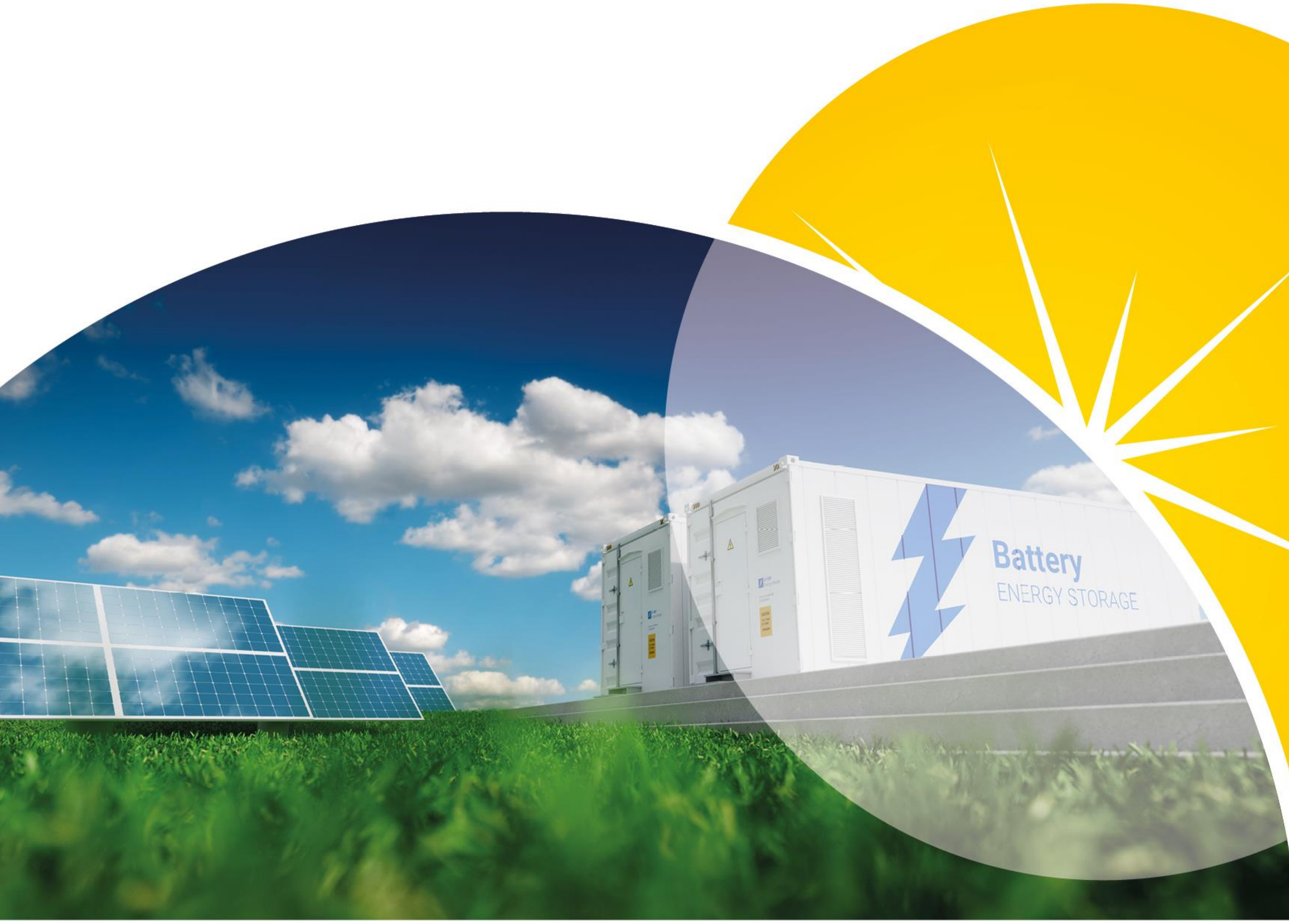
The economics of merchant solar co-located with battery storage systems



Preface

The role of battery storage systems in Great Britain's electricity system has been the subject of renewed focus following the power outages that caused widespread disruption on 9th August 2019.

Ongoing trends in the development of the system mean that the proportion of non-synchronous generation (primarily wind, solar and interconnector imports) is increasing. This tends to reduce the inertia of the system, i.e. its resistance to a change in frequency. Low system inertia can be a contributing factor towards power outages, amplifying the effects if power plants trip.

Low system inertia can be managed if there is enough flexible capacity able to provide 'synthetic inertia' and fast response to a change in frequency. Among the possible sources of flexible capacity, batteries stand out because of their especially quick response times, which are typically a fraction of a second.

As National Grid seeks to achieve its stated intention of being able to operate a zero carbon system by 2025 (with ever higher levels of non-synchronous wind and solar), it is likely to need to increase its procurement of flexible capacity such as batteries.

This report does not focus on power outages or inertia, but looks more broadly at the economics of solar systems co-located with battery storage. However, we note that the economics we set out here could be further improved by a decision by National Grid to increase its procurement of flexible capacity, which could imply higher ancillary services revenues for batteries.

Contents

1. Executive summary

Co-location of solar and battery systems can reduce investment risk and accelerate subsidy-free deployment. In this report we examine the opportunity for investment in co-located solar and battery systems (also called "hybrid systems") in Great Britain (GB). We find that subsidy-free hybrid systems are quickly becoming an investable opportunity for equity investors and asset finance lenders.

