilon\{Europe, [1;24]\},$$
$$\sum_{DispTech} P(Country, DispTech, t)$$
$$= ResLoad(Country, t) + \sum_{Country2\in Europe} NetExports(Country, Country2, t)$$
$$+ \sum_{Stotech} Sto(Country, Stotech, t) + Surplus(Country, t) - UnservedLoad(Country, t)$$

Where *Sto* is the variable describing the consumption of the storage technologies (*Stotech*).

The demand and VRES infeed is (perfectly) known for the upcoming 24 hours. *ResLoad* is the parameter describing the residual load (in MW), i.e. the load minus the VRES infeed. If the production is insufficient to meet the load, there is some unserved load (variable *UnservedLoad*). In case of an over-production from inflexible generation (due to non-dispatchable VRES or inflexible thermal power plants), there is some production curtailment (variable *Surplus*). The interconnections between the European countries allow for exports and imports (*NetExports* is the variable for exports minus imports).

European interconnections and electricity exchanges

Each country is represented as a node of the European grid (24 nodes and 50 lines). We assume that all power flows (variable *LineFlow*) must be lower than 90% of the installed net transfer capacity (*Capacities*) in order to represent a 10% margin for technical and economic constraints of the lines, such as an unplanned outage or an imperfect market (e.g. market power of an actor).

$$\forall(Country1, Country2, t)\epsilon\{Europe, Europe, [1;24]\},$$
$$LineFlow(Country1, Country2, t) \leq 0.9 * Capacities(Country1, Country2)$$

Because the load profiles and the VRES production are parameters given in local time, we have to take into account the three European time-zones. Therefore we group the Europe countries in the subsets *Europe0* (UCT+0), *Europe1* (UCT+1) and *Europe2* (UCT+2). The net exports are the exports (in local time) minus the imports (at the same time, which may require a time conversion).

$$\forall(Country0, Country, t) \in \{Europe0, Europe, [1;24]\},$$
$$NetExports(Country0, Country, t) = LineFlow(Country0, Country, t)$$
$$-0.98 * \big(LineFlow(Country, Country0, t)_{s.t.Country\ \epsilon\ Europe0}$$
$$+ LineFlow(Country, Country0, t+1)_{s.t.Country\epsilon\ Europe1}\big)$$

$$\forall(Country1, Country, t) \in \{Europe1, Europe, [1;24]\},$$
$$NetExports(Country1, Country, t) = LineFlow(Country1, Country, t)$$

$$-0.98 * \big(LineFlow(Country, Country1, t)_{s.t. Country\ \epsilon\ Europe1} + LineFlow(Country, Country0, t+1)_{s.t. Country\ \epsilon\ Europe2} + LineFlow(Country, Country0, t-1)_{s.t. Country\ \epsilon\ Europe0}\big)$$

$$\forall (Country2, Country, t) \in \{Europe2, Europe, [1; 24]\},$$
$$NetExports(Country2, Country, t) = LineFlow(Country2, Country, t) -0.98 * \big(LineFlow(Country, Country2, t)_{s.t. Country\ \epsilon\ Europe2} + LineFlow(Country, Country2, t-1)_{s.t. Country\ \epsilon\ Europe1}\big)$$

We consider a fixed 2% loss[15] in all international exchanges (based on the average French total losses in the transmission grid), regardless of the length of the line or the meshing of the national grid. For our application of coupling EUCAD with a long-term foresight model, we do not use here a more detailed DC load flow computation, by lack of the necessary input data and time; it is part of the perspectives of our work.

Minimum and maximum operating point

The first operating constraint of the production and storage capacities are described with a maximum power output. Production technologies also have a minimum power output, when they are not switched off.

$$\forall (Country, DispTech, t), P(Country, DispTech, t) \leq status(Country, DispTech, t) * Pmaxi(Country, DispTech, t)$$

$$\forall (Country, DispTech, t), P(Country, DispTech, t) \geq status(Country, DispTech, t) * Pmin(Country, DispTech)$$

$$\forall (Country, Stotech, t), Sto(Country, Stotech, t) \leq STOmaxi(Country, Stotech, t)$$

The variable *status* is a binary variable indicating if a technology is producing (1) or if it is switched off (0). This is implemented even though we only consider an entire technology and do not describe single power plants. The minimum power output of a technology *Pmin* is the one of a single power plant of this technology (500 MW for nuclear, 400 MW for coal, 200 MW for gas and 0 MW for peaking and fast-reacting technologies[16]; these values are adapted from [38,214–217] by assuming common sizes of power plants). A power plant fleet management would define the plant-by-plant constraints but we don't have the necessary level of detail in the input data (moreover, the computation time would be much higher and prevent a coupling with a long-term model). The maximum power output (*Pmaxi* for producing technologies, *STOmaxi* for storage technologies) depends on the hour of the day: the planned outages for maintenance reasons are situated when the residual load is the

[15] Another possibility is to take into account quadratic losses that depend on the power transferred. Our try was unsuccessful because of the CPLEX solver in GAMS 24.3. With GAMS 24.4 it has become possible, but the computation time are prohibitive, so this option was therefore abandoned.

[16] Some technologies are considered to have a full flexibility (within an hour, the time-step of EUCAD): oil and gas turbines, oil conventional thermal, hydro lake and all storage technologies (V2G, stationary batteries, pumped hydro and a-CAES) and DR.

lowest (this is exogenous to EUCAD). We also define *Pmax* and *STOmax*, the daily maxima of *Pmaxi* and *STOmaxi*.

$$\forall(Country, DispTech, t), Pmax(Country, DispTech) = max_t \left(Pmaxi(Country, DispTech, t)\right)$$

$$\forall(Country, Stotech, t), STOmax(Country, Stotech) = max_t \left(STOmaxi(Country, Stotech, t)\right)$$

Minimum on- and off-time constraints

Thermal power plants often have constraints of minimum on-time and off-time [131,209], i.e. they cannot start-up and shut-down repetitively in short time-scales. For example, nuclear power plants must manage the xenon effect when they stop producing, which implies at least 6 hours of successive off-time. More generally for thermal power plants (nuclear, coal or gas), the boiler's temperature must be managed: long heating times imply technical and economic constraints (fatigue induced by each start-up cycle, lost fuel for heating purposes and reduced efficiency during the start-up cycle). We include two constraints on the status of dispatchable power plants.

Minimum on-time: $\forall(Country, DispTech), \forall t_1 and\ t_2, s.t. t_2 \geq t_1 - t_{on}(DispTech) and\ t_2 \leq t_1,$

$$status(Country, DispTech, t_1) \ \geq status(Country, DispTech, t_2) - status(Country, DispTech, t_2 - 1)$$

Minimum off-time: $\forall(Country, DispTech), \forall t_1 and\ t_2, s.t. t_2 \geq t_1 - t_{off}(DispTech) and\ t_2 \leq t_1,$

$$1 - status(Country, DispTech, t_1) \\ \geq status(Country, DispTech, t_2 - 1) - status(Country, DispTech, t_2)$$

The parameters t_{on} and t_{off} are the minimum on-time and off-time, defined for each technology (values are from [217]).

However, these constraints are mostly valid for the management of a single power plant; when managing a fleet of several power plants, the constraints can be overlooked. Indeed, the computation times are more than doubled (+152%), for very close results (in terms of production or storage hours). Therefore, we ignore these constraints in future computations.

The ramping constraints

The dynamic constraints linked to ramping and cycling of the power plants are classical components of unit commitment problems [218,219]. The ramping speed depends on the allowed gradients of temperature and pressure, the overall thermal inertia (boiler, heat exchangers, circuits), the safety and operational cost of heat exchangers, the speed of the heat storage and generation, and the initial design of the power plant [48]. In our approach, we represent both the technical and economic consequences of ramping (data based on [24]). The technical constraint is defined by the limited speed of output variations, at the hourly time-step.

$$\forall(Country, DispTech, t), R(Country, DispTech, t) \\ = P(Country, DispTech, t) - P(Country, DispTech, t - 1)$$

$$\forall(Country, DispTech, t), R(Country, DispTech, t) \leq Rmax(DispTech)$$

$$\forall(Country, DispTech, t), -R(Country, DispTech, t) \leq Rmax(DispTech)$$

Rmax is the parameter defining the maximum rate of (positive or negative) output variation between two consecutive hours. Estimations in the literature vary widely [21,192,199,214,215,217,220]; the values used here are in the upper range because we find that they match better with the real-world comparison carried out (see III.1.2): 35% for all thermal technologies, except for nuclear (20%) and some fast ramping technologies which are supposed to be able to ramp 100% in one hour (gas simple cycle, combined cycle gas, and the *FastRamping* subset, which includes gas turbine, oil turbine, oil simple cycle, hydraulic lake, and all storage technologies, detailed later).

We also account for an economic impact of ramping (*RampingCost*), included in the total cost. Indeed, although it may be technically possible to ramp up or down a thermal power plant, the costs associated (O&M, ageing, etc.) may discourage such actions. The cost due to the ramping of thermal capacities is proportional to the fuel, operation and maintenance costs;

Based on [24], we consider that a 1 GW coal power plant incurs a cost of around 2450 $ for a 330 MW change in output (around 640 $ for gas power plants). We represent this cost as a quadratic function of ramping, which discourages big cycles but has little impact on small output variations.

$$\begin{aligned}\forall(Country, DispTech), RampingCost(Country, DispTech) \\ = RampCost(DispTech) * Pmax(Country, DispTech) \\ * \left(\frac{1}{0.33 * Pmax(Country, DispTech)}\right)^2\end{aligned}$$

RampCost defines the cost of ramping by a third of the installed capacity in one hour. In the total operating cost *TotCost*, *RampingCost* is multiplied by the square of *Ramp*.

We do not represent the start-up and shut-down trajectories of the power plants [221] because we lack a plant-level description. The ramping constraint and cost (that are high for a strong output variation) are already partly avoiding unrealistic operation of thermal power plants.

Frequency reserve requirement

A European-wide frequency reserve constraint is also accounted for, upwards and downwards. The contribution of each technology is not the same: fast-reacting technologies and storage can contribute up to their full installed capacity, but other technologies are limited by a 15-min ramp (a fourth of the hourly ramping capabilities for simplification).

$$\forall t, \sum_{Country\ \epsilon\ Europe} \left(\sum_{\substack{DispTech \\ s.t. not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} + \sum_{FastRamping} \big(Pmaxi(Country, FastRamping, t) - P(Country, FastRamping, t)\big) + \sum_{Stotech} Sto(Country, Stotech, t) \right) \geq 0.07 * TotLoad(t)$$

$$\forall t, \sum_{Country\ \epsilon\ Europe} \left(\sum_{\substack{DispTech \\ s.t. not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} + \sum_{FastRamping} \big(P(Country, FastRamping, t) - status(Country, FastRamping, t) * Pmin(Country, FastRamping)\big) + \sum_{Stotech} \big(STOmaxi(Country, Stotech, t) - Sto(Country, Stotech, t)\big) \right) \geq 0.07 * TotLoad(t)$$

The need for frequency reserve is assumed to be 7% of the total load (*TotLoad*), corresponding to the primary and secondary reserves in France (2.5%+4.5%); it could change with higher penetrations of VRES (see the modelling of ancillary services in II.3.2 for storage investments) but we did not focus our work on this aspect.

Storage constraint

Additional equations are necessary to take into account the specificities of storage. Their technical and economical characteristics are already analysed in [56] and [201]. The most important constraint is that all storage capacities must ensure the balance between consumed electricity and produced electricity plus the efficiency losses.

$$\forall (Country, StoProdTechnos), \sum_{t} \big(Sto(Country, StoProdTechnos, t) * efficiency(StoProdTechnos) - P(Country, StoProdTechnos, t)\big) \geq 0$$

The subset *StoProdTechnos* includes all technologies storing and producing electricity: hydro pumping, Compressed Air Energy Storage (CAES), Demand Response (DR), batteries and EV used for Vehicle-to-Grid (V2G). The parameter *efficiency* is the round-trip efficiency of these technologies. In the baseline scenario it is fixed in time (see II.2.3 - Table 7) but it could also follow an endogenous or exogenous learning process.

Demand response constraints

DR is also known as load shifting; it shifts power in time like storage (so that the storage balance equation also applies to DR), which allows it to integrate the VRES variation and improve the reliability of the power system [222]. However, DR also has specific constraints, difficult to model because there is little experience on how a dynamic demand side program can control various electric appliances [39,223] (each consumer and each electric appliance are specific).

EUCAD's assumptions are that the "produced" power during an hour (obtained by reducing the consumption) impacts the next hour for one third (rebound effect); the rest of the shifted energy can be dispatched across the entire day by EUCAD.

$$\forall(Country, t), Sto(Country, DR, t) \geq P(Country, DR, t-1)/3$$

DR is also constrained in the energy shifted each day. Our working hypothesis is that it is activated only once per day (either at full power for one hour or at partial load but divided in several time-periods).

$$\forall Country, \sum_{t} P(Country, DR, t) \leq Pmax(Country, DR) * 1$$

This corresponds to a production and storage profile as in Figure 27-left. With this activation constraint, the role of DR in the supply and demand balance remains limited. We carried another test of the baseline scenario, with 4 activations per day (see Figure 27-right).

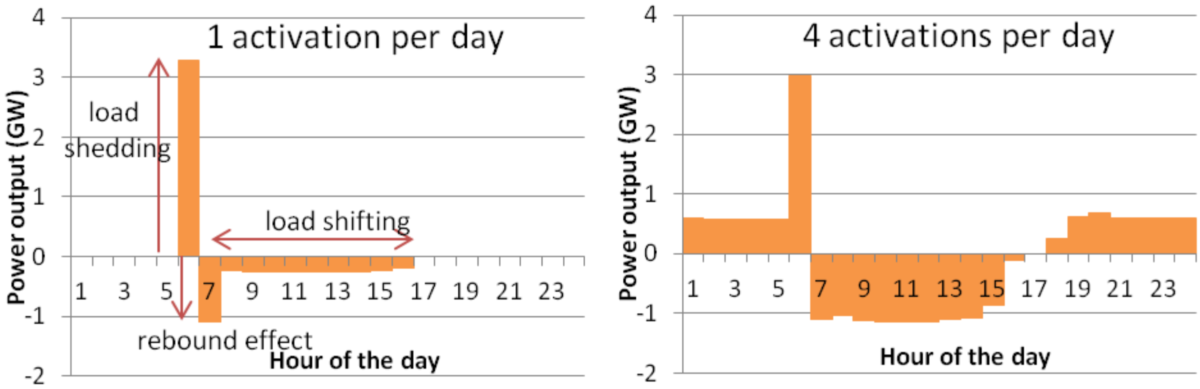

Figure 27: Example of DR production and consumption profile, as computed by EUCAD, with one activation per day (left) and four activations per day (right). France, one of the summer days, 2050, baseline scenario (EUCAD output).

The general behaviour of DR is similar, but when allowing four activations per day we get a smoother participation to the supply and demand balance: the solar production is displaced to night-hours (just like a 100% efficiency storage would do). The rebound effect constraint remains active, so the continuous periods of production (at night) or consumption (day-light hours) are obtained by activating some consumers on a rotating basis during the night and choosing to dispatch the load-shifted energy (2/3rd of the curtailed load) in daylight hours.

The case of dispatchable energy sources

Some components of the power system have stored energy, available for electricity production; hydraulic dams and hydrogen fuel cells are modelled in this way in EUCAD.

Hydro lakes have water inflows, which are considered as a free stored energy arriving every day in the dams. This energy can be dispatched when it is most valuable. Therefore the optimisation sets a daily limit to their production (still limited by the installed capacity). The longer-term management of the water resource (weekly and seasonal storage) is not represented. All valley effects (dams can be situated one after another, in a chain) and non-energetic constraints (touristic, fishing or agricultural activities) are neglected.

The hydrogen fuel cell technology is handled as a decentralized production in POLES, meaning it competes with the electricity retail prices and not with the rest of the centralised production technologies. The resulting electricity production from hydrogen fuel cells is considered to be available for electricity production just like hydro lake's water inflow.

$$\forall(Country, StockIn), \sum_t P(Country, StockIn, t) \leq EnergyINday(Country, StockIn)$$

The parameter *EnergyINday* is the daily energy available, equally distributed across all days of the year (except for hydro inflow, which can evolve differently in summer and in winter, according to the HadGEM2-ES environmental model [181]). The subset *StockIn* contains hydro lakes, hydrogen fuel cells, but also V2G. Indeed, EV used for V2G services also have a maximum energy to produce each day, because the use of an electric vehicle battery for V2G is limited by the consumer's driving needs and comfort. This is detailed later.

The case of dispatchable loads

Symmetrically, some sectors have dispatchable electricity consumptions, which are modelled as energy to be produced from electricity; it is the case of water electrolysis and EV charging in EUCAD.

Hydrogen production can be obtained from different fuels; a competition between them defines the amount of H_2 that water electrolysis has to supply. Similarly, in the transport sector, hybrid and full-electric vehicles are competing with the other types of vehicles, and the power system has to supply the energy consumed by EV.

$$\forall(Country, StockOut), \sum_t Sto(Country, StockOut, t) \geq EnergyOUTday(Country, StockOut)$$

Similarly to *EnergyINday*, the parameter *EnergyOUTday* designates the energy to be supplied by the power system during the day; it evolves over time (for EV we considered a higher consumption in winter than in summer, caused by the car heating[17]). *StockOut* is the

[17] Data are from the French Institute of science and technology for transport, development and networks (IFSTTAR): 59% of the yearly consumption happens in winter and 41% in summer.

subset of (dispatchable) technologies that have to consume a certain amount of energy across the day (EV charging and water electrolysis). Our definition of sets and subsets of technologies implies that another constraint is necessary in EUCAD to ensure that these consuming-only technologies are not producing.

$$\forall(Country, StockOut, t), P(Country, StockOut, t) = 0$$

EV constraints

The management of EV batteries is also an active area of research, summarised in [184]. Madzharov et al. use a unit commitment problem [185] to emphasize the benefits for the system of controlling the EV charging. Nunes et al. [149] use EnergyPlan to model the interactions between the power system (with high shares of VRES such as solar) and the transport sector (EV charging optimisation).

In EUCAD, there is only one constraint added specifically for EV: the daylight charging (7h - 19h) cannot represent more than half of the daily EV charging (assumption explained in II.2.2).

$$\sum_{t=7}^{19} Sto(Country, G2V, t) \leq 0.5 * EnergyOUTday(Country, G2V)$$

This represents the 50% night-charging constraint that arises if we assume that the EV drivers will charge their vehicle at home and reach a full state-of-charge of the battery before leaving their home in the morning. Therefore, a day-light charging can only cover half of the daily consumption, corresponding to the morning trip.

All the other specific constraints of EV are already represented with the other equations for dispatchable loads (daily EV charging), for storage (V2G storage cycle) and for dispatchable energy sources (maximum V2G energy storage). The parameters used (*STOmaxi*, *Pmaxi*, *EnergyAvailable* and *EnergyToBeProduced*) are crucial to these constraints; the underlying assumptions are detailed below.

Although the EV fleet is not connected to the grid at all times, the connected vehicles still represent more than 80% of the total fleet at all times of the day (see chapter 2, Figure 15 [183]). The connecting power is set at 3.2 kW and the battery size is 24 kWh, which are the characteristics of the Nissan Leaf and are in the range of most commercial EV today [184]. These characteristics may be improved in the future due to the development of battery technologies (higher energy density, lower cost). On the other hand, not all EV participate in the charging optimisation every day because they don't all behave similarly in terms of driving pattern and personal behaviour (e.g. some drivers may only use their vehicle on week-ends). By lack of further information, we stick to these numbers and consider that all EV not used are available to the grid.

V2G agreements are expected to develop progressively, linked with the power system needs (see the investment mechanism in chapter 2). The EV battery is larger than the daily average driving need: it usually allows for trips of more than 100 km, whereas the driving need is evaluated at 35 km per day in Portugal [149] and 32 km in Western Australia [224].

Therefore, the underutilization of the batteries can be exploited by the system with a V2G application – as long as the driving needs are not affected. We translate this comfort limitation into a minimum of 30% of the battery capacity unused (V2G can only control 70% of the energy capacity remaining after driving needs). As an example, a Nissan Leaf with a consumption of 0.137 kWh/km will still have half the theoretical capacity of its battery available for V2G, after a 35 km drive and with a 30% comfort reserve.

EUCAD general diagram

The general diagram of EUCAD is shown in Figure 28.

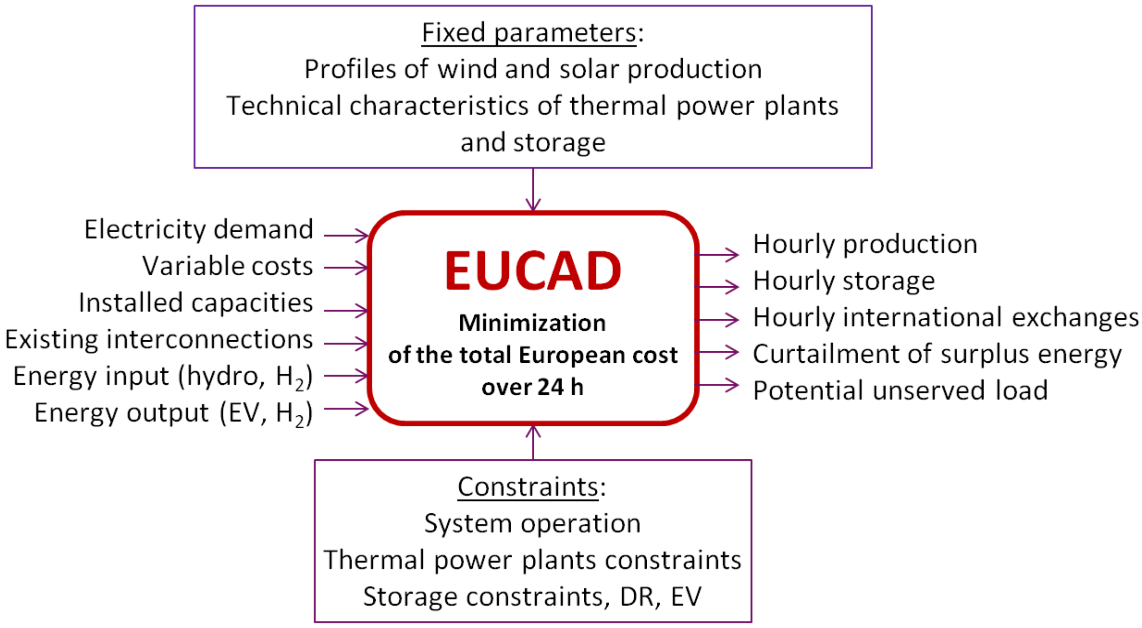

Figure 28: EUCAD diagram (EUCAD stand-alone version).

III.1.2. Validation of EUCAD's results

We carried out two real-case validations of EUCAD, in an isolated country (France with fixed exports) and in an interconnected Europe. The fixed parameters for the first validation test are:

- load profile and international exchanges from RTE data [17],
- installed capacities and variable costs from POLES database,
- availability of nuclear (maximum power available on the day), run-of-river hydro (base-load hydro production of the day), lake hydro (energy available for hydro production on the entire day), wind and solar (non-dispatchable production of the day), from RTE data.

For the second validation test on the whole Europe, we use:

- load profile provided by ENTSO-E [225],
- installed capacities and variable costs from POLES database,
- availability of French nuclear (maximum power available on the day) and run-of-river hydro (base-load hydro production of the day), lake hydro (energy available for hydro production on the entire day) from RTE data [17],

- wind and solar production from an additional extensive work[18] of collecting as many European renewable production data as possible (in case of missing data we extrapolated it to neighbouring countries, so as to fill all 24 EUCAD countries).

The first national test, for France, was carried out with a national version of EUCAD, with no interconnections. Only the dispatchable power plants (including storage) are computed. We have tested a day per month and the main results can be summarised, with one example in winter (Figure 29) and one in summer (Figure 30).

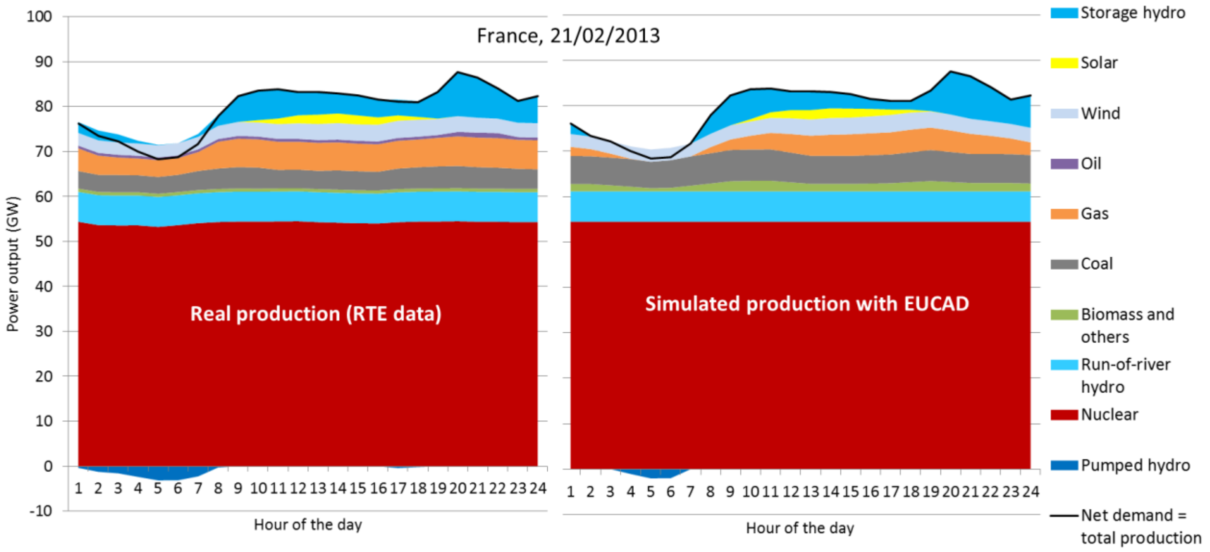

Figure 29: Comparison of the real power plant dispatch (RTE data, left) and EUCAD national computation (right). France, 21/02/2013.

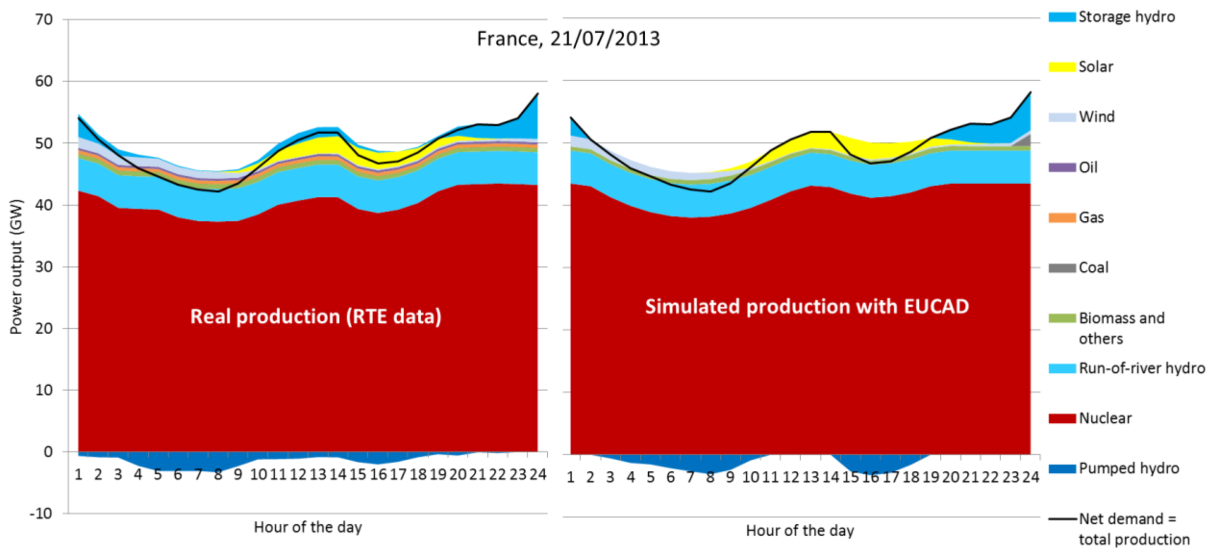

Figure 30: Comparison of the real power plant dispatch (RTE data, left) and EUCAD national computation (right). France, 21/07/2013.

[18] Study carried out with the help of Sacha Hodencq, Valentin Maillot, Romain Bick, Martin Encinas, Anne LOZE, Hannah Goux, Capucine Grange and Marie Volatier.

This analysis contains a lot of information and entails multiple comments. For the first national validation test, we see that:

- There is a good match in the operation of nuclear and hydro power plants. This confirms that the load following capabilities are well taken into account.
- However, in the winter day there is in EUCAD an exaggerated role of coal and an under-evaluation of gas and oil power plants. This observation was also found by Brancucci [43] with a different optimization model (EUPowerDispatch). We propose several possible explanations:
    - The European air pollution regulation imposes a limited number of hours of production until 2015 for old French polluting coal power plants, which is not taken into account in EUCAD.
    - The real fuel efficiency may also be over-estimated and the international coal prices used in POLES' database may be an approximation for what EDF (the main French producer) actually pays.
    - The (small) size and actual availability of the coal power plants may have an impact (EUCAD only considers the capacity installed for entire technologies, without consideration of the size of the power plants).
    - Finally, the redispatching uncertainties are not modelled in EUCAD; they could favour flexible power plants and disadvantage coal power plants (thus coming closer to the reality).

In addition, we observe that on week-end days the match is not as good (not shown here), mainly because:

- Hydro lakes offer weekly storage, while EUCAD only has daily storage;
- Some dispatchable power plants are stopped during the week-end because this period of lower consumption justifies the shut-down and start-up costs, for example for short maintenance works).

The second European comparison was carried out for 12 representative days of the years 2012, 2013 and 2014 (see more on the used clustering algorithm of wind and solar productions presented in III.1.3), of which two are shown in Figure 31 (winter) and Figure 32 (summer). We choose to observe French data again because they are the most precise and reliable data at the time of our study.

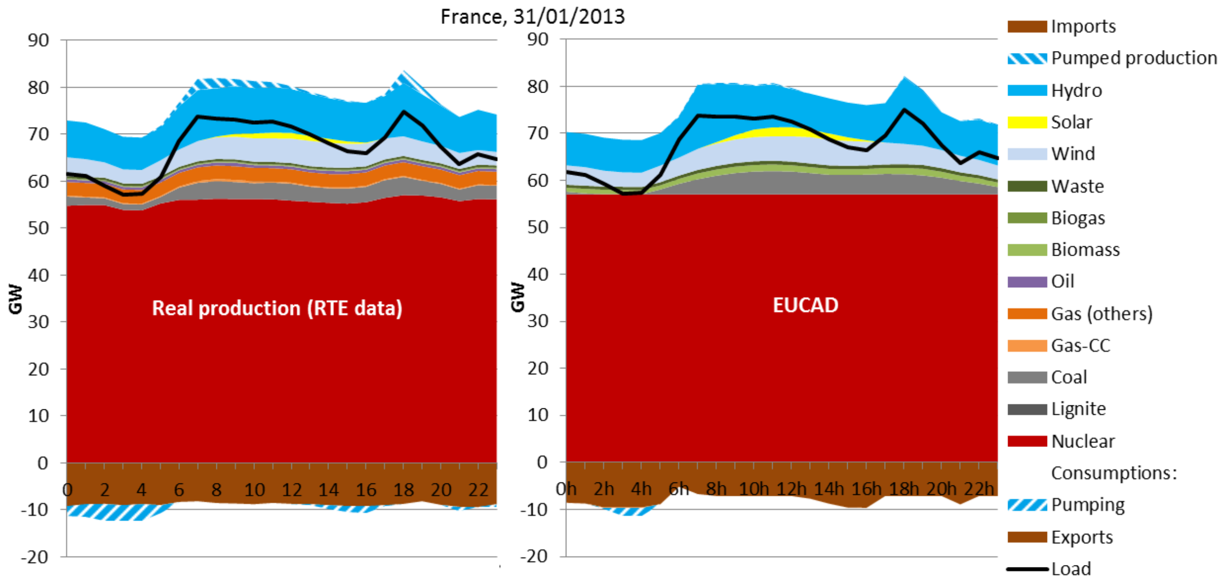

Figure 31: Comparison of the real production data (RTE data; on left) with EUCAD European computation (right). France, 31/01/2013.

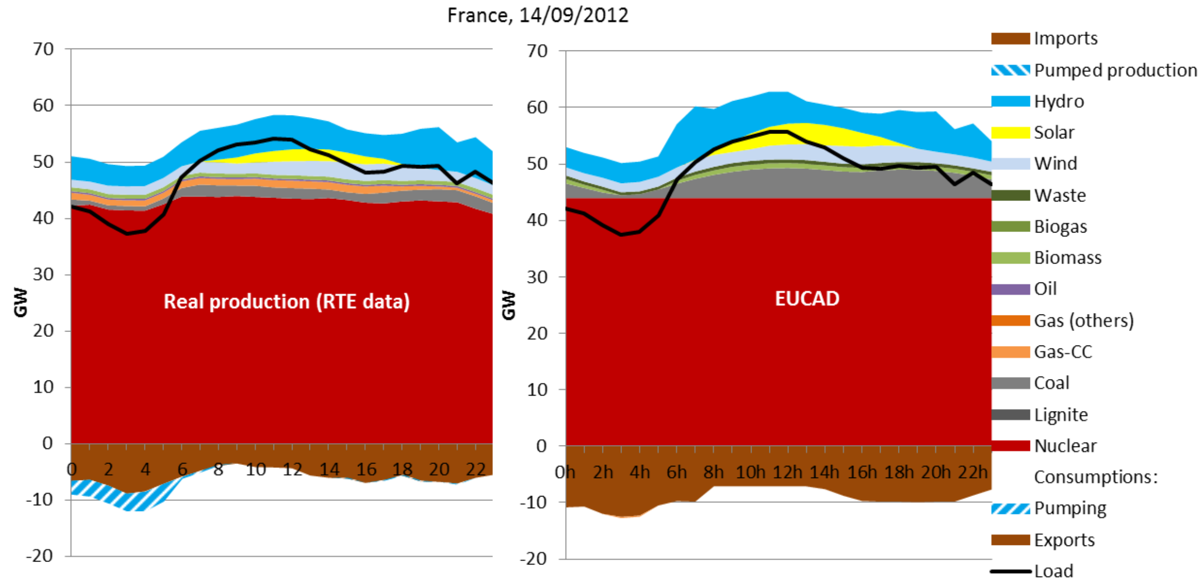

Figure 32: Comparison of the real production data (RTE data; on left) with EUCAD European computation (right). France, 14/09/2012.

For the second European-scale comparison, the relevance of the representation of interconnections in EUCAD can be verified. We observe some additional biases compared to the national validation:

- Hydro storage is less used in EUCAD than in reality; interconnections are preferred (the losses occurring in international exchanges is smaller than for hydro pumping efficiency losses: 2% *vs*. 25%)
- For France only, nuclear power is used in a more stable way in EUCAD than in the reality (EDF chooses to use its nuclear power capacity in load following mode, contrary to other countries which use nuclear in full-load mode). EUCAD finds that it is

economically more efficient to run the nuclear power plants in full-load and export the surplus to neighbours, thus offsetting more expensive and CO_2-emitting power plants.

In a more general perspective, the structure of EUCAD loses some aspects of the actual electricity production:

- EUCAD uses optimization, which, despite the operating constraints, may lead to situations of “winner takes all”, whereas the reality is never a “first optimum”;
- The geographical details within a country (e.g. voltage constraints, congestions of the internal grid) cannot be captured with EUCAD;
- All the technical and economic constraints cannot be known, as they are private and sensitive data.

The observed discrepancies with the real power system operation could not be effectively corrected with the available data and knowledge of the technical and economic operating constraints and strategies, but in theory further work in this direction remains possible.

III.1.3. Representation of the variability of wind and solar production

As explained earlier, wind and solar production are variable at different time scales. On the seasonal scale, we observe patterns of higher solar production during summer (in the Northern hemisphere) and higher wind production during winter (at least in Europe). At the weekly scale, the system may face exceptionally long periods of high or low wind, typically 5 days per year with production below 8% of installed wind capacity [226]. For solar, the biggest pattern is the day-night alternation. We also have some hourly variations for wind and solar, more difficult to predict 24 h in advance. From a modelling perspective, the time horizon to consider depends on the study to carry out. Here we compute several days per year at the hourly time-step, so that we can represent hourly, daily and seasonal variations (summer/winter). Shorter-term variations are not relevant for us since we consider the whole Europe with only one node per country (local and fast variations tend to level out).

The former modelling of VRES variability in POLES is based on fixed coefficients (see Figure 9), later enhanced with annual load factors by two-hour blocks (see Figure 12). This is still too aggregated to take into account the VRES impacts on the power system. The most precise option would be to use several years of historical data to cover all real meteorological variations[19], but it needs significant amount of input data and computation time. In order to stay coherent with POLES’ logic and computation time, we solve EUCAD for several days, divided in summer and winter.

In the following sections, we present two different methods for representing the variability of VRES.

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[19] Possible future changes in the meteorological situation are still overlooked, for example local and national wind and solar resource impacted by climate change.

High, medium and low production days

The first possibility is to use similar "high", "medium" and "low" days as in the residual load duration curve presented in chapter 2 (see Figure 13). We build 9 days of VRES resource for the summer period (April to September) and 9 days for the winter period (October to March), by combining high, median and low resource days for wind and for solar. For EUCAD we use real daily profiles at hourly time-step in order to preserve the real hourly variations of W&S. The "high", "median" and "low" definitions correspond to the 1st, 5th and 9th deciles of the daily productions of wind and solar (for France, 2013, RTE data [17]). This approach needs assumptions on the frequency of occurrence of each typical day (see Table 9), chosen in order to best fit the wind and solar annual production.

	High solar (1st decile)	Medium solar (5th decile)	Low solar (9th decile)
High wind (1st decile)	1%	6%	3%
Medium wind (5th decile)	7,5%	45%	22,5%
Low wind (9th decile)	1,5%	9%	4,5%

Table 9: Probability distribution of the high, medium and low production days of wind and solar.

This data analysis is applied to other countries by scaling the yearly average to their annual capacity factors. The capacity factors of the three wind and solar typical days are shown in Figure 33. The total VRES production is the multiplication of the hourly capacity factors by the installed capacity; for each season there is a combination of the high, medium and low production days of solar and wind. The solar with thermal storage is built based on the solar photovoltaic (PV), with an extension of the production until the end of the day thanks to thermal storage (accounting for an 80% efficiency).

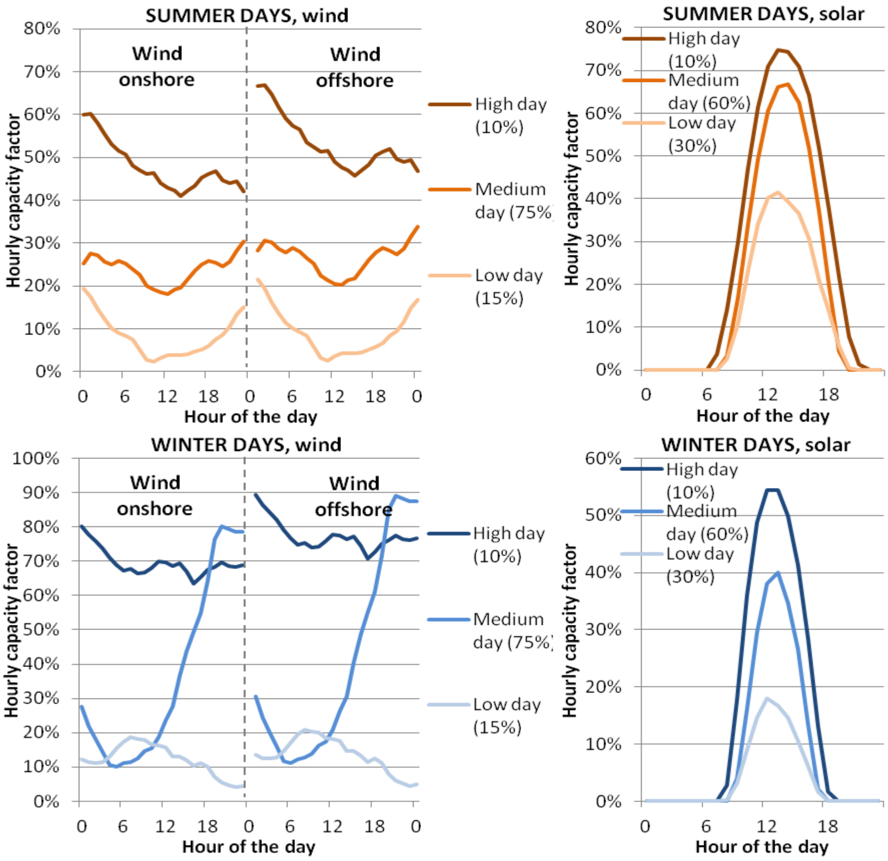

Figure 33: Three typical days of wind (left side) and solar (right side) production per season (summer on top, winter on bottom), with the probability of occurrence in parentheses.

The limits of this approach are that the same production profiles are applied to all European countries simultaneously, without any possibility of geographically levelling out the production (worst case for wind and solar production). Another limit is that the production levels of the different VRES have to be combined one by one.

Clustering algorithm

These limits can be corrected by a European-wide analysis of wind and solar production. This is why a hierarchical clustering algorithm (developed by Nahmacher et al. [133]) is used: it defines several typical days of wind and solar production at the European scale.

The algorithm starts with 365 clusters (all wind and solar production days of the 2006 meteorological year). A metric is used (the quadratic distance) in order to define the two closest clusters, which are grouped in a single cluster. The weight of the cluster (number of days it contains) is changed and a day of the new cluster is defined as the typical day of this cluster (the “centroïd”). It is chosen so as to minimise the distance with all the other days of its cluster. In the next step, the new clusters are compared again, until the number of clusters reaches a predefined number (a lower number of clusters implies a higher total error, i.e. a higher total distance between all the days and their clusters – see Figure 34).

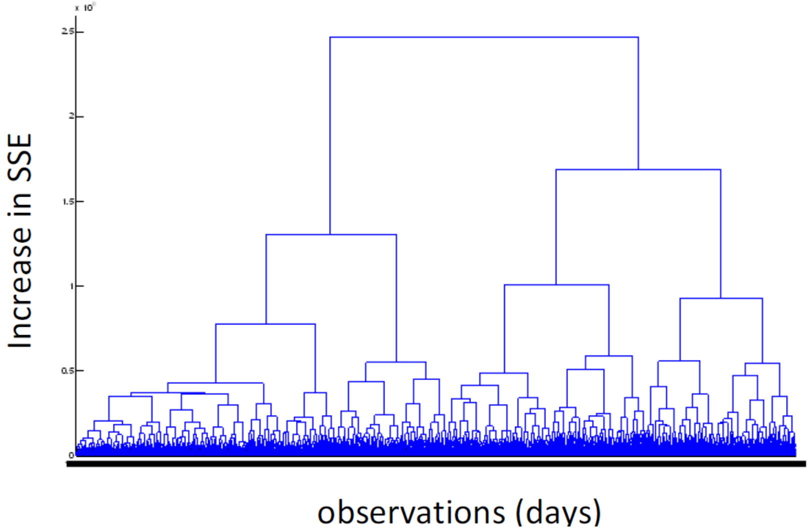

Figure 34: Dendrogram of the clustering algorithm showing the consecutive grouping of two clusters to a joint cluster and the resulting increase in the overall sum of squared errors (SSE, y-axis). All days (x-axis) are consecutively grouped together until only one cluster is left [133].

The input data used are the reconstructed wind and solar capacity factors across all Europe for the meteorological year 2006 [145], independently from the currently installed capacities (therefore we also have a production profile for VRES that are not yet developed in all countries, e.g. offshore wind). These capacity factors are multiplied by the maximum installable potential per country [147], so as to ensure that the size and weight of each country is respected in the metric of the algorithm. The result is a certain number of days, each defined by the wind and solar production of 24 countries. The annual wind and solar capacity factor is ensured by scaling the clustered days. The hourly capacity factors of solar and wind (onshore and offshore) in France are shown in Figure 35 for 12 typical days. Since clustered days do not only represent the French situation (they rather correspond to a European-wide analysis), the Figure 35 is not necessarily totally representative of the French situation.

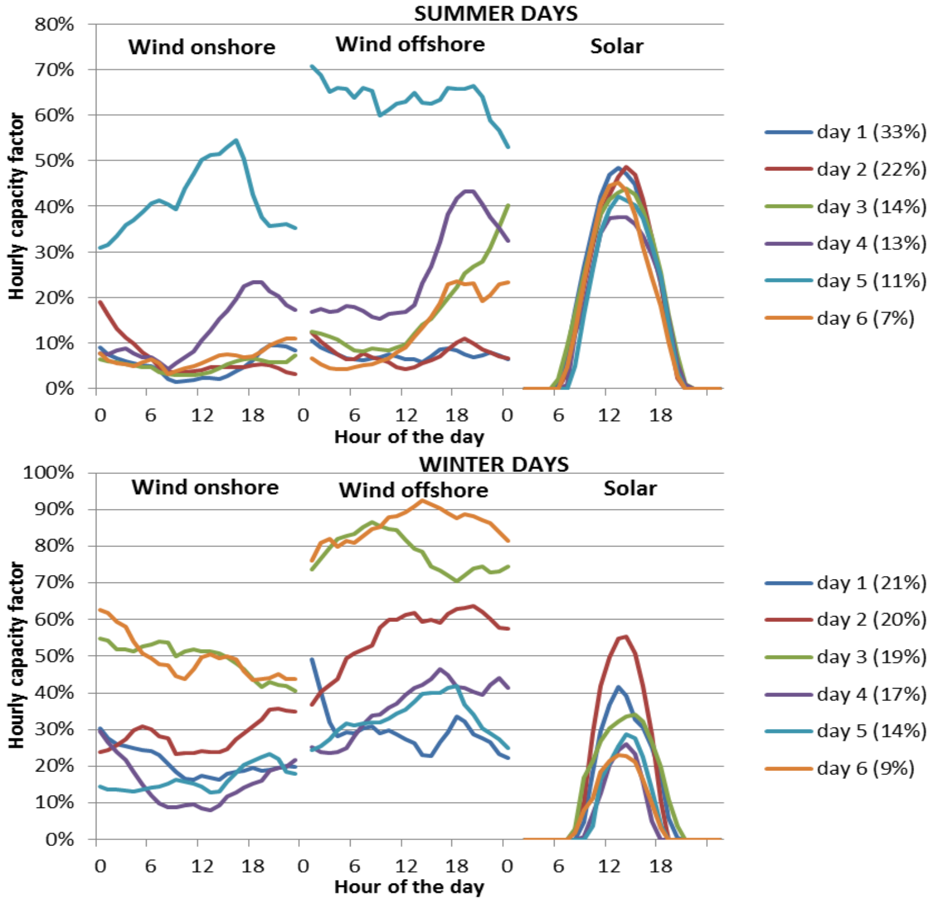

Figure 35: The 12 typical wind and solar production days for France, obtained with the cluster algorithm (summer on top, winter on bottom); the probability of occurrence is indicated in parentheses.

The European share of VRES in electricity production in 2050 is illustrated for all 6 clusters in Figure 36 and Figure 37.

