Study of energy storage installation potential

Executive summary

FOREWORD

This study was financed by the ADEME, the ATEE and the DGCIS in the framework of the future development of the energy storage sector. The research was carried out with two technical contributors (ERDF and RTE) and was co-financed by ten companies that are references in the field (Alstom, Areva, Dalkia, EDF, E-On France, GDF Suez, GrDF, Orange, Saft and Total), represented by ATEE. All of the industrial stakeholders were active members of the steering committee and contributed to the study by participating in interviews and supplying data. The French General Directorate for Energy and Climate also provided significant support to this study.

The elements presented in this report, as well as their interpretation, are the result of the work carried out by Artelys, ENEA Consulting and the G2Elab, and the industrial members of the consortium cannot be held in any way responsible for them. Notably, the 2030 energy mix scenarios studied were drawn up from prospective analyses carried out independently by RTE and ADEME and do not necessarily reflect the vision of these organizations nor of the other companies.

AUTHORS

The work was carried out by the following people:

- Project management (Artelys): Arnaud Renaud
- Project leader (Artelys): Laurent Fournié
- Modelling of energy systems, quantification, economic calculations (Artelys): Pierre Girardeau, Maxime Chammas, Guillaume Tarel, Alice Chiche, Pierre De Freminville
- Forward-looking study of storage technologies, financial analysis and case study (ENEA): Olivier Lacroix, Loïc Rakotojaona, Luc Payen
- Physical behavior of electricity grids (G2Elab): Delphine Riu, Anne-Fleur Kerouedan

Artelys is a company specialized in optimization, forecasting and decision support. Through experience garnered in the performance of some one hundred study and software projects in the energy field, Artelys has become one of the world references in the optimization and techno-economic analysis of large energy systems. Artelys has in particular developed its Artelys Crystal software suite, dedicated to the economic optimization of energy system management and investments.

ENEA is a consulting firm specialized in the fields of energy and sustainable development and is a leader in the industrial sector. From strategy through to implementation, ENEA provides support to its clients in energy transition, and particularly with regard to their positioning in innovative sectors such as energy storage.

G2Elab is a joint research laboratory associating the CNRS, Grenoble-INP and the Université Joseph Fourier in Grenoble. It covers a wide range of competencies in the field of Electrical Engineering: electrical energy, materials, innovative systems and processes, modelling and design. With over 100 permanent staff, 110 PhD students and 50 Master's students, G2Elab is a major player in these fields on both the national and international levels.

Context, study objectives and method

In view of the present-day focus on the development of renewable energies, energy storage appears as a possible solution to help integrate fluctuating renewable energies, improve energy efficiency, provide flexibility to energy systems and reinforce grid safety.

The aim of this study is to assess the energy storage installation potential in Metropolitan France and its overseas territories at the 2030 time horizon and to identify the most economically relevant technologies. For electricity storage, we examined stationary systems serving the electrical system. The markets associated with electrical mobility, uninterrupted supply and nomadic storage systems were not examined.

The work was broken down into three sections:

- Firstly, the **social welfare** was calculated: **the benefit of adding energy storage capacities was calculated for the community as a whole** (consumers, producers, grid operators, etc.) and does not take into account regulatory constraints or incentive mechanisms. The work was carried out in the framework of three prospective scenarios for the national electricity generation mix: the Intermediate and New Mix scenarios from RTE's Supply-Demand Balance forecast and the ADEME scenario.
- This benefit was then **compared with cost forecasts for the 2030 time horizon** for the different energy storage technologies selected in the framework of this study. A panel of 30 technologies was studied. When the comparison was positive for a technology, a business model was proposed to assess the level of profitability of the investments and to identify the regulatory obstacles to be eliminated.
- Finally, the economically viable **installation potential** (capacity and type of energy storage) at the 2030 time horizon was assessed according to different scenarios and the impacts in terms of associated jobs were estimated.

The valuation calculations were based on the optimization of generating fleet production costs, for the community as a whole, while taking into account the technical constraints of the power generation facilities, the studied grid constraints and the supply-demand balance at hourly intervals, as presented in Figure 1.

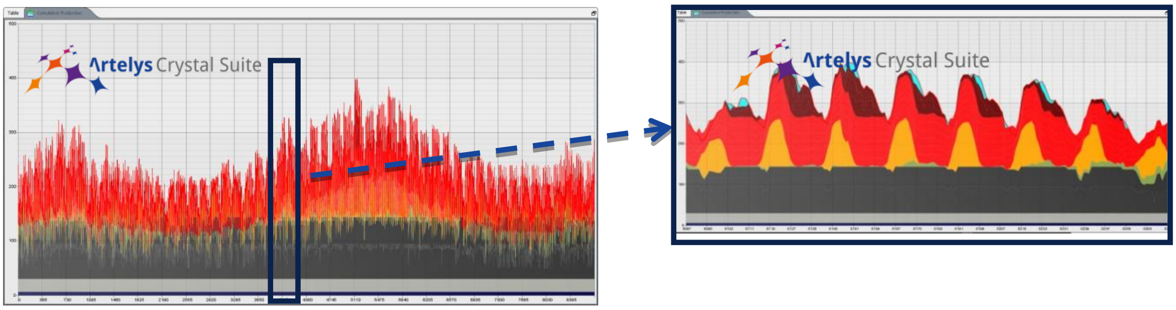

Figure 1 - Example of supply-demand balance at hourly intervals (island zone segment). Generation levels are totaled (one color per type of generation) to satisfy demand (on the left: annual horizon, on the right: focus on a single week).

The potential energy storage value is calculated by comparing the cost for the community of the optimized management of an energy system with or without storage. This value essentially stems from savings in generation costs as storage becomes a substitute for expensive generation means (**arbitrage value**), from savings due to the deferral of investment in peak generation means (**supply capacity value**), in the grid (**solution for network congestion**), or ancillary services (**spinning reserves and voltage support**).

This approach is particularly well adapted to assess the benefits of different technologies at the national or supra-national scales. It is used by ENTSO-E to analyze the costs and benefits of common interest projects in European electricity grids.

It does however have the following limitations:

- The costs are assessed from the point of view of the community and do not reflect the opportunities that a project proponent might have due to specific regulatory measures. Hence, a breakdown of electricity supply costs (for example: energy share/ power share/ fixed share of the TURPE[1], distribution of CSPE[2], etc.) that only imperfectly takes into account the real situation and cost disparities for the community, can make certain projects profitable for their developer while they would not be profitable for the community.
- This approach assumes that the market is open to free and undistorted competition and may neglect market power effects.
- This methodology does also not take into account externalities such the impact on employment and the societal benefits associated with the emergence of a new technological sector in a country (growth in know-how, exports), the energy externalities (independence) or the social acceptability of the deployment of a technology or grid facilities.

Proposed case studies taking into account foreseeable regulatory changes and employment impact assessments provide a complementary vision.

Ten energy storage usage segments were modelled in order to analyze the opportunities derived from deploying energy storage solutions at different points on the electricity grid. The installation potentials attained on these segments cannot however be added up, given their required partial redundancies to meet the needs of the French electrical system. Segments focusing on heat storage were also studied.

Presentation of the electricity mix scenarios studied

The three 2030 national electricity generation mix scenarios studied are presented in Figure 2 and Figure 3. The following characteristics have a major impact on the valuation of the storage:

- The share of intermittent renewable energies remains limited: 36% to 56% of installed power capacity and 20 % to 40% of annual electricity generation, depending on the scenario studied. Higher shares of intermittent energies, for example in a longer time frame, could reinforce the value of energy storage.

[1] Network Access Tariff
[2] CSPE funds the equalization tariff, support for the development of renewable energies, cogeneration, and the basic needs tariff that provides access to inexpensive electricity to low-income households. It is paid by consumers based on their consumption volume.

- The share of intermittent renewables generation to be curtailed to maintain the supply-demand balance remains low: 0.05% of the annual intermittent renewable generation for the RTE Intermediate scenario, 0.3% for the RTE New Mix scenario and 1.8% for the ADEME scenario.
- The French electricity generation mix is characterized by a high share of nuclear power generation, with very low variable costs, which strongly reduces the value of energy transfers between the hours at renewable energies' marginal cost and the hours at base generation (nuclear) marginal cost.
- The French electricity mix already has high electricity storage capacities (4.3 GW of PSPS and 13 GW of hydropower with reservoirs), which deteriorates the value of additional electricity storage capacities.

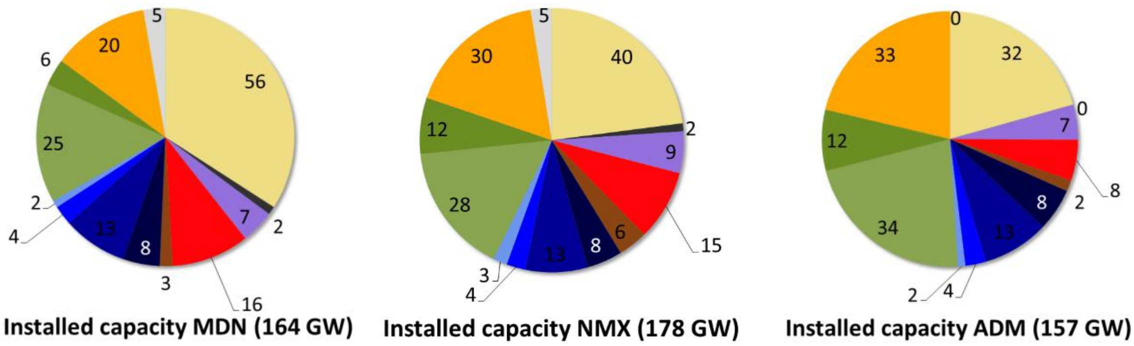

Figure 2 – Installed capacity by source (in GW), for each 2030 scenario studied (MDN= RTE Intermediate scenario, NMX= RTE New Mix scenario, ADM= ADEME scenario). Each of these three scenarios can ensure the supply-demand balance at an hourly interval.