- Subsidy-free solar has an important role to play in the decarbonisation of the GB energy system. Rapid reductions in the costs of solar technology mean that "merchant" projects, with exposure to power market prices, could soon be widely deployed.
- The pace and scale of deployment will depend on the level of investor confidence, which affects the cost of capital for new projects. This can be improved by helping investors mitigate the market risks associated with merchant solar, especially the risk of price cannibalisation.
- Co-location of new solar assets with battery storage systems can unlock additional revenue streams and reduce the risks of merchant business models. Additionally, the maturity of battery technology and business models compared to alternative flexible technologies reduces market risks.
- The return on investment for different hybrid projects depends on the configuration and relative sizing of the solar and battery elements, as well as the battery duration. We find project internal rates of return (IRRs) of between 6.6% and 7.6% for hybrid assets deployed in 2020 in our base case market scenario, compared with 4.0% for standalone solar and battery assets. Projects will be attractive for investors willing to apply a discount rate below the IRR.
- To be confident to invest in hybrid systems, investors need to understand the impact of various risks on hybrid asset revenues. The IRR for the optimal system configuration with a 1-hour battery may vary by ±2.8pp across a range of alternative market scenarios, so investors will show different levels of readiness to invest depending on their views of the likelihood of these scenarios.

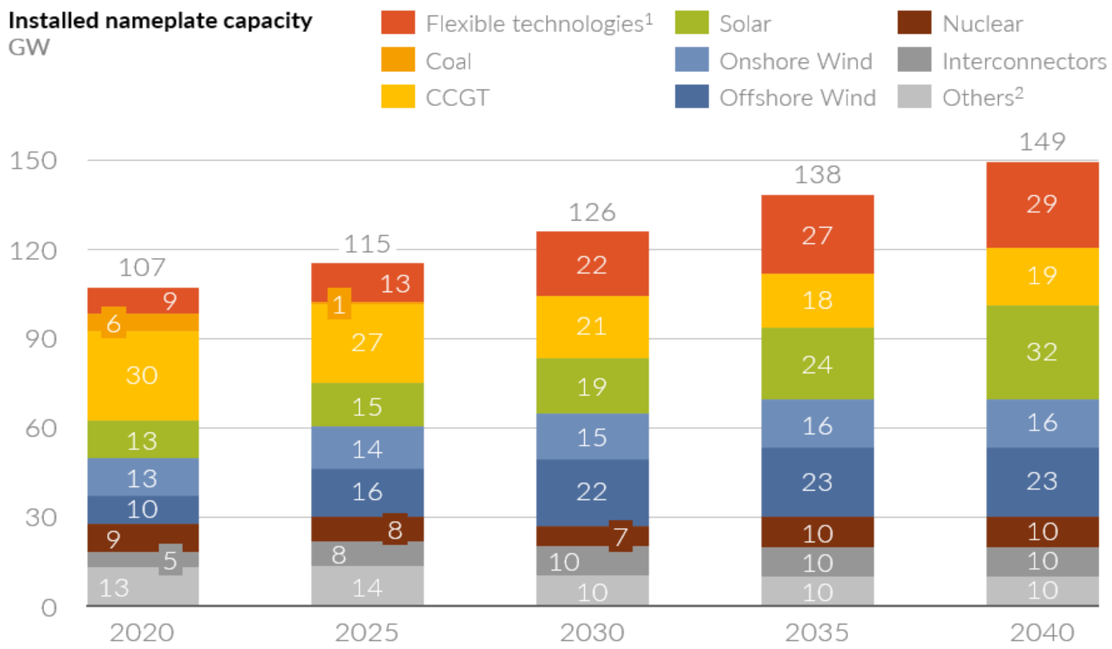
- Debt leverage can increase the returns for equity owners. Given the level and volatility of forecasted revenues, projects could be able to achieve debt leverage of c. 35%, which can effectively increase equity IRR by 0.3pp.
- Although regulatory and network barriers have limited deployment of co-located assets in the past, changes to regulation are resolving key issues. For example, the removal of Final Consumption Levies by Ofgem is reducing costs for batteries, while National Grid's work on wider access to the balancing mechanism is improving revenue prospects for smaller projects.

2. The economics of merchant solar

Market and policy uncertainty in the short-term have challenged investor confidence in the deployment of merchant solar, but mid- to long-term opportunities remain strong.

Great Britain is experiencing significant changes to its electricity generation mix. The policy commitment to phase-out coal by 2025 and the recent reductions in expected nuclear deployment are opening up opportunities for additional baseload gas and renewable capacity. Higher penetration of intermittent wind and solar generation is displacing baseload capacity and increasing price volatility in the energy market. It is also increasing the need for flexible assets, including gas peaking, Demand-Side Response (DSR) and battery storage technologies, which benefit from the rising price of volatility. We show Aurora's projected generation mix for GB in Exhibit 1.

Exhibit 1: GB capacity mix forecast



Notes: 1) Batteries, DSR, Recips and OCGT 2) Biomass, CHP, Pumped Hydro and others

The UK's commitment to a carbon intensity target of 100gCO_2/kWh by 2030[1] has been a major driver of changes in the system to date, and will continue to shape policy in the years ahead: growth of capacity both for renewables and the flexible technologies needed to balance their intermittency are likely to continue.

Rapid falls in the costs of renewable technology, especially for solar, have raised the prospect of widespread deployment of merchant renewables without subsidy. The pace and scale of this deployment will depend on the expected returns of these projects, and the risk appetite of investors.

The perceived level of risk in subsidy-free solar PV investment is reflected in the required Internal Rate of Return (IRR). Based on discussion with industry stakeholders and Aurora's subscriber base, we estimate the range of required IRR from merchant solar projects is between 9% and 12%[2]. The IRR for an average new project has been rising, mainly due to the reduction in capital expenditure (CAPEX) for solar projects. In Aurora's base-case scenario it will take until late 2024 to exceed 9%, although sites with advantageous solar resource and grid connection infrastructure will be able to enter earlier than the average.

