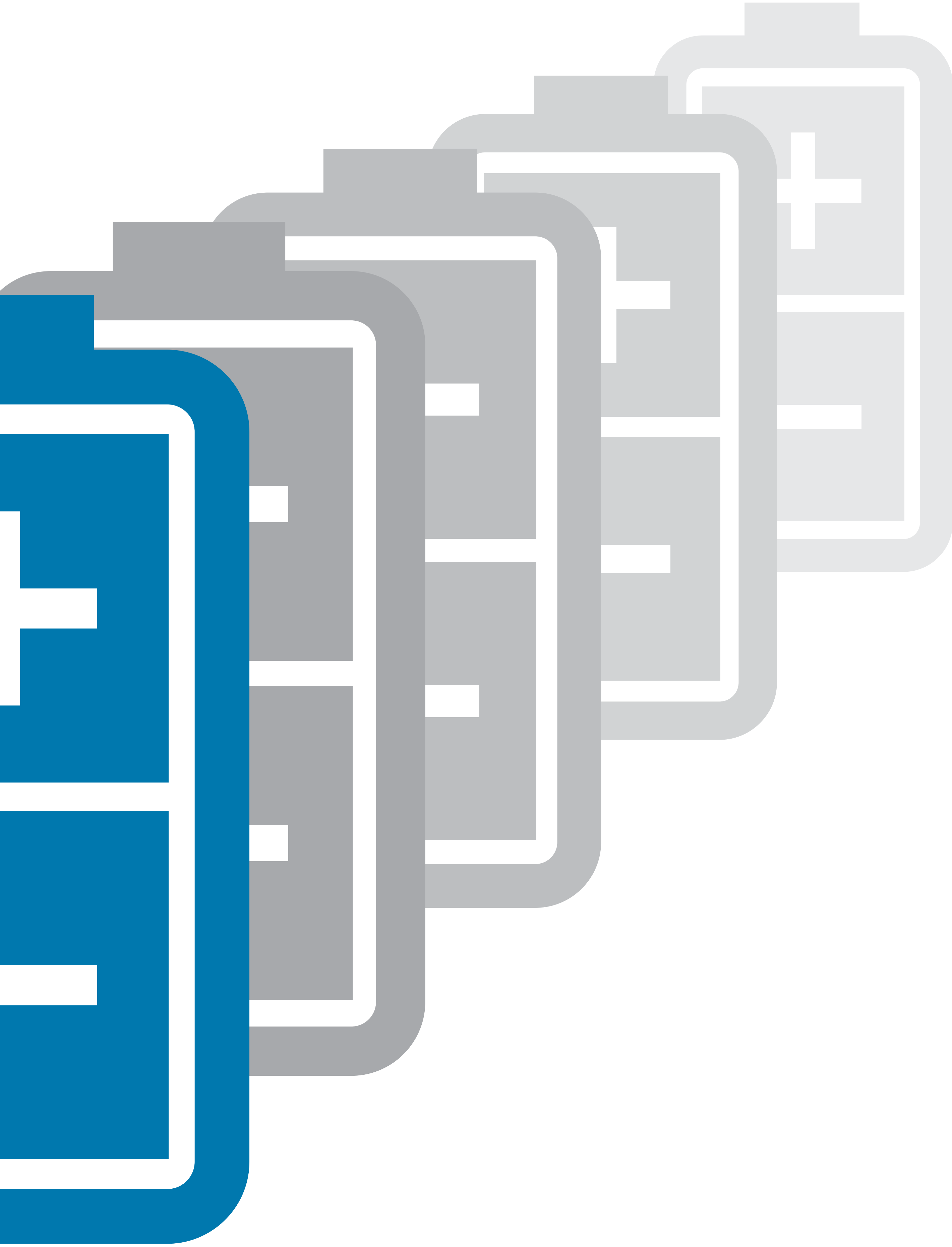
| | |
|---|---|
| **L** | litre |
| **LFP** | lithium ferrophosphate, a type of battery chemistry |
| **Li-ion** | lithium ion |
| **LMP** | locational marginal price |
| **LTO** | lithium titanate, a type of battery chemistry |
| **mBtu** | million British thermal units |
| **MISO** | Midcontinent Independent System Operator |
| **MW** | megawatt |
| **MWh** | megawatt hour |
| **MW/h** | megawatt per hour |
| **NaNiCl** | sodium nickel chloride, a type of battery chemistry |
| **NaS** | sodium sulphur, a type of battery chemistry |
| **NCA** | lithium nickel cobalt aluminium, a type of battery chemistry |
| **NMC** | lithium nickel manganese cobalt, a type of battery chemistry |
| **NPV** | net present value |
| **NYISO** | New York Independent System Operator |
| **OCGT** | open-cycle gas turbine |
| **OPEX** | operating expenditure |
| **O&M** | operation and maintenance |
| **PCS** | power conversion system |
| **PHES** | pumped hydro energy storage |
| **PV** | photovoltaic |
| **REC** | renewable energy certificate |
| **REE** | Spanish electrical network (Red Eléctrica de España) |
| **RoCoF** | rate of change of frequency |
| **RR** | replacement reserves |
| **RTM** | real-time market |
| **SOC** | state of charge |
| **SRMC** | short-run marginal cost |
| **T&D** | transmission and distribution |
| **ToU** | time of use |
| **VOM** | variable operational and maintenance (costs) |
| **VRB** | vanadium redox battery, a type of flow battery |
| **VRE** | variable renewable energy |
| **VRLA** | valve-regulated lead acid, a type of battery |
| **V2G** | vehicle to grid |
| **W** | watt |
| **Wh** | watt hour |
| **ZBB/ZnBr** | zinc bromine battery, a type of flow battery |



# Executive summary

Renewable energy technologies have expanded rapidly in recent years because of steep cost reductions, innovation and policy support. The ongoing transformation of the power sector introduces new challenges that require changes in the way that policy makers, regulators and utilities plan, manage and operate the power system. The rapid expansion of renewable electricity calls for a more flexible energy system to ensure that a power system with large shares of variable renewable energy (VRE) resources can be operated reliably and cost-effectively.

With its unique capabilities to absorb, store and then reinject electricity, electricity storage is seen as a prominent solution to address a number of technical and economic challenges of renewables integration. **Electricity storage** can provide a wide range of services that support **solar and wind integration** and address some of the new challenges that the variability and uncertainty of solar and wind introduce into the power system. In a market setting, when allowed to participate in the wholesale market, storage can consume or feed in electricity in response to price signals, in particular increasing demand when prices are very low – or even negative. While **negative prices** could be a sign of inflexibility in the system, storage can prevent such phenomena from happening by consuming electricity and being paid to do so.

When coupled with solar photovoltaic (PV), storage can prevent the **cannibalisation of revenues** during the middle hours of the day,[1] increasing the profitability of solar PV and consequently creating the opportunity for more solar to be deployed. Solar PV generation can exceed electricity demand during the middle of the day; storage can absorb part of this electricity and reinject it at later stage, effectively **reducing curtailment** due to overgeneration or grid constraints. It can do this whether in a market or a vertically integrated setting.

## Electricity storage services help to address the challenges of solar and wind variability

In addition, electricity storage can participate in capacity and ancillary services markets, **offering grid services** like provision of **primary and secondary reserves** as well as **firm capacity.** Indirectly storage can support cost reduction, **deferring the need for generation and transmission capacity** by reducing the need for peaking plants and easing line congestion. When connected behind the meter, electricity storage can support integration of distributed renewables and the active participation of prosumers in demand management, with resulting reductions in average household electricity bills. A key element is that storage can efficiently provide multiple services simultaneously, thereby **stacking revenues** for greater profitability.

Different storage technologies are intrinsically more suited to providing certain services rather than others. For instance, **batteries** have proven to be very **rapid in responding** to signals (e.g. set points from the system operator). This opens the way for new system services that have a higher value than conventional ones (e.g. one unit of fast frequency response can replace multiple units of primary reserve), effectively calling for a revision of grid services to capture the full value of new storage technologies.

When **large volumes** of electricity need to be shifted from one time to another (e.g. later in the day, week or month), **pumped hydro** has historically been the main technology to achieve this. Pumped hydro may therefore see a renaissance in solar and wind-dominated power systems, where new technologies such as variable speed pumping can provide additional system services in addition to simply bulk arbitrage.

Overall, electricity storage could play a key role in facilitating the next stage of the energy transition by enabling higher shares of VRE in power systems, accelerating off-grid electrification and indirectly decarbonising the transport sector. However, the **system value of storage** is often poorly accounted for in electricity markets, resulting in so-called **"missing money"** where market revenues for investors are insufficient to make projects viable, causing sub-optimal deployment of electricity storage. **In vertically integrated settings**, however, the **same entity can capture the full value of storage**, including savings in both production cost as well as investment, provided that the right incentives are in place to explore the potential of storage to reduce the cost of supply.

1 Maximum generation from PV takes place when the sun is at its highest point – depressing electricity prices at this time. As additional PV further reduces prices during the middle hours of the day, more PV deployment leads to less revenues for PV generators, as most of their generation takes place during the hours with the lowest price.


The Electricity Storage Valuation Framework (ESVF) designed by the International Renewable Energy Agency (IRENA) and presented in this report aims to guide the development of effective storage policies for the integration of variable renewable power generation. The ESVF and its accompanying modelling methodology describe how to assess the value of electricity storage to the power system and how to create the conditions for successful storage deployment.

## Report structure

This report describes IRENA's ESVF and its detailed methodology for valuing electricity storage. The report is organised into three separate parts:

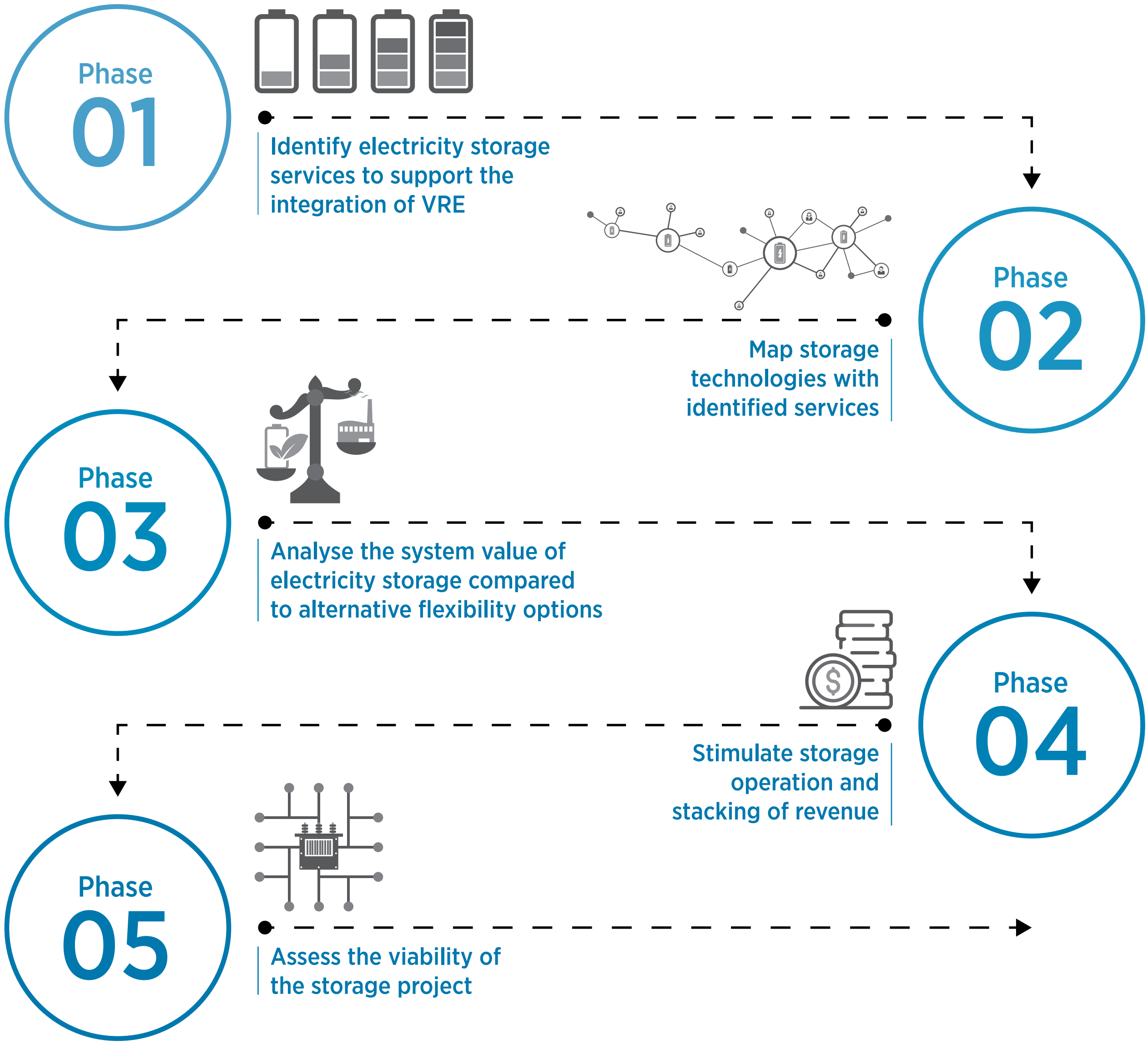
**Part 1** addresses **power system decision makers, regulators and grid operators**, aiming to give them with an overview of the process of valuing electricity storage in power systems. It provides an outline of the ESVF, describing its components and the sequence of steps that it uses to quantify the benefits of electricity storage and assess project viability under the existing regulatory framework. This part also describes the services that electricity storage can provide for the integration of VRE resources and identifies a number of storage uses to support VRE integration.

Part 1 also considers the role of the regulatory framework in supporting the development of storage projects that are demonstrated to be of net positive benefit to the power system, but may not see adequate revenues at the project level to justify being built. It allows the comparison of different measures by their effectiveness in supporting the deployment of storage projects that are worthwhile pursuing (i.e. projects that cost less than the value they provide to the system).

**Part 2** of the report provides a detailed description of the ESVF methodology and is directed at **power system experts and modellers** who may wish to adopt this approach for electricity storage valuation studies. Electricity storage valuation studies have recently been developed in support of a number of regulatory reforms. The methodology provided in Part 2 can be used for future studies, to provide consistency among them. Inputs and outputs for the various phases of the ESVF are discussed, including how to use power system modelling tools in each phase of the analysis. Particular attention is given to identifying and valuing benefits from the introduction of increasing amounts of electricity storage into the power system, and assessing the suitability of the regulatory framework to the deployment of the amount of storage projects that can provide value to the system.

**Part 3** presents **eight real-world cases** of storage use, corroborated by examples of cost-effective storage deployment based on one main use and often supported by additional revenues derived from other uses. This part also highlights storage projects' ability to stack multiple revenue streams to reach commercial viability. These concrete examples are structured according to the following logical sequence: a) how such cases are driven by accelerated deployment of VRE; b) how the challenges have been transformed into a business case; c) how this led to storage deployment; and d) how storage is performing in the provision of these services compared to other grid assets or generators.

**Figure:** Electricity Storage Valuation Framework




### Summary of report structure

| Report Title | Type of content | Format | Target audience |
|---|---|---|---|
| Part 1: Framework overview | Overview of the process of valuing electricity storage in power systems | Brief report | Power system decision makers, regulators and grid operators |
| Part 2: Using power system models to assess storage value and viability | Detailed description of the ESVF methodology | Detailed report | Power system experts and modellers |
| Part 3: Real-world cases of storage use in power systems | Eight selected cases | Small briefs, one per case | Policy makers, energy planners, general public |

# Part 1: Framework overview

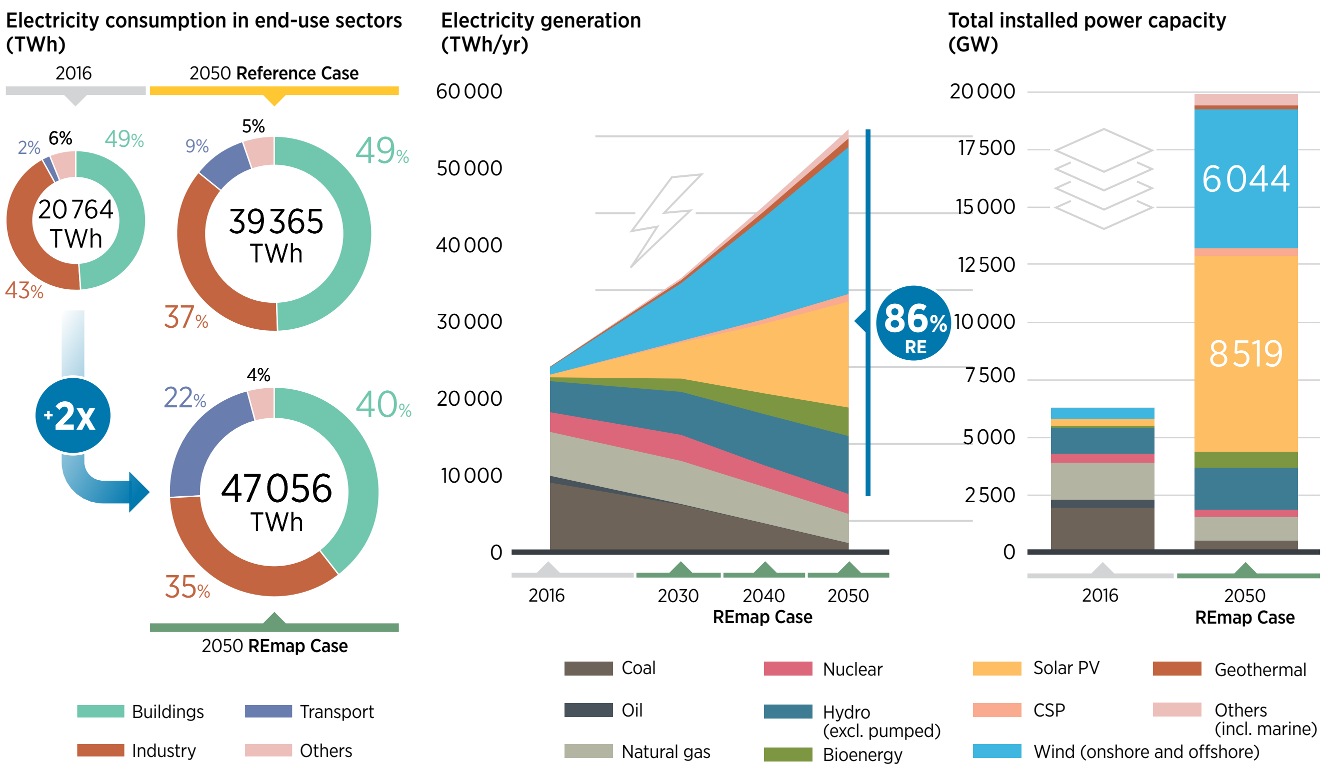
## 1. Introduction

Electricity storage refers to technologies that store electrical energy and release it on demand when it is most needed. The storage process often involves conversion of electricity to other forms of energy and back again.[2] With its unique ability to absorb, store and then reinject electricity, electricity storage[3] is seen as a key solution for addressing the technical challenges associated with renewables integration alongside other solutions (e.g. more flexible demand, accelerated ramping of traditional power plants). Consequently, storage is garnering increasing interest in the power sector and is expected to play a key role in the next stages of the energy transition.

