WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

SOLAR STORAGE

BALANCING AND SETTLEMENT BUSINESS IMPACT STUDY

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Contents

Glossary

Abbreviation	Term
ANM	Active Network Management
BESS	Battery Energy Storage System
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
B & S	Balancing and Settlement
BSC	The Balancing and Settlement Code
DG	Distributed Generation
DNO	Distribution Network Operator
DUoS	Distribution Use of System (Charges)
DSO	Distribution System Operator
TO	Transmission Owner
DSR	Demand Side Response
EBSCR	Electricity Balancing Significant Code Review
ESS	Energy Storage System
LIFO	Last In First Out
STOR	Short Term Operating Reserve
TSO	Transmission System Operator

1 Executive Summary

Electricity storage projects are trying to establish viable business cases within a regulatory framework that was not developed with storage in mind. The existing frameworks reflect the industry changes from 1998 onward to enable competition among market actors. Subsequent legislation and incentives have maintained the focus on competition, which has been successfully delivered, however the sector now faces new challenges resulting from the increased amount of renewable generation.

As well as providing other services, electrical energy storage can support a more sophisticated approach to operating the distribution network as an alternative to greater network investment. It is important to appraise whether the regulatory framework itself is limiting the deployment of storage or limiting the benefits derived from it.

Several issues exist within the legal and regulatory framework which affect the deployment and utilisation of distribution connected electricity storage within the GB market. For example, to prevent vertical integration from reducing competition, the framework prohibits DNOs from involvement in generation and supplying electricity.

The Poyry report that considered these issues in 2014 found that (Poyry, 2014)

1. Default treatment of storage as a subset of generation (on discharge) and load (when charging) creates uncertainty and raises potential issues. The exact nature of the issues will depend on who owns the asset. This is particularly of note when the distribution business is the asset owner due to the constraints of the Distribution Licence. A comparison of the issues arising for two defined ownership structures can be found in sections 5.1 and 5.2.
2. The generation licence exemption route does provide flexibility to progress distribution connected storage projects of appropriate size in a manner consistent with unbundling requirements.
3. De Minimis business restrictions do place a loose limit on deployment by Distribution Network Operators (DNOs), if storage continues to be classed as generation.
4. However, possible application and operation of assets is affected though by the need to ensure that competition in generation and supply is not distorted.

These regulatory issues have differing implications for different ownership models. They are of greater significance for the business models which entail DNO ownership and operation of the storage asset. This stems principally from the concern that DNO activity in storage projects could distort competition in generation and supply activities.

DNO led and owned development of smaller scale storage projects is therefore possible within the regulatory framework, but ensuring that such activity avoids distorting competition in generation and supply is a major factor which appears to block operation(though not ownership) of the assets by DNOs under the current framework. The regulatory framework does not prevent DNOs from procuring storage services from third parties, however third party owned storage may be less likely to be located at a site where it can provide a useful service to the DNO than DNO owned storage. For example, where storage is expected to provide services to National Grid that may be required at any time of day or year then developers are more likely to select a location where an unrestricted connection can be provided rather than where network constraints exist.

Whether the limited scale of DNO storage/ownership permitted would be a barrier to efficient network operation requires a full market analysis which is beyond the scope of this report. In broad terms, the UK demand level runs at an average of 34.42GW. Storage capacity of c. 1.6GW has been predicted by 2020 with 500MW relating to DNO and Grid Services. (Eunomia, 2016). The current level of storage capacity, stands at just 24MW, comprised of projects that would be considered exclusively as lighthouse or proof of concept in nature. Additionally, connection applications for hundreds of MW of storage have been received, indicating an expected change in capacity of several orders of magnitude. If DNOs are limited in their ability to own and operate storage there is a risk that the storage will be installed at locations that are not beneficial to DNOs, reducing the overall benefits from storage and increasing the requirement for network investment.

At present the trade-offs between the potential for extra income from DNO services and the possibility of reduced income from National Grid services are hard for storage providers to evaluate. DNOs may be unwilling to commit to long term contracts with storage operators rather than looking for shorter term options that involve storage as part of a wider market for flexibility services

There are a number of possible activities to promote DNO ownership and operation of storage in line with market requirements:

- Clarifying/modifying treatment of electricity storage within the framework, including classification and requirements for licences to operate;
- Enabling DNO operation of electricity storage assets for balancing or constraint management purposes in a transparent and non-distortionary manner, delivering consistency with unbundling requirements;
- Considering the potential for GB DNOs to trade in a non-speculative manner under a model similar to that under which National Grid fulfils its system operator role; and
- Including storage investments appropriately within price controls. This would need additional consideration. For instance, it could come in the form of an ‘investment allowance’ or equally it could provide the justification to reduce their overall investment after allowances have been set, thus funding the storage from these benefits.

Recommendations

DNOs have an opportunity to reduce the investment required to manage constraints via periodic and timely storage discharge and recharge.

In the short term DNOs should continue to deliver these practices up to a De Minimus of 2.5% of their revenue (approximately 15 projects per DNO licence). Beyond this De Minimus it is considered by the Regulator to be distortive to the market. The following are therefore recommended positions for consideration:

1. Apply for a change to the distribution licence condition that increases the 2.5% de Minimus cap (Section 6.1.1) on supply and generation activities to a suitable number based on an assessment of market demand for storage (DNOs to provide market forecast evidence).
2. To remove this value associated with this de Minimus so that this activity is unlimited in volume but critically is more heavily governed by a specific set of 'scenarios', a basis for which would be the usage cases in this project. The governance arrangements could include providing the DNO with the role of storage provider of last resort such where a positive business case could be demonstrated that could not be provided by the market. This would allow the market to flow unconstrained, with DNOs being able to participate fully, and also provide the protection against concerns of distortion of the supply and generation markets.
3. A combination of the measures in 1 and 2.

2 Scope

This analysis forms part of the Solar Storage project carried out by Western Power Distribution working with British Solar Renewables ltd. funded by the Network Innovation Allowance. The project involves commissioning and testing a Battery Energy Storage System (BESS) on a PV farm site so that the benefits to the solar farm user and DNO can be tested.

