Integration of Storage into a Renewables Portfolio to Optimise Revenue & Grid Connection Utilisation

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Abstract— **Policy changes in Great Britain mean that solar generators (and other onshore renewables) face the prospect of developing sites without subsidy support. Co-locating energy storage technologies will potentially allow developers to realise extra value from their existing or planned sites by stacking revenue streams. One aim is to optimise the use of the existing grid connections, - in many areas of high solar potential, developers face costly reinforcements and long timescales for new grid connections. Other benefits include revenue from ancillary services, reduced network charges or increased network credits, and 'arbitrage' - selling power at peak times and buying it during off-peak periods. Co-location could help solidify the business case for subsidy-free solar sites in the UK.**

Based on project experiences with renewables developers, this paper sets out a methodology which developers can use to assess opportunities for co-locating energy storage with an existing portfolio of distribution-connected sites (operational or in development). Considerations include:

- **The opportunity to better utilise or accelerate the grid connection of the site, for sites with constrained grid connections;**
- **The potential to add additional PV generation to increase the site's capacity factor;**
- **The size of the revenue stream from avoided network costs;**
- **The size of the revenue stream from ancillary services;**
- **The physical space available and the likelihood of receiving planning permission for the site.**

The paper will present the results of a simple spreadsheet-based modelling tool which is used to explore the benefits of different sizes of battery (MW and MWh) and additional PV capacity on a particular site. The tool considers the limits of the existing grid connection, and simulates battery behaviour under a year's half-hourly generation profile. The tool can estimate the additional revenue for a range of battery sizes and C-factors, and therefore provide an indication of the benefits of storage and the optimal size to install on a particular site.

This paper also comments, based on project experience, on existing barriers in the UK to the deployment of energy storage with solar power, including technical, commercial and consenting barriers, and sets out some ideas on how these barriers could be addressed. Resolving these issues is key to allowing the UK to access the maximum benefits from storage in a timely and efficient manner.

Keywords- ***storage, battery, revenue streams, grid connection, co-location, solar, feasibilty***

I. INTRODUCTION

Electricity storage has the potential to accelerate the grid integration of renewable technologies. There are several ways it can accomplish this: by peak shaving to reduce the need for network reinforcements; by time-shifting generation export towards peak demand times, or towards times of self-consumption; and by providing additional ancillary services to the grid, such as frequency response.

Grid-scale battery storage has grown rapidly in recent years, due to increasing grid penetration of intermittent renewable generators and falling costs of batteries. For example, lithium-ion battery cell costs are decreasing at 17% per year [1]. In the UK, interest was sparked by a tender opportunity from National Grid, the transmission system operator, for Enhanced Frequency Response (EFR). EFR requires rapid (in less than 1 second) changes in active power in response to grid frequency changes. In August 2016, battery storage providers won 100% of all EFR contracts awarded, totalling 201MW [2].

It is predicted that solar and wind developers will look to review their existing and planned sites to assess whether electricity storage would increase their returns. The benefits of storage are expected to vary significantly on a site by site basis.

This paper will outline a methodology for identifying solar sites likely to benefit from energy storage, and for a detailed assessment of the benefit. Barriers to the efficient adoption of electricity storage are explored from a UK perspective. Recommendations for policymakers are provided.

II. METHODOLOGY

This paper outlines a process for assessing the suitability of a portfolio of renewable energy sites for co-location with storage. The proposed methodology takes into account the limitations of time and budget at an early stage of project development and therefore uses a two stage assessment, to rapidly limit the scope of the analysis to those sites which demonstrate suitability to key criteria.

The two distinct stages are defined as follows:

- **Stage One:** High level review of sites – based on six straightforward criteria, an assessment can be made of which sites in a portfolio are most likely to be suitable for, and to benefit from, the installation of battery storage;
- **Stage Two:** For the most promising sites, a detailed co-location assessment can be undertaken.

A. Stage One: High level review of sites

A portfolio of generation sites can be rapidly assessed to determine whether there is potential to benefit from adding storage. Table I gives a summary of the assessment factors, each of which is described in detail below.