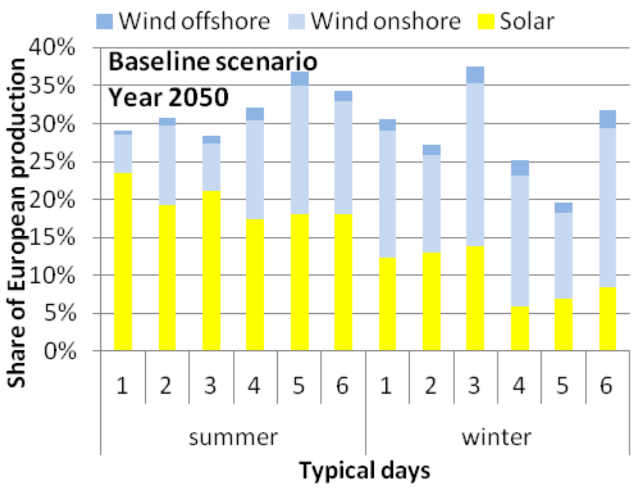

Figure 36: VRES share in Europe electricity production for the 12 typical days obtained with the cluster algorithm. 2050, baseline scenario (POLES+EUCAD).

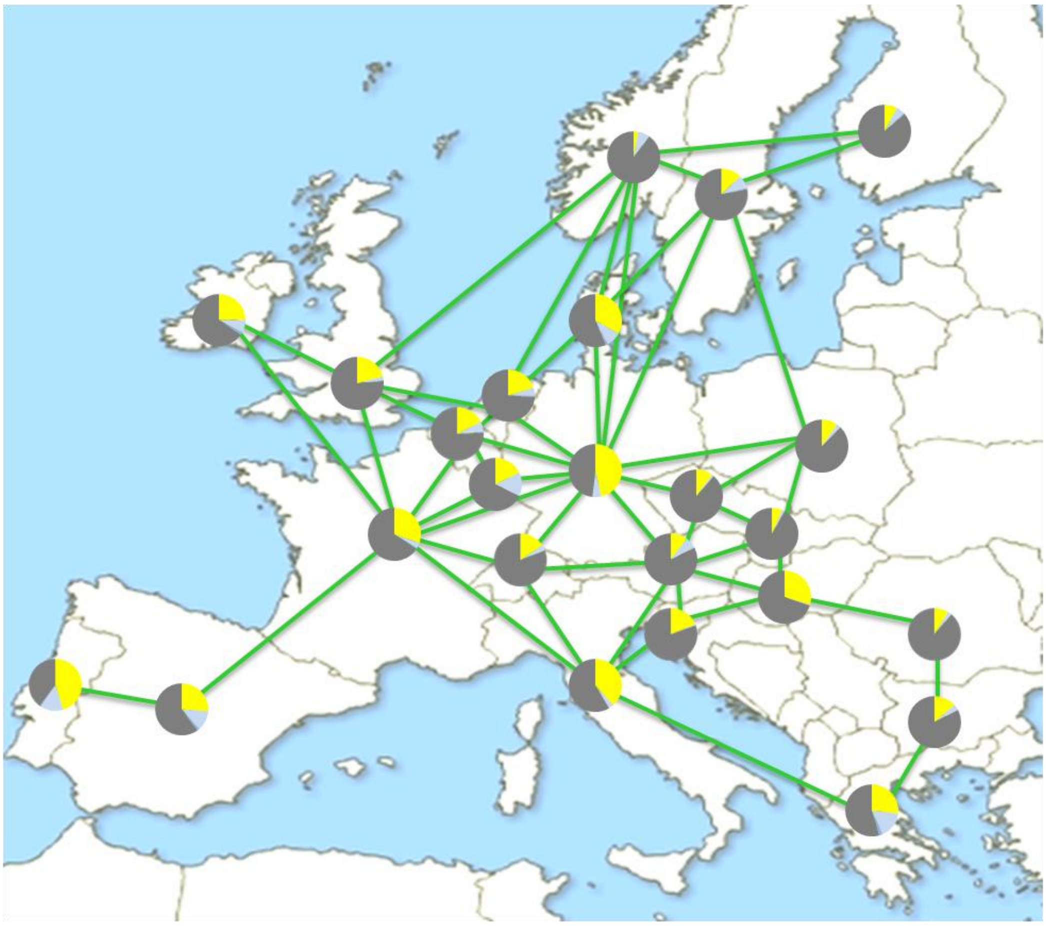

Figure 37: Spatial distribution of the summer day, type 1. In green are the grid connections between countries. 2050, baseline scenario (POLES+EUCAD).

The two options of representation of the VRES variability are illustrated with the aggregated electricity dispatch, which are weighted averages of the 9 days per season (high/medium/low for wind and for solar) in Figure 38, and of the 6 clustered days per season in Figure 39.

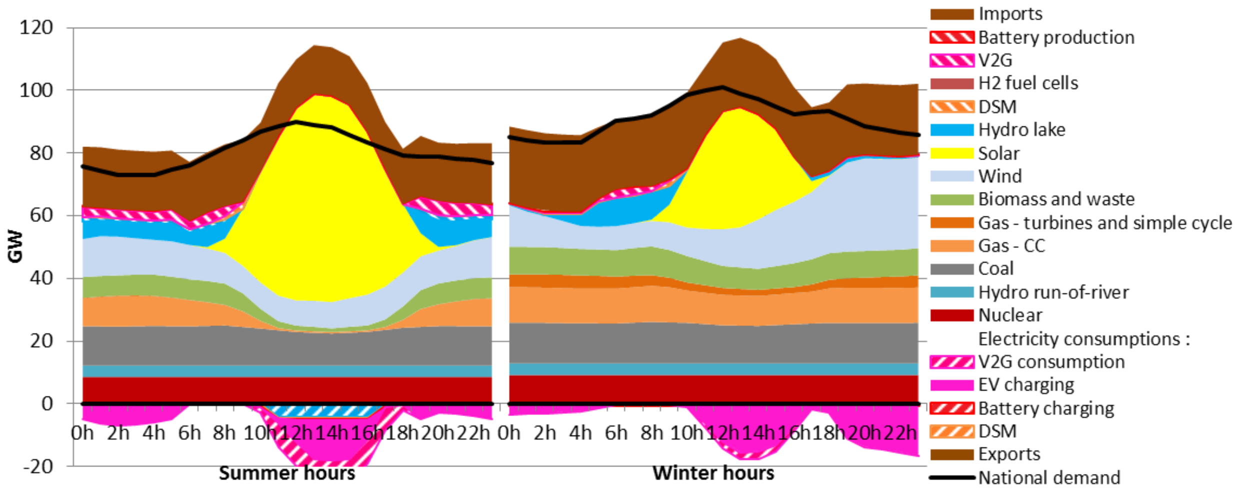

Figure 38: Aggregated dispatch from EUCAD based on high, medium and low production days for wind and solar (9 days per season). France, 2050, baseline scenario (POLES+EUCAD).

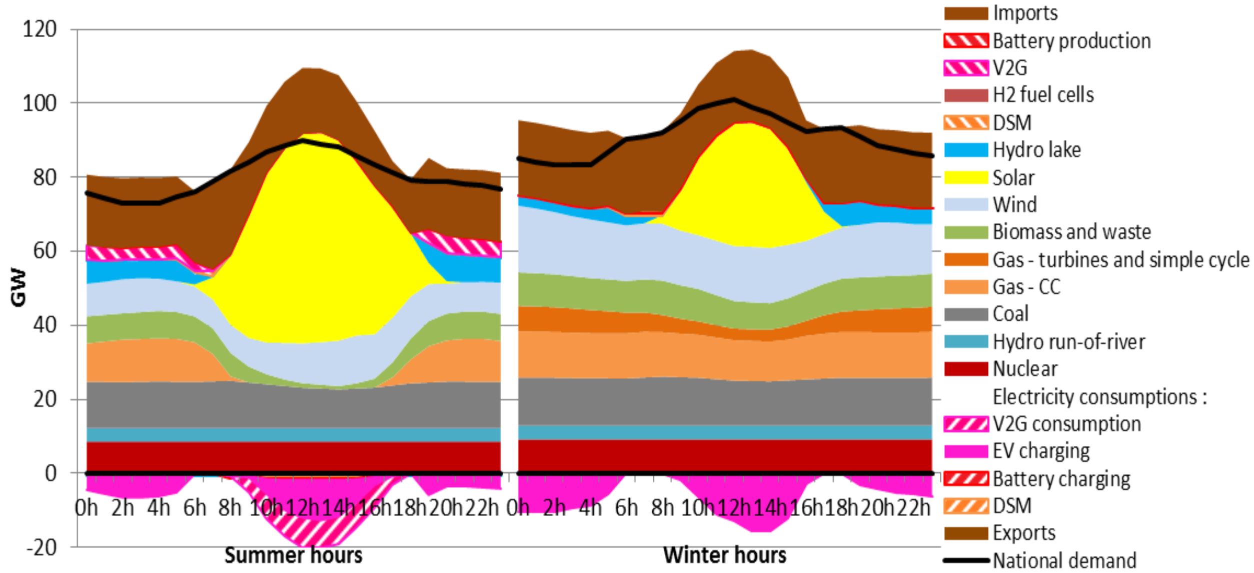

Figure 39: Aggregated dispatch from EUCAD based on 6 clustered production days for wind and solar per season. France, 2050, baseline scenario (POLES+EUCAD).

We observe a notable difference between the results of the two approaches, mainly because of the specific shape of the wind and solar production in the medium day for the first option. This situation has consequences on the operation of other power plants. In the rest of this research work, we keep the clustering approach because the international correlation of wind and solar production are taken into account, which is essential to represent the impacts of VRES on the European power system.

Choosing the right number of clusters is an important question. We tested 3, 6, 9, 12, 15 and 18 days per season, and a different calibration method (presented in appendix H). We see little difference between 6 and 18 clustered days per season when aggregating the productions; therefore we use six days, thereby limiting the computation time.

III.2. A direct coupling of POLES and EUCAD

The particularity of our research work is that EUCAD has been developed with the objective of being directly coupled with POLES. We present here how this connection is performed and what it brings to POLES.

III.2.1. EUCAD, a new power system operation for POLES

Coupling POLES and EUCAD

As EUCAD only represents the European interconnected system, it does not cover the 33 other regions of POLES. Therefore, the improved modelling presented in chapter 2 is kept the same for these countries. The 24 countries of EUCAD could be extended if necessary; the only necessary input is the grid interconnection with the other countries of EUCAD. Even an isolated country could be handled, with interconnections set at zero. However, adding countries impacts the computation time, therefore we focus on the European interconnected countries.

For the 24 countries handled in EUCAD, there is an exchange of information between POLES and EUCAD for every simulation year. The data are sent between Vensim software and GAMS languages using a specific function (dll library) developed at JRC – IPTS in Seville. POLES sends input data to EUCAD; then EUCAD computes the operation of the power sector and sends back the results to POLES. POLES then moves to the next simulation year, which changes the value of EUCAD inputs. This is represented in the POLES+EUCAD diagram of Figure 40.

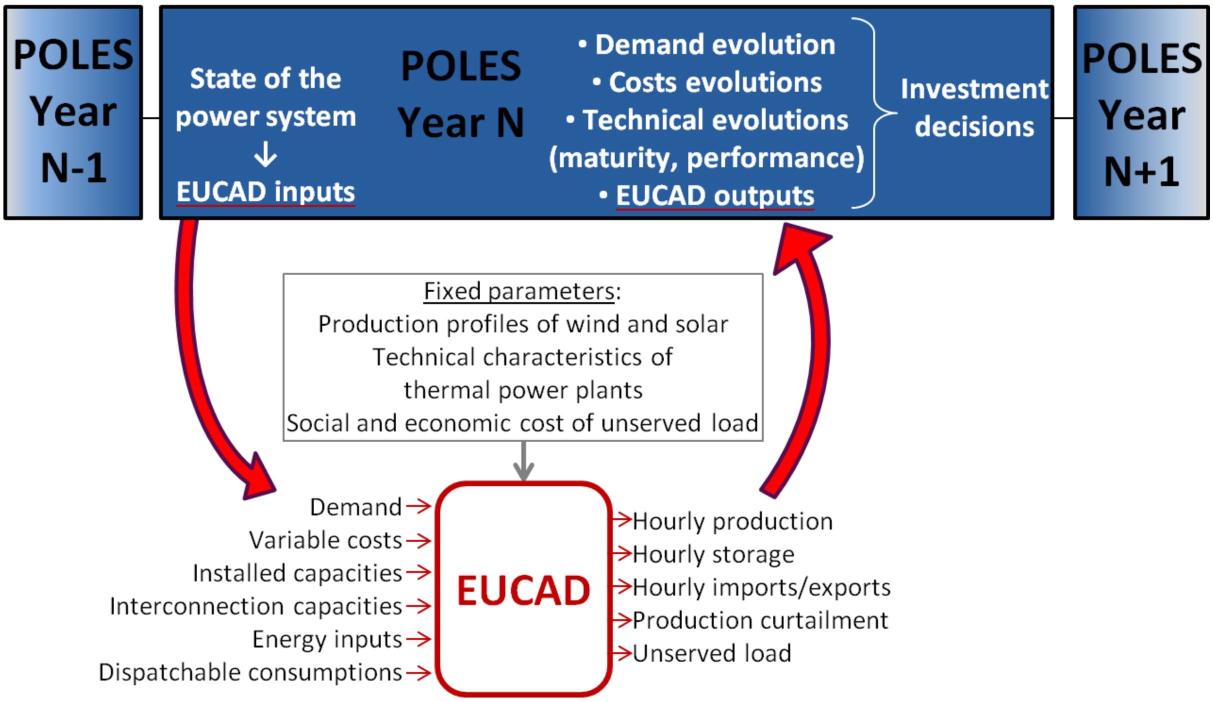

Figure 40: Diagram of the coupling between POLES and EUCAD. This concerns only the power system so the rest of POLES is not represented (see figure 6 for a more general overview of POLES).

These data exchanges allow a long-term evolution of some parameters (in POLES: the electricity demand (load level and shape), the installed capacities (producing power plants, storage, DR and grid), the operation costs (variable costs), the energy available for electricity production (hydro, decentralised H_2 fuel cells) and the dispatchable energy consumptions (EV, water electrolysis). The parameters are impacted by the relative fuel prices, the GDP and population, the "learning-by-doing" and "learning-by-searching" effects, exogenous assumptions on the maturity of a technology, etc.

On the other hand, some other parameters are kept constant: the VRES production profiles, the operating constraints of thermal power plants (ramping capabilities and costs, minimum power output) and the social and economic cost of unserved load. A more precise modelling, with endogenous evolution of these parameters, is possible in case more knowledge becomes available.

EUCAD computes each of the VRES production days sequentially (even though parallel computing would be more efficient). This is the most time consuming operation of POLES+EUCAD; although a single EUCAD computation only takes a few seconds[20], computing 6 days per season adds up to tens of seconds, for every simulation year.

EUCAD outputs are aggregated to two-hour blocks and sent to POLES. The improved modelling replaces the POLES-only modelling.

- The production of all the dispatchable capacities replaces the former simulation equations in POLES (VRES annual production is kept identical).
- The decisive improvement to POLES enabled by the coupling of EUCAD is the operation of storage and DR technologies, replacing the assumptions of Table 8.
- The consumption from EV charging is also improved and used in the road transportation load curve (replacing the aggregation of II.2.2).
- The international exchanges and water electrolysis load curve of every European country are also updated with EUCAD's outputs, instead of the dispatch shown in II.2.4. (see Figure 39 for an example of dispatch). As a result, an exporting country (such as France in 2013) can become an importing country in some hours of the day as well as in the annual balance (which is the case of France in the baseline scenario), and vice-versa.
- Other results of interest for POLES are the curtailed production[21] or load (when there is a shortage or excess of energy supply).

Although EUCAD does not provide a perfect representation of the reality of the power system operation (see III.1.2), the detailed constraints and the diversity of the computed days allow a meaningful representation of electricity storage, exports and imports. This is especially interesting as EUCAD can also be applied to future power systems computed by POLES, while keeping storage and grid considerations into account.

Illustrating the new modelling detail of POLES+EUCAD

We illustrate here the scientific contribution of coupling POLES with EUCAD. We use the working hypotheses of the baseline scenario described further in chapter IV. Its main characteristics are:

- no new energy policy implemented (no carbon value or similar environmental regulation);
- a significant increase of electricity consumption (due to a constant increase of the GDP in absolute terms and a substitution from oil to electricity in final energy demand);
- a moderate increase of the global share of VRES in the power supply (around 25% worldwide in 2050 and 50% in 2100).

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[20] The computer used is a DELL laptop with Intel Core i7 processor, 2.80 GHz, 8 Go of RAM. A year composed of 12 days takes 34 s to compute.

[21] The estimations of surplus production from II.2.3 are replaced with EUCAD output, which can account for grid interconnections.

- Concerning France: low new nuclear investments, creating a strong need for imports after 2040.

We show in Figure 41 the evolution of the production of coal (pressurized supercritical technology), gas (combined cycle technology) and storage (battery technology), in the night and in the day-light hours.

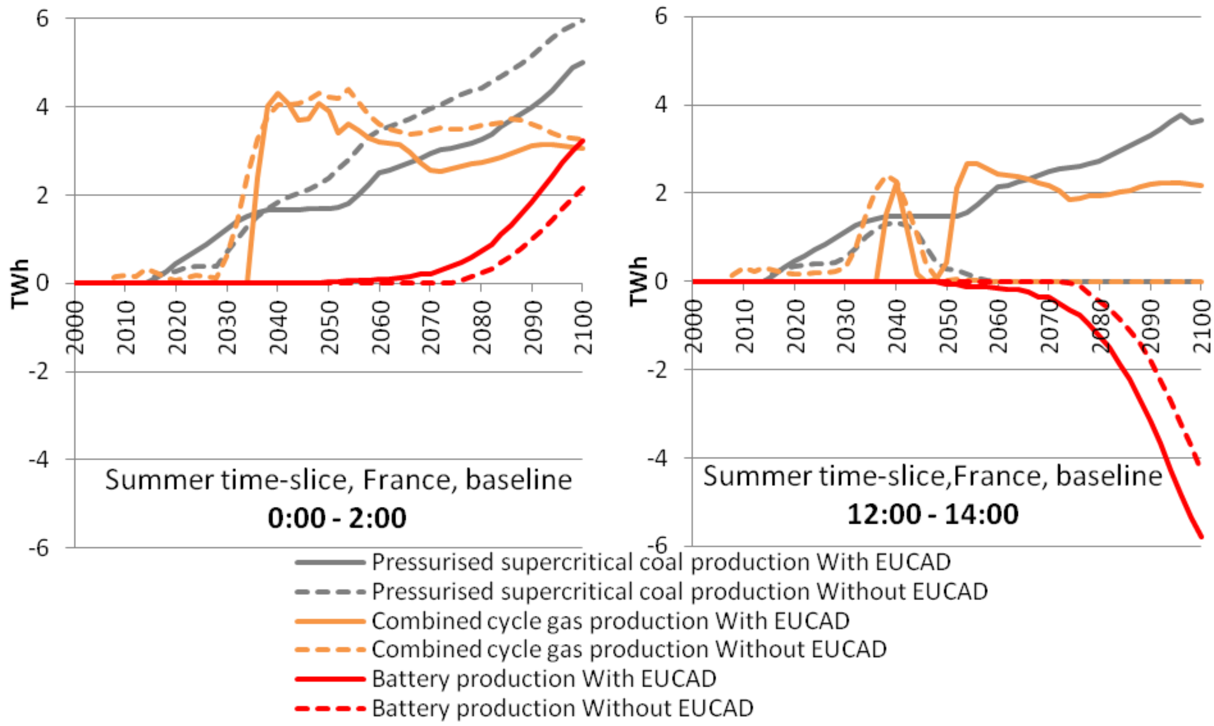


Figure 41: Comparison of coal, gas and storage production (or storage) in POLES only and in POLES+EUCAD. France, baseline scenario (POLES only vs. POLES+EUCAD).

The coal and gas power productions are stopped during day-light hours in 'POLES only' modelling, as solar production is high. Conversely, when coupling EUCAD, the European optimisation allows these power plants to keep producing on these periods, while decreasing their night production. Storage allows this better integration of the productions, displacing more surplus solar energy to night-hours in EUCAD European-wide optimisation than in POLES (national) simulation.

The international electricity exchanges are not constant anymore thanks to POLES+EUCAD coupling, as illustrated in Figure 42.

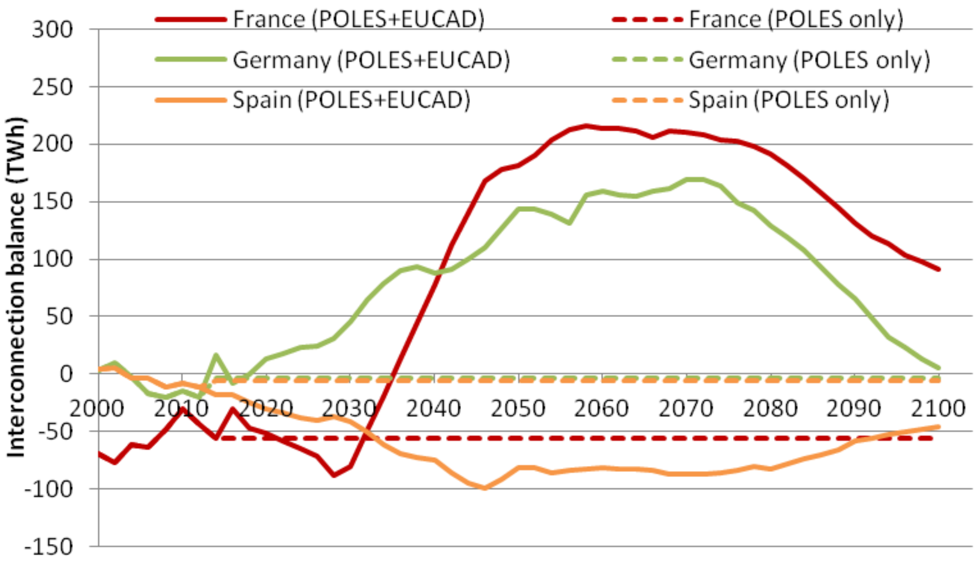


Figure 42: Comparison of the electricity exchanges in United Kingdom, France, Germany and Spain. A positive value indicates an importing balance. Baseline scenario (POLES only vs. POLES+EUCAD)

In our baseline test case, the decrease in French and German base-load power plants (nuclear and part of coal in Germany), pushed out by the solar peak production in day-light hours, creates a need for imports (coming from countries such as Spain or Switzerland).

In the same baseline scenario, surplus energy curtailment is totally avoided when using the optimisation model EUCAD, instead of 3 TWh when using POLES' simulation approach and its approximations. In both cases there is no unserved load.

III.2.2. Impacts of EUCAD on the planning of investments of POLES

Impact on dispatchable power plants investments

EUCAD defines the operation of each technology. The full load hours are used in POLES in the total costs, which impact the distribution of investments and, ultimately, the price of electricity for consumers (and thus, the future electricity demand). The evolution of the electricity exchange balance also has a strong influence on the future investment needs.

EUCAD also gives information on the potential surplus energy that could be wasted. This curtailed surplus energy is deduced from the VRES production, which reduces the annual capacity factor of wind and solar technologies (and increases their cost). The potential unserved load, which indicates a failure of the investment mechanism, turns out to be non-existent in our scenarios but could be a warning of a lack of investment in flexibility options.

Impact on storage and DR investments

The operating hours of electricity storage and DR are also a result of the coupling with EUCAD. However, they do not represent the entire economic profitability of a new capacity; they are only an indication of the usefulness of storage and DR for the system (which also includes system security or stability). Since it is difficult to couple storage operation from EUCAD with storage investments in POLES (*idem* with DR), we keep the method exposed in II.3. The assumptions on storage and DR operation (Table 8) are replaced with the real operating hours from EUCAD. The main difference is that in 'POLES only' modelling, the energy value is dispatched across all storage technologies, whereas in 'POLES+EUCAD' modelling, there is an independent optimisation of each technology and an optimal use of the flexibility of interconnections. This favours more the technologies with higher efficiency than in 'POLES only' modelling (and less the technologies with low efficiency). An illustration is given for our baseline scenario in Figure 43: in this case, the higher efficiency of batteries compared to pumped hydro triggers an earlier development than in the 'POLES only' modelling, and there is no boost of pumped hydro investment at the end of the century.

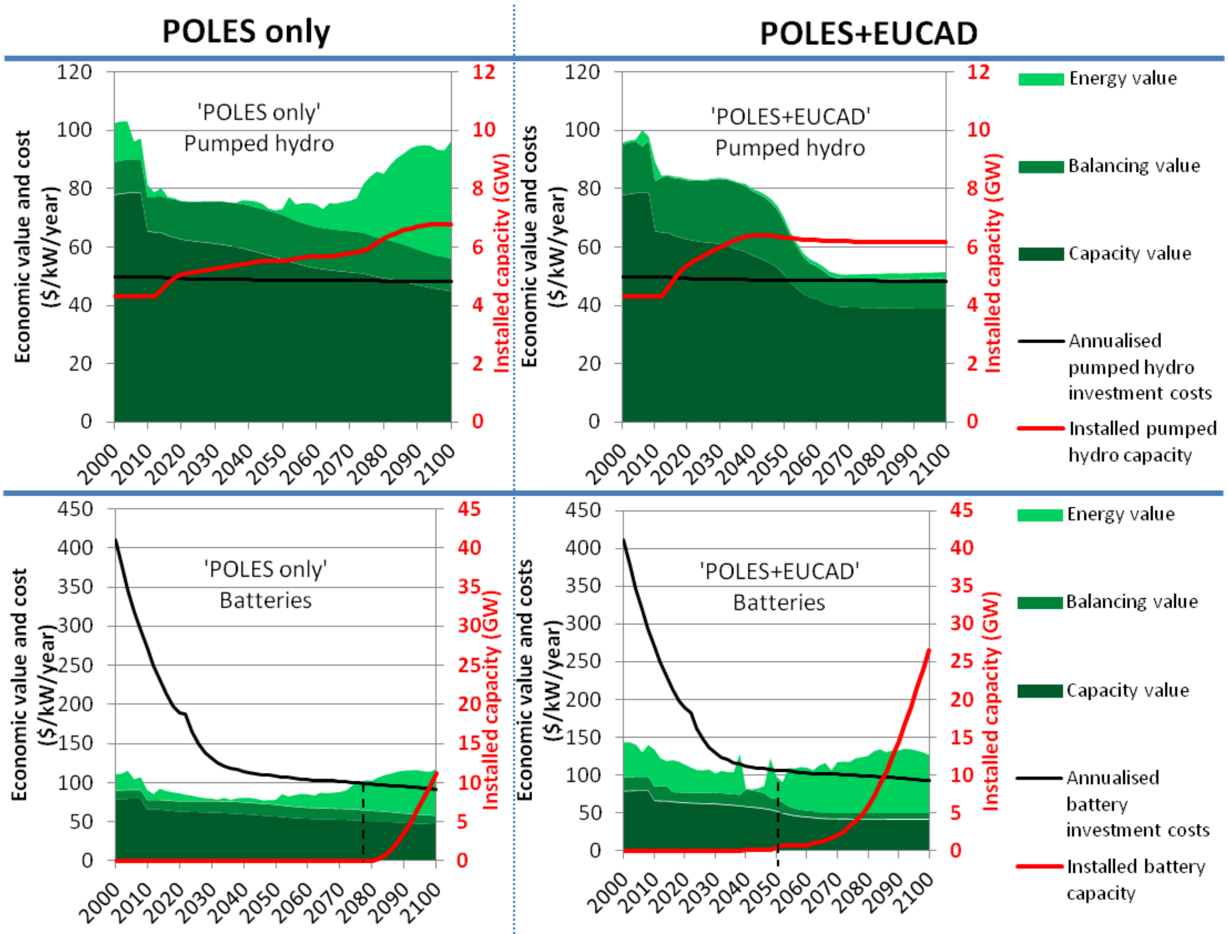


Figure 43: Investment mechanism for pumped hydro (top) and Lithium-ion batteries (bottom), without (left) and with coupling EUCAD to POLES (right). France, baseline scenario (POLES only vs. POLES+EUCAD).

These comparison graphs entail several comments on POLES+EUCAD modelling:

- A sudden drop in batteries' energy values appears in 2040, because the full energy value of POLES is used before the first capacities are installed by lack of feedback from EUCAD. After 2046, EUCAD indicates a positive energy value for battery storage, and the energy value rises again.

- Balancing value can compensate partly for the lack of energy value (e.g. for pumped hydro at the beginning of the century or for batteries between 2040 and 2046). The plant is used to provide ancillary services instead of participating only in the energy market (see the modelling hypotheses of II.3.2).

One limit of our improved representation with POLES+EUCAD is that they are limited to European countries. Storage investments are therefore generally higher in the other countries (especially for a-CAES), where the simulation equations presented in II.2.3 do not benefit from EUCAD feedback. Conversely, batteries tend to be developed earlier in EUCAD's countries.

Concerning the shadow market price computation, its combination with the European average of peak- and base-load prices is abandoned, since the interconnections are already taken into account in the storage operating hours computed in EUCAD.

Impact on grid investments

The grid interconnection capacities are based on NTC data for 2010 (current installed capacities) and for 2025 (projected capacities according to ENTSO-E) [43]. The capacities are not necessarily the same in the import or in the export direction. For the rest of the century, we use the following working hypotheses on the investment mechanism:

1. We limit the maximum installable interconnection capacity to twice the installed capacity of 2025.

$$Capacity_{max} = 2 * Capacity_{2025}$$

2. The evolution of these capacities is linear between 2010 and 2025. After 2025, it follows an endogenous trend, which depends on the utilisation rate of the lines (as computed in EUCAD): the lines often used are strengthened (a utilisation rate of 1 would lead to a 5% increase of the line capacity in the next year).

$\forall n > 2025, \forall (country1, country2) \in Europe,$

$$Capacity_{n+1}(country1, country2) = \min\big(Capacity_{max}, Capacity_n(country1, country2) * trend_n(country1, country2)\big)$$

$$trend_n(country1, country2) = 1 + BuildingRate * \frac{Exports_n(country1, country2)}{Capacity_n(country1, country2) * 8760}$$

$Exports_n$ is the sum of all exports between two countries in the year *n*. The building rate *BuildingRate* is set at 5% in the baseline scenario; it can be modified and discussed, but we use this value as a first approximation. Investments in interconnection capacities are treated separately for import and export directions; they follow respectively the trend of electricity imports and exports.

This representation of the grid investment mechanism is based on parameters (installable interconnection potential, building rate), which coherence is confirmed by the forecasted investments up to 2025, as seen in Figure 44 for the total French interconnections.

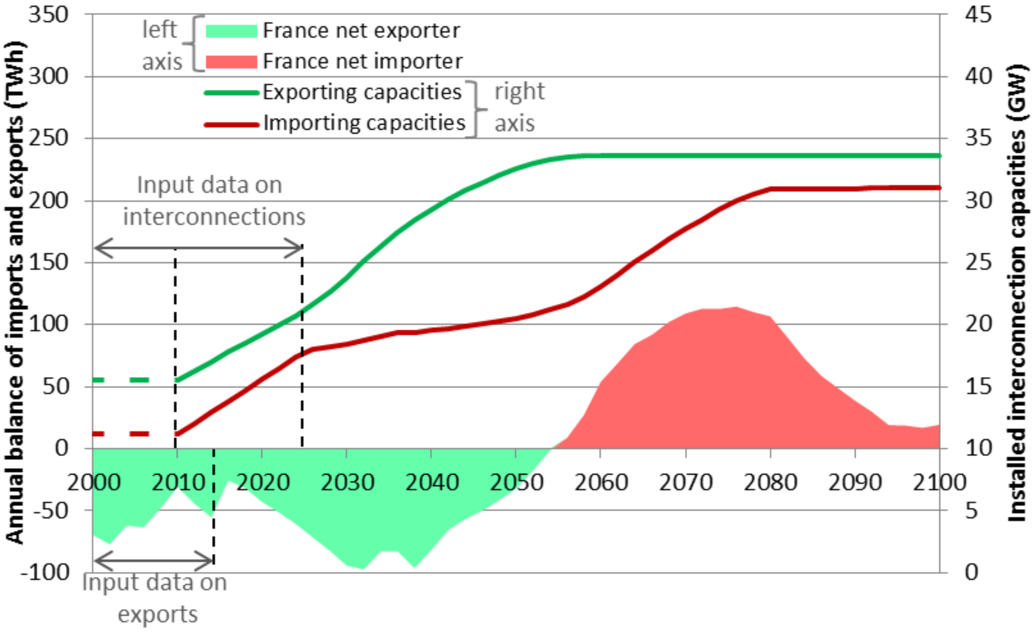


Figure 44: Importing and exporting capacities for France, in relation with net imports and exports. Baseline scenario (POLES+EUCAD).

This test case shows how the current exporting state of the French power system may change into an importing situation (if no specific energy policy is enforced). The interconnection lines are greatly increased from 16 GW in 2010 to 22 GW in 2025 (as forecasted by ENTSO-E) and up to 31 GW in 2050. This increase follows the strong imports of the baseline scenario. After 2060 the interconnection capacities saturate at around 38 GW, which represents the maximum assumed potential for most frontiers. An improvement of these hypotheses would be interesting perspectives of this work; however the input data is difficult to find.

A more precise representation of the congestion costs would allow a comparison between the value of a grid extension and the building costs. However, the congestions are not represented in EUCAD. As an example, Fürsch et al. [227] have developed an iterative computation of grid extensions based on a DC load flow model and an investment and dispatch optimisation model (DIMENSION).

III.2.3. New possibilities of POLES coupled with EUCAD

The linkage between the two programming languages (Vensim and GAMS), and therefore between POLES and EUCAD, allows the combination of the long-term coherence of an energy scenario (carried out in POLES) and the short-term operation detail in the power system (with EUCAD). The computation times are increased with EUCAD optimisation but they remain manageable[22].

[22] One hour on a DELL laptop with Intel Core i7 processor, 2.80 GHz, 8 Go of RAM

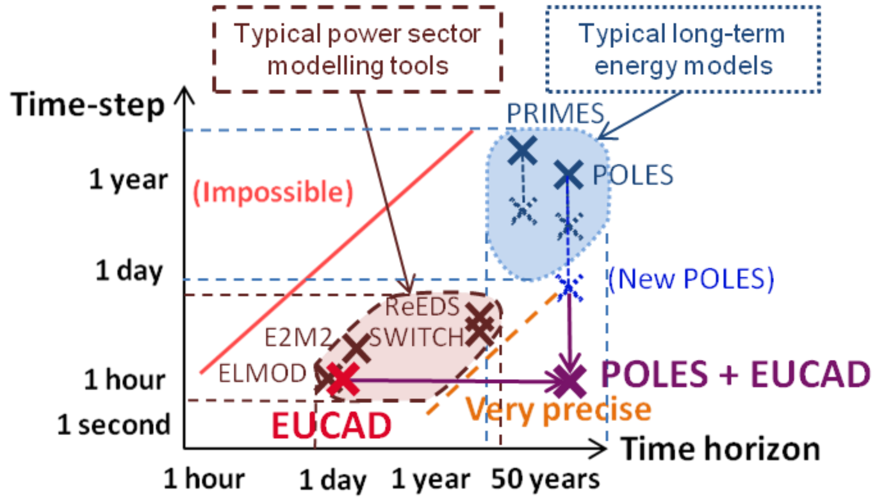
By applying the typology from the first chapter, we clearly see that the direct coupling between POLES and EUCAD brings a new level of detail to long-term foresight studies (see Figure 45 and Table 10).

POLES coupled with EUCAD

► **Context and positioning of POLES+EUCAD:**

	Criteria	Value of the criteria
General logic of the model	**Represented energies**	Electricity, oil, coal, gas, biomass, H2, etc.
	Evolution over time	Evolving parameters (POLES)
	Computation logic	Simulation (POLES) and optimization (EUCAD)
Power system: choices of representation	**POLES+EUCAD's approach**	System approach
	Choice of dynamics of the power system	Operation (EUCAD) and investment planning (POLES)

► **Temporal characteristics:**



► **Spatial characteristics:** 57 regions (POLES); 24 European countries (EUCAD)

Figure 45: Characteristics of POLES+EUCAD according to our typology (see I.3).

Modelling tool	POLES+EUCAD
Optimisation constraints	
Demand	Decomposed by sector
Operating reserves	Y
Capacity reserves	Y
Grid	Y (new)
Minimum renewable penetration	N (not compatible with a simulation model)
Start-up time	optional (new)
Costs	
Fixed (O&M, investment)	Y
Variable (O&M, fuel)	Y
Variable fuel efficiency	Y (new)
Start-up	Y (new)
Reserves, ancillary services	Y (new)
Grid	Y (new)
Renewable subsidies, CO_2 taxes	Y
Capital	Y
Risk premium, mark-up	Y
Renewable energy sources	
Hydraulic resource	From a hydrological model (new)
VRES production profile	Statistically determined / Clustering algorithm
Curtailment of excess energy	Y (new)
Impacts of VRES on:	
Operating reserve	Y (new)
Capacity reserve	Y (improved)
Grid costs	N
Storage economic value	
Optimisation of the system	Y (new)
Ancillary services	Y (new)
Capacity value	Y (new)
Grid	
Nodes and lines	57 regions (world), 24 nodes for Europe, 48 interconnection lines (new)
Type of computation	Commercial exchanges (“transport model”) (new)

Table 10: Characteristics of POLES+EUCAD according to our typology (see I.3).

Our typology established earlier is useful to realise the progress made (in darker green) compared to the pre-existing POLES model (see Table 6). It also shows a margin for improvements in the representation of the effects of VRES on the electric grid; this would need a significantly higher level of detail in EUCAD (and possibly, computation time).

Conclusion of chapter 3

In order to thoroughly evaluate the long-term development of electricity storage, a model needs both a long-term perspective for investment strategies and a small-enough time-step to represent the technical and economic values of storage for the system. In order to overcome this difficulty, we have developed EUCAD, a unit commitment and dispatch model that is then coupled with the long-term foresight model POLES.

EUCAD optimises the whole European power system operation, taking into account system operating constraints (balance between production and consumption, frequency reserve), thermal power plants constraints (ramping constraints), storage constraints (pure storage, dispatchable input energy, dispatchable consumptions, EV) and demand response constraints (rebound effect, daily maximum activation). In order to represent the diversity of VRES production, we compute EUCAD for several wind and solar situations of production across Europe, chosen with a hierarchical clustering algorithm.

EUCAD is then coupled with POLES year-after-year. The main inputs of EUCAD evolve in time thanks to POLES investment mechanisms. EUCAD's results give insights in storage operation and grid interconnections' management, with correlated time-steps. The investment mechanisms in POLES are influenced by EUCAD through the operating hours of dispatchable power plants, electricity storage (and DR) and grid interconnections.

This annual coupling of POLES and EUCAD is an improvement to the state-of-the-art that improves significantly the electricity module of a long-term model such as POLES. In the next chapter, we analyse the development of storage in a baseline scenario with POLES+EUCAD. Then we study the impacts of a strong development of VRES on storage. We also investigate the influence of a higher technical and economic performance of storage on its development.

IV. Storage development in long-term energy scenarios

The improvements of POLES' power sector module (presented in chapter two) and the coupling of the power sector operation with EUCAD (presented in chapter three) allow studying the development of electricity storage in long-term energy scenarios. In this chapter we present the results of scenarios built using POLES+EUCAD. One should be conscious that projections of any development path of the energy system until 2100 are very ambitious. Most substantial modification to the economy (e.g. economic crisis, political regimes' evolution, war) or to the energy system (e.g. technological breakthrough) is overlooked. Some elements of the energy system that could play an important role are also missing in POLES, such as the availability of rare earth metals. The long-term energy scenarios however allow studying the evolution of the energy system in response to certain energy policies. The long-term horizon is mostly useful to observe the very long-term structural changes. Concerning electricity storage, it is particularly useful to go beyond 2050 since some storage technologies are only expected to develop after 2050 (e.g. batteries in the baseline scenario). Extending the time horizon until 2100 is then the only way to observe the emergence of such technologies.

First we show a baseline scenario, which is a hypothetical situation with no energy policy implemented, although this is not representative of the most probable evolution of the energy system. Then, we evaluate the effects of two sensitivity analyses on the level of VRES development and on the technical and economic performance of electricity storage. Finally, we present a different perspective of the energy system, with a strong climate-friendly energy policy, defined so as to ensure more than 66% chances of limiting the global warming to 2°C by the end of the century.

IV.1. A baseline scenario

We present first the baseline scenario, which used as an illustration in the previous figures of this thesis.

IV.1.1. Description of the baseline scenario

Caveat

In this thesis work, we have developed a new power sector module for the long-term model POLES. In order to show the new scientific capabilities of POLES (coupled with EUCAD), we use a baseline scenario. This scenario does not include any energy-environment policy (no emission certificates or CO_2 markets, no subsidies to renewable energy sources after 2015, no particular regulation on pollution, etc.). The choice of this scenario corresponds to a working hypothesis, used later as a point of comparison. It rather corresponds to a "default situation" or benchmark case than to any realistic political situation in the upcoming decades.

Its conclusions should therefore not be considered predictions of the future state of the power system, but indications on the "default" evolution of the system in the absence of any energy policy.

The main features of the baseline scenario are a high increase of electricity demand, an intermediate VRES share in the electricity mix (around 25% worldwide in 2050 and 50% in 2100), and a rather low nuclear scenario for France (not all current nuclear power plants are replaced and the installed nuclear capacities stabilise at around 15 GW).

Exogenous hypotheses of the baseline scenario

Since POLES is not a general equilibrium model and only deals with the energy system, exogenous inputs are necessary to describe the rest of the economy (see Figure 6). Three kinds of inputs are used in any scenario: population, GDP and resource constraints, in particular fossil energy sources. A fourth exogenous input can be added: the carbon value, which describes climate policies carried out by governments. The remaining inputs come from a database (TechPOLES) describing the existing system (2000 to 2013) and the technological assumptions, crucial for the calibration of the model.

In the baseline scenario, population increases from 6.1 billion people in 2000 to 9.5 billion people in 2050 and 10.8 billion in 2100. The global economy (see Figure 46) increases five-fold between 2000 and 2050, and again increases by +150% between 2050 and 2100[23].

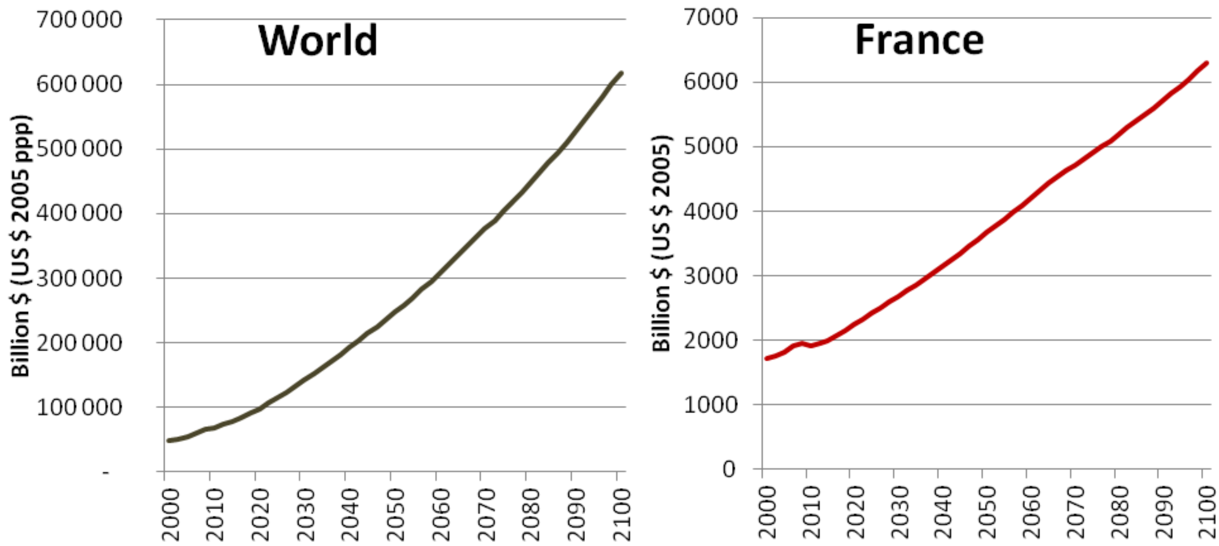


Figure 46: GDP hypotheses for the world (with purchase power parity) and for France, in US$2005. Baseline scenario (POLES input data)

The resource database (oil, gas, coal, uranium) is prepared by the EDDEN laboratory in collaboration with Enerdata, (partly) based on reports elaborated by the United States

[23] The population and GDP hypotheses are the same as in the European project AMPERE (7th Framework Program) [228].

Geological Survey. The baseline scenario is a “no policy” scenario: there is no implementation of any carbon price or carbon tax (a different scenario is presented in IV.3 that considers it). The currently enforced policies (feed-in-tariffs, green certificates) are stopped in 2015.

Energy demand and prices

We now present a general overview of the modelling results for this baseline scenario. Despite significant endogenous energy efficiency improvements, the GDP and population increase have significant impacts on the energy consumption (all types of energy vector), which rises from 79 000 TWh (in 2000) to 152 000 TWh in 2050 (respectively 186 000 TWh in 2100). Figure 47 decomposes the end-use energy consumption, by fuel and by electricity sector.

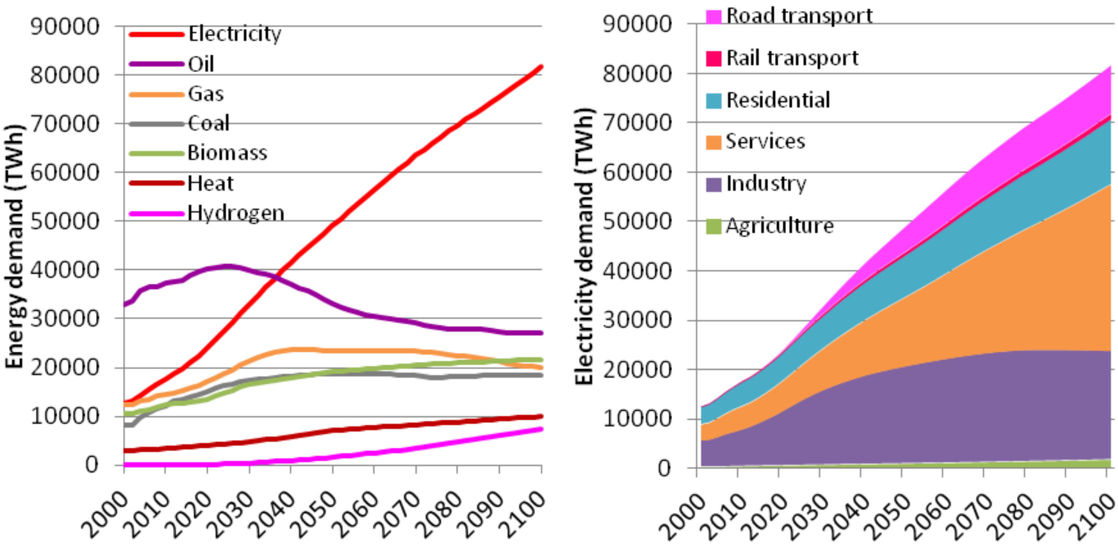


Figure 47: Global energy needs in the baseline scenario; decomposition by end-use fuel (left) and decomposition of electricity needs by sector (right) (POLES+EUCAD).

Electricity demand has the fastest growth (almost fourfold between 2000 and 2050), reaching a third of the end-use energy consumption in 2050 and 43% in 2100. This evolution is driven by each sector’s activity, particularly the industry and services sectors. The price competition between electricity and other fuels for substitutable energy demand sectors (e.g. gas for heating or oil for transport). The oil, gas and coal prices are presented in Figure 48.

