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Abstract

In this paper we demonstrate the role of electricity storage for the integration of high shares of Variable Renewable Energy Sources (VRES[3]) in the long-term evolution of the power system. For this a new electricity module is developed in POLES (Prospective Outlook on Long-term Energy Systems). It now takes into account the impacts of VRES on the European power system. The power system operation relies on EUCAD (European Unit Commitment And Dispatch), which includes daily storage and other inter-temporal constraints. The innovative aspect of our work is the direct coupling between POLES and EUCAD, thus combining a long-term simulation horizon and a short-term approach for the power system operation. The storage technologies represented are pumped-hydro storage, lithium-ion batteries, adiabatic Compressed Air Energy Storage (a-CAES) and electric vehicles (charging optimisation and vehicle-to-grid). Demand response and European grid interconnections are also represented, in order to include to some extent these flexibility options.

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[2] *Disclaimer:* The views expressed are purely those of the writer and may not in any circumstances be regarded as stating an official position of the European Commission.

[3] Abbreviations:

a-CAES: adiabatic Compressed Air Energy Storage

CCS: Carbon Capture and Storage

DR: Demand Response

EUCAD: European Unit Commitment And Dispatch

EV: Electric Vehicles

LCOE: Levelized Cost Of Electricity

POLES: Prospective Outlook on Long-term Energy Systems

V2G: Vehicle-to-Grid

VRES: Variable Renewable Energy Sources

Keywords
Electricity storage; Long-term modelling; Power system dispatch; Variable renewable energy sources; Flexibility.

1. Introduction

Climate concerns among governments are pushing energy policies towards a more sustainable way of producing electricity, with a strong reduction of CO_2 emissions. These long-term ambitions are developed, tested and studied with long-term energy modelling tools. They feature a global rise in renewable energy production: hydro power, biomass, geothermal, marine energy (thermal, wave or tidal), but most of all they forecast a strong expansion of wind and solar power generation (Griffin et al., 2013; Luderer et al., 2013). Borenstein (Borenstein, 2015) points out that "renewable energy technologies have made outstanding progress in the last decade. The cost of solar panels has plummeted. Wind turbines have become massively more efficient. In many places some forms of renewable energy are cost competitive".

However, solar and wind energy sources (also called Variable Renewable Energy Sources, VRES) present some challenges for the management of the power sector (as summarized in (Albadi and El-Saadany, 2010) for wind power and (Komiyama and Fujii, 2014) for solar power). They are variable across several time-scales: years, seasons, days, hours and even less. 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. Finally, they are uncertain, as meteorological forecasts always have a margin for error, causing variations in the energy production. VRES have a strong impact on the power sector since they are used first in the merit order (the marginal cost is zero). The residual load (demand minus VRES infeed) has to be covered by other (dispatchable) technologies.

1.1 Storage and other flexibility options

Several possibilities allow a better integration of VRES in the power sector (Benitez et al., 2008; De Jonghe et al., 2011). Electricity storage can store energy when it is available, and produce again when energy is needed (e.g. using price differences). Electricity storage also has the potential to increase grid efficiency and reliability, optimizing power flows and complementing VRES power production (Parfomak, 2012). The technical particularities of many storage technologies are presented in (Akhil et al., 2013; Rastler, 2010). The main factors that could favour the development of storage are technology advances and price decreases, a development of VRES, an increase in fossil fuel prices, a development of deregulated energy markets including markets for high-value ancillary services and local challenges of acceptability of new transmission and distribution facilities (Denholm and Hand, 2011). (Sioshansi et al., 2012) discuss technical issues as well as policy-related barriers to actual storage deployment in power markets.

We focus this paper on the role of energy storage in long-term scenarios since the subject was not a lot investigated up to now (Després et al., 2015). We choose to concentrate here on hydro pumping (the most commonly used electricity storage technology today, with 99% of installed storage capacities); adiabatic Compressed Air Energy Storage (a-CAES), as it is a high-potential, high-capacity technology (with efficiency and costs more advantageous than power-to-power hydrogen storage) and Lithium-ion batteries (which have a very high development potential, benefiting from the development of electric vehicles). The hydrogen sector is also considered, although its development is computed differently than daily storage technologies. The hydrogen production (through water electrolysis) is in competition with the other hydrogen production methods. Conversely, electricity production with a hydrogen fuel cell competes with other decentralised production technology and the retail electricity price.

Electricity storage has the potential to bring big changes to the transport sector, as Electric Vehicles (EV) are an alternative to fossil-fuelled cars. EV batteries can also be used for vehicle-to-grid (V2G) applications, with specific operating constraints (e.g. a minimum state-of-charge). V2G could imply a discharge of some EV batteries while others are charging; this has yet to be allowed by the regulation and commercially developed, but electricity exchanges between consumers and prosumers are a promising growth area.

Demand side management programs can also reduce the impact of variable generation by shifting load between two periods, for example through EV charging optimisation or Demand Response (DR). This is based on the reaction of demand to supply variations, through tariff incitation or remote control of electric appliances (Aghaei and Alizadeh, 2013; O׳Connell et al., 2014). DR and EV charging are in competition with the other storage technologies to cut electricity bills, reduce peak power demand and lower greenhouse gas emissions. However, they have additional modelling constraints: the rebound effect for DR (increased consumption on the periods following the DR activation), the availability at a given hour and the driving needs.

Another main option for integrating VRES in the power sector is a better management of the electric grid. Its potential is big, both at the local level, with smart, micro-grids, and at the international level, by developing stronger interconnections and super-grids.

Instead of mitigating the time-variations of the residual load, the other main solution is to guarantee the production-consumption balance with fast-responding power plants (e.g. gas turbines). They can compensate the absence of VRES production (so-called "back-up" capacities) as well as balance the short-term output variations (load-following mode).

Our objective is to achieve an explicit representation of the integration challenges of VRES and of the flexibility options mentioned above in a long-term forecasting energy model. We use the POLES model.

1.2 POLES (Prospective Outlook on Long-term Energy Systems)

POLES was developed by Univ. Grenoble Alpes (EDDEN team) and JRC IPTS (Joint Research Center Institute for Prospective Technological Studies). It is a bottom-up simulation model (Després, 2015a; Després et al., 2015; *POLES Manual, Version 6.1*, 2010). It covers 57 regions of the world (some regions include several countries) and is run in this paper from 2000 to 2100. The markets for oil, gas and coal are represented. It also represents in detail the biomass and hydrogen sectors. We focus in this article on the power sector module, comprising 41 production technologies, of which 5 are decentralized technologies and 10 are VRES, and a detailed decomposition of the demand side in 9 main sectors (industry, agriculture, service, residential, transport, transport and distribution losses, auto-consumption, net exports and hydrogen production from electrolysis). The simulation year is divided in 24 two-hour blocks (12 for a typical summer day, 12 for a typical winter day). All sectors have their typical load profile for summer and for winter, which are then aggregated.

The technical characteristics of VRES and the flexibility options (particularly storage) represent an increasing difficulty for the modelling of the power sector. Indeed, the required temporal resolution does not correspond to the typical time step of long-term prospective energy models (often one year, subdivided in a few representative time-slices) (Poncelet et al., 2014). For example, wind and solar have average load factors per two-hour seasonal blocks in POLES. This prevents any precise representation of the impact of VRES variability. The main simulation constraint relative to wind integration challenges is a balancing cost, computed as an additional mark-up cost. There is also a ceiling on the ratio of VRES capacities and easily dispatchable capacities.

It is not possible to directly increase the time-step of POLES since it would increase significantly the modelling complexity and the computation time. As a result, a new approach is necessary for POLES. The originality of our work is that it combines the long-term forecasting horizon of POLES (Prospective Outlook on Long-term Energy Systems) with a short-term, newly developed, European Unit Commitment And Dispatch model (EUCAD). EUCAD computes the balance between supply and demand at the hourly time-step for all European countries at once.

In the following section, we will describe the modelling framework and the methodology used in this paper, both for the operation of the power system (with EUCAD) and its capacity planning (upgrades in POLES). In section three, we show some results, first with the development and utilisation of the flexibility options, then with the role of storage for integrating VRES in the power system, using several indicators. Section four gives conclusions and perspectives on further research.