Could merchant solar projects enter the market even sooner? Higher cash-flow certainty through long-term Power-Purchase Agreements (PPA) would increase confidence among stakeholders, and reduce the cost of capital. In addition, continued technological innovation may accelerate reductions in cost and increases in generation output (due to better load factors), which will have a direct impact on asset returns. If everything else is kept equal, reduction of the required IRR by 1pp or 10% lower CAPEX trajectory could make economic deployment of merchant solar feasible by 2022.

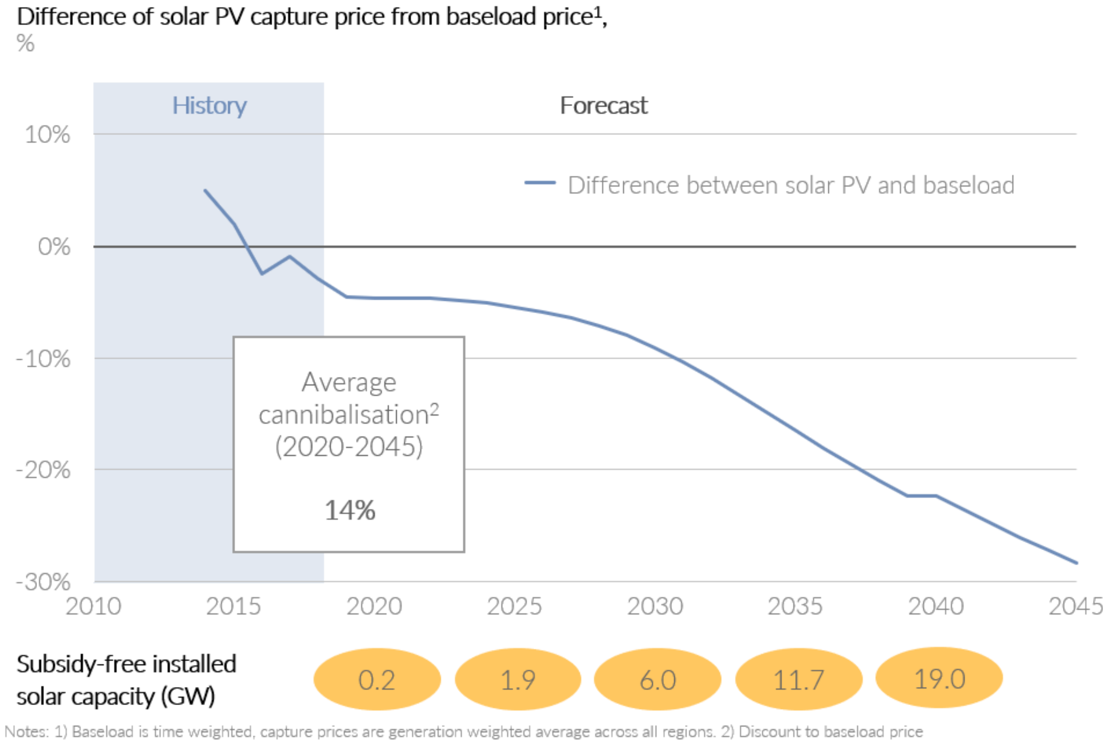
To achieve faster deployment, one challenge solar projects will need to overcome is the risk of cannibalisation, where high deployment of solar capacity leads to reduced captured prices for all solar assets, due to correlation in generation patterns. We expect this to drive solar capture prices to a 14% discount on average baseload prices for the 2020-2045 period (see Exhibit 2). Finding a way for investors to mitigate this risk could have a major positive impact on investor confidence and the rate of solar deployment. Co-location with batteries could provide this kind of mitigation, as we discuss in the next section.

---

[1] https://www.gov.uk/guidance/carbon-budgets

[2] Pre-tax, real and unlevered.

Exhibit 2: Discount of solar capture prices to baseload



3. Co-location of solar and batteries

> Co-location of solar and battery systems can help hedge risks and may offer additional value compared with standalone assets.

Battery storage is a rapidly growing energy technology class that has promising future prospects. Price volatility in the power system due to penetration of intermittent renewable capacity drives the opportunity for energy arbitrage business models. Increasing demand for ancillary system services offers additional upside, especially given battery systems' fast response rate.

Like merchant solar, battery storage assets are subject to market risks. Low price volatility caused by higher penetration of flexible technologies, smart-charging electric vehicles and DSR may result in reduced price spreads and margins for batteries.

Investment in a portfolio of assets can help mitigate risks for both solar and batteries. Storage technology offers a hedge against solar price cannibalisation, while solar revenues benefit from low price volatility.

In addition to these portfolio benefits, co-location of new solar assets with battery storage may unlock further savings and revenue streams:

- Co-location of assets may lead to up to 50% reduction of the battery's Balance of System (BoS) costs (due to shared foundations, access roads etc.), fixed costs (operation and maintenance, land lease, business rates, etc.) and network costs due to the use of a shared grid connection point
- Battery storage can regulate short-term variability in the solar generation output and avoid balancing costs in cases when this output is different to the system's Final Physical Notification (FPN)
- Battery storage allows for the avoidance of energy spilling in cases where solar capacity is higher than the grid connection, which allows for oversized solar PV assets and more revenue from solar generation

In Exhibit 3 we summarise the key benefits of different configurations of standalone or co-located solar and battery storage assets.