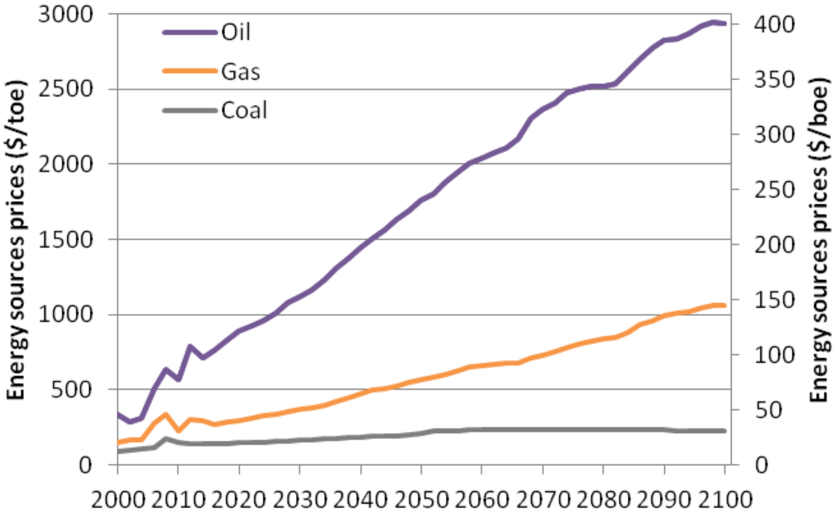


Figure 48: Global oil, gas and coal prices in $2005 per ton of oil equivalent ($/toe, left axis) and in $2005 per baril of oil equivalent ($/boe, right axis). Baseline scenario (POLES+EUCAD).

The strong increase of oil prices fosters a shift of road transportation energy demand from gasoline vehicles to electric vehicles (hybrid or full-electric), which reach 10% of the global electricity demand in 2050[24].

Installed electric capacities

We show in the next paragraphs the results of the baseline scenario at the global level (although our improvements are not the same for European and non-European countries, since EUCAD only covers 24 countries out of 57 world regions). The Figure 49 shows the built electricity producing capacities, for the baseline scenario and at the global level.

[24] Depending on the country, electricity prices range from 1500 to 3000 $/toe (i.e. 130 to 260 $/MWh).

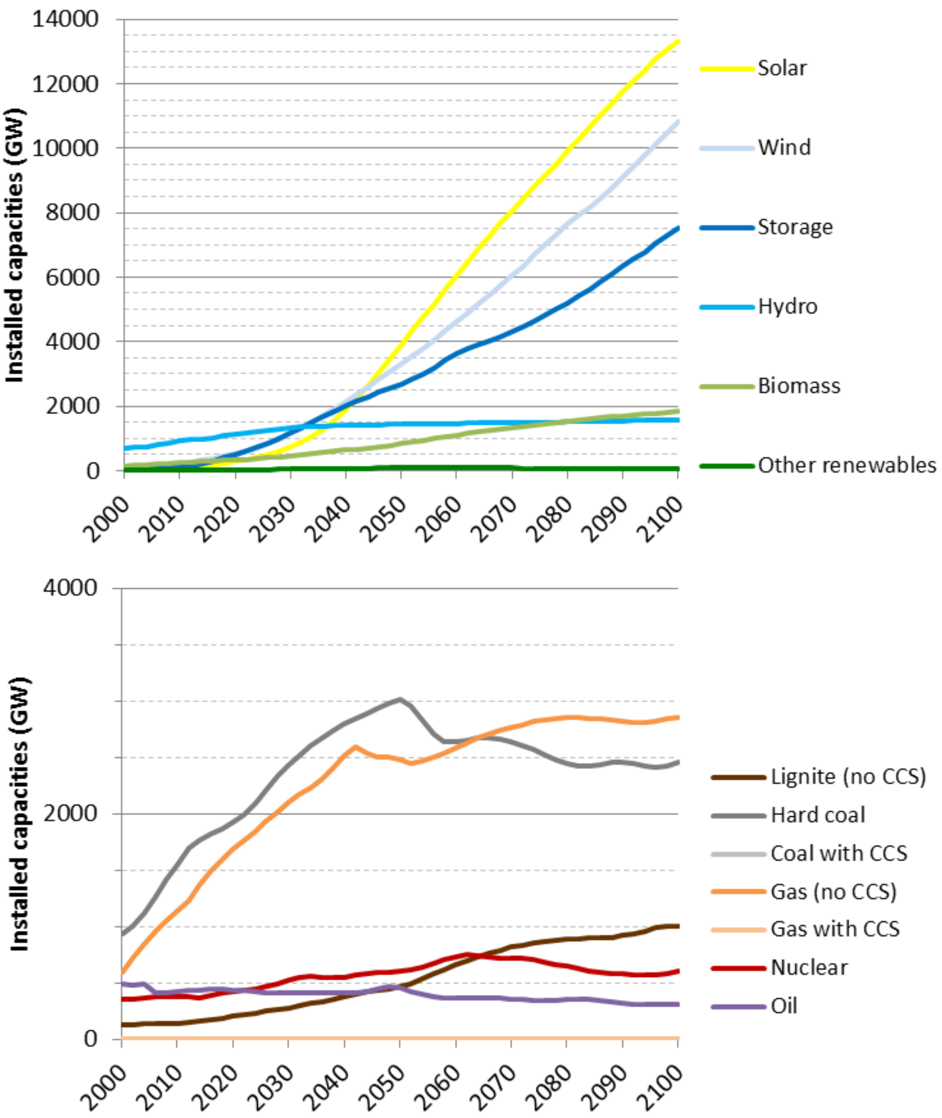


Figure 49: Global installed capacities of the different technologies in the baseline scenario. Renewable and storage technologies on top; fossil fuel and nuclear technologies on bottom (POLES+EUCAD).

The baseline scenario sees a strong development in wind and solar installed capacities, up to 57% of all installed capacities at the end of the century. The development of other renewable sources (marine and geothermal technologies) is marginal. Coal and gas power plants also develop fast until the middle of the century. In this baseline scenario there is no carbon value, so CCS (Carbon Capture and Storage) technologies are not developed. Installed nuclear power is expected to double by 2065, with the development of a fourth generation of nuclear reactors starting in 2050 (which surpasses standard nuclear reactors in 2090). However, the role of nuclear remains limited compared to fossil fuels and renewable technologies. The different storage technologies are expected to develop strongly in this baseline scenario, with the assumptions of Table 7. The distribution of storage and DR technologies is shown in Figure 50.

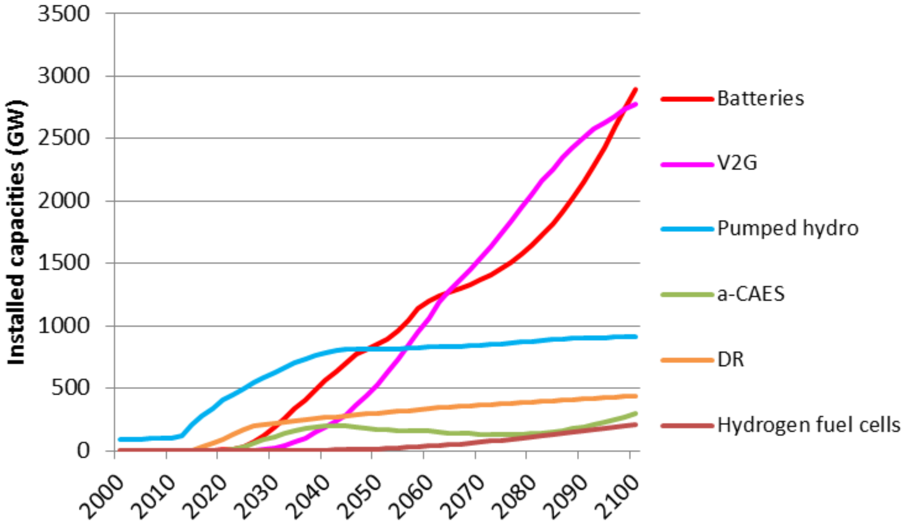


Figure 50: Global development of storage and demand response capacities in the baseline scenario (POLES+EUCAD).

EV batteries used for V2G services are expected to represent a very important source of flexibility for the system, pushed by their low investment cost. Stationary lithium-ion batteries have higher investment costs than V2G batteries, but the availability and the deployment potential are higher. With the baseline hypotheses, both V2G and batteries are expected to develop strongly from 2030 onwards. However, a sensitivity analysis carried out on the lifetime of batteries shows that the V2G and stationary batteries can develop much later (resp. 2040 and 2095) and much less (resp. 1505 and 32 GW worldwide) if their lifetime is divided by two (i.e. respectively 5 and 6.25 years). Therefore the lifetime is a crucial determinant of the development of stationary batteries.

Pumped hydro develops strongly in the next 30 years but is then limited by the competition with other storage technologies with better efficiency (V2G and stationary batteries). A sensitivity analysis on pumped hydro potential shows that, although pumped hydro is sensitive to this potential, the other storage technologies are not affected. Finding a probable maximum development potential is difficult; a study by the European Joint Research Centre [229] puts the potential at very high values compared to what looks socially acceptable, at least today. Adiabatic CAES also develops significantly at the global level – mainly in non-European countries, as EUCAD barely uses this technology because of its lower efficiency compared to other technologies. In the case of halved lifetime for V2G and stationary batteries, pumped hydro is not a lot affected at the global level (mainly in Europe), but a-CAES increases much more after 2040 (up to 1000 GW worldwide in 2100).

Demand response is limited relatively early (around 2025) because of its small assumed potential (5% of the peak demand, see Table 7) and high value to the system. A sensitivity analysis (see appendix B) shows that the installable potential is reached in any case and has little influence on the other technologies' development. Finally, hydrogen develops significantly after 2060 (but the investment mechanism is different than for DR or other storage technologies), even if the long-term hydrogen storage is not taken into account in POLES (it is considered as a decentralised technology, so the investment mechanism is different).

Power supply

The electricity supply has to meet the end-use consumption, but also the auxiliary losses (power plant auto-consumption, grid losses) and storage consumption. These components make up for almost 20 000 TWh in 2100 for the entire world. In the power supply decomposition of Figure 51, we observe a global increase of the role of decarbonised electricity production (50% in 2050), in particular wind and solar energy sources, which reach a quarter of the global electricity production in 2050 (and a half in 2100).

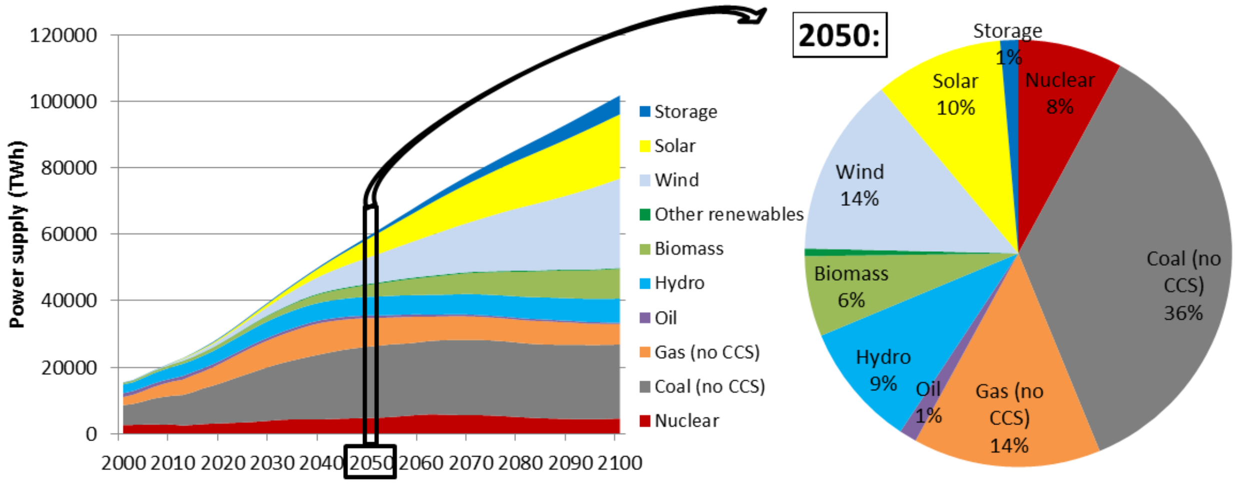


Figure 51: Global electricity supply by energy source in the baseline scenario; time evolution (left) and decomposition for the year 2050 (right) (POLES+EUCAD).

In order to cover the strong consumption increase, electricity generation from coal triples in the first half of the century, and maintains this level afterwards (this is not surprising considering the price of coal in Figure 48, lower and increasing less than oil or gas). This is completely different when a carbon value is introduced (see IV.3). Some new advanced coal technologies are developed: supercritical pressurised coal and integrated coal gasification with combined cycle. Similarly, power generation from gas more than triples by 2040 and slowly decreases afterwards. Nuclear generation is multiplied by 2.2 between 2000 and 2062, decreasing afterwards. Hydro production doubles in the first 30 years, increasing slowly for the rest of the century. Biomass, wind and solar develop fast and increase their share in the total electricity production steadily, reaching 30% in 2050 and 55% in 2100. Electricity production from hydrogen remains small, amounting about 1.6% of total electricity supply in 2100. It is included in the “storage” category, together with pumped hydro, a-CAES, batteries, V2G, and DR. Altogether, their share in the electricity production is 1.5% in 2050 and rises up to 5.8% in 2100.

Electricity costs

The electricity production costs have a fixed part (annualised investment cost, fixed O&M cost) and a variable part (fuel cost, variable O&M cost). The Figure 52 shows the decomposition by technology of the European average electricity production costs.

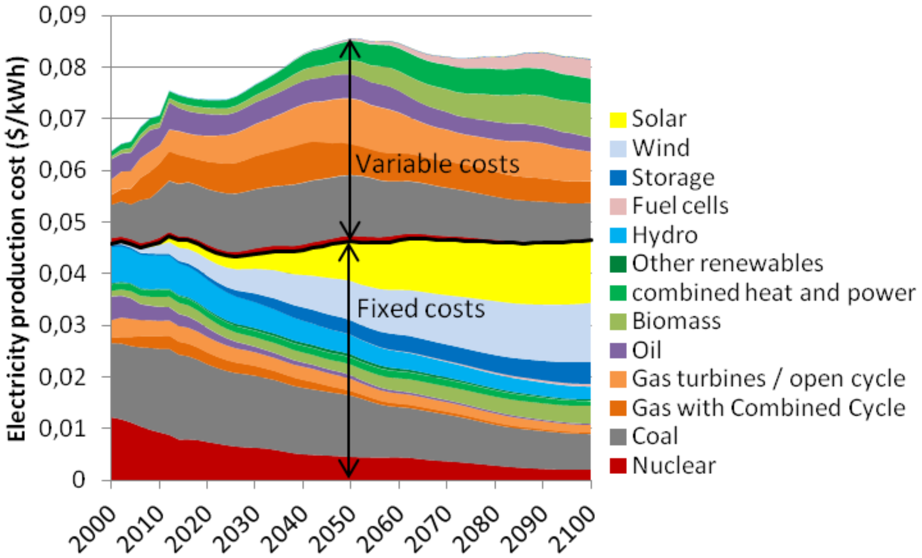


Figure 52: European average electricity production cost, separated in fixed and variable costs for each technology. Baseline scenario (POLES+EUCAD).

This production cost corresponds to a yearly *average* of costs (while the spot market average price is based on the *marginal* price). We observe the growing impact of wind, solar and storage in the fixed costs. Conversely, the impact of coal and nuclear is reduced. The variable costs are increasing until 2050, driven by decentralised biomass and gas turbines[25]. The average production cost is peaking in 2050 and decreases slightly afterwards.

CO_2 emissions

Concerning CO_2 emissions, we observe an increase from 23 $GtCO_2$ in 2000 to 45 $GtCO_2$ in 2040, slowly decreasing afterwards (down to 42 $GtCO_2$ in 2100). The deployment of non-fossil energy sources plays a great role in this stabilisation, but the emission tendency corresponds to a CO_2 atmospheric concentration of between 900 to 1000 ppm in 2050. This value far exceeds what is considered today as an acceptable range for climate stabilisation (i.e. 450 to 550 ppm for a scenario with a 2°C temperature increase compared to pre-industrial era). This demonstrates the necessity for the enforcement of an ambitious policy fighting global warming. Such a policy is studied in IV.3.

IV.1.2. Evolution of the European power system in POLES+EUCAD

In this section we focus on the evolution of the European power system, with its coupling of EUCAD's operation and POLES' capacity planning. As a close-up, we show the results for the two largest electricity consumers, France and Germany.

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[25] The development of decentralised small-scale Combined Heat and Power (CHP) gas power plants also induces higher variable costs, due to the increasing cost of the fuel (e.g. in France, multiplication by seven of the gas prices along the century).

Evolution of the installed capacities

The installed capacities are shown in Figure 53 for the 24 European countries (abbreviated Europe-24 in this work) represented in EUCAD (i.e. European Union, minus Balkans, islands and Baltic countries, plus Norway and Switzerland).

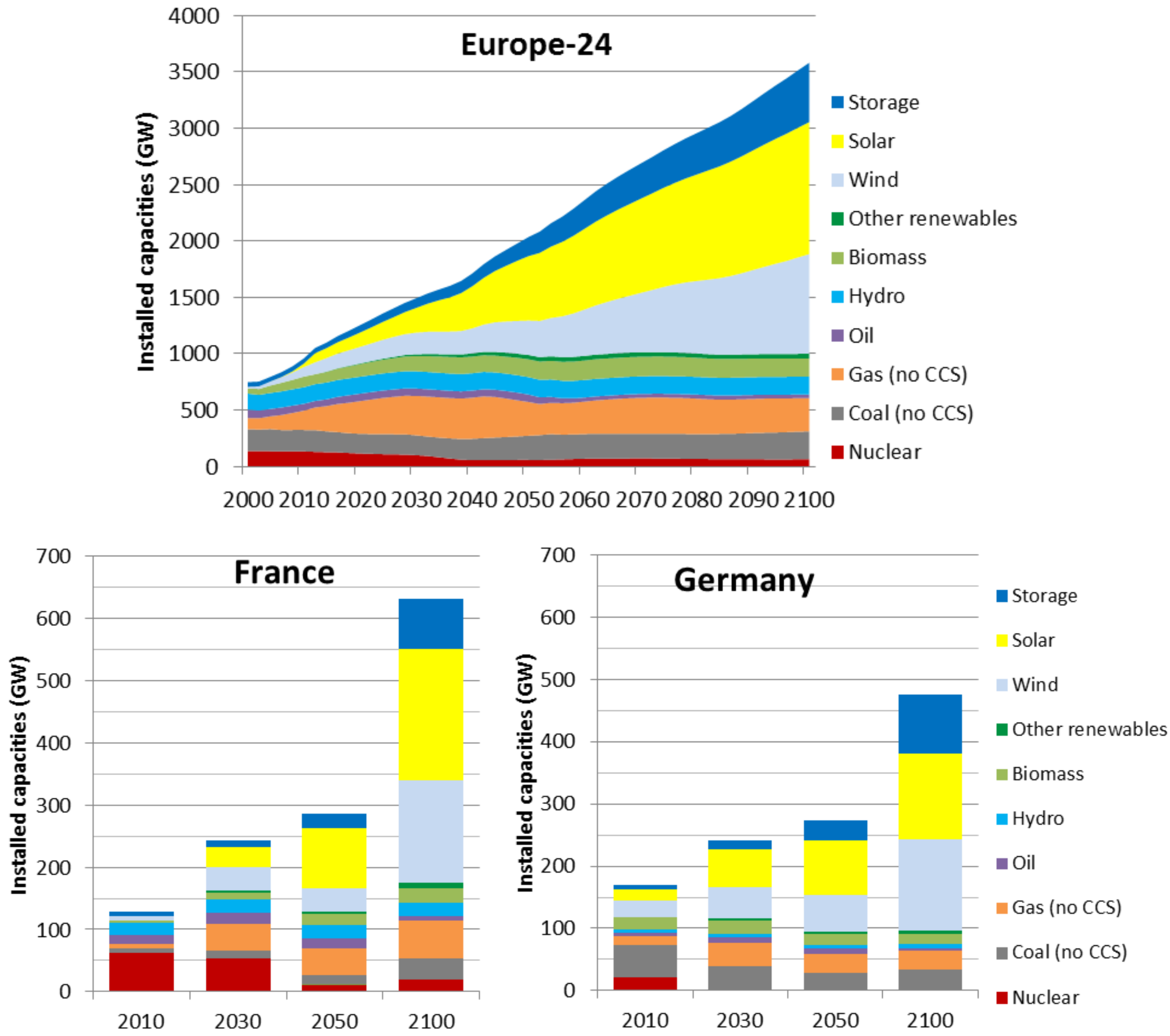

Figure 53: Installed capacities for Europe (top), France (bottom-left) and Germany (bottom-right). Baseline scenario (POLES+EUCAD).

The development of wind and solar capacities drive the increase in installed capacities, although fossil power plants keep an important role (in particular coal, with still 253 GW at the end of the century). The oil-fuelled peaking power plants, already rare, decrease further. Conversely, gas power plants as a whole slightly increase, in order to meet the increasing electricity demand in situations with low wind and solar availability. More precisely, after a first phase of slow expansion up to 170 GW for Europe, combined cycle gas power plant are replaced by gas turbines (which rise to around 200 GW). This can be explained by technical differences between gas turbines and combined cycle gas power (which combines the gas expansion in a gas turbine and the gas heat in the thermodynamic cycle). The later has a higher efficiency (thus useful for semi-base production), but also some stricter operating constraints and higher investment costs. On the other hand, the low investment cost and high flexibility of gas turbines foster their development in power systems with very high shares of VRES.

The storage capacities, detailed in Figure 54, also develop strongly.

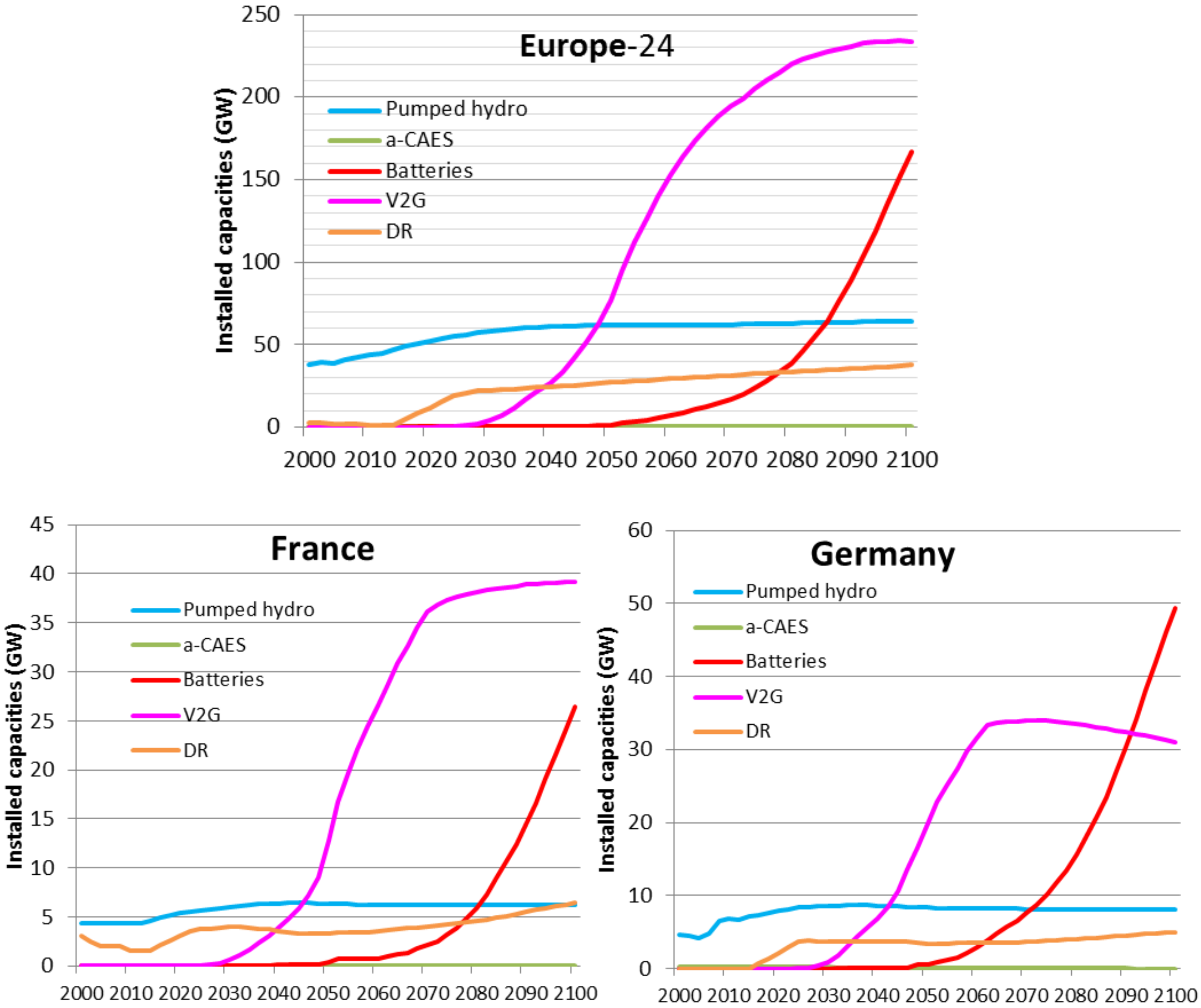

Figure 54: Installed storage and DR capacities for Europe (top), France (bottom-left) and Germany (bottom-right). Baseline scenario (POLES+EUCAD).

We observe a strong development of batteries and V2G in the second half of the century. They replace other peaking capacities that would be necessary to cover the increasing demand. V2G stabilises after 2070 because it (almost) reaches its maximum installable potential. However, when dividing the lifetime by two, we see different behaviours: stationary batteries do not develop until 2090 and only amount to 10 GW in 2100 and V2G develops twice as slow and does not go beyond 140 GW in the century.

With the working hypotheses of the baseline scenario, hydro and a-CAES remain low in Europe, penalised by their lower efficiency compared to DR, EV charging optimisation (which both have no overall losses) and also by batteries (80% efficiency). Pumped hydro relies on the lower costs of replacing old facilities. However, the efficiency of Lithium-ion batteries in real operation may be lower, while pumped hydro may improve its efficiency (e.g. through variable speed pumping mode); this would favour the development of pumped hydro. Pumped hydro may also compete if the lifetime of batteries is lower; when dividing it by two for V2G and stationary batteries, pumped hydro is boosted to 72 GW in 2100 in Europe-24 (+8 GW).

On the other hand, a-CAES efficiency (65% in our working hypotheses, which is already quite high compared to current projects) seems too low to compete with Lithium-ion batteries. The investments in a-CAES remain very low, between 290 MW and 500 MW, because they are rarely dispatched by the European optimisation – which is a significant difference with the non-European countries (that do not have the feedback of operating hours on the investment decisions).

As for DR, their high efficiency (100%) and low investment cost implies a quick development, but its potential is reached early (just like at the world level in Figure 50).

The development of grid interconnection capacities is shown in Figure 55.

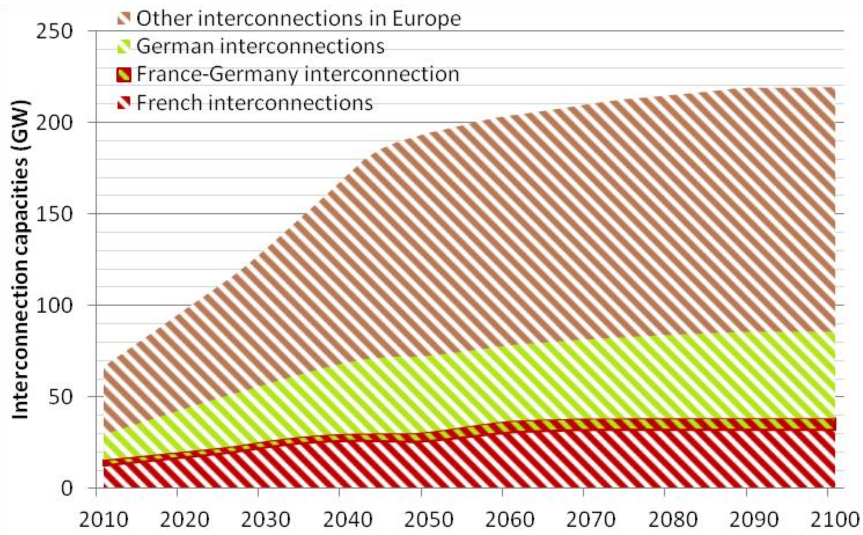

Figure 55: Installed grid capacities in Europe, France and Germany. Baseline scenario (POLES+EUCAD).

The increase in grid capacities is general all over Europe. This figure confirms the fact that Germany and France are two very important platforms for electricity exchange, making up for 44% of all European electricity interconnections until 2030, down to 39% after 2060.

Evolution of the power supply

Electricity production in the baseline scenario is described in Figure 56 for Europe, France and Germany[26].

[26] The baseline scenario shown here assumes a strong increase of electricity demand; this is due to a substitution of oil in several energy demand sectors (transport, residential, etc.).

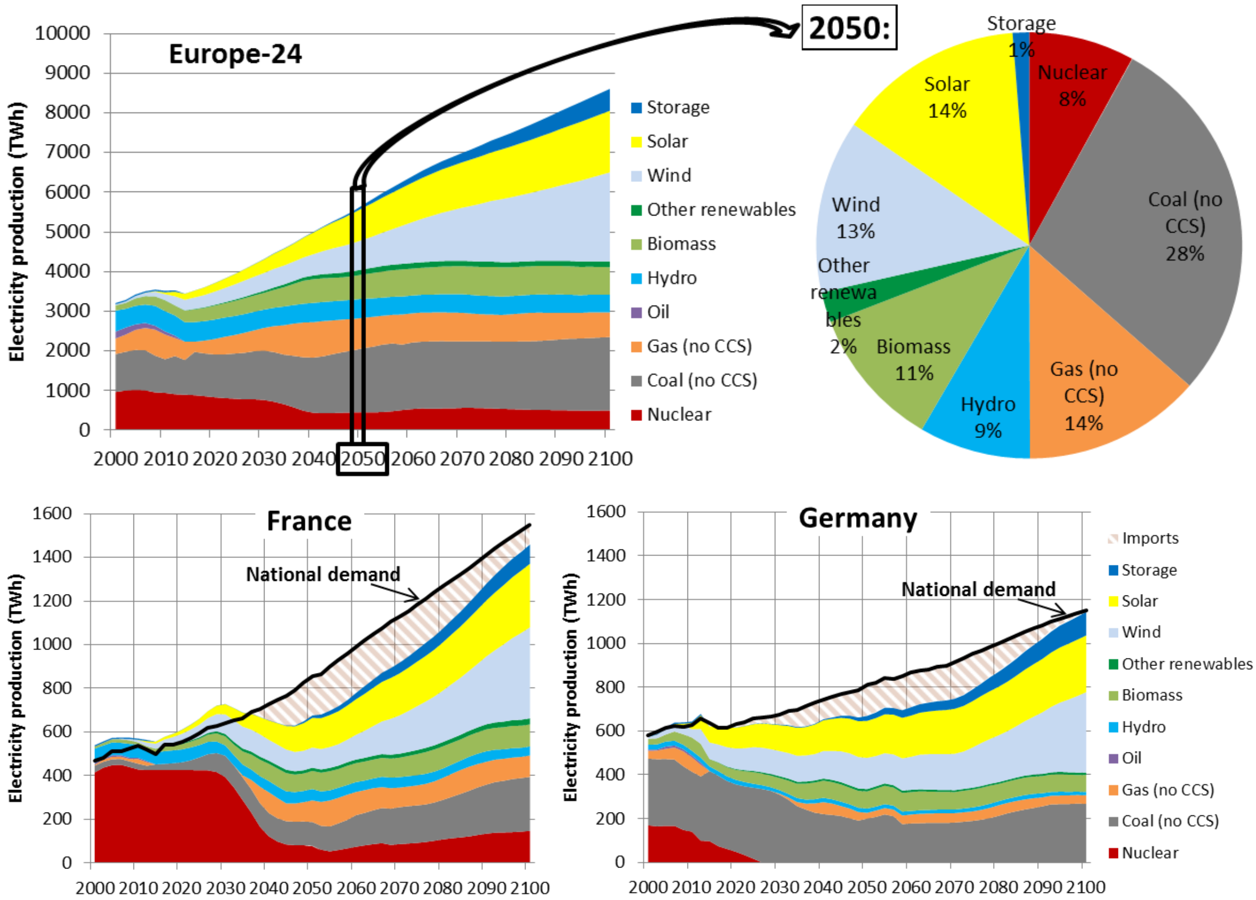

Figure 56: Electricity supply for Europe (top), France (bottom-left) and Germany (bottom-right). Baseline scenario (POLES+EUCAD).

At the European level, nuclear production is divided by two during the century, partly compensated by coal production. The gas power stays relatively constant (although the share of each technology changes: until 2050 combined cycle power plants are almost the only gas power used, but in the second half of the century gas turbines strongly expand and reach around 200 TWh of electricity produced. The largest increase comes from renewable sources, in particular biomass, solar and wind. Electricity production from storage plants becomes non-negligible in the second half of the century, even reaching 6.2% of the total electricity production in 2100 (which is more than nuclear, at 5.8%, or hydro production, at 5.2%). We show the distribution among storage and DR technologies in Figure 57.

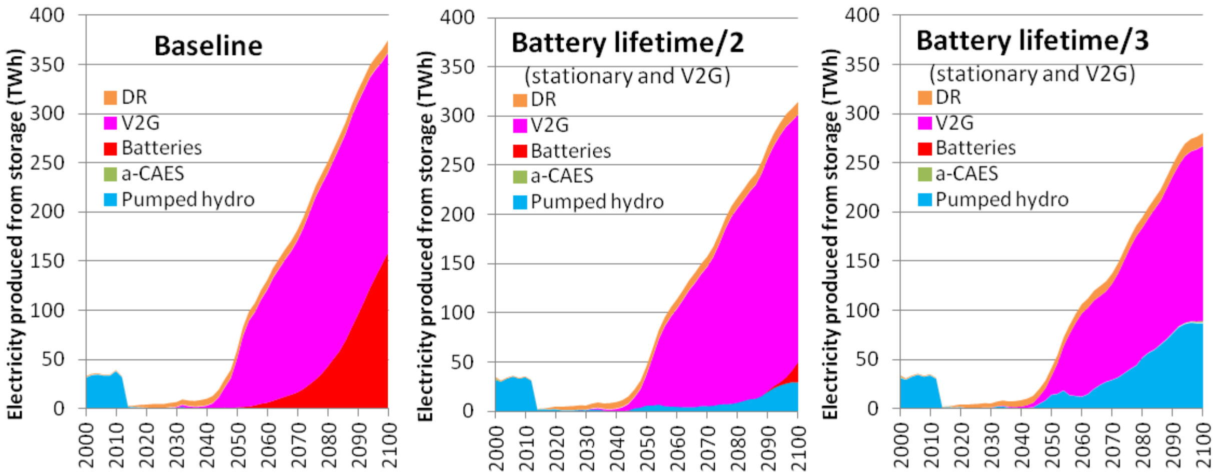

Figure 57: Distribution of the electricity produced from storage between pumped hydro, a-CAES, DR, V2G and stationary batteries. Baseline scenario and two sensitivities (POLES+EUCAD).

The hypotheses of the baseline scenario mainly feature V2G and stationary battery production, with a negligible production from hydro pumping or a-CAES (which impacts their installed capacities – see Figure 54). Using different hypotheses, with a battery lifetime divided by two, gives a different dispatch (85% from V2G at the end of the century, 5% from DR, 10% from pumped hydro; batteries and a-CAES are negligible). Dividing the battery lifetime by three favours more pumped hydro (30% of the total electricity produced from storage) and less V2G (65%).

The French and German cases in Figure 56 also show the important role that international exchanges may have. France becomes a net importer in 2036 according to EUCAD optimisation (2020 for Germany). This is well correlated with the ramp-down of nuclear power, which is a cheap energy source to operate. France overtakes Germany as the first European electricity consumer in 2045. The dynamics of the international exchanges of France and Germany are more closely monitored in Figure 58.

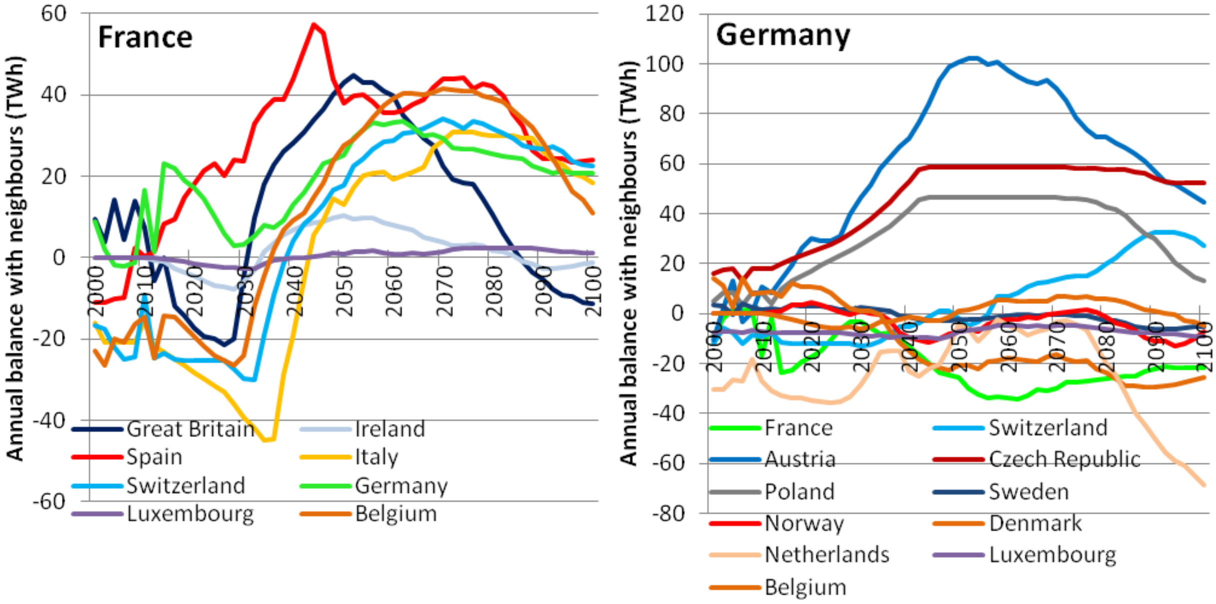

Figure 58: International annual importation balances for France (left) and Germany (right); positive values indicate imports, negative values are exports. Baseline scenario (POLES+EUCAD).

While in the baseline scenario France becomes a net importer from most of its neighbours after 2045, Germany imports a lot of power from eastern countries (Czech Republic, Austria, Poland), which benefit from cheap resources (wind and solar are developed but coal and lignite as well as nuclear energy in Czech Republic remain predominant); and it exports power to western countries (Netherlands, Belgium, France).

IV.1.3. Operation of the European power system

EUCAD gives interesting details on the operation of the European power system, for each of its 24 countries. As an example, we present here the dispatch of two typical days in 2050:

- the type 1-summer day, with a high solar (23.6% of European production) and low wind production (4.9% wind onshore, 0.5% wind offshore);
- the type 6-winter day, with a low solar (8.4%) and high wind production (21.1% onshore, 2.3% offshore).

Table 11 displays the corresponding solar and wind shares in 4 European countries.

Share (1-summer / 6-winter)	Germany	Italy	France	Spain
Solar	46% / 21%	38% / 17%	30% / 9%	26% / 8%
Wind	5% / 21%	3% / 9%	4% / 34%	14% / 67%

Table 11: Share of VRES in the national power production. 2050, baseline scenario.

European interconnected grid

The interconnection lines are operated differently depending on the demand and non-dispatchable productions in each country. This is illustrated at the European scale in the Figure 59 and the Figure 60.

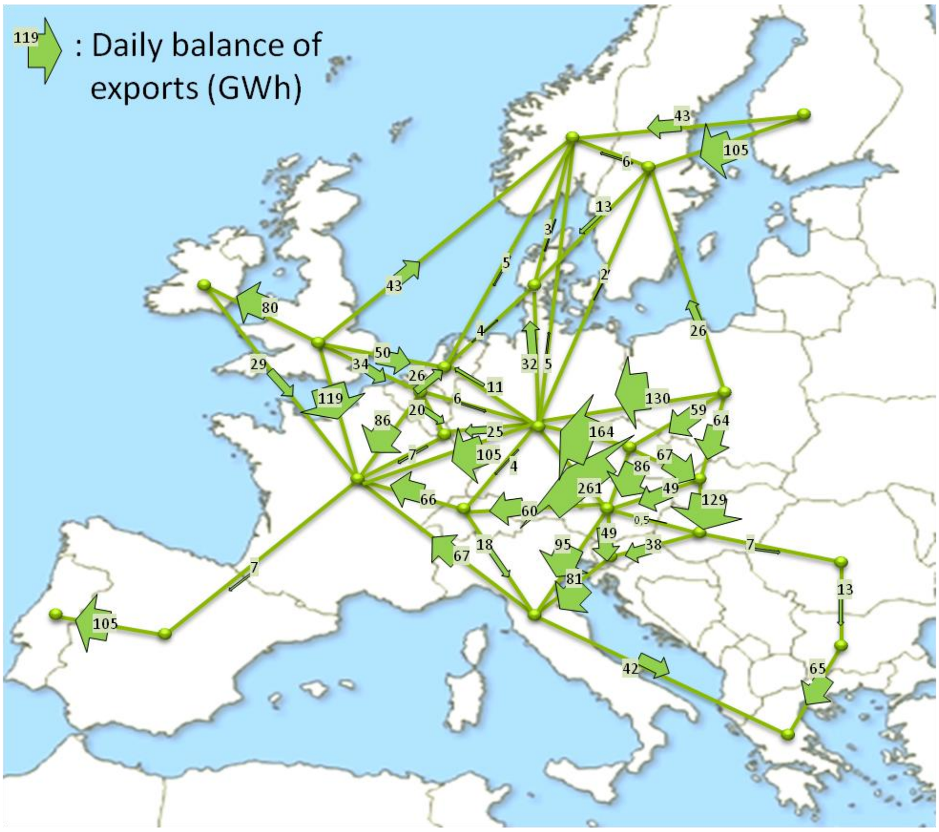

Figure 59: Balance of international exchanges in the typical day type 1-summer (high solar and low wind production). 2050, baseline scenario (POLES+EUCAD).

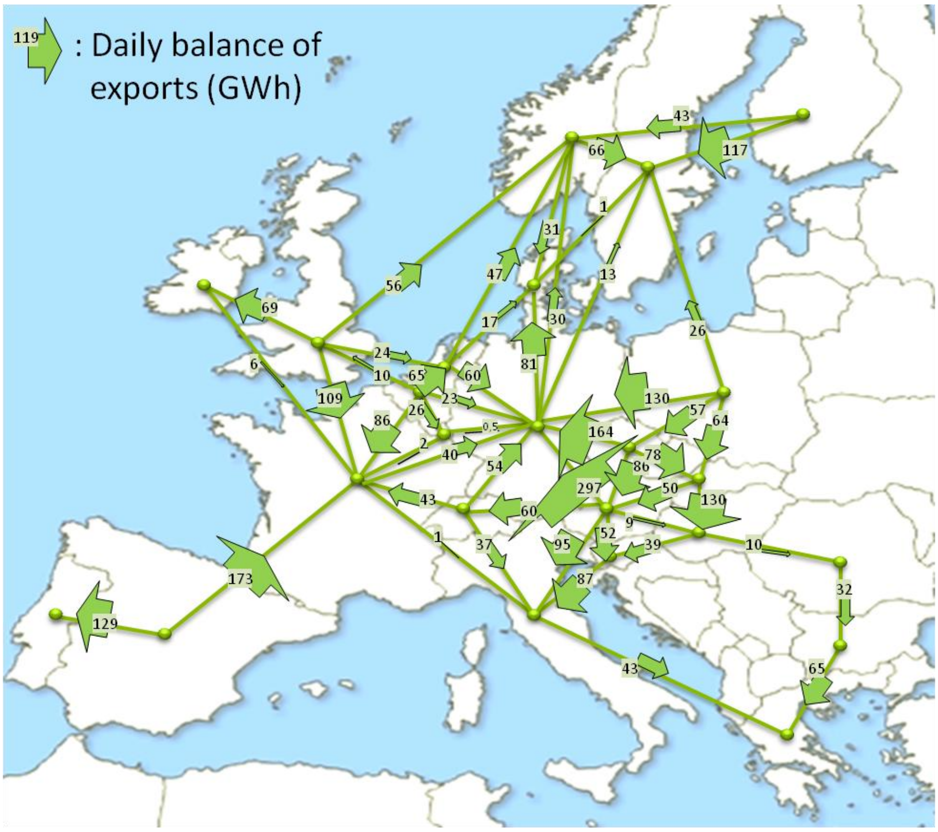

Figure 60: Balance of international exchanges in the typical day type 6-winter (low solar and high wind production). 2050, baseline scenario (POLES+EUCAD).

These two different situations of demand, wind and solar, and thus of the level of the residual load, show different levels of exchange because the marginal production costs change in each country. The lines allow for a European-wide optimisation of the power system operation, by better using the cheapest power plants throughout Europe, in particular the VRES. Here are a few examples:

- Germany and Italy export to France (respectively 105 and 67 GWh) when the solar production is high but import (resp. 40 and 1 GWh) when it is low; this can be explained by the solar penetration, higher in Germany (46% on the typical 1-summer day) and Italy (38%) than in France (30%): these countries benefit from VRES with zero marginal cost, which brings down their prices;
- the exact opposite happens between Spain and France. Their solar penetrations are quite close but the wind penetrations are much higher in Spain in the 6-winter day, causing exports to France (173 GWh vs. -7 GWh in the 1-summer day).

This is confirmed by the hourly export or import nature of France with its neighbours shown in Figure 61.

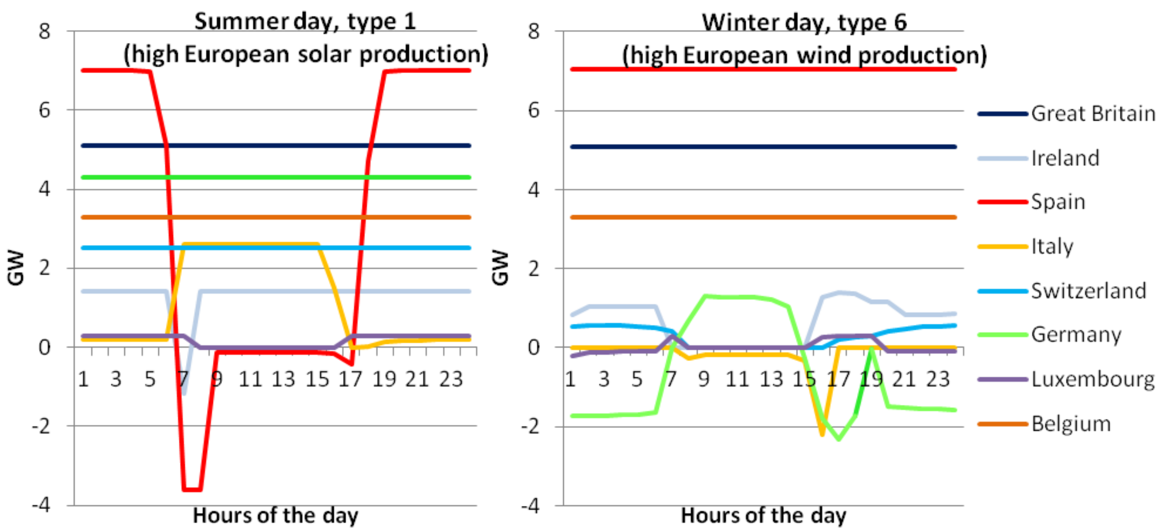

Figure 61: Net imports of France from neighbouring countries. Daily exchanges for 2050, for the type 1-summer day (left) and the type 6-winter day (right); positive values indicate imports, negative values are exports. Baseline scenario (POLES+EUCAD).