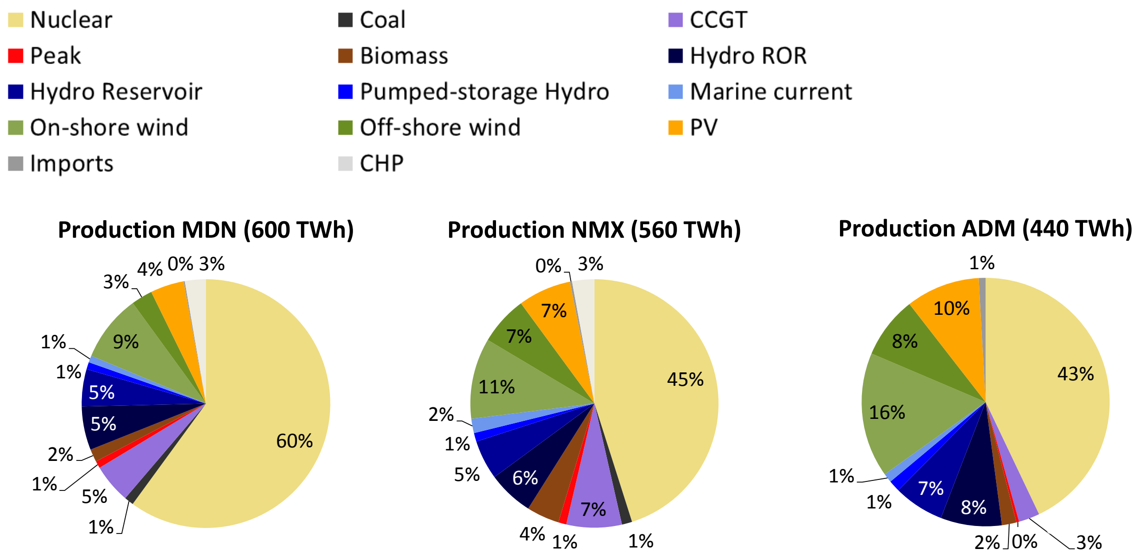

Figure 3 – National share of electricity generation for each source, for each 2030 scenario studied (MDN= RTE Intermediate scenario, NMX= RTE New Mix scenario, ADM= ADEME scenario)

Evaluation of needs for flexibility

At the 2030 horizon, electricity storage requirements for **daily cycles** will remain similar to current ones. Indeed, for up to 20 GW of installed PV (RTE Intermediate scenario), PV generation coincides with periods of high demand, thus reducing the arbitrage possible between peak hours and off-peak hours. Above 30 GW (RTE New Mix and ADEME scenarios), residual demand (after deduction of PV generation) drops significantly on sunny summer days, creating new electricity storage opportunities for the evening peak. It must be noted that the 20 and 30 GW thresholds depend heavily on the energy policies of neighboring countries: a massive roll-out in Europe of PV without associated electricity storage would lead to new electricity storage opportunities in France, given the high level of interconnection between European networks. An extension of this study to the European scale would be necessary in order to properly quantify this impact.

On the other hand, electricity storage requirements for **intra-weekly cycles** will increase significantly by 2030: increases in tertiary uses lead to differences in demand between weekdays and weekends that are more marked than today. National wind power generation, whose installed capacity objectives are high in all the scenarios studied (between 30 and 46 GW), statistically varies over cycles of several days as weather conditions averaged over the entire country generally remain stable for several days. The combination of these two factors leads to an almost 50% increase in the need for flexibility over one week compared with the current situation and thus to opportunities for intra-weekly storage.

Moreover, electricity storage can play an important role in the supply-demand balance on very cold days. By storing during periods of low demand and discharging during ultra-peak hours, investments in generating capacities, such as combustion turbines, can be avoided. This electricity storage **supply capacity value** represents roughly one half of the total value presented and is not contingent on the evolution in fuel prices. It nevertheless depends heavily on the duration of discharge and the electricity storage penetration rate: long-term electricity storage makes it possible to time-shift demand to days where consumption is lower, while a massive roll-out of “short term” electricity storage will not make it possible to compensate for an extended shortage in generating capacities, as the electricity storage cannot be recharged between two ultra-peak periods.

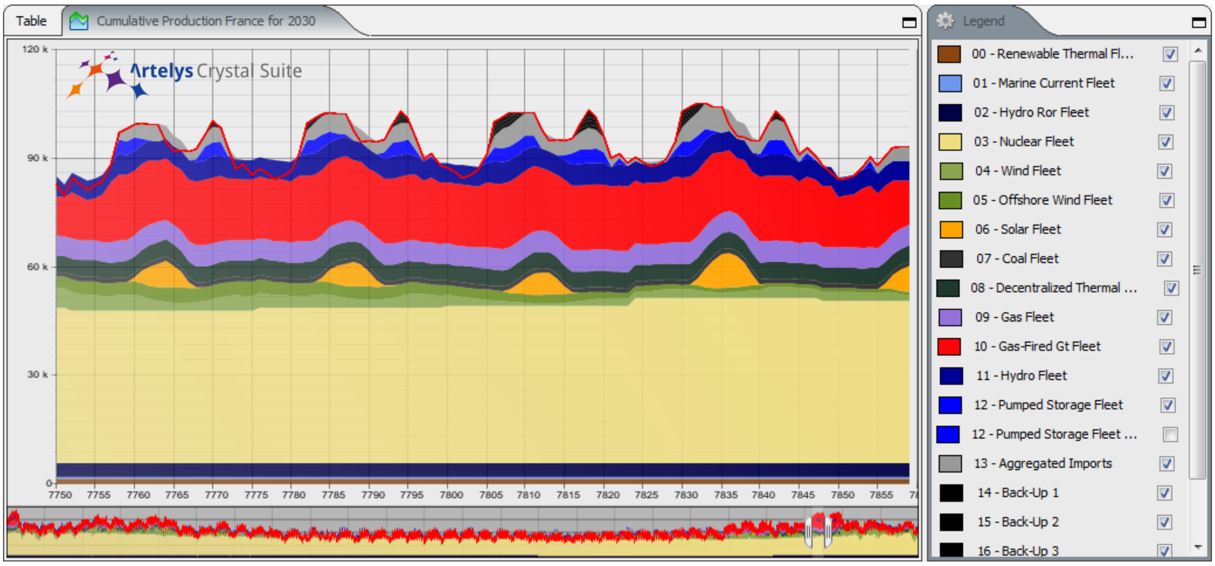

Figure 4 – Example of a situation (4 days of very cold weather without wind, French segment) where 5-hour electricity storage can reduce shortfalls (shortfalls in black and electricity demand in red). With a massive roll-out of 5-hour electricity storage capacities, it will not be possible to recharge between the peak hours of the morning and the evening.

Recommendations

Based on the 2030 scenarios studied, the flexibility requirements for electricity uses will not significantly increase with respect to the current situation, as PV generation coincides with periods of high demand for electricity. From this standpoint, the French electrical system seems to have the appropriate resilience for a substantial introduction of renewable energies (up to 46 GW wind power and 33 GW solar in the ADEME scenario), which will not lead to a high additional cost associated with the need for flexibility[3]. This observation could realistically be very different for energy mix scenarios with a higher share of intermittent generation, as should very likely be the case for more distant time horizons or in the case of a massive roll-out of PV in Europe without any associated storage.

We therefore do not recommend the massive deployment of electricity storage in the short term, but rather a focus on upstream R&D or demonstration projects aiming at developing stationary storage solutions capable of increasing the share of renewables in the mix in a competitive manner after 2030.

For this, the **overseas territories** represent an extremely interesting experimentation terrain for the development of stationary electricity storage. While the French installation potential remains limited (200 to 400 MW), the projects studied (surface CAES, Li-Ion batteries, etc.) are cost-effective for the community and the prospects for worldwide deployment are promising (by taking into consideration not only the islands but also the regions in which the electricity grid has a low level of interconnection), which thus leads to an interesting starting point for the creation of a French export industry for stationary storage systems. This type of industry, according to the hypotheses for the

[3] The additional cost associated with flexibility requirements is only the cost linked to maintaining the supply-demand balance on the national grid, despite the intermittent nature of renewable production. The investment costs for the different scenarios were not studied in this report.

deployment of stationary electricity storage worldwide and the competitive position of French industry, could generate up to 10,000 full time equivalent[4] jobs in France on average by 2030.

Between now and 2030, in **Metropolitan France,** the only cost-effective **mass electricity storage systems** will be Pumped Storage Power Stations, assessed at 1 to 1.5 GW[5] of installation potential, depending on the mix scenario. While specific local contexts (impossibility of reinforcing the grid, societal acceptance difficulties, etc.) may generate sporadic opportunities, decentralized or diffuse electricity storage is most of the time less economically viable than grid reinforcement solutions or the curtailment of excess intermittent generation.

Most electricity flexibility needs can be satisfied through the dynamic management of electricity demand (i.e. **end-use energy storage**). For example, the dynamic management of the recharging of existing hot water heaters in homes[6] could generate savings of 40 to 85 M€/year, for a limited cost in the context of the advantageous usage of future intelligent meters or the more dynamic use of tariff signals (on-peak hours / off-peak hours). Similarly, by managing the recharging of electric vehicles (between 1 and 9 million vehicles, depending of the scenario) according to national electricity generation costs, we could eliminate an additional cost of 100 to 300 M€/year caused by direct charging (unscheduled charging of electric vehicles by user).

In terms of **ancillary services**, the study shows that a highly responsive electricity storage system dedicated to supplying the primary reserve in Metropolitan France would generate savings for the community of 250 to 450 k€/MW/year installed. For this, flywheels and batteries appear to be promising solutions: the forecasted investment cost at the horizon 2030 for ½ hour of storage is estimated at 180 k€/MW/year for flywheels (assuming 20 years of depreciation) and 80 k€/MW/year for a Li-Ion battery (assuming 10 years of depreciation). A more detailed analysis (with modelling of reserve activation at an intra-hourly time step) is however necessary to quantify the operational costs and the technical feasibility of using the different technologies to this end. The installation potential is 600 MW in France (primary reserve volume). Regulatory modifications would be required to allow the exclusive participation of an electricity storage system in the reserve.