The most promising sites for merchant hybrid solar and battery are already being developed today. In the next section we discuss how the configuration of a new asset can be optimised.

Exhibit 3 Portfolio and co-location benefits

Key
- Full benefits
- Partial benefits
- No benefit
- Negative impact

	Standalone	Retrofit	New build co-located
	Own and operate each asset separately and independently	Co-locating batteries with existing subsidy supported assets	Subsidy free assets co-located with new build batteries
Portfolio benefits	Full portfolio benefits	Full portfolio benefits	Full portfolio benefits
Cost savings		Partial cost savings, extent limited by existing design	Cost savings can be fully realised
Asset oversizing	Partially possible though cannot capture spilt power	Some subsidised assets have oversized solar to grid	Solar can be oversized and battery captures spilt power
Sub optimal dispatch	No sub-optimal dispatch of storage assets	Storage output restricted by RES asset generation	Storage output restricted by RES asset generation
Self balancing	FPNs[1] can be settled at a portfolio level	Self balancing possible	Self balancing possible

Notes: 1) Final Physical Notification

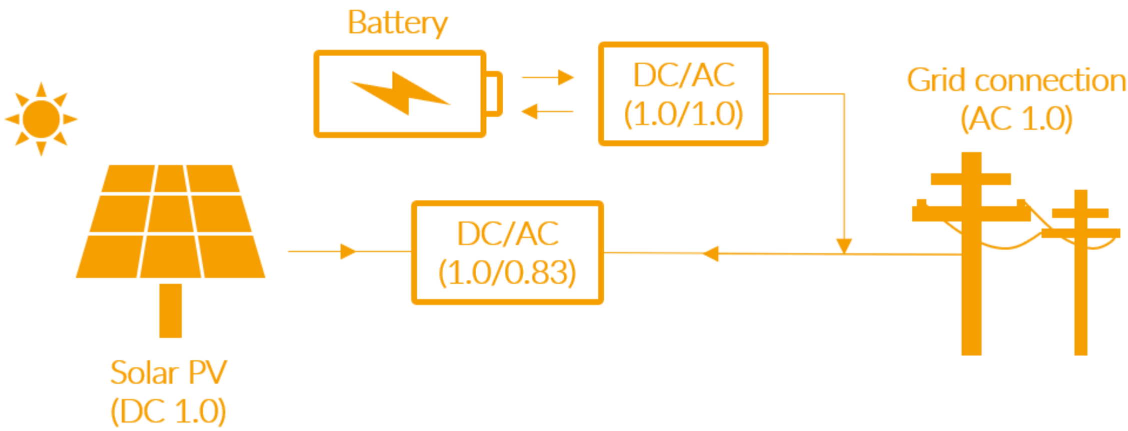
4. Optimal system configuration

> The optimal configuration of assets maximises the IRR of the total hybrid system and includes equal capacities for the DC solar and battery elements.
>
> In a base case market scenario, project IRR ranges from 6.6% to 7.6%, depending on the configuration and size of the different system elements.
>
> Investment in assets with advantageous technical characteristics and sophisticated trading strategies would be economic as soon as next year.

Given the potential of co-located solar and battery storage to increase investor confidence in subsidy-free projects, it is important to understand what the optimal configuration of the components is in such hybrid assets. Total returns of systems are highly dependent on the relative size of grid connection, solar and battery components.

In this section we assess the business case of different assets by looking at the range of cost and revenue streams, and their effect on the hybrid system's Net Present Value (NPV) and IRR. We assess the range of possibilities by modelling new solar plants co-located with 1-hour and 2-hour duration batteries, assuming an AC-connection configuration (see Exhibit 4). The optimal sizing of the system components is part of the underlying analysis.

Exhibit 4 Example of hybrid configuration considered in the analysis



Although we do not assume revenues from ancillary services here, we expect that these could provide additional revenue opportunities for hybrid assets in future.

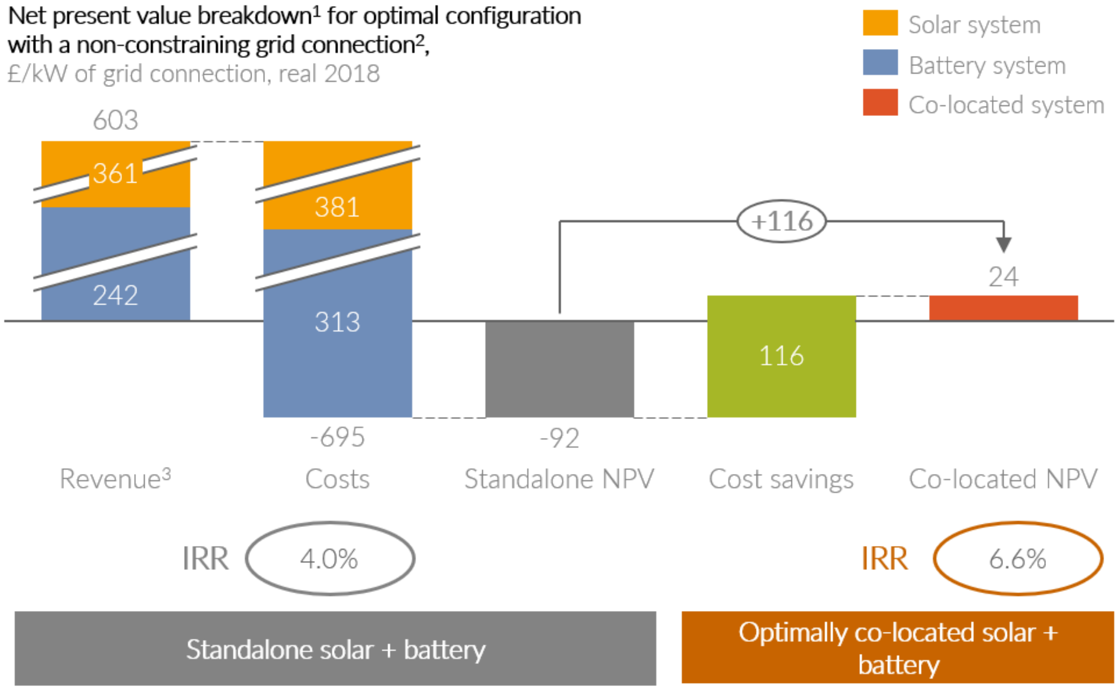
The replacement of baseload thermal capacity with renewable technologies will result in the loss of synchronous capacity and inertia in the system. Low inertia can contribute to power system outages such as the event on 9th August 2019, when there was widespread disruption across GB after two large generators tripped and there was insufficient backup capacity to stabilise the grid frequency.