We observe fast dynamics in the exchanges with Spain (in the 1-summer day) and Germany (in the 6-winter day). For example, we clearly see that, in the 6-winter day, Germany imports from France during the night (higher wind production in France) but exports to France during daylight hours (higher solar production in Germany). More generally, the exchanges are particularly dynamic in the early morning and late afternoon, because the solar production is picking up or falling down and because of the constraints on EV charging.

This is visible with the dispatch of all technologies for these same days, shown in Figure 62.

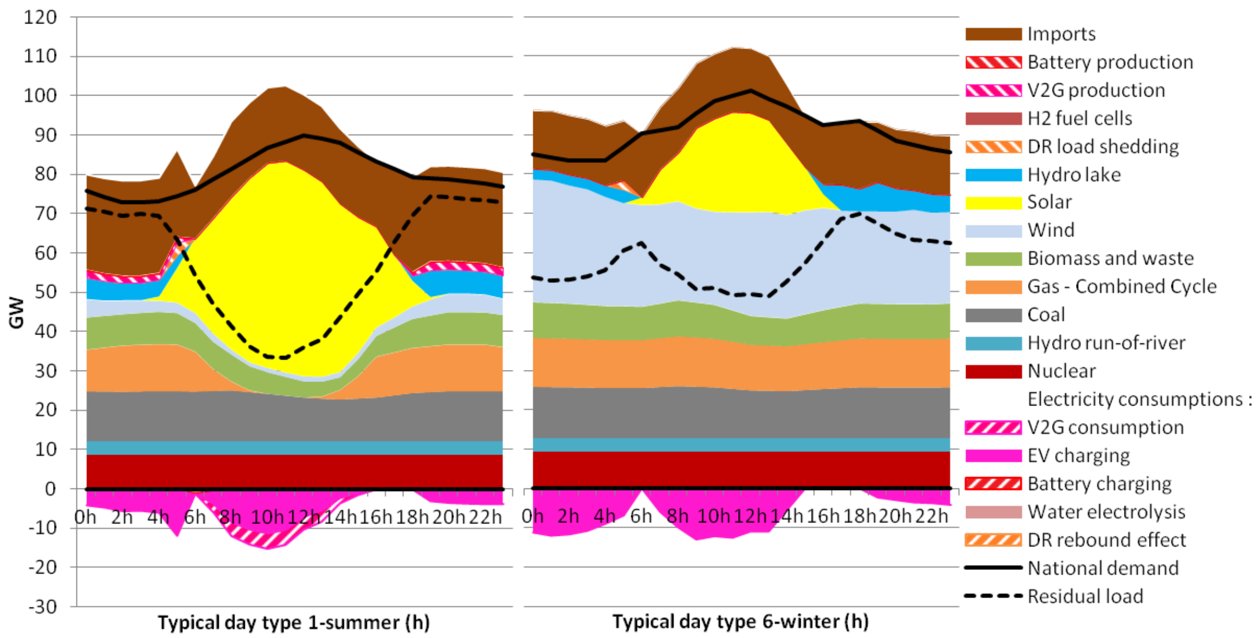

Figure 62: Power system dispatch for France, 2050, baseline scenario (left: type 1-summer; right: type 6-winter) (POLES+EUCAD).

One also observes an almost constant production of thermal power plants (nuclear, coal, gas and biomass), despite a very variable residual load (dashed line). This is enabled by the imports (presented above) and the other flexibility options (described below). Another example is shown in appendix I, with the case of Switzerland.

Storage operation

Contrary to pumped hydro or a-CAES, batteries and V2G storage strongly expand in the baseline scenario (although not at the same time). As their efficiency is the same, their operation profile is similar; we show the example of batteries in Figure 63.

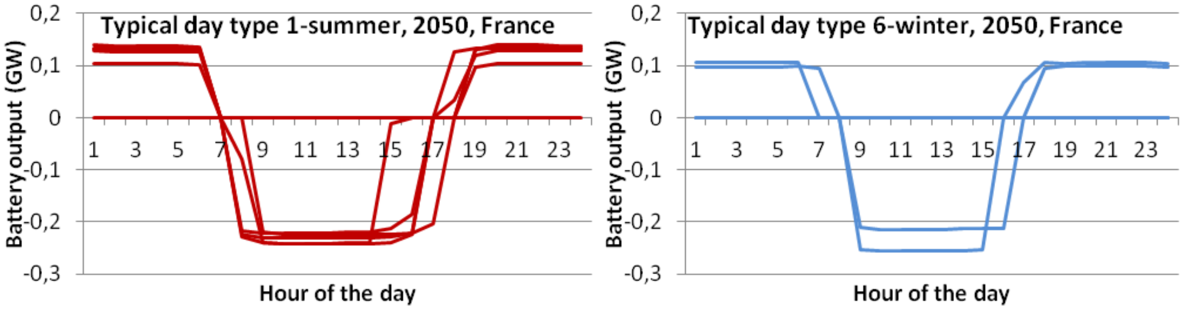

Figure 63: Battery operation (installed capacity of 0.36 GW) in the six typical days of summer (left) and in winter (right). France, 2050, baseline scenario (POLES+EUCAD).

Batteries are mostly used as a way to integrate the solar production (especially in the summer season, for five of the six typical days), by storing during day-light hours and producing during the evening and the night. Batteries are less used in the winter season (only two of the six winter days use batteries) because the residual load is flatter (solar production being lower; see Figure 62).

Hydropower operation

We focus here on hydro production, both from lakes and from pumped storage, which both feature a high flexibility (although pumped storage has 25% losses). In real hydro power plants, they are often not entirely separated (i.e. the upper reservoir is often not isolated). We present the results for France and Portugal (respectively 11.8 GW and 1.9 GW of installed hydro lake power and 4.3 GW and 1 GW of pumped hydro power in 2050). While France is very well connected to its neighbours, which reduces the interest for storage, Portugal is more electrically isolated (its only grid interconnection, with Spain, goes from 1.5 GW in 2010, to 3 GW in 2025 and 6 GW after 2045). The Figure 64 shows the evolution of the operation of hydro lake and pumping (the 12 typical days are plotted, for three different years).

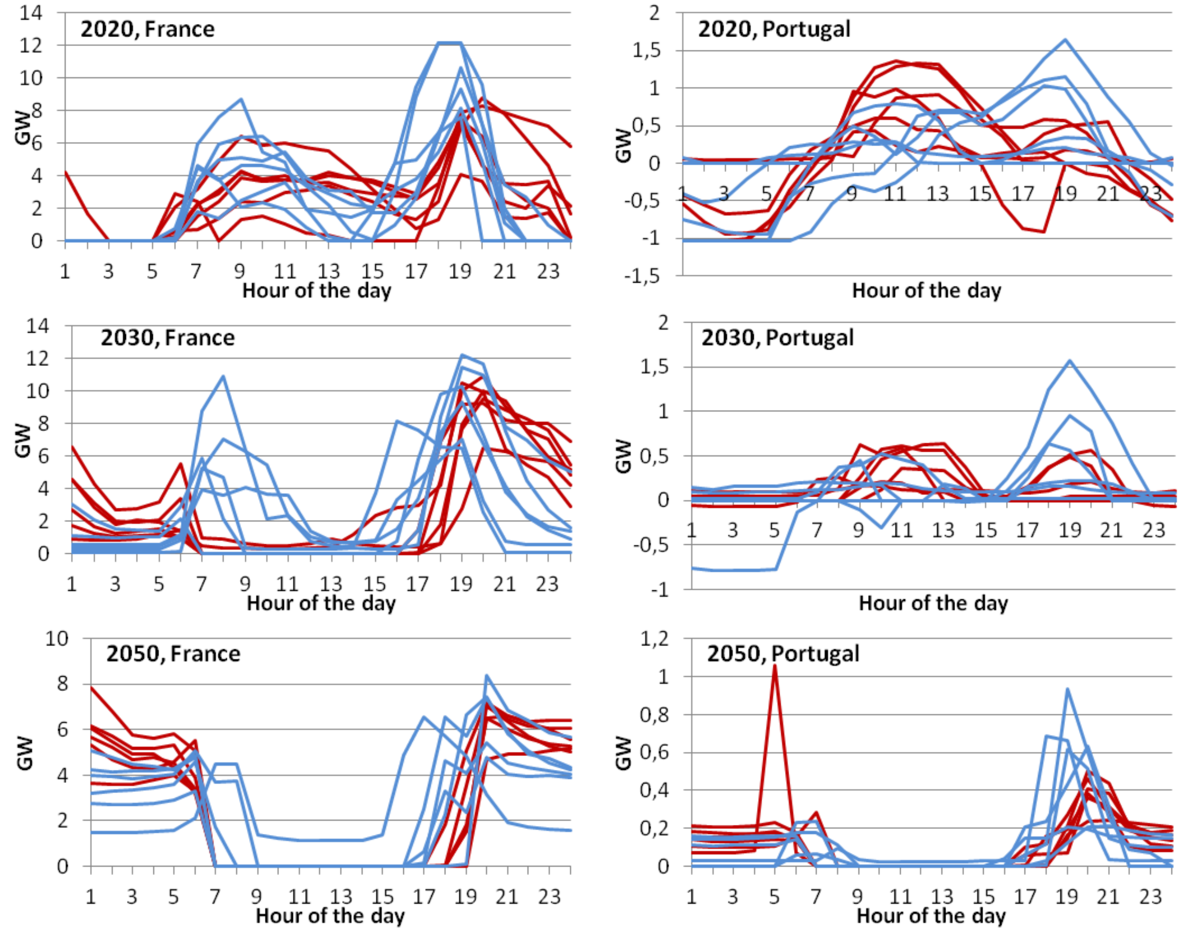

Figure 64: Operation of lakes and pumped hydro for France (left) and Portugal (right), for the 12 typical days (red: summer; blue: winter) of the years 2020, 2030 and 2050. A positive value indicates a production. Baseline scenario (POLES+EUCAD).

For both countries we observe an optimisation of the hydro resource operation according to the VRES. After a rather chaotic transitional period (2020 and 2030), the producing periods are displaced to night-time, when solar production is null (see the 2050 graphs), and demands peaks (7pm consumption peak). Pumped hydro is not used in France but is dispatched in Portugal until 2032, the country being initially more isolated. After this date, the grid interconnection of Portugal has increased sufficiently and other storage technologies with better efficiency have appeared (V2G and batteries).

This collapse of pumped hydro in the baseline scenario is an important difference with the past situation. A trend is already noticeable today[27]: the value of bulk storage is decreasing as solar production removes the day-night spread of prices. Only short periods of the day (early morning and late afternoon) are still showing high prices. In theory, the business model of bulk storage could reappear at very high solar penetration, when day-light hours have a significantly lower residual load than night-hours. However, this scheme will be much more

[27] April 2015 already saw lower “peak prices” (average from 8am to 8pm) than “base prices” (24-hour average) on the European Power Exchange (EPEX) spot market power market in Germany/Austria, if we include week-end days [230].

unreliable (because of the solar variability across days and seasons). In addition, POLES+EUCAD shows that other storage options will have appeared by then (at least in the baseline scenario), offering a better efficiency than pumped hydro (EV charging and V2G options, DR, batteries, thermal storage, etc.). In a scenario with reduced lifetime of batteries, we observe a revival of pumped hydro after 2050 (see Figure 57), not being as much threatened by V2G and stationary batteries. Another possibility for pumped hydro is to concentrate on the integration of wind power in time-scales longer than the daily cycle. However, reducing the number of operating cycles decreases the profitability of such power plants. This longer-term storage is not represented in POLES+EUCAD yet and represents a perspective for future works.

We also underline the risk of a modelling bias in EUCAD concerning pumped hydro:

- Pumped hydro has other economic values than the energy value (e.g. the capacity value, associated with high market prices, or the system security value), which could lead to more operating hours than represented in EUCAD;
- The efficiency may be different from one pumped hydro plant to another: the most efficient plants would then be more often dispatched than the used average;
- Pumped hydro (as well as a-CAES) also offers a weekly storage (or longer), not represented in EUCAD;
- EUCAD has an over-optimistic dispatch of the interconnections, overlooking the physical constraints of the interconnected grid and thus reducing the need for a local storage;
- The pumped hydro technology could improve, e.g. with a more flexible operation in pumping mode or a higher availability.

Electric Vehicles dispatch

EV offer two degrees of flexibility: first, the charging optimisation; then, using the EV batteries for V2G applications. The Figure 65 shows the total power output from EV by 2050.

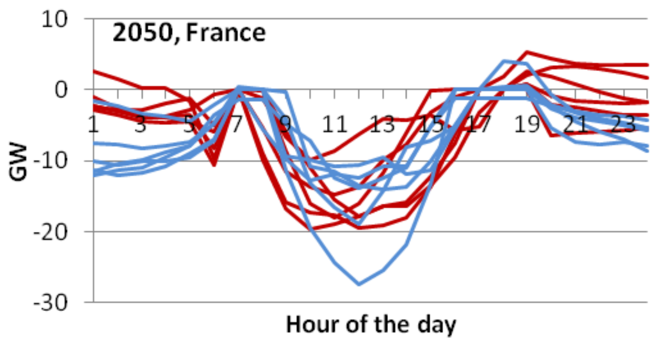

Figure 65: Net power production from EV charging and V2G (8.6 GW of installed V2G); a positive value indicates a net production. France, 2050, baseline scenario (POLES+EUCAD).

The operation of V2G alone is very similar to batteries, since the efficiency is the same. The sum of EV charging and V2G production still shows some positive net production in the evening of four summer days and one winter day: the remaining energy in EV batteries after the daily trip can be used to supply energy to the system in the evening, before charging again during the night.

The constraint on the maximum charging of EV in hours between 7am and 7pm (see III.1.1) implies that at least half of the charging is done during the night. Therefore, it can happen that V2G is used to later charge EV. This still makes sense if the vehicles are not the same: many unused vehicles could be used to optimise the rest of the power system, including the charging of other EV. However, this would create premature ageing of the batteries; the realism of this scenario depends on the regulation (enabling energy sales by EV owners) and on the business model of the batteries (buying or renting the battery, commercial offers to remote control the state-of-charge of the battery, etc.).

DR operation

Demand Response has strict operation constraints, which limit its role in the dispatch. Figure 66 shows how DR is used in 2050 in France.

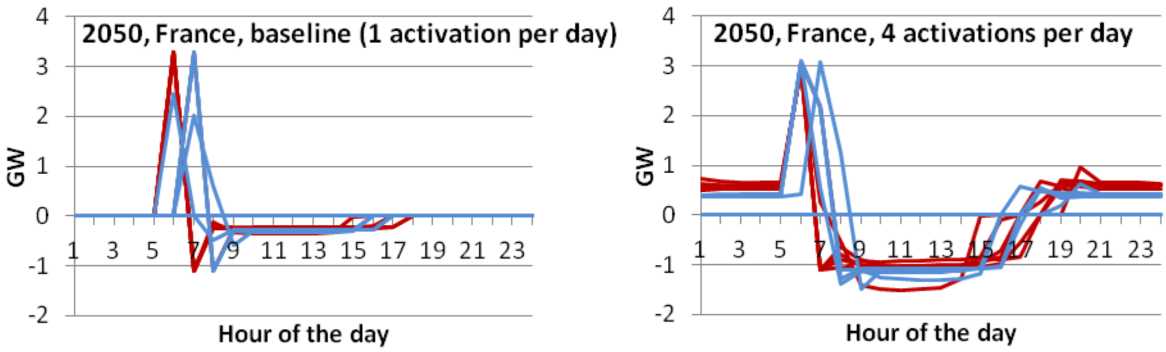

Figure 66: Demand response activation (installed capacity of 3.3 GW), for 1 activation per day (left) and 4 activations per day (right); a positive value indicates a net production. France, 2050, baseline scenario (POLES+EUCAD).

We find that DR is most often used at 6am in summer and 7am in winter. Its role is to help the morning transition period, when load is ramping up but solar production is still null or very low, while EV are disconnecting their charging point. The rebound effect (one third of the load shedding) occurs when solar production is more important, which reduces the potential negative consequences of DR. We also observe that the rest of the shifted load is displaced to day-light hours, when solar production is abundant. When enabling 4 activations per day (right) instead of only one, we see a smoother operation profile, with a peak in the morning transition period, an increase in consumption in day-light hours and a reduction at night.

IV.1.4. The economics of electricity storage

The high development of VRES in the baseline scenario creates an opportunity for storage to reduce the overall cost of the system. We analyse the role of the four storage technologies represented (pumped hydro, a-CAES, batteries and V2G, gathered in the “storage” denomination in this section), of demand response and of the EV charging. Based on the same baseline scenario, we run four different versions of EUCAD:

- with all flexibility options (normal version of EUCAD);
- without storage technologies;
- without storage technologies and without DR;
- without storage technologies, DR and EV charging optimisation.

We present here several indicators of the system impacted by the presence or absence of storage and DR options.

Storage reduces the curtailed surplus energy

Thanks to the flexibility options available in the system, no surplus energy has to be curtailed in EUCAD in the baseline scenario (this is not true anymore in the “climate policy” scenario presented in IV.3). However, hindering the different options causes some surplus energy, as seen in Figure 67.

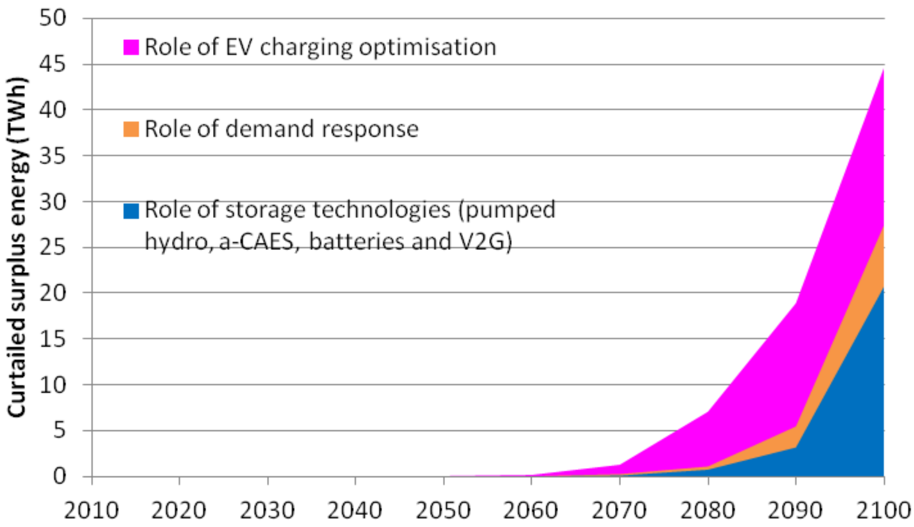

Figure 67: Role of storage, DR and EV charging optimisation in avoiding curtailed surplus energy. Total for Europe, baseline scenario (POLES+EUCAD).

Our results indicate that storage options avoid surplus energy by better integrating VRES to the power system. However, this surplus energy is negligible compared to the total European VRES production (3800 TWh in 2100). The case without storage technologies, DR or EV charging optimisation gives a surplus energy of 0.57% in 2090 and 1.17% in 2100 of the VRES production.

Storage decreases the European average production cost

We consider the total European average production cost of the system as defined in IV.1.1 (sum of the variable and fixed costs), but with the variable part being computed by EUCAD (i.e. optimisation at the European scale and including the fuel costs, ramping costs and social and economic costs of unserved load). The variable part of the operating cost is increased when taking out storage options, since the operating cost minimisation has fewer degrees of freedom. We tested a single POLES+EUCAD baseline simulation by taking out the flexibility options in the operation optimisation; Figure 68 shows the impacts on the total European production cost (the investments include the development of all flexibility options; only the variable part is affected by the different tests with or without these options).

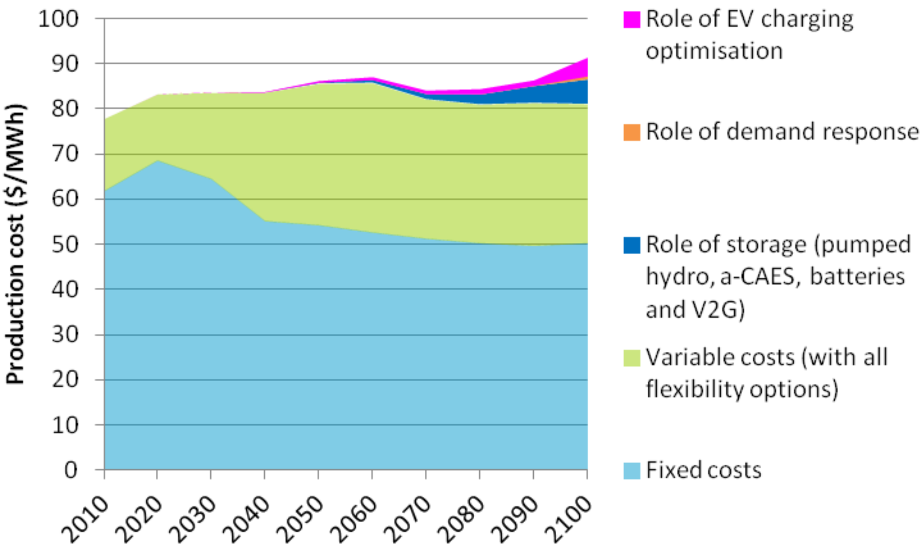

Figure 68: Impact of removing storage, DR and EV charging optimisation on the total European electricity production cost (based on the baseline scenario; POLES+EUCAD).

Some unserved load appears in 2100 when taking out the flexibility options (which impacts the total European operating cost computed in EUCAD). We see that storage technologies become particularly valuable to the system in the second half of the century. DR has a marginal role because its development is quite limited (with the potential of the baseline scenario) and its utilisation constraints are high (one activation per day at maximum, rebound effect). EV charging optimisation plays an important role, although its long-term cost reduction potential stays more limited than for storage technologies (again because of its operating constraints).

In this analysis, we have kept international trade available, as well as the flexibility of hydro lakes, of hydrogen fuel cells and of water electrolysis. Taking out the international exchanges would drastically increase the total operating cost of the European power system, due to some unserved load in countries dependent on imports (see appendix J).

Storage is profitable to the system

The value of storage is not just the reduction of the average production cost; it also participates in other aspects (e.g. the supply and demand balancing, at the short- and long-term). We now compare the economic benefits and costs of existing storage for the European power system (see Figure 69). The costs are the annualised fixed costs of storage technologies, while the benefits include:

- the energy value, which is approximated to the reduction of the operating cost as computed above[28] (which takes into account the storage losses);
- the capacity value, approximated to the capacity value of a new storage as estimated in II.3.2;
- the balancing value, approximated to the balancing value of a new storage as estimated in II.3.2.

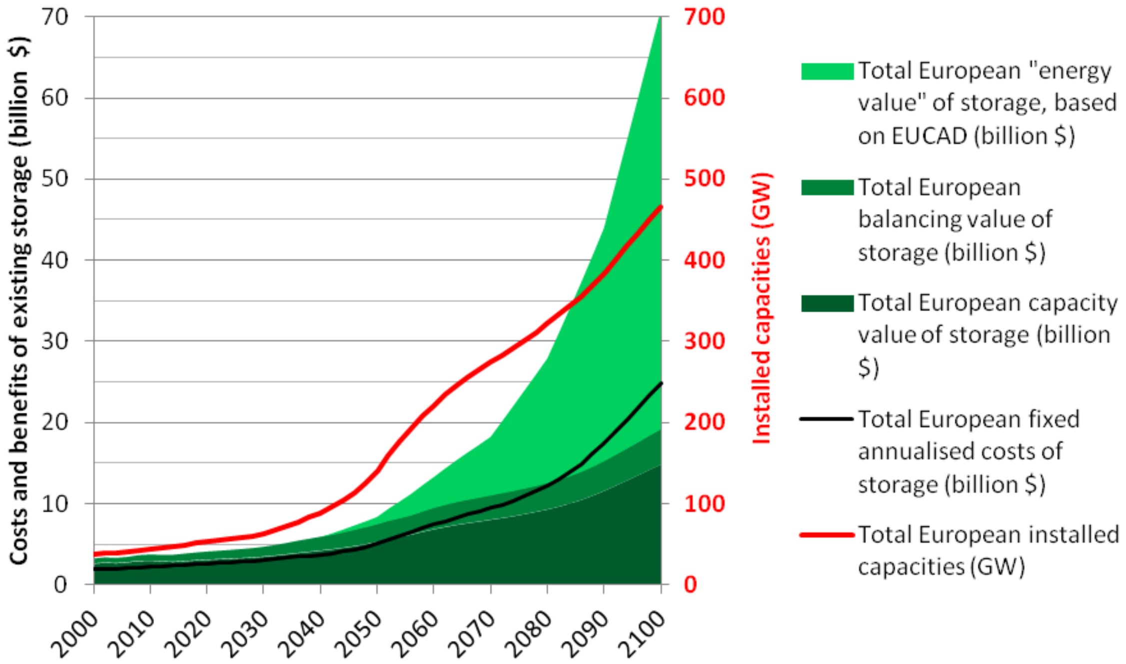

Figure 69: Comparison of the total cost of storage technologies (black line) and the three values identified for storage (green areas). In red is indicated the development of installed storage capacities. European total, baseline scenario (POLES+EUCAD).

The capacity value of storage increases in time because the storage capacities increase and their share in the capacity market is assumed to increase as well[29]. The same happens with the balancing value, although the market also increases with the penetration of VRES. The energy value is not computed in the same manner as the energy value used in POLES investments but the expansion of storage still corresponds well with the evolution of the three values, which validates the modelling choices of POLES' investment mechanism (EUCAD feedback is integrated properly in POLES' investments).

The total value of storage for the system is positive (the green areas of the benefits are higher than the black line of the costs – at least in the baseline scenario). We see that the

[28] This computation of the energy value of storage represents the value of all *existing* installed technologies; on the other hand, the energy value computed in POLES (presented in II.3.2) corresponds to a *new* additional storage capacity.

[29] The total size of the market could not be evaluated, only the potential revenues for storage are. As explained in II.3.2 and shown in figure 24, the incremental capacity and balancing value of storage decrease when the installed storage capacities increase.

energy value gains importance in the second half of the century and becomes preponderant, which demonstrates a real interest for displacing energy between periods of time. This is both linked to the increased VRES penetration, which brings more variability in the residual load, and to the change in the electricity mix, which increases the spread in variable costs (and thus, in prices[30]) by developing flexible peaking capacities (such as gas turbines) with low investment costs but high fuel costs.

IV.2. Comparison of the baseline scenario with alternative scenarios

In comparison with the baseline case ("no policy" case), we study here two alternative scenarios in order to explore different technical and economic assumptions (a third scenario with a different energy policy is explored in IV.3).

In the first scenario, we test the sensitivity of the development of storage to the technical and economic assumptions on storage ("Storage Performance" scenario). This uses alternative hypotheses to those presented in II.2.3, with a higher technical and economic performance of storage. The assumptions are summarised and compared to the baseline in the following Table 12 (more detail in appendix K).

Baseline and Storage Performance assumptions	Pumped hydro		a-CAES		Batteries (Li-ion)		V2G (Li-ion)	
	Baseline	Storage Perform.	Baseline	Storage Perform.	Baseline	Storage Perform.	Baseline	Storage Perform.
Efficiency	75%	83%	65%	69%	80%	88%	80%	84%
Fixed O&M costs ($/kW/year)	4.3	3.3	32.2		10.75	6.43	10.75	
Variable O&M costs ($/MWh)	8.6	1.6	0		2.15	1.4	2.15	
Learning rate	0.61%	2%	5%	7%	10%		1%	

Table 12: Summary of the Storage Performance characteristics at the end of the scenario (exogenous assumptions).

The second scenario uses lower investment costs for renewable energy technologies, so that their development is facilitated ("New Renewable" scenario). While the investment costs of the baseline scenario are endogenous (based on historical costs and learning rates), the "new renewable" scenario has exogenous VRES costs (not linked to the evolution of installed

[30] After a first period of decreasing price spread, it increases again after 2050. Pumped hydro plants lose value in the first period, and only regain this value after 2050 if batteries are not too developed (e.g. if their lifetime is in the lower range). In the baseline scenario it is not the case and pumped hydro stays low, but in scenarios with halved lifetime of batteries, they develop further in the second half of the century.

capacities any more). They decrease faster than the baseline between 2014 and 2030 (transitional period) and are then fixed at half the baseline costs.

IV.2.1. General impacts on the power system

First, we analyse the different impacts on the power system between the three scenarios.

Installed electric capacities

The impacts of the three scenarios on the power system are compared for Europe, France and Germany. We present in Figure 70 the elements of the Storage Performance (SP) and New Renewable (NR) scenarios that are significantly different from the Baseline (BL) scenario. For example, the hydraulic capacities are the same between all three scenarios and are not shown. The demand response capacities are also very close, mainly influenced by their assumed potential.

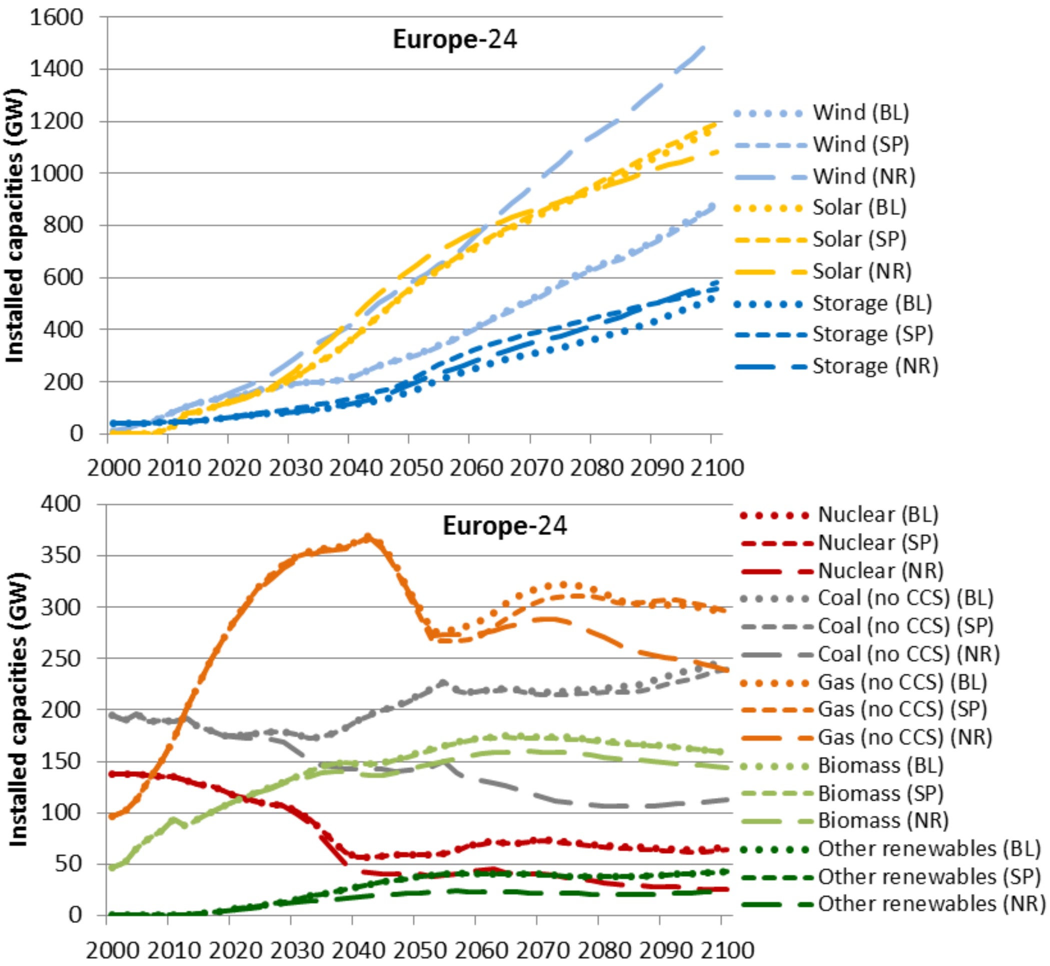

Figure 70: Installed capacities in Europe for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR). Wind, solar and storage power on top; nuclear, coal, gas, biomass and other renewable power on bottom (POLES+EUCAD).

As anticipated, the development of storage is faster in the Storage Performance scenario (+28% at the European level in 2050), and the development of VRES is higher in the New Renewable scenario (+42% in 2050). Some other interesting effects are visible:

- The New Renewable scenario has more impact on the development of wind power than of solar power, thus showing that wind power is more sensitive to costs than solar power; this shows a competition between solar and wind, the latter being more cost-efficient and able to push out fossil-fuel power.
- The Storage Performance scenario allows the integration of a slightly higher share of VRES.
- The New Renewable scenario also increases the need for storage (detailed by technology in IV.2.2) by 10 to 15% after 2045, compared to the Baseline scenario, which already indicates the strong link between VRES and storage.
- All coal, gas, nuclear, biomass and other renewable (geothermal and marine) energy sources are massively reduced by the increase in wind and solar production (-16% in 2050 and -33% in 2100 for the total of these capacities); this effect is particularly strong for nuclear and coal power, which are typically base-load power plants and suffer more from the VRES development (reduction of more than 50% after 2075).
- The coal and gas power plants are slightly decreased in the Storage Performance scenario (-1 to -2%), meaning that storage can displace a small amount of production capacities (this is also linked with our modelling of *daily* storage only).

The cases of France and Germany are illustrated in Figure 71.

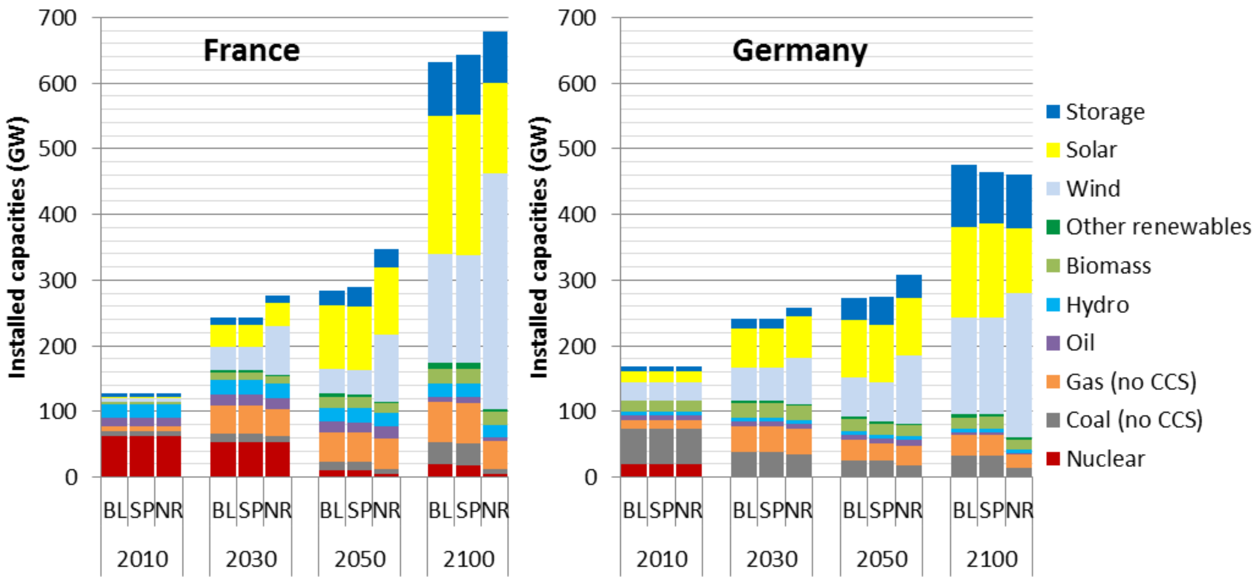

Figure 71: Installed capacities in France (left) and Germany (right), for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

We observe that the scenario with a high storage performance affects very little the installed capacities in France, and shows a slightly stronger development of solar power in Germany (in the long-term). The scenario with strong VRES development (NR) squeezes out the nuclear and coal power from the French power system (in Germany the coal is reduced but not abandoned, while the nuclear is phased-out by 2022 according to the political decision following the Fukushima accident in 2011). In both countries, gas power plants play a fundamental role among the installed dispatchable power plants (gas turbines for the most part).

If we consider the European grid capacities, very little differences appear between the three scenarios studied: a total of 219 GW of installed international grid capacities in 2100 in the baseline scenario; 219 GW as well for the Storage Performance scenario and 215 GW in the New Renewable scenario. The sensitivity of our modelling of grid investments to the development of storage or VRES is low.

Power supply

As the installed capacities already suggest, the power supply is very close between the Baseline and Storage Performance scenarios. Therefore we only show in Figure 72 the power supply of the New Renewable scenario.

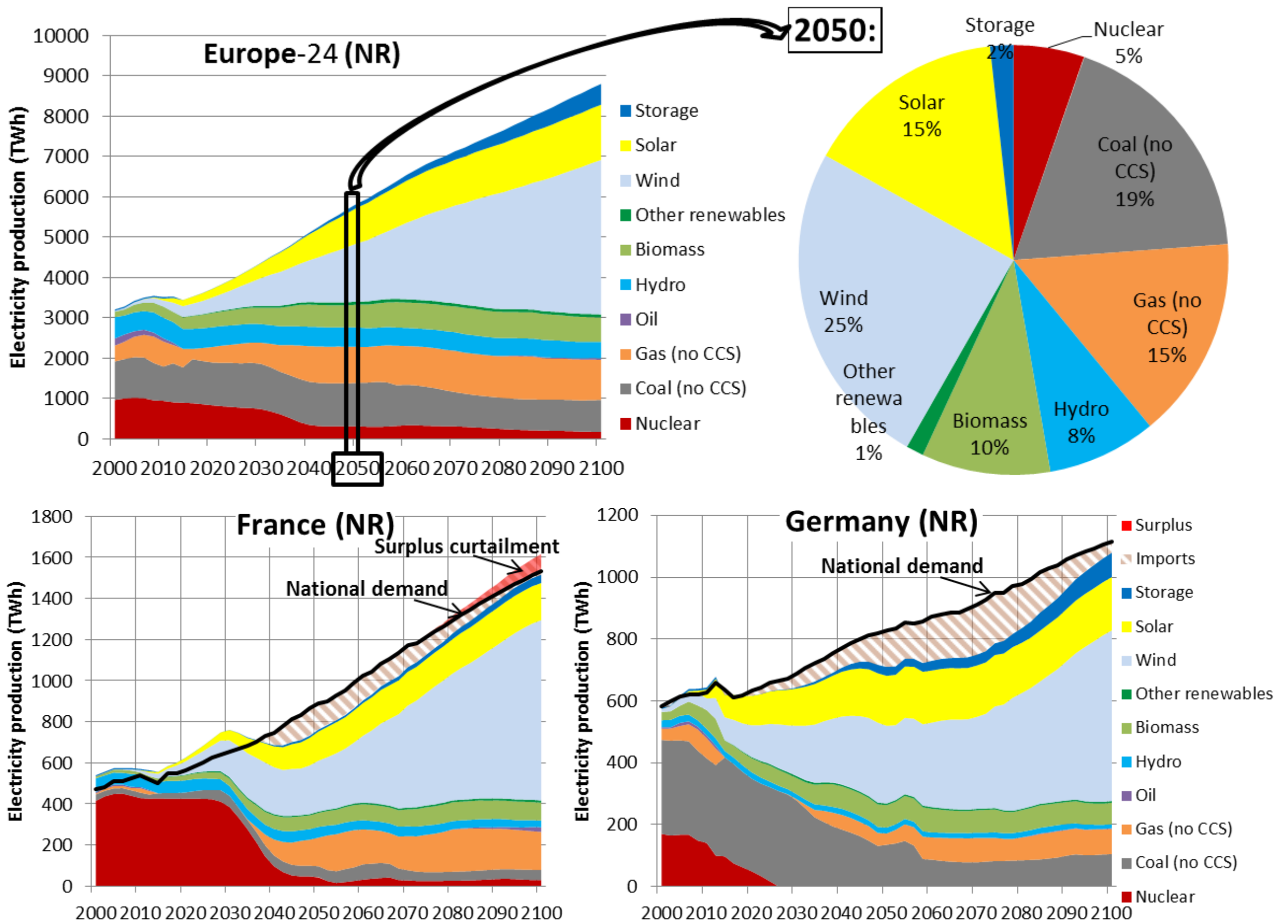

Figure 72: Electricity supply for Europe (top), France (bottom-left) and Germany (bottom-right). New Renewable scenario (POLES+EUCAD).

Compared to the baseline (Figure 56), the high wind and solar development reduces the dispatchable productions (-18% in 2050, -31% in 2100). There is a sharp decrease (a third in 2050, almost two-thirds in 2100) in coal and nuclear productions, which shows that VRES strongly affect the base-load productions. Gas power replaces this production in a large part (265 TWh increase at the European level in 2100 compared to BL), but when looking more closely at the producing technology, we see different effects. Compared to the baseline scenario, there is a further decreased use of combined cycle power plants (270 TWh in 2100 in the baseline but only 180 TWh in the New Renewable), and a sharp increase in gas turbines production (205 TWh in BL but 665 TWh in NR). The low investment costs and flexibility brought by gas turbines also justify the development of oil production (41 TWh in NR in 2100, compared to less than 1 TWh in BL), half of which is in France (22 TWh in NR in 2100)[31].

Despite the much higher VRES development in the New Renewable scenario than in the Baseline scenario (especially wind power; solar power is slightly lower), we find that the development and operation of storage technologies are only around 10% higher. In the New Renewable scenario, the higher wind power (but slightly lower solar power) does not imply a much higher need for daily storage, because the residual load has less day-night variations than in the baseline (which is more influenced by the solar production profile). In addition, the periods of low (or negative) residual load in the night are more easy to accommodate thanks to the EV charging (in EUCAD the EV charging during day-light hours is limited to 50% of the daily need).

Some energy surplus appears in the New Renewable scenario (114 TWh in Europe in 2100, 86 of which are in France). The flexibility options cannot absorb entirely this surplus because it lasts entire days, while storage in EUCAD only has daily storage; therefore it cannot displace energy between days.

Electricity exchanges

The international exchanges are impacted by the scenario assumptions (Figure 73).

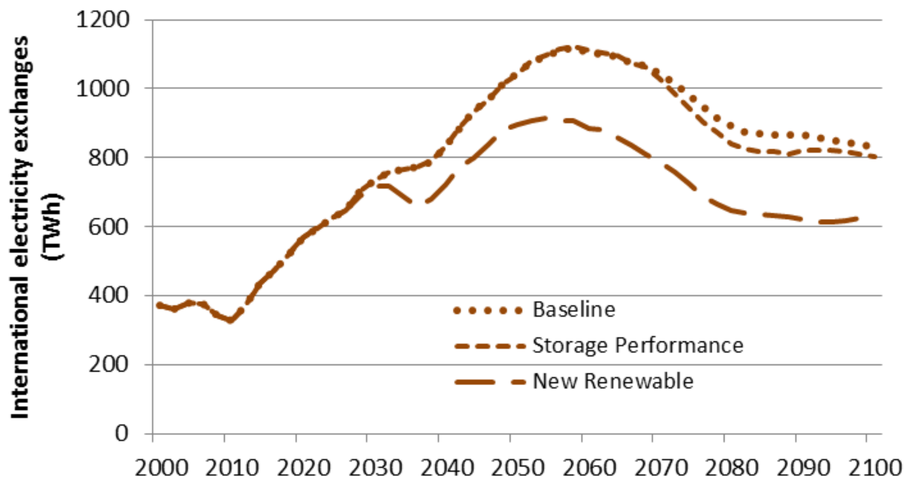

Figure 73: International electricity exchanges in Europe for the scenarios Baseline, Storage Performance and New Renewable (POLES+EUCAD).

The stronger development of storage in the SP scenario allows a decrease of international electricity trade of 3 to 6% at the end of the century – which also decreases the grid losses.

[31] The oil and gas prices are close to those presented in Figure 48.

The stronger development of VRES (in particular wind) decreases far more the electricity transiting between countries (-25%). It is difficult to formulate an explaining hypothesis, since the entire European power system mix[32] is in interaction and changes from one scenario to another.

Electricity costs and price

The evolution of the European production costs is shown in Figure 74 (separated in fixed and variable parts), for the Baseline and New Renewable scenarios (the Storage Performance scenario is very close to the Baseline).

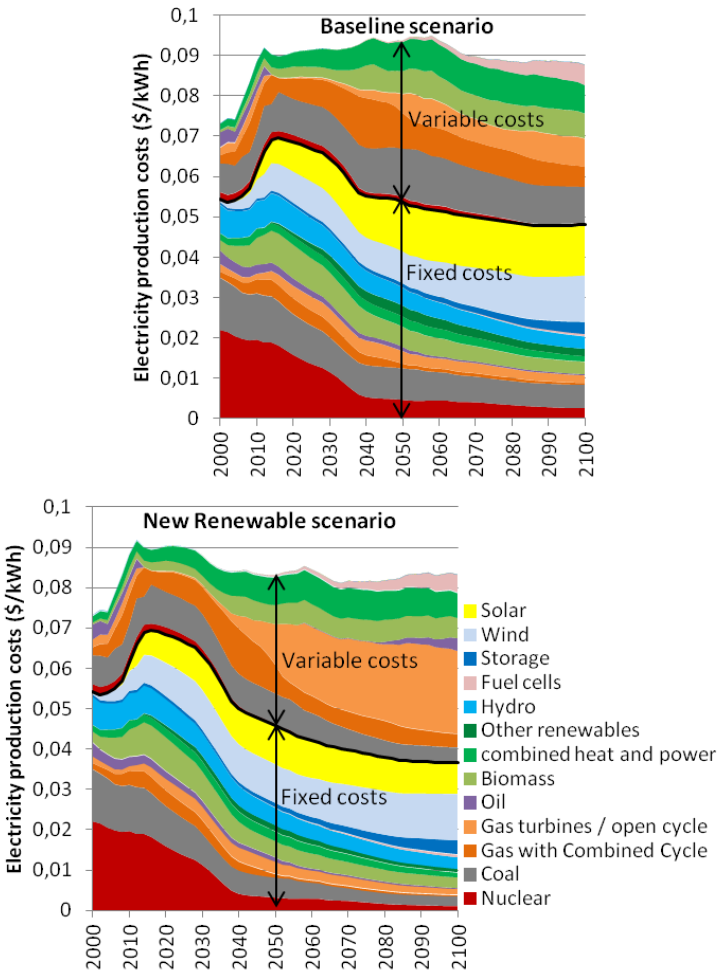

Figure 74: Average European cost structure in the Baseline (left) and in the New Renewable scenario (right) (POLES+EUCAD).

The impact on the cost structure of wind and solar is reduced in the New Renewable scenario, despite higher wind investments. The costs associated to coal and nuclear (installed capacities and operating hours) are smaller in the NR scenario, pushed out by the high penetration of VRES in the power system. The New Renewable scenario has much

32 This evolution takes into account the correlation between VRES production profiles across Europe thanks to our modelling of typical days of VRES production profiles.

higher variable costs due to gas turbines and oil-fuelled power plants because it requires them for compensating the variability of wind and solar.

The main difference observed in the Storage Performance scenario compared to the baseline is the (fixed) storage cost, 23% higher than in the baseline. However, when considering the total European production cost, it is still reduced by 0.77$/MWh (around 0.8%).