Thermal energy storage seems to be a very interesting solution in the context of the creation or extension of a heating network. It introduces complementary flexibility to the supply-demand balance, making it possible to drastically reduce the investment costs in heating plants (biomass plants and peak capacities). The installation of heat storage on heating networks represents a potential in the order of 5 to 10 GWh_{th} by 2030 in France. It would nevertheless be necessary to modify the regulations in order to definitively qualify the renewable status of stored thermal energy of renewable origin. The **coupling of heat storage with cogeneration plants** is particularly interesting since it makes it possible to manage cogeneration according to the price of electricity and independently of the demand for heat: when the demand for heat is insufficient, it is stored for later use in the best value conditions.

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[4] In the upper-range deployment scenario selected, between 8000 and 25,000 jobs, depending on French industry's share of the global market (between 10 and 30 %).

[5] If other flexibility solutions are developed (i.e. electricity demand control), this installation potential will be significantly reduced.

[6] This management must vary according to weather forecasts since 2030 off-peak hours are hours with high levels of PV and wind power generation.

Figure 5 to Figure 10 present the results of the value created by a storage facility in k€/year per MW of installed energy storage (per installed MWh for thermal storage) for the different segments and 2030 scenarios studied, without taking into account the investment costs for a specific technology. The segments are described in more detail on the following pages.

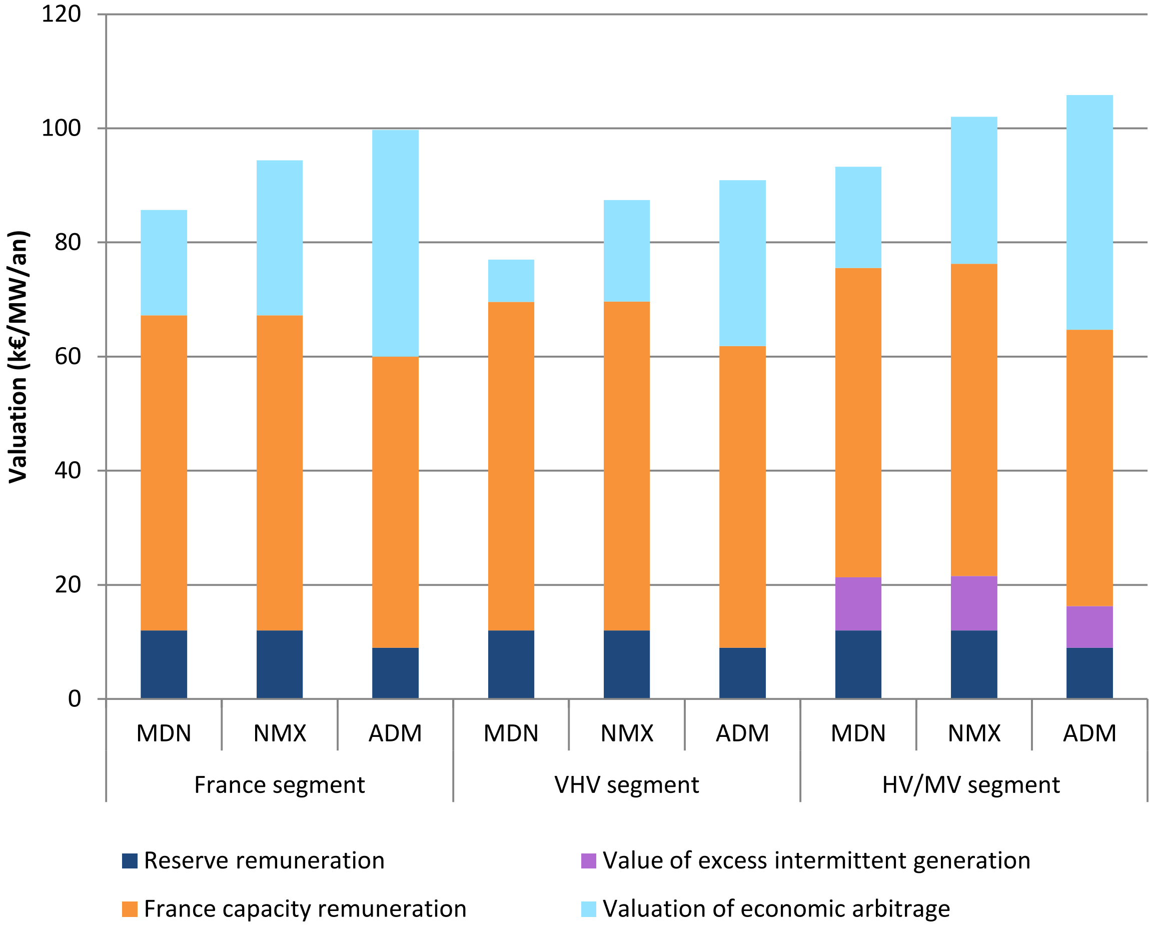

Figure 5 – Gross valuation of electricity storage (5-hour storage and 80% efficiency), segments: France, VHV and HV/MV

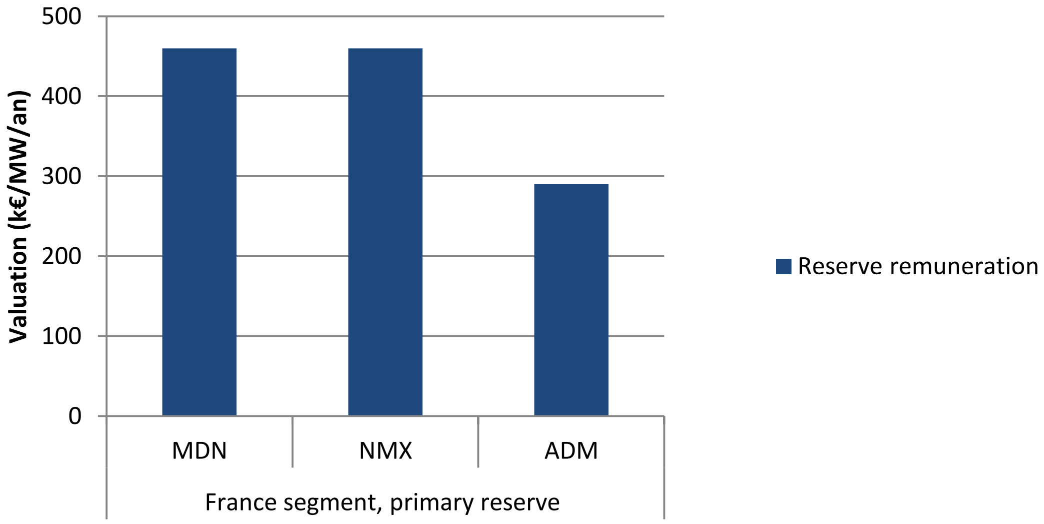

Figure 6 – Gross valuation of electricity storage, France segment (storage dedicated to primary reserve)

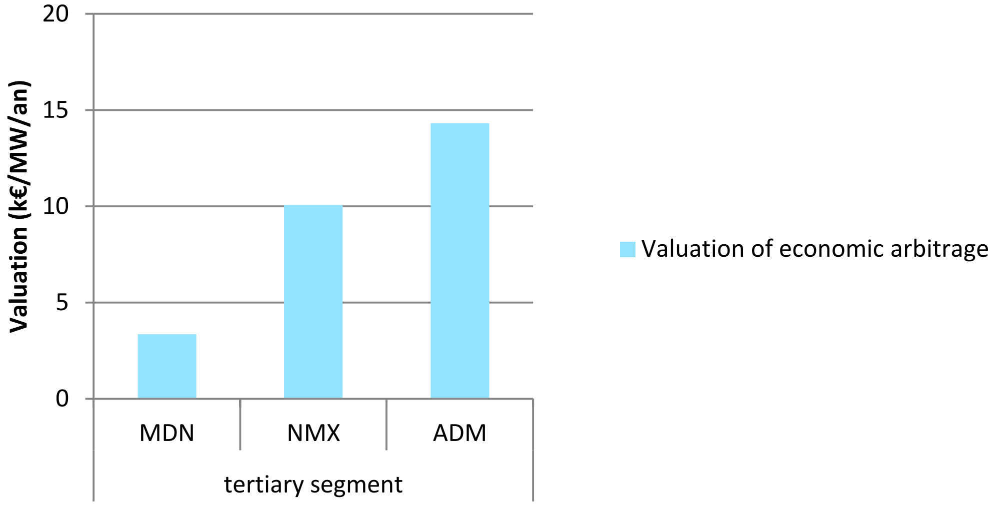

Figure 7 – Complementary valuation of UPS electricity storage, tertiary segment (4-hour storage and 80% efficiency)

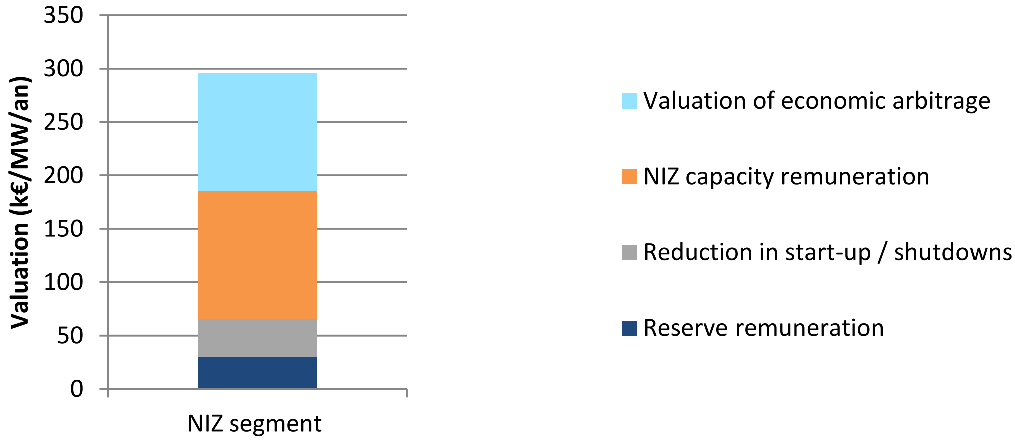

Figure 8 – Gross valuation of electricity storage, NIZ segment (5-hour storage and 70% efficiency)