2. Methodology

We elaborate a new power sector module for POLES in order to take into account the specific constraints of VRES and storage (Després, 2015a).

2.1 Power system operation

The representation of the power system operation requires technical and temporal detail. For example, the variability of wind and solar power is based on inter-temporal constraints (VRES production changes from one hour to another). Electricity storage also needs this type of constraints (it has to be balanced across time), which suggest an optimisation approach. Therefore, for European countries we base the power system operation on the newly developed EUCAD (European Unit Commitment And Dispatch), detailed in (Després, 2015b). The other countries still rely on simulation equations in POLES, not detailed here (see the supplementary materials in appendix D). EUCAD uses the GAMS optimisation language, while POLES uses the Vensim language; the interface is managed with a specific library of functions developed at the European Joint Research Centre of Seville (IPTS). For each simulation year of POLES, EUCAD is run with data sent by POLES: the electricity load curve, the installed grid capacities between countries, the storage and production power plant capacities, the variable production costs and some information on hydrologic conditions, hydrogen usage and EV development. EUCAD minimizes the total cost of a 24-hour day of operation of the entire European power system (24 interconnected countries[4]).

[4] 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.

$$TotalCost = \sum_{Country \in Europe} \sum_{Tech \in DispatchableTechnologies} \sum_{h=1}^{24} (VariableCost(Country, Tech) * Production(Country, Tech, h) + RampingCost(Tech) * Ramp(Country, Tech, h)^2 + SocialEconomicCost * UnservedLoad(h))$$

EUCAD determines the variables *TotalCost* (the total European operating cost), *Production* (the hourly production of a technology) and *Ramp* (the hourly output variation of a technology), based on the *VariableCost* (variable production cost from POLES), the *SocialEconomicCost* (the social and economic cost of an electricity outage, approximated at 20 000 $/MWh based on (Leahy and Tol, 2011; Marignac and Legrand, 2003; Mignon, 2012; Praktiknjo et al., 2011)[5]) and the *RampingCost*[6] (the cost of varying the output of a technology, calibrated based on (Kumar et al., 2012), see appendix A). EUCAD dispatches simultaneously the production, storage and demand response of each country's technology while obeying the following constraints:

- Balance between production and demand (minus imports and potentially unserved load, plus exports and potentially surplus energy);
- Instantaneous frequency reserve (spinning and non-spinning reserves);
- Minimum output, maximum output and hourly ramping limits for thermal technologies (see appendix A for details);
- Maximum imports and exports between countries (based on Net Transfer Capacities (Brancucci Martínez-Anido, 2013), also known as a "transport model");
- Within-day storage (see appendix B for detail on the storage technologies);
- Hydro infeed in lakes, hydrogen used in fuel cells in decentralized production, hydrogen production from water electrolysis and EV charging;
- Load shedding (during one hour, followed by a one-hour rebound effect of a third and an optimal dispatch of the remaining two-thirds of the displaced energy).

Wind and solar production profiles are based on the meteorological characteristics of the year 2006, adapted to POLES capacity factors. The simultaneous wind and solar productions in all Europe were used to choose 12 typical days of European wind and solar production profile (6 in summer and 6 in winter) with a hierarchical clustering algorithm developed by Nahmmacher (Nahmmacher et al., 2014). This ensures a good representation of the variability of wind and solar. The effects of a large geographical area on this variability are also included.

POLES uses EUCAD's outputs of hourly production or storage of all dispatchable technologies, as well as the international electricity exchanges. Each day has a different frequency (clustering algorithm's result) and POLES uses weighted averages. When some curtailment of surplus energy appears in EUCAD computation, POLES uses it to update its VRES capacity factors. The investments and the links between electricity and the rest of the energy system are then handled in POLES. The system state is updated and POLES moves on to the next simulation year. This year-after-year coupling, illustrated in Figure 1, is a new modelling feature that improves the state-of-the-art.

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[5] This penalty is so high that there is no observed electricity outage, whatever the scenario.
[6] The ramping capabilities are associated to a cost proportional to the square of the ramp requirement, which simulates the non-linear additional wear and tear and partial-load efficiency losses.

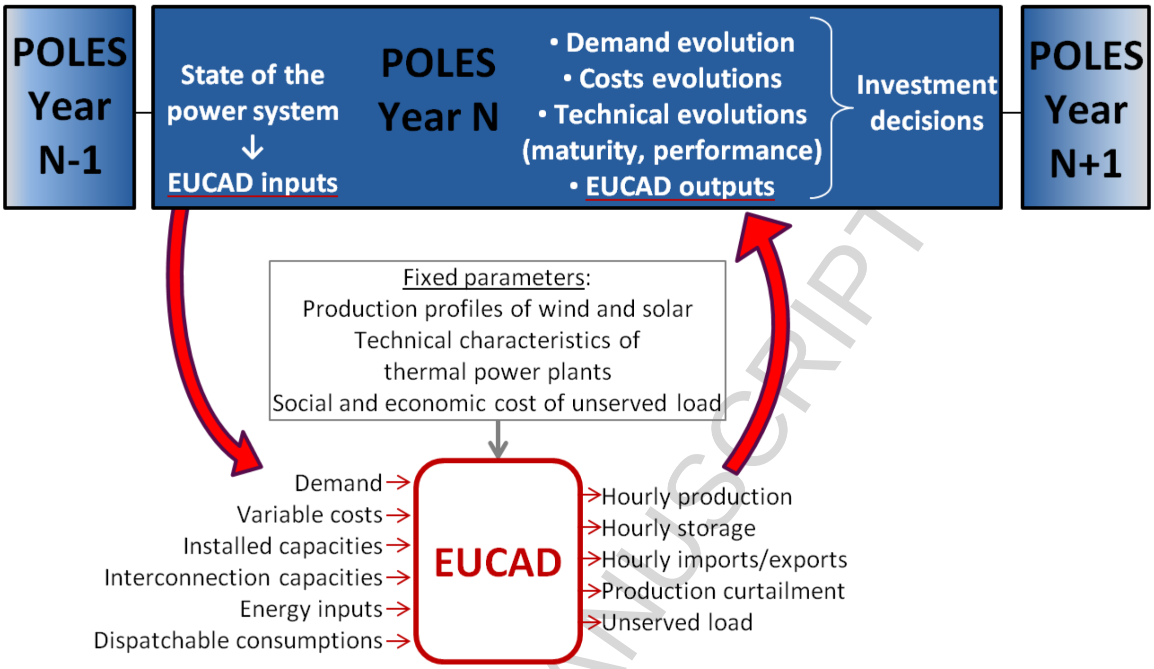

Figure 1: Diagram of the coupling between POLES and EUCAD

Compared to the previous POLES-only modelling, the POLES+EUCAD coupling allows inter-temporal constraints in the power system operation modelling, which brings new features (Després, 2015a). The main improvement is the representation of different forms of electricity storage (pure storage such as hydro pumping or stationary batteries, demand side management such as EV charging or demand response programs, or supply side flexibility such as hydro lakes or hydrogen management). The other main improvement is the simulation of the international exchanges between the European countries. Moreover, some technical operation constraints such as ramping constraints or minimum power output are added (Després, 2015b).

2.2 Capacity planning

The investment mechanisms in POLES are also significantly improved; both for production power plants, which now include the effects of the variability of VRES, and for storage plants, which have a new investment rationale.

2.2.1 Production power plants

The capacity planning of each of the 57 POLES regions is based on a residual load duration curve that considers the variability of demand and (existing) VRES. The 24 annual time slices (with a summer and a winter day of two-hour blocks) are brought to 648 time slices (54 days) defined with:

- 12 two-hour blocks for summer and winter days (pre-existing);
- Three levels of demand (low 20%, medium 55% and high 25%)
- Three levels of wind production (low 10%, medium 80% and high 10%)
- Three levels of solar production (low 10%, medium 80% and high 10%)

The variability of the demand is calibrated by increasing the residential and service consumption by 40% in the high demand day, while decreasing the residential, service and industrial consumption by 30% in the low demand day (based on the French load curve in 2013). The wind variability is computed based on the first and last deciles of daily wind production in France (at hourly time-step). Solar days use country-specific solar irradiation data (weighted to fit the residual load duration curve). The resulting endogenous residual load duration curves are computed for every year and every country or region. A comparison is shown in Figure 2 between the residual load duration curve of POLES and the equivalent for EUCAD dispatch (weighted residual demand, ordered for both cases from highest to lowest).