The electricity prices are derived from historical data and from the evolution of these costs. In Figure 75 we show the average price over all sectors, for the Baseline, Storage Performance and New Renewable scenarios.

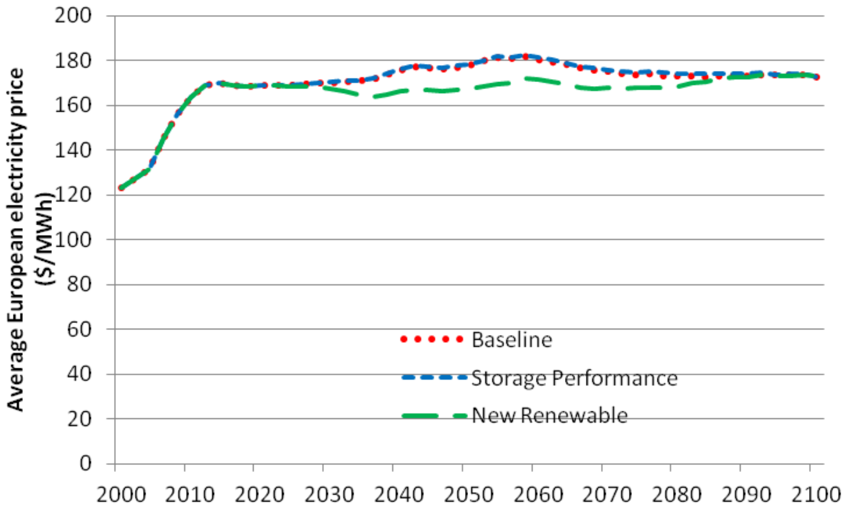

Figure 75: Average European electricity price for all consumption sectors, for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

The average price increases in the first years (which corresponds to input data), but then stabilises. The slight increase of the BL and SP prices is avoided in the New Renewable scenario thanks to the halved VRES investment costs. However, the wind and solar investment costs seem to have no influence on the total average price in the long run. This finding is also put forward by a study from the French energy agency ADEME [231]. The long-term electricity consumption adapts to the price of electricity.

Emissions

Figure 76 shows the evolution of the European GHG emissions (in the y-axis, in CO_2 equivalent) and of the VRES penetration in the energy mix (x-axis).

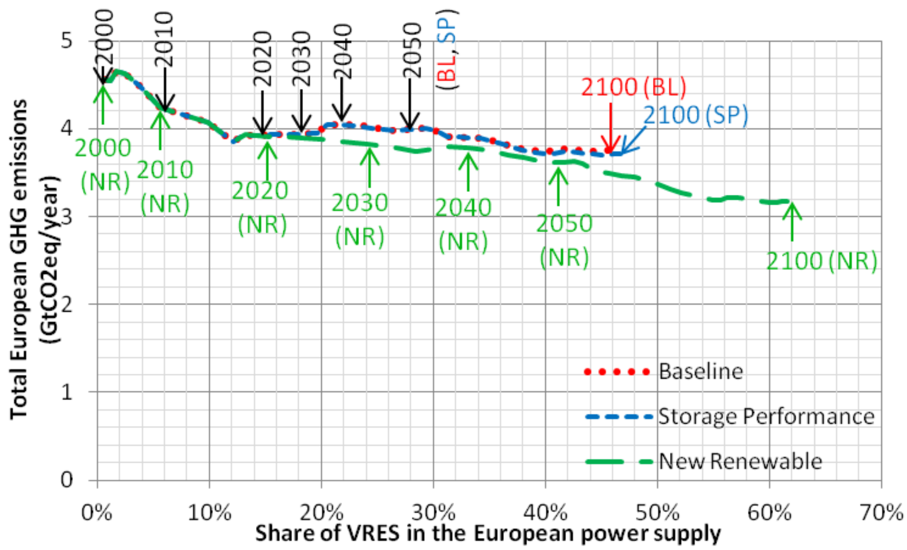

Figure 76: Total GHG emissions in Europe relative to the VRES share in the European power supply, for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

We observe a faster (especially between 2020 and 2040) and deeper reduction in GHG emissions in Europe in the New Renewable scenario than in the baseline scenario (18% less emissions at the end of the century). This is well explained by the increase in VRES penetration (the cheaper VRES in NR are developed more than in BL). We also see with the Storage Performance scenario that improved storage technologies allow a slightly better integration of VRES (the share of VRES is higher at the end of the century) and a decrease in the total emissions.

IV.2.2. Impacts on storage development

We look at the impact of the same three scenarios on the different storage technologies.

Development of storage technologies

The installed storage capacities and electricity produced by storage technologies are detailed for the different scenarios in Figure 77 and Figure 78.

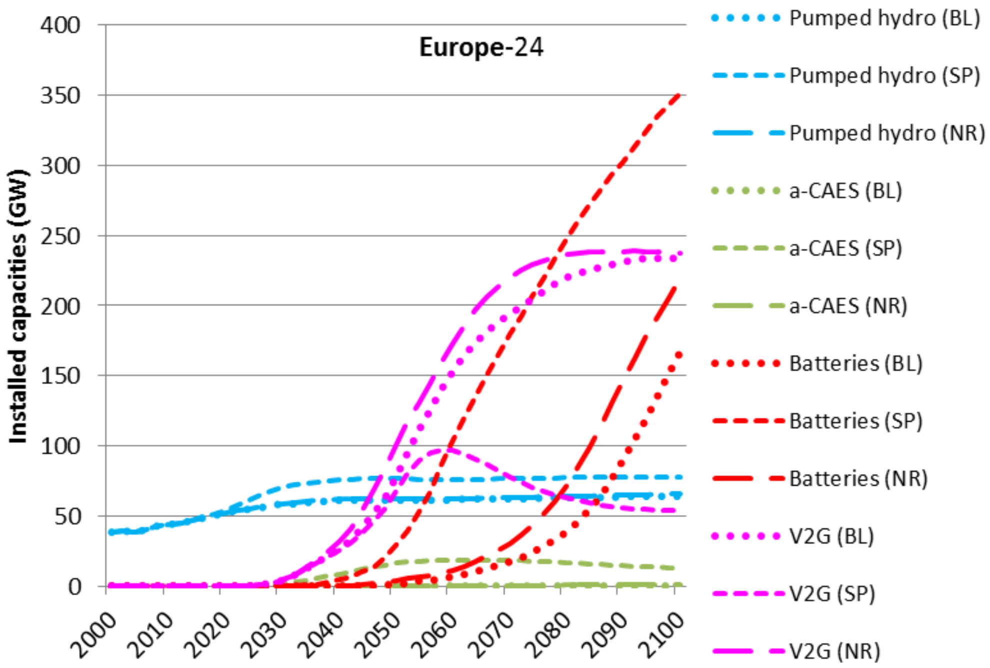

Figure 77: Installed capacities of all storage technologies in Europe for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

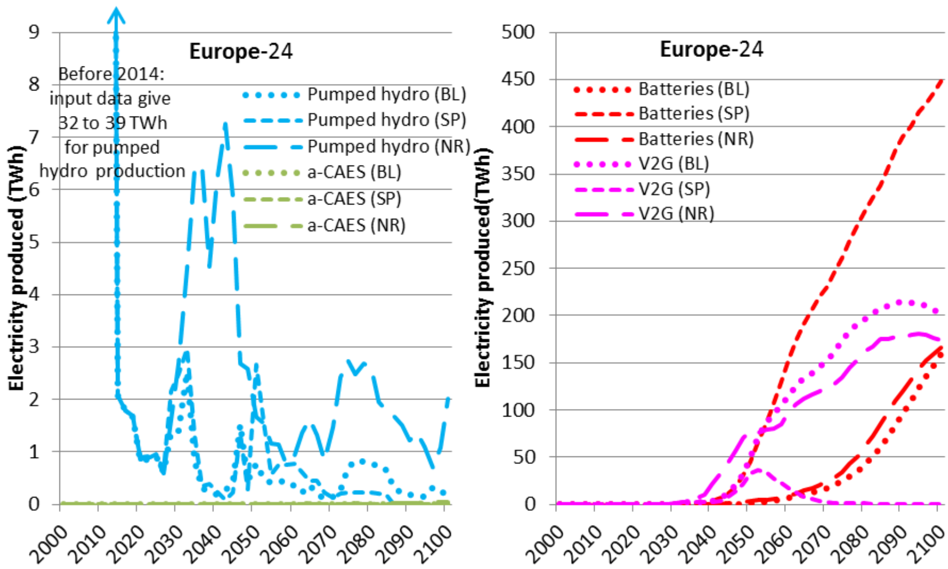

Figure 78: Electricity production of all storage technologies (pumped hydro and a-CAES left, V2G and batteries right) in Europe for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

The Storage Performance scenario gives an idea of the maximum storage capacities that can be expected in Europe – for a scenario with no energy policy. Pumped hydro and a-CAES reach 81 GW and 15 GW respectively for the entire Europe (compared to 68 GW and less than 1 GW in the baseline). However, they are still very little operated in EUCAD, as their efficiency is lower than the one of batteries or V2G. This is also the reason of the low impact of the New Renewable scenario on the development of pumped hydro and a-CAES. The main economic value justifying these investments is the capacity value, followed by the balancing value (these value do not appear in EUCAD's computation of the electricity produced as shown in Figure 78).

In the Storage Performance scenario, only V2G is less developed, while batteries are twice as much developed (compared to the baseline). The key drivers are the efficiency and the investment costs:

- In the Storage Performance scenario, the batteries' efficiency are assumed to increase more than V2G's (reaching respectively 88% and 84% in 2055[33]); thus batteries have higher operating hours than V2G and the economic value of batteries is higher in the SP scenario than in the baseline;
- Although batteries' investment costs are higher than V2G's (which explains the still strong development of V2G until 2060), the batteries' investment costs decrease faster in SP than in BL (thanks to its learning rate of 10% in SP, compared to 8% in BL).

The consequence is that, after 2060, V2G are totally replaced by batteries. However, the total of batteries and V2G is only around 2% higher in SP (414 GW) than in BL (405 GW).

The New Renewable scenario also has a noticeable impact on the technologies with higher efficiency (V2G and stationary batteries). V2G is developed earlier than in BL, but also reaches its potential sooner. Batteries take over and see a 30% higher development in NR than in BL.

Economic values of storage

Figure 79 shows the different economic value of batteries (energy value, capacity value and balancing value) in the three scenarios studied.

[33] The losses of a round-trip storage cycle for V2G may remain higher than stationary batteries because of non-optimal charging and discharging conditions, which can lead to much lower overall efficiency. See IV.2.3 for further sensitivities on the efficiency.

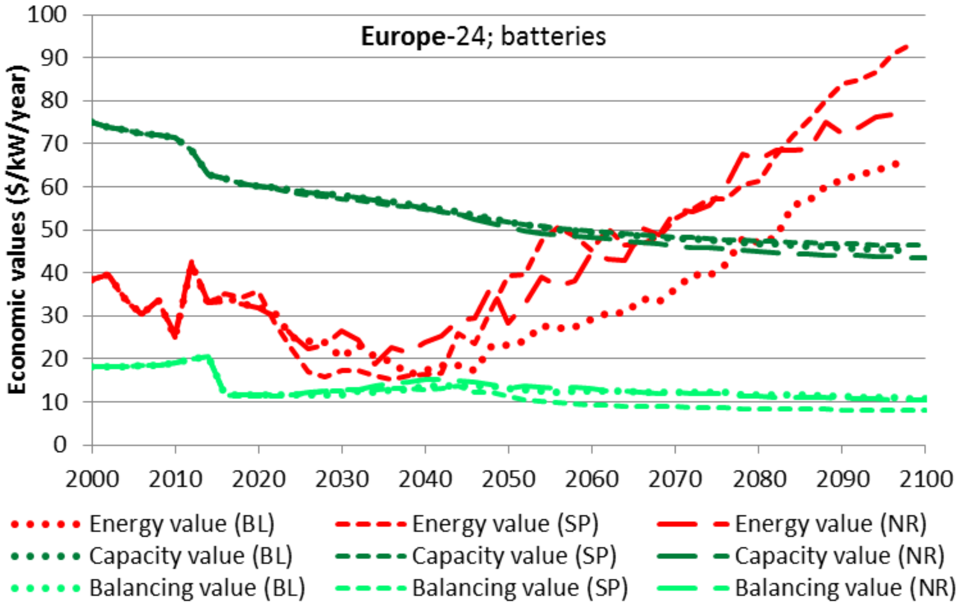

Figure 79: Economic values for batteries (energy, capacity and balancing values), averaged over Europe, for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

The most impacted value is the energy value. It is increased by around 20 $/kW/year in the SP and in the NR scenario, benefiting from its higher efficiency for SP and from a higher daily spread of prices for NR. Both SP and NR allow higher potential revenues for batteries in the energy-only market than in the baseline. This increased value induces higher investments. Batteries, as well as the other storage technologies, show a small impact of the Storage Performance and New Renewable scenarios on the balancing and capacity value; therefore we only show in Figure 80 the energy values of pumped hydro, a-CAES and V2G.

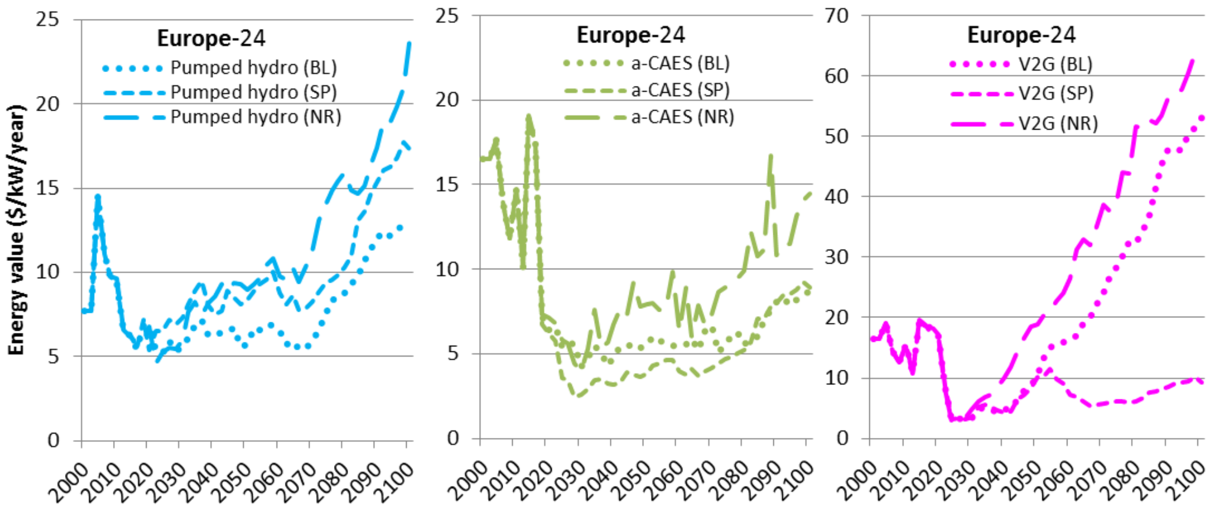

Figure 80: Energy value for pumped hydro (left), a-CAES (centre) and V2G (right), averaged over Europe, for the scenarios Baseline (BL), Storage Performance (SP) and New Renewable (NR) (POLES+EUCAD).

This figure shows that the higher investment in pumped hydro in the SP scenario is not really driven by a higher energy value (it is rather linked to the lower O&M and investment costs, see appendix K). The impact on a-CAES is even smaller. V2G, however, sees a strong decrease of their economic value, linked to its low utilisation (it is replaced by batteries, as explained earlier).

The New Renewable scenario gives a higher energy value for all storage technologies, because the daily spread of prices computed in POLES is higher (more solar production at noon, more peaking consumptions). However, this is not necessarily synonymous with higher operating hours when we use the optimisation of EUCAD instead of the simulation logic of POLES (see Figure 78, where V2G is less used in NR than in BL, even if the energy value of Figure 80 shows the opposite).

IV.2.3. Battery storage sensitivity to technical and economic performance

We extend the analysis of the Storage Performance scenario by testing the sensitivity of storage development to the technical and economic characteristics of storage. In appendix B we study the impact of the maximum potential for development of the different storage technologies. We focus here on the development of batteries. Indeed, the other represented technologies are more limited in potential (pumped hydro, V2G) or in efficiency (a-CAES) and so they respond less to the modelling assumptions. On the other hand, batteries are expected to expand strongly. The Research and Development (R&D) in the field is dynamic, which could lead to significant improvements in the technical and economic performance (i.e. the round-trip efficiency and the costs). The scaling-up of the battery manufacturing may also bring strong cost reductions.

Battery development sensitivity to efficiency

First, we consider the development potential of batteries for a range of efficiencies. In the baseline scenario we used an efficiency of 80%, which may be lower than some commonly used figures of 85 to 90%. However, in this number we include all possible losses related to a round-trip storing cycle (e.g. the non-optimal use of the converters, the non-optimal management of the state-of-charge of the battery, or even the losses for cooling down the room when operating the battery). The sensitivity of battery development with the efficiency is shown in Figure 81, both in terms of installed capacities and stored electricity.

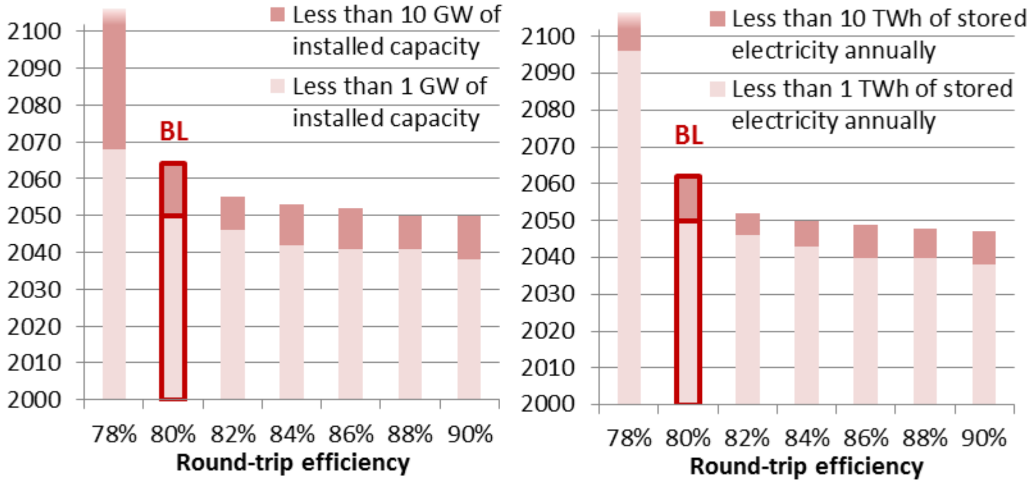

Figure 81: Sensitivity of battery development to the efficiency, in terms of installed capacity (left) and stored electricity (right) in Europe. Based on the baseline scenario (POLES+EUCAD).

Increasing the round-trip efficiency has a strong impact on the development of batteries, especially since it competes with other storage technologies. The effect is strong and non-linear here because of V2G storage, which efficiency remains 80%. Once batteries have a higher efficiency than V2G, they are used in priority over V2G and develop faster. Additional improvements to the efficiency do not really move forward the battery installation and operation. On the other hand, another test with 78% efficiency shows that the 10 GW- and 10 TWh-threshold are not reached before 2100. In this case, V2G (which is much less expensive than stationary batteries but is assumed to have an 80% efficiency) seems to be enough to cover the storage needs, without the need for batteries.

The efficiency defines which technology is operated, once it is built. The efficiency also impacts a portion of the economic value (the energy value), which in turn influences the investments. However, the other values (capacity and balancing) are (almost) not impacted by the efficiency.

Battery development sensitivity to fixed costs

We also assess the sensitivity of battery development to economic parameters. The main ones are the investment cost and the O&M costs (fixed and variable). The learning rate (i.e. the speed at which the costs decrease when the cumulated capacity doubles[34]) determines how the fixed costs evolve. Figure 82 shows the sensitivity of batteries to the learning-by-doing coefficient.

[34] There is also a coefficient for the learning-by-searching, i.e. the amount of cost reduction for each doubling of the R&D spending, but we consider it is small and has less impact.

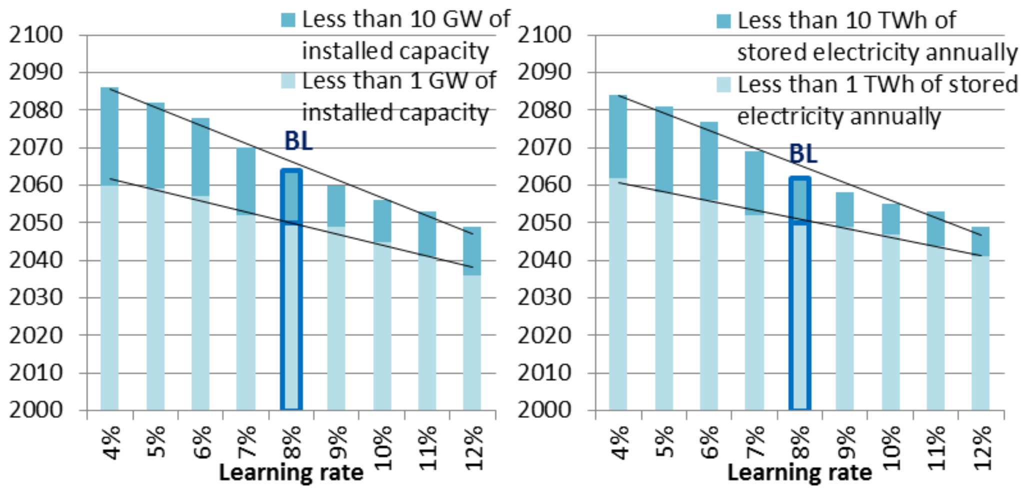

Figure 82: Sensitivity of battery development to the learning-by-doing coefficient, in terms of installed capacity (left) and stored electricity (right) in Europe (based on the baseline scenario; POLES+EUCAD).

It is clear that increasing the learning rate accelerates the development of storage. For each additional percentage point of learning rate, the 10 GW-threshold and 10 TWh-threshold are moved 4.8 years forward (respectively 3 and 2.5 years for the 1 GW- and 1 TWh-threshold).

This analysis supports the conclusion that decreasing the fixed costs (investment and O&M) is a key driver for reaching an earlier development of battery technologies. Indeed, it is the basis for investment decisions. Its influence appears to be higher than the efficiency.

Both the operation and building of batteries depend on a competition with the other storage technologies (mainly in terms of efficiency for the operation and of costs and economic value for investments). Our analysis suggests that it is more interesting, in our particular context, to concentrate on decreasing the fixed costs (either investment or O&M costs) than increasing the battery efficiency. However, the working hypotheses of the baseline scenario raise a *caveat*: batteries already have the highest assumed efficiency, so that only their costs (in particular relatively to V2G) are influencing their development.

On the other hand, if the availability of raw materials or rare earth is lower, prices will not go down as quickly, which could postpone the battery investments until the end of the century.

As for the other storage technologies, a-CAES offers a low investment cost but is little developed (its efficiency of 65% is substantially lower than the other storage technologies). Pumped hydro, with a lower investment cost than batteries and a reasonably high efficiency (75%), is situated in-between these two extreme situations (a-CAES with a low cost but low efficiency, batteries with a high cost and high efficiency). We observe that pumped hydro develops quickly, illustrating again that the cost factor is outweighing the efficiency benefits.

In the next section we look at a scenario with climate action: a carbon value is implemented in POLES, which changes considerably the energy mix and storage development.

IV.3. A scenario with a climate-friendly energy policy

We present here a different vision of the future than the baseline scenario presented in IV.1. It is based on a strong energy policy that ensures 66% chances of limiting to 2°C the global warming at the end of the century, compared to the pre-industrial era. The lever used in POLES is a worldwide carbon value (see appendix L), which is set to 18.3 $/tCO_2$ in 2020 but increases steeply afterwards (735 $/tCO_2$ in 2050, 963 $/tCO_2$ in 2100). All the main figures presented in IV.1 for the baseline scenario are in appendix L; we present here a few highlights of this "Climate Policy" scenario (CP), compared to the Baseline (BL) scenario. First we look at the entire energy and power sector, then we focus on the impacts for electricity storage.

IV.3.1. Impacts on the energy and power sector

Impacts on the different energy sources

The strong carbon value has impacts on the use of fossil fuels, which keeps their prices at a lower level than in the baseline scenario. The overall energy demand with the strong carbon value is much lower than in the baseline, especially for these fossil fuels (see Figure 83).

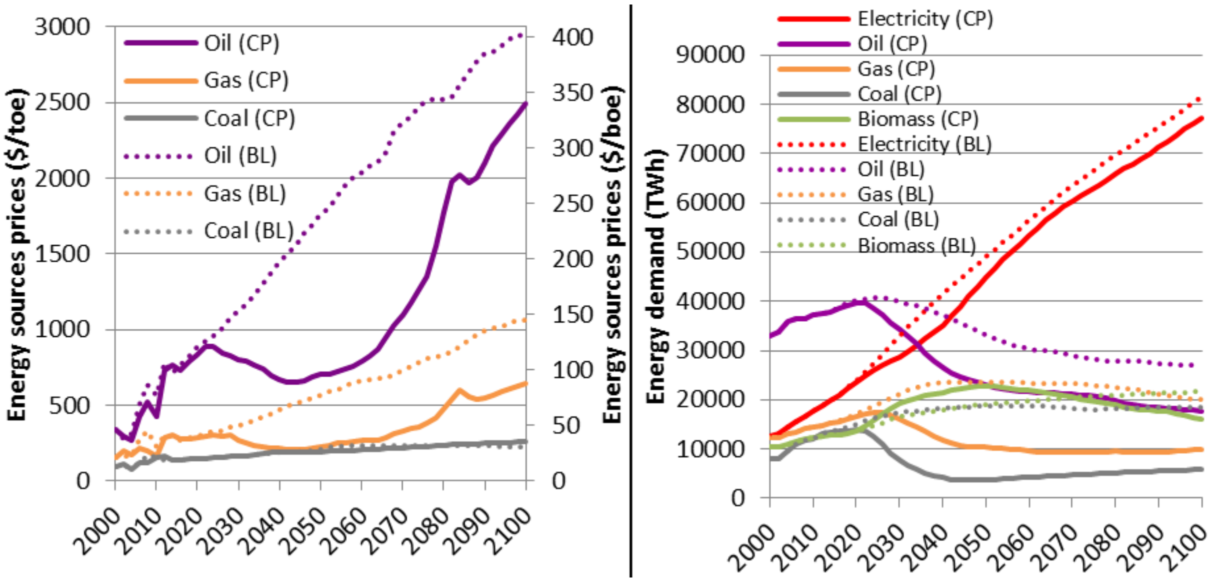

Figure 83: Fossil fuel prices (left) and global final energy demand by fuel (right), compared between baseline (BL) and climate policy (CP) scenarios (POLES+EUCAD).

The resources are not used as much as in the baseline scenario, with a strong decrease between 2020 and 2040. The demand for oil, coal and gas are much smaller, partly transferred to electricity (e.g. in the transport or in the heating sectors).

Impacts on the installed electric capacities

The main differences in installed electric capacities in Europe (EUCAD's 24 countries) are shown in Figure 84 (the figures for the entire world, for France and for Germany are included in appendix L).

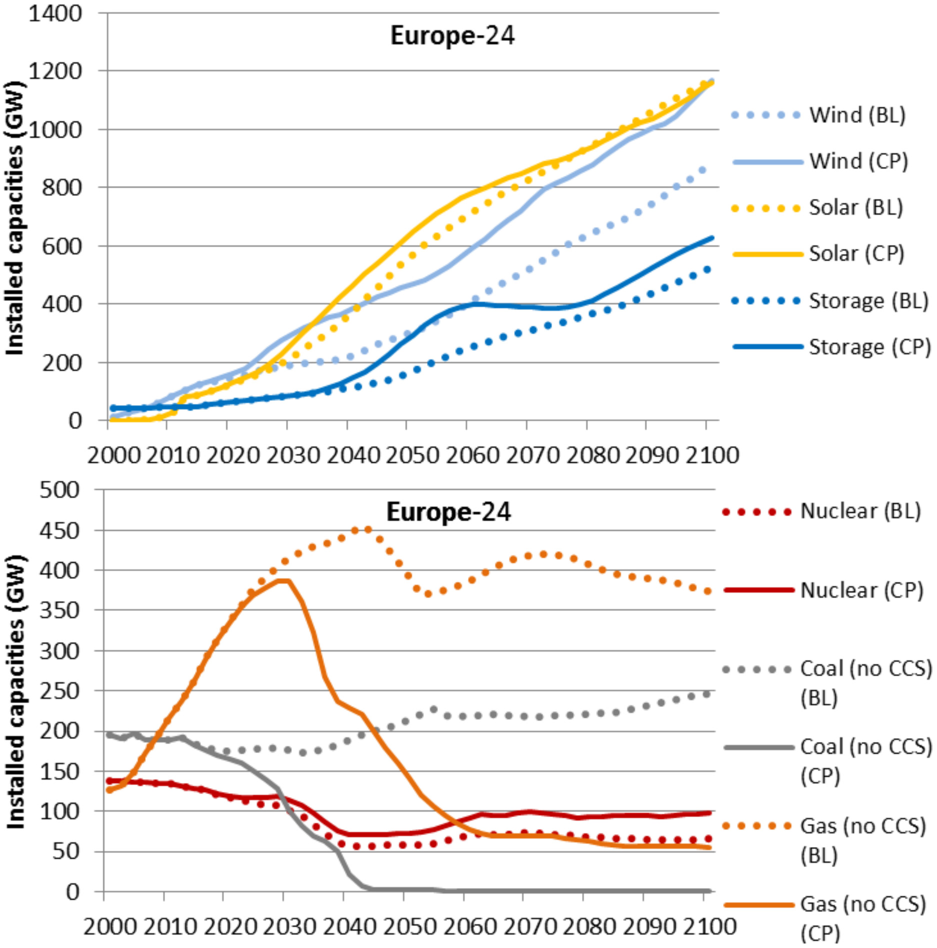

Figure 84: Electricity production capacities in Europe-24, compared between Climate Policy (CP) and Baseline (BL) scenarios (POLES+EUCAD).

Electricity producing technologies based on coal and without CCS are almost abandoned after 2040, pushed out by the strong carbon value. The same happens after 2050 for gas power plants without CCS. This is compensated by the development of CCS technologies (not shown here, see appendix L), which reach 1921 GW in Europe in 2050 (204 GW of coal, 1717 GW of gas) and 2150 GW in 2100 (573 GW of coal, 1577 GW of gas). In France only, 40 GW of CCS power plants are developed in 2050 (mainly gas) and 75 GW in 2100. Gas associated with CCS is preferred to coal with CCS because there is less CO_2 to store and the total production cost is smaller.

The decarbonised technologies are developed faster in the climate policy scenario. Storage plays a more important role in the power system than in the baseline scenario. It has a faster development in the 2040 decade, further analysed in IV.3.2.

Impacts on the power supply

The abandonment of coal power is also visible in the energy produced, and even sooner than the existing producing capacities: in 2030 coal without CCS does not produce anymore in Europe. The French and German power supply are quite different than in the baseline scenario, as visible when comparing Figure 56 and Figure 85.

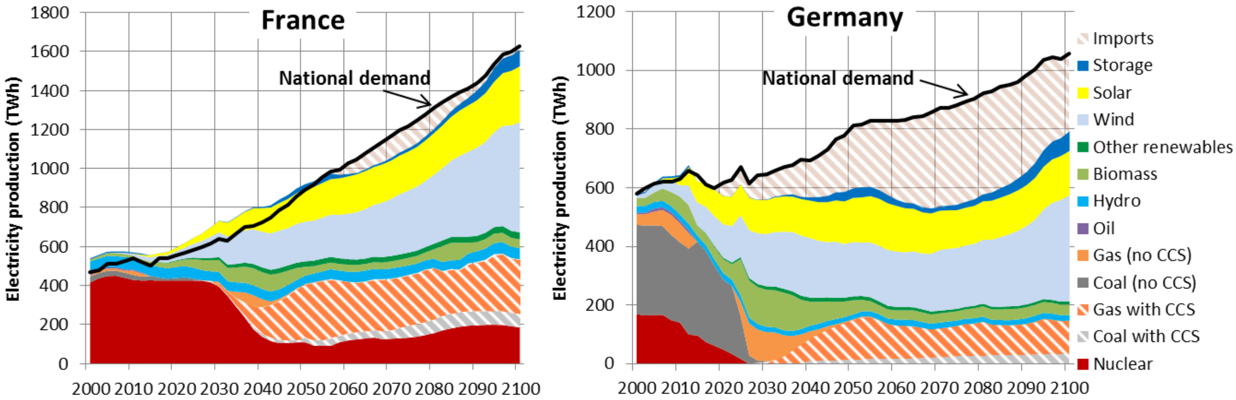

Figure 85: Electricity production in France (left) and in Germany (right). Climate policy scenario (POLES+EUCAD).

In the climate policy, a strong development of gas with CCS replaces the drop of French nuclear power (due to the end of life of the current reactors) and German coal power (including the very polluting lignite power plants). VRES represent 40 to 50% of the electricity consumption, after 2040 for France and after 2025 for Germany. The balance of exports and imports is largely different from the baseline scenario (in the climate policy, France is almost balanced instead of being largely importing, while Germany imports a much higher proportion of its electricity).

Electricity costs and prices

The decomposition (by technology and separated between fixed and variable parts) of the European average electricity production costs is shown in Figure 86 for the climate policy scenario.

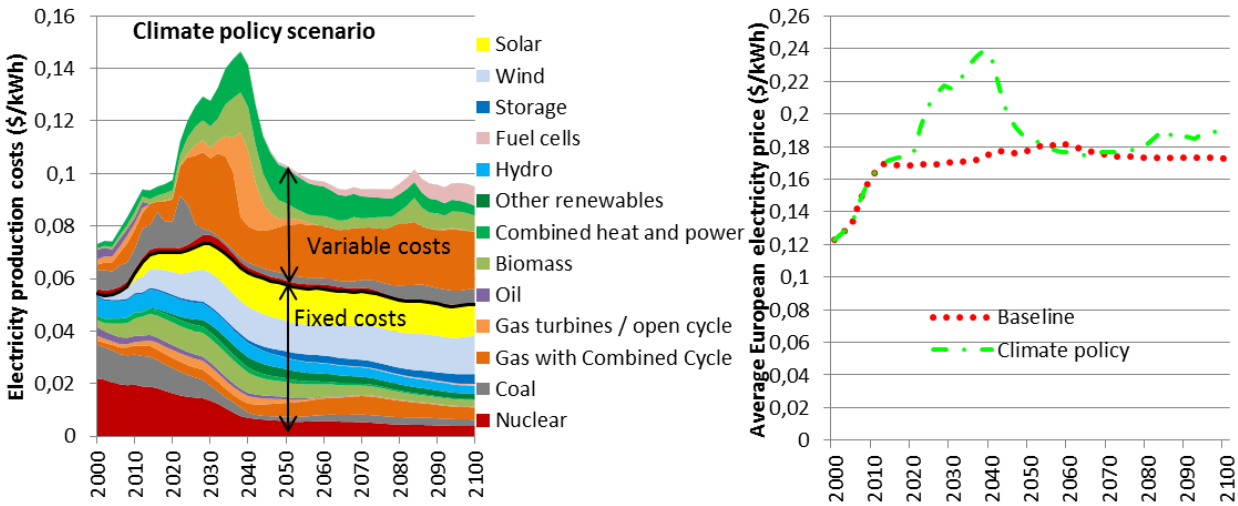

Figure 86: Electricity production costs (left) and electricity prices (right), compared between the baseline (BL) and the climate policy scenario (CP) (POLES+EUCAD).

There is a price peak between 2020 and 2040, due to the abandonment of conventional coal power plants and the switch to gas power plants. Renewable technologies also develop but only start to offset the gas turbines and open cycle gas power plants after 2040. This reduces the production costs and the prices to a level close to the baseline.

CO2 emissions

The following Figure 87 represents the emission trajectory of the climate policy scenario, relative to the previously presented Baseline and New Renewable scenario.

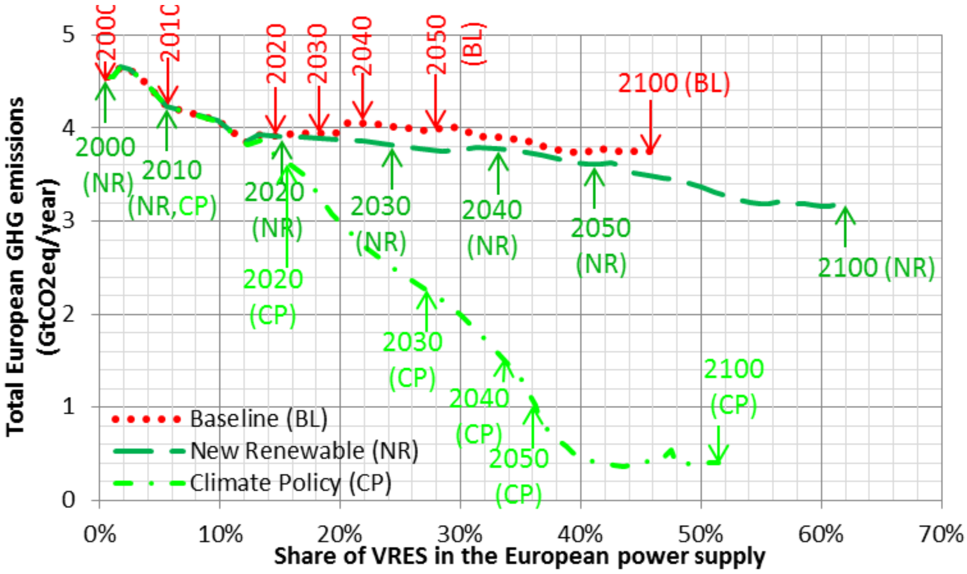

Figure 87: European GHG emissions evolution, in relation to the share of VRES in the power supply, compared between baseline (BL), New Renewable (NR) and Climate Policy (CP) scenarios (POLES+EUCAD).

The impact of the carbon value on the European GHG emissions is much higher than the mere reduction in wind and solar investment costs (New Renewable scenario), although the share of VRES in the power supply mix is smaller (52% in 2100 for CP, compared to 62% in NR). The rest of the GHG emission reduction is attributable to a lower energy demand and to the development of CCS technologies.

IV.3.2. Impacts on electricity storage

The installed storage capacities are shown in Figure 88.

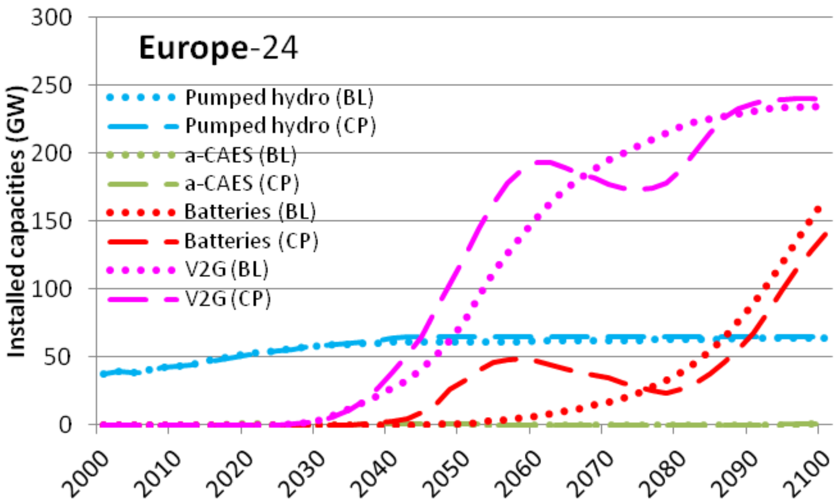

Figure 88: Installed storage technologies in Europe, compared between the Baseline (BL) and the Climate Policy (CP) scenarios (POLES+EUCAD).

With the same storage hypotheses as in the baseline scenario, the investments in pumped hydro and a-CAES are not changed, contrary to V2G and stationary batteries. The development of batteries starts around 2040, which is 10 years earlier than in the baseline scenario, and develops much faster until 2055. V2G also develops faster until 2055. Then we observe a plateau of battery capacities and an decrease of V2G capacities. The V2G and stationary battery increase again around 2080. In 2085 V2G is limited by its potential (i.e. 60% of all existing EV); batteries take over and increase faster. This investment structure is very different from the baseline scenario. We analyse the two peaks of investments, in the 2040 and 2080 decades and find two different kinds of energy value for storage.

1/ A high carbon value

There is a dynamic effect in the development of gas capacities with CCS: they are only progressively developed after 2030 because the CCS technologies needs time to develop. Therefore, other technologies without CCS are still needed in the 2040 decade, creating a high opportunity for storage: the differences in production costs between technologies with and without CCS are very high. This effect almost disappears around 2070, when gas with CCS becomes predominant[35]: being used both for semi-base and peaking capacities, the price spread[36] is reduced to zero in most days, and storage has less/no value.

2/ A solar surplus at noon

After 2070, gas with CCS stabilizes and storage finds another high value, the coupling with solar. The excess production in the middle of the day is absorbed, thus avoiding the operation of expensive capacities at night. This represents a rather stable income for storage because solar production is often in surplus.

[35] The strong development of gas with CCS is necessary for meeting the peak demand. Daily storage cannot replace these dispatchable production capacities.

[36] The price spread computed in POLES and EUCAD aggregates all power plants of the same technology, which overlooks possible cost differences between power plants.

In short, the first fast development of storage is mostly driven by the strong increase of the carbon value (which leads to a progressive development of CCS technologies), while the second ramp up of storage answers the challenges of the high VRES deployment (in particular the solar surplus production).

Conclusion of chapter 4

In this chapter we presented several scenarios carried out with the POLES+EUCAD model described in the previous two chapters. First we looked closely at the baseline scenario used in this work, which is a scenario without any energy policy and with a strong role of electricity in the energy sector. Nonetheless, the development of VRES reaches 28% of French electricity production in 2050 and 46% in 2100. We analysed the installed capacities and power supply, for Europe (24 countries), for France and for Germany; since no carbon value is implemented in this scenario, the fossil fuels are still extensively used and no CCS technology is developed. The major expected evolution is the growth of wind and solar productions, covering the major part of the increase in energy demand. With our working hypotheses (no carbon constraint, no energy policy), nuclear power decreases, replaced by coal and gas. Cheap and flexible gas turbines are preferred to combined cycle gas power plants (at the expense of CO_2 emissions), in order to accommodate for the variability of wind and solar power.

As for flexibility options, we found a strong development of V2G and demand response with our baseline storage hypotheses. For different tested values of maximum installable potential, they reach it this potential, driven by their low investment costs compared to their high system value (displacing load, but also participating in the available capacities in periods of high residual load and participating in the ancillary services). The relatively low investment cost of pumped hydro also brings an early development, although it is driven by the capacity and balancing values rather than the energy value. Adiabatic CAES has a low development, penalised by its low efficiency. Most of the investments in the lithium-ion battery technology take place in the second half of the century, when the energy value of storage really rises. However, the investment decisions are very sensitive to the lifetime; a lower lifetime hypothesis for stationary batteries delays their development until the very end of the century. An analysis carried out with EUCAD shows a real value of storage for reducing surplus energy curtailment, but also for reducing the average electricity production cost of the system. More generally, the system value of storage appears significantly positive in the second half of the century, in this baseline scenario and with this chosen set of technical and economic parameters of storage.

Then, we compared the baseline case with two other scenarios, one pushing further electricity storage by using higher technical and economic performance assumptions, another encouraging VRES development through reduced investment costs. The Storage Performance scenario has a small influence on other installed capacities, but still allows a slightly higher VRES penetration and lower average electricity production cost. On the other hand, the scenario with strong VRES development shows a significant development of flexibility options such as gas turbines and storage technologies – in particular batteries.

We also carried out a set of sensitivity scenarios that study the development potential of storage technologies (here, batteries) with respect to their investment cost and efficiency. We find that the battery development is particularly dependent on the learning-by-doing effect on fixed costs. On the other hand, the role of efficiency in the economic value is much smaller – at least for stationary batteries, which already have the highest efficiency with our hypotheses. Therefore, we advise a stronger effort towards the reduction of fixed costs than towards the efficiency improvement – although the efficiency should not be left behind, as its role is determinant in the operation of the power system.

Finally, we present a scenario with a strong energy policy that reaches the 2°C maximum global warming target. This scenario offers a different vision, compared to the baseline scenario. Coal power plants are mostly stopped by a strong carbon value, while gas power plants take over in a first transitional period. Then, CCS technologies rise and gas power plants with CCS replace all fossil-fuelled power plants without CCS. The result of this scenario is a stronger wind and solar development, and a high development of CCS. This allows the global GHG emissions to drop considerably between 2020 and 2040. Storage plays a more important role, at first by avoiding the use of power plants without CCS, and then by integrating the solar surplus of the middle of the day. This creates two different storage investment stages, first around 2040 and then around 2075.

* * *

We summarise our conclusions in a SWOT (Strengths, Weaknesses, Opportunities, Threats) analysis for lithium-ion batteries (Table 13).

Strengths	Weaknesses
- can operate for several hours in a day, which increases its value (compared to V2G) - highest efficiency available (among our storage technologies)	- High fixed costs - Reduced life-time
Opportunities	**Threats**
- High learning rate allows sooner investments - Could substitute V2G if efficiency also progresses faster	- A slower learning rate - An increase in the price of raw materials or rare earths necessary in the batteries - Losing the efficiency advantage to a cheaper technology (technological breakthrough)

Table 13: SWOT analysis of stationary lithium-ion batteries.

Other technologies with high economic value such as pumped hydro or DR are not threats to batteries since their potential is quite limited and prevents them from really competing with batteries once these become affordable.

Conclusion and perspectives

Conclusion on the role of storage in long-term energy scenarios

The ongoing energy transition is poised to bring high shares of variable renewable energy sources in the power system, mainly wind and solar. However, the impacts of these variable energy sources on the power system are not negligible. A power system breakdown (e.g. black-outs) can be avoided thanks to flexibility options that could compensate the wind and solar variability. These options consist in the development of flexible power plants, storage technologies, demand response and grid infrastructure. The specific focus of our work is on storage, but we consider the entire power system since each of its components is linked to the others in the continuous balance between power supply and demand.

Long-term energy modelling tools are commonly used to study long-term scenarios of the energy system and power sector. Our first contribution to this scientific area is the development of a common approach to categorise any energy model or power sector modelling tool. The different criteria were designed as a functional guide for understanding how a model compares to others, in particular concerning the issue of wind and solar integration in the power system. Given that the particularities of storage are not well described in state-of-the-art energy models, we identified a need for improvement.

Our second contribution to the long-term energy modelling field has been carried out on the POLES (Prospective Outlook on Long-term Energy Systems) model. The detailed technological description of this simulation model makes it an interesting basis, but, as for many other long-term energy models, it did not – prior to our work – explicitly account for storage. Besides, its representation of the variability of wind and solar power was non-existent. Therefore, we developed and implemented a novel representation of the power system operation and of the investment mechanisms for power plants, storage and grid interconnections. Thanks to a residual load duration curve of 648 time slices per year (54 days divided into two-hour blocks), the yearly variations of wind and solar productions are now better represented. On one hand, it allows the simulation in POLES of the dispatch of electric vehicle charging, storage and demand response operation. On the other hand, the power plants' investment mechanism is much improved by this new approach, which now shows how the variability of wind and solar power slashes the expected full load hours of dispatchable power plants, while high investments in peaking capacities are still necessary. The storage plants' investment mechanism is added, including several economic values (energy, capacity and balancing values). A single value would not be enough for justifying storage investment, and would not represent the wide spectrum of storage values. The competition of storage with already existing flexible options (storage, demand response and fast-reacting thermal capacities) is included.