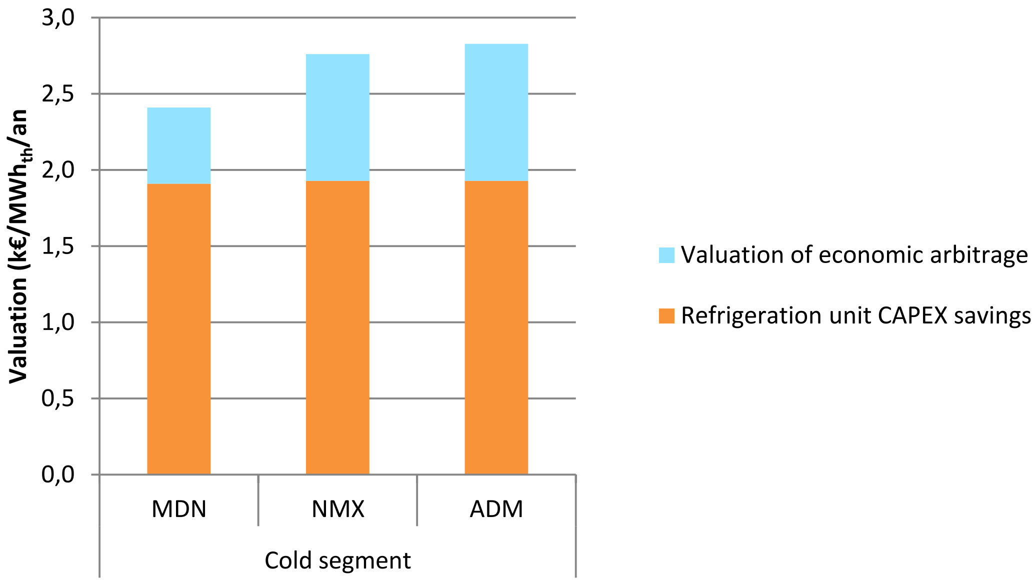

Figure 9 – Gross valuation of thermal storage, cold segment (storage 30MWh$_{th}$, loss rate 1%/hour)

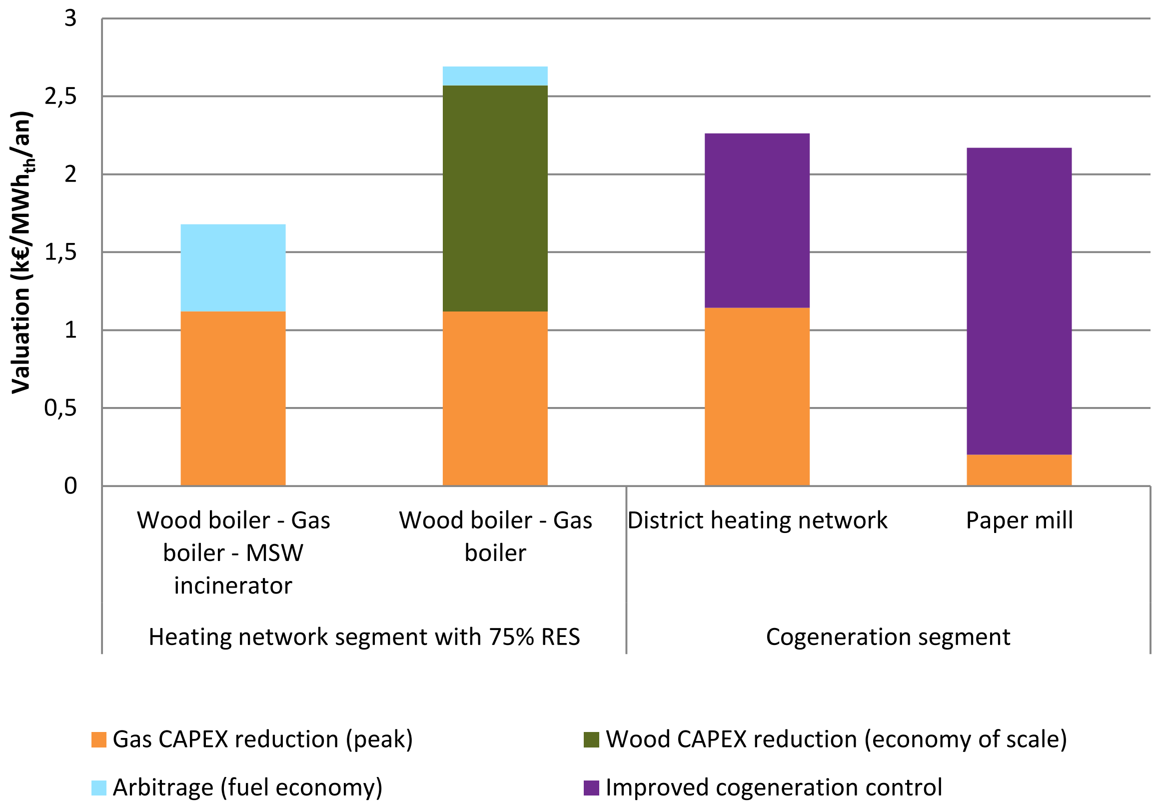

Figure 10 –Gross valuation of thermal storage, heating network and cogeneration segments (10-hour storage, 50MWh$_{th}$, loss rate 0.1%/hour)

France segment (electricity storage)

Description of segment: the Metropolitan France context, not including any network constraints. Simplified modelling of imports-exports was carried out and simulations were performed for 20 years of climate scenarios (temperature, wind power production, PV production) and nuclear plant availability. This segment is used to evaluate the potential of mass electricity storage, but also to determine the arbitrage and guaranteed capacity values of the other segments.

Services studied: guaranteed capacity, arbitrage, frequency regulation (limited to 12% of its capacity)

Technologies studied: PSPS, CAES, H_2, Pb-A, Li-ion, Na-S, Zn-Br.

Valuation results and installation potential: For the scenarios studied, flexibility is essentially needed for the transfer of energy over several days. Pumped Storage Power Stations (PSPS) thus appear to be a good compromise between reasonable investment costs, proper electricity storage capacity and the possibility to cycle regularly throughout the year to reach a sufficient level of profitability. The additional installation potential for PSPS is evaluated between 1 GW and 1.5 GW at the 2030 horizon in France; these values depend heavily on site availabilities and the evolution of the generation mix. The other technologies studied are not cost-effective at the 2030 horizon, unless real breakthroughs drastically reduce costs.

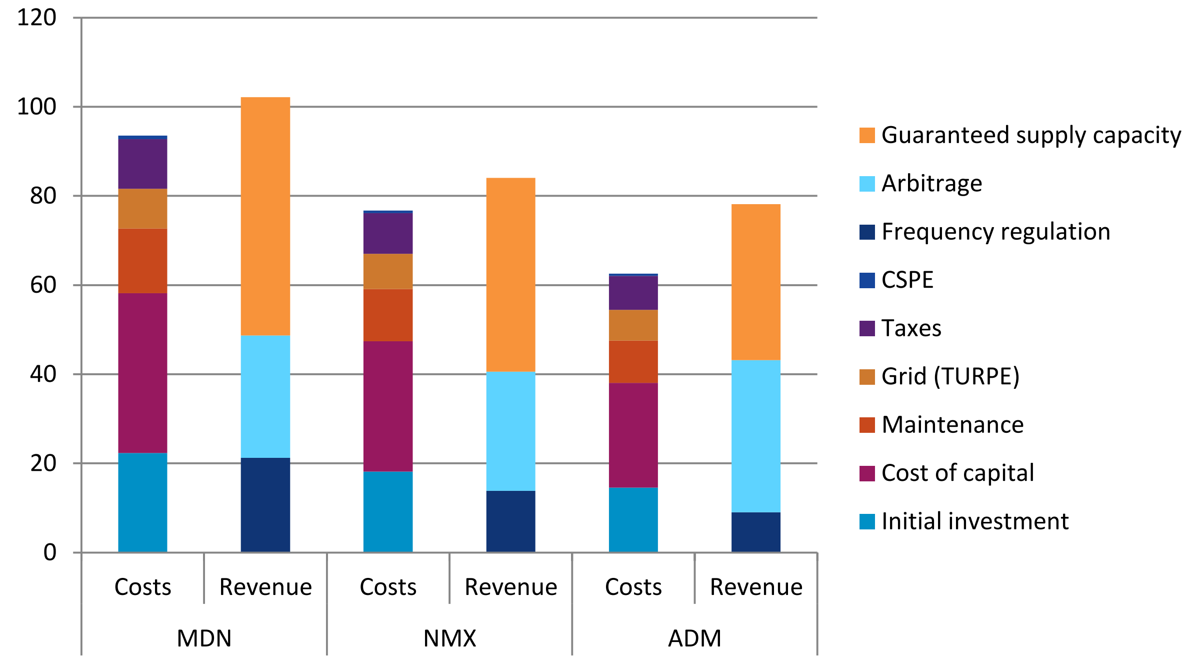

Figure 11 – Comparison for energy mix scenarios of revenue and complete costs discounted over the service life of 24-hour 800 MW PSPS (efficiency 83%), in €/MWh delivered (LCOS method). The cost differences between scenarios are explained by different cycling. Moreover, the revenues are considered net of electricity purchases. The discount rate used in the study is 5.25 % not including inflation.

Scope of application of the results and prospects: The imports-exports modelling was calibrated on the years from 2010 to 2012 and takes into account the recent deployment of PV in Germany. If the deployment of PV in Europe develops without any associated electricity storage, additional opportunities for electricity storage will appear in France. On the other hand, if other European countries develop electricity storage on their territories, this will reduce the potential for electricity storage in France.

Moreover, mass electricity storage is competing with demand management. If demand management is reinforced by 2030 in France or in bordering countries, the potential for PSPS will be reduced.

Regulatory aspects and support for the industry: For PSPS, beyond the capacity value to which the capacity mechanism will give access, changes in the regulatory context will only be of marginal impact. Indeed, for mass distribution systems, the CSPE is not a high cost, as long as it remains capped. The impact of all the other taxes is higher but also remains limited. However, as the challenges essentially involve investment, providing access to financing at preferential rates could be a much more effective lever to makes systems of this type cost-effective.

France segment (end-use energy storage)

Description of segment: The context is the same as in the previous segment (Metropolitan France, not including any network constraints), but in this case we examined end-use energy storage (hot water tanks, electrical vehicle batteries, etc.) to time-shift electricity demand without deteriorating quality of service (EV batteries must be recharged by morning). Guaranteed capacity values are not taken into account in this segment.