The high-level project objectives are as follows:

1. Design BESS, control algorithms, supporting telecoms etc.
2. Procure, install and commission equipment.
3. Run trials and write report.
4. Identify regulatory and licence issues that affect the adoption of battery storage and suggest changes necessary, e.g. for participation on the Balancing Mechanism.

The objective of this report is to fulfil objective 4). Four activities comprise this scope:

1. Determine how Energy Storage System (ESS) Balancing Mechanism Units (BMUs) are currently treated under the B&SC and document the current unit costs and overheads.
2. Identify regulatory hurdles and operating cost challenges to fast response BMUs.
3. Propose regulatory and license condition changes to enable market entry of energy storage.
4. Consolidate findings into a report.

3 Background and context

3.1 Network Issues relating to Distributed Generation

Distribution Network Operators (DNOs) are actively planning for the effects of increasingly large volumes of Distributed Generation (DG) on their networks.
As distribution networks were designed to support one-way flow, the connection of distributed generation can cause a number of different problems for the DNO by

- Raising voltages on the network above upper limits
- Increase the current flowing within the lines and cables above their capacity causing thermal overload
- Increase the energy that could be supplied under fault conditions above the fault level capacity of the installed equipment
- Causing reverse power flow issues
- Increasing harmonics

As well as using the traditional approach of reinforcing the network to enable it to manage maximum power flows (that are typically seen only on a small number of occasions each year), DNOs are using innovative smart grid approaches to manage the bi-directional power flows thus reducing the need for expensive additional network capacity.

3.2 Better forecasting and anticipatory investment

In response to increasing levels of grid constraint within the distributed network across the UK, Ofgem and DECC have invited DNOs to consider a more proactive approach to forecast grid investment to support the pipeline of growth of distributed generation.

The “Next Step” guidelines issued by Ofgem as part of the “Quicker and more efficient connections” consultation state that, in the future, anticipatory investment to support electricity generation may be undertaken by DNOs in cases where there is a strong evidence base to support investment, backed by local stakeholders, and a low risk of stranded or non-value added investment. Grid investment should also be considered alongside other solutions to grid constraints, such as effective queue management, flexible connection agreements and Demand Side Response (DSR).

The guidelines have identified three potential models under which costs of anticipatory investment could be recovered. These include:

i. cost recovery from all customers (socialised)
ii. cost recovery from subsequent connection customers, and
iii. costs funded by 3rd parties (developer/landowner) on behalf of future customers from whom they recover costs in a similar way to the second comer rule already applied by DNOs.

It is not immediately clear whether this is likely to hinder or promote the take-up of storage by DNOs. On the one hand it appears to promote greater levels of traditional reinforcement, which would reduce the opportunities for storage, but on the other hand alternatives to grid investment are not ruled out. The requirement for low risk of non-value adding or stranded investment suggests that if storage can be relocated cost effectively it could be preferable as a form of anticipatory investment operating on a temporary basis until the justification for traditional reinforcement is clearer. The containerised battery used in Solar Storage should lend itself to relocation more easily than solutions that are housed in purpose built constructions. If the battery is relocated at the end of the project this will give an insight into the relocation costs to evaluate whether there is a business case for DNO owned storage to enable greater DG connection ahead of traditional reinforcement.

3.3 Scale and impact

For background the summary results of the distributed generation study scenarios (published by Regen SW) are shown in the table below and show a growth from a current (October 2015) baseline capacity of circa 1.5 GW to circa 5 GW by 2030 under the most ambitious Gone Green scenario (Figures 1 and 2).

Growth estimates for the other scenarios, Consumer Power, Slow Progression and No Progression are lower. However, even under the lowest No Progression scenario, there is an expected growth pathway to 2.5 GW of distributed generation capacity by 2030.

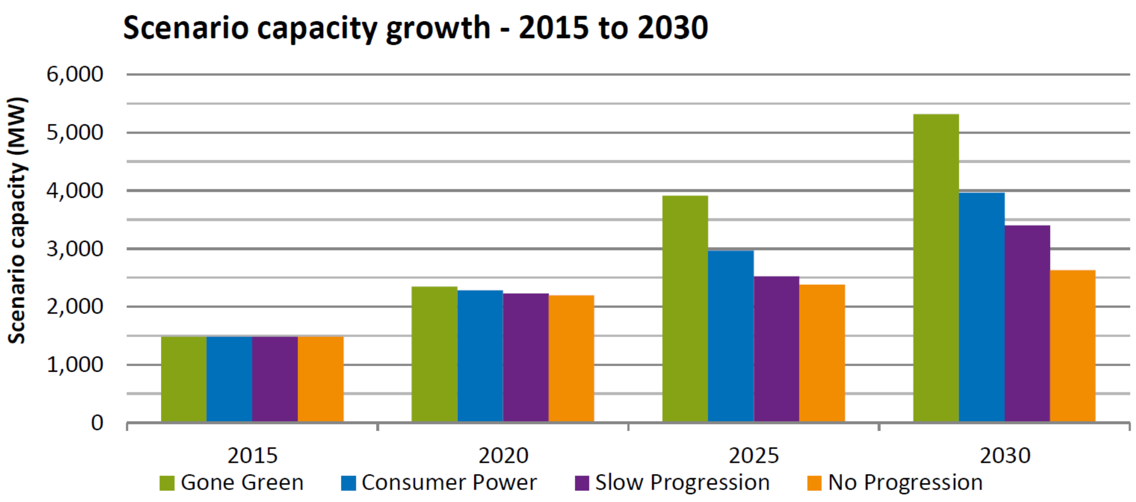


Figure 1 (Regen South West, 2015)