By enabling higher shares of variable renewable energy (VRE) in the system, storage capacity accelerates off-grid electrification and indirectly helps to decarbonise the transport sector.

Based on recent analysis by the International Renewable Energy Agency (IRENA, 2019a), the renewable share of global power generation is expected to grow from 25% today to 86% in 2050. The growth is especially strong for VRE technologies – mainly solar photovoltaic (PV) and wind power – with an increase from 4.5% of power generation in 2015 to around 60% in 2050. Furthermore, almost half of PV deployment could be achieved in a distributed manner in the residential and commercial sectors, in both urban and rural locations (IRENA, 2019a) (Figure 1).

**Figure 1:** Electricity generation mix and power generation installed capacity by fuel, REmap case, 2016–50

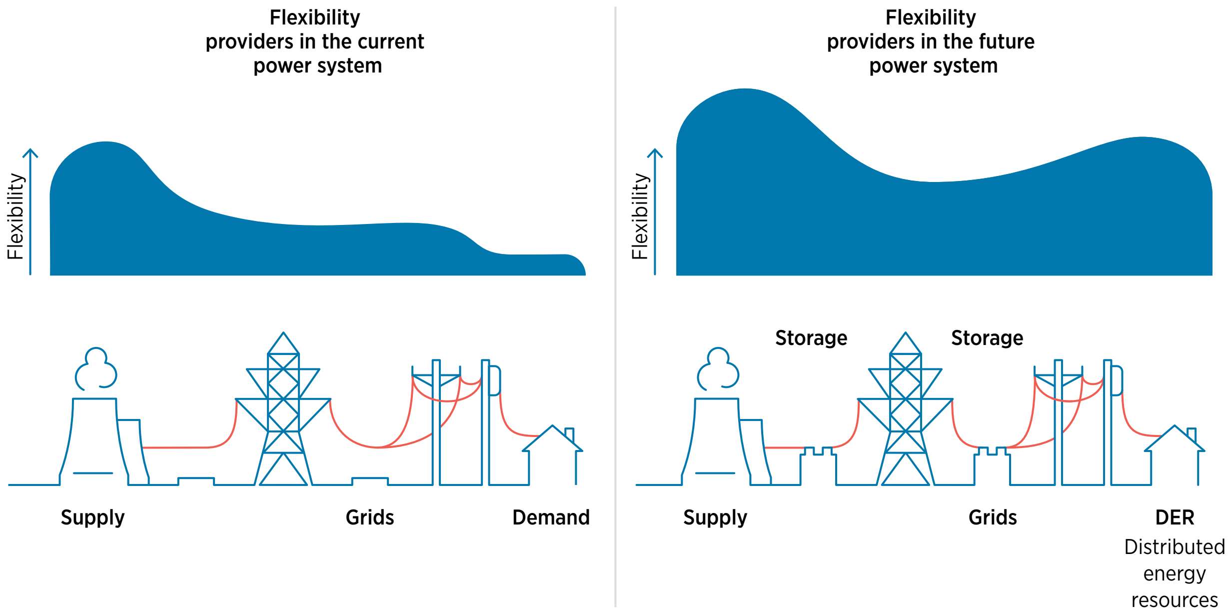



**Note:** IRENA's REmap case includes the deployment of low-carbon technologies, based largely on renewable energy and energy efficiency, to generate a transformation of the global energy system that limits the rise in global temperature to well below 2°C above pre-industrial levels. The assessment considers the renewable energy potential assembled from the bottom up, starting with country analysis done in collaboration with country experts, and then aggregating these results to arrive at a global picture; CSP = concentrated solar power; RE = renewable energy.
Source: IRENA (2019a).

2 As in the case of pumped hydro where electricity is used to lift water to higher altitudes (converted to potential energy); when electricity is needed water is released to spin the blades of a hydro turbine and produce electricity. Examples of other electricity storage technologies include batteries, flywheels and compressed air energy storage (CAES).

3 This report refers to all energy storage technologies that can absorb and reinject electricity (i.e. batteries, flywheels, pumped hydro, CAES etc.).

**Figure 2:** Traditional flexibility providers (left) versus emerging flexibility providers (right)




Source: IRENA (2019b).

As renewable technologies mature, policy makers, regulators and utilities are confronted with new challenges related to planning, managing and operating the power system. The rapid expansion of renewable resources prompts the need for a more flexible energy system to ensure that variable resources can be integrated into the power system reliably and effectively.

Traditionally flexibility has been provided by conventional thermal generation with high ramping capabilities, low minimum loads or short start-up times, such as open-cycle gas turbines. However, to integrate very high shares of VRE, flexibility should be harnessed in all parts of the power system to minimise the total cost of providing flexibility (Figure 2). Electricity storage together with other mitigation measures (for example demand response, flexible generation, and smart transmission and distribution networks) could enable the integration of solar and wind power at very large scales (IRENA, 2018a, 2019b).

However, the pace at which electricity storage needs to be deployed in each of these cases varies depending on progress in the energy sector's transformation, the economics of alternative technologies that can provide similar or alternative solutions and progress in electricity storage costs and performance.[4]

The main barriers to large-scale storage deployment are:

a. **Cost and technological maturity.** Battery costs are declining fast while technical parameters such as degradation rates and energy density keep improving. Deployment of batteries – both stationary and in electric vehicles (EVs) – is currently picking up; they are expected to play a key role in increasing flexibility in the energy sector, although in energy terms pumped hydro remains by far the largest source of electricity storage (IRENA, 2017a).

b. **Difficulty for storage owners to monetise value.** There remains a lack of clarity around the monetisation and fair allocation of benefits of storage among stakeholders. This is due to the complex nature of power grids and dynamic interaction among system elements. Each power system has its own physical structure, electricity demand and, in the case of competitive environments, electricity market design and regulatory framework, meaning that no single solution fits all cases. Use of sophisticated tools and development of appropriate methodologies are needed to effectively guide policy makers on how to best develop appropriate policies to support monetisation of storage benefits among owners and stakeholders in general (IRENA, 2017a).

4 In deregulated markets, barriers can arise due to regulatory frameworks and electricity market design not being adjusted to compensate storage for the value it provides to the system.

The Electricity Storage Valuation Framework (ESVF) as presented in this report is a continuation of IRENA's previous work on the role of energy storage in facilitating VRE integration (IRENA, 2015a).[5] The ESVF is designed to be used to identify the value of electricity storage to different stakeholders in the power system. It allows stakeholders to analyse both the value and challenges of implementing electricity storage systems. The framework considers: a) the value electricity storage brings to the power system; b) ways to optimally utilise electricity storage; and c) an approach to ensuring that the monetisable revenues for the identified amount of storage are higher than costs, to ensure deployment and reduction of total system cost.[6]

The ESVF addresses the first of these by identifying the services electricity storage can provide. Values are assessed by comparing the cost of operating the power system with and without electricity storage. The framework also describes a method to identify electricity storage projects in which the value of integrating electricity storage exceeds the cost to the power system. Because the value of electricity storage is realised throughout the power grid, often the project owner may not be able to earn revenues for all of the services the project is providing. This makes it difficult for the developer to economically justify the deployment of the electricity storage system. The ESVF can be used to support development of policies to support monetisation of the benefits of electricity storage based on their system value and fair allocation of such benefits among stakeholders. This report includes several recommended policy measures to provide incentives and compensation for the development of cost-effective electricity storage systems. These policy measures can be considered and applied on the basis of the results of the analysis.

More specifically, the **ESVF aims to address** the following questions:

- What services can storage provide to help integrate more VRE into the power system? What other peripheral services does the same storage provide?

- Which storage technologies can provide these services? What are the associated costs?

- How does storage compare with other alternative flexibility measures, such as demand response, more flexible generation or even stronger transmission networks, in effectively reducing total system costs?

- For the services that storage can cost-effectively provide, how should storage projects be deployed to realise the optimal benefits? Assuming optimal operation, would a project be financially viable under a specified market setting?

- Is there a missing money problem between the value storage provides to the system and the value realised by the storage owner? If yes, what are best policy recommendations to bridge the gap?

- How can analysis through a systematic approach support policy development to effectively answer the above questions?

The framework **answers these guiding questions** in a sequence of five phases (Figure 3):

1. In **Phase 1** of the framework, the services that electricity storage can provide to integrate more VRE into the power system are identified. Categorisation of electricity storage services is partly based on previous IRENA work on electricity storage (see Box 1 and Box 2) (IRENA, 2015a; 2017a).

2. In **Phase 2** of the framework, the attributes of a variety of storage technologies are scored to rank their suitability to providing the services identified in Phase 1. This phase helps prevent the analyst from making the wrong choices for storage at the beginning of the modelling process.

3. In **Phase 3**, electricity storage is valued for its effectiveness in providing the identified services compared to alternative options such as energy efficiency, demand response and new fossil-fuelled power plants. The various services electricity storage provides at the system level eventually amount to a number of economic benefits of both an OPEX and a CAPEX nature that need to be estimated.

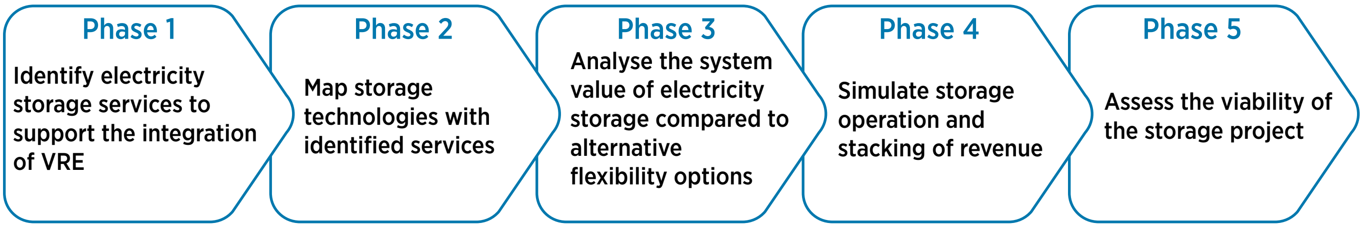
4. In **Phase 4**, the framework analyses the actual operation of a storage project, assuming the project is a price-taker under the market prices simulated in Phase 3. In this phase, the project revenue received is maximised by combining the various services the project can provide. This applies mainly in deregulated environments.

5. In **Phase 5**, the framework accounts for the revenue of the storage project over its lifetime, determines whether such revenues are sufficient to deem the storage project financially viable, and if not, how to identify possible remedies. The output of this final phase is a project-level cost and benefit analysis, where the cost refers to the costs of building and operating a storage project and the benefit refers to the combination of project-level and system-level benefits attributable to the project. In this phase, the result should be that monetisable revenues are adjusted to be higher than costs yet lower than the system value of the project.

5 See Box 1.

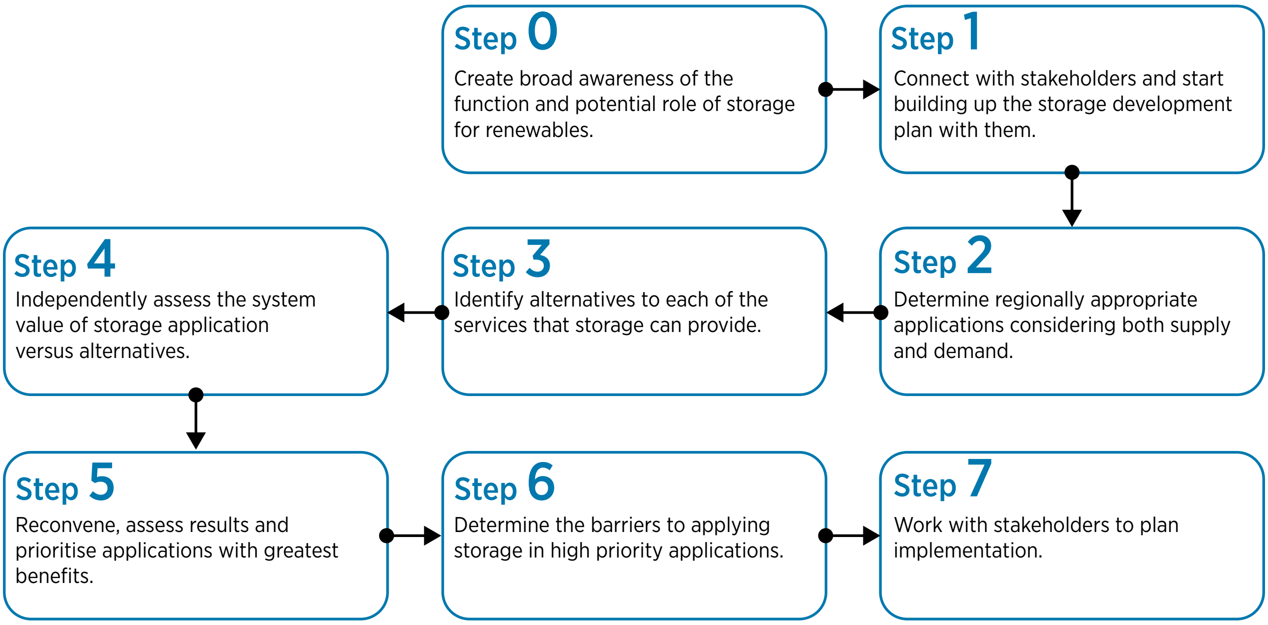
6 Total system cost in power systems planning refers to the total cost of physical infrastructure additions and operating a power system over the period of a study. It is often split into operating expenditure (OPEX) and capital expenditure (CAPEX) elements. The main component of OPEX is the cost of fuel to generate electricity. The main CAPEX component is the annualised investment costs over the period of the study.

**Figure 3:** Electricity storage valuation framework: Five phases




**Box 1:** Renewables and electricity storage: A technology roadmap for REmap 2030

In June 2015 IRENA released "Renewables and electricity storage" (IRENA, 2015a), a report intended to provide a broad roadmap for developing electricity storage. This roadmap, based on a combination of literature reviews, studies and findings from stakeholder workshops, highlighted priority areas for storage deployment, noted key areas for international co-operation and set out a framework to monitor progress.




This electricity storage roadmap identified 14 action items that were subdivided over 5 priority areas. These areas are:

1. **System analysis**, which helps to assess the role of storage in the power sector and is required by all countries.

2. **Storage on islands and in remote areas**, which is the most immediate area where electricity storage can support renewable energy deployment.

3. **Consumer-located storage**, which is relevant for countries expecting a high share of rooftop solar PV systems in the power sector.

4. **Generator-located storage**, which is important for countries in categories 1 and 3.

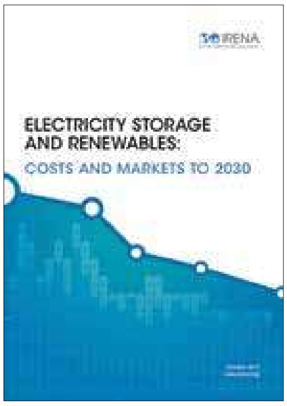
5. **Storage in transmission and distribution grids**, which is relevant for countries making the transition to power systems based on renewables but with limited power system flexibility.

The present report aims to address the priorities that IRENA identified in 2015 by developing the IRENA ESVF with a methodology to systemically assess the value of electricity storage and to engage and guide policy makers. The figure in this box shows the steps identified in the 2015 report for engaging and guiding stakeholders in developing energy storage policies for renewables. The present report provides a framework and a methodology to address steps 3–6 in the process.

**Box 2:** Electricity storage and renewables: Cost and markets to 2030

The electricity storage roadmap launched by IRENA in 2015 identified that two of the most important elements to be considered when assessing the economics of electricity storage are costs and value. In October 2017 IRENA launched the report “Electricity storage and renewables: Cost and markets to 2030” (IRENA, 2017a) in order to analyse the current and future costs of electricity storage.

Some of the main findings of this report are that the rapid deployment and commercialisation of new battery storage technologies have led to rapid cost reductions, notably for lithium-ion batteries. However, battery electricity storage still offers enormous deployment and cost-reduction potential. By 2030 the total installed costs could fall by between 50% and 60%, driven by optimisation of manufacturing facilities, better combinations and reduced use of material.




Apart from costs, the report also maps the different services that storage can provide to the grid and the main parameters of different battery storage technologies. A tool* was also made available online to perform a quick analysis of the approximate annual cost of electricity storage for different technologies in different applications.

This IRENA report covers half of the most important elements needed to economically assess electricity storage: the costs. To analyse the value of electricity storage in different power systems and complement the 2017 costing report, IRENA has developed the ESVF being described in the present report.

* Download the tool here: https://irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets.

The ESVF has been designed as an instrument to inform policy making on the basis of detailed and complex analysis. Such analysis requires the use of a) a large amount of data, and b) appropriate optimisation tools. An analyst wishing to apply the ESVF will need to choose between relevant modelling tools with different capabilities and costs, and at the same time develop models/study cases that are both representative of reality (i.e. assumptions are reasonable, data are accurate) and practical (i.e. do not require unreasonably large amounts of data, have reasonable running times).

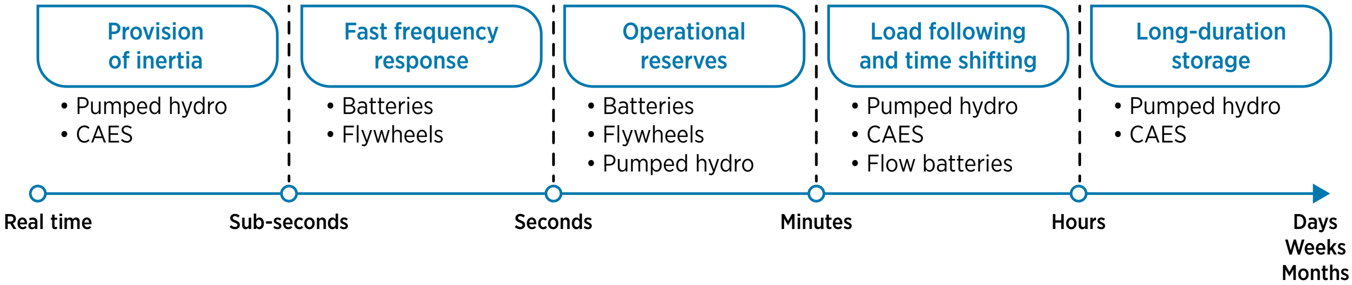
## 2. The role of electricity storage in VRE integration

Since the first quarter of the 20th century electricity storage, mainly in the form of pumped hydro, has been used to provide a wide range of grid services that support the economic, resilient and reliable operation of power systems. The great majority of global electricity storage capacity deployed up to the present day is pumped hydro due to its favourable technical and economic characteristics (IRENA, 2017a). Over the last hundred years, the electricity storage industry has continued to evolve and adapt to changing energy and operational requirements and advances in technology.

