GREENBYTE

THE BATTERY BONUS:

USING STORAGE TO BOOST RETURNS

An investigation about how best to calculate financial returns from a battery storage system attached to a renewable energy plant.

Summary

This document features a hypothetical case study of the potential impact of adding a battery to an existing 500MW renewable energy plant. We have simulated a day of operation using real data from the plant and a modelled battery. This simulation is specifically focused on the UK market.

We demonstrate that significant returns can be achieved at a wide range of investment levels, corresponding to different battery capacities. At an investment level of around US $96m, resulting in a battery capacity of 100MWh, levelised net return (subtracting capital and operating costs) is estimated at US $30,000/day, or approximately $11m/year.

Introduction

Grid-scale storage remains an expensive and uncommon addition to a renewable energy project. But the tide is turning at the start of the 2020s.

Installed grid-scale storage capacity is reaching several gigawatts and rising globally. Exponential declines in the cost of lithium-ion batteries continue. The UK is set for a storage explosion and is preparing to accommodate the data that flows from it in Greenbyte.

The question is not whether IPPs, utilities and investors will expand into storage. The questions are when and how. When will I be able to get a return on an investment in storage, and how can I do that? The answers are: now, and read on.

Our research approach

This e-book focuses on lithium-ion batteries, but the approach that it pursues can be generalised to any form of grid-scale storage.

An excellent analysis published by Lazard in 2019, called **'Levelized Cost of Storage Analysis'** has already demonstrated the potential return on batteries attached directly to the grid. It calculated the levelised cost of storage per MWh.

This measure assumes an operational lifespan and usage profile, then calculates the total capital and operational costs, and divides by the total electricity delivered (discharged) by the battery over its lifetime.

The Lazard study modelled an independent battery owner, in various markets, buying and selling battery power directly to the grid.

It assumed that the battery was used to provide frequency stabilisation and peak power and showed that it was possible to generate very respectable returns. The Lazard study assumed that the battery owner purchased electricity from grid.

In contrast, our study considers a battery attached to a renewable energy plant that is subject to regular grid curtailment.

We consider a curtailment that occurs when the plant is producing more power than the grid can consume. Under the agreement with the transmission system operator the plant reduces production, leaving the wind, solar or other energy unharnessed.

We assume that some portion of this energy can be captured and used to charge the battery. As a result, the battery captures energy that would otherwise be lost, and is therefore free, ignoring marginally increased operational costs.

Finally, we must also note here that there are other reasons why production could be curtailed at a wind farm, such as a technology problem or human error. In this study, however, we focused purely on the impact of curtailment that is being forced on the power plant operator by the TSO due to high levels of electricity production.

How we work out the available charging power

Our study starts by selecting a renewable energy plant with regular curtailments from the Greenbyte portfolio. In this case we have chosen a wind farm, but a solar farm would have been equally appropriate.

For this plant we first estimate the total possible electricity production – the total ‘potential power’ – as follows:

We use the wind-speed data for each turbine, along with a model of how the turbine output varies with wind speed (a power curve) to work out the potential power for that turbine. That is, we calculate the power that each turbine could produce if it was not being curtailed.

We then subtract the actual power produced by each turbine to calculate the lost production: the energy that is being lost each second due to the grid curtailment.

We aggregate this across the site and then re-label the total lost production as the ‘available charging power’. Thus, the available charging power is the power that could have been generated but was not, owing to curtailment restrictions.

The battery model

Using the available charging power from the real wind farm, we then simulate the charging and discharging of a virtual battery.

For this study we used a simple model of a battery that specified a minimum and maximum charge, and a charge/discharge rate that would fill or deplete the battery within one hour.

The charge and the discharge rate would, in practice be set by both the chemistry of the battery and the size of the AC-DC inverter (which converts between the AC power of the wind turbines and the grid, and the DC power of the battery).

Simulation: A day at the wind farm

We modelled a whole range of battery capacities attached to the wind farm, for a single day of operation.

On the day we studied, there was curtailment from midnight until early morning, and none for the rest of the day. This is typical given the normal load pattern of the grid.

This means that the battery will charge during the period of grid curtailment in the night when the wind farm cannot export to the grid, and discharges in the day when the wind farm is exporting power and the battery smoothes fluctuating production.

We started with the battery at its minimum charge level.

While there is available charging power, the battery rapidly reaches its maximum charge level because it is a large wind farm – c.500MW headline capacity – and there is a lot of available power compared to the size of the battery.

The battery then stays at maximum charge until the curtailment is lifted. Then the battery starts to discharge its power, delivering its stored power to the grid until it reaches its minimum level.