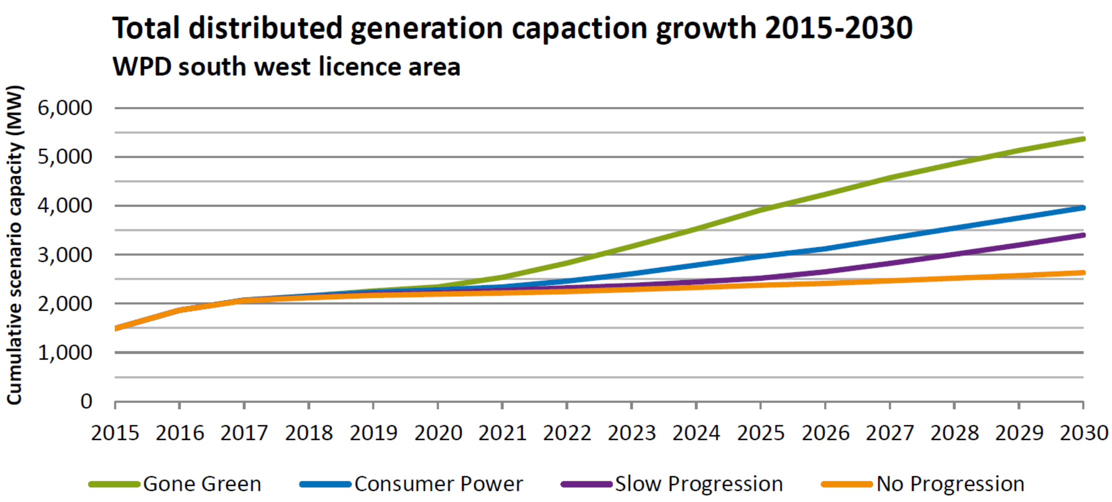


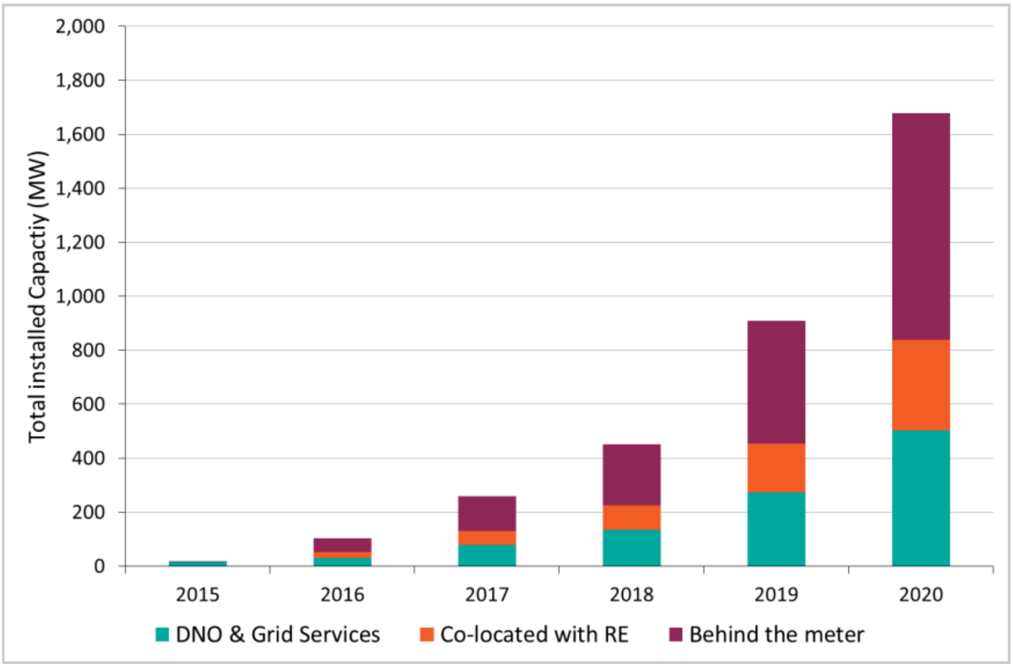
Figure 2 (Regen South West, 2015)

The latest data from the Energy Networks Association (ENA) regarding the current capacity of storage applications in each DNO region is shown in Figure 3.

DNO	No. of Formal Applications	Capacity (MW)
ENWL	14	420
NPG	11	270
SP Manweb	7	230
SSE	64	1,006
WPD – battery	159	3,118
WPD – pumped	8	220
WPD – total	167	3,338
UKPN	91	1,423
TOTAL	354	6,687

Figure 3 - Latest data from the Energy Networks Association (ENA) (Energy Networks Association, 2015) regarding the current number of storage applications in each DNO region

This data is changing rapidly and as of 14th March WPD total storage applications have a combined capacity of over 7GW.



Source Eunomia: Investing in UK Electricity Storage

The Energy Storage Network has lobbied to establish a target for 2GW installed storage capacity by 2020. This seems in line with the estimates from the other studies.

3.4 Challenges

Any licensed Distribution Network Operators (DNOs) must manage flows on to as well as from their networks, they must manage intermittency, and are increasingly likely to be given a tacit role in facilitating market development for new technologies as a natural bi-product of their activities in seeking to reduce or avoid costly network asset modifications.

Innovations in the technology of data collection and management make this role all the more important. Smart meters clearly have a very important place, providing a much higher degree of granularity than has been previously available. Greater volumes of data means greater complexity in network operation, but the increased amount of data also means that, with appropriate management tools, system reliability can be improved and real-time constraint management introduced.

It is not just the technical arrangements that need to adapt to meet the challenges posed by distributed energy. The commercial and regulatory environment mirrors the traditional technical model, and will need to adapt as well.

In Great Britain, DNOs were created from the unbundling of the public electricity suppliers and have de facto monopoly distribution rights in their local area. Any other licensed operators in that area have tended to be associated with housing or industrial estates with multiple customers buying energy from licensed suppliers. Other sites with no domestic customers, or below a certain capacity threshold, have operated private wire networks under a statutory exception from the requirement to hold a licence. Private wire networks have offered opportunities for distributed energy providers to sell their export to other customers connected within the private network, thus limiting the import and export of power through the point of connection to the DNO network. The netting off between demand and generation reduces the TNUos and DUoS charges payable on the electricity generated and consumed within the private wire network.

A virtual private wire network seeks to provide the benefits in relation to trading arrangements using a public network. This is sometimes known as the virtual MPAN approach. This approach can be used to deliver Local balancing markets through community schemes using bi-lateral contracts.