In addition to pumped hydro, a number of electricity storage technologies with varying costs and technical affinity for providing specific services have emerged and are currently at different stages of maturity and deployment. Such technologies include, for example, solid batteries, flow batteries, flywheels and compressed air energy storage (CAES). The various services electricity storage can potentially offer to support grid operations have often been grouped under energy services, ancillary services, transmission and distribution infrastructure deferral and congestion relief, and customer energy management services (Sandia National Laboratories, 1993, 1994, 2010; EPRI and US DOE, 2003; CAISO, 2007; DOER and MassCEC, 2016; ENTSO-E, 2016; EASA and EERA, 2017) (see Figure 6 below and Part 3 of this report, which provides examples of applications of electricity storage for eight different cases).

Recent developments have greatly increased interest in electricity storage. These include advancements in storage technologies and reductions in storage costs (for lithium-ion batteries in particular), the development of liberalised electricity markets and markets for ancillary services, challenges in building new transmission and distribution infrastructure, the enabling role that storage can play in solar and wind replacing diesel generators in an off-grid context, and the need for solutions to integrate the large amounts of VRE being deployed in power systems.

**Figure 4:** System services that electricity storage can provide at varying timescales




Electricity storage is expected to play a critical role in facilitating the integration of VRE into power systems and the energy transition more generally (IRENA, 2018a, 2019b). Integrating high shares of VRE is challenging due to its inherent characteristics. More specifically, variability and uncertainty related to solar and wind resources pose technical challenges for the process of balancing supply and demand, which in turn increases the need for system flexibility. Increasing system flexibility requires a range of measures, with storage being one of them. Others include flexible generation, demand-side management, smarter and stronger transmission and distribution networks, and sector coupling (e.g. hydrogen production from renewable energy[7] and vehicle-to-grid flexibility) (IRENA, 2018a, 2019b). As explained in more detail in other parts of this report, the ESVF is designed to compare electricity storage against alternatives considering both technical suitability to providing the intended service and cost-effectiveness.

Integration of VRE has direct impacts on system operations as it affects the magnitude of grid services needed as well as the timing and operational profile of each service. The impacts of VRE are characterised by a range of timescales that extend from sub-seconds (for example, when a cloud passes over a PV plant in a small power system) to years (the lead time of new transmission lines to ease congestion). Thus, to be effective for a specific application a storage technology needs to have the appropriate technical characteristics, namely response time, power capacity and energy capacity (Denholm et al., 2010) as well as synchronous inertia capabilities. The latter is very important in the context of VRE integration, as very high shares of non-synchronous VRE generation can undermine system stability without the use of appropriate measures.

At the shortest timescale (sub-seconds) certain storage technologies, such as pumped hydro, can provide inertia as a first line of defence in case of sudden loss of generation and can reduce a system's dependence on thermal generators to limit the rate of change of frequency. From sub-seconds to seconds, electricity storage (mostly batteries, but also in specific applications flywheels) is suitable for providing fast frequency response, which is currently being implemented as a service in some power systems (e.g. United Kingdom). At a timescale of seconds to minutes, storage has been used mainly for the provision of operational reserves (mainly batteries, flywheels and pumped hydro). From minutes to hours pumped hydro, CAES and flow batteries can be used for load following and time-shift of energy (energy arbitrage), and from hours to days, weeks or even months electricity can be stored in long-term electricity storage,[8] which is necessary at very high VRE penetration (Figure 4).

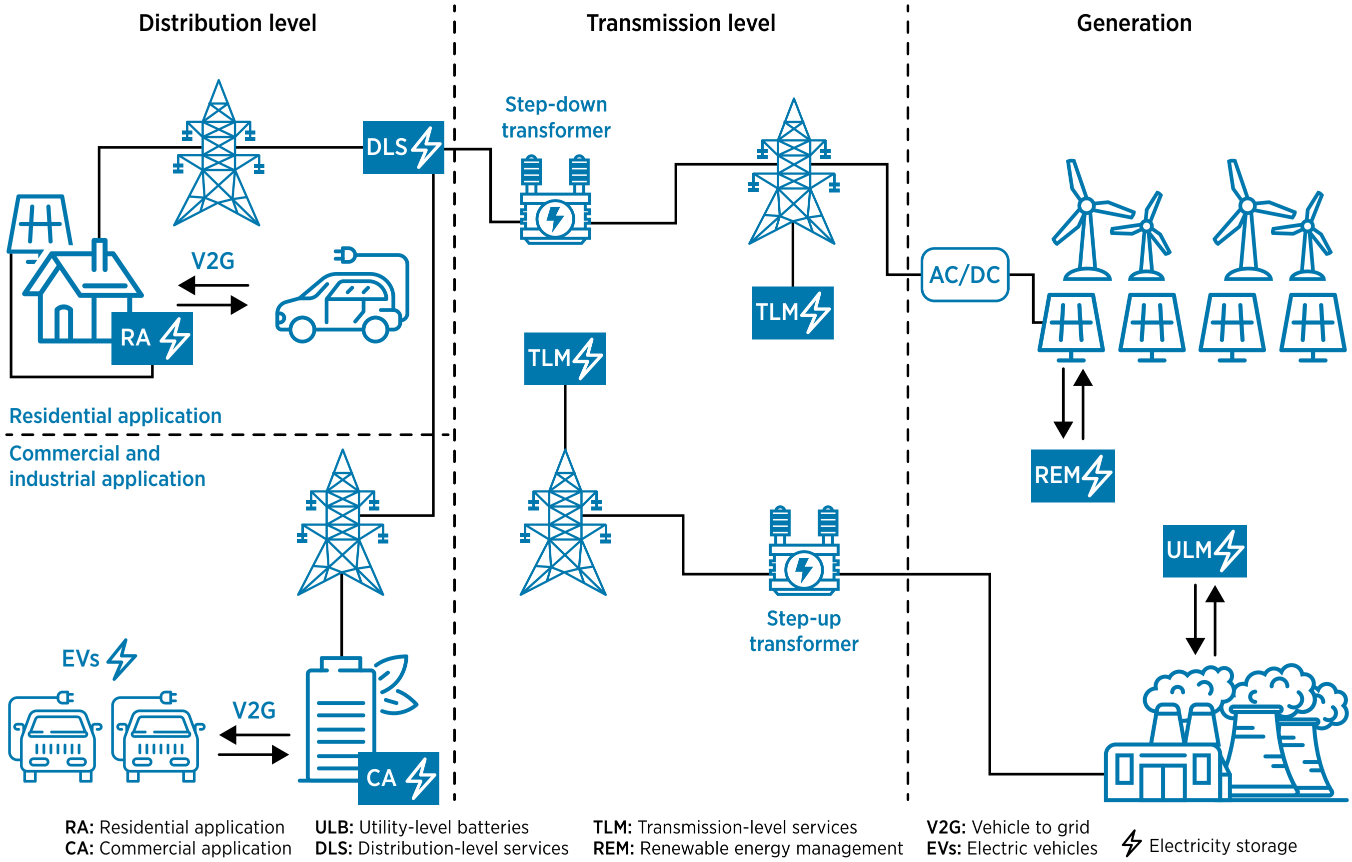
Notably, while the ESVF can be used to compare costs and benefits of electricity storage against other flexibility alternatives at a system level (Phase 3 of the framework), full implementation of the ESVF (Phases 1 to 5) provides insights specific to electricity storage; in other words, the ESVF is not designed to provide policy recommendations for alternatives to electricity storage.

The services that electricity storage can provide depend on the point of interconnection in the power system. For example, when connected to the grid at the transmission level, electricity storage can support increasing shares of VRE (as explained above), participate in electricity market bidding to buy and sell electricity, and provide ancillary services at the various timescales relevant to technical capabilities of each technology. When connected at the distribution level, electricity storage can provide all of the above services and in addition can be used to provide power quality and reliability services at the local substation, defer distribution capacity investment, and support integration of distributed renewable energy. It can also be connected to other generation facilities, allowing for higher price capture, provision of grid services and at the same time savings on connection costs. Finally, electricity storage can be placed behind the meter (Figure 5) to support a customer in increasing PV self-consumption, thereby reducing electricity bills (where time-of-use demand-side management schemes exist), improving power quality and reliability, and potentially enabling participation in energy management, wholesale and ancillary services markets through aggregators (EPRI and US DOE, 2013; RMI, 2015; IRENA, IEA, REN21, 2018).

7 The framework focuses only on electricity storage options. Specific sector-coupling options like hydrogen production (seasonal storage of electrofuels), heat pumps and electric boilers (thermal storage) are not addressed in this report.

8 Although the framework is about electricity storage, power-to-hydrogen and power-to-heat are likely to be key for the provision of long-duration energy storage, with hydrogen being a large-scale storage option with the potential to go back to electricity (although inefficiently).

**Figure 5:** Grid applications of energy storage




Physical location and operational mode (coupled with generators or standalone), along with the regulatory environment and market structure under which electricity storage operates, greatly affect the type of analysis needed to estimate both system-wide and project-wide benefits of electricity storage. These considerations are explained in more detail in Phase 3. For example, electricity storage can be operated as a standalone unit or co-located with generation facilities, e.g. solar PV and wind farms. In the case that storage is co-located with a PV farm, rather than being a standalone unit it is an asset of a "hybrid power plant".[9]

Electricity storage can mitigate the impact of VRE variability and uncertainty simply by providing grid services. The California Independent System Operator (CAISO) describes how storage can, for example, bid to supply ancillary services by providing frequency regulation and operating reserves to restore frequency imbalances related to VRE uncertainty, or by providing load-following services bridging the gap between real-time unit commitment and real-time dispatch (NERC and CAISO, 2013). Storage can be used to shift the time of VRE delivery by essentially charging when wind is blowing (in many but not all cases, wind production is higher at night-time when electricity prices are low) and discharging during peak hours to maximise revenue. Similarly, it can potentially increase the capacity credit of VRE by allowing it to participate in capacity markets and potentially defer the need for conventional capacity.

Electricity storage can also be used to support integration of VRE by reducing variability and generation forecast error and improving power quality. Potential cost savings, for example, can result from a reduction in penalties imposed by the operator where there is a restriction on maximum ramp induced by generators, or from avoiding penalties related to unbalancing (failing to provide the amount of energy bid into the market). In addition, with appropriate mechanisms in place, the VRE/storage owner can offer system-wide benefits by providing area regulation (Sandia National Laboratories, 2010). Notably, in a vertically integrated utility, storage should ideally be installed where its value to the system is the highest,[10] while in liberalised markets there might be an incentive for generators or consumers to install storage to maximise their revenues, which might not translate into the highest system value for that given amount of storage. In specific settings (e.g. South Australia and Hawaii) auctions calling for combined solar PV and storage have been used to deploy "system-friendly" VRE projects.

**9** The ESVF is designed to assess the value of electricity storage as standalone plant only.

**10** In reality utilities do not always operate in a way that maximises system benefit; this can happen due to technological conservatism, outdated regulations, lack of proper planning capacity etc.

Finally, the maximum project value from electricity storage is obtained when the operation is co-optimised to provide multiple services.[11] Numerous studies have used data from electricity markets that confirm that investing in electricity storage for just one service, e.g. for arbitrage, frequently does not pay back the investment. However, when it provides additional services, for example a variety of ancillary services in parallel with arbitrage, and these multiple services are monetised, then profits are greatly improved (Nikolakakis and Fthenakis, 2018; Drury, Denholm and Sioshansi, 2011; Sioshansi et al., 2009; Salles et al., 2017; Teng et al., 2015; Zakeri and Syri, 2016). The ESVF described in this report puts emphasis on the need to optimise storage operation for multiple services, stacking different types of potential benefit to assess the optimal value.

## 3. Methodology

The ESVF is a guide for decision makers to identify the value of storage on an electricity grid with increasing VRE penetration, exploring a variety of possible applications and mechanisms to make storage projects viable. Notably, the ESVF is mostly useful for assessing the value of storage to the power system as a whole. It allows for comparison of storage deployment costs, while identifying a) optimal amounts of additional storage to minimise total system cost; b) viability of storage projects based on the existing regulatory framework and a set of possible uses; and c) regulatory measures that might facilitate deployment of storage, at a cost not exceeding system-level benefits.

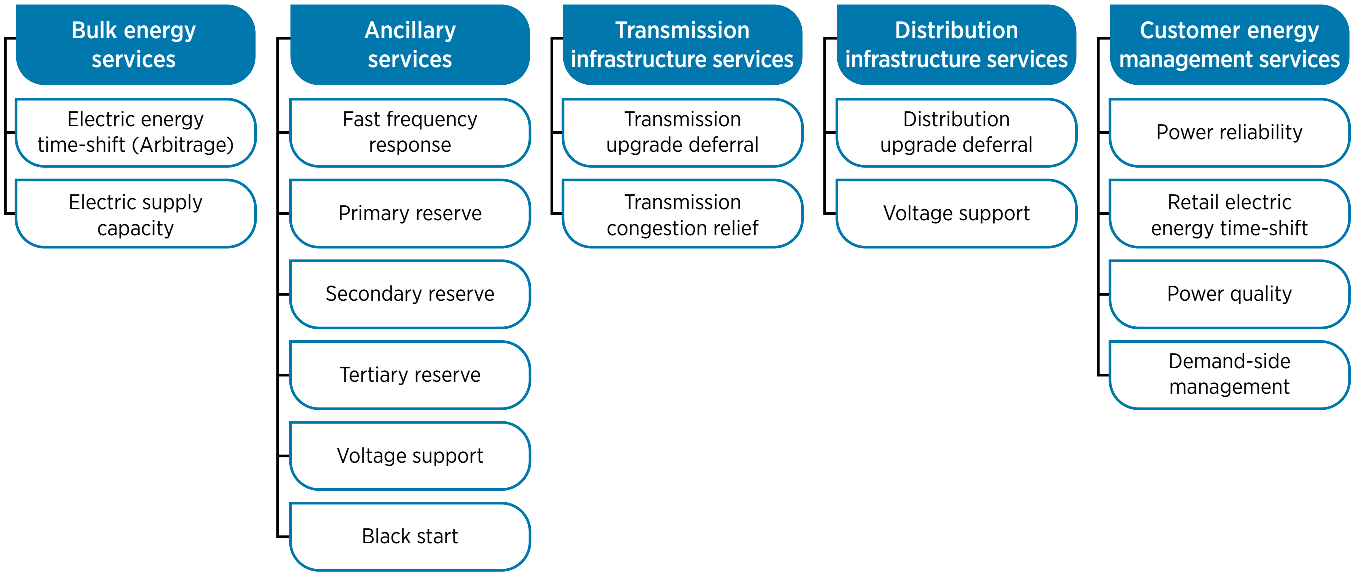
The ESVF starts in Phase 1 by highlighting the services from storage that are relevant to VRE integration in a specific context (e.g. country, plan, regulatory framework). Such services can subsequently be grouped together to strengthen project viability. Based on this, a mapping of the technologies best suited to provide such services is performed, giving a tentative ranking by applicability (Phase 2). Phase 2 aims to prevent the analyst from making unsuitable choices for storage at the beginning of the modelling process. These two phases can be conducted in a simple analytical environment (e.g. spreadsheet), while the following phases require modelling tools capable of performing optimisation.

Phase 3 requires a dispatch of the power system to assess the value of storage. This is complemented by a least-cost investment phase to compare storage with alternative flexibility options. Once the optimal amount of storage and other flexibility measures are identified, a set of data in Phase 3 (for example electricity prices) can be used to simulate storage operation in Phase 4. This phase shifts the focus from system-level to storage-focused analysis, by taking the outputs of Phase 3 as inputs and reoptimising storage dispatch to maximise the revenues from multiple services that storage can provide. Finally, these revenues are compared with system value from Phase 3 in the final phase of the ESVF, Phase 5. In this last phase, project viability is assessed by looking at the gap between monetisable revenues and project cost. This allows the comparison of alternative regulatory measures to solve the missing money problem often associated with new technologies, which were not considered when the market they are entering was designed. More detailed discussion about the phases of the ESVF follows below.


Photograph: Shutterstock

11 Apart from the stacking of multiple services, there is the value of "dual participation", which is applicable to behind-the-meter storage and means the value of behind-the-metre storage in providing both grid services and individual services (i.e. to the household in which it is located).

**Figure 6:** Electricity storage services and their relevance to renewable power integration




### Phase 1: Identify electricity storage services supporting the integration of VRE

Phase 1 of the framework identifies the services that electricity storage can provide to integrate more VRE into the power system. The list of services, as presented in Figure 6, is based on studies that categorise electricity storage options according to their ability to support grid services, that is, to release energy, provide firm capacity, defer the need for investment, support customer energy management and directly support integration of VRE (EASAC, 2017; EPRI and US DOE, 2013; Southern California Edison, 2013; EASA and EERA, 2017).

From the services presented in Figure 6, the following are recognised as contributing to VRE integration in either direct or indirect ways (although their value and definition varies from country to country depending on grid infrastructure and market design): wholesale energy time-shift, energy supply capacity, fast frequency response, primary and secondary reserves,[12] frequency regulation, transmission and distribution upgrade deferral, capacity investment deferral, retail energy time-shift and power reliability (including supporting voltage through reactive power injection, possibly black start services). For example, behind-the-meter storage can support both integration of distributed energy sources and active participation of prosumers in overall energy management (RMI, 2015). However, in order for its full value to be realised, the operator of the distribution system needs to have a more active role and prosumers need to be able to participate in the various energy markets through a number of schemes, as in the case of the aggregators (IRENA, 2019b).

As noted in Section 2 above, electricity storage can indirectly provide secondary services in parallel to its originally planned primary role. Thus, the contribution of electricity storage to facilitating VRE integration might be indirect. For example, a standalone pumped hydro unit performing services such as electricity arbitrage (buying electricity when is cheap to sell when its value is high), fast load following, frequency response or provision of inertia, could also be reducing VRE curtailment at the same time. Similarly, a CAES unit co-located with VRE and having as its primary role maximising the profit of the hybrid plant (for example via provision of firm capacity, energy arbitrage and ramping control) could also indirectly defer the need for peak capacity and reduce the need for ancillary services.