1) Grid Connection: Storage can add value where the grid connection is challenging, by time-shifting part of the generation and therefore reducing the peak export of the site. This includes situations where obtaining grid capacity for the entire capacity of the PV site is prohibitively expensive or slow, because upstream network reinforcements are required above a certain export value. Storage is also well placed to benefit sites which have a "constrained" or "actively managed" connection so may be curtailed by the network operator at certain times.

TABLE I. FACTORS TO CONSIDER IN HIGH LEVEL REVIEW OF SITES

Factor	**Conditions where co-location of storage is most suitable**
Grid connection	Constrained or actively managed connection High costs of upstream reinforcement Connections delayed by upstream reinforcement
Opportunity for additional solar generation	Physical space Low expected landscape impacts Low noise impact, Low ecological impact Low flood risk Favourable local planning policy
Network charging	Site with high time-of-use credits available Situated in zone with high triad values
Ancillary services	In future, once revenue streams are established, consider the locational suitability for these services
Onsite loads	Sites with high demand at times of high energy prices Sites where onsite generation and onsite demand occur at different times
Site suitability for battery	Physical space Low expected landscape impacts Low noise impact, Low ecological impact Low flood risk

2) Opportunity to Install Additional Solar Generation: Storage can be beneficial on sites where there is the potential to install additional generation, but the costs of a higher capacity grid connection are prohibitive. A combination of additional generation and storage could maximise site export.

The potential for additional solar generation may be limited by various consenting and environmental factors which should be assessed. Environmental factors differ from site to site, and include ecological considerations, flood risk considerations, noise impacts and many others. However, one consideration which has been found to be relevant for the majority of solar sites is cumulative landscape impact. The installation of additional solar PVs may create an overly industrialised landscape which creates potentially unacceptable significant cumulative impacts. It is important to assess all environmental factors as well as site-specific and energy-specific local and national planning policy to ensure that the site has physical capacity to accommodate the additions.

3) Network Charging: In many countries, use of network charges are time-dependent, to discourage use of the network during peak times. Storage can be used to time-shift the generation, to reduce network charges or increase network credits.

Sites connected at 11kV or below in GB face network charges which follow the Common Distribution Charging Methodology (CDCM) in the Connection and Use of System Code (CUSC). Users classified as non-intermittent typically face a time-of-use tariff split into green, orange and red time bands.

Sites connected to the distribution network at voltages above 20kV have network charges determined by the EHV Distribution Charging Methodology (EDCM) in the CUSC. These include a super-red export credit, paid to generators who export during the super-red time band – typically 16.00 to 19.00 on winter weekdays.

Distribution-connected generators in GB also have the opportunity to participate in "Triad avoidance". Suppliers are charged for use of the transmission network based on their net demand at Grid Supply Points during "Triad periods" – three peak half hours in each year. Distribution connected generators can enter a contract with suppliers to generate during expected triad periods, thereby helping suppliers reduce their use of network charge.

It is noted that a major review is ongoing into use of network charges in Great Britain. The regulator, Ofgem, are concerned that the current system allows flexible demand and generation users to avoid paying for sunk and fixed costs of the system. In a scenario with very high levels of distributed generation and storage, there is a risk of a "utility death spiral" [3] where flexible users are able to avoid network charges but the remaining users, including vulnerable domestic customers, must pick up those costs instead.

4) Ancillary Services:. Co-located storage can enable solar PV developments to offer a controllable, inverter connected renewable energy source to the grid, which is eligible for the provision of a number of existing ancillary services, as shown in Table II. The location specific requirements for these services can help prioritise and select those sites most suited to co-location.

Beyond the simple provision of power at dedicated times for peak shaving and reserve services, the four quadrant control capabilities of storage inverters can allow the co-located solar-storage combination to provide more sophisticated future services:

- **Network Constraint Management** – This is an existing Ancillary Service procured by National Grid through bilateral agreements for transmission constraints. On a DNO network, this is a future service expected to form a key part of a DSO's toolbox.
- **Voltage Control** – The provision of reactive power to support & control system voltage. This is an existing ancillary service, but it is highly location specific so needs to be considered early in any project;
- **Phase balancing & Power flow optimisation** – Inverters have the capability to independently control power and power factor on each phase. Coupled with a controllable energy source this is potentially a very attractive way to resolve power flow issues on distribution networks;
- **Enhanced Fault Ride Through** – A potential new ancillary service arising from system stability issues on the transmission network. Inverter connected storage has the potential to respond quickly to system faults and help the network 'ride through' them by injecting both active and reactive power post-fault.