Commercial and contractual arrangements are complex, and because electricity is flowing across the DNO’s system a licensed supplier will need to be involved. Management of the virtual private wire network operator is also more complicated because the operator must manage the imports and exports at the various connection points and the net position with the DNO. It may also be useful to employ a demand aggregator to manage demand-side response within the distributed energy scheme.

Pros and Cons of local demand balancing via Private and Virtual Private Networks

Pros

- Potentially lower bills for end users as a result of the reduction in transmission and distribution charges
- Reputational benefits for the DNO or private wire operator.
- Distributed energy schemes may also help to alleviate congestion on the grid, which may help DNOs by deferring infrastructure investment.

Cons

- On the other hand, DNOs may find themselves with stranded assets as customers go off-grid.
- Who pays for any stranded asset is an unanswered question.
- Requirement to manage intermittency across a virtual private wire network with reduced visibility of what is going on inside that private wire network.

Active network management (ANM) is going to become the norm, involving generators having a different relationship with the DNO through connections that are managed to optimise the distributed energy scheme operation as a whole, rather than giving each generator firm entry capacity up to its rated capacity. All this may require changes to the current licensing arrangements (particularly around exemptions of greater volumes are prevalent) and to the DNO price controls. Ultimately, however, it is innovation and technology that will drive the necessary regulatory changes – not the other way round.

3.5 How will the active management of DG increase in future?

The amount of DG controlled under constraint management schemes administered by DNOs is likely to continue to increase steadily and expand from current trial areas due to the increasing volumes of distributed and intermittent generation. The rate of growth is expected to be relatively modest initially, constrained by the roll out of schemes by DNOs in the recently agreed April 2015–March 2023 price controls, but accelerate thereafter as constraint management through actively managed DG become integral to DNOs' business plans under future price controls. WPD has now implemented its sixth ANM zone and expects ANM to be available within all of its area by 2021. ANM connection offers are now twice as likely to be accepted than conventional connection offers. This is associated with the existing commercial arrangements for connection charges and imperative of getting connected quickly.

3.6 How does active management of DG link to Balancing and Settlement?

Active management of DG currently operates outside the Balancing and Settlement arrangements, which operate at a national level. Unlike transmission connected generators, distributed generators operating under ANM schemes (LIFO or pro-rata) currently receive no compensation for curtailment. The generator must accept the risk of curtailment when connecting to a constrained part of the network, while benefiting from a lower cost non-firm connection.

At the same time, the Transmission System Operator (TSO) is essentially blind to the constraints management actions being taken by DNOs, and suppliers with offtake agreements with distributed generators are exposed to resulting imbalances caused by DNO actions. While the volumes of constraints management actions are small, such inaccuracies in the Settlement processes have little overall impact. However, as the volume of DG increases, having accurate economic signals of the cost and value of local constraints management becomes increasingly important for the efficient operation of the system. As such, Settlement will need to become more sophisticated.

During 2015 WPD were provided and allowance to trial an exemplar solar storage project connected to its southwest region distribution network.

The project addressed the following industry problem statement.

Integrating storage with renewable generation offers a route to addressing some or all of the following issues:

i. Renewable generation does not predictably match peak local demand.
ii. Renewable generation is often ‘spikey’, which can introduce short-term impacts on grid voltage or other quality of supply factors.
iii. Unpredictability, lack of control mechanisms and power quality mean grid operators use conservative rules to allocate grid connections.
iv. Grid operators have to introduce new equipment to manage power quality, a service which could be provided by operators of utility scale renewable installations.

In order to create a project, the learning from which would provide answers to the problem statement, the following scope was defined:

A battery and control system will be integrated with a 1.5MW PV array connected to WPD South West’s 11kV network. Analysis of the detailed data set created by carrying out a set of well-defined trials (usage cases) will form the technical core of the project. The use cases will demonstrate:

1. Sale of energy stored in the battery for a higher price;
2. Better matching of generation profiles to demand profiles;
3. Use of storage to peak lop PV generation above a (dynamic) power threshold;
4. Import electricity from the grid at times of low demand;
5. Absorption and supply of reactive power to help manage the network voltage.
6. Reduced connection capacity requirement per MWp generation capacity;
7. More predictable PV output through smoothing PV's steep ramp rates;
8. Raise or lower the export power threshold depending on thermal or voltage constraints;
9. Show the control system allows smart co-ordination of multiple storage systems.

In addition to these use cases, there are other potential income streams for fast operating storage assets which will be borne in mind as a part of this study, but as yet there is no direct intent to participate in them i.e.

- STOR
- Frequency response / enhanced frequency response
- Limiting imbalance charges for suppliers & generators
- Capacity market

4 Current baseline status

4.1 Ownership structure on which initial assessment is based

The ownership structure of this initial assessment is for British Solar Renewables. This is classified as a third party owned (contracted services).

NB: This ownership model is the main one the project will investigate for wider learning, but within the project itself the 300kVA 640kWh BESS is actually owned by WPD.

Key Attributes:

- Third Party builds and owns the asset.
- DNO maintains the asset through contracted services.
- Third Party makes business case orientated decisions regarding the optimisation of traditional generation revenues vs. enhanced revenues enabled via storage capacity.

4.2 BSC Assessment

4.2.1 Trading Parties

Under any route-to-market, the energy linked to a storage asset must feed into the settlement processes.

Settlement arrangements are specified in the Balancing and Settlement Code (BSC) and (outside of the arrangement of direct Power Purchase Agreements (PPAs) by developers) any entity who wishes to physically trade power must be a Trading Party and hold energy accounts to manage their physical and contractual positions. DNOs are parties to the BSC. However, they are not Trading Parties and do not hold energy accounts.

The BSC does not itself block distribution businesses from market participation. This stems, instead, from the licence requirement to avoid distortion of competition in generation and supply. It effectively blocks vertical integration at scale with common ownership of generation, supply and distribution. DNOs using assets capable of generation to manage network constraints are unlikely to distort the generation market as the use of the assets should be infrequent. Were generation / storage assets required to be used for significant proportions of the year it is likely that traditional reinforcement would be better value for money.