Services studied: arbitrage

Technologies studied: Managing the recharging of household domestic hot water tanks and electric vehicles, "power to gas".

Valuation results and installation potential: The management of the recharging of household domestic hot water tanks in a dynamic way to coincide with periods of low net demand would generate savings of 40 to 85 M€/year for a cost that is limited to the installation of relevant control systems and/or adapted regulation modalities.

Managing the recharging of electric vehicles according to electricity generation marginal costs would make it possible to avoid an additional cost of 100 to 300 M€/year that would be caused by direct charging (unscheduled charging of electric vehicles).

For "power to gas" systems, as illustrated in figures 12 and 13, the forecasted investment costs for 2030 lead to injected gas costs of between 100 to 200 €/MWh$_{PCI}$ depending on the technology and scenario considered. These costs are higher than the selected hypothesis for this study of a gas price of 30 €/MWh$_{PCI}$ in 2030 (World Energy Outlook scenario from the International Energy Agency).

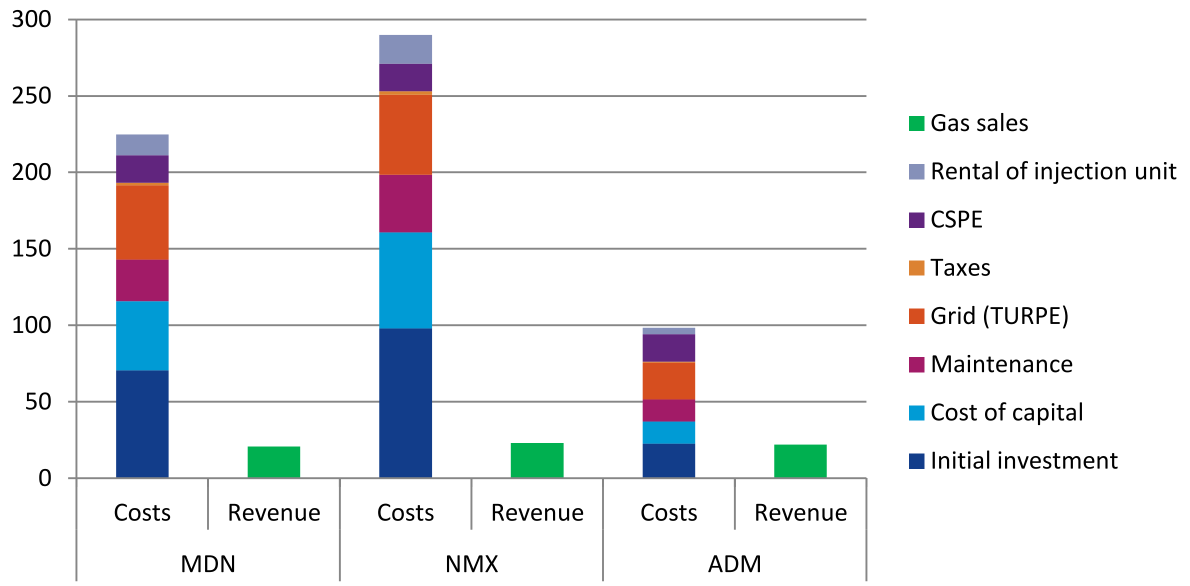

Figure 12 - Comparison for the energy mix scenarios of revenue and complete costs discounted over the service life of a 10 MW$_e$ hydrogen injection PEM electrolysis system, in €/MWh$_{PCI}$ injected (LCOS method for a gas valuation hypothesis at 30 €/MWh$_{PCI}$)

Scope of application of the results and prospects: the current on-peak/off-peak hours management system does not appear well adapted to the 2030 contexts studied. Indeed, the off-peak hours studied in 2030 should be in line with sun forecasts (due to high PV production). It will thus be necessary to manage in a dynamic way according to weather forecasts in order to capture a large portion of the previously mentioned values.

For the study, the assumption was used that all of the water heaters (17 million devices) or electric vehicles (1 to 9 million vehicles, depending on the scenario studied) are managed. Partial management of the stock would nevertheless make it possible to capture a substantial portion of these valuations.

The “vehicle to grid” case was not studied.

For “power to gas”, applications other than injection into the gas network (the only option considered in this study) may turn out to have a higher added value and therefore be more cost-effective. Examples include the local use of synthetic methane or hydrogen for mobility applications.

Regulatory aspects and support for the industry: The development of demand management will require sending to the end customer a price signal that takes into account the reality and diversity of electrical system costs, which is currently only partially possible with the regulated tariff. At minimum, it requires the development of contracts through which an operator (aggregator) would have the necessary latitude to manage energy-consuming systems, for example in a service logic: guaranteeing the charging of vehicles or the availability of hot water. The emergence of these types of contracts should be facilitated by the creation of mechanisms, such as the new load shedding mechanism (NEBEF), making it possible to derive value on the markets from these quantities of shifted energy, rather than just through the adjustment mechanism (tertiary reserve).

For “power to gas”, the development of this sector seems likely to be dependent on the setting up of support mechanisms for the 2030 horizon, a feed-in tariff for example, similarly to that applied to biomethane injection today. Figure 13 shows that, for example, in the ADEME scenario, a 100 €/MWh_{PCI} feed-in tariff coupled with a CSPE exemption would make hydrogen production economically viable.

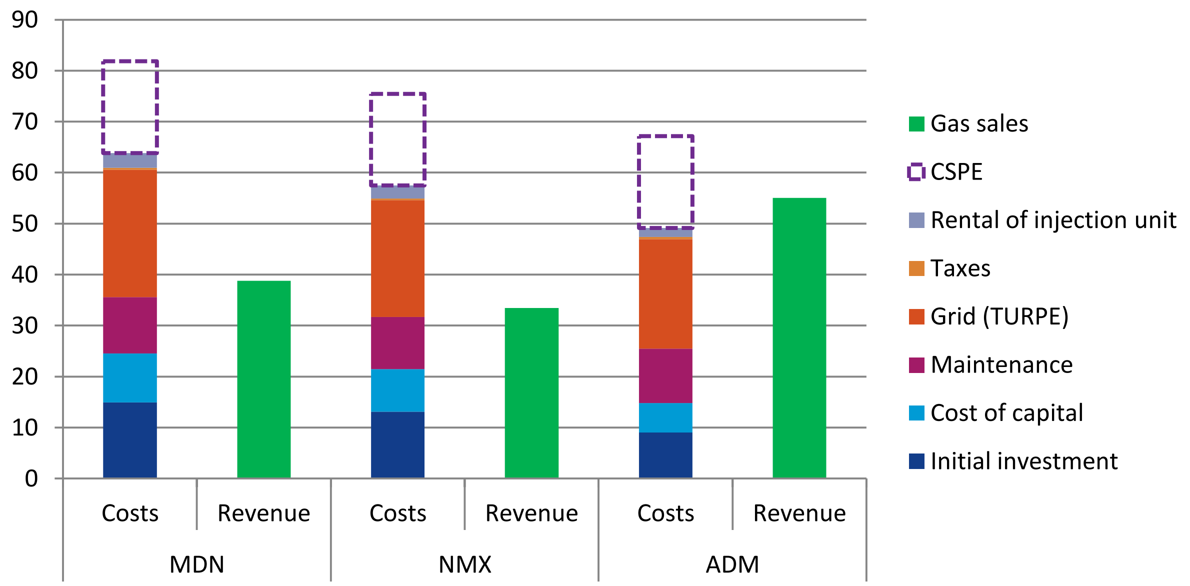

Figure 13 - Comparison for the energy mix scenarios of revenue and complete costs discounted over the service life of a 10 MW_e hydrogen injection PEM electrolysis system, in €/MWh_{PCI} injected (LCOS method for a gas valuation hypothesis at 100 €/MWh_{PCI}). The revenues are net of electricity purchases.

France segment, primary reserve (electricity storage)

For this segment, only a valuation analysis was carried out. A supplementary study is necessary (with modelling of reserve activation at an intra-hourly time step) to evaluate the technological constraints and operating costs of electricity storage systems dedicated to the primary reserve. Cost forecasts to 2030 for flywheels and batteries, given for comparison, only include fixed costs (investment and annual maintenance).

Description of segment: The aim of this segment is to assess, for the selected 2030 scenarios, the value that could be derived from highly-reactive electricity storage dedicated to the supply of the primary reserve in Metropolitan France. This storage must be available year round and must be able to handle frequency variations at all times. The value of one MW of electricity storage dedicated to the reserve was calculated as savings generated for the community if the need for spinning reserves are decreased by one MW.

Services studied: primary reserve

Technologies considered: flywheels and batteries

Valuation results and installation potential: The study shows that electricity storage dedicated to the primary reserve would generate savings for the community of 250 to 450 k€/MW/year installed. This valuation must be compared with the investment cost forecasts for 2030 for flywheels and batteries, estimated (for ½ hour of storage) at 180 k€/MW/year for flywheels (hypothesis of a 20-year depreciation) and 80 k€/MW/year for Li-Ion batteries (hypothesis of a 10-year depreciation). The installation potential would be 600 MW in France (volume of primary reserve).