Service identification is a one-time[13] exercise to define the types and specifications of services that storage can provide, so that the methodologies to evaluate the cost-effectiveness of storage can be developed. Phases 3 and 4 might need to be repeated to extract valuable insights. Moreover, a significant portion of storage value is expected to come from deferral of other investments, such as peaking plants or transmission and distribution (T&D) investment, especially in systems where electricity demand is growing or where VRE constitutes a significant share of electricity generation.

Such considerations are discussed in more detail in the explanation of Phase 4. The ESVF allows the feasibility of multiple value streams to be assessed. The services electricity storage can provide, as detailed in Phase 4, are grouped into cases. In each case, electricity storage will provide a combination of services; each service in the

12 The terminology around ancillary services varies in different parts of the world.

13 As new technologies and services are developed over time, mapping of storage technologies is subject to change in the future. However, it only needs to be assessed once at the beginning of a storage valuation exercise for a given project.

case must be compatible with the others so that double counting is avoided. To construct a case, a storage asset's primary function is often considered first, while other services are secondary. For example, electricity storage can perform energy arbitrage, but the same asset could reserve some capacity to provide other types of service at the same time, such as primary reserve. The provision/allocation of services is the subject of optimisation in Phase 4.

### Phase 2: Mapping of storage technologies with identified services

The storage services identified in the previous phase are complemented by a comprehensive analysis of the technical and commercial parameters of prevailing electricity storage technologies to determine those suitable for each service. In this phase, scores are assigned to different technologies by weighting technical attributes against their relevance in specific applications, and the resulting matrices are used to evaluate how suitable a specific technology is in a certain application. The outcome of this phase is a ranking of storage technologies based on their technical affinity to provide the services defined in Phase 1.

Based on IRENA (2017a), the key techno-economic parameters of selected electricity storage technologies are considered, as listed in Table 1.

Depending on the application for which the technology is considered, the parameters should be weighted according to their importance for each application. After this, each technology can then be scored in terms of its suitability for each application, by calculating a weighted average of the ranking of each techno-economic parameter for that application.

**Table 1:** Techno-economic parameters for electricity storage suitability assessment

| Technical |
|---|
| Efficiency (AC-to-AC) (%) |
| C-rate minimum |
| C-rate maximum |
| Maximum depth of discharge (%) |
| Maximum operating temperature |
| Safety (thermal stability) |
| **Economic** |
| Storage CAPEX (USD/kWh) |
| Power converter CAPEX (USD/kW) |
| Development and construction lead time |
| Operating cost (USD/kWh) |
| Energy density (Wh/kg) |
| Energy density (Wh/L) |

Notes: AC = alternating current; kW = kilowatt; kWh = kilowatt hour; Wh/kg = watt hour per kilogram; Wh/L = watt hour per litre.

### Phase 3: Analyse the system value of electricity storage compared to alternative flexibility options

One of the goals of the ESVF is to assess electricity storage against other flexibility options. Typically, this happens in Phase 3 of the framework. While electricity storage is a key technology to decarbonise the energy system (Sisternes, Jenkins and Botterud, 2016; IRENA, 2018a), there might be specific cases where it is not competitive against alternatives. In Phase 3 electricity storage is valued both for its effectiveness in providing identified services and its economic attractiveness compared to alternative options. Alternative technologies could be, for example, other flexibility sources like demand response and flexible generation, or even enhancement of the transmission network (the latter would require a model that optimises transmission together with generation). The comparison is performed through a combination of least-cost capacity expansion optimisation and production cost modelling.

Capacity expansion optimisation is a methodology widely used to identify long-term least-cost pathways in the power sector through appropriate optimisation tools and relevant inputs. The objective of the analysis is to identify the least-cost investments that meet the projected profile of electricity demand (current or future demand) of a power system subject to technical and applicable policy constraints.

While capacity expansion software estimates operational costs, it will not usually be able to do so within a timeframe representative of real-time operations (i.e. modelling system operation at the sub-hour level as in the case of intraday markets and sub-hourly dispatch). For that reason, the simulation within the capacity expansion software is integrated with production cost simulation software, to estimate accurately the operational costs of a power system. Production cost optimisation is a computational method to simulate the unit commitment and economic dispatch of the generation fleet of a power system over time steps of an hour or less.

Optimisation of investment needs to consider a number of real-world constraints, as in the case of policy goals (e.g. $CO_2$ targets), fuel availability and system reliability (i.e. any changes in the physical structure of the system should not compromise system reliability). The basics of power system optimisation are discussed in detail in IRENA (2018a). In addition, IRENA has developed an open-source tool, called the IRENA FlexTool, capable of performing both capacity expansion and production cost optimisation with a focus on power system flexibility. The FlexTool is also capable of comparing electricity storage with other flexible options as in the case of EVs, electric boilers, heat pumps and hydrogen production (IRENA, 2018b).

The ESVF's approach to estimating the system-wide value of storage comprises the following steps:

- **Step I:** To identify optimal investments, electricity storage is considered together with alternative technologies (such as energy efficiency, demand response, new transmission and peaking power plants) in a least-cost capacity expansion optimisation. Production cost simulations are needed for an accurate estimation of the value and optimal amount of storage, as well as the costs of storage to the system over the period of study (one or multiple years).[14]
- **Step II:** Step I above is repeated with storage removed from the available options (the alternative technologies mentioned in Step I are included). The capacity expansion analysis will provide a set of alternative solutions to serve system needs. Production cost simulation is used to estimate operational costs accurately.
- **Step III:** A comparison of total system costs from Steps I and II gives the total system value of storage over the period of study. Phase 3 will only deploy electricity storage if this is beneficial for the system; the difference compared with the "no new storage" scenario is deemed to be the benefit of adding electricity storage to the system.

In general, the main types of benefits that can be estimated by following the methodology proposed above relate to cutting OPEX costs and lowering CAPEX investment needs. These factors are outlined in Table 2.

1. **Savings in CAPEX** from deferring the need for alternatives (including peak capacity, demand response and transmission infrastructure). Savings in CAPEX are estimated by comparing the results of capacity expansion optimisation between the "with storage" and "without storage" scenarios.

2. **Savings in OPEX**. OPEX reductions can be estimated using the results of the production cost models. Typical production cost models are capable of isolating various OPEX types, namely fuel costs (including start-up costs), variable operation and maintenance (O&M) costs, reliability costs (i.e. cost of unserved energy), VRE curtailment costs (depending on market setting) and, when applicable, the cost of emissions.[15] In high VRE scenarios, the main cost reductions come from fuel savings. Table 2 categorises the various storage benefits according to whether they are OPEX or CAPEX in nature.

Deployment of electricity storage can additionally bring a number of indirect cost savings to the system and society in general. These could relate to system reliability (e.g. when storage provides inertia to the system) or even system security (e.g. when storage supports penetration of renewables and as a result energy independence, as in the case of countries that lack natural resources). These might be difficult to quantify. More detailed discussion about quantifiable benefits of electricity storage and other issues related to the complexities of modelling and scenario development follows in Part 2.

**Table 2:** Electricity storage benefits from Phase 3

| | |
|---|---|
| **OPEX** | Reducing **costs for producing electricity**, including fuel consumption, variable O&M, and start-up and shutdown costs, by:<br>• Replacing energy generation during peak<br>• Replacing load-following cycling thermal generation<br>• Replacing other sources of ancillary services<br>• Reducing congestion<br>• **Increasing VRE penetration.** |
| **CAPEX** | Reducing the **cost of capital investment** by:<br>• Deferring the need for peaking capacity<br>• Improving the capacity factor of VRE (less VRE capacity needed to achieve climate goals)<br>• Deferring the need for T&D capacity. |

14 Even if storage is no better than the alternatives, this does not mean it brings no value to the system. It simply means alternative solutions can perform the needed services at less cost. In addition, even if storage is not used in system-level capacity expansion, its project-level value might be positive (for example, if appropriate market structures to support storage exist). However, in that case further exploration of policies to support storage deployment based on its system-wide value would serve no purpose.

15 Additional types of social costs, such as health impacts related to specific types of pollutants, can also be considered in the analysis.

### Phase 4: Simulate storage operation and stacking of revenues

Phase 4 of the framework analyses the actual operation of a storage project, assuming the project is a price-taker under the system-marginal prices obtained from simulations in Phase 3. In this phase, the revenue that the storage project receives is maximised by combining the various services the project can provide. In reality, very large electricity storage participating in energy markets has the potential to affect prices; thus, the results of Phase 4 represent a marginal project beyond the scenario in Phase 3 used to extract system-marginal prices.

This phase of the ESVF therefore assesses the revenue streams that electricity storage can bring to a project owner under specific market settings. A wide range of project-level benefits and costs of electricity storage depend on the market and regulatory environment surrounding the system of interest. Again, for this type of exercise dispatch simulation software (i.e. production cost software) is used for the analysis. However, the objective of the analysis is different from the previous step. Instead of **minimising** total system costs, the model rather **maximises** profits of a specific electricity storage project within the overall optimal storage portfolio resulting from Phase 3, under the assumptions below.

While in the previous step the charging and dispatching of the electricity storage device was decided on the basis of the needs of the whole system, in this case the decisions of the project are based on its individual economic interest. While in vertically integrated environments the two objectives coincide, in liberalised power markets the results are likely to be different and the focus is on privately owned storage systems participating in wholesale energy (and ancillary services) markets.

The model in this phase ignores the physical infrastructure of the remaining system, focusing solely on the storage project. In simplified terms, the model assumes that the remaining system's behaviour is unchanged, as the individual project is not able to influence key system variables. Examples of such variables are a) market prices of electricity, b) prices for provision of different types of grid services, c) the shape of net demand, d) reliability indicators, and e) dispatch of all other generators, including VRE. Such an approach (or model) is called a price-taker model. Re-dispatching the full system to realise the maximum benefit of the storage unit alone is challenging, as different pools of assets use different profit-maximisation algorithms.[16]

The choice of different long-term future scenarios affects project-level profits. This is because when electricity storage exists in a power system, it contributes to reducing the gap between peak and valley prices (because electricity storage time shifts low-cost electricity towards peak periods). The more storage that is integrated, the larger the smoothing effect on prices,[17] which affects profitability when participating into electricity markets (Drury, Denholm, and Sioshansi, 2011; Nikolakakis and Fthenakis, 2018). Similarly, the system-level price of reserve provision depends on reserve requirements and on the capacity available to provide reserves, which again depends on the available storage portfolio. The system price of reserves drops as the level of storage increases.[18]

Using the inputs from the no new storage case (Step II above) provides insight into the value of storage during the early stages of storage deployment. Results represent the viability of a project under the assumption the situation continues for long period of time (i.e. there will be neither large-scale deployment of storage nor other significant changes to the physical structure of the system). Thus, if further storage is deployed, the longer-term economic viability of the project is uncertain, as in reality revenues could decrease (for example if VRE deployment stalled). The assumption is that if the amount of storage identified in the earlier stages of the framework is the actual amount that is expected to be deployed, the results of this phase will be reasonably accurate.

The model used to simulate project-level revenues needs to incorporate a number of typical services offered by storage in electricity markets. Examples include the following:

**Energy arbitrage:** This involves making a profit from charging the device when electricity prices are low and selling it when electricity prices are high. Depending on its technical characteristics a storage device can participate in either day-ahead or intraday markets, or both. Such bulk energy services are usually provided by electricity storage that has both large capacity and slow discharge time (such as pumped hydro and CAES), reducing the gap between peak and valley prices (because electricity storage time-shifts low-cost electricity towards peak periods). To simulate benefits from electricity arbitrage, a time series of system-wide electricity prices is needed representing operation of the generation mix identified from the previous step, Phase 3. When the price-taker model assumes perfect foresight of electricity prices, there is a risk of overestimating the value of energy arbitrage.

16 This is because the objective function of the optimisation needs to be the maximisation of storage profits subject to technical constraints (i.e. balancing supply and demand, start-up time constraints, ramping constraints etc.). If the whole system was participating in the production cost simulations with the above objective, all system assets would be dispatched with a goal of maximising the benefits to the storage project, not the benefits to the system. However, this is not representative of real-world operations.

17 This is one of the main reasons that energy arbitrage alone is not a viable long-term revenue stream for energy storage. As the storage capacity increases, the potential for profiting from arbitrage decreases.

18 The required level of reserves also depends on the uncertainty in the system introduced by VRE sources such as solar and wind power. The higher the solar and wind deployment, the larger the operating reserve requirement, which contributes to increased need for reserves.

Modern algorithms allow the uncertainty of electricity prices to be accounted for and can be used for improved results (Krishnamurthy et al., 2018; Salles et al., 2017).

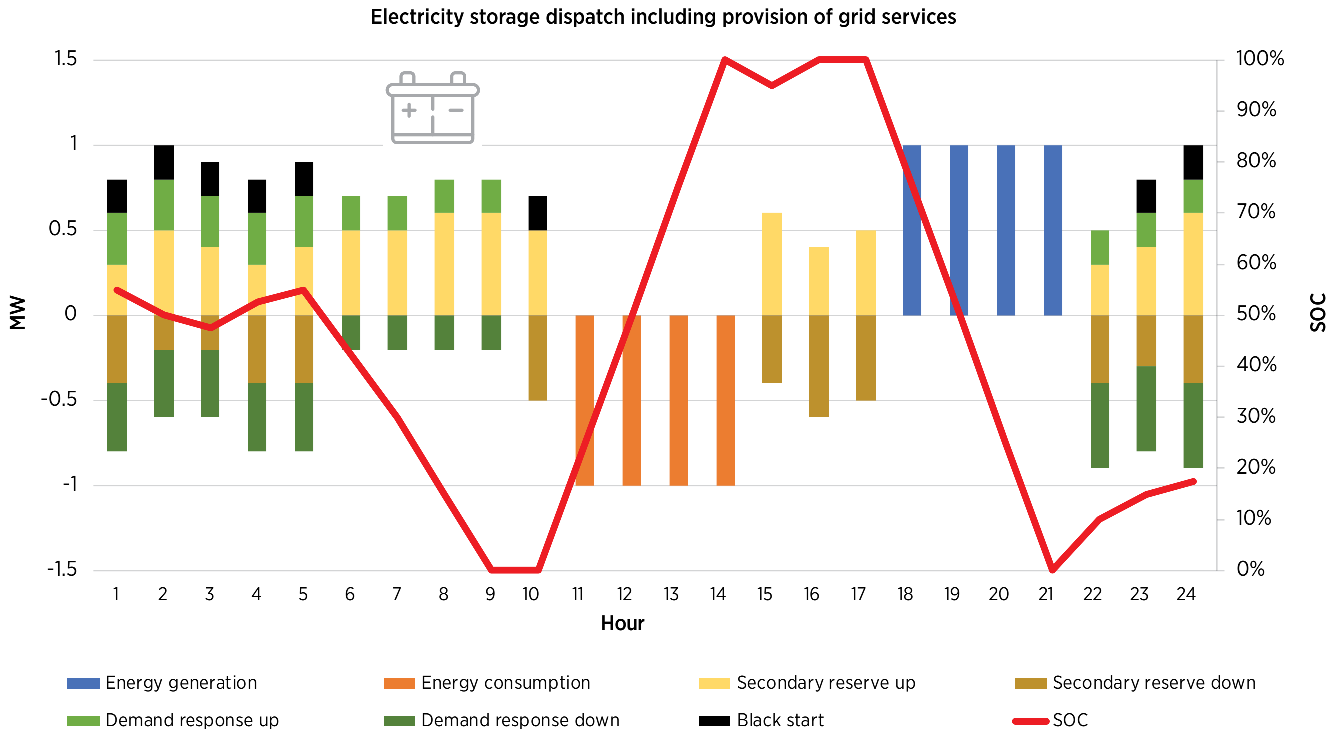
Finally, when not coupled with VRE, electricity storage charges up with electricity from various other types of generators. However, in a system with high proportion of VRE, electricity prices will be low during hours with high VRE penetration and essentially storage will mostly be contributing to smoothing out the net load. At low VRE levels (and potentially at higher VRE levels as well), electricity storage providing energy arbitrage could be contributing to increasing the capacity factor of cheap coal power plants and their energy share in the mix, as their lack of flexibility is compensated by storage flexibility.

**Provision of ancillary services:** These comprise a set of operational services whose primary role is to ensure reliable operation of the grid under both a) normal conditions and b) contingencies. The terminology, types and role of ancillary services vary around the world. For example, discussion around ancillary services in the United States and Europe can be found in NREL (2013) and Holttinen et al. (2012) respectively.[19] Payment for ancillary services can be based on capacity procured, electricity produced or both depending on the case. Payments for various services need to be input in the model.[20]

Ancillary services usually comprise frequency regulation, black start support and voltage control. Black start and voltage control cannot be explicitly modelled using dispatch tools and thus cannot be assessed using the ESVF. Electricity storage can simultaneously provide multiple services. For example, storage providing both energy arbitrage and operational reserves can potentially withhold some of the capacity that could be used for arbitrage if the payment is high enough. However, simulating actual utilisation of storage in ancillary services markets can be challenging.

Utilising the system-marginal prices from Phase 3, the various services a storage project can provide can be optimised to maximise the revenue the project receives. As a result of the optimisation, the hour-to-hour (or intra-hour) dispatch of the electricity storage project and stacking of its various revenue streams can be visualised. Figure 7 shows the type of output from storage service stacking that can be expected from Phase 4. In this illustration, the entire capacity of a 6 megawatt-hour (MWh) electricity storage facility is used to shift VRE from hours 11–14 to hours 18–21.

**Figure 7:** Illustrative output from Phase 4




**Note:** SOC = state of charge.

19 This report uses terminology most relevant to European countries.

20 For example, payment for providing ancillary services in Ireland can be found in: *www.eirgridgroup.com/site-files/library/EirGrid/Ancillary-Services-Statement-of-Payments-and-Charges-2017-2018.pdf.*

### Phase 5: Assess the viability of storage projects: System Value vs Monetisable Revenues

The system-wide benefits of storage can only be realised if the storage project is deemed viable, meaning that there are enough revenue streams to reward project developers/owners for their investment. Unfortunately, some system benefits cannot be monetised or are not directly attainable by the project owner. Therefore, in many cases there is insufficient incentive for a prospective project developer to go ahead.

Comparing calculated system benefits from Phase 3 with the project owner's potential revenue streams for the set of services optimised in Phase 4 can be instructive. The electricity prices derived from the simulations in Phase 3 are used here to calculate the revenue streams for an electricity storage project.