Low system inertia can be managed if there is enough flexible capacity able to provide 'synthetic inertia' in the case of an outage. Providing enough flexibility in the long term as the system develops will require the development of new markets. Although the form of revenues from these markets is unclear, it is very likely they will provide an upside to fast-response technologies such as battery storage systems.

In Exhibit 5 we show the projected NPV breakdown of the optimal hybrid system under a base case market scenario. We assume grid connection capacity is not limited, and can be sized to accommodate maximum export to the grid from both solar and battery systems simultaneously. The waterfall chart illustrates the present value of standalone asset revenues and costs, and CAPEX and OPEX savings due to co-location ("cost savings"). Assuming a discount rate at 6% (pre-tax real), the NPV of this system is £24 per kW of grid capacity and reflects an IRR of 6.6%.

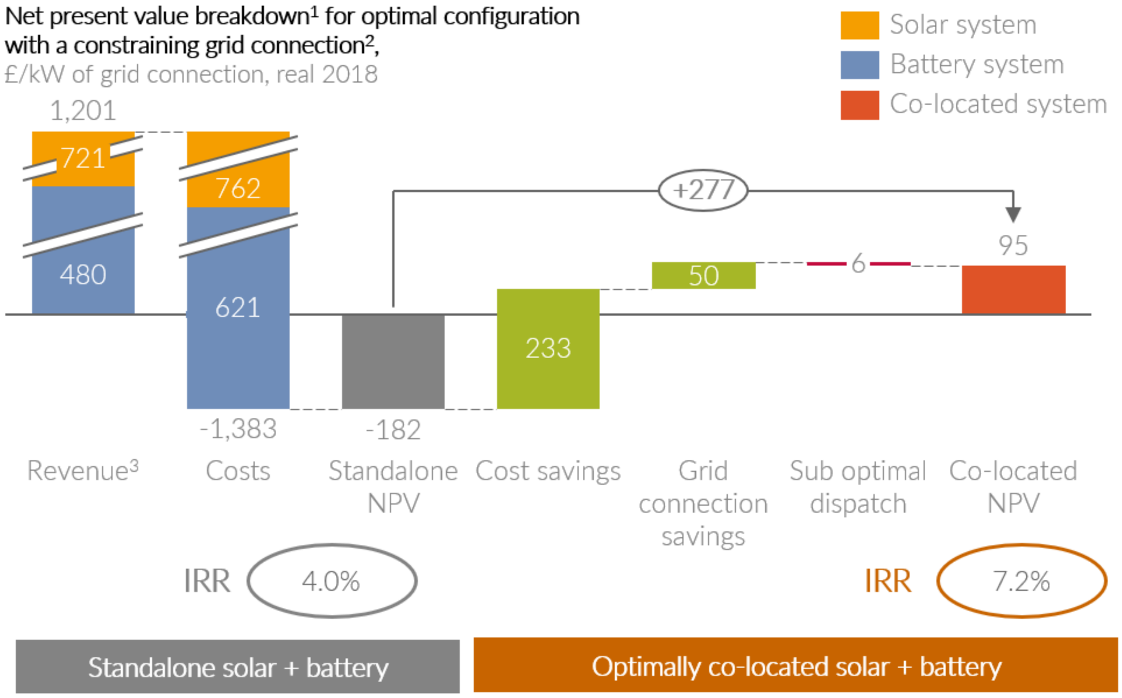
A different optimal configuration of hybrid systems can be achieved in cases where the total output of the solar and battery elements is higher that the available grid connection. This system benefits from the utilisation of a common grid connection point ("asset oversizing") but at the expense of suboptimal dispatch of the battery due to the limited grid connection capacity. The NPV of this configuration under a base case market scenario is £95 per kW of grid capacity and reflects an IRR of 7.2%. We show the NPV breakdown of the optimal 1-hour battery system in Exhibit 6.

Exhibit 5 Net present value breakdown for optimal configuration of a system with a non-constraining grid connection and a 1-hour battery



Notes: 1) Discounted at 6% pre-tax real, 2) Reflects a system with 0.5kW DC solar and 0.5kW battery capacity for each 1kW of grid capacity. Assuming 25 year lifetime, battery duration of 1-hour and refurbishment of battery cells after 8 and 16 years. 3) Includes wholesale, BM, CM and embedded benefits.

Exhibit 6 Net present value breakdown for optimal configuration of a system with a constraining grid connection and a 1-hour battery



Notes: 1) Discounted at 6% pre-tax real, 2) Reflects a system with 1kW DC solar and 1kW battery capacity for each 1kW of grid capacity. Assuming 25 year lifetime, battery duration of 1-hour and refurbishment of battery cells after 8 and 16 years. 3) Includes wholesale, BM, CM and embedded benefits.