The modelling of these advanced ancillary services is not covered within the scope of this paper, but is the subject of ongoing work to refine the operational modelling of co-located battery storage.

5) Onsite Loads: Onsite behind-the-meter consumption is typically more cost effective than exporting to the network, due to decreased losses, decreased use of network charges, and avoidance of levies and taxes. This relies on the PV being sited at or close to a high load site.

Storage can particularly benefit sites with onsite loads, by maximising the times when the onsite load can use the electricity from the solar site, and minimising the amount of electricity that must be imported from the grid.

6) Site Suitability for Battery: The high level review should assess whether it is feasible to install electricity on this site. As with assessing the potential for additional solar generation, it is essential to consider all potential environmental impacts as well as energy policy and planning policy implications in the installation of battery storage. Each site should be considered separately taking into account site-specific implications.. The assessment of physical space, land use, consenting and environmental factors should all be considered when assessing the suitability for a co-location site.

TABLE II. ANCILLARY SERVICE OPPORTUNITIES IN THE UK FOR PV + STORAGE

Service	Status	Connection Requirements	Location specific?	Minimum Size?
Frequency Response	Current	Un-constrained Connection	No	No*
Short Term Operating Reserve (STOR)	Current	None	No	No*
Voltage Control (Reactive Power)	Current**	Transmission Connection	Yes	Yes
Transmission Constraint Avoidance	Current**	Transmission Connection	Yes	-
Enhanced Fault Ride Through	Future	TBC	Yes	-
DNO Reinforcement deferral	Future	Distribution Connection	Yes	-
Phase balancing	Future	Distribution Connection	Yes	-
Power flow optimisation	Future	TBC	Yes	-

*Minimum MW thresholds apply to this National Grid Service, but aggregators operate effectively to allow smaller parties to participate.

**Services currently exist, but are only procured from a handful of large scale transmission connected generators.

B. Stage Two: Detailed Co-location Assessment

1) Co-location Assessment Tool

A tool was developed to simulate the behaviour of the battery across an entire year, using 30 minute time steps. This tool has a number of static inputs, such as the battery size, efficiencies, PV capacity, grid capacity etc, as well as some dynamic inputs such as the solar resource profile.

The tool used simple logic to determine how the battery will behave in each half hour, depending on which revenue streams/services it is responding to. The behaviour of the battery is constrained by the charging/discharging rate and the maximum size

The technical outputs from the annual simulation are then fed into a simple discounted cash flow (DCF) model, which compares the capital costs of the PV, the battery and the grid connection with the operational costs and revenues derived from the model. This derives both the net present value of the co-located system as well as the internal rate of return. For simplicity, the DCF model only captures the most significant capital and operational costs.

2) Details of Site

A typical site, “Devon Solar Park” that would be identified by the Stage 1 search has been used. Note that, for client confidentiality reasons, this is a fictitious site based on an amalgamation of real data sources.

Devon solar park has space available and planning permission for 15MW of solar generation. A grid connection for 10MW, consisting of 2km of 33kV buried cable to a primary substation, is available for £1.1 million. However, to obtain grid capacity of 15MW, upgrades to the DNO’s 132/33kV transformers would be required, with £1.3million in costs attributed to the generator, i.e. a total grid connection cost of £2.4million. These scenarios are shown in Table III.

The site is in the south west of England. It falls in the South West TNUoS network charging zone, so can receive £43/kW if exporting during the three yearly Triad periods. It has been assumed to receive a super-red credit of 2.5p/kWh, which is a typical value for this region.

3) Modelling Assumptions

It has been assumed that there are no onsite loads in this instance. The site is assumed to sell its electricity at the index price, and is assumed to be subsidy free.

Projected costs for PV in the year 2020 have been used for this analysis. Current electricity prices have been assumed, however this may be pessimistic, prices may rise in the future.

The solar profile used was taken from the Smart Grids Forum Workstream 3 report [4]. Winter average and summer average half-hourly profiles were scaled to provide daily profiles. It is recognised that the use of average profiles is a limitation to the results presented in this paper, and further work could consider a detailed analysis of a year’s data including the hour-by-hour effect of cloud cover.