The final reading in our simulation was 68.33MWh, which was the total power delivered by the battery during this hypothetical day. In other words, this is the total power that would otherwise have been lost owing to curtailment.

Size of the 'battery bonus'

The size of the 'battery bonus' for renewables project operators mainly depends on the size of the battery. This is because the window for charging the battery is small, but the available charging power in this window is large.

Figure 2 displays the size of the extra energy delivered compared with the capacity of the battery (assuming the inverter size scales with the battery capacity).

The battery energy bonus increases in proportion to the size of the battery, up until the point where all of the available charging power is consumed, which is where the curve flattens out. However, at this point the hypothetical battery is now the size of a nuclear power plant. In the next section, we consider realistic battery capacities only.

The grey region in Figure 2 indicates batteries that are larger than the biggest batteries in the world today and therefore excluded from our analysis.

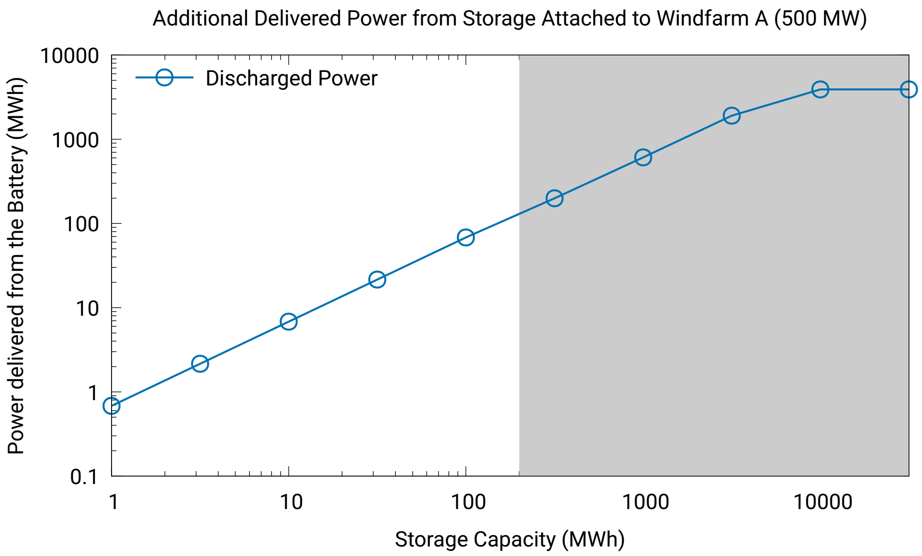
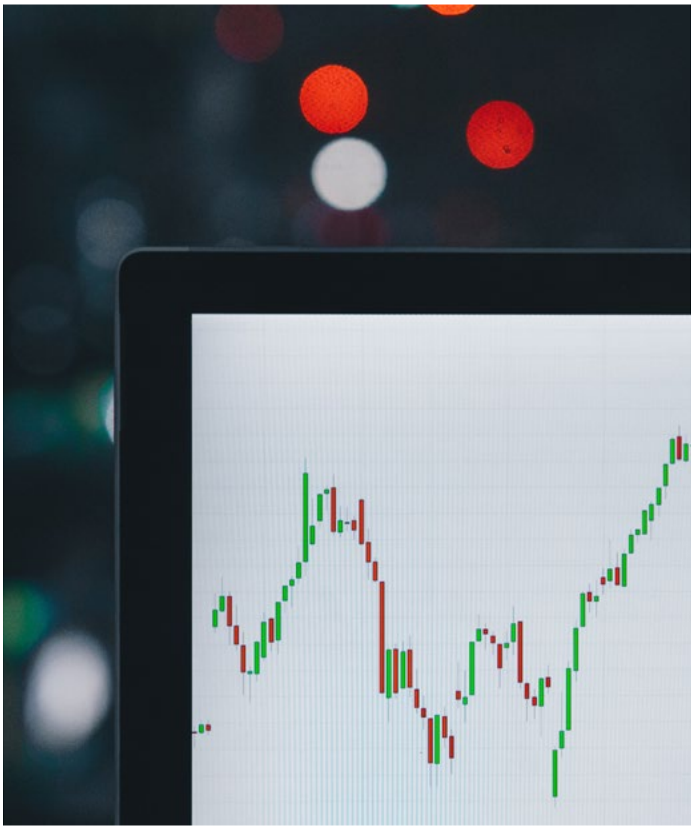


Figure 2: The 'battery bonus'. The amount of additional energy delivered per day from the renewable energy plant, as a function of the battery capacity. The grey region indicates batteries larger than the largest battery in the world today.

Estimating the financial returns

Using the data published by Lazard we can now estimate the possible returns from the battery. Since this is a UK wind farm, we use the UK data from the Lazard study.