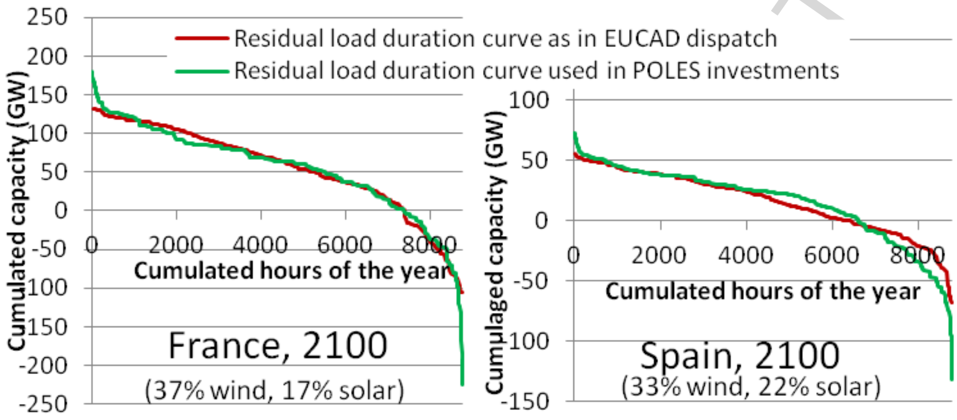

Figure 2: Comparison of the residual load duration curve used in POLES for investments and built from EUCAD dispatch, for the year 2100 in France (left) and in Spain (right), 2°C policy scenario.

This shows the good match between the national residual load duration curves used in the dispatch (built with a clustering algorithm) and in the investment mechanism (based on high, medium and low typical days). The main differences are visible in the extremes: the clustering algorithm tends to underestimate them (since the most extreme days are grouped in one of the 12 clusters), while the combination of extreme high and low situations chosen for POLES tends to overestimate them (since such extreme situations may never happen in reality). This leads to a computation of the power system operation based on more representative conditions and to investments based on a more conservative nationwide extreme-event sizing. Moreover, the clustering algorithm (used in EUCAD) takes into account the correlations (and anti-correlations) between all 24 European countries, so that the European dispatch in EUCAD can include international exchanges. On the other hand, the investments in POLES are computed nationally, independently from the neighbours (a rather conservative assumption as well, by lack of international coordination).

For each of these 54 days, the investments are estimated after simulating the impact of EV charging, DR and storage on the residual load duration curve (see appendix D and Figure 3).

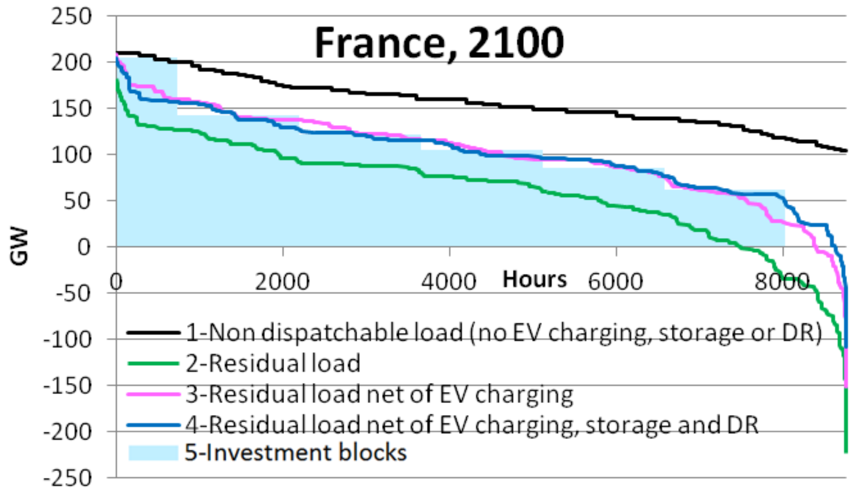

Figure 3: Load duration curve and residual load duration curves (lines) built in POLES; expected capacities for each block of hours (coloured area). France, 2°C policy scenario, 2100 (36% wind and 18% solar in the electricity mix).

The EV charging dispatch (labelled 3 in Figure 3) occurs in priority on hours with lowest residual load. We consider a minimum of 50% of the EV charging occurring during the night (which is the easiest way to charge an EV, and matches the daily journey cycles). All storage technologies (pumped hydro, adiabatic CAES, lithium-ion batteries and EV batteries used as V2G) and DR capacities are then dispatched (labelled 4 in Figure 3) on the lowest and highest residual load hours of each of these 54 days, taking into account their efficiency. This reduces the spread between minimum and maximum load within each day. The number of hours of negative residual load in this example (France, 2100, in a 2°C policy scenario) decreases from 367 h (step 3, after EV charging optimisation) to 126 h (step 4). The corresponding solar production is absorbed by within-day storage. The peak consumption is only reduced by within-day storage to a limited extent (only 4 GW here, despite the 83 GW of installed storage). Indeed, on such peaking days the residual load is already very flat without storage: the load is consistently high throughout the day, the solar production is low and the EV charging absorbs the residual load variations. A limit of our modelling is that within-day storage does not allow using storage across days; however, this ensures that an exceptional peaking period of several days can also be covered. As a consequence, our modelling choices tend to under-estimate the participation of storage to the peaking periods of the residual load duration curve. Grid interconnections and international cooperation are not accounted either in peaking periods. The model therefore has to use conventional peaking production capacities that constitute a security reserve. In future works, the coupling with EUCAD could be enhanced by using the same typical days in the investment mechanism and the same international exchanges as computed in EUCAD.

All future investments (including wind and solar) are then based on the residual load duration curve, aggregated to seven investment blocks (8760 h, 8030 h, 6570 h, 5110 h, 3650 h, 2190 h and 730 h). Each of these blocks corresponds to different expected capacity factors (the peak residual load is the value used for the 730 h investment block, as shown in Figure 3), thereby defining the expected profitability of each power plant, different for each investment block. The investments are a mix of all technologies (using a distribution function and not a “winner-takes-it-all” situation), based on this expected production cost (with an elasticity) and a non-cost parameter capturing technological maturity. The only centralised power plants handled differently are the run-of-river and lake hydro, which follow an exogenous trend.

2.2.2 Storage power plants

Electricity storage cannot be compared with production technologies since it brings other values to the system (Akhil et al., 2013; Rastler, 2010) that we categorize in three parts.

Energy value

The “energy value” comes from the production management, relying on a difference of prices (the “price spread”) within a period of time. Electricity is stored in periods of excess production (low prices on the spot market), and produced during periods of high demand (high prices). In our modelling we focus on daily storage, which has to be balanced across the 24 hours of the day (and therefore cannot produce in a sustained manner throughout entire days), with a perfect forecast of these 24 hours.

In order to represent this investment logic, we simulate shadow prices in POLES, with a “merit order” logic (adding capacities according to their ascending variable cost, until demand is met). The impact of existing EV charging, storage and DR on the demand is included. For each of the 648 time-slices, the marginal technology sets the electricity price. The additional storage capacity operates as long as there is an interest in buying and selling, which is limited by the round-trip efficiency and the assumed reservoir size of each technology (we assume its operation does not significantly affect the shadow prices). For the European countries, EUCAD feedback on the number of operating hours of storage is used to adjust POLES simulation equations (see appendix D). The resulting profits over the 54 typical days of the year are aggregated into an “energy value” of storage. Any additional storage reduces the price spread on the following years, therefore reducing the market for further storage.

Capacity value

A second value for storage is to use it as a back-up plant. It can supply electricity in the few peak periods with exceptionally high market prices. These prices are supposed to pay for the fixed costs of the peak power plants (another possible market design is a dedicated capacity market). A storage plant can replace another dispatchable peak capacity (“capacity value”). The capacity value is not included in the energy value since the exceptionally high prices are not purely built from marginal costs of production, as used in the energy value.

In our modelling, the capacity value is assumed to be the fixed cost of the extreme-peak power plant used during the year (i.e. the built technology with the lowest fixed cost). The capacity value of each storage technology also depends on the size of its reservoir (see appendix B), and thus on its availability at hours with highest residual load.