4.2.2 Balancing Mechanism Units (BMUs)

All trading parties have two energy accounts (production and consumption) into which feed the physical flows of Balancing Mechanism Units (BMUs) linked to the party. BMUs are the units of trade and settlement, used to account for physical flows at smallest aggregation of independently controllable apparatus. Most large generation units are an individual BMU, with small generators often aggregated within a supplier’s BMU. The linkage between BM Units, production/consumption accounts and trading parties is summarised in Figure 4.

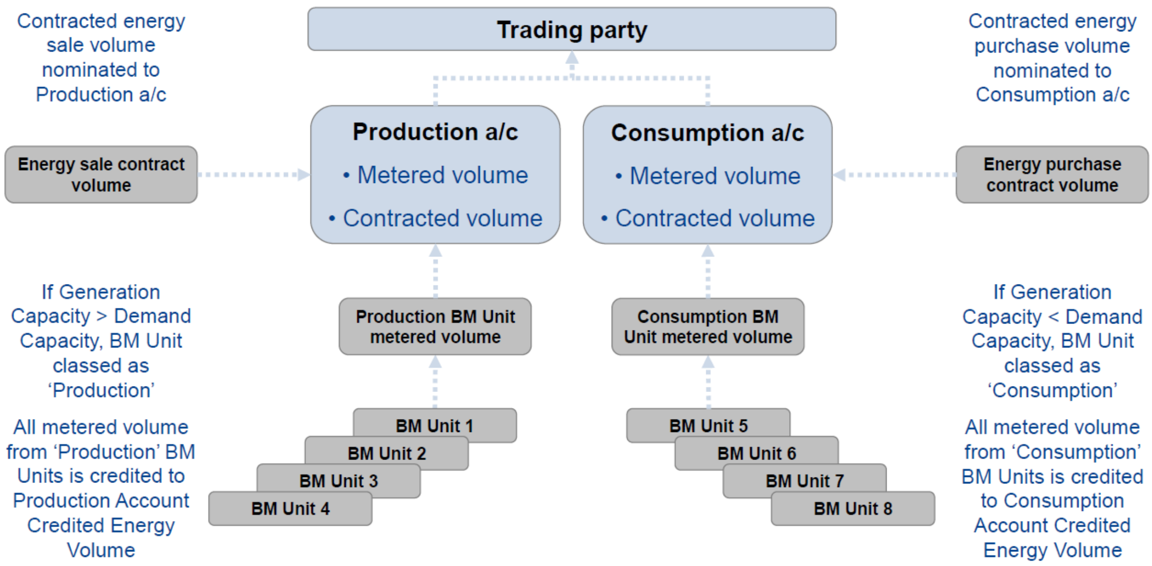


Figure 4 - BM Units and Production/Consumption Accounts

On any given settlement day BM Units also need to be registered as either production or consumption units (P/C Status). This defines which Energy Account a given Unit's energy production/consumption feeds into on said settlement day (i.e. Production BM Units are linked with the Production Account and vice versa).

There are several types of BM Unit, each representing different aspects of the system:

- BM Units directly connected to the transmissions system (typically generation units);
- BM Units embedded in a distribution system;
- BM Units related to an interconnector; and
- BM Units covering supply.

There is no specific category for storage and the existing definitions within the BSC would treat (at least some categories of) storage as a generating unit, as illustrated through the reproduced definitions in Table 1.

Term	Definition
Generating Unit	Means any Apparatus which produces electricity
Apparatus	Means all equipment in which electrical conductors are used or supported or of which they form part

Table 1 – BMU definitions relevant for treatment of storage

Distribution connected storage is currently treated as an embedded BM Unit. However, given that there will be energy flows into and out of a storage BMU, arrangements more analogous to those in place for interconnector BMUs may be a more appropriate reflection of the physical nature of a storage asset.

Interconnector BMUs under the BSC

Given the two-way electricity flow from a storage device it can, to some degree, be likened to the dynamics of an interconnector. It is thus worth considering BSC arrangements for interconnectors and how this can potentially be applied to assist the future deployment of storage.

Section K5 of the BSC sets out the following requirements for interconnectors:

The metering system must allow for quantities of imports and exports to be measured separately.

(For accuracy this means import and export metering being in place.) The benefits of such a solution should extend to more accurate settlement.

An Interconnector Administrator and an Interconnector Error Administrator must be appointed. In the case of storage it would not seem necessary to deploy these roles, and this is one of the challenges of using this hypothetical arrangement.

An Interconnector BM unit is a notional BM unit.

Upon being appointed, an Interconnector Administrator is automatically allocated two BM units (designated as a Production BM Unit and a Consumption BM unit). This is in contrast to other apparatus/collections of apparatus where a single BM Unit is assigned.

In relation to Production Interconnector BM Units the value of demand capacity shall at all times be zero.

In relation to a Consumption Interconnector BM Units the value of generation capacity shall at all times be zero.

4.2.3 Implications of trading arrangements for value of flexibility

In addition to influencing participation in the wholesale market, the trading arrangements influence the value that storage assets may realise through the market. The imbalance settlement arrangements are a particularly important driver of value as generators and suppliers are likely to pay storage operators to provide a service to reduce their imbalance positions. The intention of electricity imbalance (or cashout) arrangements is to settle energy taken or produced without a contract. But the current calculation methodology serves to dampen cashout prices and so weaken the signals and incentives that they provide:

- The current 'main' imbalance price is calculated on the basis of the weighted average of the 500 MWh most expensive energy trades needed to balance the system. This approach serves to dampen cashout prices, as the costs of more expensive balancing actions are muted through the averaging process. This creates a mismatch between the costs of balancing the system at the margin and imbalance exposure for parties who are out of balance. Therefore, the weighted average approach dampens cashout prices and the signals that they create for parties to balance their positions.
- The way in which the costs of STOR feed into cashout prices has a dampening effect on cashout prices. When exercised through the Balancing Mechanism, utilisation fees do feed directly into cashout price calculation as accepted offers. But the price levels are fixed in the tender process, well in advance of potential delivery, meaning that they cannot reflect the underlying supply/demand fundamentals and system tightness in real-time. In periods of tightness, Balancing Mechanism offers linked to STOR contracts are likely to displace other offers which are (a) not 'cross-subsidised' by an availability payment and (b) likely to reflect increased scarcity value linked to system tightness. Utilisation fees for non-Balancing Mechanism STOR are not reflected at all. Availability payments are included in cashout prices in periods of historic utilisation of STOR through a Buy Price Adjuster (BPA), which is an adder to the prices derived from other balancing actions. It is an imperfect proxy for when reserve is actually used and valued most.
- In extreme circumstances, the SO can instruct the Distribution Network Operators to reduce demand through voltage reduction (brownouts) or disconnection (blackouts) in order to balance the system. These balancing actions are not included in the calculation of cashout prices. As a result, cashout prices at periods of system stress are dampened as they do not reflect the costs of these balancing actions.