However, this first series of improvements does not entirely address the scientific challenges faced by long-term foresight models regarding the representation of storage and the integration of wind and solar power. In particular, the necessary time-step and technical detail for these challenges call for a new modelling approach. Our third contribution, which we believe is the main progress of this thesis work on the state-of-the-art, is the direct two-way coupling of the long-term energy model POLES with a short-term power sector optimisation tool. Indeed, the precise representation of the power system operation is more appropriately represented in an optimisation model, which can take into account the technical dispatching constraints of thermal power plants, the grid constraints of the interconnections, and the constraints associated to the different forms of storage. This is why we developed EUCAD (European Unit Commitment And Dispatch). It minimises the operating cost of the entire European power system. It allows a representation of electricity storage (hydro pumping, adiabatic CAES, batteries, hydrogen), as well as specific constraints for thermal power plants (e.g. ramping capabilities), hydro power (water inflow), electric vehicles (charging, and discharging with V2G), demand response (load shifting and rebound effect) or international exchanges. EUCAD has been tested on a real situation (France in 2013), then applied to several typical days per year (chosen with a clustering algorithm) in order to include a certain level of diversity of the European wind and solar production. Then, we coupled POLES with EUCAD in order to benefit from the long-term coherence of an energy scenario in POLES on one side and of the technical detail of EUCAD on the other side. The results of EUCAD are used in POLES, thereby significantly strengthening the representation of the power supply, storage operation, international exchanges and surplus energy curtailment. In this way, EUCAD’s feedback to POLES also impacts the investment planning. We summarised this new coupled model using the typology developed in the first chapter; it clearly emphasises the benefits drawn from this new direct coupling, while the computing times remain reasonable.

Finally, we analysed several scenarios produced by this new approach. First, we present a baseline case (without any energy-environment policy), for comparison with the other scenarios. We find that, for our baseline scenario, storage technologies are expected to be significantly developed mostly in the second half of the century. This finding remains very sensitive to the life-time of Lithium-ion batteries. Next, we carry several sensitivity analyses: a variation with high performing storage technologies (technically and economically), and a variation with cheaper wind and solar power (through exogenous investment costs). Our analysis demonstrates the mutual influences of storage and VRES: a higher storage performance allows a (slightly) higher development of VRES, and a higher development of VRES implies a (significant) increase in storage development. The variability of wind and solar requires very flexible capacities (gas and oil turbines) and storage capacities, especially when the development of wind and solar is fostered by lower investment costs. Finally, we present a climate-friendly energy policy scenario, based on a strong worldwide carbon value. This scenario shows a different perspective for the energy system, with a significantly reduced energy demand and a strong development of renewable and CCS technologies that replace conventional coal and gas power plants. Storage is also affected and benefits from two different types of economic values: avoiding the operation of technologies without CCS – thus reducing the GHG emissions and avoiding the carbon taxes – and integrating the solar surplus in the middle of the day. This creates two waves of investment in storage.

The sensitivity of storage to its efficiency and costs is also tested with a range of other scenarios. The relative efficiencies of the different storage technologies impact their operating hours, which in turn affect their economic value. However, it appears that the fixed costs of storage are even more decisive in the development of storage. We would recommend to direct research and industrial efforts in priority towards the reduction of costs – especially for the technologies which efficiency is already higher than pumped hydro. Technologies with lower efficiency but also lower investment costs can still develop (e.g. pumped hydro), relying more on their balancing and capacity values. Technologies with a low efficiency, such as a-CAES, should first focus on improving their efficiency, in order to bring it closer to the rest of the competition (e.g. 75%).

In conclusion, our work allows the study of storage in the future power system by enhancing a long-term energy model and coupling it with a short-term operation model. We demonstrated that storage becomes really valuable for the system in the second half of the century, even in a “no policy” scenario. A different scenario with a 2°C energy policy sees an earlier storage development and shows two different values for storage: avoiding GHG emissions of technologies without CCS, and better integrating the solar surplus at noon. With the chosen working hypotheses, the installed capacities in storage become significant after 2050. The storage technology that stands out to benefit from this economic value depends on the life-time of batteries. Variable renewable energy sources do have an impact on storage development, as well as on the development of flexible peaking capacities. The connections between peaking capacities, storage, demand response and grid interconnections are difficult to disentangle; there is no direct relationship between the share of variable generation and a necessary storage capacity. The storage need can only be determined through a specific study that includes the rest of the energy system. The dynamic evolution of the system is also fundamental to the study of electricity storage, because of the long time constants of the power system and the learning effects for new technologies. Our modelling allows such an approach, even though there are still some perspectives for improvement.

Perspectives

Other scenarios exploring decarbonized energy systems could be carried out that we do not have the time to analyse here. They may for instance incorporate different levels of energy demand, carbon values or specific energy policies (e.g. nuclear development in France). It is also up to future users to add other storage technologies or other constraints on the power system operation. Thanks to a concise coding of EUCAD, the model is easily adaptable. Many modelling assumptions were necessary to complete the modelling of storage, in particular regarding the investment mechanism. They are a best guess of the real life mechanism, but further knowledge on the subject could enhance the assumptions. The important point is that the storage modelling capability is now included in POLES+EUCAD. Other perspectives to this work are presented here.

Load profile

The focus of this work is on the wind and solar variability, which plays a huge role in future power systems; however the load profile could also be improved. One could apply the same clustering algorithm to the load as the one used for wind and solar power. This could be used as an improved input data for EUCAD.

The residual load duration curve in POLES could also be improved by using a clustering algorithm instead of the high, medium and low days of demand, wind production and solar production. This would presumably reduce the number of time slices (currently, 648), which tend to slow down the model and lead to data storage problems[37].

Power system operation

Non-European countries do not benefit from the technical detail brought by EUCAD yet. It could easily be extended, once the input data are available (consolidated data on the hydrogen sector and the hydro productions and installed capacities, potential interconnection capacities with neighbours). This would presumably not slow down EUCAD too much, since Europe is the biggest interconnected network in the world; other smaller international networks would be quicker to compute[38].

Some improvements could be carried out on EUCAD; indeed, the remaining discrepancies between the model results and the reality of the French power system could be corrected. The uncertainties of the real time market (forecasting errors) could be added in order to include a shorter horizon of variability of wind and solar (intra-day). Some unit commitment models already take into account the impact of wind uncertainty [205,232,233] and develop stochastic unit commitment models. However, one should keep in mind the expense of the computing time.

Storage operation could be improved by a representation of the balancing market, which may increase the use of storage. A longer-term storage (in particular for pumped hydro and a-CAES) could also be added, for example by solving week-days and weekend-days, or by doing a preliminary optimisation of the water management across the year (e.g. at the weekly scale [160]). A remaining question not addressed here concerns the links between the different represented values of storage (in particular ancillary services and arbitrage) and how they may impact its operation.

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[37] The Vensim software used for POLES can currently only save one every two years computed in order to avoid the data overflow – an update of the software used for POLES would also solve this last problem.

[38] Nearly all European interconnected countries (excepting the Baltic and Balkan regions, and the neighbouring areas such as Morocco and Russia) are already included; all countries not interconnected with Europe would be computed independently (and therefore, in a much faster time).

Grid representation

First, the maximum installable interconnection lines between European countries could be improved if some data were available or with realistic country-specific assumptions.

Second, the European-wide optimisation of EUCAD has a very simple representation of the power flow, corresponding to commercial contracts. This could be improved with a DC load flow (commonly used in unit commitment models) or even an AC load flow (more detailed but much longer to compute). This would likely increase EUCAD computation time. However, it could also bring additional details on the grid congestions. Eventually, it would provide valuable input to the interconnection investment mechanism.

A security constrained optimal power flow could also be used, in order to check the security of the unit commitment and dispatch in case of a line, load or generator outage.

In any case, the electric grid should be geographically more detailed than a single node per country, both in POLES and EUCAD. Indeed, some grid constraints can also appear within a country.

Finally, the grid should be better taken into account in the investments of the rest of the power system (e.g. in the residual load duration curve).

Other decision variables for storage development

We think that the investment mechanism for storage could be improved with other factors than energy, capacity and balancing values.

First, the regulatory framework is crucial for the development of storage in both large-scale plants and small-scale devices. For large-scale storage installations, the market prices should ensure that the capacity value of storage is rewarded, either with peaking prices or with a dedicated capacity market. The way grid taxes are levied among producers and consumers should also be adapted for storage plants (in 2015 in France, the profitability of pumped hydro operators is greatly affected by the taxes they have to pay on the totality of the stored electricity). This also holds for small-scale storage devices that would want to sell their stored energy by using the grid. In addition, the price variations for the end-user are crucial for storage development. However, for now, many market designs offer fixed rates to the consumer (thereby shaving-off the peak prices and not passing-on the lowest prices). The current (or near-term) development of smart meters can enable more dynamic pricing offers – although it is not a guarantee in itself.

Second, the battery system costs may decrease sooner than simulated in our exercises, thanks to other markets for storage. Some market opportunities may appear in countries with high electricity prices, whether they are caused by taxes and levies (e.g. Germany), by grid costs (e.g. countries with low population density) or by production costs (e.g. islands). This can incentivise some actors to go off-grid, using renewable resources and storage. As an example, a development of small-size battery storage is probable in Germany in the coming years (i.e. before 2020), as owners of solar panels will want to consume a higher share of their own electricity (produced at a lower rate than the retail price). Another cost reduction potential is the development of batteries for mobile applications such as electric vehicles. The large-scale manufacturing may result in a simultaneous reduction of stationary battery's costs. However, each battery application (depth of discharge, maximum power drawn from the battery, etc.) requires a different design (e.g. the electrolyte membrane), which may reduce the cross-sector learning-by-doing. Besides, the battery system costs are often much more expensive than the battery pack in itself (due to installation costs, to the inverter, etc.); distinguishing the evolution of each component in a long-term foresight model is not easy. Moreover, the life-time of batteries is also a critical factor to their development.

Another key factor influencing the investment costs and potential of development of storage (just as for other electricity technologies) is the raw material needs, in particular for lithium and rare earths used in batteries. Any progress on the recycling of batteries may alleviate this constraint, but the technical difficulty is real.

Finally, the storage development depends more generally on political considerations, industrial strategies, environmental concerns and social factors such as the involvement of citizens in their energy supply chain. All these aspects are difficult to include in a global long-term energy model, since they are very country- and time-dependent.

Appendices

Appendix A: POLES' power generating technologies

POLES has 41 technologies represented, listed in the tables below.

Fuel	Technology name	Description
Nuclear	NUC	Conventional nuclear design
	NND	new nuclear design (4th generation)
Coal	PFC	pressurised coal supercritical
	PSS	pressurised coal supercritical with CCS
	ICG	integrated coal gasification with combined cycle (CC)
	ICS	integrated coal gasification with CC and CCS
	LCT	Lignite
	CCT	Coal Conventional Thermal
Gas	GCT	Gas Conventional Thermal
	GGT	Gas turbine
	GGC	Gas CC
	GGS	Gas CC with CCS
Oil	OCT	Oil Conventional thermal
	OGC	Oil CC
Water	HRR	Hydraulic run-of-river
	HLK	Hydraulic with reservoir (lake)
	HPS	Pumped hydro
	SHY	Small hydro (<10 MW)
	OCE	Tidal and wave
Earth	GEO	Geothermal
Biomass	BTE	Biomass Conventional Thermal
	BGTE	Biomass and Gasification
	BGAE	Biogas
	BCS	Biomass Conventional Thermal with CCS
	BTC	Biomass with combined heat and power (CHP)
	BGTC	Biomass and Gasification with CHP
	BGAC	Biogas with CHP
	BWC	Biodegradable waste with CHP
Wind	WN1, WN2,WN3	Wind onshore with different quality of the resource
	WO1, WO2,WO3	Wind offshore with different quality of the resource
Solar	CPV	PV power plant (centralised)
	DPV	Decentralised PV
	SPP	Solar thermal power plant
	SPPS	Solar thermal power plant with thermal storage
Decentralised technologies	CHP	Decentralised CHP
	HFC	Hydrogen fuel cell
	GFC	Gas fuel cell

Table A-1: Technologies of the electricity sector in POLES

We add new storage technologies, described in the following table.

Technology name	Description
CAE	Adiabatic Compressed Air Energy Storage with thermal storage
BAT	Lithium-ion batteries
V2G	Vehicle batteries used in Grid-to-Vehicle and Vehicle-to-Grid
DSM	Demand Response

Table A-2: New technologies of electricity storage in POLES

Each technology is aggregated to a country or region (individual power plants are not described). The characteristics of a technology are the following:

- Input: fuel, efficiency of the process, GHG emissions
- Development potential
- Maturity of the technology
- Lifetime
- Fixed cost, including installation costs, fixed O&M costs, CO2 sequestration cost for CCS technologies, subsidies or taxes
- Variable cost, including fuel costs, variable O&M costs, subsidies or taxes (in particular, the carbon value)
- Discount rate
- Historical installed capacities for each of the 57 regions or countries of the world
- Learning rate, including learning-by-doing and learning-by-searching

All these values can evolve over time, imposed by the user or driven by learning effects. For some technologies, there can be a floor investment cost, mostly used for technologies with small cumulated installed capacities and which grow fast.

Pumped hydro is already well established and its learning rate is low, therefore its costs almost stay at the historical level. However, batteries, a-CAES, V2G and DSM develop strongly in our scenarios, so a floor cost could be used to prevent abusive learning-by-doing effects in the early development stages. We decided to use 80 $/kW for V2G and DR. For batteries and a-CAES we do not use floor costs; instead, we fix exogenously the investment costs until 2020 by following the trend shown in [186] between 2013 and 2030 values. This ensures that the costs in POLES stay in line with the short-term estimates. It replaces a hazardous estimation of the floor cost of batteries; indeed, our test show that the investment costs can be very sensitive to the floor cost when we only use exogenous costs until 2013.

Appendix B: Storage and DR sensitivity to its development potential

We show here how the installable potential influences the investments in storage. Note that the investment mechanism is independent for each technology of storage or DR, but they take into account the existing capacities. Two effects are at play in the investment mechanism:

- the installation speed depends on the maximum installable capacities;
- once a technology reaches 80% of its installable potential, the installation speed decreases (such that it respects the maximum potential).

First, we show in figure B-1 the sensitivity of storage and DR to the V2G maximum installable potential.

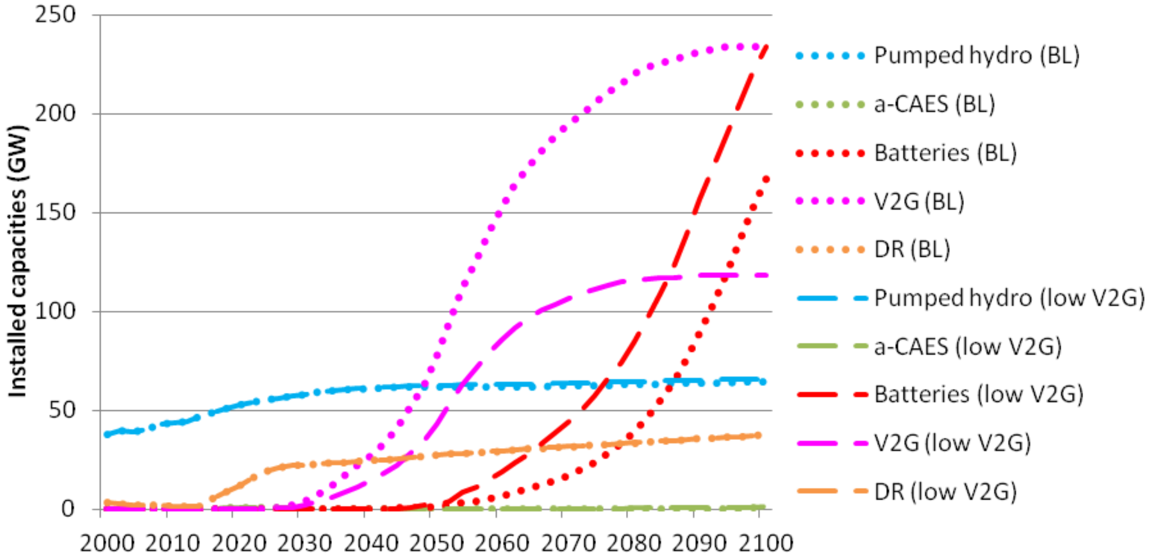


Figure B-1: Comparison of the development of storage and DR in Europe in the baseline scenario (BL) and in a scenario with a maximum installable potential in V2G at half of the baseline potential (low V2G) (POLES+EUCAD).

As expected when dividing the V2G potential by two, its development is twice as slow and half as high. The main effect on the other technologies is a higher battery development. Indeed, batteries have the same efficiency as V2G. Hydro pumping and DR already are close to their full potential. Adiabatic CAES has a too low efficiency to replace V2G.

Then, we analyse the sensitivity of storage and DR to the batteries' maximum installable potential (figure B-2).

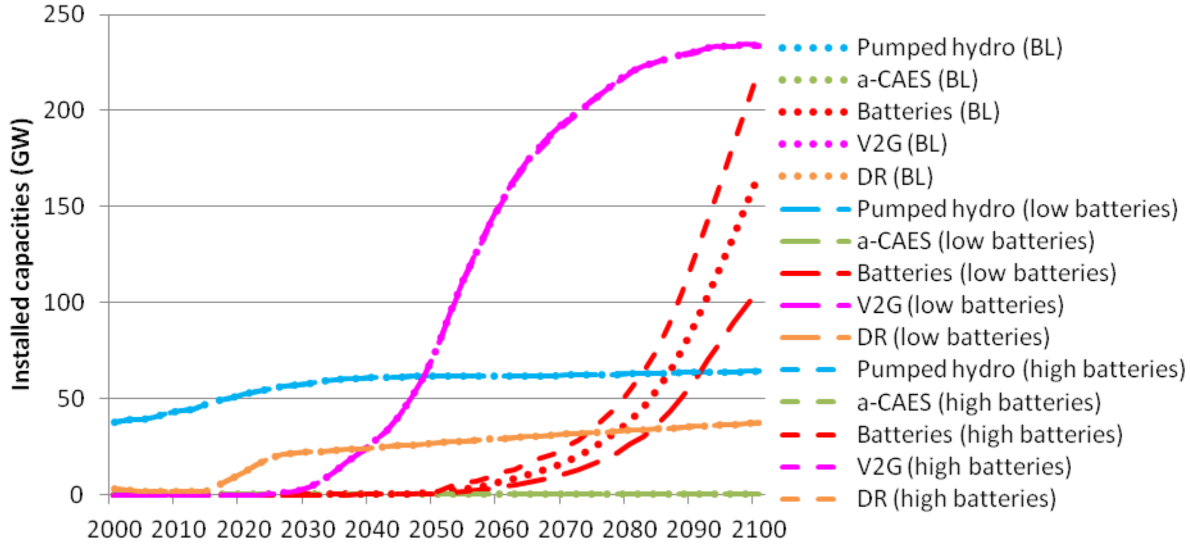


Figure B-2: Comparison of the development of storage and DR in Europe in the baseline scenario (BL) and in scenarios with a maximum installable potential in batteries multiplied by two ("high batteries") or divided by two ("low batteries") compared to the baseline potential (POLES+EUCAD).

It is interesting to note that the potential of batteries does not affect the investment in the other storage technologies. Hydro pumping, V2G and DR are already at their maximum potential, while a-CAES remain excluded by their low efficiency. Only the development of batteries is impacted by its assumed potential.

Third, we explore the sensitivity of storage and DR to the maximum installable potential of pumped hydro (figure B-3).

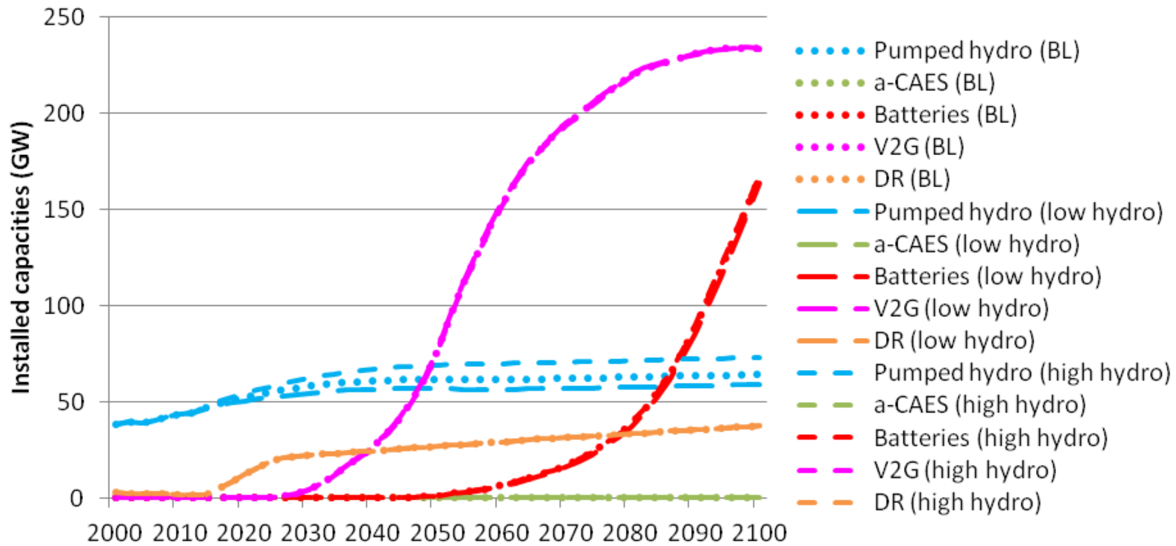


Figure B-3: Comparison of the development of storage and DR in Europe in the baseline scenario (BL) and in scenarios with a maximum installable potential in pumped hydro multiplied by +133% ("high batteries") or by 83% ("low batteries") compared to the baseline potential (POLES+EUCAD).

Similar to the battery potential, the effect on other storage or DR technologies of the pumped hydro potential is small.

Finally, we look at the impact of demand response on the storage development (figure B-4).

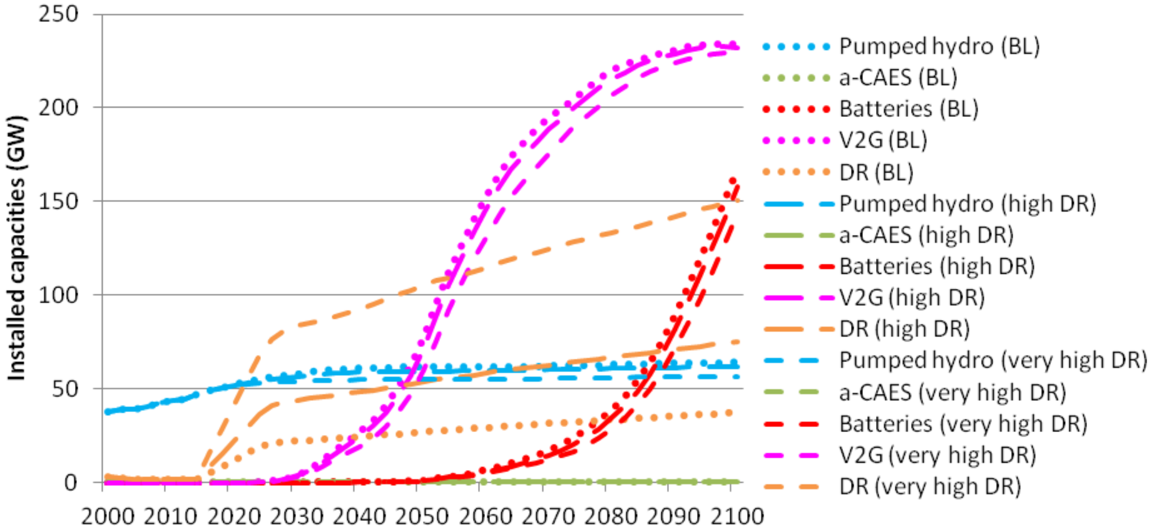


Figure B-4: Comparison of the development of storage and DR in Europe in the baseline scenario (BL) and in scenarios with a maximum installable potential in batteries multiplied by two ("high DR") or by four ("very high DR") compared to the baseline potential (POLES+EUCAD).

This figure confirms the fact that DR is developed quickly, only blocked by its potential. Indeed, the maximum installation speed of storage or DR is a tenth of the maximum installable potential. Since we do not have data for the existing DR capacities, the investments only start after 2014; in 2025 almost all the potential is already used. After that, DR increases because the demand increases as well (and the installable potential is linked to the peak consumption). The impact on the other technologies is interesting. We see that hydro pumping, batteries and V2G decrease a little when the installed DR capacities double. This is due to two effects:

- DR has a higher efficiency than the storage technologies, so it is really reduces the value of other storage technologies;
- On the other hand, DR has strong constraints that imply that it cannot replace a storage capacity (it cannot be used more than one hour in a day).

DR impacts the economic value of the storage capacities, and so it influences their development, but only to a small extent.

We conclude that pumped hydro, batteries, V2G and DR are very sensitive to their maximum installable potential (in the baseline scenario). However, the effect on the development of the other storage technologies is small for batteries and pumped hydro. The availability of V2G has a strong impact on the development of stationary batteries. DR decreases slightly the economic value of investments in all other storage technologies. The basics of the baseline scenario are still true (fast development of hydro pumping, V2G and DR; development of batteries starting around 2050; a-CAES remains very little developed); only the level of development is sensitive to the installable potential.

Appendix C: Simulating the operation of storage

As POLES' software does not compute any optimisation, we use exogenous assumptions on the number and amplitude of "production" and "storage" hours of the storage and DR technologies. The figure C-1 shows the maximum potential utilisation of each technology as a percentage of its total installed capacity, for each two-hour block of the 54 days represented.

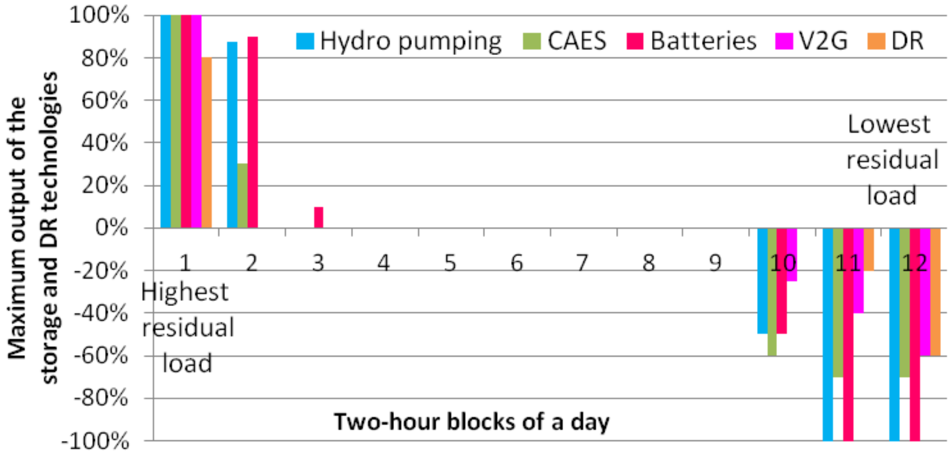


Figure C-1: Assumed maximum use of storage and DR for the 12 two-hour blocks of a day. A positive value indicates a production; a negative value indicates consumption (POLES only).

These assumptions (in particular the production levels in the second and third blocks with highest consumption) can evolve during a scenario if the efficiency of a technology evolves. These values are multiplied by the installed capacity in order to define the storage and DR operation. Then two constraints adjust the resulting load (in order to give a residual load net of EV, storage and DR):

1. the three two-hour blocks with higher (respectively lower) residual load (net of EV) must stay at a higher (resp. lower) level of consumption than the fourth block;
2. if the first constraint induces an unbalance between the produced and stored energy (taking into account a weighted efficiency of storages and DR), the excess (resp. missing) stored energy is dispatched equally on the four blocks with highest (resp. lowest) consumption.

We do not detail here the involved equations for the sake of clarity. We rather detail the different steps in figure C-2, with one of the 27 typical days of the year 2050 in France (medium demand, low wind and high solar).

Note that here our example is based on a storage dispatch with EUCAD feedback, so the utilisation hours of each storage and DR technology are not the same as in the theoretical assumptions of figure C-1 (EUCAD gives a strong role for V2G, which has a higher efficiency, and a small role for pumped hydro; batteries and a-CAES are still very small in 2050 in the baseline scenario).

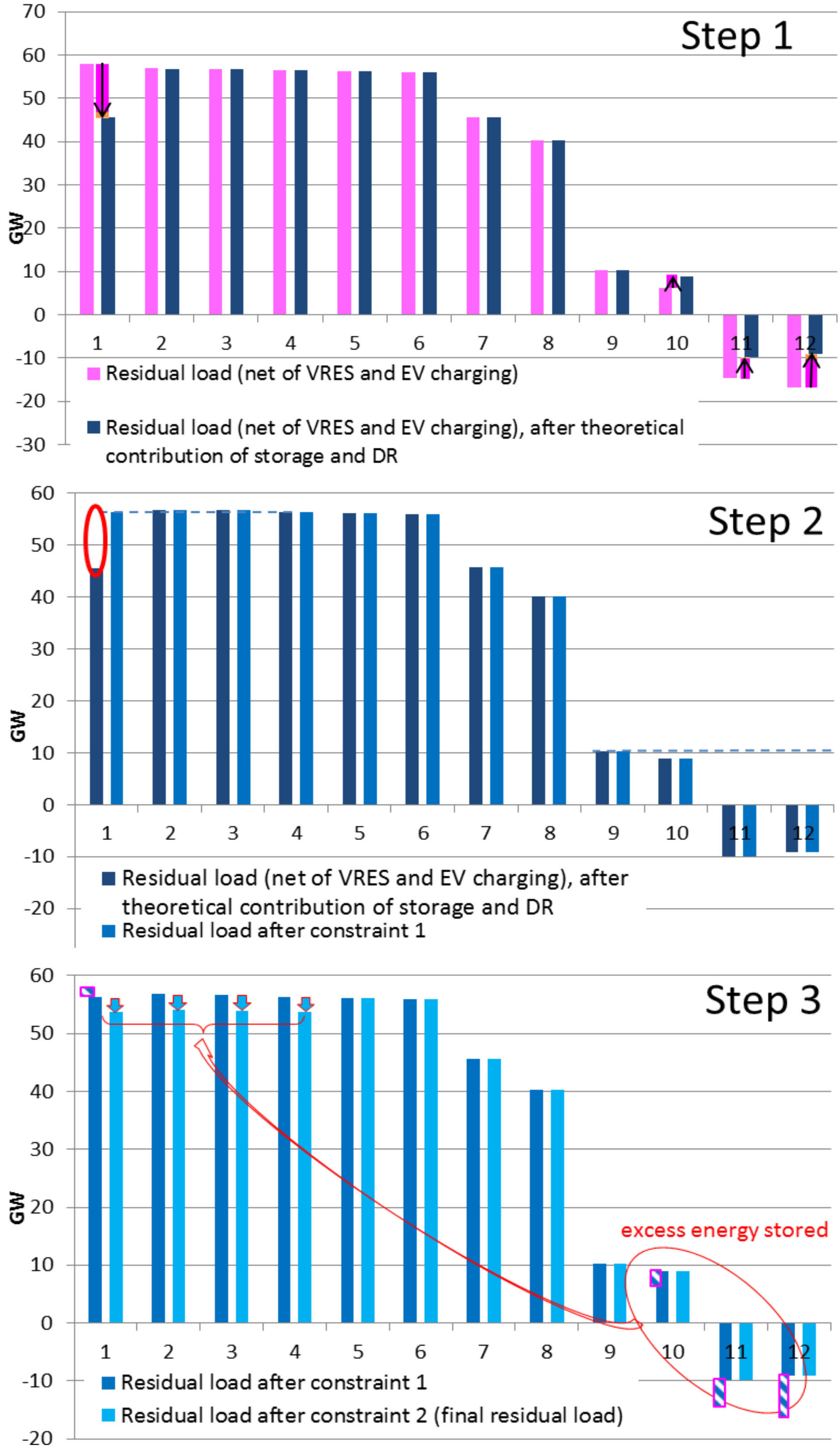


Figure C-2: Focus on the operation of storage and DR on a particular day (medium demand, low wind, and high solar). The different steps are shown: theoretical contribution of storage and DR (top), adding the constraint 1 (middle) and adding the constraint 2 (bottom). France, 2050, baseline scenario (POLES only).

Appendix D: Electricity storage and demand response in the power market

We analyse here the operation of demand response relative to a storage technology, in order to show their similarities and differences from the market participants' point of view and the system point of view.

On one hand, electricity storage operators participate in the power markets by buying power at times of low prices and selling at high prices. The energy is stored in the technology and released later (figure D-1).

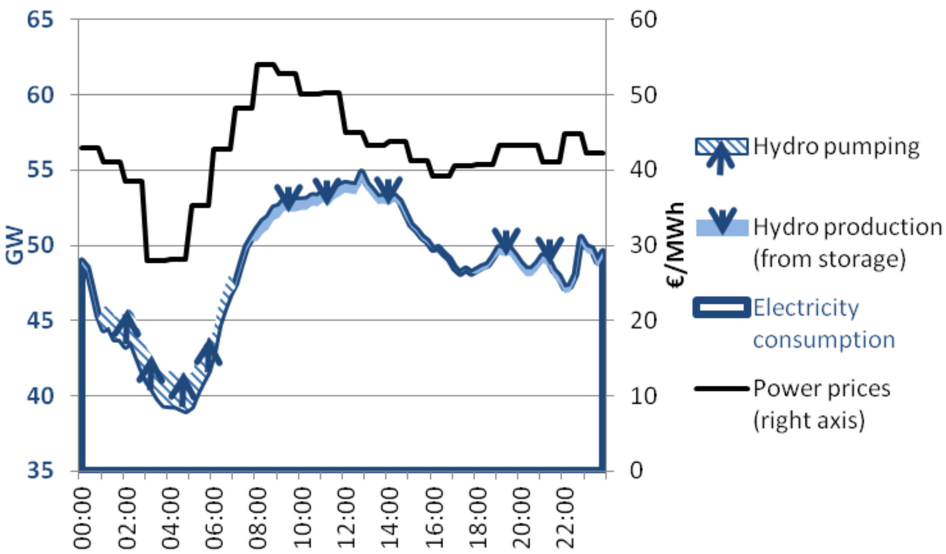


Figure D-1: Hydro pumping operation according to power prices. 15/04/2015, France, RTE data.

On the other hand, Demand Response (DR) operators sell a capacity at periods of high prices. The energy is "not consumed", thus allowing to use the scheduled production for another need. However, in general the consumption is not just cancelled; it is displaced to another time (figure D-1). This is independent from the business model of the DR aggregator.

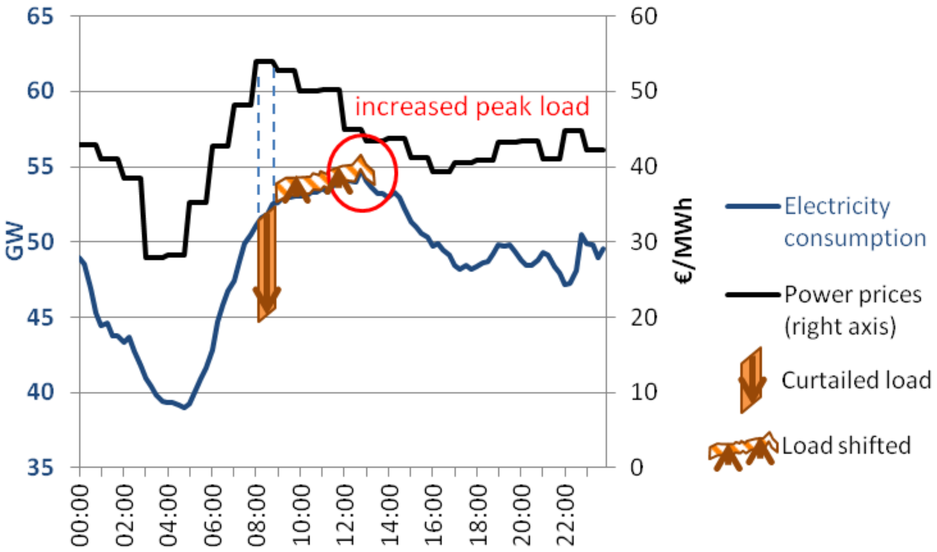


Figure D-2: Demand response operation. Based on 15/04/2015, France, RTE data.

In figure D-2, the DR aggregator sells the plain orange zone at 8am, at a market price of 53.98 €/MWh. The consumption is reduced for one hour and the system avoids the alternative use of a production power plant. However, an additional consumption will most probably be observed on the following hours (orange dashed surface). The energy will be consumed and paid at this moment (here, the five hours following the load shedding). This cost of buying later the curtailed energy is supported by the energy provider (which, in the end, has to cover the consumption of its contracted consumers), not by the DR aggregator. There are two differences with storage operation: the storage operator can optimise the hours of consumption, and he has to buy the consumed energy himself.

In fact, the energy provider will pay once for the curtailed energy (which is equivalent to paying for a producing capacity) and another time for the capacity needed to cover the dashed area corresponding to the displaced consumption. A comparison with a storage operator is given in the figure D-3.

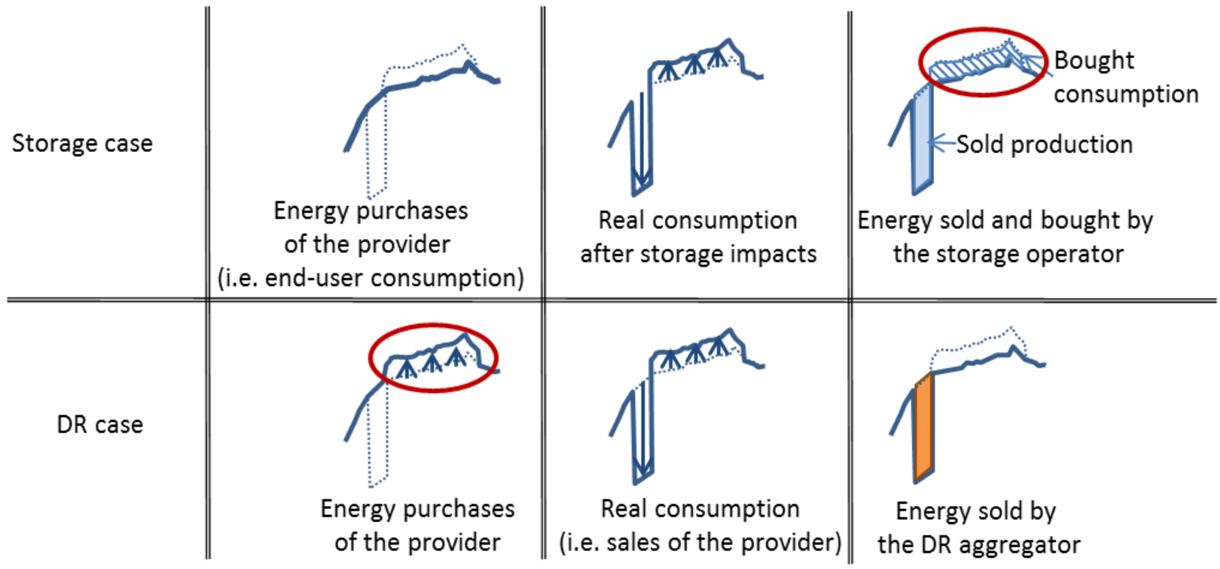


Figure D-3: Comparison of the storage and DR effects on consumption and money transfers.

Note that, depending on the shape of this load shifting, the rebound effect could also lead to another peak in consumption (thus reducing the environmental justification for policy support of load shedding).

If the shifted energy is lower than the curtailed energy (overall round-trip efficiency higher than 100%), the energy provider is selling less electricity to its customers and earns less benefits from sales (since the retail price is fixed for the entire day). What we demonstrated here is that the electricity supply may also cost more to the electricity provider. In some market designs (e.g. France since the Voltalia-EDF court case), DR aggregators have to pay a fee to the electricity provider for decreasing their profits (which, as argued here, is not the main problem, but rather the increase of purchasing costs).

Independently from the market design, there is a benefit for the society if the shifted energy (dashed area) is cheaper than the curtailed energy (plain area), just like for storage. The difficulty with DR is that the shifted energy is not optimally dispatched and can have undesirable effects on the prices.

Therefore, we conclude that the value chains for a DR aggregator or a storage operator are different. A DR aggregator does not need to buy the “stored” energy (that it sells on the market as a load shedding capacity), whereas a storage operator does.

Despite these differences due to the market design, in the viewpoint of the system supply and demand balance (see figure D-3-middle), DR and storage are similar: they displace a load between time periods. That is why we use the same basis of equations for the operation optimisation in EUCAD (with additional constraints for DR) and the same capacity planning mechanisms in POLES.

Appendix E: Test of the flexibility of the power system

The sum of flexibility brought by dispatchable capacities (obtained by multiplying the available dispatchable capacities by their flexibility coefficient) has to be higher than the sum of variability brought by VRES and demand.

For dispatchable technologies, we used the parameters from [192], reproduced and completed in table E-1. The parameters are considered to be constant in time up to 2010 and after 2030, with a linear evolution between 2010 and 2030.

	Flexibility parameter	
	2010	2030
Nuclear	6%	1%
Coal	14%	15%
Oil open cycle	30%	100%
Gas combined cycle	50%	100%
Hydro (run of river)	10%	10%
Import capacity	20%	20%
Electric vehicle	20%	20%
Hydro (lakes and pumped storage), other gas and oil, biomass, electrolysis, CAES	100%	

Table E-1: Flexibility coefficients, based on [192].

For wind and solar technologies, as well as for the demand, we carried out our own analysis based on RTE data for the year 2013 [17]. For each two-hour block of POLES (12 in summer, 12 in winter), we computed the maximum up- and downward 30-minute variability of demand, wind and solar (that dispatchable capacities have to meet). They are expressed as ratios of the peak power for demand or of the installed capacity for wind and solar. They are reported in table E-2 (maximum upward variation of the residual demand: maximum upward variation of demand and minimum downward variation of VRES) and E-3 (minimum downward variation of the residual demand: minimum downward variation of demand and maximum upward variation of VRES).

	Summer			Winter		
	Demand	Wind	Solar	Demand	Wind	Solar
0 h - 2 h	0%	-3,4%	-0,1%	2,1%	-3,6%	0%
2 h - 4 h	0%	-2,7%	0%	0,3%	-4,2%	0%
4 h - 6 h	2,6%	-3,1%	0%	3%	-3,9%	0%
6 h - 8 h	4,5%	-3,7%	0%	4,8%	-3,2%	-0,1%
8 h - 10 h	2,3%	-4,5%	1,3%	2,2%	-4,2%	0%
10 h - 12 h	1,4%	-3,5%	-0,3%	1,6%	-3,3%	-0,2%
12 h - 14 h	1,3%	-3,1%	-2,9%	1,6%	-3,8%	-4,4%
14 h - 16 h	0,6%	-2,6%	-4,9%	0,2%	-4,3%	-7,6%
16 h - 18 h	0,9%	-3,3%	-8,6%	4,5%	-5,3%	-9,2%
18 h - 20 h	2,4%	-4,6%	-8,9%	6,2%	-3,6%	-7,9%
20 h - 22 h	2,4%	-4,7%	-5,1%	2,4%	-3,5%	-1,1%
22 h - 24 h	3,8%	-3,5%	0%	3,5%	-4,2%	0%

Table E-2: Upward half-hour variability of demand (relative to peak demand), wind and solar (relative to installed capacity), by two-hour blocks. Based on our own computation, data for France, 2013 [17] (POLES+EUCAD).

	Summer			Winter		
	Demand	Wind	Solar	Demand	Wind	Solar
0 h - 2 h	-3,4%	3,6%	0%	-3,3%	3,40%	0%
2 h - 4 h	-2,4%	2,1%	0%	-3%	4,50%	0%
4 h - 6 h	-0,9%	2,7%	0%	-1,8%	3,30%	0%
6 h - 8 h	-0,8%	3,4%	5,4%	-0,8%	4,50%	5,50%
8 h - 10 h	-0,7%	6,8%	9%	-0,7%	4,60%	9,50%
10 h - 12 h	-0,9%	4,6%	8,9%	-1,1%	4,90%	8%
12 h - 14 h	-2,6%	3,4%	4,8%	-2,8%	4,80%	4,50%
14 h - 16 h	-2,3%	5,1%	1,8%	-2,4%	3,70%	1,30%
16 h - 18 h	-1,2%	4,7%	0,1%	-1%	5,70%	0%
18 h - 20 h	-1,6%	3,6%	-0,2%	-2,9%	5,70%	0%
20 h - 22 h	-2,5%	5,2%	0%	-3,4%	3,70%	0%
22 h - 24 h	-1,6%	4,8%	0,1%	-1,7%	2,80%	0%

Table E-2: Downward half-hour variability of demand (relative to peak demand), wind and solar (relative to installed capacity), by two-hour blocks. Based on our own computation, data for France, 2013 [17] (POLES+EUCAD).

We present the results of the flexibility test for France in figure E-1, for each two-hour block of the summer and winter days and for the up- and downward variations.

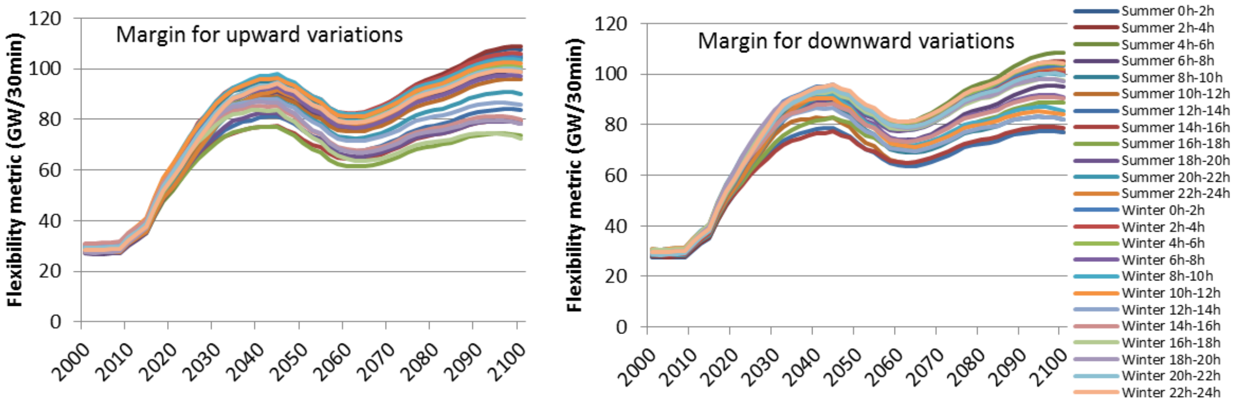


Figure E-1: Flexibility indicator in the upward (left) and downward directions (right) for the 24 two-hour blocks in France. Baseline scenario (POLES+EUCAD).

We see that the available flexibility stays well above the variability of demand, wind and solar: there is no constraint on investments for reasons of flexibility. This is because the power system needs big capacities of peaking power in order to meet the demand in periods of low wind and low solar, and these capacities are also very variable. There is no need for an additional investment mechanism specific to a variability constraint.

Appendix F: EUCAD structure and equations

EUCAD is an optimisation program developed using the GAMS language. Therefore, it is divided in sets (the indices), parameters (fixed tables of data), variables (which are computed by the optimisation) and equations (which define the constraints of the optimisation). We present these elements here.