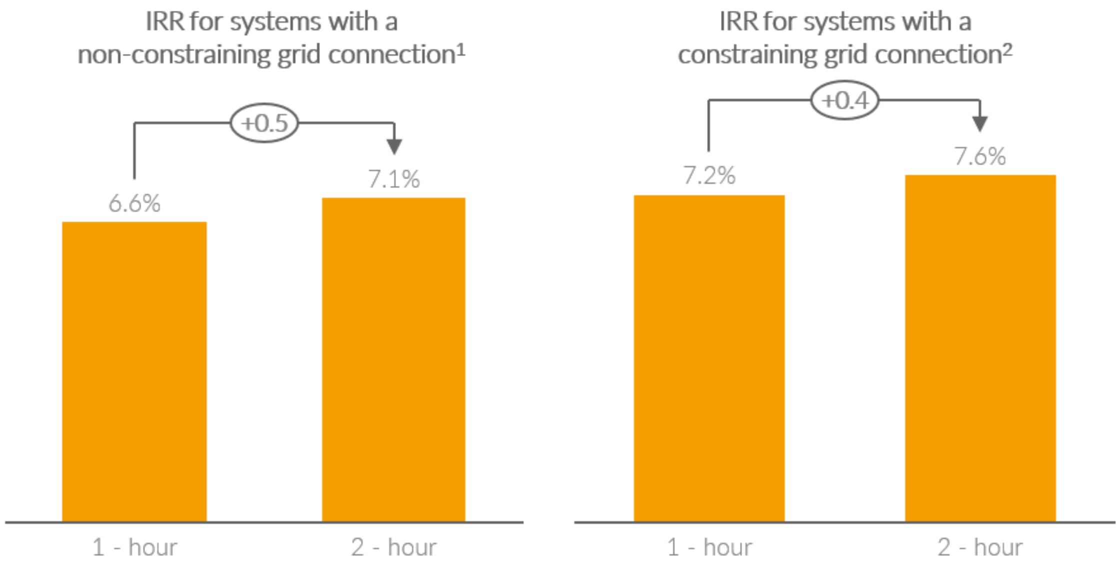
Figures in this analysis reflect model outputs for an average hybrid asset. We expect sites with higher solar resource, lower grid connection costs and more sophisticated trading strategies to be able to achieve even higher NPV and IRR outcomes.

For example, over the last few months, Anesco batteries have seen increasing participation in the balancing market (BM), leading to gross margins in that market of up to 27%[3] more than the modelled average. Assuming these higher margins can be sustained over the asset lifetime, a project would achieve IRR of up to 1pp higher than in our model, which would make certain assets a viable investment option for investors willing to accept an IRR of 8% as soon as 2020.

[3] Reflecting gross margins of the best Anesco asset, and maximum BM access of 16 hours per day.

In addition, co-located assets with battery systems of longer storage durations achieve higher IRR in 2020 by up to 0.5pp. We show the modelled IRR of the optimal 1-hour and 2-hour hybrid systems (for a base case market scenario) in Exhibit 7.

Exhibit 7 IRR for optimal configurations of different co-located systems



Notes: 1) Assumes a co-located system with 1kWp DC solar, 1kW of battery storage and a 1 kW grid connection. 2) Assumes a co-located system with 0.5kWp DC solar, 0.5kW of battery storage and a 1 kW grid connection.

5. Economics of co-location in different market scenarios

Commodity prices are the most important driver of the revenues of solar and battery assets.

The IRR of co-located assets with a non-constraining grid connection may vary by up to ±2.8pp across different scenarios.

To be confident in investing in co-located systems, investors need not just a view of the expected returns, but also an understanding of how the systems might perform in different market conditions. The level of investor confidence will affect the cost of capital for new projects and hence the rate of storage and renewables deployment and GB's prospects for meeting its decarbonisation targets. To the extent that faster deployment drives down costs, there is potential for a self-reinforcing cycle of buildout and cost improvement.

In this section we analyse the main hybrid-system configurations in a range of alternative scenarios.

Aurora regularly assesses the impact of various risks on hybrid asset revenues, including different commodity prices, nuclear buildout and subsidised renewable deployment trajectories. We consistently find that fuel and carbon prices have by far the largest impact on the value of both solar and battery projects.

We developed three alternative market scenarios by combining different price outcomes for gas, coal and carbon:

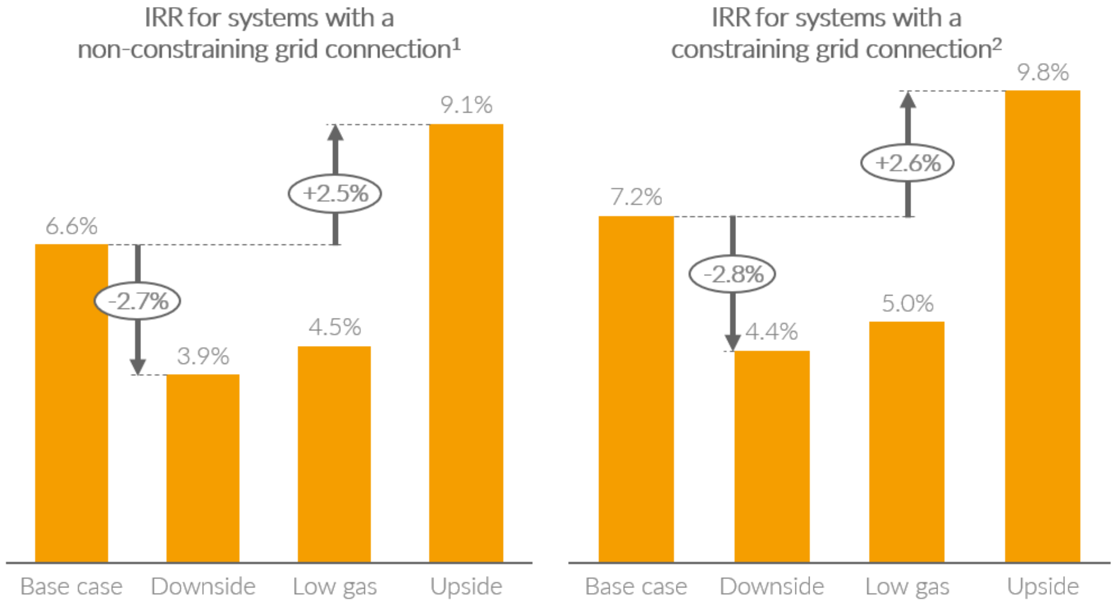
- The *Upside* scenario is based on plausible high gas, coal and carbon price outcomes.
- The *Low Gas* scenario uses the same coal and carbon prices as our central case, along with a moderately reduced gas price.
- The *Downside* scenario combines very low fuel and carbon price trajectories. This case reflects a low-probability and high-impact downside outcome for co-located solar and battery systems.

Table 1 summarises the average values for key input assumptions. We show the consequences of the different scenarios on the IRR of the example systems from the previous section in Exhibit 8.

Table 1: Key input assumptions across market scenarios (average 2020-45 values)

	Units	Base Case	Low gas	Upside	Downside
NBP gas price	€/MWh	27.3	16.3	39.6	16.3
ARA coal price	€/tonne	60.7	60.7	74.6	46.6
EUA carbon price	€/tonne	34.4	34.4	50.0	19.8

Exhibit 8 IRR for optimal system configurations in different market scenarios



Notes: 1) Assuming a co-located system with 1kWp DC solar, 1kW of battery storage (1-hour) and a 1 kW grid connection. 2) Assumes a co-located system with 0.5kWp DC solar, 0.5kW of battery storage (1-hour) and a 1 kW grid connection.

In practice, the Downside scenario is unlikely for two main reasons:

- The projected capacity mix in this scenario would result in an average grid carbon intensity of 102 gCO_2/kWh in 2040. GB will need to reduce emissions intensity to below 100gCO_2/kWh by 2030 to meet its 5th legally binding carbon budget[4]. The prospect of missing this target by a decade could accelerate policy interventions and wider system changes in support of renewables deployment, which would reduce the likelihood of the scenario.
- There is a negative correlation between coal and carbon prices. A potential fall in coal prices would lead to increased consumption of coal for power generation across Europe. This would result in increased demand for European Union Allowances (EUA), which is the tradable unit under the European Union Emissions Scheme (EU ETS); this would in turn increase carbon prices in GB.

Overall, we expect the likely actual market outcome will be closer to the base-case scenario, with a plausible range between the *Low gas* and *Upside* scenarios.

6. Considerations for lenders

> Debt leverage can increase equity IRR by 0.3pp in the system configuration with a non-constraining grid connection.

Investor confidence plays a crucial role in the development of co-located solar and battery projects. Therefore, it is important to understand the underlying factors that shape the risk profile of projected revenues, and in particular revenue volatility and the ability of projects to incur and repay debt.

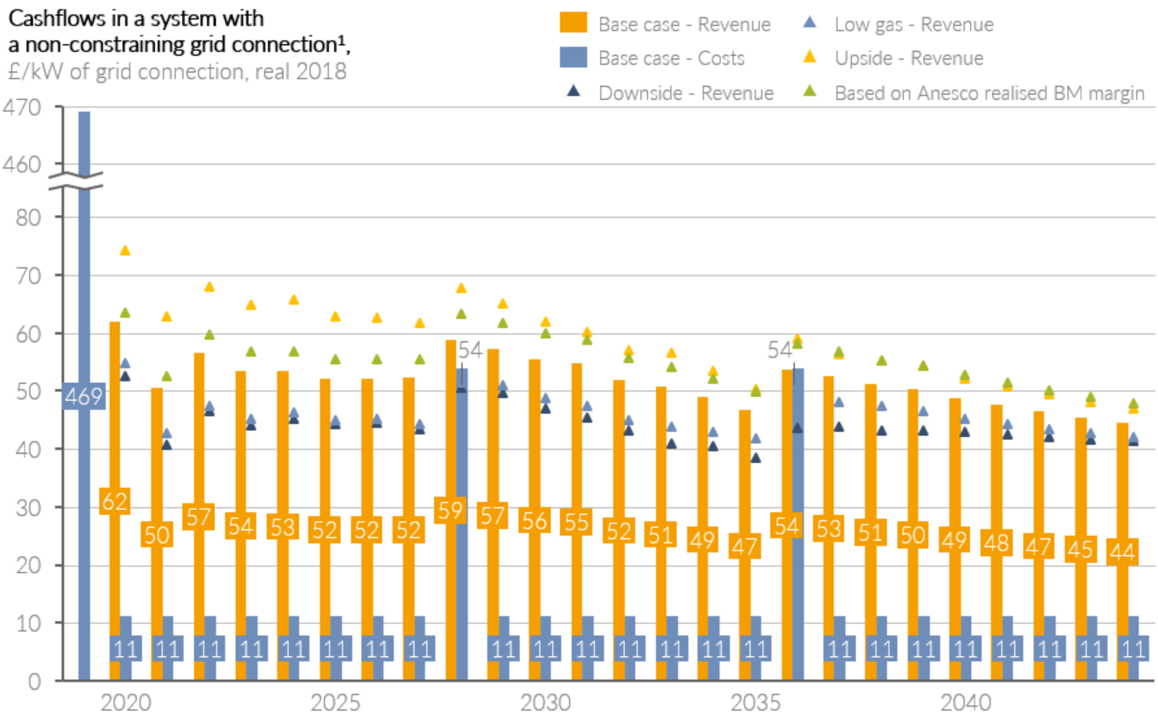
Overall, gross margins for the co-located system are driven by three factors:

[4] https://www.gov.uk/guidance/carbon-budgets

- Battery degradation results in decreasing storage capacity over time, and leads to the requirement for cell repowering after 8 and 16 years of operation.
- Increasing volatility in the system over the next decade drives the deployment of additional batteries and alternative flexible technologies. This in turn results in a plateau in energy arbitrage revenues after 2027.
- Solar revenues reach a peak in mid 2020s, and then follow a downward trend which is consistent with the increased solar penetration and price cannibalisation.

We show a breakdown of the projected cashflows in an example of a system configuration with a non-constraining grid connection in Exhibit 9.

Exhibit 9 Cashflow breakdown for optimal system with un-constrained grid connection



Notes: 1) Typical gross margins for a co-located system with 0.5kWp DC solar, 0.5kW of battery storage (1-hour) and a 1 kW grid connection. Assuming 600 cycles/year on average for the battery, linear degradation and cell repowering after 8 and 16 years of operation.

In this example, revenues are c. £54k per kW of grid capacity on average for the first 8 years of operation, which implies a fixed cost coverage ratio (FCCR) of 4.8. This ratio ranges from 4.1 in the *low gas* to 5.8 in the *upside* scenario.

Raising debt after the construction of a co-located solar and battery project can increase its equity IRR. Suppose a lender plans for the "Low Gas" scenario, implying an average net operating income of £35k/kW. Assuming a debt service coverage ratio (DSCR) of 1.5, the project will be able to raise up to £150k of debt in the first year of operation, at an assumed interest rate of 5% (pre-tax real) and an 8-year repayment period. The total achievable leverage in this example is 32% of the hybrid system's initial CAPEX. Given this amount of debt, the implied levered IRR for an equity investor planning for the base case scenario effectively increases from 6.6% to 6.9%.

7. Barriers and risks

> Previous regulatory and network barriers which have limited deployment of co-located assets in the past have now mostly been resolved.

Investment in co-located solar and battery storage systems is already profitable under certain circumstances, and CAPEX cost reductions will improve profitability over time. Although a number of barriers have restricted the business case for hybrid assets in the past, recent policy changes and initiatives from the system operator and regulator have alleviated many of these challenges.

- Battery systems have historically been liable to Final Consumption Levies (FCL) when charging from the grid, which reduced the returns from energy arbitrage. The introduction of modified generation licences was indicated by Ofgem in late 2018: these remove FCL for storage systems. Battery owners have increasingly been obtaining these licenses and so been exempt from the levies. Our modelling assumes that FCL will have been completely removed by the year of commissioning (2020).
- Currently, co-located projects with combined capacity over 50MW are treated as Nationally Significant Infrastructure Projects and must apply for State approval. BEIS[5] is creating a new threshold for hybrid projects, which

[5] Department for Business, Energy and Industrial Strategy

will mean that approval will be required only if an individual element is more than 50MW.

- Meanwhile, projects of less than 50MW have been unable to participate as individual assets in the balancing mechanism, which is an important source of revenue for batteries. However, battery owners have increasingly been gaining access to the balancing mechanism through aggregators. Additionally, National Grid's work on Wider Access to the balancing mechanism should resolve the issue when it goes live in Q4 2019. The system operator has shown ambition to achieve higher participation of smaller assets in the BM, which is reflected in the addition of the Distributed Resource Desk in its control room, and the increasing volumes of bids and offers being accepted over the last year. Our modelling assumes full participation of the projects in the balancing mechanism.
- The ongoing targeted Charging Review (TCR) is aiming to create a more level playing field among participants in GB energy markets. Among other changes, the proposed removal of Balancing Services Use of System (BSUoS) payments and charge exemptions for embedded generators will have a negative impact on co-located systems. Our modelling assumes only the removal of BSUoS payment, which reduces the IRR of hybrid systems entering in 2020 by approximately 0.8pp.
- Congestion of distribution networks poses a constraint on the deployment of new embedded solar systems. The Network Access consultation launched by Ofgem is considering time-profiled and other types of non-firm access that may allow more projects to access connections. The availability and cost of solar connections will depend on the DNO and local network conditions. This barrier to entry will provide a strong advantage to existing holders of grid connections, and funders aiming to leverage existing sites, as it enhances the total value of the asset and signposts a potential exit route if there is sufficient demand from new investors to obtain suitable sites.

We expect that as more of the barriers to co-located solar and storage projects are resolved, investor confidence will increase and deployment of these projects will accelerate.

8. For further information

The analysis in this report is based on Aurora's standard market forecast and set of assumptions. For a complete description of the input assumptions and other aspects of the market forecast not included here, please contact Aurora at sales@auroraer.com to obtain a copy of our latest GB Power Market Forecast report.

Aurora Energy Research Ltd.
2-3 Cambridge Terrace

Oxford OX1 1TP
United Kingdom
+44 (0)845 299 3569
evangelos.gazis@auroraer.com
auroraer.com