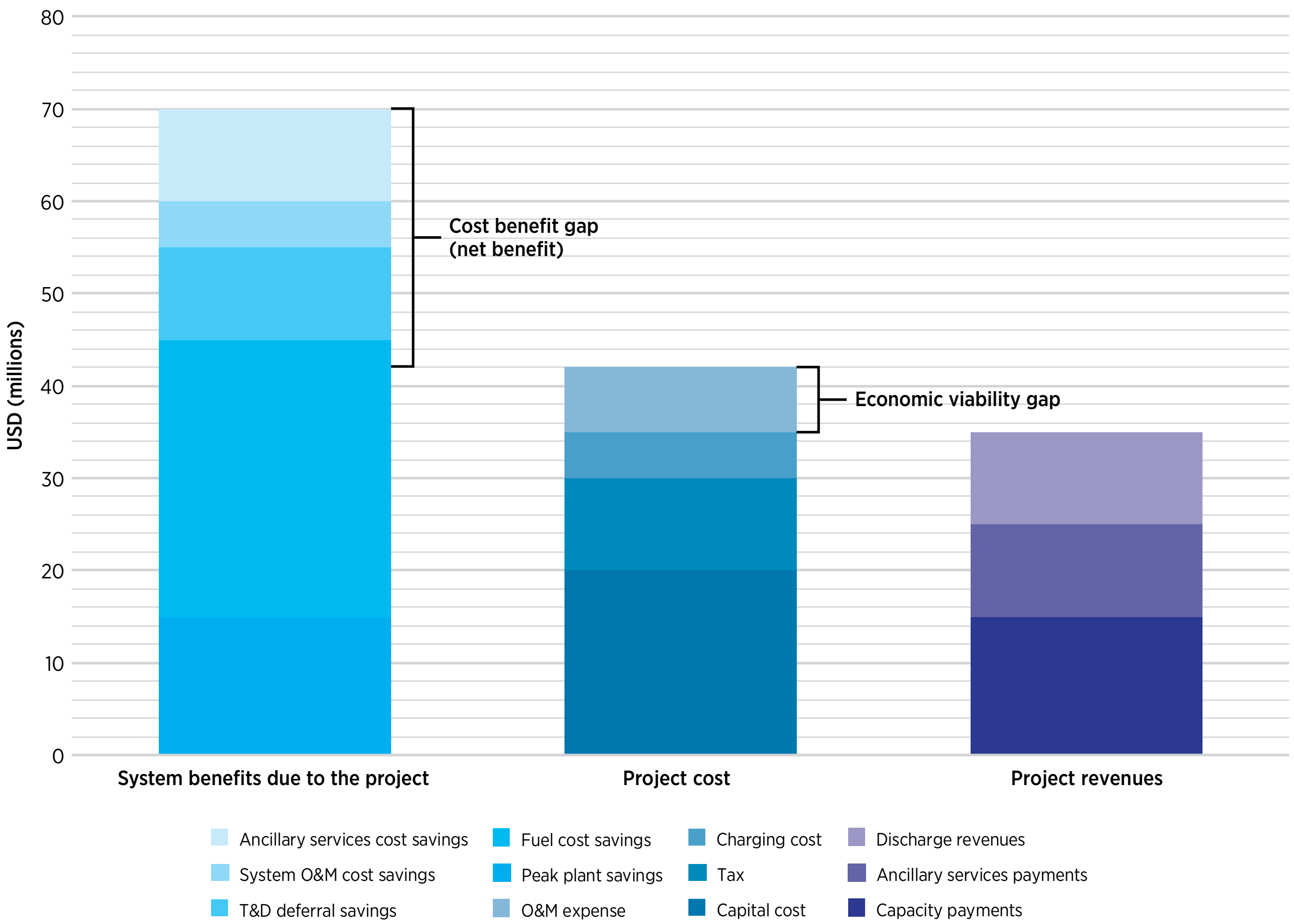
The outputs represent the revenue streams available to a storage project owner alongside the associated system benefits. If the revenue streams available to the project owner are not enough to cover the cost of the storage project, but the system benefits attributed to this project outweigh the cost, stakeholders can use the results of this analysis to identify the most beneficial uses and to consider methods to incentivise their deployment.

The output of this final phase is a project-level cost and benefit analysis. Cost refers to the cost of building and operating a storage project under a specified case. Benefits refer to both system level (non-monetisable) and project level (monetisable) benefits.

The benefits are categorised as monetisable or non-monetisable. If the total benefits exceed costs, but monetised benefits are less than costs, it means that the project developers do not have enough economic incentive to build this project even if it has a benefit-to-cost ratio of greater than one. In this case, policy intervention would be needed to enhance the overall social good.

Figure 8 shows an example of the outcome from a project feasibility model. In this particular example, although the system benefits outweigh the costs, the monetisable benefits are less than the costs, making the project economically infeasible for the project owner. The difference between the cost and the monetisable benefit, or the economic viability gap, if greater than zero, could be due to high storage capital costs or unfavourable market mechanisms.

**Figure 8:** Illustrative output from Phase 5



# 4 Recommendations

## 4.1 Recommendations for different storage stakeholders

A framework must be developed that both compensates storage providers for the value they can provide to the system and is in line with wider policy objectives. Various policy measures can be implemented to ensure that electricity storage projects are sufficiently compensated to be deployed, yet not overcompensated (RMI, 2015). Policy recommendations that may be relevant for regulators, vertically integrated utilities, the research community and electricity storage developers are listed below.

### For electricity storage developers

As IRENA's latest costing report on storage suggests (IRENA, 2017a), by 2030 total installed costs for battery storage could fall by 50% to 60%. Electricity storage developers have a variety of market-specific business models available to make a viable case for their projects. An example of a business model for distributed storage is that of aggregators. As IRENA's "Innovation landscape brief on aggregators" (IRENA, 2019c) highlights, aggregators can operate a diverse pool of distributed energy resources, including storage, creating a sizeable capacity similar to that of a conventional generator. This allows them to participate in different markets and therefore monetise revenue streams otherwise not accessible to individual, small-scale storage projects. Collaboration, in particular with regulators and utilities, is vital to highlight the benefits that electricity storage can provide to the system and discuss which business models could help accelerate electricity storage deployment.

### For vertically integrated utilities

Vertically integrated utilities may want to consider upgrading their planning tools and run open multi-stakeholder consultations to allow rate designers, planners and grid operators to work together to capture electricity storage's full range of capabilities. Other recommendations for utilities include having updated and expanded modelling of storage in integrated resource plans, updating procurement processes for the performance or services required, as opposed to technology-specific requirements (which might preclude storage), and exploring new ownership models for electricity storage (ESA, 2017).

Most power systems worldwide are based on a vertically integrated utility structure where capturing the full value of storage is potentially more straightforward, compared to a more complex deregulated environment where issues such as ownership structure of storage assets and the missing money issue are a major concern. In an environment where generation, storage and grid assets are owned by the same entity, such entities can capture the full value of storage for the system, provided this is accounted for correctly. This framework aims to support such valuation process, as well as providing insights for both vertically integrated and unbundled settings.

### For regulators

A key recommendation for regulators is that of eliminating barriers to electricity storage participation in energy, capacity and ancillary services markets (for instance, see FERC, 2018). An example of barriers could be the reserve duration requirement, which could be too long for many storage systems, or the minimum capacity to participate in the ancillary services market, which could be too large for some storage systems. An option in this case would be to design a new product where storage could participate to provide its full value.

Another option is to explicitly include storage among the various technology options or to eliminate technology-based discrimination in ancillary services markets. An important feature of storage is its ability to stack revenues from providing multiple services; however, in some cases the regulatory framework does not allow it to do so (for instance, this has been addressed in California with Decision 18-01-003 in Rulemaking 15-03-011 [CPUC, 2018], which allows stacking of T&D reliability with generation services).

A further option for regulators is that of creating markets that are able to capture the full value of storage, such as the performance-based regulation implemented by the PJM for fast frequency response (IRENA, 2017b). For more information on fast frequency response and other examples of implementation of storage cases, please see Part 3 of this report. Another possible recommendation for regulators is that of requiring utilities and transmission/distribution system operators to use a least-cost and standardised methodology that compares electricity storage providing a full range of stacked services against incumbent technologies. This should apply across all planning processes – including distribution planning, transmission planning and resource planning.

The regulatory frameworks for storage exhibit fundamental differences depending on its classification as demand or generation and on which stakeholders are allowed to own storage assets.

For behind-the-meter storage, a careful review should be conducted of how to provide monetisable revenue streams to consumers that invest in storage, as lack of price signals often makes the case for behind-the-meter storage unviable (for more information see dedicated chapter in Part 3).

Regulatory innovation is essential to accommodate higher shares of VRE using storage. A particular example of this is in Japan, where as opposed to the transmission system operator procuring ancillary services directly, some utilities require larger PV projects to use battery storage to meet grid frequency requirements and thus control their feed-in of electricity. A clear example of this is the 38 megawatt (MW) Tomakomai solar PV project located on the northern Japanese island of Hokkaido.

The PV plant has a battery that was one of the world's largest at the time of its construction in 2017: a circa 20 MW/10 MWh lithium-ion battery. The sole purpose of the storage system is to meet the frequency requirements of the local energy utility, Hokkaido Electric Power Company (IRENA, 2019b).

**For the research community**

A key recommendation for the research community is to develop and validate appropriate tools and detailed methodologies to perform storage valuation as described in this report (Part 2 in particular). Objectives may include, for example, increasing the time resolution of tools (e.g. hourly to sub-hourly), ensuring that chronology is preserved, or capturing how storage value decreases with increasing amounts of storage. Moreover, of utmost importance is modelling future scenarios and potential technical and economic impacts to inform policy makers and regulators in their decision making.

## 4.2 Policies and regulations to support cost-effective storage deployment

There are two ways to improve the economic feasibility of storage projects: a) by compensating project developers using various policy incentives to make up for the economic viability gap, or b) by improving existing market mechanisms to increase the monetisable benefits available to storage in order to reduce the gap.

**Policy incentives:** Policy incentives to make up for the economic viability gap of electricity storage projects can be similar to those that have been used to support VRE deployment in its early stages of development. These include:

- **Feed-in-tariffs (FITs):** To encourage deployment of VRE projects, many governments pay a fixed price per kWh, irrespective of wholesale electricity market prices, for electricity generated from renewable resources. A FIT can also be a policy measure to incentivise deployment of storage for VRE integration. The electricity generated from a combined VRE and storage asset is paid a fixed price, or the feed-in rate, reflective of the higher value to the system that a combined VRE plus storage project can provide compared to VRE only.

- **Feed-in-premiums (FIPs):** In this particular scheme, the electricity generated from a combined VRE and storage asset is sold on the electricity spot market, and the producers are offered a premium that is above the market price. The FIP can either be fixed (independent of the market price) or sliding (varying depending on the market price) and should be reflective of the value of the services provided in addition to the energy.

- **Capacity payments:** Periodic payments to the project owner for its contribution to system adequacy (for instance, by avoiding the need for investment in peaking plants) support project viability with a predictable revenue stream, especially when the wholesale energy and ancillary services prices are too volatile to make a storage project financially viable. For example, the California Public Utility Commission requires the utilities to procure capacities with a monthly payment under contract to ensure there are enough resources in the market for competitiveness and reliability purposes.[21] However, depending on how capacity mechanisms are designed, they might be detrimental to storage projects by reducing price volatility and remuneration for flexibility from such assets.

- **Grants:** Grants are used to reduce the capital costs of the storage asset. This policy measure can be specified as a percentage of the capital costs. Rebates such as the Self-Generation Incentive Program (SGIP) in California, focusing on behind-the-meter storage, are a widely applied form of grant.

- **Peak reduction incentives:** To reduce demand peaks, some jurisdictions have demand response programmes to incentivise load reduction. Storage can be used to reduce load during system peak hours. The project owner is only paid the peak reduction revenue when the storage asset happens to reduce load during the system peak hours. In the case where a consumer tariff is linked to the maximum demand, storage can provide significant savings by reducing the capacity charge component of the tariff.

- **Investment tax credits (ITCs):** If most of the electricity used to charge the storage asset comes from VRE, the project can be made eligible for ITCs. Many ITC structures have a VRE-charging threshold above which the project can capture ITCs. For example, if the charging threshold is 80%, the project is eligible for ITCs only when more than 80% of the charging electricity comes from VRE. An ITC is defined as a percentage of total CAPEX if the storage asset charges solely from VRE. If less than 100%, but more than the threshold percentage, of electricity comes from VRE, the ITC is pro-rated based on the percentage of charging electricity. The ITC benefits are usually distributed over a number of years. This is a US-specific example of current regulatory options where storage support is linked directly to renewables. It might not be ideal to replicate it as-is elsewhere, as it might lead to over-incentivising storage.

21 See the latest rules on such contracts, called resource adequacy contracts, from CPUC, "Proposed Decision Refining the Resource Adequacy Program", 21 November 2018, *http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=243570563*.

- **Accelerated depreciation:** This policy measure enables depreciation of the storage asset at an accelerated rate to receive tax benefits. Many such policy constructions have a defined depreciation rate, or other standard rates such as double-depreciation or a modified accelerated cost recovery system (MACRS).

**Market mechanisms:** Existing electricity market settings have typically been designed to balance supply and demand, separating generators and load as distinct entities. In electricity storage, the roles of generating and consuming electricity overlap, making it difficult for storage to fit into existing market frameworks, unless it is treated differently at different points in time, specifically as a load while charging and a generator while discharging. Consequently, regulatory and market barriers to the full utilisation of electricity storage remain in many markets (Gissey, Dodds, and Radcliffe, 2018; Sandia National Laboratories, 2013).

Because the participation rules and market mechanisms differ from region to region, solutions that fit every local situation are hard to devise. However, modifying rules to allow electricity storage to fully participate in the electricity markets is critical to realising the system benefits that electricity storage can provide, and to ensuring sufficient monetisable revenues for storage projects to be viable.

In a landmark ruling in February 2018, the Federal Energy Regulatory Commission (FERC) in the United States required the regional grid system operators under its jurisdiction to revise their tariffs to establish mechanisms that recognise the physical and operational characteristics of electricity storage, to facilitate its participation in the markets. FERC Order 841 (FERC, 2018) sets requirements for such participation models.

To comply, the storage resource must:

- Be allowed to provide all capacity, energy and ancillary services that it is technically capable of providing.
- Be able to set the wholesale market clearing price.
- Have appropriate physical and operational characteristics.
- Be able to manage its own state of charge (UtilityDive, 2018).

Grid operators under FERC jurisdiction are currently finalising their proposed responses to comply with the FERC order, with implementation of the revised market rules scheduled for December 2019. In the European Union, the role of electricity storage in facilitating VRE integration was officially recognised in the Electricity Market Design Directive where new rules were formally adopted in May 2019. Improvements in the directive aim to reduce barriers to energy storage; it mandates non-discriminatory and competitive procurement of balancing services and fair rules in relation to network access and charging (European Commission, 2019; Norton Rose Fulbright, 2019).

## 5. Conclusions

### Why storage valuation matters

Electricity storage technologies are a critical enabler for integrating large shares of VRE into power systems, facilitating the acceleration of the energy transition through rapid and scalable deployment and efficient provision of ancillary services, with the ability to be located virtually anywhere in the grid. VRE generators are increasingly co-deploying storage to maximise the profitability of their generation assets (e.g. increasing capture price, accessing ancillary services revenues). Similarly, customers are installing behind-the-meter storage to reduce their electricity supply cost, often in conjunction with rooftop PV; such assets, if aggregated, can provide valuable additional services to the grid.

Electricity storage deployment is currently taking place in all parts of the grid and by a multiplicity of stakeholders. The ESVF presented in this report is intended to support regulators and other stakeholders in the use of modelling tools to assess the system value of electricity storage in a power system and assess the monetisable revenues of storage projects under an existing regulatory framework. The results can be used to support policy makers in understanding whether there is a “missing money issue” to be addressed and in developing appropriate frameworks to ensure the efficient deployment of storage to facilitate the energy transition.

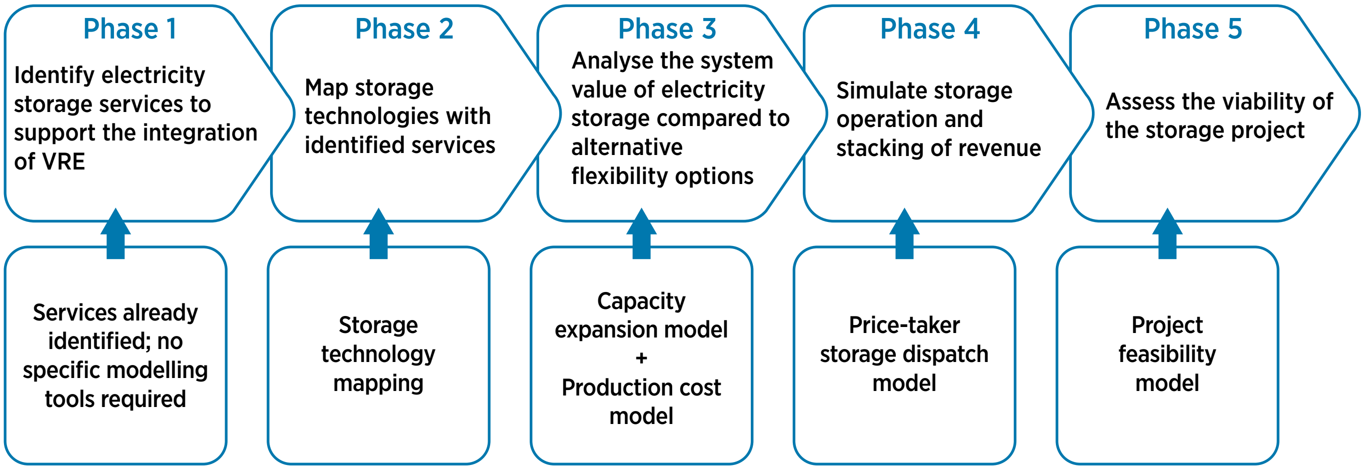
The overview of the ESVF in Part 1 is intended to provide power system decision makers, regulators and grid operators with an understanding of how to value and, where appropriate, support the deployment of electricity storage in the grid system.

Part 2 describes specific details of the ESVF methodology, including a methodology to carry out the analysis: the type of modelling tools necessary, information flow between phases, proposed model structure, step-by-step instructions on how the benefits are calculated, and expected inputs and outputs of the phases are discussed in detail.

Part 2 is intended for a technical audience to examine the logic of the framework’s methodology and then adopt it for electricity storage project cost–benefit analysis using the necessary power system modelling tools.

# Part 2: Using power system models to assess value and viability

**Figure 9:** ESVF phases and the types of models used




## 1. Introduction

Part 2 of this report aims to support analysts apply the Electricity Storage Valuation Framework (ESVF). The ESVF has a number of phases that require expert use of advanced optimisation models. The following sections explain which types of models are needed and how interested stakeholders and analysts can use them to complete the analysis. To implement the ESVF, several different types of models must be used to carry out the analysis (Figure 9).

**Phase 1** of the framework identifies the services that electricity storage can provide to integrate more variable renewable energy (VRE) into the power system. No specific modelling tools are required for this phase.