Balancing value

The third value (“balancing value”) is supposed to estimate all ancillary services. For example, storage plants can offer frequency regulation (primary and secondary reserve, balancing market), voltage regulation, black-start (re-starting a power plant in an islanded grid). They can also delay a grid investment (Poudineh and Jamasb, 2014). The economic value depends on the existence of an adequate market or special agreements (e.g. with transmission operators).

We take into account the ancillary services of storage based on an estimate of the value of hydro pumping in the balancing market in France in 2008 and 2013 (18.8 $/kW/year). This estimation grows linearly as the share of VRES increases (with an estimated target value of 45 $/kW/year for a 100% penetration of wind and solar). We assume that the balancing value is only available when storage capacities are not already operating (storage or production) and benefiting from an energy or capacity value.

For both the capacity and balancing value, we use smaller expected revenues if the installed storage capacity is higher than 10% of the peak demand. Indeed, the competition with already existing storage makes it harder for new entrants. The total of the energy, capacity and balancing values is compared with the annualized costs. If the result is positive, new storage plants are built, proportionally to the maximum installable potential.

2.3 Limitations

The methodology used in POLES+EUCAD has a few limits that we summarize here.

First, the representation of the power system operation uses aggregated installed capacities per technology, with no plant-by-plant description, thus limiting the impact of the unit commitment technical constraints (Després, 2015b).

Concerning the investment planning, the new use of a residual load duration curve accounts for the constraints of a power system with high shares of variable renewable energy sources (e.g. variability and non-dispatchability of solar and wind; decrease of the base-load needs and increase in the peak-load needs). However, this formulation necessarily uses some approximations. The calibration of the high, medium and low days of the load, wind and solar production is partly based on an analysis of the French situation. By lack of data, some local specificities are overlooked when extrapolating this to the other POLES regions. Moreover, the inherent limitations of the residual load duration curve are that each region manages its investments in an independent way, potentially leading to some over-investment. Indeed, the international exchanges often contribute to the balancing of supply and demand in tightly-constrained situations[7]. For example, the smoothening effect of the load, solar resource and wind resource in an international grid may relieve the stress on the national system but is not accounted in the investment mechanism (although it is used in EUCAD's operation).

Another limit of our modelling is that we only focus here on daily storage, while weekly storage and seasonal storage are not explicitly represented (except for the hydrogen sector). In the day of maximum residual load, the intraday variations are small, so within-day storage is of little use, not being able to use stored electricity from other days of lower residual load.

One should also note that the investments in grid interconnections (see appendix D) are not linked to the rest of the installed capacities, but rather to the utilisation rate of the power lines, considered as an estimation of the congestion costs.

3. Results

3.1 Storage investments

We present here how the different storage technologies of POLES+EUCAD are developed in a long-term scenario with a 2°C policy scenario, characterised by a particularly strong increase between 2020 and 2040 of the carbon value (i.e. the shadow value of carbon emissions that satisfies a climate constraint) and a slowing down of the increase in the

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[7] POLES does not entirely benefit from the optimised international exchanges computed in EUCAD, which are aggregated to 24 two-hour blocks before using them in the load duration curve of POLES.

second half of the century. The time horizon is 2100 (the resulting fossil fuel prices are shown in appendix E), which allows a comparison of the long-term trends with other Integrated Assesment Models (Luderer et al., this issue; Pietzcker et al., this issue), despite the high uncertainties. The hybrid and full-electric vehicles develop strongly, adding up to a third of all vehicles in 2035 and two thirds in 2100.

Figure 4 shows how the total storage capacities and other flexibility options develop in Europe (30 countries, i.e. European Union, Norway and Switzerland).

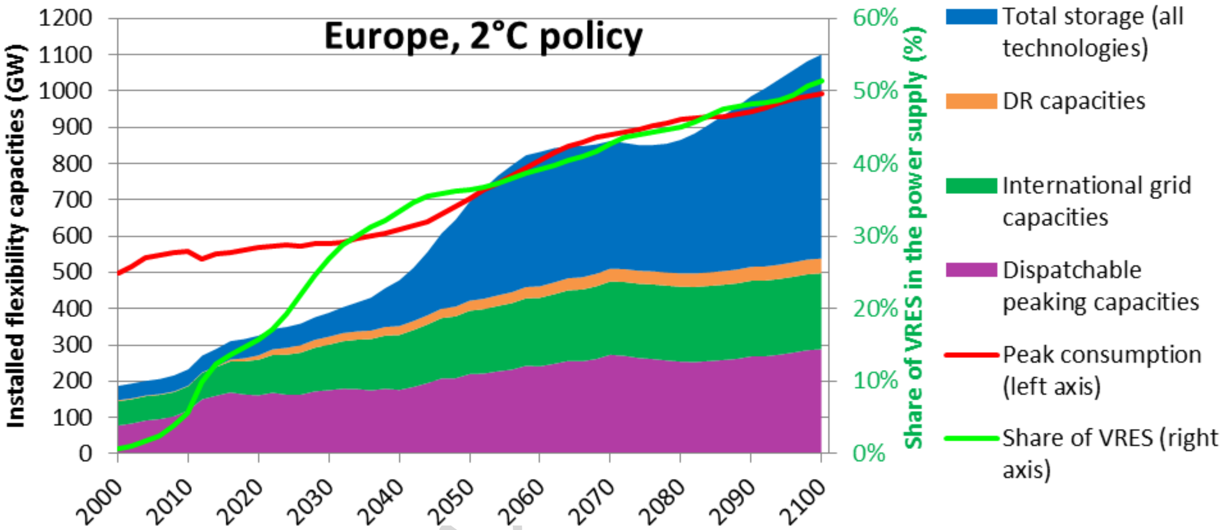

Figure 4: Development of the different flexibility options: peaking capacities (i.e. the dispatchable capacities built for 730 h or less of operation), grid capacities (the sum of all European interconnections), DR and storage capacities (sum of pumped hydro, a-CAES, V2G and stationary batteries). 2°C policy scenario, Europe 28+2.

The sum of the flexibility options shown in this figure represents a third of the installed production capacities in 2100. Their development follows the ever steeper residual load duration curve, due to the low capacity credit of wind and solar. Grid interconnections[8] are strongly developed in the first half of the century, thus ensuring solidarity between countries and levelling out the VRES variations. The development of European interconnections slows down when approaching the assumed maximum potential. DR also reaches quickly (around 2025) its potential (fixed exogenously at 5% of the peak load); indeed, its assumed costs are largely lower than its benefits for the system. Storage capacities take over in the second half of the century, for VRES penetrations above 35%.

In Figure 5 we focus on the long-term development and operating hours (charging or discharging mode) of the four storage technologies represented[9] (hydro pumping, a-CAES, V2G and batteries). We only report here the full load hours corresponding to the optimisation of the power sector operation; EUCAD does not compute the storage utilisation for the capacity markets or ancillary services, although they also influence the investment decisions.

[8] Grid capacities are based on data from the ENTSO-E for 2010 and 2025, gathered in (Brancucci Martínez-Anido, 2013). After 2025, the connection lines are developed proportionately to their number of full load hours, which is assumed to be a proxy for the congestion costs; the maximum installable potential is assumed to be twice the level of 2025. See appendix D for more details.

[9] A proxy of the reservoir size is evaluated and shown in appendix B.