The batteries used in the model have been assumed to be lithium-ion. Further analysis could consider other promising technologies, such as sodium-sulphur, which are most efficient for high energy lower power applications.

4) Results

Table III shows the internal rate of return for Devon Solar Park with no co-located energy storage. Two sceanarios are presented:

1. In scenario 1, a 15MW connection has been chosen, leading to expensive reinforcement on the network (a transformer replacement) at a cost of £1.3 million. This reduces the viability of the project with an IRR of 6.6%;
2. In scenario 2, the export capacity has been reduced so as to not trigger the upstream reinforcement. This removes the reinforcement cost, such that the reduction in IRR is not so significant. However, around 7% of the produced energy is ‘spilled’ due to this export constraint. This results in an IRR of 7.0%.

It is noted that the results presented do not assume any future increases in energy prices. Therefore, the actual returns for these projects are low.

A battery could be used to recover this spilled energy. For example, a 5 MW, 10 MWh battery captures 54% of the spilled energy. The modelled battery can also earn revenue from other streams – it can perform simple arbitrage to export at higher price times, and can export in triad periods and periods of super-red credits.

However, battery prices are currently too high for this to be viable. With today’s battery costs, the addition of the battery causes the IRR of the project to fall to 4.2%.

TABLE III. GRID CONNECTION SCENARIOS FOR DEVON SOLAR PARK

Scenario	PV capacity (MW)	Grid Capacity (MW)	Grid Cost	IRR at 25 years	Exported Energy (MWh)	Spilled Energy (MWh)
Upstream reinforcements triggered	15	15	£ 2,400,000	6.62%	23692	0
Reduced Capacity to avoid reinforcement	15	10	£ 1,100,000	7.02%	21964	1730

TABLE IV. INTERNAL RATE OF RETURN AT 25 YEARS FOR VARIOUS BATTERY SIZES – FOR ESTIMATED BATTERY COSTS IN 5 YEARS TIME

	C factor		
MW Capacity	**1**	**0.5**	**0.25**
3MW	***3MWh***	***6MWh***	***12MWh***
	6.910%	7.093%	6.928%
5MW	***5MWh***	***10MWh***	***20MWh***
	6.809%	7.090%	6.778%
10MW	***10MWh***	***20MWh***	***40MWh***
	6.387%	6.651%	5.921%

We explored the impact of a decrease in battery costs. We tested in what year a battery would become worthwhile, if battery costs are assumed to continue falling at 17% per year, as current trends. In five years time with such cost reductions, a 5 MW, 10 MWh battery would increase the project's IRR to 7.1%. This IRR represents an improvement on the constrained solar park and on the solar park with paying for grid reinforcements.

Tables IV shows the IRRs by different MWh sizes and MW capacities of battery, all assuming battery prices in 5 years time with a cost reduction of 17% per year.. These are all based on a scenario with a 10MW grid connection and 15MW peak PV capacity installed, i.e. the third scenario in Table III. A range of c factors (i.e. ratios of MW to MWh) were explored.

The best IRR is for a 3 MW/6 MWh battery. The main sources of revenue for this battery are:

- Increasing the average value of energy exports by performing arbitrage between periods of low and high prices;
- Additional revenue from use of system charges due to triad avoidance and super-red credits;
- Mitigating the impact which the export constraint has on yield by capturing spilled energy.

5) *Conclusions*

The results presented here show that under certain conditions, battery storage may increase the viability of solar projects. This is particularly the case when a grid constraint limits the export capacity of the site. However this is likely to only work when battery prices have fallen considerably from their current levels.

For the site considered, in 5 years we would expect a battery to become a viable option. However, the viability of battery co-location and the optimal battery size will depend heavily on the specific features of the project, including network charging zones and the amount of MWh lost to grid constraints. Projects benefit where batteries can target multiple revenue streams, however this is not technically or contractually feasible in every case. Therefore a detailed assessment should be undertaken at the feasibility stage of the project.

The priority of revenue streams was chosen in each case and assessed to produce the optimum IRR. Capture of spilled energy is therefore not the main revenue stream in some cases. We would recommend that the battery's actions prioritisation of signals, and arbitrage strategy, should be considered in detail, as this can have a significant effect on IRR.