Overcoming these weaknesses will sharpen cashout prices and the incentives for parties to balance. This will increase the value of flexible and reliable capacity, such as storage, which can help parties to balance their positions. This is recognised by Ofgem in its Electricity Balancing Significant Code Review (EBSCR), which has led to the development of a proposed package of reforms to the cashout arrangements outlined for consultation as follows:

- To make cash-out prices more marginal by reducing the volume of actions on which the cash-out price is based to 1MWh (a 'fully marginal' cash-out price);
- To improve pricing of reserve by amending the price of STOR actions in the cash-out price calculation such that they are based on a Reserve Scarcity Pricing function; and
- To introduce a cost in the cash-out arrangements for voltage control (brown-outs) and disconnection (black-outs) emergency balancing actions.
- In addition, Ofgem is proposing the adoption of a single cashout price for all imbalances in a given settlement period, rather than the current dual price approach. Ofgem's analysis suggested that the proposed reforms would make cashout prices sharper and improve incentives for investments in flexible capacity.

4.3 Overheads

In principle, parties seeking to trade wholesale power have various route-to-market options.

These range from a pure merchant approach where various products are sold spot via their in-house trading desk, to long-term all-inclusive bilateral offtake agreements where an offtaker takes volume risk and defines at the outset of the contract pricing rules (including price-risk mitigation measures) for all products bundled together. Along this spectrum, there are numerous combinations entailing a higher (or lower) market commitment, hence a higher (or lower) risk for the generator and potentially higher (or lower) realisable value:

- Traditional Power Purchase Agreements (PPAs) with, typically, licensed electricity suppliers, are the most common approach for independent producers. They may take various forms and predominantly differ for the structure of the electricity pricing terms, e.g. fixed prices, floored and/or indexed. In each case the counterparty will expect to take a share of the total value to compensate it for transaction costs it incurs, any risks it is taking on under the contract and to provide a margin.
- Trading services approach involves outsourcing trading activities to an external entity that is active in the market and will interface with the market on behalf of the generator. This is the model envisaged under a 'Contracted services' business model.
- Trading on own account is predominantly used by larger players, including utilities, that can benefit from economies of scale and in-house trading expertise. The generator may incur additional balancing, trading and risk management costs under this strategy, but is generally able to retain a higher value. This is the model envisaged under 'DNO merchant' business model as described in section 5.1.

The trade-off between these options balances the overheads of direct market participation (e.g. trading functions, accession to industry codes, posting credit cover, etc.) versus the discount to the power price associated with outsourcing trading. If a DNO owns the storage asset, it will not be able to trade it directly given the block on DNO trading in today's regulatory arrangements mentioned previously, leaving either of the other two routes available. If the storage asset is owned by a market participant then all routes are open, with the choice linked to the circumstances of the individual.

4.4 Overhead Scenario Calculation

In order to assess the impact of BSC overheads. costs were calculated based on 'storage' and 'renewables with storage' scenarios according to an agree set of parameters. The summary of BSC monthly costs for these scenarios is defined in Table 2.

BSC Cost Estimate						
	Stand Alone Storage			Renewables Connected Storage		
Main Specified Charges	**Charge**	**Units**	**Cost (£)**	**Charge**	**Units**	**Cost (£)**
CVA BM Units (£/month)	100	1	100	100	**1**	100
Supplier Base BM Units (£/month)	100	0	0	100	**0**	0
Supplier Additional BM Units (£/month)	100	0	0	100	**0**	0
Contracts Traded (£/MWh)	0.0007	0	0	0.0007	**0**	0
CVA Metering Systems (£/month)	50	2	100	50	**2**	100
Base Monthly Charge (£/month)	250	1	250	250	**1**	250
SVA Specified Charges						
HH MSIDs (£/MSID/month)	0.7	0	0	0.7	**0**	0
Annual Consumption Charging Net SVA Costs						
NHH Energy (£/NHH MWh/month)	0.008	0	0	0.008	**0**	0
Annual Production Charging Net SVA Costs						
Production Energy (£/MWh/month)	0.006	873.6	5.2416	0.006	**931**	5.586
Annual Net Main Costs						
Energy Fee (£/MWh)	0.04026	740	29.7924	0.04026	**5399**	217.3637
Total (£/month)			**485.03**			**672.95**

Table 2: Summary of monthly BSC costs based on set development parameters.

Against the production parameters provided, the annual cost of BSC overheads for Stand Alone Storage is £5,820.36 and for Renewables Connected Storage is £8,075.40.

In order to determine the impact of these overheads on the viability of embedded storage, assuming that there is a commercial case for the asset connection notwithstanding BSC overheads we must analyse the current connection applications. In this context it has been assumed that it is unlikely that a party would oversize the battery to the connection i.e. 50MW battery behind a 40 MW connection.