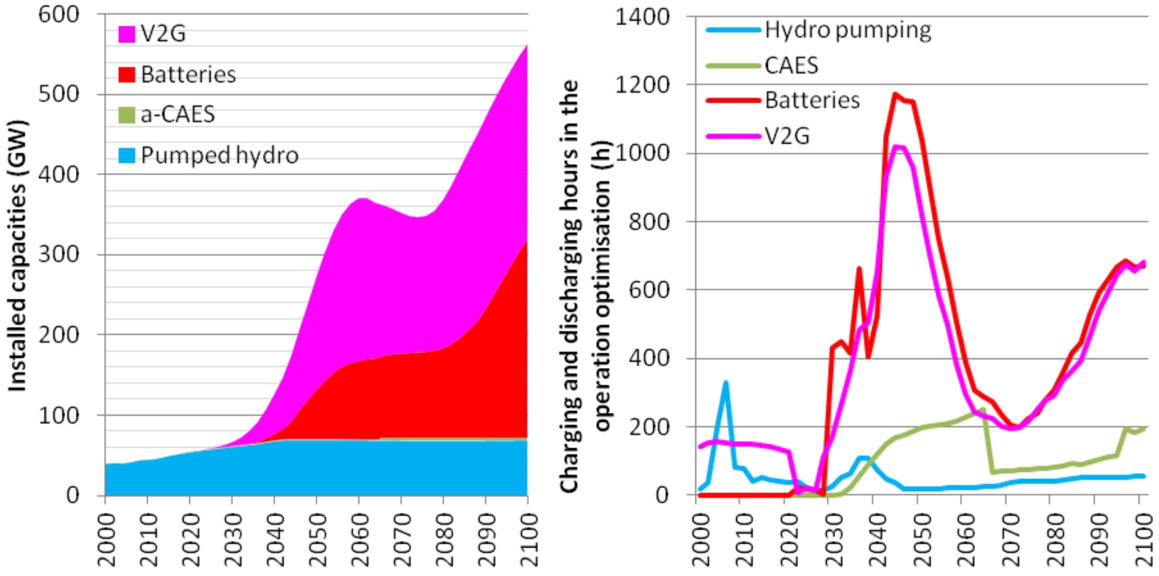

Figure 5: Installed capacities (left) and hours of utilisation (i.e. sum of charging and discharging) in the operation optimisation (right) of the different daily storage technologies. 2°C policy scenario, Europe 28+2.

The currently dominant pumped hydro technology is expected to increase slowly at first. It is driven by its low investment cost and its capacity and balancing economic values. We see on the right part of Figure 5 that the operation of pumped hydro for the daily power sector optimisation (i.e. the energy value) is rather low. Therefore, the majority of the operating hours (historically around 1900 hours) are expected to come from other reasons (not represented in POLES+EUCAD): weekly storage, balancing and capacity values. The assumed maximum potential for pumped hydro is approached around 2040, thus slowing down further investments.

Adiabatic CAES develops slowly (2.5 GW at the end of the century), penalised by its low efficiency (65%). However, the longer-term services of storage (over 24 h), not represented here, could lead to stronger investments in a-CAES or pumped hydro.

In the right part of the Figure 5, we see that the technologies with highest efficiency (lithium-ion batteries, either stationary or in EV) are used in priority in the daily operation optimisation. Accordingly, there is a strong rise of EV and stationary battery capacities after 2040. V2G programs develop strongly, following the EV development, since their installation costs are very low (see appendix B; the battery is assumed to be already paid by the transport applications; only the controlling device is new[10]). The higher installation cost of stationary batteries compared to EV batteries is compensated by their higher utilisation for energy and capacity economic values[11].

The slow-down of battery and V2G investments around 2060-2070 (Figure 5-left) is due to a dip in the operating hours (Figure 5-right): the energy value decreases (however, the other

[10] By lack of data and to limit the computation time, we did not include the premature ageing of the batteries (both in EV and as stationary batteries) associated with storage cycles. Besides, no specific business model is considered, e.g. through transactions between the system operator and the owner of the EV battery.

[11] The balancing value is slightly higher for V2G since they are expected to be connected and in an idle state more often than stationary batteries, so that they could be used to provide short-term frequency reserve power.

drivers for storage installation, namely balancing and capacity values, still maintain a certain level of investments). To explain this, we distinguish two different effects. The first period of storage development around 2050 is driven by the very high carbon prices assumed for reaching the 2°C global warming target. Carbon Capture and Storage (CCS) technologies have not yet fully replaced the CO_2-intensive capacities (CCS is only developed after 2030, as shown in appendix C). The spread of marginal costs between power plants with and without CCS creates a high value for storage that increases the capacity factor of CCS technologies. The second period of storage development, after 2080, is linked to the increasing role of VRES that need storage for covering the demand reliably and integrating better the solar production in day-light hours.

In the 2070 decade, the investment dynamics in POLES forecast a peak development of combined cycle gas power plants with CCS ("gas+CCS"). Indeed, our modelling of within-day storage (daily balance with no longer-term management of the state of charge, no difference in the marginal prices within a single technology) underweights its role in the reduction of the peak residual load. More peaking capacities are needed to meet the peak demand. Around 2070, gas+CCS are used both for semi-base and peaking purposes, which irons out the price spread – and the storage value. After 2070, gas+CCS decrease slightly, partly replaced by coal power plants with CCS, partly relying more on VRES coupled with storage. Indeed, surplus solar productions at noon become more frequent (inducing some curtailed surplus energy, see 5.2). Daily storage is then used to displace this surplus energy to night-hour periods, thus avoiding the use of any fossil fuelled plant.

In addition, storage can only develop when based on several economic values – not only the daily optimisation of the power sector operation. For example, batteries expand in 2040 because the energy, balancing and capacity values (respectively 62 $/kW, 16 $/kW and 54 $/kW) are higher than the fixed annualised costs of 2040 (122 $/kW). In some situations, the balancing and capacity values alone can be enough to invest in storage, for example when costs are low enough (e.g. pumped hydro, which annualised cost of 50 $/kW in 2040 is already compensated by the capacity value of 52 $/kW and the balancing value of 18 $/kW; the energy value of 32 $/kW is an additional source of revenue). However, the technologies with strongest development (V2G and stationary batteries) all have an essential role in the optimisation of the power sector operating cost.

In conclusion, the storage investments can be explained by two effects: the impact of a high carbon value on the relative variable costs of technologies with and without CCS, and the impact of frequent surplus solar energy at noon, which can be displaced to night hours. The pattern has to repeat itself often in order to create a reliable source of revenue for storage. On the other hand, storage can suffer from competition with "back-up" technologies that become predominant (such as gas+CCS in situations where it has replaced most technologies without CCS). These peaking capacities are particularly necessary if there is no cheap surplus energy to store and displace to hours with higher residual load.

3.2 Storage operation

To illustrate the value of storage with increasing VRES generation, we choose to focus on one typical day of high wind and solar production in France in the year 2100 as an illustration (see Figure 6).

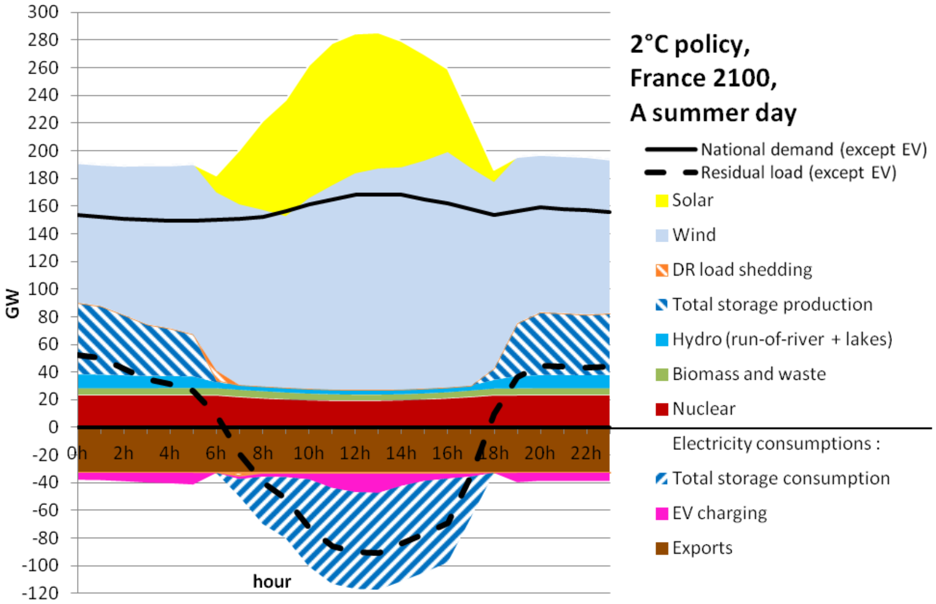

Figure 6: Power sector operation (result of EUCAD optimisation); negative values indicate consumption. 2°C policy scenario, 2100, France.

In this example, we clearly see the role of storage for absorbing the solar production surplus during day-light hours, and producing during night-hours, thus avoiding the use of more expensive power plants (Denholm and Hand, 2011). The production profile of hydro lakes is changed compared to the current operation mode: they mainly produce during night-hours (except for the run-of-river part), when the residual load is higher.