**Phase 2** requires inputs from storage technology experts in determining the suitability of various technologies for different countries. No specific types of models are recommended; instead, the information can be collated in a spreadsheet to show the attributes and scoring criteria applied to each technology to reflect their suitability in providing the services.

In **Phase 3** a capacity expansion model is utilised to optimise the capacity of storage and any alternative technologies. The phase then requires multiple iterations of production cost model runs to evaluate and optimise the benefits of having storage in the electric power system.

In **Phase 4** a price-taker storage dispatch tool is used to optimise the storage operation to realise maximum possible multiple stacked benefits. As an output from the dispatch tool, the hourly (or sub-hourly if data are available) operation of the storage should be accessible for further analysis. This tool is useful mostly for project developers in liberalised power systems with an electricity market; in other situations the stacked benefits of storage can be drawn from the production cost model in Phase 3.

In **Phase 5** a project feasibility model should be used to study the costs and monetisable revenues for storage project owners. This model should help identify the cases where the benefits to the system of a specific storage project exceed costs, but monetisable revenues for the projects are not enough to cover the costs, preventing projects from being deployed.

In these cost-effective cases, a variety of regulatory options should be considered to ensure that cost-effective projects are deployed. Policy makers and regulators can then use the results of this analysis to identify the economic viability gap and devise appropriate incentives so that projects that are seen to be worthwhile at the system level are sufficiently compensated at the project level to move forward. This is particularly relevant in the case of a liberalised market.

In liberalised markets storage can be owned by a variety of entities, in conjunction with generation, consumption or as a stand-alone market participant. This scenario requires assessing the value that such storage can provide to the system and adjusting the regulatory framework to ensure that such projects will be realised. A variety of mechanisms exists to achieve this; the main objective of this phase of the framework is to verify that the different models of storage ownership can access enough monetisable revenues to ensure their deployment, not exceeding the value they provide to the system or the amount of storage above which its marginal cost exceeds its marginal value. This aspect is particularly relevant as for some services the value of storage decreases rapidly, with an oversupply of storage reducing monetisable revenue streams for all storage projects and the risk of making all projects become less profitable until at one point they become unviable. In the case of vertically integrated environments, utilities are sometimes willing to accommodate independent project developers and thus a similar approach can be used to ensure project developers are sufficiently remunerated.

The information flow in Phases 3–5 of the ESVF (those that require modelling), as well as that between phases, is presented in Figure 10.

**Figure 10:** Information flow between modelling-based phases of the framework (Phases 3–5)

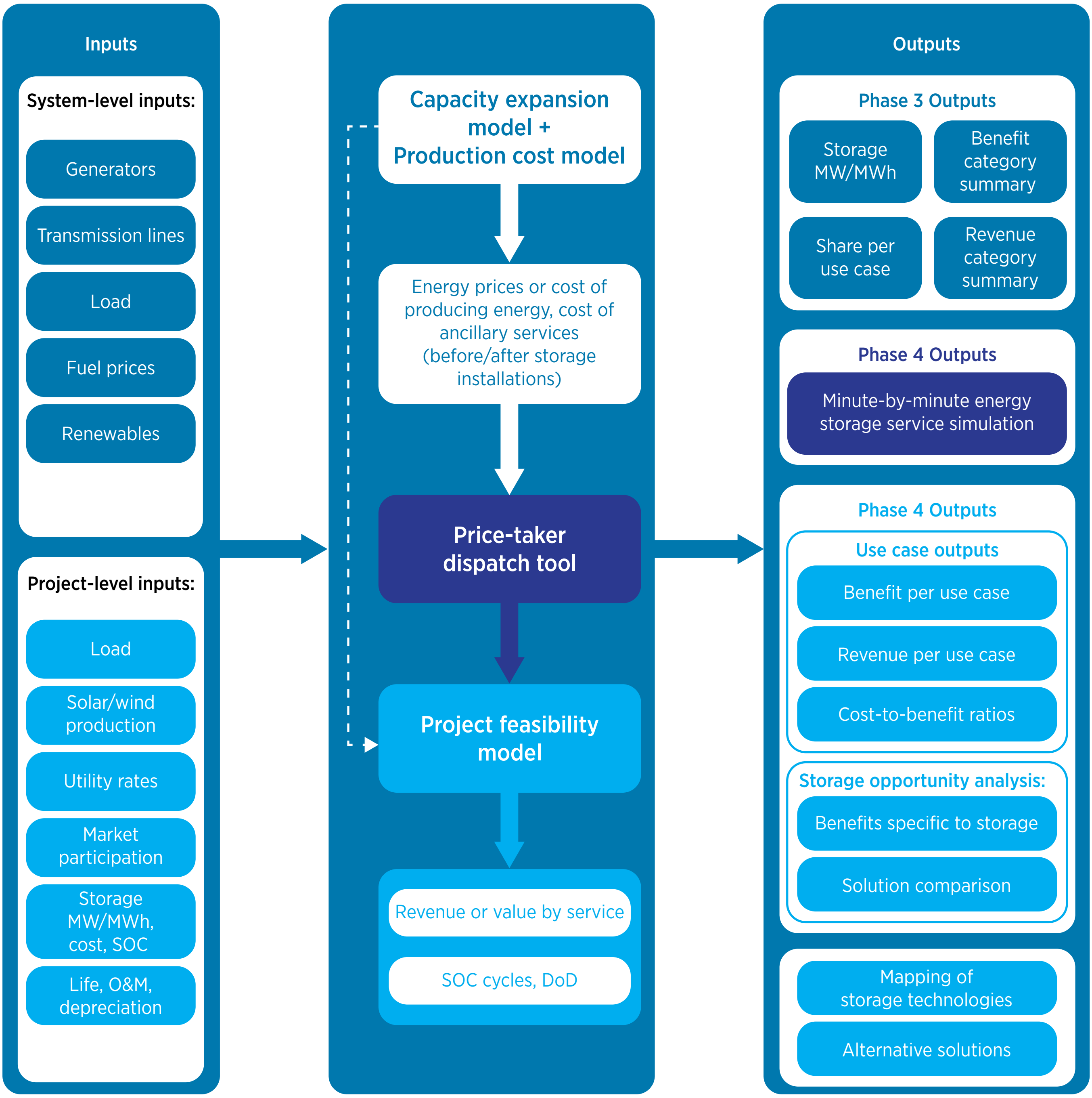


Figure 11 shows an example of the outcome from a project feasibility model in Phase 5. In this example, although the system-wide benefits outweigh the storage costs, the monetisable benefits are less than the costs, making the project economically infeasible for the project developer/owner. The difference between the cost and the monetisable benefit, or the economic viability gap, if greater than zero, could be due to high storage capital costs or unfavourable market mechanisms. In this specific example, compensating storage for offsetting the need for peaking plant capital investment would be sufficient to make storage projects viable, something that can be, for example, achieved with a capacity market in which storage is allowed to participate.

## 2. Methodology

### Phase 1: Identify electricity storage services supporting the integration of VRE

As mentioned previously, all the services that electricity storage provides in supporting the integration of VRE are identified in Phase 1. Figure 12 shows the variety of services that have been identified by past analyses, with the red boxes representing those services that are quantifiable within this framework. For this phase, no specific modelling tools are required.

**Figure 11:** Economic viability gap identified in the project feasibility analysis

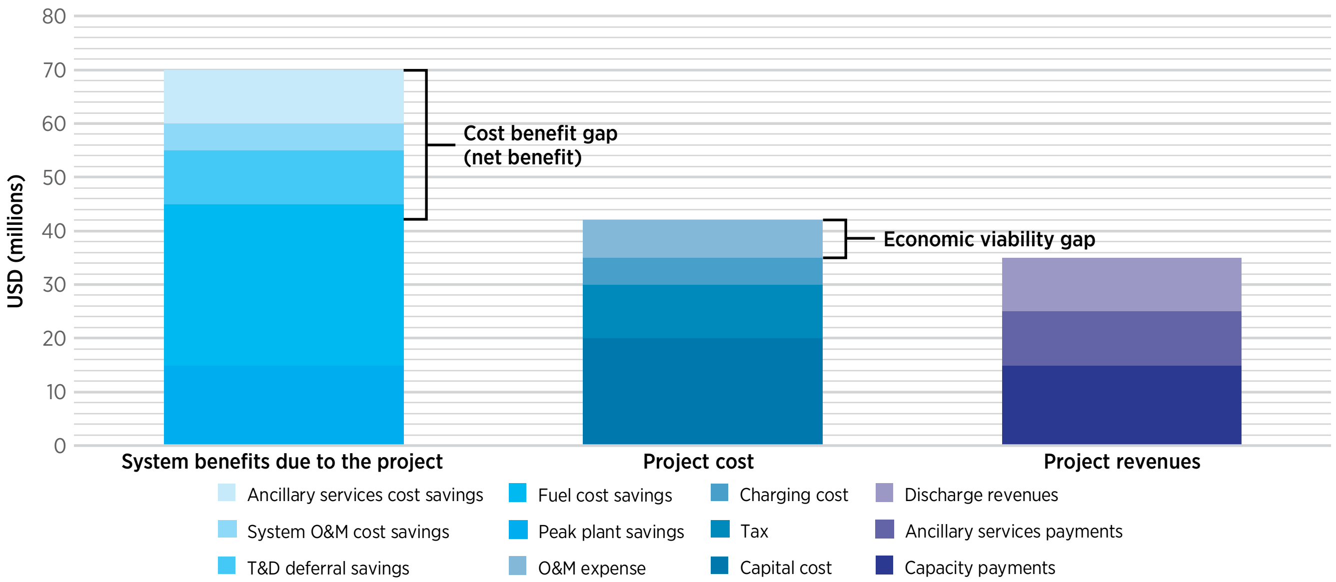
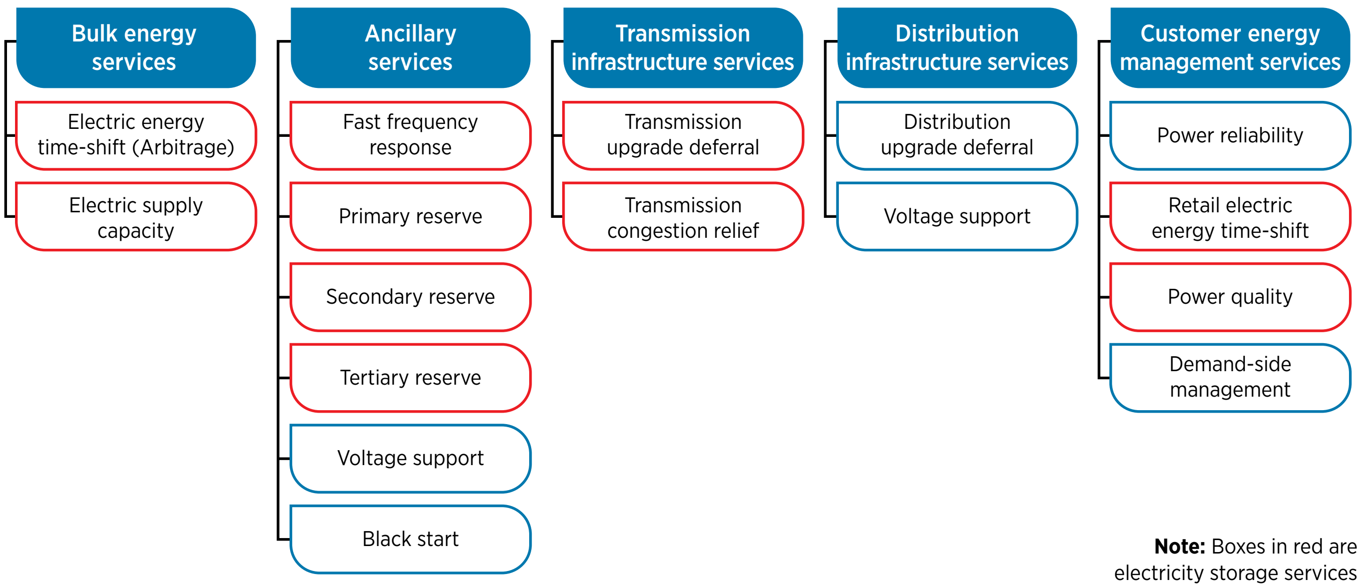



**Figure 12:** Quantifiable electricity storage services




**Note:** Boxes in red are electricity storage services that are quantifiable within this framework.

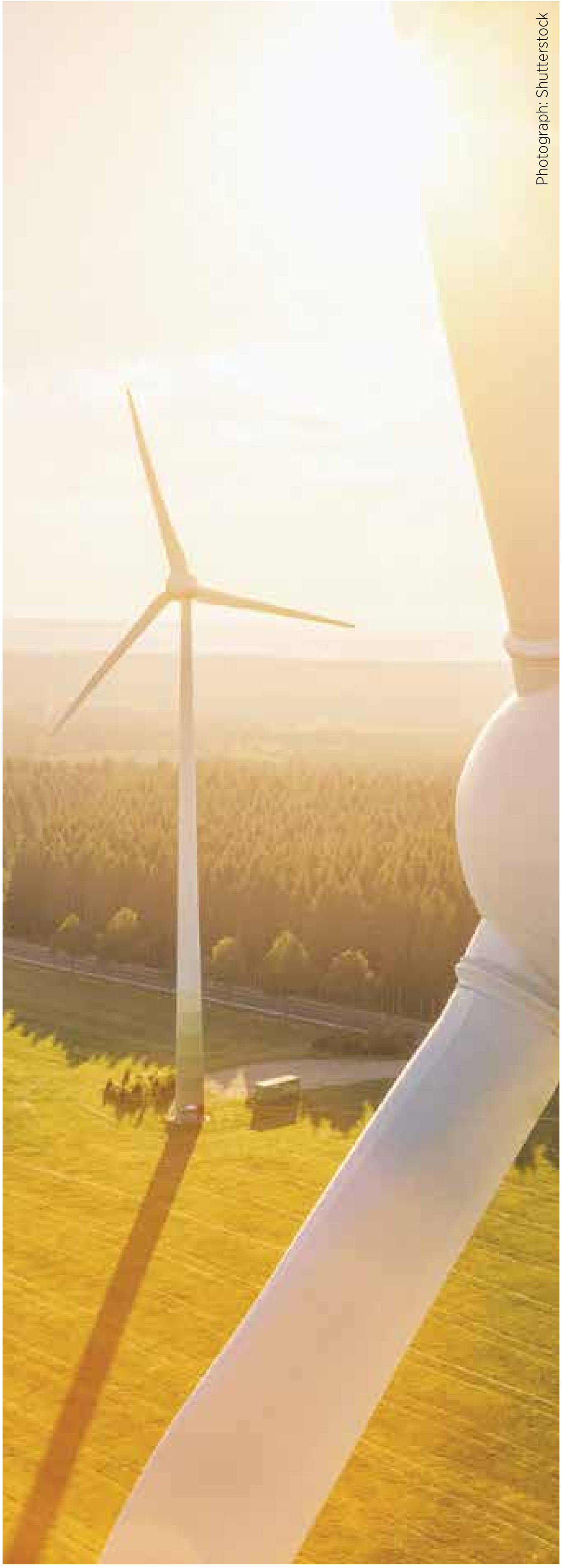
### Phase 2: Storage technology mapping

In Phase 2 of the ESVF, an overview of the suitability of different storage technologies for various applications must be established. The method described below ranks storage technologies based on various technical and commercial parameters for each service. A list of suggested storage technologies for consideration can be found in Table 3.

**Table 3:** Storage technologies for consideration

| | |
|---|---|
| **Mechanical storage** | Pumped hydro storage<br>CAES<br>Flywheels |
| **Lead-acid batteries** | VRLA |
| **High-temperature batteries** | NaNiCl<br>NaS |
| **Flow batteries** | Vanadium flow<br>ZnBr hybrid flow |
| **Lithium-ion batteries** | NMC<br>NCA<br>LFP<br>LTO |

**Notes:** CAES = compressed air energy storage; LFP = lithium ferrophosphate; LTO = lithium titanate; NaNiCl = sodium nickel chloride; NaS = sodium sulphur; NCA = lithium nickel cobalt aluminium; NMC = lithium nickel manganese cobalt; VRLA = valve-regulated lead acid; ZnBr = zinc bromine.


Photograph: Shutterstock

### Methodology

#### Step 1: Assigning competitive scores to technologies

The suggested storage technologies are listed based on various technical and commercial parameters (see Figure 13):

- Technical parameters: AC-to-AC efficiency, rate of charge, rate of discharge, energy density, power density, minimum C-rate,[22] maximum C-rate, depth of discharge (DoD), maximum operating temperature, and safety as indicated by thermal stability (where applicable).

- Commercial parameters: storage capital expenditure (CAPEX), power conversion system capital expenditure (PCS CAPEX), years required for project development and construction, operating costs, operating life, and maturity of technology.

Sample default values for these attributes can be found in IRENA's costing analysis (IRENA, 2017a), but the values can also be adjusted based on country-specific or project-specific information. Sample values are presented in Figure 13.

22 C-rate is a measure of the ratio between the power rating and the energy rating of a storage device. A 1C rate means that at full power, the storage will be depleted in 1 hour. A 2C rate = 30 minutes for the device to be completely discharged, while C/2 = 2 hours for a full discharge, and so on.

**Figure 13:** Sample default values for storage technology mapping

| Parameters | VRLA | Pumped Hydro | CAES | Flywheels | NMC | NCA | LFP | LTO | NaS | NaNiCl2 (Zebra) | ZBB | VRB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Technical | | | | | | | | | | | | |
| Efficiency (AC-to-AC) (%) | 81% | 80% | 64% | 85% | 92% | 92% | 86% | 96% | 81% | 85% | 72% | 72% |
| C-Rate min | C/10 | C/20 | C/10 | 1C | C/4 | C/4 | C/4 | C/4 | C/8 | C/8 | C/8 | C/8 |
| C-Rate max | 2C | C/6 | C/4 | 4C | 2C | 1C | 2C | 10C | C/6 | C/6 | C/4 | C/4 |
| DOD (%) | 50% | 90% | 40% | 85% | 90% | 90% | 90% | 95% | 100% | 100% | 100% | 100% |
| Max. Operating Temperature (°C) | 50 | NA | NA | NA | 55 | 55 | 65 | 65 | NA | NA | 50 | 50 |
| Safety (Thermal Stability) | High | NA | NA | NA | Medium | Low | High | High | Medium | Medium | Medium | High |
| Commercial | | | | | | | | | | | | |
| Storage Capex ($/kWh) | 226 | 21 | 48 | 2 656 | 339 | 284 | 466 | 880 | 436 | 323 | 696 | 268 |
| Development & Construction (Years) | 0.25 | 5 | 3 | 1 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 1 | 1 |
| Operating Cost ($/kWh) | 3 | 2 | 1 | 80 | 8 | 8 | 8 | 6 | 8 | 8 | 15 | 11 |
| Energy Density (Wh/L) | 75 | 1 | 4 | 110 | 470 | 410 | 410 | 410 | 220 | 215 | 45 | 42.5 |
| Power Density (W/L) | 355 | NA | NA | 7 500 | 5 050 | 5 050 | 5 050 | 5 050 | 140 | 210 | 13 | 2 |
| Life (full equivalent cycles) | 500 | 20 000 | 20 000 | >100 000 | 3 500 | 1 500 | 3 500 | 10 000 | 5 000 | 3 500 | 4 000 | 10 000 |
| Maturity of Technology | M | M | C | EC | C | C | C | EC | C | D | EC | EC |

**Notes:** kg = kilogram; kW = kilowatt; kWh = kilowatt hour; L = litre; VRB = vanadium redox battery; W = watt; Wh = watt hour; ZBB = zinc bromine battery.