Sets

SH: two-hour time-slices for the summer and for the winter days

SHsummer: two-hour time-slices for the summer day

season: season of the day being computed (summer or winter)

Europe: European countries (a.k.a. *Europebis*)
└ *Europe0*: European countries in the UCT+0 time zone
└ *Europe1*: European countries in the UCT+1 time zone
└ *Europe2*: European countries in the UCT+2 time zone

EletechAll: All of POLES' technologies
└ *EleDisp*: Dispatchable technologies
└ *EleVRE*: VRES technologies

└ *Biomass*: Biomass technologies
└ *Coal*: Coal technologies
└ *FastTechno*: Fast ramping technologies
└ *StockIn*: Production technologies with a maximum available energy
└ *StoTech*: Storing technologies

└ *StockOut*: Storing technologies with a minimum energy stock to produce from electricity

└ *StoProdTechnos*: Storing and producing technologies

t: Hours of the day (a.k.a. *tt*)

└ *tG2V*: Daylight hours, on which G2V is charging less than half of its needs
VREdays: Clustered days of VRES production

Parameters

- **Parameters directly defined in EUCAD**

day(*season*): Binary parameter indicating the season of the year (summer 0,winter 1)

SocioEcoCost(*Europe*): Social and economic cost of not delivering electricity (k$ per GWh)

efficiency(*StoProdTechnos*): Round trip efficiency of storage technologies

Input parameters of EUCAD

TotLoadAllC(*Europe*,*SH*): Total load for every country (GWh duringthe time-slice SH)

VarCost(*Europe*,*EleDisp*): Variable cost of dispatchable technologies for every country ($ per kWh)

ACIPreal(*Europe*,*SH*,*EletechAll*): Installed power of all technologies for every country, available on each SH (GW)

EnergyAvailable(*Europe*,*StockIn*): Energy available annually (water inflow in the lakes, hydrogen for fuel cells, maximum available battery energy for V2G activity) (GWh)

EnergyToBeProduced(*Europe*,*StockOut*): Energy to be produced annually (hydrogen produced by water electrolysis, EV charging needs) (GWh)

Capacities(*Europe*,*Europe*): Capacities of the lines between two countries (GW)

VREprofile(*Europe*,*season*,*t*,*VREdays*,*EleVRE*): Production profiles for each VRES technology and each resource day (% of installed capacity)

VREcoefs(*season*,*VREdays*): Weighting coefficients for each *VREdays* (number of days corresponding to the cluster)

Country by country parameters for the resolution day after day

TotLoad(*Europe*,*t*): Total load of each European country (GW)

LoadEurope(*t*): Total load of all Europe (GW)

ResLoad(*Europe*,*t*): Residual load for each computed day, for every country (GW)

Pmax(*Europe*,*EletechAll*,*t*): Maximum production of a technology at a given time of the day (GW)

PmaxDay(*Europe*,*EletechAll*): Maximum of power available in an entire day (GW)

STOmax(*Europe*,*Stotech*,*t*): Maximum storage power at a given time of the day (GW)

FastRamp(*Europe*,*EleDisp*): Secondary and tertiary fast reserves of a technology (GW)

t_on(*EleDisp*): Minimum on-time (h)

t_off(*EleDisp*): Minimum off-time (h)

Pmin(*Europe*,*EleDisp*): Minimum production of a technology (GW)

Rmax(*EleDisp*): Hourly up or down ramping capabilities (GW per hour)

RampCost(*EleDisp*): Hourly ramping cost: proportional to fuel and O&M costs ($ per 33% ramp of a 1MW plant)

Output parameters (used to store the results of the variables computed for each day)

ElecProd(*Europe*,*EletechAll*,*t*,*season*,*VREdays*): Energy productions for every day and every country (GW)

ElecSto(*Europe*,*Stotech*,*t*,*season*,*VREdays*): Energy storage for every day and every country (GW)

Export(*Europe*,*Europe*,*t*,*season*,*VREdays*): Exports from a country to another country (GW)

EnergyNotDistrib(*Europe*,*t*,*season*,*VREdays*): Energy Not Distributed (load curtailment) (GWh)

Curtailment(*Europe*,*t*,*season*,*VREdays*): Curtailed energy from excess production (GWh)

TotalCost(*season*,*VREdays*): Result of the optimization with VRES profiles (k$)

NationalCost(*Europe*,*season*,*VREdays*): National production cost (k$)

The input parameters (from POLES) are TotLoadAllC, VarCost, ACIPreal, EnergyAvailable, EnergyToBeProduced, Capacities, VREprofile, VREcoefs.

Variables

TotCost: Total cost to minimise (k$ per day)

status(*Europe*,*EleDisp*,*t*): “on” (1) or “off” (0) status of a power plant

P(*Europe*,*EleDisp*,*t*): Production level (GW)

Sto(*Europe*,*StoTech*,*t*): Storage level (GW)

R(*Europe*,*EleDisp*,*t*): Ramp between hour t-1 and hour t (GW per hour)

Curtailed(*Europe*,*t*): Curtailed production (GW)

UnservedLoad(*Europe*,*t*): Unserved load (curtailed demand) due to unavailability of production (GW)

NetExports(*Europe*,*Europebis*,*t*): Net exports from a country to another (GW)

LineFlow(*Europe*,*Europe*,*t*): Power flow on the line from a first country to another (GW)

Status is a binary variable (it can only be zero or one); *P*, *Sto*, *Curtailed*, *UnservedLoad* and *LineFlow* are positive variables. *R* and *NetExports* can be positive or negative.

Equations

EUcost: total European operating cost. The optimisation objective of EUCAD is expressed as the minimisation of the total European power system operation cost. The 32 dispatchable technologies of 24 European countries[39] are optimised over a 24-hour period. The total cost is made up of the variable production costs, the cost of ramping, and the social and economic cost of unserved load.

[39] Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxemburg, Netherland, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, United Kingdom.

$$TotCost = \sum_{Country \in Europe} \sum_{t=1}^{24} \Bigg(SocioEcoCost(Country) * UnservedLoad(Country,t) + \sum_{\substack{DispTech \\ s.t. Pmax(Country,DispTech)>0}} (VarCost(Country,DispTech) * P(Country,DispTech,t) + RampingCost(Country,DispTech) * R(Country,DispTech,t)^2) \Bigg)$$

PequalC(*Europe*,*t*): Balance of production and consumption. We account for the national production, the national consumption (including storage), the net exports and the potential unserved load or surplus energy (overproduction is curtailed, whether it comes from VRE or inflexible thermal generation).

$$\forall (Country,t) \epsilon \{Europe,[1;24]\},$$
$$\sum_{DispTech} P(Country,DispTech,t) = ResLoad(Country,t) + \sum_{Countrybis=1}^{24} NetExports(Country,Countrybis,t) + \sum_{Stotech} Sto(Country,Stotech,t) + Surplus(Country,t) - UnservedLoad(Country,t)$$

IntercoNTC(*Europe*,*Europebis*,*t*): interconnection limit (NTC)

$$\forall (Country,Countrybis,t) \epsilon \{Europe,Europe,[1;24]\},$$
$$LineFlow(Country,Countrybis,t) \leq 0.9 * Capacities(Country,Countrybis)$$

ExportsImports0(*Europe0*,*Europe*,*t*): total net exports in the time zone UTC+0. The net exports are the exports (in local time) minus the imports (at the same time, which may require a time conversion). We consider a fixed 2% loss in all international exchanges (i.e. the average French total losses in the transmission grid).

$$\forall (Country0,Country,t) \in \{Europe0,Europe,[1;24]\},$$
$$NetExports(Country0,Country,t) = LineFlow(Country0,Country,t) - 0.98 * \big(LineFlow(Country,Country0,t)_{s.t. Country \in Europe0} + LineFlow(Country,Country0,t+1)_{s.t. Country \in Europe1}\big)$$

ExportsImports1(*Europe1*,*Europe*,*t*): total net exports in the time zone UTC+1

$$\forall (Country1,Country,t) \in \{Europe1,Europe,[1;24]\},$$
$$NetExports(Country1,Country,t) = LineFlow(Country1,Country,t) - 0.98 * \big(LineFlow(Country,Country1,t)_{s.t. Country \in Europe1} + LineFlow(Country,Country0,t+1)_{s.t. Country \in Europe2} + LineFlow(Country,Country0,t-1)_{s.t. Country \in Europe0}\big)$$

ExportsImports2(*Europe2*,*Europe*,*t*): total net exports in the time zone UTC+2

$$\forall (Country2,Country,t) \in \{Europe2,Europe,[1;24]\},$$

$$NetExports(Country2, Country, t) = LineFlow(Country2, Country, t)$$
$$-0.98 * \left(LineFlow(Country, Country2, t)_{s.t.Country\ \epsilon\ Europe2} + LineFlow(Country, Country2, t-1)_{s.t.Country\ \epsilon\ Europe1}\right)$$

Pmini(*Europe*,*EleDisp*,*t*): minimum production output.

$$\forall(Country, DispTech, t), P(Country, DispTech, t) \geq status(Country, DispTech, t) * Pmin(Country, DispTech)$$

Pmaxi(*Europe*,*EleDisp*,*t*): maximum production output.

$$\forall(Country, DispTech, t), P(Country, DispTech, t) \leq status(Country, DispTech, t) * Pmaxi(Country, DispTech, t)$$

STOmaxi(*Europe*,*Stotech*,*t*): maximum production of consuming technologies.

$$\forall(Country, Stotech, t), Sto(Country, Stotech, t) \leq STOmaxi(Country, Stotech, t)$$

Ramping(*Europe*,*EleDisp*,*t*): defining the ramping of a technology.

$$\forall(Country, DispTech, t), R(Country, DispTech, t) = P(Country, DispTech, t) - P(Country, DispTech, t-1)$$

PosRamp(*Europe*,*EleDisp*,*t*): limit on the hourly ramping in the positive way.

$$\forall(Country, DispTech, t), R(Country, DispTech, t) \leq Rmax(DispTech)$$

NegRamp(*Europe*,*EleDisp*,*t*): limit on the hourly ramping in the negative way.

$$\forall(Country, DispTech, t), -R(Country, DispTech, t) \leq Rmax(DispTech)$$

PosFlex(*t*): upwards secondary reserves.

$$\forall t, \sum_{Country\ \epsilon\ Europe} \left(\sum_{\substack{DispTech \\ s.t.not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} + \sum_{FastRamping} \left(Pmaxi(Country, FastRamping, t) - P(Country, FastRamping, t)\right) + \sum_{Stotech} Sto(Country, Stotech, t) \right) \geq 0.07 * TotLoad(t)$$

NegFlex(*t*): downwards secondary reserves.

$$\forall t, \sum_{Country\ \epsilon\ Europe} \left(\sum_{\substack{DispTech \\ s.t.not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} \right.$$
$$+ \sum_{FastRamping} \big(P(Country, FastRamping, t) - status(Country, FastRamping, t)$$
$$* Pmin(Country, FastRamping)\big)$$
$$\left. + \sum_{Stotech} \big(STOmaxi(Country, Stotech, t) - Sto(Country, Stotech, t)\big) \right)$$
$$\geq 0.07 * TotLoad(t)$$

StoBalance(*Europe*,*StoProdTechnos*): managing the state of charge of the technologies that store and produce.

$$\forall(Country, StoProdTechnos), \sum_{t} \big(Sto(Country, StoProdTechnos, t) * efficiency(StoProdTechnos)$$
$$- P(Country, StoProdTechnos, t)\big) \geq 0$$

EnergyIN(*Europe*,*StockIn*): respecting the total energy stock available for electricity production (hydro lakes and hydrogen fuel cells).

$$\forall(Country, StockIn), \sum_{t} P(Country, StockIn, t) \leq EnergyINday(Country, StockIn)$$

EnergyOUT(*Europe*,*StockOut*): respecting the total energy stock that must be produced by electricity storage (EV charging, hydrogen production by water electrolysis).

$$\forall(Country, StockOut), \sum_{t} Sto(Country, StockOut, t) \geq EnergyOUTday(Country, StockOut)$$

PositiveOUT(*Europe*,*StockOut*,*t*): ensuring that these technologies are not both producing and storing electricity.

$$\forall(Country, StockOut, t), P(Country, StockOut, t) = 0$$

DRactivation(*Europe*): maximum shifted energy in a day.

$$\forall Country, \sum_{t} P(Country, DR, t) \leq Pmax(Country, DR) * 1$$

DRrebound(*Europe*,*t*): direct rebound of the load shedding.

$$\forall(Country, t), Sto(Country, DR, t) \geq P(Country, DR, t-1)/3$$

EVdayCharging(*Europe*): a minimum of 50% of the charge occurs at night.

$$\sum_{t=7}^{19} Sto(Country, G2V, t) \leq 0.5 * EnergyOUTday(Country, G2V)$$

Two additional constraints are optional:

min_on_time(*Europe*,*EleDisp*,*t*,*tt*): the minimum ON time of a thermal power plant.

$$\forall(Country, DispTech), \forall t_1 and\ t_2, s.t. t_2 \geq t_1 + t_{on}(DispTech) and\ t_2 \leq t_1,$$

$$status(Country, DispTech, t_1)\ \geq status(Country, DispTech, t_2) - status(Country, DispTech, t_2 - 1)$$

min_off_time(*Europe*,*EleDisp*,*t*,*tt*): the minimum OFF time of a thermal power plant.

$$\forall(Country, DispTech), \forall t_1 and\ t_2, s.t. t_2 \geq t_1 + t_{off}(DispTech) and\ t_2 \leq t_1,$$

$$1 - status(Country, DispTech, t_1) \geq status(Country, DispTech, t_2 - 1) - status(Country, DispTech, t_2)$$

Finally, a “solve” equation minimises the total production cost, using CPLEX solver. The results are aggregated in output parameters and transferred to POLES (or excel for visualisation) by using a *gdxxrw* function.

Appendix G: Value of lost load

In EUCAD, the Value of Lost Load (VoLL) is set at 26000 €/MWh for France and 11500 €/MWh for Norway [210], 12900 €/MWh for Ireland [211], and an estimation of 16000 €/MWh for all other European countries [212] (respectively 32500 $/kWh, 14400 $/MWh, 16100 $/MWh and 20000 $/MWh, with a rate of 1 €=1.25 $). Other estimates can be found in [213].

This value is at the higher end of the estimates of other macroeconomic studies or surveys. However, one should be aware that the VoLL is highly dependent on the length of the electricity shortage, on the hour of the day and the day of the week, and the type of consumers being affected. Currently, a common rule is to shed the residential loads first; however, it is the sector with the highest VoLL, especially during evenings and week-ends (as most people are at home), although not during night hours. This strategy is questionable because it leads to a higher VoLL than an all-sector average.

Another way of computing a “reasonable” VoLL is by comparing the fixed cost of a peaking power plant with the maximum hours of lost load, three hours per year in the French case. Assuming an annual fixed cost of 66 $/kW/year for a (gas or oil) combustion turbine (POLES data), we get a 22000 $/MWh VoLL. This indicates that any perceived cost of the unserved load higher than 22000 $/MWh is not efficient for the society: building an additional peaking capacity would be beneficial to the society. This number is in line with the literature values we found.

In any case, the value is several orders of magnitude (around 200 times) higher than the variable cost of any power plant, which means that EUCAD optimization won’t be very sensitive to this value. It will only impact the total cost of the system, in the cases where there is some unserved load.

Appendix H: The cluster algorithm impact on EUCAD results

We analyse in this appendix the impact of the choice of the typical days of VRES production profile.

<u>Characterising the wind and solar production profiles</u>

The prior representation of wind and solar variability in POLES was based on averaged capacity factor per two-hour block (figure H-1).

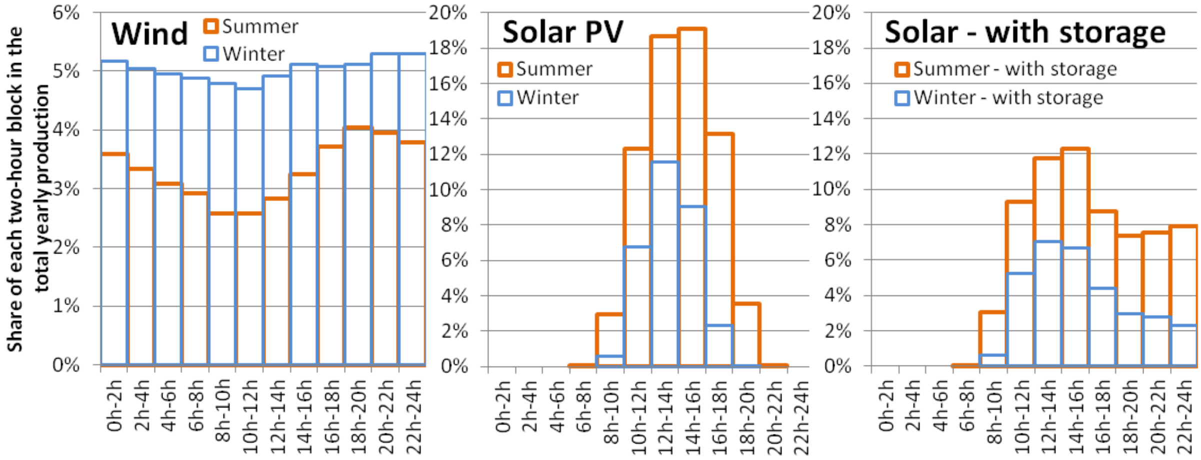


Figure H-1: Wind, solar and solar with storage production profiles, averaged for each two-hour block of POLES (pre-existing POLES modelling).

Instead, we use typical days of wind and solar production profile. The demand profile is fixed in POLES in all cases. The only changing parameter is the method for choosing the wind and solar production profiles.

A first option is to use high, medium and low levels of production, derived from a French analysis but applied to all other countries. The days corresponding to the first and last deciles of production were chosen for the “high” and “low” days. All these production profiles, shown in figure H-2, are real days of production in France, so that they conserve the real variability within a day.

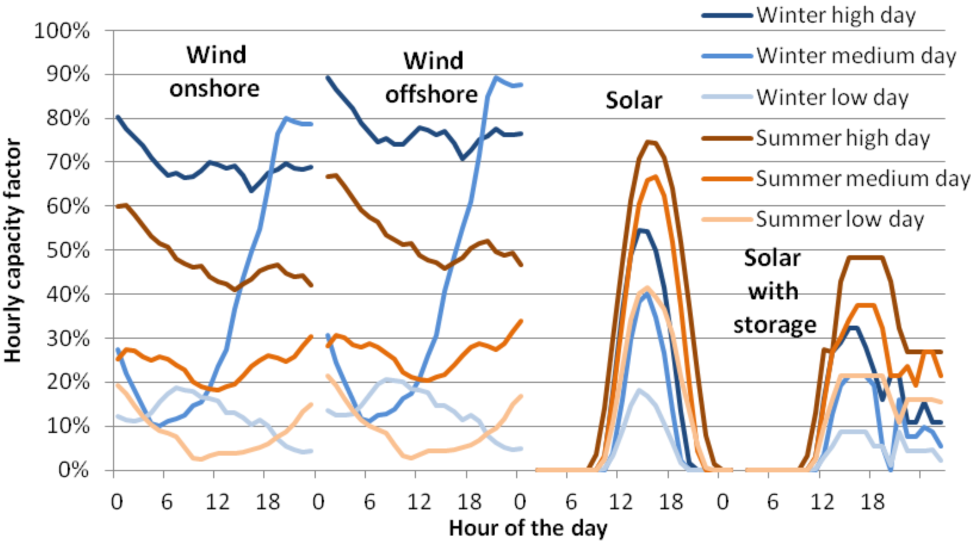


Figure H-2: Wind onshore, wind offshore, solar and solar with storage production profiles, based on assumptions of high, medium and low days of production.

A second possibility, chosen in our work, is to use a clustering algorithm in order to define the production profile inputs that are the most representative of the actual wind and solar production across a year. The algorithm is detailed further in [133]. The chosen number of clusters is important for the precision of the results and for the computation time. The data input of the algorithm is also decisive. We present two methods for the calibration.

The inputs should be national productions for each VRES (in MW, so that we keep the relative weights of all countries). The first calibration method is to compute them based on the wind speed and solar irradiance (meteorological year of 2006 [145,147]). The national productions are obtained with a maximum installable capacity (again, this maximum potential ensures that the weight of each country is conserved). Once we have defined the typical days, we divide the national productions (in MW) by the same maximum installable capacity, to get the hourly capacity factors in each country, for wind and solar. The figure H-3 summarises this process.

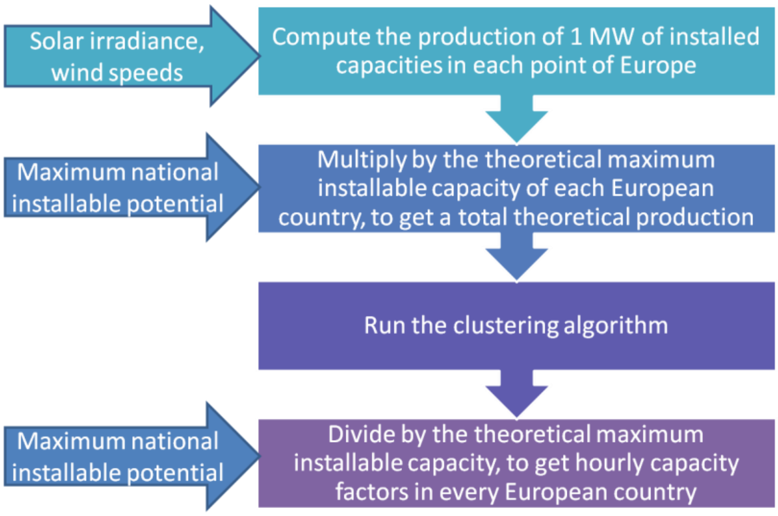


Figure H-3: Diagram of the computation process of the cluster algorithm based on the maximum production potential (based on the 2006 meteorological year).

In figure H-4 we show the resulting wind and solar production profiles for 6 typical days per season, in France (all other countries are available as well – simultaneously with France).

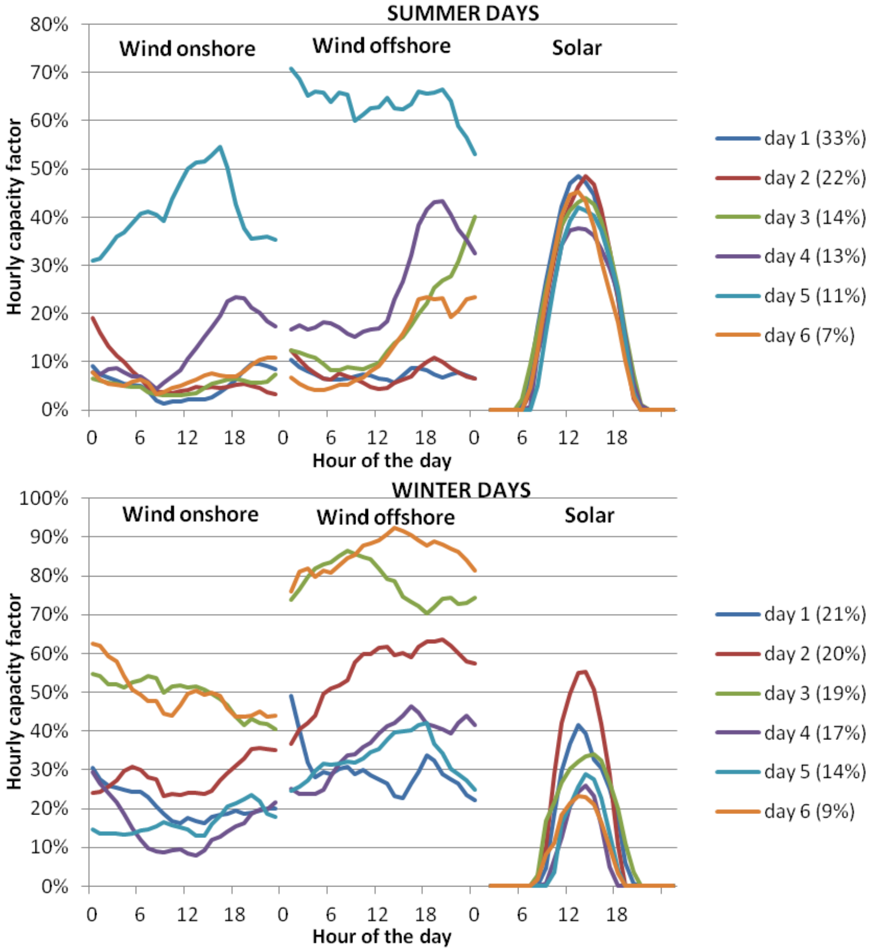


Figure H-4: Wind onshore, wind offshore and solar production profiles in France for six typical days per summer or winter season, based on clusters of the maximum production potential (based on 2006 meteorological data).

Another calibration method that we explored is to apply this clustering algorithm to the currently produced electricity from wind and solar. For this, we collected data on the wind and solar productions in as many European countries as possible, for the years 2012, 2013 and 2014. Based on 7 countries for solar production data and 13 countries for wind production, we extrapolated the missing data in order to cover the 24 European countries used in EUCAD. After running the algorithm on the actual production output of each country, we divide them by the installed capacities to get the hourly capacity factor – again extrapolating for the missing data or for countries with zero installed capacities yet. The process is shown in figure H-5.

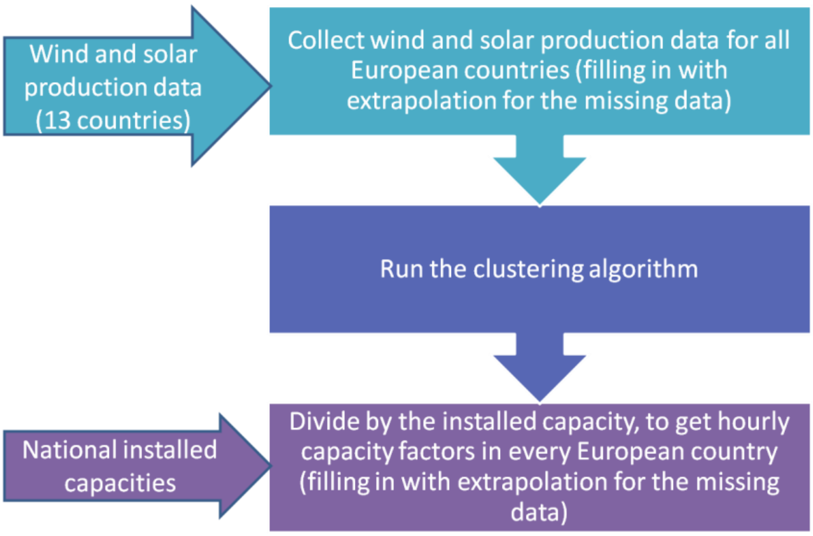


Figure H-5: Diagram of the computation process of the cluster algorithm based on the real production (based on 2012, 2013 and 2014).

The result of this calibration is shown in figure H-6 for France.

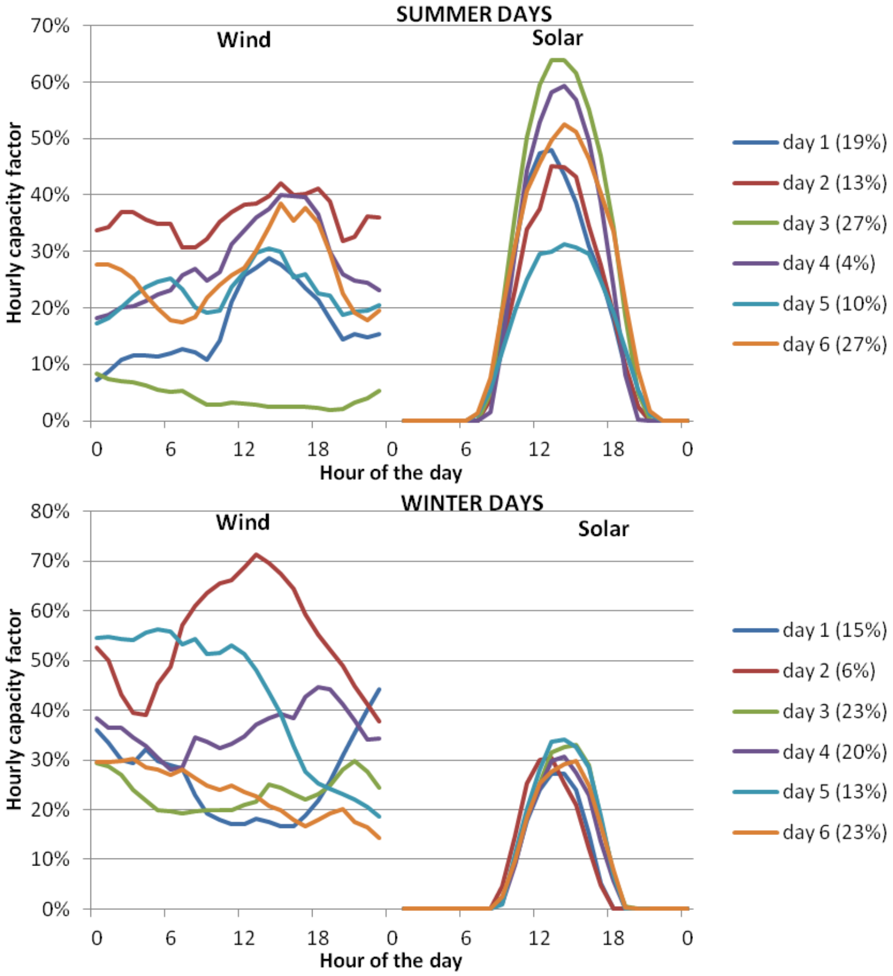


Figure H-6: Wind and solar production profiles in France for six typical days per summer or winter season, based on clusters of the real production (based on 2012, 2013 and 2014 actual productions).

We observe that, compared to the first clustering calibration, the diversity of the French productions is relatively higher with the second approach (based on real productions). This is due to the fact that the second approach gives a higher weight to the French case than to the rest of European countries:

- The French wind and solar capacities are relatively high, in comparison with some other European countries lagging behind in terms of wind and solar; on the contrary, in the first calibration method, all countries are supposed to have installed their maximum potential;
- France is one of the countries for which solar and wind data were available, so it has been used in other countries (part of the production profiles of Switzerland, Luxembourg, Italy (for 2012), Great Britain (for solar), Spain (for solar before 2014)); this increases the role of the French production profile, by lack of more information.

Both calibration methods have their *pros* and *cons*. The first approach uses consistent data for the whole Europe, but has to be based on (rather arbitrary) theoretical installable capacities. The second approach uses real production data, with the real weight of production between countries according to their level of development of wind and solar; however, we only could get data from 25% of the countries for solar production and 50% for onshore wind production[40]. In addition, both approaches are only valid for a given ratio of wind and solar installed in each country (a theoretical maximum installable potential for the first approach, the current installed capacities for the second); ideally they should be updated in time to adjust the ratio of wind and solar in each European country (every country does not develop their wind and solar capacities at the same speed).

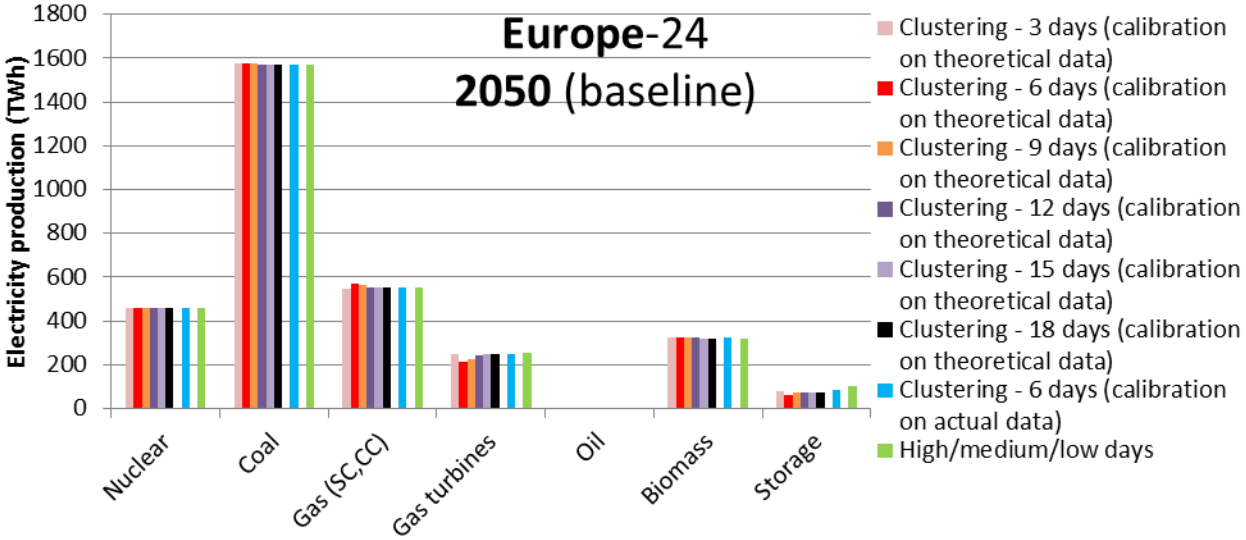
<u>EUCAD results with the different modelling choices</u>

We make a comparison between several options for representing the variability of wind and solar:

- Typical days with high, medium and low production profiles combined for wind and solar;
- Clustering approach using the theoretical maximum installable capacities, for 3 typical days per season, 6 typical days per season, 9 days, 12 days, 15 days and 18 days;
- Clustering approach using the real production profiles.

The sum of the energy produced by the different technologies along the year for each option is represented in figure H-7.

[40] We gathered 0% of the countries needed for offshore wind production, as it is not yet developed (only Denmark has available data for the three studied years, but rather inconsistent, so we did not include it into the clustering algorithm).



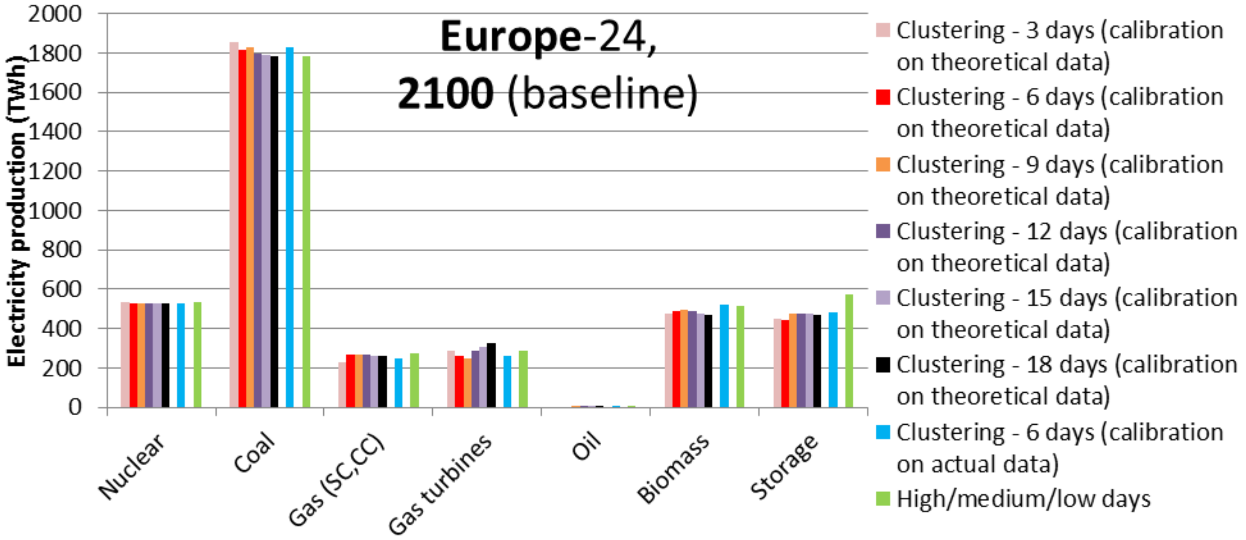


Figure H-7: Annual production by technology for different options of representation of the wind and solar production profiles, for the whole Europe in 2050 (top) and 2100 (bottom) in the baseline scenario (POLES+EUCAD).

The black bars correspond to the most precise representation that is based on theoretical potentials; the other clustering options based on the maximum potential should be compared with it. However it is difficult to say if the two other options (calibration on actual data and high/medium/low days) are better. By construction, the high/medium/low option may be a bit off track, since it is based on an analysis of the French case only. We observe some differences in the operation of gas turbines because they are the marginal producers (the variable cost is the highest), so they are the most affected by the form of the VRES production.

In our work, we used the 6 days of clustering based on the first calibration method with theoretical potentials (in red), thus avoiding too high computation times and having a calibration closer to the future of each country (based on the installable potential rather than the current installation level, which is not representative of the future).

POLES results with two different weighting of the clustering algorithm

We carried out two baseline scenarios with POLES, using 6 typical days of wind and solar production profiles, with the two calibration methods presented earlier: using the maximum installable potential of wind and solar across Europe (BL_Th), or the actual productions of 2012, 2013 and 2014, extrapolated when necessary (BL_Ac). The results are close for most of the variables. We show in figure H-8 and H-9 the installed capacities and the electricity produced for the most relevant technologies (the "gas" category includes the decentralised combined heat and power).

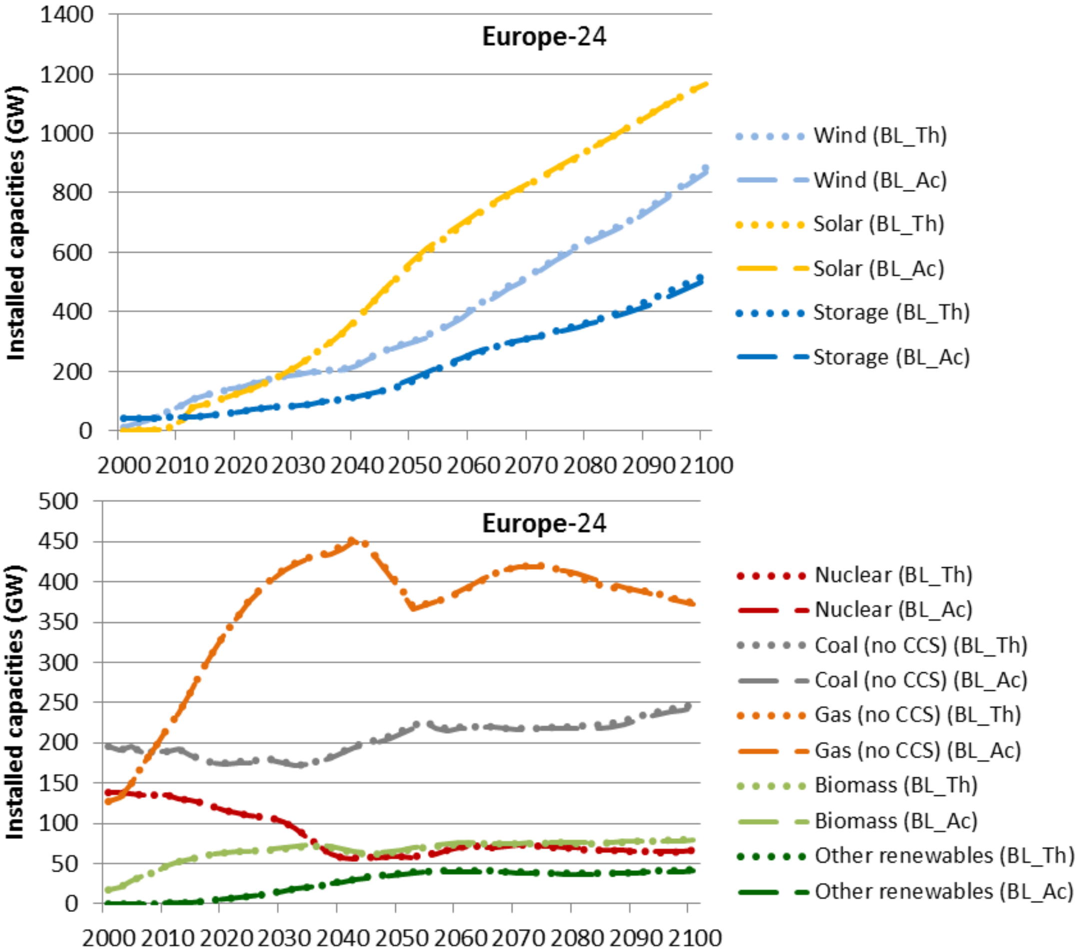


Figure H-8: Installed capacities of the main technologies in Europe, with 6 typical days based on two calibration methods (with theoretical potential BL_Th and with actual production data BL_Ac), for the baseline scenario (POLES+EUCAD).

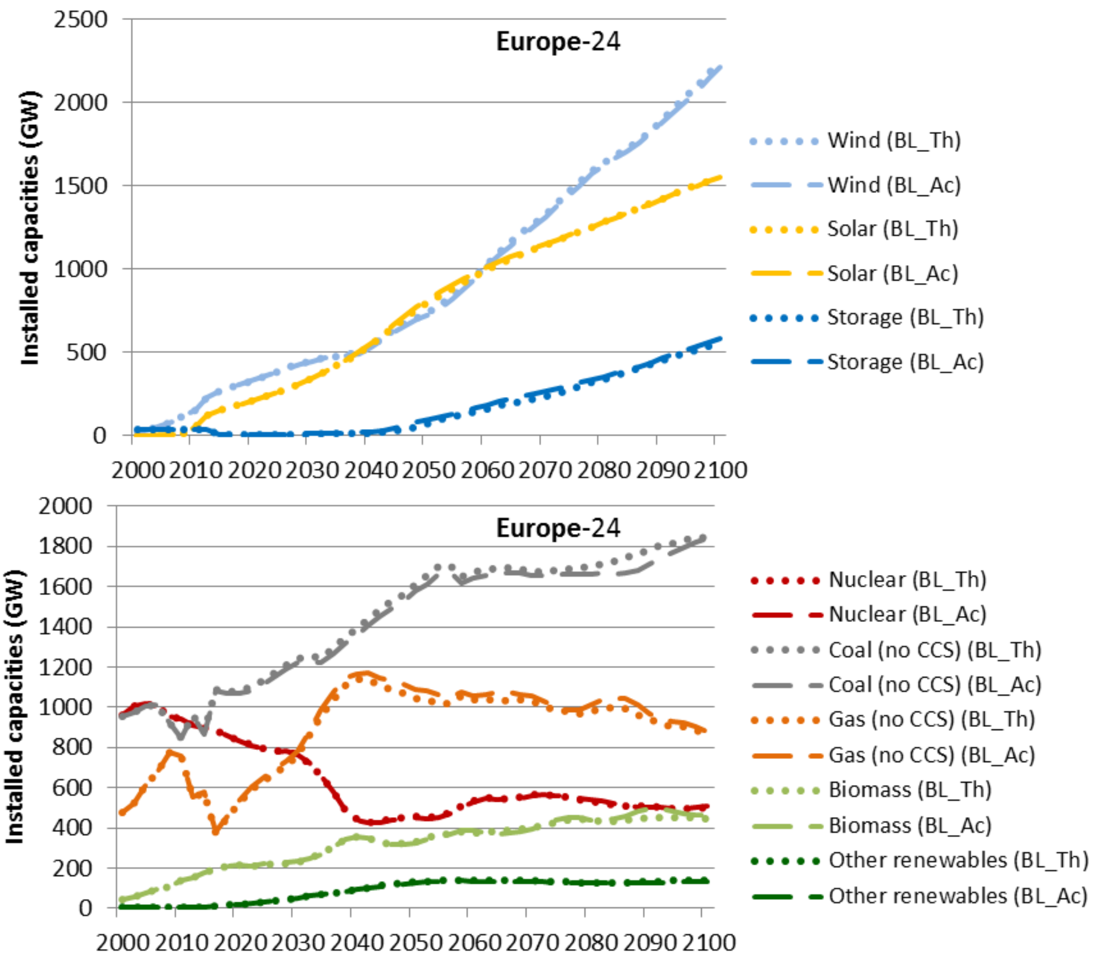


Figure H-9: Electricity production of the main technologies in Europe, with 6 typical days based on two calibration methods (with theoretical potential BL_Th and with actual production data BL_Ac), for the baseline scenario (POLES+EUCAD).

In figure H-10 the installed capacities in France and Germany are displayed.

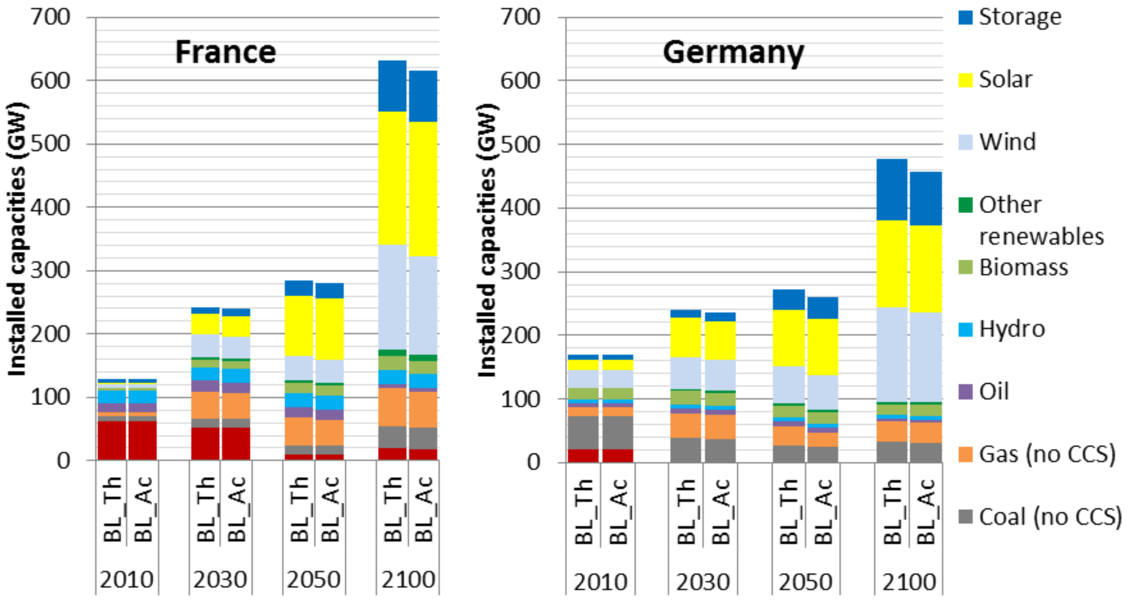


Figure H-10: Installed capacities in France and Germany with 6 typical days based on two calibration methods (with theoretical potential BL_Th and with actual production data BL_Ac); baseline scenario (POLES+EUCAD).

We observe very similar installed capacities across Europe. There is only a slightly higher use of gas power when using the real production profiles in the calibration instead of the theoretical production.

We conclude this sensitivity test by suggesting a continuous adjustment of the weighting between the countries and energy sources along the scenarios. However, this is more complex to model and would not bring much additional detail, as shown by our test of two different calibrations of the cluster algorithm.

Appendix I: Example of the power system operation in Switzerland

We present here another example, completing the case of France presented in the body of this work.