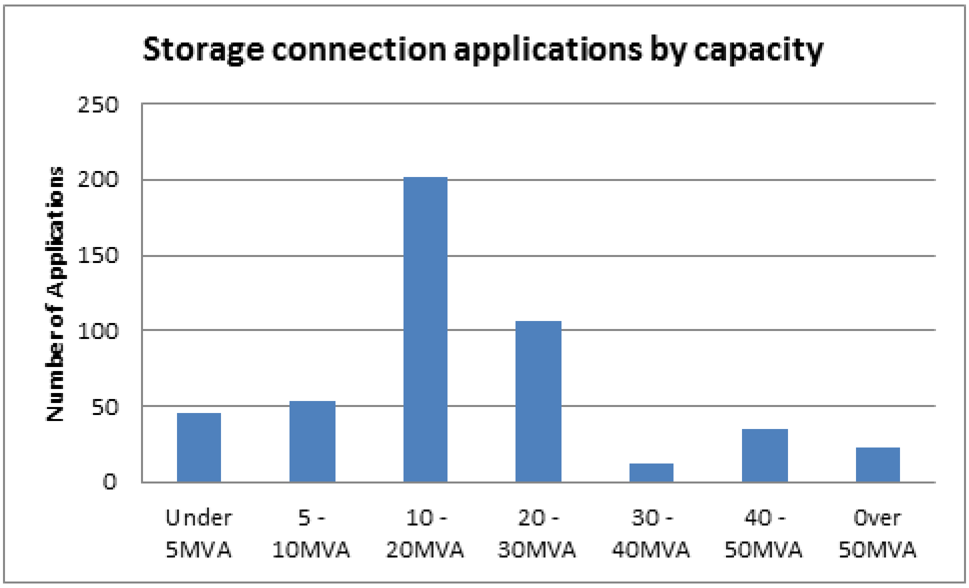


Figure 5: The number of storage related connections in the WPD southwestern region

70% of applications for a storage connection are greater than 10MW. This may be driven more by the EFR tender than being a long term market trend. We know from the parameters used to create the schedule of BSC overheads in Table 2 that the forecast BSC costs would be incidental to the business case of such an asset, and as such would not be deemed inhibitive. For those applications in the 0-10MW range, it is harder to analyse, but it is likely that the above statement is also true for applications with a 5MW capacity and above, meaning that a large majority of the current pipeline of storage projects for which connection applications are in process should not be affected by BSC overheads in a way that threatens their viability.

5 Ownership Scenario Models in Scope

There are a number of parties with an interest in storage assets.

Generators or Suppliers would have an interest in reducing imbalance costs. Aggregators, would use them to provide commercial services to National Grid. These ownership cases are covered by “third party” business case described below.

The TSO is currently prevented from owning assets to provide services due to the likely distortion of the market.

Transmission network constraints are unlikely to be managed with battery storage due to their scale and therefore TO are not expected to have an interest in battery storage.

Customers, with PV may be interested in maximising their self-consumption via battery systems; however, they would only participate in providing services via an Aggregator.

For DNOs the following ownership models were identified in the Poyry report Electricity Storage in GB: SNS4.13 – Interim Report on the Regulatory and Legal Framework.

The two ownership models in the scope of this report are;

1. DNO ownership, and
2. 3rd party ownership with DNO providing contracted services.

The Code and overhead impacts of these models are described in Section 4 of this report (Current baseline and status)

5.1 DNO ownership

DNO merchant- Full merchant risk, exposed to power price and balancing services

Key Attributes:

- DNO builds, owns and operates the asset. Full operational control.
- DNO monetises additional value streams directly on a short-term basis (e.g. trading).
- Possible barriers: Costs of accessing the market, DNO skills and capabilities, regulation and shareholder expectations of risk.

5.2 3rd party ownership with DNO providing contracted services

DNO offers a long-term contract (e.g. 10 years) for services at a specific location with commercial control in certain periods:

- Third party builds and owns the asset. DNO has full operational control, or operational control set out by defined parameters based on a contracted services model for asset maintenance and operation.

6 Regulatory and cost assessments

6.1 DNO ownership

In this instance the DNO is, in effect, the generator and as such should have a registered BMU under which the generation unit participates in the balancing and settlement process.

There are specific conditions that are unique to this scenario which are imposed via the Distribution Licence conditions, rather than by the BSC, namely:

DNO ownership of generation licence exempt storage is possible under unbundling, with operational separation.

The unbundling requirements mean that, as a general rule, TSOs and DNOs must be independent from generation and supply activities. As energy storage is classified as a subset of generation by default, this means that TSOs and DNOs are unable to own and operate storage assets that require a generation licence. This acts as a block for the deployment of large storage facilities by network operators as an alternative to conventional reinforcement or for network management purposes.

However, as highlighted above, it is possible for exemptions from the requirement to hold a generation licence to be granted. Four defined class exemptions exist, of which one is relevant here. This allows projects to be exemptible as a ‘small generator’:

- If output to the total system (GB transmission system and all distribution systems) is less than 10MW; or
- If output to the total system is less than 50MW and the declared net capacity of the power station is less than 100MW.

It is important to note that the ‘small generator’ class exemption applies on a per generating station basis. This means that exemption is possible for multiple projects that fall under the defined size thresholds, regardless of the cumulative scale of the projects when considered collectively and the potential impact that they could have on the market in aggregate.

Additionally, power stations which do not fall into any of the exemption classes listed above may apply to DECC to seek an individual exemption. Power stations capable of exporting between 50MW and 100MW to the total system that connected after 30 September 2000 are generally granted exemption via this route.

Some instances of network ownership and operation of storage do exist.

In Italy, Art 36, paragraph 4, decree law 93/11 allows the TSO (and DSOs) to build and operate batteries. However, this must be justified through a cost/benefit analysis that shows that the energy storage system is the most efficient way to solve the problem identified (e.g. compared to the build of new line). Remuneration from the storage asset should not be higher than the (measurable) cost of alternative solutions.

Terna, the Italian TSO is currently working on six pilot projects with a rated capacity of 6MW and 40MWh, and two of 15MW. In addition to these pilot plants, the company's Terna Plus subsidiary, which is responsible for new business development in Italy and abroad, is looking to commercialise energy storage alongside other emerging technologies such as renewables and smart grid systems.