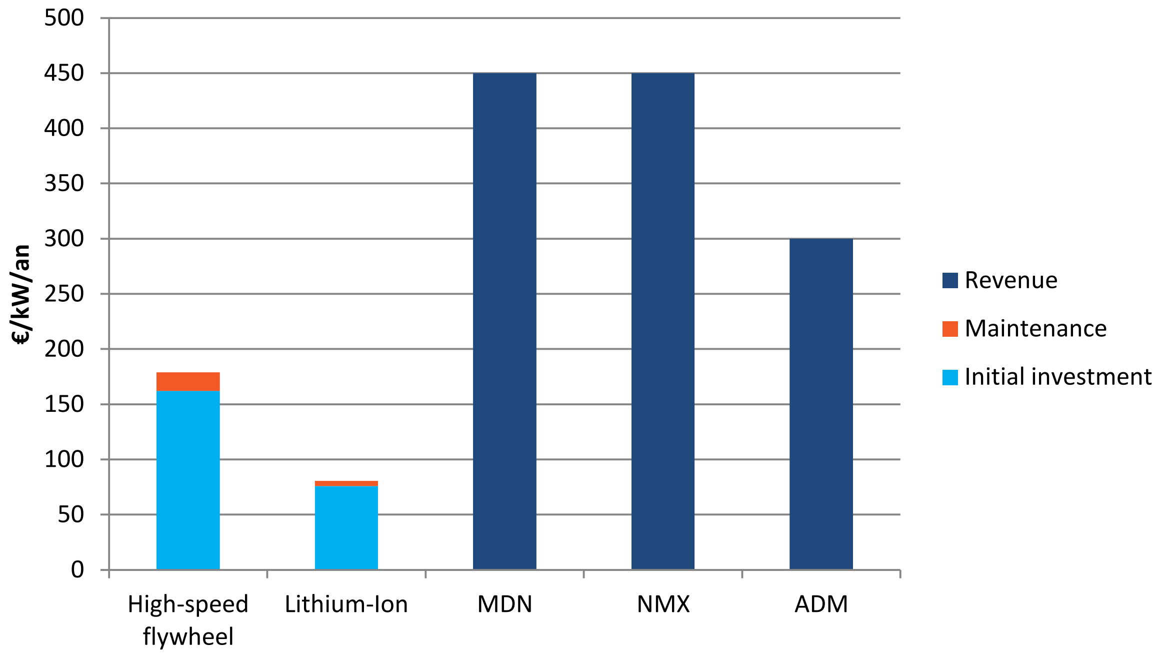

Figure 14 - Comparison of annual revenues and costs for a flywheel and a Li-ion battery in €/kW. The costs presented do not include the recharging costs and energy losses required to guarantee the availability of the primary reserve service. We have also supposed that ½ hour discharge duration was sufficient to supply this service.

Scope of application of the results and prospects: The cost of the spinning reserve is particularly high for the selected 2030 scenarios. Indeed, for a high number of hours in the year, the spinning reserve must be supplied by nuclear power plants that can therefore not produce at maximum power; this leads to a high additional cost for the community. Very reactive electricity storage can help reduce this additional cost. The phenomenon is less obvious for smaller electrical systems (islands).

The ability of these storage means (flywheels or batteries, whose discharge time is very short) to ensure primary regulation requires that the minimum quantity of energy to be supplied or absorbed in response to a sudden imbalance between production and consumption be maintained at all times and in all circumstances. Since, in real operating conditions, frequency constantly fluctuates around its nominal value, these means will constantly supply or absorb generally low powers, but which integrated over several hours, may be sufficient to exhaust or saturate the low storage capacity. The precise quantification of these effects, which requires the modelling of reserve activations in an intra-hourly time step, was not performed in this study. It does however appear plausible that it will fairly frequently be necessary to proceed with power adjustments to restore the adequate power supply or absorption margins.

Regulatory aspects and support for the industry: The use of this installation potential will require major regulatory changes: today, only systems in operation can aspire to supply the reserve. In future, it should be possible for dedicated systems to participate in the reserve, without otherwise being called upon for energy supply.

NIZ segment (electricity storage)

Description of the segment: The segment studied is an island zone (or NIZ, for Non Interconnected Zone). The installed capacity of intermittent renewable energies (mainly PV) represents 30% of the generation mix. The variable costs associated with electricity generation in thermal plants were doubled to take into account the small size of the power plants and the high cost of importing fossil fuels.

Services studied: guaranteed supply capacity, arbitrage (including reduction in thermal plant start-up costs), frequency adjustment (limited to 12% of its capacity)

Technologies studied: Surface CAES, Li-ion, Na-S

Valuation results and installation potential: The value for the community of the first MW of electricity storage is high, at roughly 300 k€/year for 5 hours of storage. The installation potential in France nevertheless remains low. It was estimated between 200 and 400 MW, but it is obviously much higher at the global level (by taking into consideration not only the islands but also the regions in which the electricity grid has no or only a low interconnection level).

Surface CAES, like batteries, seem well adapted to this context with internal rates of return (IRR) above 7% for most of the technologies considered (IRR 17% for CAES, 7% for Li-Ion and 8% for Pb-A and Zn-Br). Marine PSPS may also meet the challenges of NIZ, depending on the siting opportunities.

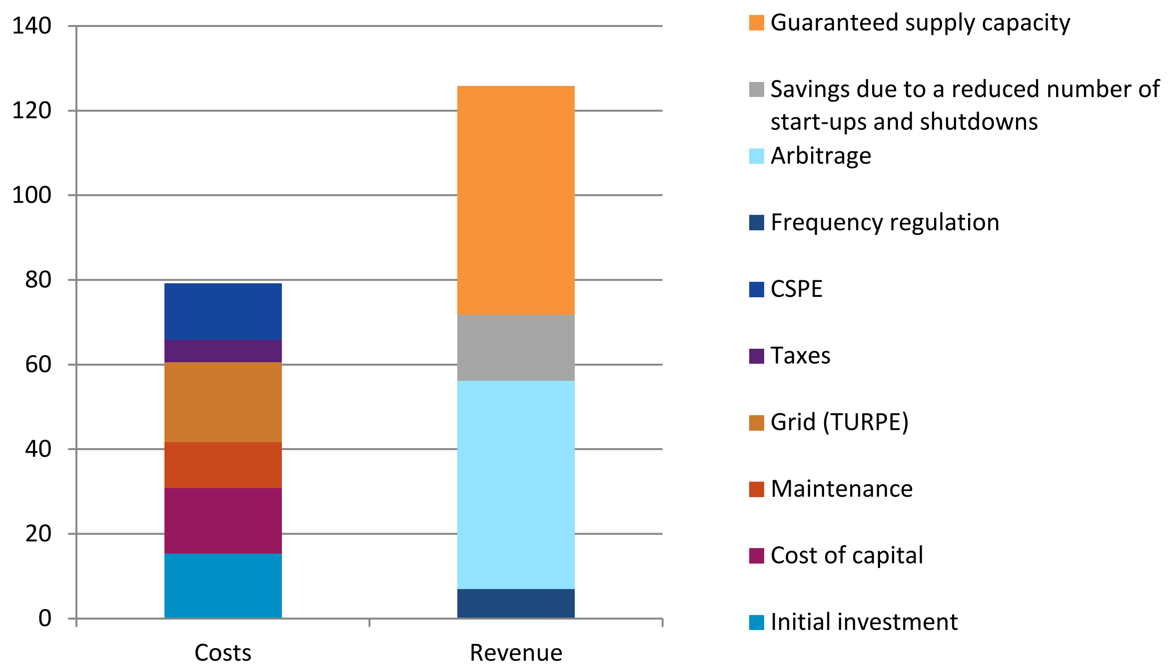

Figure 15 - Comparison of complete revenues and costs discounted over the service life of a 20 MW surface CAES system with 7 hours of storage (efficiency 65%), in €/MWh (LCOS method)

Scope of application of the results and prospects: The high storage values in NIZ are linked to the high variations in both consumption and intermittent production due to limited geographical averaging. For higher penetrations of intermittent energy in the local production mix, fuel savings from electricity storage will be even higher. Moreover, the supply capacity value of electricity storage will strongly depend on the load curve and the local generation mix, particularly for short term storage (i.e. Li-Ion batteries).

Regulatory aspects and support for the industry: The regulations in force in French NIZ now encourage the operators of intermittent renewable energies to install electricity storage systems coupled to the renewables production system.

This smoothing out of renewables generation is however sub-optimum from the standpoint of the community since the signals used to manage electricity storage only partially correspond to the structure of the costs for the community. The electricity storage valuations presented in Figure 15 can only be fully captured by an integrated manager and are based on the optimization of the operation of the entire production fleet (optimization of start-ups / shutdowns for example).

Beyond the measures already in force, and to make NIZ terrains of experimentation for electricity storage, it seems relevant that the public authorities favor the installation of electricity storage systems operated by an integrated manager, for example via a tendering mechanism. The integrated management of storage means would thus avoid the implementation of market mechanisms which are superfluous given the size of the networks concerned.

VHV segment (electricity storage)

Description of the segment: The segment studied concerns a region of France that imports most of its energy and that is characterized by the absence of nuclear power plants. The percentage of intermittent renewables (mainly wind power) in the local generation mix varies from 43% to 65% of installed capacity. The hypothesis that local electricity generation and import capacities were insufficient to meet electricity demand for 10 hours a year was used.

Services studied: arbitrage (France segment and local fuel savings), congestion relief and local guaranteed supply capacity (reduction of failures).

Valuation results and installation potential: For the three scenarios studied, the upgrading of the VHV grid or the local construction of thermal power plants were the most economic solutions. If these two solutions are not possible for technical or societal acceptance reasons, the economic efficiency of the deployment of electricity storage systems must be compared with demand management actions (not studied in this report).

As the valuation of storage is lower for this segment than for the France segment, a dedicated case study was not carried out on this segment.

Scope of application of the results and prospects: The results presented are strongly linked to the low share of base production in this segment. During off-peak hours, local electricity demand is mostly met with electricity imports (produced in nuclear plants whose variable costs are much lower than those of the thermal power stations in the region studied). This massive importing of electricity saturates the VHV line. Local electricity storage can therefore no longer be charged at the marginal cost of nuclear during these hours and loses opportunities for nuclear-CCGT arbitrage. In the case of local energy production in nuclear plants, the value of electricity storage will be reinforced.

HV/MV segment (electricity storage)

Description of the segment: The interest of electricity storage to support the deployment of wind power production in rural areas was examined through the case of a 40 MW source substation that is saturated in terms of export up to 500 hours per year. Three solutions were analyzed and compared: upgrading of the source substation, peak shaving of excess wind power production, and electricity storage.

Services studied: arbitrage (France segment), guaranteed supply capacity (France segment), congestion relief.

Technologies studied: H_2, Pb-A, Li-ion, Na-S, Zn-Br.

Valuation results and installation potential: The most economical solution for the community is either the peak shaving of wind power production or the upgrading of the grid (as of 200 hours of curtailed wind power production), depending on the installed wind power capacity and the characteristics of the grid. Electricity storage is not cost-effective in the different cases studied: the benefits derived from congestion relief are insufficient to offset the technological costs associated with the small size of the storage system.