Sources: Customized Energy Solutions (CES) market expertise for "Development and Construction", data sheets of key manufacturers for "C-Rate","Max. Operating Temperature" and "Life" and IRENA (2017a) for the rest.

A sample exercise to assign competitive values follows:

Based on the values of technical and commercial parameters, competitive scores of 1 to 5 can be assigned to each parameter, with 5 representing the best score and 1 representing the worst (see Table 4). For some parameters, such as efficiency, DoD, operating costs, and life, relative merits are not difficult to recognise. Thus, a 5 can be awarded to the technology that is most efficient or has the deepest DoD cycle, lowest operating costs, or longest life.

For other parameters:

- Scores for C-Rate are based on the maximum output power possible for a technology. For example, a 10 MWh LFP battery can output power at 20 MW (=2C) with an appropriate power conversion system, whereas a 10 MWh CAES will most likely be designed for a discharge time of 4 hours or more which corresponds to C/4. The C-Rate score for LFP is therefore higher.

- Scores for initial capital costs, length of development and construction, space required, and maturity of technology can be found in past analyses (IRENA, 2015a; Lazard, 2017; E3, 2017; HECO, 2016). These factors may change from country to country and the scores should therefore be adjusted as appropriate.

**Table 4:** Sample look-up table for competitive score

| Score | 5 | 4 | 3 | 2 | 1 |
|---|---|---|---|---|---|
| **Technical** | | | | | |
| **Efficiency** | > 95% | 86.25–95% | 77.5–86.25% | 68.75–77.5% | < 60% |
| **C-rate** | 1C and above | C/2–1C | C/4–C/2 | C/8–C/4 | C/8 and lower |
| **DoD** | > 95% | 86.25–95% | 77.5–86.25% | 68.75–77.5% | < 60% |
| **Commercial** | | | | | |
| **Initial capital cost** | < USD100/kWh | USD100–325/ kWh | USD325–550/ kWh | USD550–775 / kWh | > USD1 000/ kWh |
| **Development and construction** | 6 months and less | 6–16.5 months | 16.5–27 months | 27–37.5 months | 4 years and longer |
| **Operating cost** | Lowest of all technologies | | | | Highest of all technologies |
| **Space required** | > 500 Wh/kg | 382.5–500 Wh/kg | 265–382.5 Wh/kg | 147.5–30 Wh/kg | < 30 Wh/kg |
| **Life** | Longest of all technologies | | | | Shortest of all technologies |
| **Maturity of technology** | Mature | Commercialisation | Early Commercialisation | Demonstration | Prototype |

Based on the scoring criteria in Table 4, a sample of scores for various technologies is shown in Figure 14.

**Figure 14:** Example of competitive scores for storage technologies

| Parameters | VRLA | Pumped Hydro | CAES | Flywheels | NMC | NCA | LFP | LTO | NaS | NaNiCl2 (Zebra) | ZBB | VRB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Technical | | | | | | | | | | | | |
| Efficiency | 3.4 | 3.2 | 1 | 3.7 | 4.6 | 4.6 | 3.9 | 5 | 3.2 | 3.7 | 2.1 | 2.1 |
| C-Rate | 5 | 2 | 2 | 5 | 5 | 4 | 5 | 5 | 2 | 2 | 2 | 2 |
| DoD | 1 | 3 | 3 | 4 | 4 | 3 | 4 | 4 | 3 | 3 | 5 | 5 |
| Commercial | | | | | | | | | | | | |
| Initial Capital Cost | 4.7 | 4.4 | 4.3 | 2 | 3.8 | 4.1 | 3.4 | 2 | 3.5 | 3.9 | 2.3 | 3.2 |
| Development & Construction | 5 | 1 | 2.1 | 4.7 | 5 | 5 | 5 | 4.7 | 4.7 | 4.7 | 4.2 | 4.2 |
| Operating Cost | 4.9 | 4.9 | 5 | 1 | 4.7 | 4.7 | 4.7 | 4.7 | 4.6 | 4.6 | 4 | 4 |
| Space Required | 1.5 | 1 | 1 | 2.3 | 3.3 | 3.3 | 3 | 3.3 | 1.3 | 1.2 | 1.2 | 1 |
| Life | 1.1 | 5 | 5 | 5 | 1.3 | 1 | 1.4 | 3.6 | 2.1 | 1.6 | 3.6 | 4.4 |
| Maturity of Technology | 5 | 5 | 4 | 3 | 4 | 4 | 4 | 3 | 4 | 2 | 1 | 2 |

### Step 2: Assigning weightings to parameters for applications

Next, a set of weightings is applied to each parameter under different applications. Depending on the application, some parameters are more important than others. Figure 15 shows an illustrative example of how the table of weightings for each parameter could look. As mentioned, these weightings are only illustrative and are not for unquestioned use in storage valuation exercises. For each valuation exercise the weightings should be adjusted based on the specific projects, technologies, regulatory framework and market settings.

Weightings must be adjusted for each project, technology, regulatory framework and market setting

**Figure 15:** Example of illustrative parameter weightings for different applications

| | Renewable Shifting | Renewable Smoothing | Flex Ramping | Ancillary Services | T&D Deferral | Reactive Power Management | BTM Power Management |
|---|---|---|---|---|---|---|---|
| **Technical** | | | | | | | |
| **Efficiency** | 10% | 10% | 10% | 10% | 5% | 10% | 10% |
| **C-Rate** | 0% | 15% | 0% | 15% | 0% | 0% | 5% |
| **Usable SOC** | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| **Commercial** | | | | | | | |
| **Initial capital cost** | 40% | 30% | 40% | 30% | 30% | 30% | 30% |
| **Development and construction** | 5% | 5% | 5% | 5% | 20% | 5% | 5% |
| **Operating cost** | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| **Space required** | 5% | 0% | 5% | 0% | 10% | 15% | 15% |
| **Life** | 10% | 10% | 10% | 10% | 5% | 10% | 5% |
| **Maturity of technology** | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

**Notes:** The total weighting in each column should be 100%; T&D = transmission and distribution.

Photograph: Shutterstock

**Step 3: Applying suitability matrix**

The competitive scores for different technologies and the weightings for the applications together provide an overall picture of how suitable each technology is for each application. However, the combination of scores and weightings of parameters are often insufficient because they could vary depending on the specific case. To avoid the complexity of providing competitive scores and weightings for each technology and each case, a suitability matrix is used. The suitability matrix provides an opportunity to adjust the weighted score further. For example, lead acid batteries are cost-competitive, but are less suitable for high C-rate uses such as VRE smoothing or primary/secondary reserve. While technically a lead acid battery system can be designed to provide VRE smoothing or primary/secondary reserves, its usable SOC is a limitation unless the cost increases significantly. To capture such cases, the suitability matrix is applied on top of the results from the competitive scores and parameters weightings for each application. A sample of default values in a suitability matrix is shown in Figure 16.

**Figure 16:** Example of suitability matrix for different applications

| Parameters | VRLA | Pumped Hydro | CAES | Flywheels | NMC | NCA | LFP | LTO | NaS | NaNiCl2 (Zebra) | ZBB | VRB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable Shifting | 0.8 | 1.0 | 1.0 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Renewable Smoothing | 0.8 | 0.3 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 0.3 | 0.3 | 0.3 | 0.3 |
| Flex Ramping | 0.8 | 1.0 | 1.0 | 0.5 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Ancillary Services | 0.5 | 0.3 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 0.3 | 0.3 | 0.3 | 0.3 |
| T&D Deferral | 1.0 | 1.0 | 1.0 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Reactive Power Management | 1.0 | 0.3 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 0.3 | 0.3 | 0.3 | 0.3 |
| BTM Power Management | 1.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |

**Note:** BTM = behind-the-meter.

### Application ranking

The weighted average competitive scores for each technology and for each case are calculated by multiplying the competitive scores, weighting and suitability matrices in Steps 1 to 3. Technologies are then ranked based on their weighted average score for a given case, with 1 being the most suitable for a specific application, 10 the least suitable. Rankings can be shown as a heat map of how suitable each technology is for each case (see Figure 17 and Figure 18). A green colour denotes most suitable technologies while red shows less suitable ones. The top-ranked technologies are used in the subsequent project feasibility analysis phase of the ESVF. Please note that values in this section are purely indicative, and they have to be adjusted case by case when performing the analysis depending on the system, the technologies and other specific conditions.

### Phase 3: System value analysis

The next phase of the ESVF is to conduct a system-level analysis to calculate the total economic benefit of building storage assets in a given power system. The baseline is built by selecting a starting system, either being an existing system or a future plan. This will be the reference point for assessing the potential for storage deployment to reduce total system cost. Electricity demand is an input in this type of analysis together with others (such as fuel and capital investment costs) needed to assess the total cost of the plan. If the analysis is intended to estimate the value of storage at the present time, the current demand is given. Alternatively, the same approach can be followed to assess the long-term benefits of storage by supplying some future level of demand (either assumed or deduced from a top-down or bottom-up model, fed with relevant data and assumptions), effectively developing a future long-term scenario. The analysis will then calculate the optimal amount to be built based on a combination of capacity expansion least-cost optimisation and production cost modelling.

**Figure 17:** Example of weighted scores

| Parameters | VRLA | Pumped Hydro | CAES | Flywheels | NMC | NCA | LFP | LTO | NaS | NaNiCl2 (Zebra) | ZBB | VRB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable Shifting | 2.81 | 3.97 | 3.68 | 0.71 | 3.80 | 3.79 | 3.56 | 3.23 | 3.39 | 3.35 | 2.76 | 3.29 |
| Renewable Smoothing | 2.96 | 0.95 | 0.87 | 3.26 | 4.00 | 3.81 | 3.82 | 3.62 | 0.82 | 0.80 | 0.69 | 0.81 |
| Flex Ramping | 2.81 | 3.97 | 3.68 | 1.41 | 3.80 | 3.79 | 3.56 | 3.23 | 3.39 | 3.35 | 2.76 | 3.29 |
| Ancillary Services | 1.98 | 0.95 | 0.87 | 3.26 | 4.00 | 3.81 | 3.82 | 3.62 | 0.82 | 0.80 | 0.69 | 0.81 |
| T&D Deferral | 3.88 | 3.32 | 3.31 | 0.75 | 4.04 | 4.01 | 3.86 | 3.47 | 3.55 | 3.46 | 2.94 | 3.33 |
| Reactive Power Management | 3.43 | 0.91 | 0.84 | 2.85 | 3.75 | 3.71 | 3.52 | 3.36 | 0.79 | 0.77 | 0.66 | 0.77 |
| BTM Power Management | 3.62 | - | - | 0.71 | 3.93 | 3.86 | 3.70 | 3.43 | 3.17 | 3.10 | 2.57 | 2.95 |

**Figure 18:** Example of application ranking

| Parameters | VRLA | Pumped Hydro | CAES | Flywheels | NMC | NCA | LFP | LTO | NaS | NaNiCl2 (Zebra) | ZBB | VRB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable Shifting | 10 | 1 | 4 | 12 | 2 | 3 | 5 | 9 | 6 | 7 | 11 | 8 |
| Renewable Smoothing | 6 | 7 | 8 | 5 | 1 | 3 | 2 | 4 | 9 | 11 | 12 | 10 |
| Flex Ramping | 10 | 1 | 4 | 12 | 2 | 3 | 5 | 9 | 6 | 7 | 11 | 8 |
| Ancillary Services | 6 | 7 | 8 | 5 | 1 | 3 | 2 | 4 | 9 | 11 | 12 | 10 |
| T&D Deferral | 3 | 9 | 10 | 12 | 1 | 2 | 4 | 6 | 5 | 7 | 11 | 8 |
| Reactive Power Management | 4 | 7 | 8 | 6 | 1 | 2 | 3 | 5 | 9 | 10 | 12 | 11 |
| BTM Power Management | 4 | 11 | 11 | 10 | 1 | 2 | 3 | 5 | 6 | 7 | 9 | 8 |

**Note:** 1 = best; 10 = worst.

The system-level analysis as proposed in the ESVF can be used to study standalone electricity storage systems. In standalone operation, a storage unit could be (for example) a utility-owned asset (in regulated environments) or operate independently under a specific market setting. In the first case, storage offers system services to the whole utility and storage CAPEX costs should be compared to utility-wide benefits from storage. If there is a net benefit for the utility, then investing in storage makes economic sense for the utility and there is no need to apply Phase 4 of the framework.

In the case of an independent power provider, Phase 4 of the framework can be used to assess if an independent operator could make a profit operating storage independently. Similarly, in a market environment, the system-wide benefits of storage need to be compared with the potential revenue streams a market can offer. A comparison of the two cases is not enough to conclude whether investing in storage makes sense. The financial viability of a project depends on project valuation analysis that compares CAPEX and operating expenditure (OPEX) costs and revenues.

A further comparison with system-wide benefits gives additional insights, particularly on whether policy interventions are needed to better support storage deployment.

The ESVF can be used to estimate the system-level benefits of behind-the-meter storage by aggregating the storage capacity within the distribution network to the level represented by the capacity expansion and production cost models (i.e. zonal, nodal level). The system-wide benefits of storage at the distribution level are similar to those of storage deployed on the high-voltage network, although the range of services that can be provided is wider at the distribution level.

### Capacity expansion optimisation

Capacity expansion optimisation is a method used to assess the optimal combination of investments in the power sector. Depending on the tool capabilities, such investments could include renewables, energy efficiency, demand response, electricity storage and peaking power plants, as well as sector-coupling options to reduce total system investment and operating costs. The analysis should start from the existing system and take into account the cost of additional investments in electricity storage and flexibility alternatives. The outputs are additional investment in technologies a) where electricity storage is not available, and b) where electricity storage is available, as well as the amount of storage capacity needed. Table 5 shows types of user inputs, variables and constraints for incorporation into the objective function to be minimised.

**Table 5:** Parameters used in optimising the capacity for alternative technologies

| | User input | Variables | Constraints |
|---|---|---|---|
| **Peaking generators (open-cycle gas turbines and diesel generators)** | • Capital cost (USD/kW)<br>• VOM (USD/MWh)<br>• FOM (USD/kW year)<br>• Fuel cost (USD/mBtu)<br>• Heat rate (Btu/kWh) | • New capacity<br>• Generation | • Operational range |
| **Energy efficiency** | • Capital cost (USD/kW) (cost increases with deployment)<br>• Maximum investment<br>• Energy savings per investment | • Investment<br>• Energy savings | • Maximum investment<br>• Energy savings proportional to investment |
| **Demand-side flexibility** | • Capacity cost (cost increases with deployment) | • Equipment investment<br>• Demand response exercise (up and down) | • Maximum capacity |
| **VRE** | • Capital costs (USD/kW)<br>• Capacity factor profile | • Capacity<br>• Generation | • Resources<br>• Maximum capacity |
| **Electricity storage** | • Capacity costs (USD/kW)<br>• Capacity costs (USD/kWh) | • Power and energy capacities<br>• Inventory | • Inventory<br>• Maximum capacity (power and energy) |

**Notes:** FOM = fixed operational and maintenance VOM = variable operational and maintenance.

### Production cost modelling

Using the results from the capacity expansion optimisation (optimised capacities of various technologies), the next step is to perform production cost modelling to minimise the total cost of operation with and without electricity storage. Production cost models can co-optimise the actual dispatch and allocation of operational reserves of a given generation fleet at a time step representative of real-time operations (from 1 hour to seconds) considering various real-world constraints.

Such constraints include transmission constraints, unit constraints (as in the case of ramping constraints, operational range and minimum up and down times), policy constraints (as in the case of a carbon cap or carbon pricing) and system constraints (as in the case of a non-synchronous penetration limit). The cases to be optimised are based on the results of the capacity expansion assessment (with and without electricity storage).

Production cost modelling in the system-level assessment of electricity storage is used for the following two reasons:

- To obtain a more accurate assessment of OPEX. Capacity expansion models assess OPEX at a time step much longer than 1 hour.[23] As a result, capacity expansion software returns only an approximation of production costs. After the capacity mix has been optimised, production cost models are used to verify and improve the assessment of OPEX.

- To assess operational benefits of electricity storage. Capacity expansion models are not capable of assessing the operational benefits of flexible assets in the system due to their limited temporal granularity. Capturing the actual operational benefits of electricity storage is challenging due to its fast response times compared to other technologies. The finer the temporal resolution of a capacity expansion model, the higher the accuracy of the results. Capacity expansion models can be used only to give an approximation of the capacity (power and energy) of electricity storage needed. The power capacity resulting from the capacity expansion optimisation is used as an input in a subsequent step where production cost modelling is used to improve the assessment of electricity storage needed in the system through an iterative process intended to find the optimal duration of electricity storage.

  The process should start with short-duration storage (0.5 hours or less), and gradually increase the duration to find the least-cost solution. While there might be one optimal amount of electricity storage capacity, in practice the storage portfolio will comprise an array of various durations from 0.5 to 8+ hours. To provide firm capacity, which is a large piece of the value of storage, longer-duration storage will be needed. For some markets this is 4 hours – others provide capacity value for shorter durations and some require longer. This might require another type of analysis that considers the saturation effects of storage for peak load reduction (Stenclik et al., 2018)

The steps to calculate the benefits to the power system are as follows (see also Figure 19):

**Step 1:**
Capacity expansion optimisation: electricity storage and flexibility alternatives, such as energy efficiency, demand response, renewable energy and conventional power plants, are used to meet load growth of the system. Alternatives can also include sector-coupling options such as electric vehicles, electric boilers, heat pumps and hydrogen production from renewables.

The analysis should optimise the capacity of each resource with the objective of minimising the sum of capital and operational costs for the system (total system cost). This step calls for an appropriate tool, capable of optimising storage size (both power and energy). Available tools vary in terms of granularity, technical focus and practicality, and tool selection should be made considering the characteristics of the power system to be studied and data availability. For example, if the value of storage needs to be assessed at the zonal/nodal level then available tools should be capable of modelling transmission.