We consider three revenue streams identified by Lazard.



The first is frequency stabilisation, which we call 'balancing' here. The other two are forms of peak power provision, consisting of both resource adequacy and energy arbitrage: we call these 'operating reserve provision'.

This study focuses specifically on the UK market, where frequency stabilisation and peak power provision will be the two main options for battery operators through the lifetime of the project. Operators cannot currently qualify for government support in the UK for both services simultaneously, and so we would expect operators to seek to use different support mechanisms at different times in the project lifespan.

Balancing the revenue streams

Over the 20-year lifespan of the battery, it is assumed that it will be in service for four years for frequency stabilisation, and 16 years for peak power. This is because only relatively new batteries are suitable for frequency stabilisation. This 20-year lifespan could be conservative given that 25-30 year lifespans are now expected for wind and solar farms, although this is an emerging area of research as technology evolves.

We carry out a levelised analysis: taking the battery energy bonus for each battery size, and then multiplying by the levelised net return per MWh.

$$Netreturn = batterybonus \times \left(\frac{4}{20} \times FSR + \frac{16}{20} \times PPR - LCOS\right),$$

In this equation, FSR is the average return on frequency stabilisation per MWh, and PPR is average return of peak power per MWh.

The results are displayed in Figure 3 and are quite encouraging. Taking the capacity we looked at earlier of 100MWh, or roughly the size of the Hornsdale Power Reserve in Australia, we see that the net return (including cost of capital) is US $30,000/day, or roughly $11m/year.

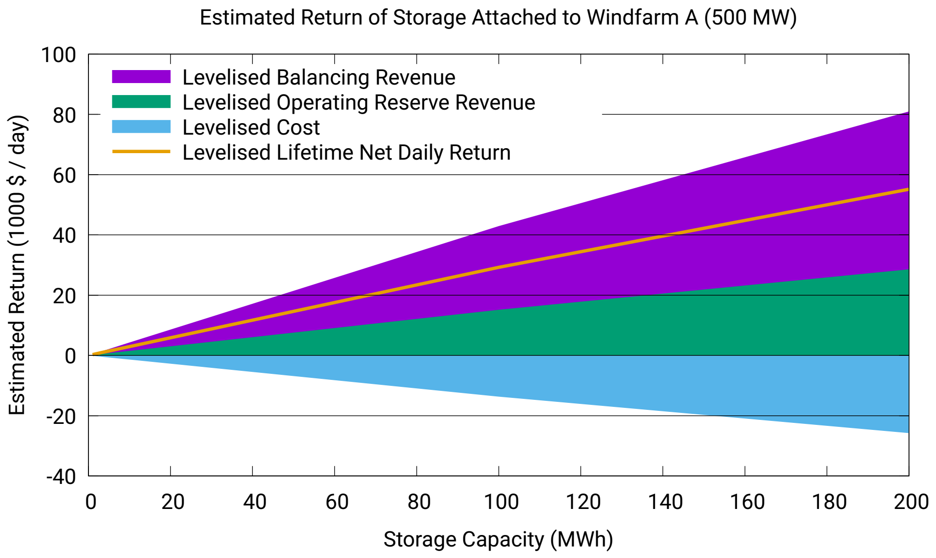


Figure 3: Estimated net return (revenue from balancing and operating reserve revenue less operational and capital costs) as a function of a battery capacity, in US $1000/day.

Analysis and discussion

The results we have presented tally with the success of projects like the Hornsdale Power Reserve, and demonstrate that the time has already come where investments in storage can deliver significant net returns.

One key benefit of having the battery 'behind the meter' – in other words, directly attached to the wind farm – is that the energy captured is effectively free.

In future, in areas where storage becomes widely adopted, it may be that the spot price of energy causes energy generation to adjust automatically and renders grid curtailments unnecessary.

However, at present, renewable energy power providers who are early adopters of storage will be able to steal a march on their competitors, by being able to sell power predictably, and provide key services to the grid.

This study had some simplifications. For example, we did not consider the efficiency of the inverter, but this would have had no effect. This is because, at reasonable battery capacities, the effective charging rate of the battery was always significantly less than the available charging power.

Equally, the chemistry of the battery would affect the allowed charge/discharge rate and cause it to change as the state of charge changed. We assume that in a real case the capacity of the inverter would always be less than that rate (except at very high/low states of charge), and our constant charge/discharge rate is a good model.

As we have discussed, we do not anticipate a more complex model changing the clear result of this study: the conclusion that renewable energy asset owners should be able to improve significantly their returns through an upfront capital investment in battery storage. Owners and others should watch this space – and, if you’d like to find out how we can support you with Greenbyte, please contact us.

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