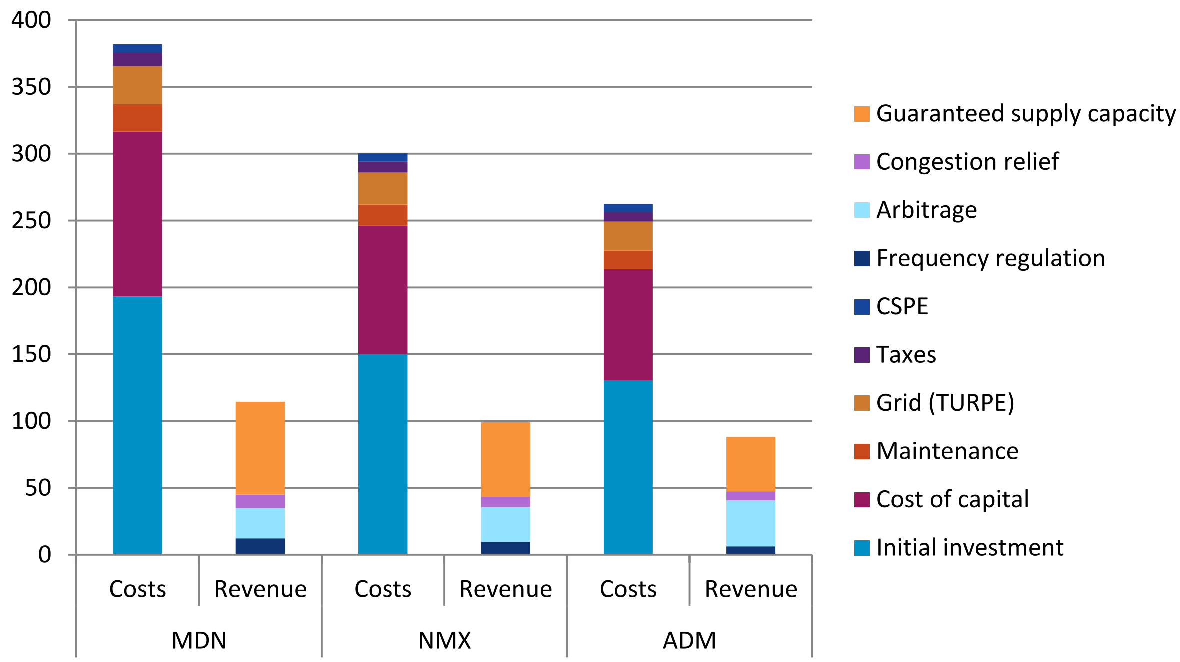

Figure 16 – Comparison of complete revenues and costs discounted over the service life of a 5 MW, 4-hour Li-Ion battery (efficiency 85%), in €/MWh discharged (LCOS method)

Scope of application of the results and prospects: The studies were based on supply-demand balance calculations at hourly intervals. Voltage support and local grid stability control services were not studied for this segment. These services may potentially create value.

While it is quite difficult to generalize grid aspects, this case study and the sensitivity analyses nevertheless show that decentralized storage in support of wind power production deployment in rural areas does not likely represent a substantial opportunity for the electricity storage sector.

The studied cases supposed that the wind power developer would be paid the market price for wind power generation. The application of feed-in tariffs for stored electricity would give an additional value to storage, without however making the installations cost-effective.

Regulatory aspects and support for the industry: In the cases that were modelled, the most economical solution is either peak shaving or grid upgrading. Regulatory evolutions allowing arbitrage between these solutions will help minimize the additional cost linked to the integration of renewables in the grid.

LV segment (electricity storage)

Description of the segment: In this segment, we examined the opportunities associated with distributed electricity storage in residential areas with high levels of PV generation. Two contexts were studied. The first concerned electricity storage to reduce grid use and improve self-consumption. In the second context, electricity storage participated in voltage support.

Services studied: arbitrage (France segment), guaranteed supply capacity (France segment), congestion relief, voltage support.

Valuation results and installation potential: Distributed electricity storage reveals new values (decrease in or deferral of grid investment costs). However, these new services are provided to the detriment of arbitrage or guaranteed capacity services. The results show that apart from some specific conditions (very high grid development costs or strong will to increase self-consumption), distributed electricity storage is not cost-effective compared with peak shaving or grid upgrade solutions.

For grid costs comparable to the tariff equalization in force, the valuations are too low to ensure the profitability of the storage system, hence, the dedicated case study was not performed.

Scope of application of the results and prospects: The results presented do not in any way challenge the benefits of self-consumption (producing electricity at the point at which it is consumed) but examine the potential of electricity storage to increase self-consumption.

Moreover, for extremely variable load curves, electricity storage with a sufficient discharge duration could reduce grid costs, in the limit of 75 €/year per kW of peak avoided (by adding up LV and HV/MV costs). As this value is very specific to the load profile, it was not studied for this report. Finally, the use of recycled electric vehicle batteries was not studied for this segment.

Tertiary segment (electricity storage)

Description of the segment: In this segment, we studied the arbitrage opportunities for a backup electricity storage system (uninterruptible power supply service). Many tertiary sites (hospitals, telecom centers, etc.) must be equipped with electricity storage that will cover their consumption in case of a temporary grid supply interruption. This market is mainly covered by lead batteries, a mature and inexpensive technology. The aim for this segment is to assess the economic benefits for a tertiary site with local PV generation to use their electricity storage system to carry out arbitrage on the markets while maintaining their UPS (Uninterruptible Power Supply) service.

Services studied: arbitrage (France segment), guaranteed supply capacity (France segment), continuity of supply

Technologies studied: Pb-A, Li-Ion, Zn-Br.

Valuation results and installation potential: The use of an existing Pb-A battery UPS system for arbitrage enables a tertiary site to generate value that could reach 10 €/kW/year (in the case of the ADEME scenario). This profitability could be increased by investing in a flow battery (Zn-Br) system that will be less costly in 2030, given the use made of the electricity storage system. On the other hand, Li-Ion systems require an initial extra investment that is too high and that is not paid back due to the low cycling in this segment.

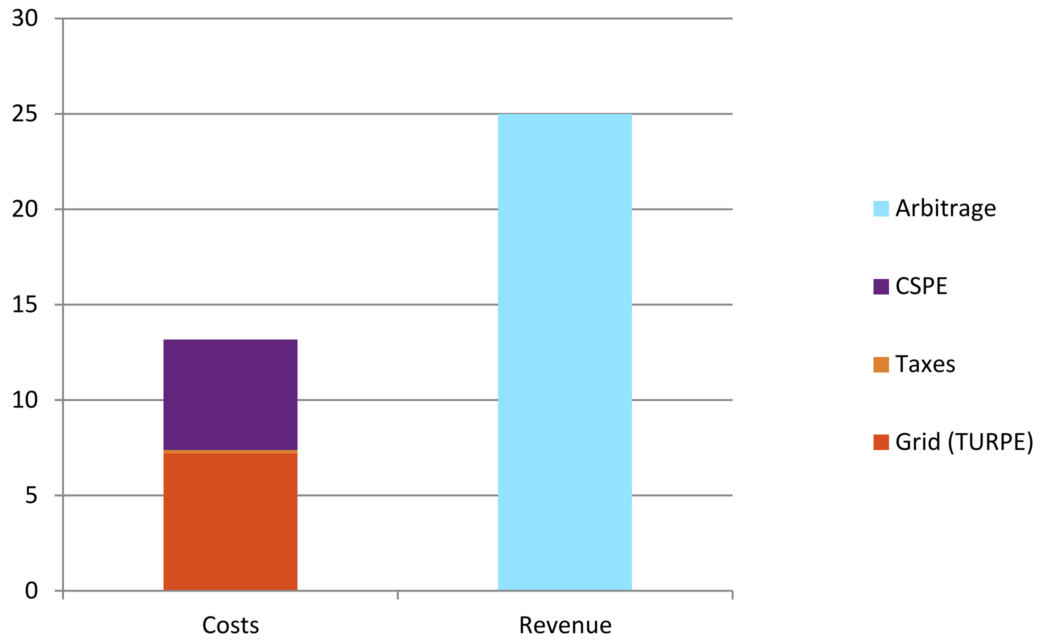

Figure 17 - Comparison of complete revenues and costs discounted over the service life of a cycling UPS system (Pb-A, 800 kW, 4 usable hours, 73% efficiency, NMX scenario), LCOS method.

Scope of application of the results and prospects: This study is only valid for sites that have already opted for UPS systems and have substantial on-site renewables generation. This segment therefore does not represent additional electricity storage potential, but gives access to a lower cost for the UPS service through the use of arbitrage.

Moreover, the capability of electricity storage to be used for arbitrage while maintaining UPS service is heavily dependent on the local electricity generation and demand curves. Similarly, for certain specific tertiary sites with a highly variable consumption curve, the use of cycleable electricity storage could make it possible to lower the consumption peak and therefore the grid infrastructure costs. The associated surplus for the community is assessed at 55 €/year per kW of avoided peak power (adding up the costs of HV/MV).

Regulatory aspects and support for the industry: The arbitrages carried out in this case are based on existing (adjustment mechanism and spot market) or emerging (NEBEF – a load shedding mechanism) market mechanisms. The size of the installations (roughly 1 MW) would however lead the manager of the tertiary site to delegate arbitrage management to an aggregator or its electricity provider for both technical and economic reasons.

Cold segment (cold storage)

Description of the segment: The segment studied is a large tertiary consumer (office building) with an internal air conditioning network; the cooling is produced locally from electricity. Cold storage can smooth demand to decrease the installed capacity needs of the refrigeration units. It also makes it possible to time-shift the electricity consumption of the refrigeration units.

Services studied: lower required cooling production capacities, lower electricity supply costs (arbitrage and guaranteed supply capacity, France segment)

Technologies studied: ice storage

Valuation results and installation potential: By 2030, with the deployment of the PV sector, air conditioning demand periods will coincide with periods of low electricity generation costs. Cold storage was not cost-effective for the case studied.