As shown, the increase in IRR for the battery is relatively modest. However, this is only based on existing sources of revenue and in practice a battery will be capable of performing much higher value services than those which have been captured in the model. This could include:

- Provision of dynamic or steady state reactive power, which could be achieved by over sizing the battery inverters;
- Provision of frequency response, which may be possible to provide while still capturing spilled energy and responding to price and network charge signals;
- Provision of local constraint management services to DSOs, including peak shaving and voltage control.

We expect that these services could potentially be provided from a co-located battery with only minor increases in capital cost for the project. These would further improve the business case for co-locating a battery with a solar PV project.

III. BARRIERS TO ELECTRICITY STORAGE AND RECOMMNDATIONS

A. *Barriers*

Three main barriers were identified during the assessment:

1. Cost of Batteries;
2. Limited Revenue Streams (at present);
3. Regulatory uncertainty.

Firstly, the costs of lithium-ion batteries are significant. A large portion of the cost scales with the energy storage (MWh) capacity. The revenue streams currently available tend to be energy intensive over a period of hours and therefore need a high installed MWh capacity resulting in a high capital cost. The results presented in this paper highlight that the viability of co-located storage is on a tipping point at present and that in a short number of years, co-located storage and solar sites could be financially viable, assuming a cost reduction of -17% per year [1].

Secondly, the model currently only considers a limited number of revenue streams. Ancillary services, at present cannot be easily "stacked" (where a single unit provides multiple ancillary services based on a priority order). The model used in this assessment accesses revenue streams from charge avoidance and optimisation of the grid connection only, but if ancillary service provision was widened to include services to Distribution System Operators (DSOs) and contracts were to allow service stacking, it would be possible to add significantly to the revenue streams and therefore improve the IRR of the combined PV + Storage System.

Thirdly, there remains uncertainty regarding the definition and treatment of storage by energy policy, network codes and even tax legislation. This poses a risk to developers seeking project finance in particular; however the 200MW of commercial storage to be built over the next 18 months under the new EFR contracts may force a precedent in many of these areas.

National Grid has already established a working group to identify and draft necessary code changes to accommodate storage plant [5].

B. Recommendations regarding charging and revenue streams

In the future, new revenue streams must be developed to fully realise the value of storage, for example in deferring distribution network reinforcement. It is important that revenue streams are designed such that they can be stacked, to ensure cost-effective provision of services. It should be noted that, as battery storage is a high capex low opex investment, longer contract periods will enable lower cost procurement of services.

The application of network charging for storage should be clarified. In general, to correctly incentivise investment in flexible energy sources such as batteries, network charging structures should be made transparent and predictable.

As discussed in Section II A, it is important to design charging regimes that reflect the benefits that storage brings to the networks, but not to overincentive flexibility and thereby load sunk and fixed costs of the network onto vulnerable users. Electricity storage has the capability to truly reduce the costs faced by network companies, and therefore we believe that a revenue stream from this will continue to exist in some form. However, the details of the charges/ credits, and possibly the mechanism (e.g. charges & credit vs. contracts for services), are likely to evolve as flexible distributed energy resources and electricity storage become more widespread.

C. Recommendations for planning legislation and policy makers

At present UK planning policy (and indeed International and European legislation) contains very little support or guidance in relation to electricity storage. International, European and national policy drivers focus on how the UK can deliver secure, clean and affordable electricity to consumers. Electricity storage can play a crucial role in achieving this. Moving forward, the planning system has an important role to play in meeting these commitments by understanding the local potential for electricity storage, renewable and low carbon technologies, identifying suitable locations to support infrastructure and setting standards for delivering these types of new development. Historically, users of the UK electricity system have been classed as generators, consumers or interconnectors. However as Electricity storage is a separate type of user (it does not generate or consume electricity, but imports it, stores it for a period of time, then exports it); this means that storage operates differently from typical generators, consumers and interconnectors. There is therefore a general lack of understanding when applying for planning consent or discussing with planning authorities about the specific technology type. This is a new technology with projects being initiated at a fast pace across the UK; it is vital that policy (at international, national and the local scale) is updated to include guidance on electricity storage to help enable this unique technology to be physically developed.

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