In addition, a study focusing on electricity storage should use capacity expansion optimisation software capable of simulating time steps as short as possible. IRENA has recently developed and made available to the public a tool capable of sizing and dispatching electricity storage, mostly applicable for high-level analysis. The IRENA FlexTool can be used for system-level analysis (both capacity expansion and production cost simulations) (IRENA, 2018b). The capacity expansion optimisation is performed twice: first, without electricity storage to set the baseline (or the "no new storage") case; and then with electricity storage added to set the "with new storage" case. The differences in the capacity mix of the two cases are used to assess CAPEX-related benefits.

**Step 2:**
Run a production cost model based on the baseline system to estimate operational costs.

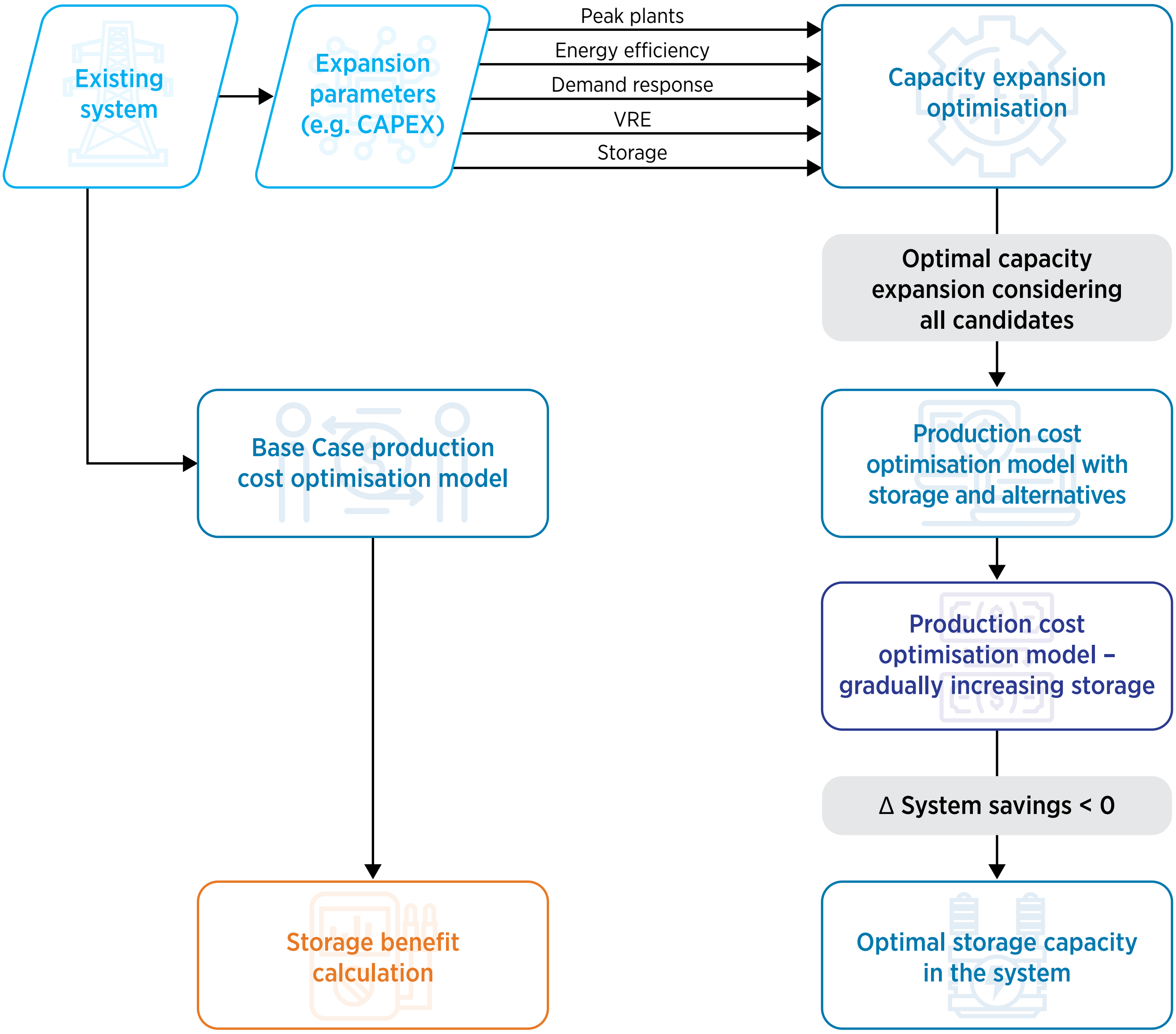
23 Many capacity expansion software tools use load duration curves as inputs, which are broken down in a number of blocks of varying duration.

**Step 3:**
Run another production cost model on the "with new storage" case, with a power rating from capacity expansion optimisation in Step 1 and an energy rating the same as the power rating (C1).

**Step 4:**
Gradually increase the energy capacity (duration) of electricity storage; run the production cost model with each increase to find out the optimal electricity storage duration that minimises the production cost. Stop increasing storage capacity when the cost of adding storage exceeds production cost reduction (when total system cost would start increasing by adding more storage capacity).

**Step 5:**
Compare the production costs between Steps 2 and 4 and analyse the benefits of storage including potential benefits from ancillary services cost reduction. Such benefits result from a) more efficient dispatch of units, since conventional generators will have more available capacity after storage takes on ancillary services, and b) deferring the need for conventional capacity (this can be quantified through capacity expansion optimisation assuming the formulation of the problem considers the need to withhold capacity for ancillary services).

**Figure 19:** Calculation steps in system value analysis



### Electricity storage benefits for the power system

As described in the previous sections, a comparison of the "no new storage" and "with new storage" cases can be made to assess CAPEX- and OPEX-related benefits of electricity storage on the power system.

In this section, the benefit categories are defined with qualitative discussion of the cost components. Power system optimisation models allocate the OPEX- and CAPEX-related costs to new investments and power system operation. However, some OPEX and CAPEX elements might be difficult to separate and quantify, as explained below.

CAPEX-related costs are usually straightforward to both quantify and separate. For example, when running a capacity-expansion exercise, the transmission capacity needed to supply either current or future demand can be identified. Running the exercise with electricity storage might defer the need for some of this transmission capacity. The CAPEX related to this deferred transmission capacity is the related benefit. Similarly, electricity storage can offer a variety of ancillary services that would otherwise be provided by conventional generators. Deployment of electricity storage increases the capacity levels available from conventional generators, thus potentially deferring the need for new capacity. The formulation of the capacity expansion models should allow these aspects of CAPEX-related benefits of ancillary service provision to be captured (Li et al., 2017). Similarly, electricity storage could defer the need for peak capacity by providing load following and shifting the timing of electricity production.

However, quantifying distribution-related CAPEX benefits is not straightforward. The difficulty relates to the practical difficulties of representing a power system at the distribution level using capacity expansion software. Similarly, OPEX-related benefits of electricity storage are hard to estimate at the distribution level, and in most cases storage capacity is aggregated for modelling purposes to the level that can be captured by the model/software. To accurately assess CAPEX- or OPEX-related benefits at the distribution level, a different approach from the one used in the ESVF is needed, potentially using network models (Zobaa et al., 2018; Joshi, Pindoriya and Srivastava, 2018; Li et al., 2018).

With regard to estimating OPEX-related savings, a straightforward comparison of production cost modelling results, between the "baseline" and "with new storage" cases, can be used to assess total fuel cost-related savings.

The total amount of fuel cost savings due to electricity storage depends on the combined effect of the various functions of electricity storage. They relate to a more economic electricity dispatch of generating assets due to electricity storage contributing energy and ancillary services. More specifically, fuel cost-related savings can result from:

- Reducing the cycling of thermal generators, which leads to a) a lower number of start-ups and b) reduced hours of operation at partial loading (which negatively affects thermal efficiency).
- Replacing expensive thermal generators during peak hours.
- Replacing flexible thermal generators for provision of load following.
- Replacing thermal capacity for provision of ancillary services. This leads to a more efficient system-wide dispatch through a) increased availability of thermal capacity for energy services, and b) dispatch of electricity storage for frequency regulation.
- Supporting penetration of renewable energy at the expense of thermal generation.
- Reduced grid operational expenditure through transmission congestion relief.
- Additional OPEX-related cost savings are:
- Reduced VOM costs for thermal generators.
- Reduced CO2 emissions (where carbon pricing is present there are direct benefits).
- Cost savings due to reduction in VRE curtailment levels.

Even though estimation of total fuel-related (and non-fuel related) OPEX savings is straightforward, further separation into individual components is either challenging or even practically impossible through the use of optimisation modelling. This is mainly due to the complex and dynamic interaction of system elements – any effort to disaggregate costs would require the introduction of additional scenarios to obtain only an estimate of additivities.

**Table 6:** Storage benefits categorised as quantifiable and non-quantifiable

| Quantifiable benefits | Benefits more difficult to quantify |
|---|---|
| **OPEX-related benefits**<br>• Total fuel cost savings due to a more economic dispatch resulting from a combination of factors (i.e. storage replacing fossil-fuelled generation and provision of ancillary services)<br>• Start-up cost savings (note that start-up cost savings are part of fuel saving costs)<br>• VRE curtailment savings<br>• VOM savings<br>• Reduced CO2 emissions (where carbon pricing is present there are direct benefits). | **OPEX-related benefits**<br>• While estimating total fuel savings is straightforward, breaking them down into separate quantifiable categories is difficult. The following elements of total fuel cost savings cannot be easily separated:<br>o Replacing costly energy generation during peak hours<br>o Supporting penetration of renewables at the expense of fossil-fuelled generation<br>o Replacing fast-responding thermal capacity used for provision of load following and other ancillary services<br>o Reduced grid operational expenditure through transmission congestion relief<br>o Reducing cycling of thermal generators.<br>• Provision of ancillary services<br>o Actual dispatch of primary and secondary reserves<br>o Voltage support<br>o Black-start savings. |
| **CAPEX-related benefits**<br>• Deferring the need for peaking capacity<br>• Transmission capacity deferral savings<br>• In some cases, deferring the need for other flexibility alternatives (e.g. heat pumps or electric boilers). | **CAPEX-related benefits**<br>• Distribution network capacity deferral savings |

Table 6 above categorises electricity storage benefits as directly quantifiable and difficult to quantify. Benefits in the first column can be quantified with optimisation models, while those in the second column are more difficult to capture with optimisation models, as they tend to be very location-specific, market-specific or requiring other modelling methodologies. More detailed discussion about individual storage benefits follows.

### A. Reduced cost of producing electricity

The reduced cost of producing electricity is manifested in the production cost models as reduced fuel costs, reduced VOM costs, and reduced start-up and shutdown costs.

Electricity storage changes the cost of producing electricity in several ways:

- **By fulfilling demand during peak hours with low-cost electricity stored during off-peak hours.** In a grid system with increasing penetration of VRE, the grid operator can store electricity during times of abundant VRE generation – usually periods with low electricity prices – to be used later. This displaces more expensive peak generation resources such as oil, reducing prices during peak hours, and avoids potential price spikes related to scarcity events. In a vertically integrated system structure where a cleared market price is not calculated explicitly, the cost of supplying electricity is lowered for the same reasons.

Figure 20 illustrates how electricity storage reduces peak load and therefore the cost of electricity during peak hours. In the top panel, load in a scenario without storage is shown as the shaded grey area, whereas load in a scenario with storage is shown in orange. By charging during off-peak hours and discharging during peak hours, as shown in the bottom panel, storage effectively flattens and reduces the peak load. If the storage device is directly connected to VRE, it performs a similar function.

In both cases electricity storage facilitates penetration of VRE in the electricity mix by a) shifting VRE generation towards peak hours and b) reducing VRE curtailment. At high VRE shares, storage supports a higher share of VRE by reducing curtailment and creating a case for viable investment in additional VRE.

**Figure 20:** Load profile over 24 hours with and without storage (top panel) and storage charge and discharge over 24 hours (bottom panel)

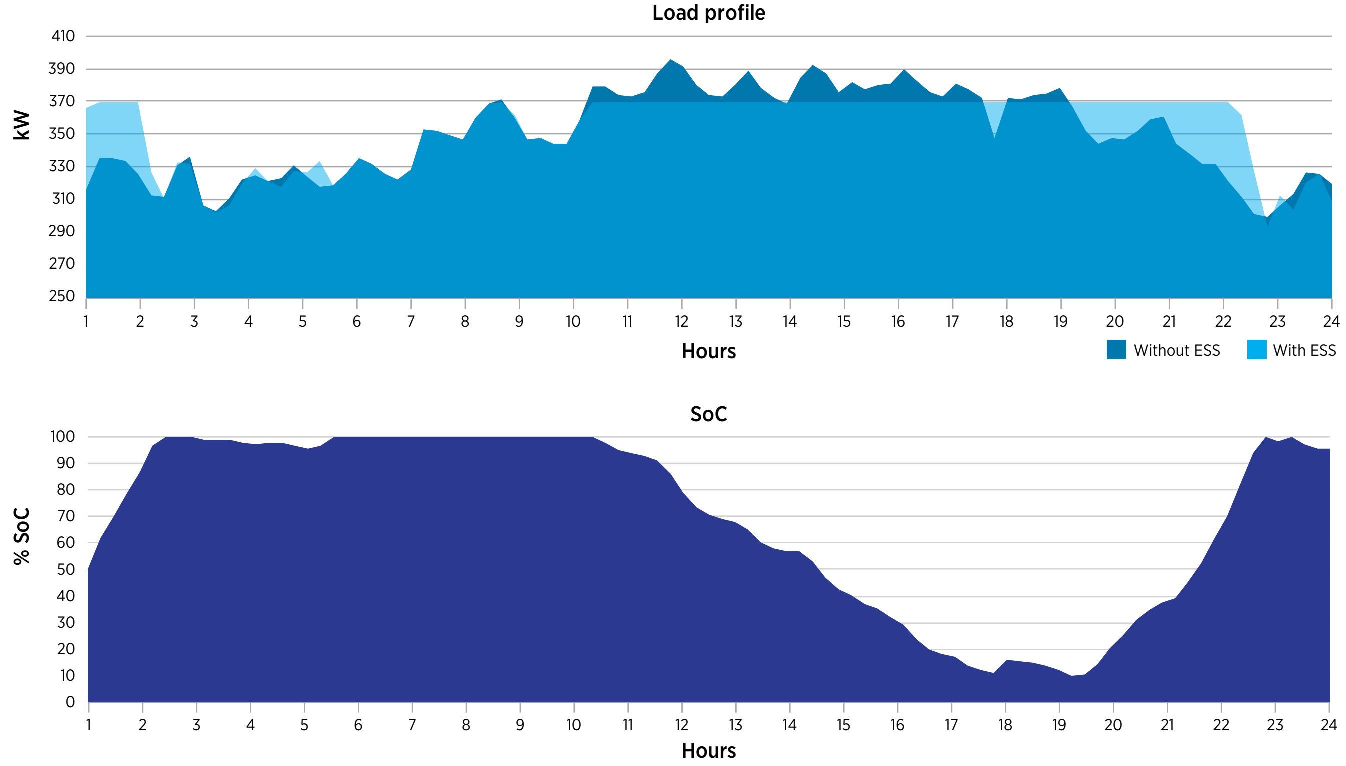
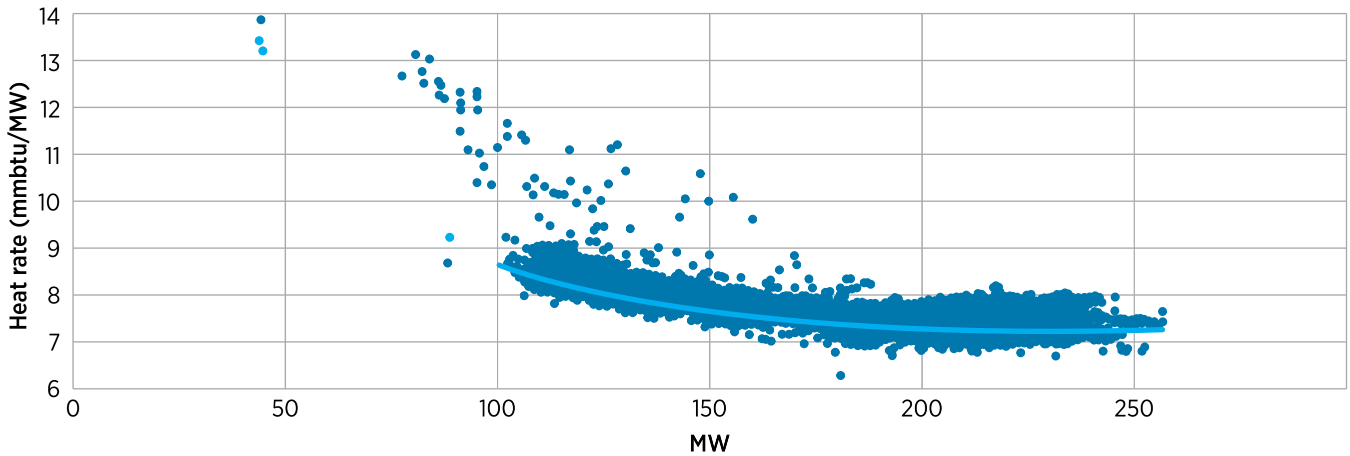



**Figure 21:** Heat rate curve of a thermal generator




Source: NREL (2012).

- **By utilising storage to follow load variations and allow thermal generators to improve overall operational efficiency.** Higher proportions of VRE on the system cause conventional thermal generators to cycle more frequently to balance fluctuations in net load caused by solar and wind variability and uncertainty (IRENA, 2018a).

As shown in Figure 21, a thermal generator's heat rate[24] increases (or its efficiency decreases) when its output deviates from its optimal operational point. If a generator follows the load by increasing or decreasing its output, it moves away from its optimal operational point, resulting in inefficient use of fuel. Instead, if electricity storage is used to meet the changes in net load, the fossil fuel generators can operate at constant and optimal output, decreasing their fuel costs and their wear and tear cost related to cycling. In a vertically integrated market structure, such operation effectively reduces the cost of serving the load; in an unbundled market, the electricity storage alleviates the load-following burden on some thermal resources while also potentially replacing some marginal units.

24 The efficiency of thermal generators is expressed as the heat rate, or the amount of thermal energy input over the amount of electricity output, usually in Btu/kWh. The lower the heat rate, the more efficient the thermal generator.

Fuel savings due to increased thermal efficiency are more significant in small systems operating mostly with diesel capacity. The example in Figure 22 shows how electricity storage can perform rapid ramping, avoiding solar curtailment and loss of load due to insufficient ramping capability of thermal generators.

## Electricity storage can perform rapid ramping, avoiding solar curtailment and loss of load

**Figure 22:** Demand, ramping curves and VRE curtailment without storage (top panel) and with storage (bottom panel)