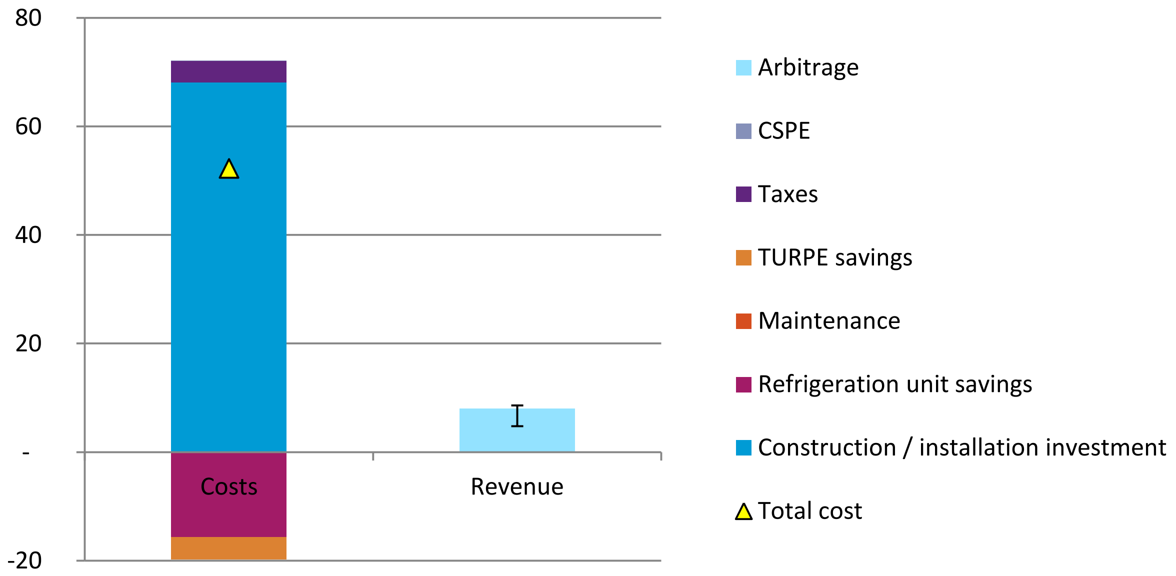

Figure 18 – Comparison of complete revenues and costs (for the MDN= RTE Intermediate scenario, NMX= RTE New Mix scenario, ADM= ADEME scenario) discounted over the service life of an ice storage system of 30 MWh$_{th}$, in €/MWh$_{th}$ discharged (LCOS method)

Scope of application of the results and prospects: The investments in cold production avoided thanks to cold storage, as well as the opportunities to time-shift electricity demand depend heavily on the cold demand curve. Some tertiary consumers may therefore have more advantageous load profiles.

Moreover, in the context of a district cooling network, cold storage can also provide services to reduce grid congestion. This service was not studied here.

Regulatory aspects and support for the industry: For the cases where the installation of cold storage is cost-effective, the potential value will only be attainable when the consumer is also subject to a price signal that takes into account the structure of the generating costs and the costs of the French electricity grid. The end of regulated tariffs planned for industrial consumers in 2015 and the creation of a load shedding mechanism (NEBEF) are steps in this direction.

Heating network segment (heat storage)

Description of the segment: For this segment, we assessed the heat storage potential of a district heating network. To this end, different heat generation mixes were studied: non-dispatchable production (household waste incineration plants or solar thermal), wood boilers and gas boilers for peak demand. An objective of 75% renewables was set for all of these mixes.

Services studied: guaranteed supply capacity, arbitrage[7], smoothing and shaping of production [8]

Technologies studied: hot water storage at atmospheric pressure, pressurized hot water storage

Valuation results and installation potential: In the context of the creation or extension of a network, heat storage can make it possible to reduce the investment costs in heat generation facilities. By smoothing demand peaks, it reduces required peak capacities. It also introduces complementary flexibility for supply-demand balancing, which avoids multiplying the number of generators and thus reduces investment costs through economies of scale. Except for contexts with a high excess of non-dispatchable heat production, fuel savings are secondary.

The installation potential for 2030 is estimated at 5 to 10 GWh_{th} to support the deployment of the heat networks planned in France for 2030.

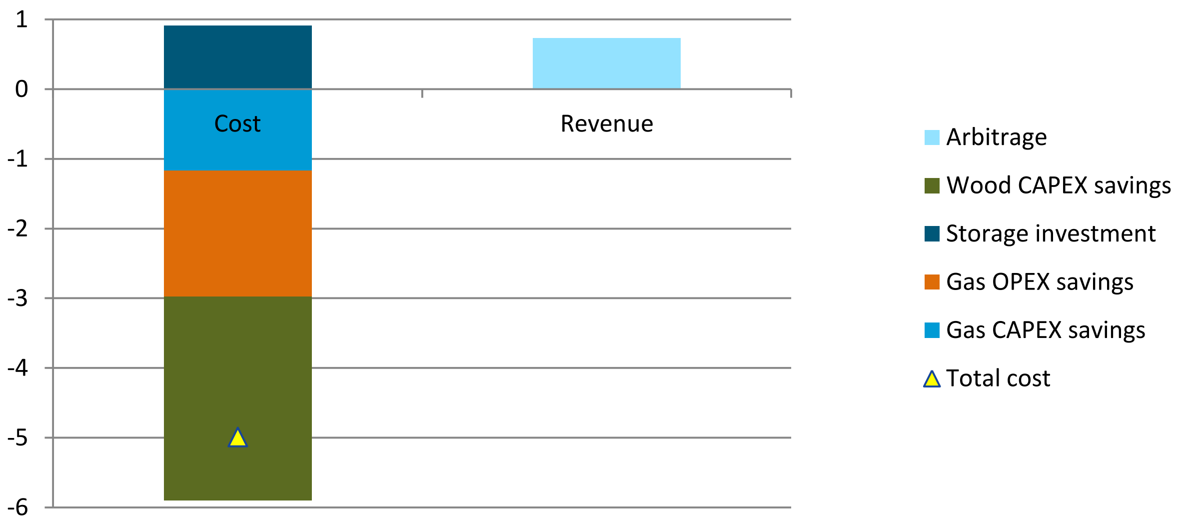

Figure 19 – Comparison of complete revenues and costs discounted over the service life of a 70 MWh_{th} pressurized water storage facility on a 75% biomass network of 200 GWh_{th}/year, in €/MWh_{th} discharged (LCOS method)

Scope of application of the results and prospects: The investment costs avoided using heat storage depend heavily on the load curve, the cost of property used and the initial situation in terms of existing peak capacity in the case of a heating network expansion. For a flat demand profile (for example, a paper mill), the savings would be much lower.

Regulatory aspects and support for the industry: It will be necessary to modify the regulations in order to permanently qualify the renewable status of stored renewable thermal energy.

[7] Including valuation of excess non-dispatchable energy

[8] Heat storage makes it possible to adapt (shape) biomass plant generation during the summer leading to reduced investments.

Cogeneration segment (heat storage)

Description of the segment: This segment is a variant of the previous one; it concerns the coupling of heat storage with a cogeneration plant. Two contexts were studied: a paper mill and a district heating network. Base generation was provided by a wood boiler that supplies 55% of the heat production. A gas-fired cogeneration plant and a gas add-on boiler supplied the remainder. The PES (primary energy saving) was set at 10%. The value of electricity generation via cogeneration was assessed at the national marginal cost of electricity generation (no feed-in tariff).

Services studied: reduction in peak generating capacity, improved cogeneration management (arbitrage and guaranteed capacity for the French electricity grid, France segment)

Technologies studied: hot water storage at atmospheric pressure, pressurized hot water storage

Valuation results and installation potential: The coupling of heat storage with cogeneration is really interesting as it makes it possible to manage cogeneration based on electricity prices, independently of heat demand: when thermal uses are insufficient, the heat is stored for a later use. Heat storage also makes it possible to optimize the cogeneration operating regime by reducing the number of short cycles.

The values presented (excluding reduction in peak production capacity) are valid for both existing and new networks.

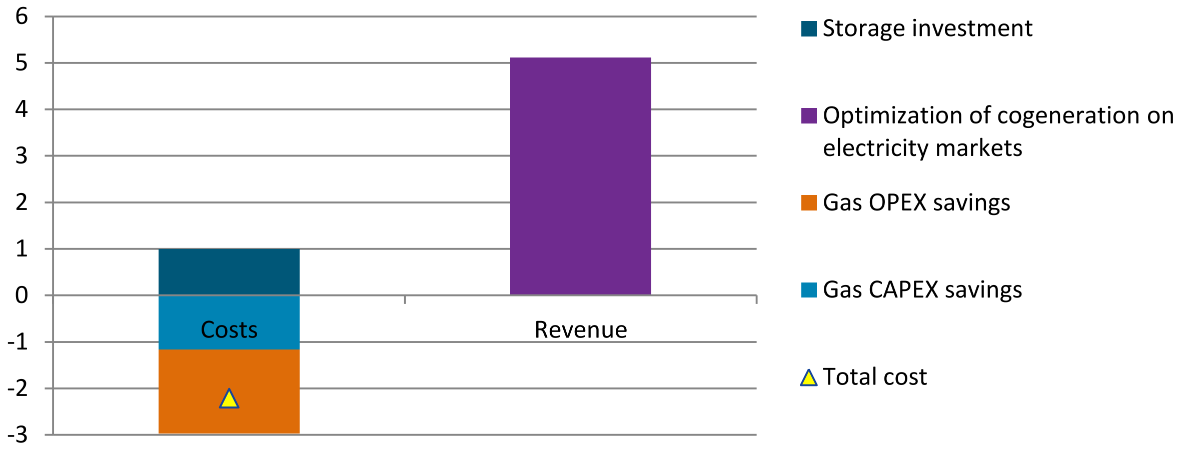

Figure 20 - Comparison of complete revenues and costs discounted over the service life of a pressurized water storage system on a 55% biomass network of 200 GWh_{th}, in €/MWh_{th} discharged (LCOS method)

Scope of application of the results and prospects: The results presented are not applicable if the cogeneration facility benefits from a feed-in tariff[9]. Indeed, the valuation of “improved cogeneration management” services depends heavily on the intra-day variations in the sales price of electricity produced from cogeneration.

Regulatory aspects and support for the industry: With the exclusion of feed-in tariffs for cogeneration facilities of more than 12 MW of electrical energy, heat storage and cogeneration coupling projects can be set up in the short term.

[9] Facilities of less than 12 MW currently benefit from a feed-in tariff. The French fleet of cogeneration facilities of more than 12 MW (2.5 GW installed) is operated in market conditions (capacity market and arbitrage).