The Figure 7 shows the power system operation for the same 2°C policy scenario but without any new storage investment (only already existing pumping hydro is available).

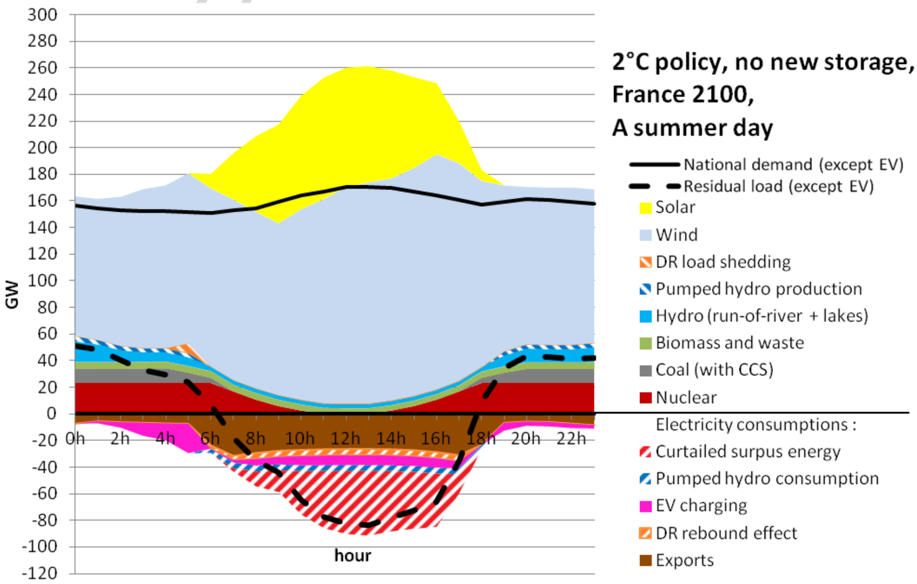

Figure 7: Power sector operation without any new storage (result of EUCAD optimisation); negative values indicate consumption. 2°C policy scenario with no new storage, 2100, France.

In this case, thermal power plants have stronger ramping requirements (here coal and nuclear are switched off during solar producing hours), causing early fatigue of the equipments. Interconnection lines are used differently, which shows that storage also has an impact on the international trade. This emphasizes the role of storage in optimising the technical and economical use of the power plants and interconnections, and thus the power spot prices.

Most importantly, some curtailment of surplus energy production occurs frequently (here, up to 48 GW of surplus power). We monitor the curtailed surplus energy in the European power system in Figure 8 (for the 2°C policy scenario, with and without new storage).

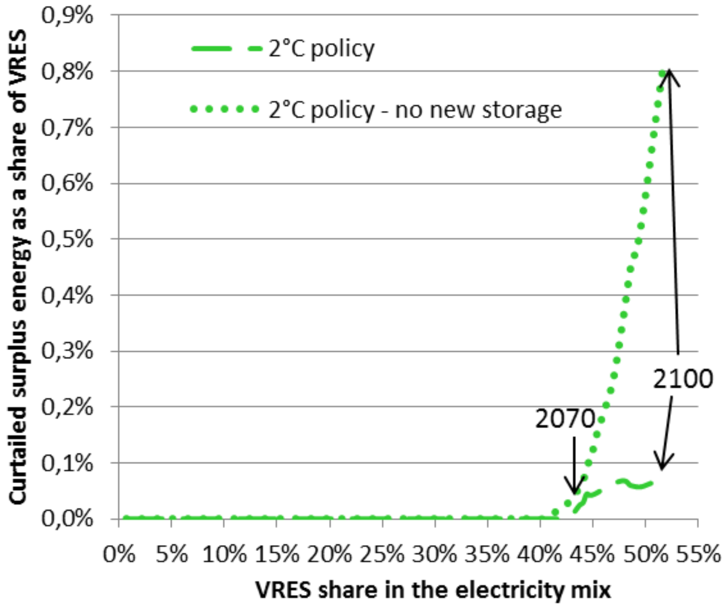

Figure 8: Curtailment of surplus energy in Europe, as a function of the VRES penetration in the system in the 2°C policy scenario, with and without new storage development.

The 2°C policy scenario has relatively little surplus energy, appearing above 43% of VRES share in the electricity mix. However, not allowing the deployment of any new storage significantly increases the surplus energy, up to 37 TWh in 2100 for the whole Europe. This emphasises the role of storage for integrating VRES.

As a consequence of blocking any new storage investment, the annual European operating costs are increased by 8% in 2050 and 12% in 2100, in particular due to the integration cost of the daily solar peak[12].

3.3 Storage and VRES integration costs

Wind and solar power sources are not equivalent to dispatchable power sources. In order to evaluate the surplus cost caused by the integration of VRES in the system, indicators of the cost of variability are used. For example, the system costs presented in (OECD Nuclear Energy Agency, 2012) consider "grid-level costs" (short-term balancing power, long-term capacity adequacy and grid extensions) as well as some other "system costs" (environmental impacts, security of supply, technological and economic development, etc.).

These "grid-level costs" are analogous to the "system LCOE" (Levelized Cost Of Electricity) used by (Hirth et al., 2014; Ueckerdt et al., 2013), which includes the additional, indirect system costs, due to the utilization of any technology that is not perfectly matching the

[12] The total production costs are very similar with or without new storage. However, they do not reflect the other market segments such as the balancing market; this additional economic value of storage should also be accounted for.

electricity needs of the consumer. We use a similar indicator, defined as the cost difference between two situations with different VRES production profiles:

- VRES with their actual production profile, including their variability; and
- A counterfactual case with VRES featuring an ideal production profile, which is defined as perfectly matching the electricity needs of the consumer[13].

The integration cost indicator could also be defined for other production power plants (e.g. baseload power plants) but we focus on non-dispatchable power sources. It comprises an investment and an operating part.

Investment costs are impacted by VRES because the variability of wind and solar impacts the structure of the rest of the power system, with steeper residual load duration curves. This increases the need for peaking power plants and reduces the necessity of base-load power plants. The overall impact is an increase in the total installed dispatchable capacities, but with a lower per-MW installation cost (by definition of a peaking capacity). We find a very small (or even negative) additional investment cost linked to the variability of VRES.

The operating part of the integration costs are computed as the difference of total system operating costs (as defined in the equation in section 2.3) between the two situations. It corresponds to the low capacity credit of VRES (requiring the operation of peaking capacities with high variable costs); the reduction of the base-load needs (with more ramping costs); and the curtailment of surplus energy (i.e. lost value for the system).

Note that the integration costs associated with the grid (congestion management, grid reinforcement) also have an influence, but they are more difficult to quantify in a general case. Figure 9 shows the operating part of the integration cost in four scenarios of the ADVANCE project (Baseline with no energy-environment policy; 2°C policy with a strong carbon value; Tax30 with a carbon value starting at 30 $/t$CO_2$ in 2020 and constantly increasing by 5% per year; Low cost based on Tax30 but with halved investment costs for wind and solar after 2030). We also show what would be the integration costs without any new storage installation.

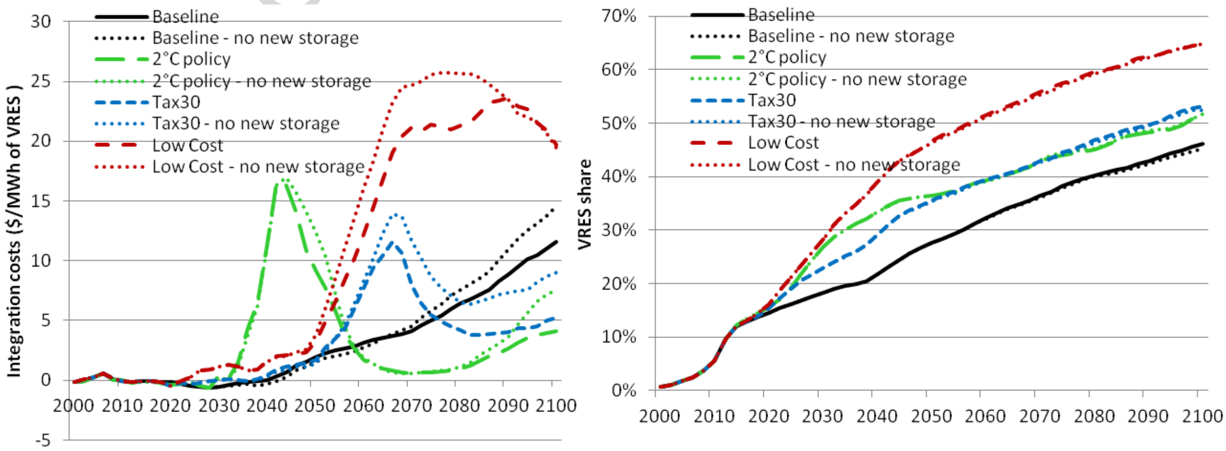

Figure 9: European system integration cost (left) and VRES share (right) for four scenarios ("Baseline", "2°C policy", "Tax30" and "Low cost"), with and without new storage development. We attribute these integration costs to VRES, although in reality they are supported by the system as a whole, and not by a single technology.