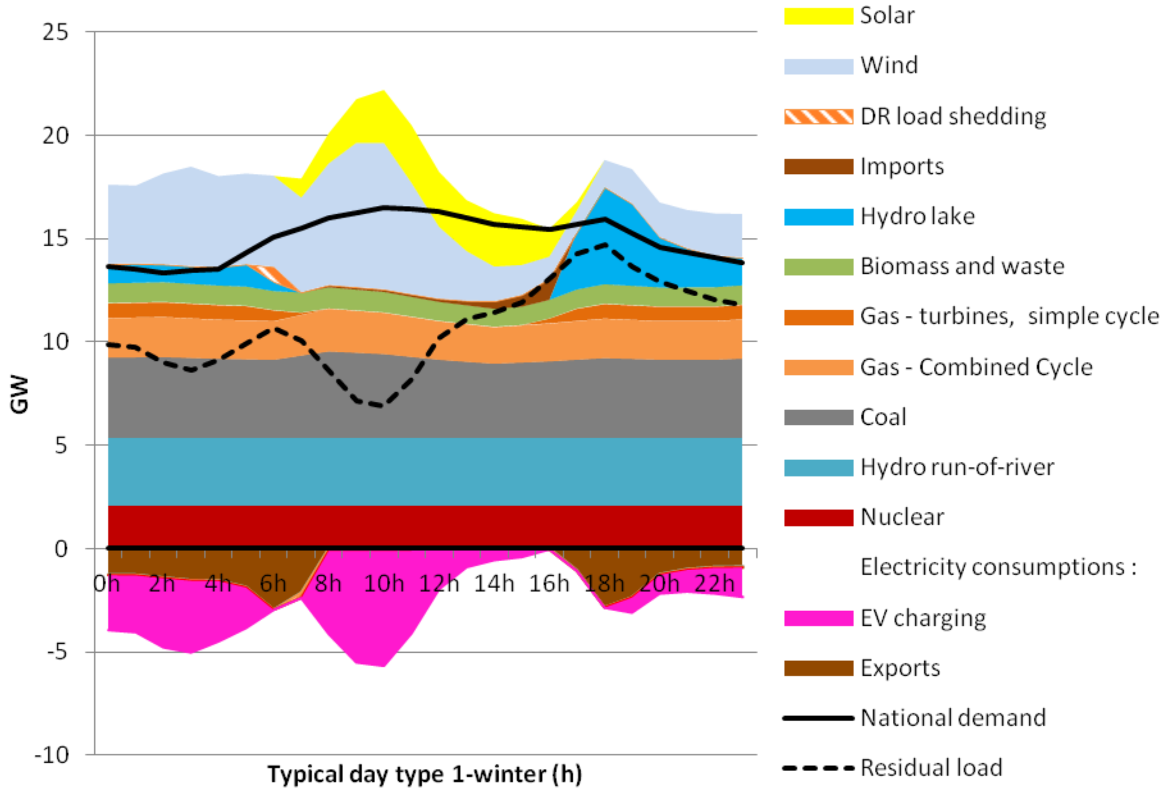


Figure I-1: Operation of the Swiss power system on a typical day of 2050 (day 1-winter), for the baseline scenario. Negative values indicate consumption (POLES+EUCAD).

The EV charging occurs at the valley of residual load, as expected. The peak production of dispatchable capacities happens at times of high residual load. What is interesting to notice is that hydro production and exports are very complementary. There is a net export during night-hours (6pm to 7am), allowed by the lakes' production. There is a net import during sun-light hours, since Switzerland apparently has proportionately less solar power installed than its neighbours.

The Swiss power system does need storage in 2050 (in the baseline scenario), its flexibility options being already well developed with EV and lake hydro production.

Appendix J: Role of the grid in the European power system

We present here the result of five different versions of EUCAD used to assess the role of the grid in the operation of the power system, by comparison with the baseline case:

- No grid and no storage technologies,
- No grid,
- Only half of the installed grid interconnection capacities,
- Normal use of the grid capacities (baseline),
- Perfectly interconnected Europe (copper plate).

We present the impact of each test for the curtailed surplus energy (figure J-1), the unserved load (figure J-2) and the operating cost (figure J-3).

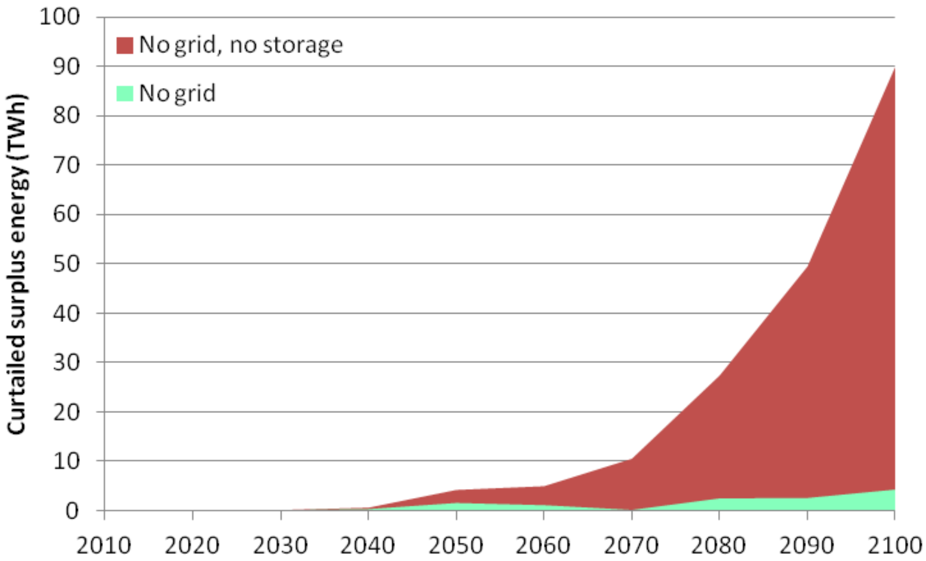


Figure J-1: Curtailed surplus energy in Europe in two hypothetical cases, with no grid and with no grid and no storage (based on the baseline scenario, which has no surplus energy).

This shows that the role of grid interconnections is less crucial than storage options (see figure 60) for the integration of the VRES production, since the curtailed surplus energy is smaller. Taking out both storage and grid implies up to 90 TWh of surplus energy (to be compared with the 3800 TWh of VRES production in 2100).

The case with half of the grid capacities, the normal case or the copper plate case do not show any surplus energy.

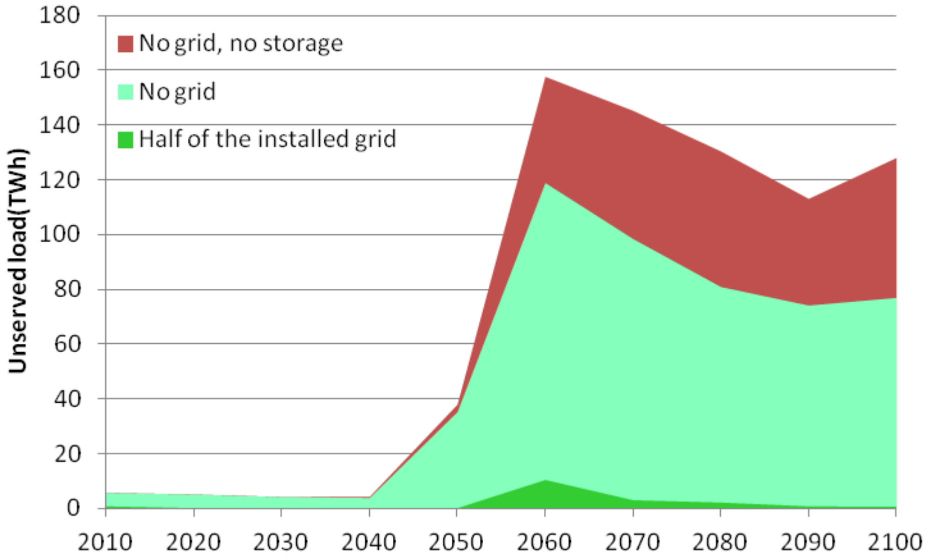


Figure J-2: Unserved load in Europe in three hypothetical cases, with no grid, with no grid and no storage, and with only half of the installed grid (based on the baseline scenario).

This illustrates the fact that the grid can be crucial in the power supply of some countries that are expected to become dependent on imports (in particular Portugal, France and Greece). The additional effect of taking out storage technologies is particularly visible starting in 2060.

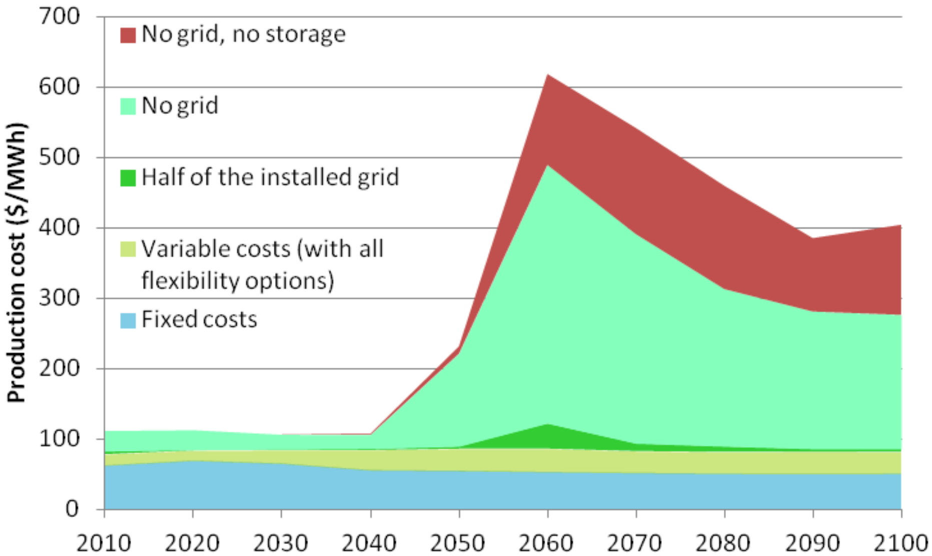


Figure J-3: Electricity production cost in different hypothetical cases (No grid and no storage technologies, no grid, only half of the installed grid capacities, normal use of the grid capacities), based on the baseline scenario.

We observe that the operating costs are strongly increased when taking out the grid capacities; this is because of the cost of unserved load. In figure J-4 we show the gain in operating costs due to a perfectly interconnected European network (compared to the increase in costs in the case with only half of the installed grid).

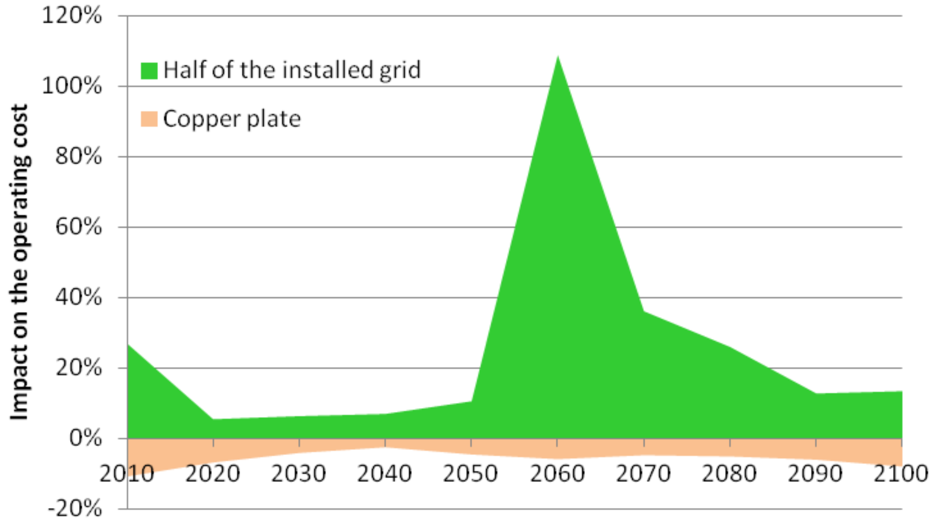


Figure J-4: Impact of the cases with half of the grid capacities and with a perfectly interconnected Europe (copper plate) on the operating cost (based on the baseline scenario)

We find that the imperfect interconnections (i.e. the congestions between countries) increase the operating cost by 3 to 8% and are rather constant across the century. This estimation could give an idea of the trade-off between building new lines and bearing the congestion costs. In particular, taking out the constraint of the line capacity limit between two countries and comparing the total European operating cost would provide an indication of the economic profitability of strengthening this interconnection.

Appendix K: Characteristics of the « Storage performance » scenario

We present here the assumptions of the Storage Performance scenario that differ from the Baseline scenario. The installable potential, life time and discount rate are kept unchanged.

Technical parameters

In the baseline scenario, the round-trip efficiencies are fixed for the whole scenario. In the Storage Performance scenario, they are improving in time (see figure K-1).

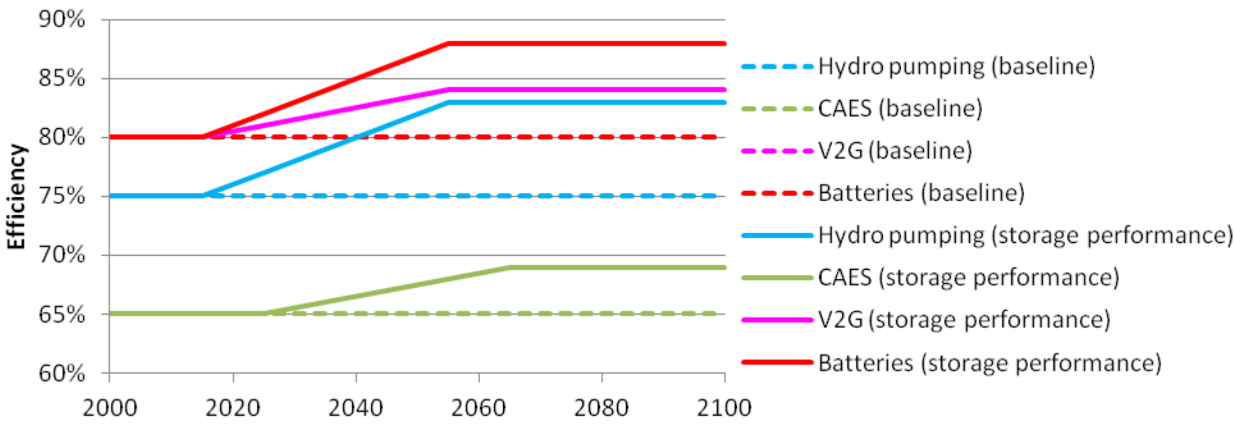


Figure K-1: Efficiency improvements of the Storage Performance scenario (exogenous assumptions)

Economical parameters

The O&M costs are reduced, both for the fixed and variable parts, as shown in figure K-2 and K-3.

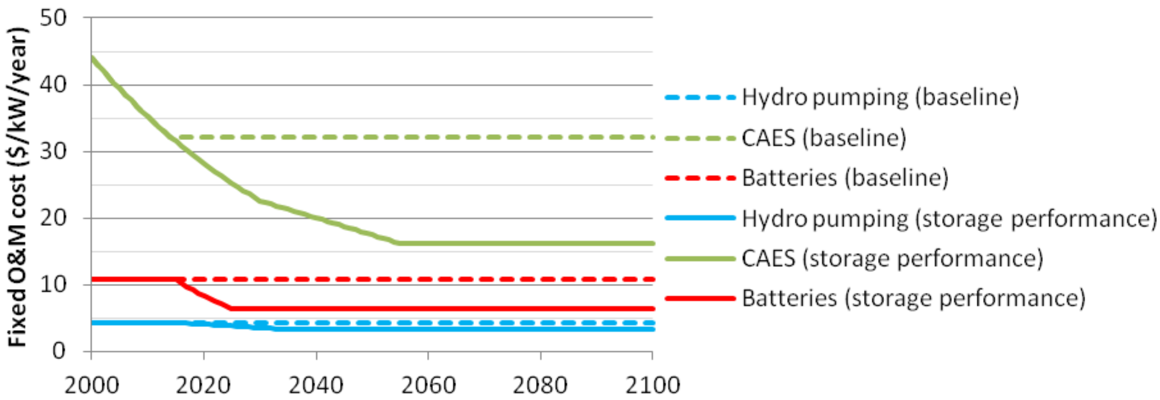


Figure K-2: Evolution of the fixed O&M costs for the Storage Performance scenario, compared to the Baseline scenario (exogenous assumptions).

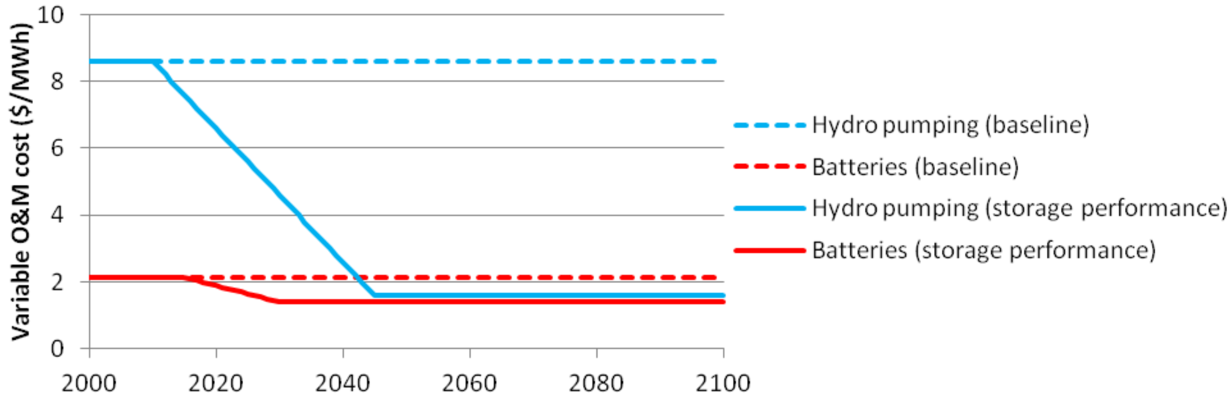


Figure K-3: Evolution of the variable O&M costs for the Storage Performance scenario, compared to the Baseline scenario (exogenous assumptions).

The learning rates (learning-by-doing) are increased by 2 points for batteries, CAES and pumped hydro. This results in the investment costs of figure K-4.

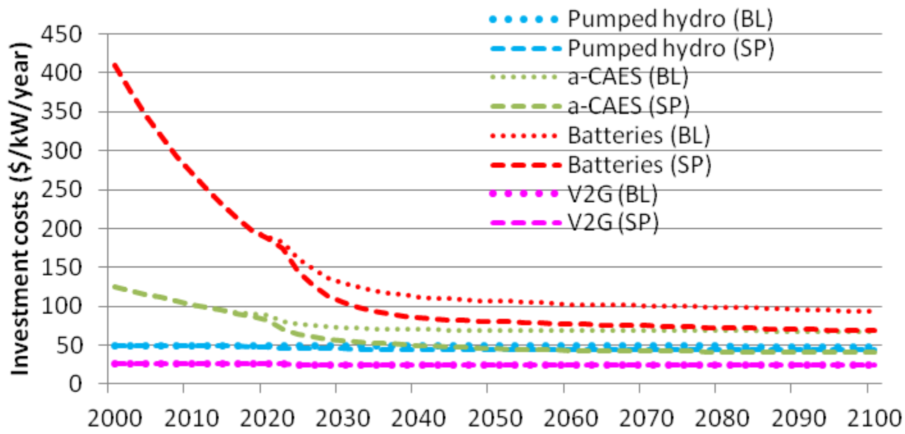


Figure K-4: Investment costs of the four storage technologies, in the Baseline (BL) and the Storage Performance (SP) scenarios (exogenous assumptions).

All the characteristics of the storage technologies (after the transitory phases are finished) are summarised in table K-1.

Storage Performance scenario	Pumped hydro	a-CAES	Batteries (Li-ion)	V2G (Li-ion)
Efficiency	83%	69%	88%	84%
Potential	10% of the total hydro potential	20% of the maximum load	50% of the maximum load	60% of EV after 2050
Investment costs	1000 $/kW or country-specific values from [187]	1075 $/kW + 43 $/kWh (2013) [186]	161 $/kW + 403 $/kWh (2013) [186]	100 $/kW until 2020
Fixed O&M costs ($/kW/year)	3.3	32.2	6.43	10.75
Variable O&M costs ($/MWh)	1.6	0	1.4	2.15
Life time (y)	55	35	12.5	10
Discount rate	4%	4%	8%	8%
Learning rate	2%	7%	10%	1%

Table K-1: Summary of the Storage Performance characteristics at the end of the scenario (exogenous assumptions).

Appendix L: The climate policy scenario

The climate policy scenario is defined so as to ensure a 2°C global warming at the end of the century. For this purpose, it uses an strong exogenous carbon value (figure L-1), which is a way to express several ways of incentivising green decisions of operation and investments (carbon tax, tradable certificates, emission trading system, private actions, etc.).

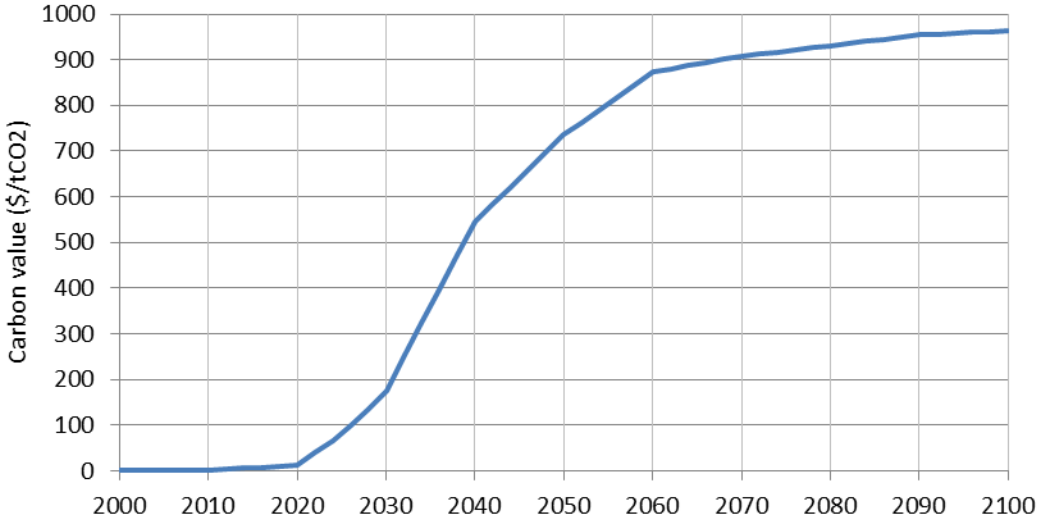


Figure L-1: Carbon value in the climate policy scenario (exogenous assumption).

The energy and electricity demand is shown in figure L-2.

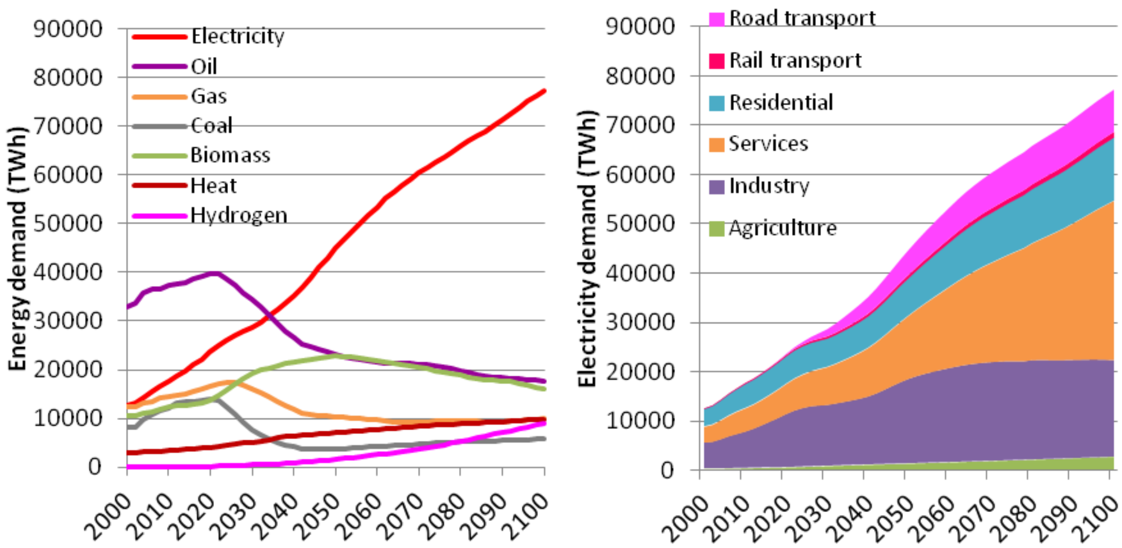


Figure L-2: Global energy needs in the climate policy scenario; decomposition by end-use fuel (left) and decomposition of electricity needs by sector (right) (POLES+EUCAD).

We observe that the demand for oil, coal and gas decreases strongly between 2020 and 2040, compared to the baseline scenario (Figure 47), while the electricity demand is slightly lower. In the following figure L-3, we show the installed capacities at the global level.

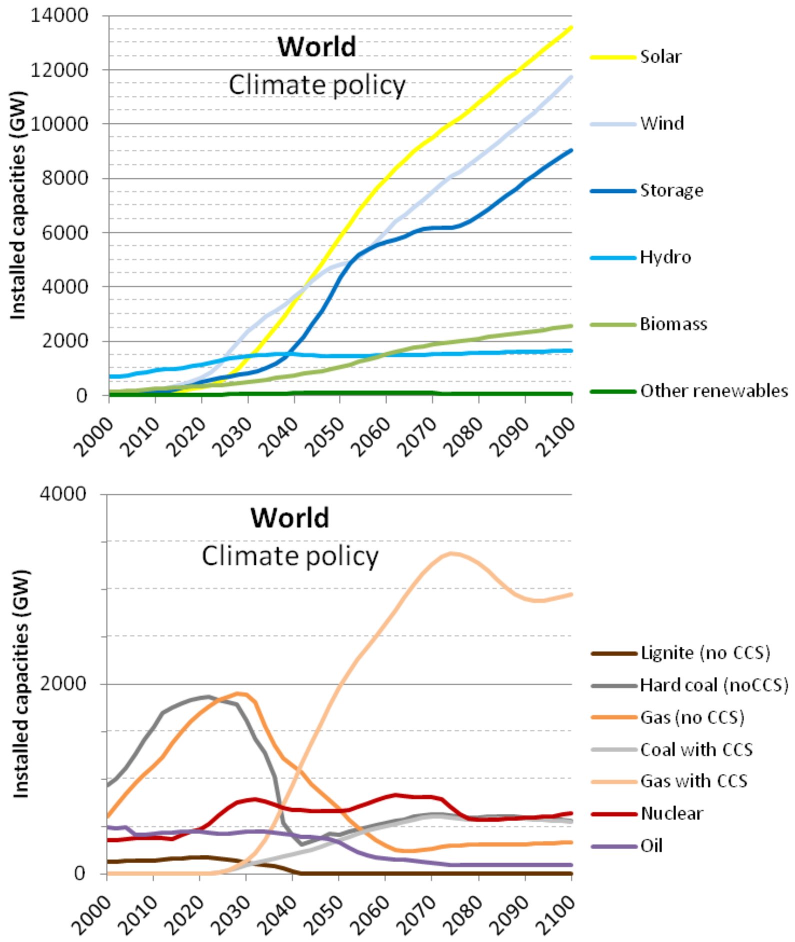


Figure L-3: Global installed capacities of the different technologies in the climate policy scenario. Renewable and storage technologies on top; fossil fuel and nuclear technologies on bottom (POLES+EUCAD).

In this climate policy scenario, we see a strong development of the CCS technologies as soon as 2030. To the contrary, conventional oil, coal and gas power plants strongly decrease. Lignite power plants are not developed anymore, due to their high carbon emissions. The wind, solar and storage capacities are not significantly higher than in the baseline. The storage technologies are more developed that in the baseline.

In figure L-4 we present the installed capacities and power supply in the whole world, in Europe-24, in France and in Germany.

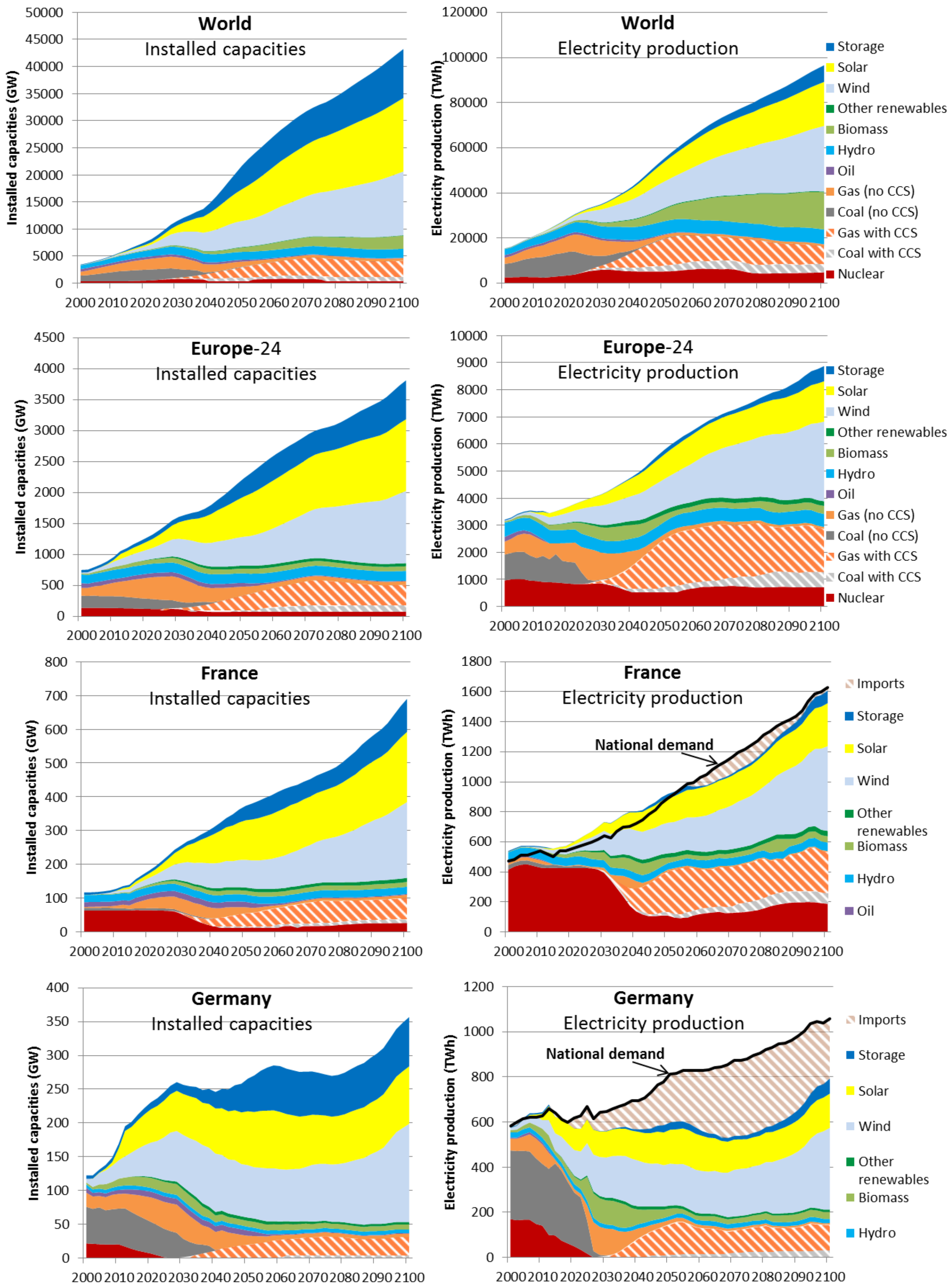


Figure L-4: Installed capacities (left) and electricity production (right) for the whole world, for Europe-24, for France and for Germany, in the climate policy scenario (POLES+EUCAD).

The case of Germany is interesting, since a relatively important storage capacity is installed, while the country relies strongly on imports, as its lignite and coal power plants are phased-out due to the high carbon value.

The figure L-5 shows the development of storage technologies in Europe, France and Germany.

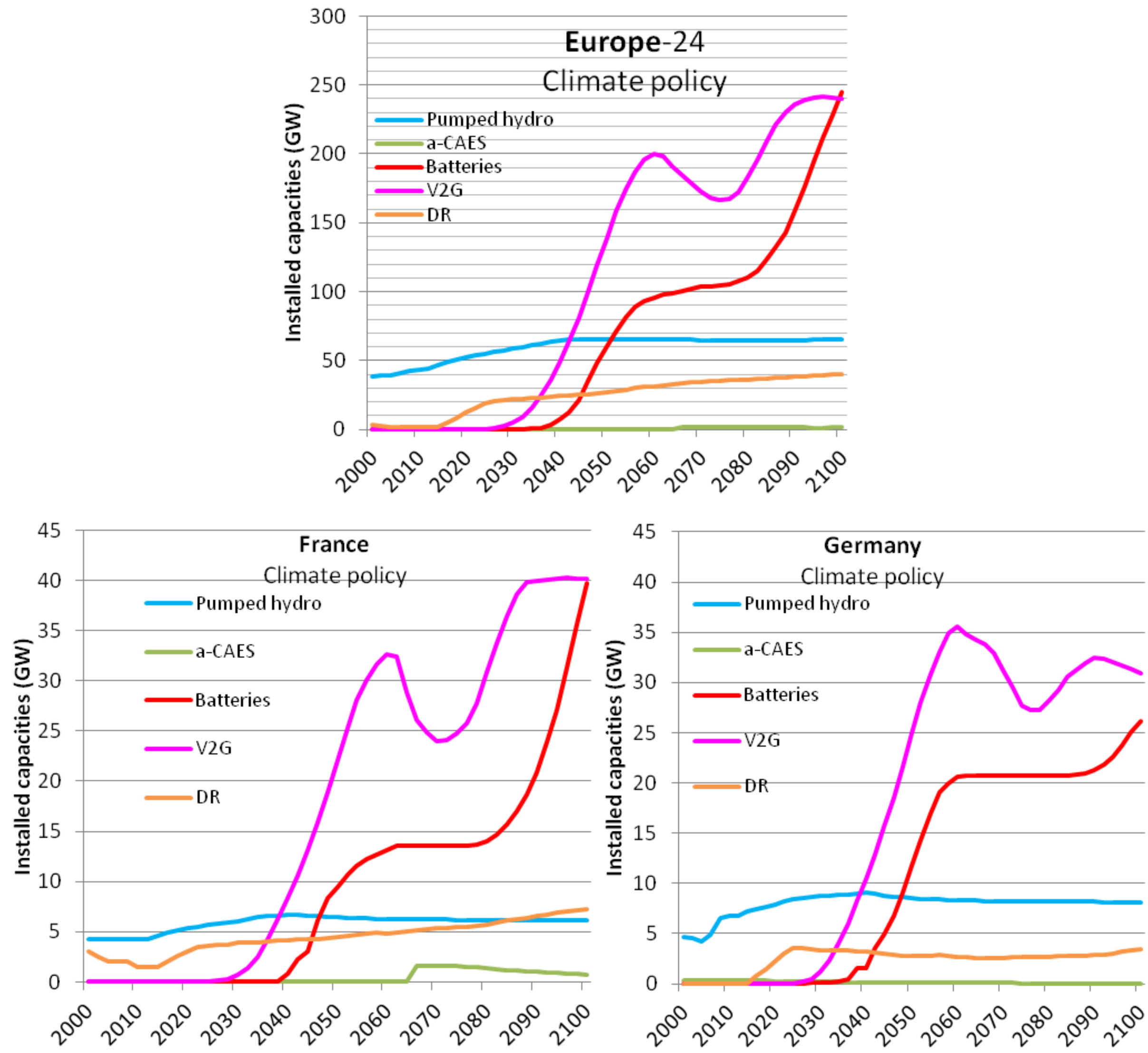


Figure L-5: Installed storage and DR capacities in Europe (top), France (left) and Germany (right), in the climate policy scenario (POLES+EUCAD).

We observe two peaks of V2G capacities in 2050 and after 2080. We identify different effects at play for these two peaks:

- The high carbon value: there is a dynamic effect in the development of gas capacities with CCS: they are only progressively developed after 2030; therefore other technologies without CCS are still needed in 2050, creating a high opportunity for storage (benefiting from the differences in production costs). This effect almost disappears around 2070, when gas with CCS becomes predominant[41]: being used both for semi-base and peaking capacities, the price spread is reduced to zero in most days, and storage has less/no value.

- The solar surplus at noon: after 2070, gas with CCS stabilizes and storage finds again a high value, coupled with solar. The excess production in the middle of the day is absorbed, thus avoiding the operation of expensive capacities at night.

In short, the first fast development of storage is mostly driven by the strong increase of the carbon value (which leads to a progressive development of CCS technologies), while the second ramp up of storage answers the challenges of the high VRES deployment (in particular the solar surplus production).

The development of batteries starts around 2040, which is 10 years earlier than in the baseline scenario, and develops much faster until 2055. After a plateau (due to the same effects as for the V2G oscillation), it increases again in 2085, especially once V2G is limited by its potential (i.e. 60% of all existing EV).

In figure L-6 we show the emission trajectory of the climate policy scenario, relative to the baseline and to the new renewable scenario.

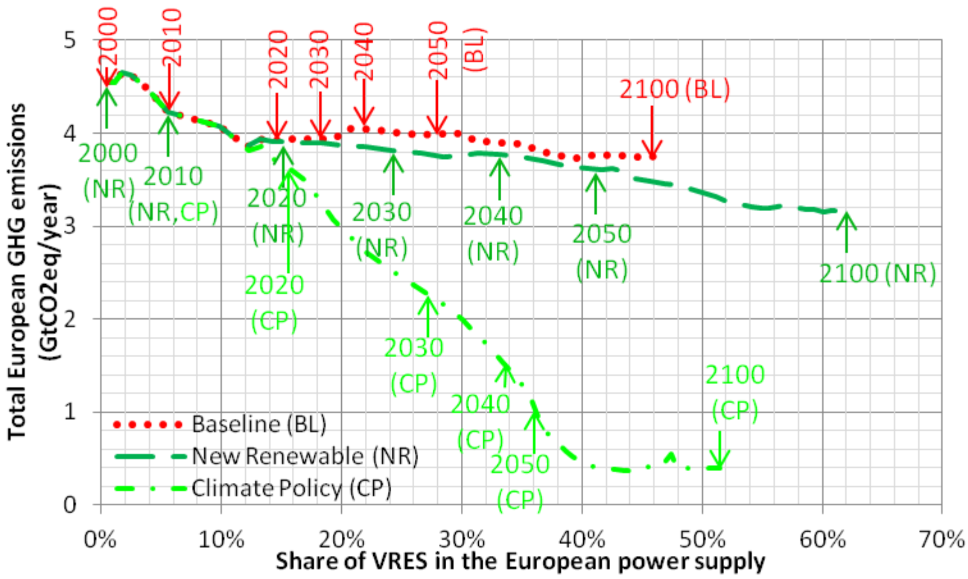


Figure L-6: Total GHG emissions in Europe relative to the VRES share in the European power supply, for the scenarios Baseline (BL), New Renewable (NR) and Climate Policy (CP) (POLES+EUCAD).

We see that the Climate Policy is much more effective in cutting GHG emissions that the New Renewable scenario. Wind and solar develop strongly (compared to the baseline), especially between 2020 and 2040, but the major emission reduction cause is the CCS technologies, which replace the standard coal and gas technologies.

[41] The strong development of gas with CCS is necessary for meeting the peak demand. Daily storage cannot replace these dispatchable production capacities.

The impact on the electricity costs and price is shown in figure L-7.

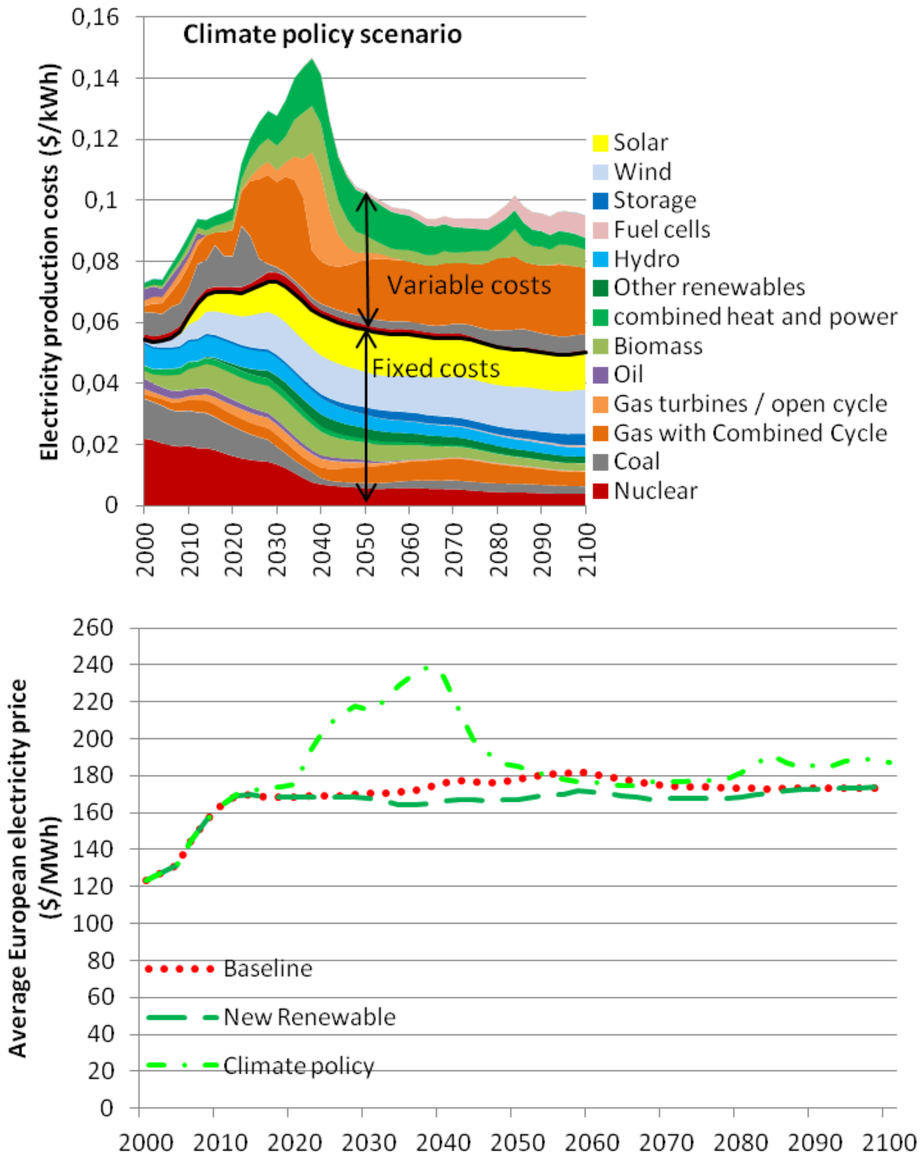


Figure L-7: Average European electricity production cost (top) and consumer price (bottom), in the Climate policy scenario (POLES+EUCAD).

We see that the high carbon value has a strong impact on the electricity costs and prices in the 2020-2050 period. However, after this period the system adapts and the costs are similar as in the baseline.

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Synthesis

The current development of wind and solar power sources calls for an improvement of long-term energy models. In particular, the power sector will be faced with high shares of variable, poorly predictable and non-dispatchable wind and solar productions, with short- and long-term impacts on the power system. Some flexibility options will be necessary, whether from production (fast-responding power plants), demand (demand response), grid (smart grids, super-grids) or storage (which has multiple values for the system). We developed a new typology that analyses the representation of these options in both long-term energy models and power sector modelling tools. We distinguish long-term energy models, adapted for studying different energy scenarios with coherent evolution of the whole energy system, and shorter-term power sector tools, more adequate for analysing the impacts of VRES on the power system and the value of flexibility options.

The model POLES has been improved in that direction. A new capacity planning is introduced, more adapted to the representation of the variability of VRES. Many different sources of flexibility are included: four daily storage technologies, long-term hydrogen storage, EV charging, demand response and European grid interconnections. A new storage investment mechanism was developed, including several economic values for storage: energy value, capacity value and balancing value. Only when adding these values does storage find an economic justification.

Yet, the simulation logic of POLES does not allow taking into account the inter-temporal constraints associated to VRES or electricity storage. Therefore we developed EUCAD, an optimisation model that minimises the European production cost, while taking into account the international grid interconnections, the ramping constraints of thermal power plants and all the different storage forms. The main improvement of our work on the state-of-the-art is the two-way coupling of POLES and EUCAD, which brings in the benefits of the long-term economic coherence of the energy system and of the precise description of the short-term power sector constraints. This overcomes the modelling difficulties identified earlier (chapter 1) and significantly improves POLES modelling (chapter 2).

Finally, we present the results of POLES+EUCAD for a conservative baseline scenario. This shows the economic benefits of developing flexibility options, in particular demand response, EV charging optimisation, V2G, and pumped hydro, which all develop up to their potential thanks to their low investment costs. On the other hand, a-CAES development is hindered by its low efficiency and low expected operating hours. Battery technologies, more expensive than V2G but with a high efficiency, are mainly developed in the second half of the century. A sensitivity analysis on scenarios with a higher storage technical and economic performance and lower VRES investment costs shows that VRES and storage development are correlated. A focus on battery sensitivity to efficiency and fixed costs shows that the later have a higher influence on battery development, which supports the conclusion that, although efficiency improvements are still necessary to ensure enough operating hours, the investment and fixed O&M costs are the key limiting factors of battery development.

Abstract

The current development of wind and solar power sources calls for an improvement of long-term energy models. Indeed, high shares of variable wind and solar productions have short- and long-term impacts on the power system, requiring the development of flexibility options: fast-reacting power plants, demand response, grid enhancement or electricity storage. Our first main contribution is the modelling of electricity storage and grid expansion in the POLES model (Prospective Outlook on Long-term Energy Systems). We set up new investment mechanisms, where storage development is based on several combined economic values. After categorising the long-term energy models and the power sector modelling tools in a common typology, we showed the need for a better integration of both approaches. Therefore, the second major contribution of our work is the yearly coupling of POLES to a short-term optimisation of the power sector operation, with the European Unit Commitment And Dispatch model (EUCAD). The two-way data exchange allows the long-term coherent scenarios of POLES to be directly backed by the short-term technical detail of EUCAD. Our results forecast a strong and rather quick development of the cheapest flexibility options: grid interconnections, pumped hydro storage and demand response programs, including electric vehicle charging optimisation and vehicle-to-grid storage. The more expensive battery storage presumably finds enough system value in the second half of the century. A sensitivity analysis shows that improving the fixed costs of batteries impacts more the investments than improving their efficiency. We also show the explicit dependency between storage and variable renewable energy sources.

Résumé

Le développement des énergies renouvelables éolienne et solaire implique de repenser les modèles à long terme du système énergétique. En effet, les impacts à court et long terme des productions intermittentes éolienne et solaire sur le système électrique entraînent un besoin de flexibilité : centrales de production très réactives, gestion de la demande, amélioration du réseau électrique ou stockage d'électricité. Le premier apport majeur à l'état de l'art est l'ajout du stockage d'électricité et du réseau électrique européen dans le modèle POLES (Prospective Outlook on Long-term Energy Systems). Un nouveau mécanisme d'investissement a été développé, mieux adapté aux enjeux des renouvelables ; il inclut plusieurs valeurs économiques du stockage. D'autre part, une nouvelle typologie applicable à la fois aux modèles de prospective énergétique et aux outils détaillés du secteur électrique, a montré l'intérêt de rassembler ces deux approches. Ainsi, la deuxième contribution principale est le couplage annuel de POLES à un modèle d'opération du système électrique, EUCAD (European Unit Commitment And Dispatch), qui optimise l'allocation technico-économique des centrales européennes de production et de stockage. Les échanges bidirectionnels d'informations permettent de bénéficier à la fois de la cohérence à long terme des scénarios économiques de POLES et du détail technique d'EUCAD. Un scénario conservateur prévoit un développement rapide des options de flexibilité les moins chères : interconnexions, stockage hydraulique et gestion de la demande – que ce soit par des effacements de consommation ou par l'optimisation de la charge et décharge des batteries de véhicules électriques. Les batteries stationnaires, plus chères, sont développées en seconde partie de siècle. Leur développement pourrait être accéléré par une réduction des coûts fixes du stockage – plus efficace qu'une amélioration du rendement. Les liens explicites entre renouvelables intermittents et stockage d'électricité ressortent aussi des résultats.