[13] The annual VRES production is redistributed proportionally to the load curve, at all times of the year.

The figure shows no smooth relation between VRES integration costs (which have peaks, see Figure 9-left) and the share of VRES in the energy mix (monotonic, see Figure 9-right); other factors influence the integration cost. At first, the scenarios show an integration cost growing with the wind and solar penetration. But then, the scenarios with carbon values (2°C policy, Tax30 and Low Cost) feature a VRES integration cost peak. The earlier peak for the 2°C policy scenario reflects the stronger and earlier increase of the carbon value. The variability of VRES implies that peaking capacities (with no CCS) are necessary. Storage avoids the use of such expensive power plants, thus reducing the integration cost. Once gas+CCS is dominant, it covers both semi-base and peaking needs and the price spread is reduced, as is the integration cost. A second period of increase of the indicator happens when the VRES increase further (around 2080).

The absence of new storage generally increases the integration costs by 3 to 5 dollars per MWh of VRE production, mainly visible after 2050 (when storage is developed).

3.4 Storage and CO_2 emissions

The different decarbonisation options participate to a different extent to the reduction of CO_2 emissions (mainly renewable energy sources, power plants with CCS and nuclear energy). For example, in the 2°C policy scenario, we estimate that the deployment of VRES is responsible for 24% of the CO_2 emission reduction in 2050 and 35% in 2100. The rest of the power system production is also responsible for a strong decrease in overall CO_2 emissions, for example through the decommissioning of oil power plants or a switch of coal to gas power. However, the management of the variability of the residual load may require fossil fuelled “back-up” power (e.g. in periods of low wind or solar production). This could have an upward impact on the emissions; in this context, storage helps containing the CO_2 emissions. As already explained, storage capacities and demand response programs are also essential to the integration of wind and solar production (e.g. by decreasing the curtailment of surplus energy). Therefore, electricity storage and demand response are playing a role in the total CO_2 emission reduction. When comparing the production from storage and demand response capacities to the total production of the system in the 2°C policy scenario, we deduce an influence on the total emission reduction of around 0.6% for storage and DR. This is a rather small but non negligible contribution to the collective effort.

4. Conclusions and perspectives

The strong development of wind and solar production has impacts on the power system and the development of electricity storage. In this paper we present a new modelling for incorporating storage in the operation and capacity planning of the power system in POLES. The coupling with EUCAD brings a new level of detail to long-term energy modelling, including storage and demand response, as well as a first simple representation of the European electric grid.

For the 2°C policy scenario, storage is a big player in the competition between flexibility options, especially in the second half of the century. We identify two different drivers of storage development: the carbon price (causing high price spreads between plants with and without CCS) and the variability of solar (causing production surplus at noon). On the other hand, once the “back-up” capacities with CCS are built, they are prioritised over storage in the operation. The minimisation of the power sector operating cost draws benefits from storage (-5% of the annual operating cost in 2050, -8% in 2100). The integration of VRES is easier with storage, as shown by the integration cost indicator (storage avoids an integration cost of 3 to 5 $/MWh of VRES), as well as the curtailed surplus energy (divided by 12) and the CO_2 emissions (-0.6%).

The long-term scenario of the energy system, carried out with POLES+EUCAD, shows that the VRES integration costs depend strongly on the scenario being considered. Influencing factors are in particular the structure of the power system and the carbon value. The system dynamics prevent any unique relation between VRES penetration in the electricity mix and VRES integration costs.

Storage can develop faster if the right policies are adopted (e.g. a specific tax regime or the possibility for prosumers to sell energy). The possibility for private consumers to sell the energy stored in their electric vehicle or their stationary battery depends strongly on the institutional and regulatory environment. These aspects would influence the discount rate and perceived costs of the technologies in POLES; this could be the base of future work.

Appendix A: Technical and economic characteristics of dispatchable technologies

	Nuclear	Coal and lignite	Gas Simple Cycle	Gas Combined Cycle	Gas turbine	Oil Simple Cycle	Oil Combined Cycle	Biomass and waste
Maximum ramp (%)	20%	35%	100%	100%	100%	100%	100%	100%
Ramping cost ($ per 33% hourly ramp)	2	2.45	1.6	0.64	0.63	2.45	0.64	1.7
Minimum output (%)	50%	40%	20%	20%	0%	0%	0%	40%

Table A: Technical and economic assumptions used in EUCAD on the dispatchable technologies for the power system operation

Appendix B: Technical and economic characteristics of storage technologies and demand response

Table B-1 shows the technical and economic assumptions chosen in the scenario shown in the article. Some of them are working hypotheses; we made no particular assumption on the business model (e.g. for DR or V2G).

	Hydro pumping	a-CAES	Batteries (Li-ion)	V2G (Li-ion)	DR
Efficiency	75% [g]	65% [a]	80% [g]	80% [g]	100% [g]
"Reservoir size" (maximum hours of production at full power in one cycle)	3.75 [g]	2.6 [g]	4 [g]	2 [g]	1.6 [d,g]
Maximum installable potential	10% of total hydro potential [g]	20% of peak load [g]	50% of peak load [g]	0→60% of EV[14] [g]	5% of peak load [d,g]
Power output investment costs ($05/kW)	1000[15] [c]	1075 in 2013, 928 in 2020 [a]	161 in 2013, 89 in 2020 [a]	100 until 2020[16] [g]	123 until 2020[17] [d,g]
Reservoir investment costs ($05/kWh)	0 [a]	43 until 2020 [a]	403 in 2013, 312 in 2020 [a]	0 [g]	0 [d,g]
Fixed O&M costs ($05/kW/year)	4.3 until 2020[a]	32.2 in 2013 [a]	10.75 until 2025 [a]	10.75 until 2025 [g]	10 [d,g]
Variable O&M costs ($05/MWh)	8.6 [a]	0.1 [a]	2.15 [a]	2.15 [g]	0.1 [d,g]
Life time (y)	55 [a]	35 [a]	12.5 [a]	10 [g]	20 [e,f]
Discount rate	4% [g]	4% [g]	8% [g]	8% [g]	5% [g]
Learning rate	0.5% [g]	5% [g]	8% [g]	1% [g]	1% [g]

Table B-1: Technical and economic parameters for storage technologies and demand response, based on (*Commercialization of Energy Storage in Europe*, 2015)[a], (Nykvist and Nilsson, 2015)[b], (EPRI, 2011)[c], (Gyamfi and Krumdieck, 2012)[d], (CRE, 2013)[e] and (Rious et al., 2012)[f] and personal hypotheses[g] when needed.

The "reservoir size" is an assumption used in POLES' investment mechanism, in order to represent (exogenously) the expected number of hours of production of a technology during a day; it takes into account its efficiency (a low efficiency technology like a-CAES is expected to operate less than, say, pumped hydro). This is not a constraint in EUCAD, which can use a storage plant several times a day.

We limit the development of load shedding to a maximum potential of 5% of the peak load as an approximation of the actually achievable reduction of consumption on a given moment. The contracted programs may be higher, but this takes into account a rate of availability (see appendix B of (Després, 2015a) for a sensitivity analysis on these parameters of maximum potential).

The discount rate is chosen at 4% for big investments (hydro pumping, a-CAES) because we assume that they can be handled by big utilities or state monopolies. On the other hand, decentralised investments (batteries, V2G) are made by small owners and have a higher

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[14] The share of EV participating in V2G has a maximum potential, growing linearly between 2020 and 2050, and staying at 60% of all EV after 2050.
[15] More country-specific values are used when available, based on the review of actual projects in (EPRI, 2011).
[16] Value kept constant until 2020, and with a floor value of 80 $05/kW afterwards.
[17] Value kept constant until 2020, and with a floor value of 80 $05/kW afterwards.

discount rate of 8%. Demand response would potentially be handled by grid operators or utilities so we choose a 5% discount rate.

The investment costs resulting from the learning-by-doing effect in POLES in the 2°C policy scenario are displayed in Table B-2.

Annualised investment costs in $05/kW/year (2°C policy scenario)	Hydro pumping	a-CAES	Batteries (Li-ion)	V2G (Li-ion)	DR
2020	50.2	89.1	191	25.7	20.0
2050	49.7	68.0	100	23.9	19.4
2100	49.3	63.8	90.1	23.7	19.2

Table B-2: Average European annualised investment costs for storage and DR technologies in the 2°C policy scenario.

Appendix C: Evolution of the European power sector in the 2°C climate policy scenario

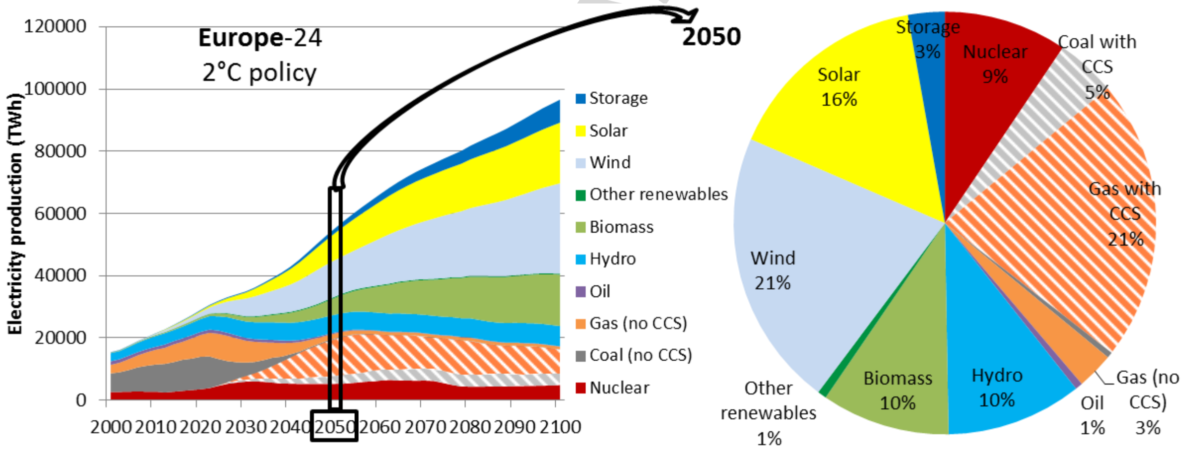

Figure C-1: European power supply in the 2°C policy scenario (POLES+EUCAD).

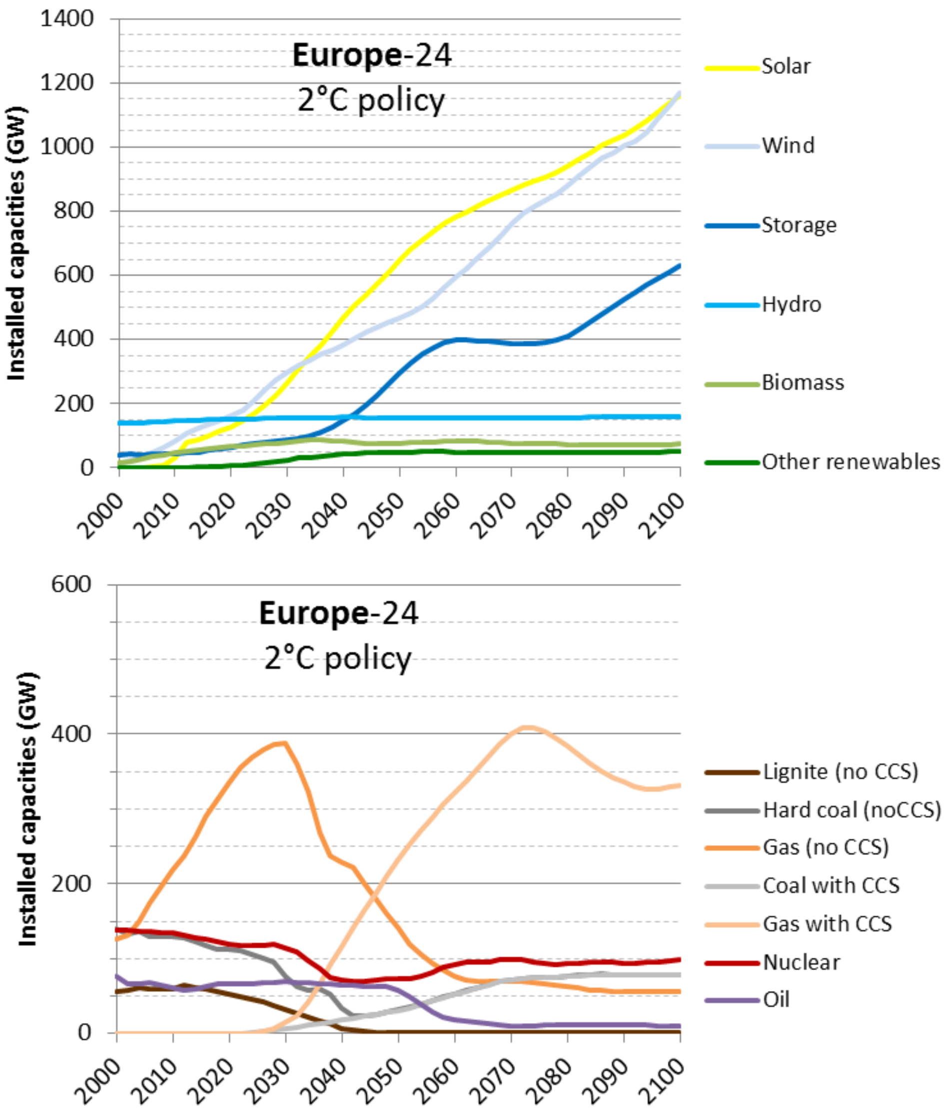

Figure C-2: European installed capacities in renewable and storage technologies (top) and in fossil-fuel technologies (bottom) in the 2°C policy scenario (POLES+EUCAD).

Appendix D: Supplementary material
See the attached file.

Appendix E: Evolution of the fossil fuel prices in France in the 2°C climate policy scenario

The figure E-1 shows POLES' output for the fossil fuel prices.

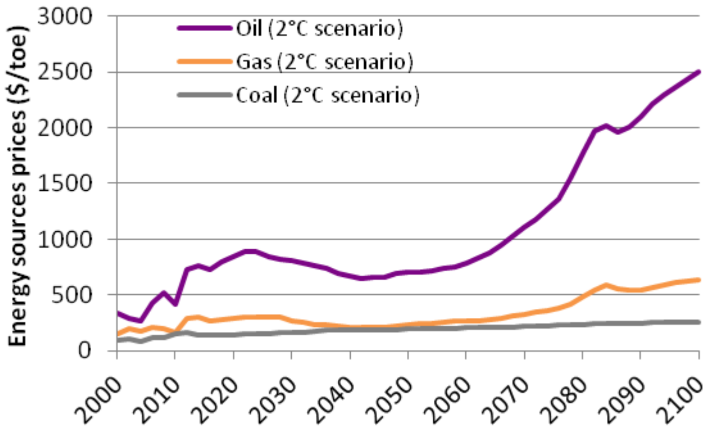

Figure E-1: Fossil fuel prices in France, in a 2°C policy scenario (POLES+EUCAD output)

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Highlights

- New coupling of a power system optimisation tool with a long-term energy model.
- New investment mechanism for storage based on multiple economic values.
- Most flexibility options are included: within-day storage, demand response and grid.
- Storage benefits from high carbon values and from surplus solar energy.
- Storage mainly needed to integrate wind and solar in the second half of the century.