Belgian law allows some level of control by TSO/DSOs on electricity storage facilities but subject to conditions that would ensure the functioning of an open, fair and transparent market. These conditions are set out in Article 9 (1) of the Belgian Electricity Act:

- The electricity is generated for balancing purposes only, with an explicit prohibition for commercial purposes;
- The stored electricity is called upon as a last resource;
- Under the form of negotiated drawing rights;
- To the limit of the power needed for ancillary services;
- Upon the prior approval of the regulator

The exemption route does, therefore, provide an avenue for potential deployment of smaller scale energy storage assets by DNOs, with operational separation.

The RAV treatment of DNO owned storage assets has not yet been determined but the recommendation proposed by UK Power Networks relating to the Smarter Network Storage project was for capital allowances up to the value of the equivalent conventional solution and that benefits from ancillary services would be apportioned between the DNO and distribution customers. This seems a sensible approach to ensure DNOs invest appropriately and that customers benefit from such investments.

6.1.1 Deployment by DNO businesses is limited by de Minimis restrictions

However, the possibility for income generation from smaller scale storage by DNOs must be considered in the context of restrictions upon the activities of DNOs specified in the distribution licence.

Standard DNO licence conditions place limitations on non-distribution activities. Restricting:

- Total turnover from non-distribution activities to 2.5% of the DNO's distribution business revenue; and
- Total investments in all non-distribution activities to 2.5% of the licensee's share capital in issue, its share premium and its consolidated reserves.

Therefore, there is a cap on the permitted revenue from and the overall level of investment in storage assets (as part of a de minimis business), if such activities are possible.

However, the limit is relatively loose and estimates suggest that up to 15 projects could be deployed on some distribution networks before either of the thresholds are close to being reached (subject to the scale of other activities which may already feed into the de minimis pot).

While the limit appears loose currently, arrangements for distribution network led storage projects need attention now to avoid this becoming an undue restriction.

6.1.2 Obligation not to distort competition in supply and generation of affects arrangements for and practicality of storage operation

More significantly, however, the Distribution Licence imposes restrictions upon activities of the distribution business to avoid distortion of competition in generation or supply activities and to avoid cross-subsidy, as outlined in Table 6.

Operation of a storage device must be considered in this context. There are two ways in which flows into and out of storage can be handled:

- unmetered flows; or
- trade to buy/sell power linked to charging/discharging of storage asset.

Whilst the net position is not material due to high round-trip efficiency, instantaneous charges and discharges are far larger than the footprint of other network equipment (such as substation heating and lighting and technical losses in cables and transformers) and larger than individual unmetered (i.e. estimated) connections such as street lighting. If a DNO were to adopt either approach, it would need to demonstrate that it was not acting in a way which could distort the market.

In the first case, the effects of import and export flows are borne by other parties through effects on losses in a non-transparent manner. This contradicts the 3rd Energy Package which states that:

‘Each distribution system operator shall procure the energy it uses to cover energy losses and reserve capacity in its system according to transparent, non-discriminatory and market based procedures, whenever it has such a function’ (Article 25.3).

Therefore, unmetered flows into and out of the storage facility may be problematic. This requires metering by the DNO or by a third party, which must be accounted for within the settlement processes, supported by trading activity to manage imports and exports.

This takes us to the second case. If the DNO undertakes trading activity to support the operation of the storage asset it clearly involves direct DNO participation in the market, potentially affecting wholesale market activity.

Trading does not necessarily require either a generation or a supply licence. As already discussed, generation licence exemption is available for storage assets of the size being considered here anyway. Also, trading to charge or discharge the storage asset does not mean that the operator is seeking:

- to ‘supply electricity to premises’, which is how supply activity is defined in the Electricity Act 1989 (see Table 2); or
- to participate in ‘the sale, including resale, of electricity to customers’.

Therefore, trading to charge/discharge the storage asset does not appear to require a supply licence. Nevertheless, trading by a DNO is may yet reach the scale where they have an impact on generation and supply competition, which creates a potential distortion. This effectively blocks operation of a storage asset by a DNO for balancing purposes.

These factors point to the need, under today’s regulatory framework, for a contractual interface with a third party to handle the energy flows when the storage facility is used for network purposes or for broader system-wide offerings. Therefore, an additional player must feature in the business case, potentially increasing its complexity.

This third party could potentially be a separate entity under the same organisation umbrella as the DNO business, as long as the distribution business itself is appropriately ring fenced from such activities to comply with unbundling requirements and associated licence restrictions. This includes the need to manage the potential for cross-subsidy between different activities within the ‘Independence of the Distribution Business’ compliance regime.

6.2 3rd party ownership with DNO providing contracted services

The regulatory assessment for this ownership scenario is discussed in section 4 of this report.

7 Compliance and financial summary table of use cases

The third party owner has none of the regulatory restrictions imposed by the DNOs License condition.

Description	Compliance		Considerations
	DNO merchant	Third Party	
Sale of energy stored in the battery for a higher price;	Only if synchronous with 'constraints' management activity, and up to 2.5% of total business revenues	No restrictions.	DNO should not be conducting this activity without being able to prove constraint avoidance. This may be time consuming and increase overhead from a practical perspective.
Better matching of generation profiles to demand profiles;	Permitted up to 2.5% of total business revenues	No restrictions.	In this context, there are two important factors. 1. Any generation / supply activity that occurs is currently permitted under the trading rules, and there is an adequate method for it so long as the development is 'justified'. 2. This activity is limited to 2.5% of DNO revenue turnover and as such there is the potential for some mismatch between the forecast market demand and the suitability of the current terminology. For instance an increase in this limit, or a removal of the limit altogether but with a tight specification of the justification of this
Use of storage to peak lop PV generation above a (dynamic) power threshold;	Permitted up to 2.5% of total business revenues	No restrictions.	
Import electricity from the grid at times of low demand;	Permitted up to 2.5% of total business revenues	No restrictions.	
Absorption and supply of reactive power to help manage the network voltage.	Permitted up to 2.5% of total business revenues	No restrictions.	
Reduced connection capacity requirement per MWp generation capacity;	Permitted up to 2.5% of total business revenues	No restrictions.	
More predictable PV output through smoothing PV's steep ramp rates;	Permitted up to 2.5% of total business revenues	No restrictions.	

Raise or lower the export power threshold depending on thermal or voltage constraints;	Permitted up to 2.5% of total business revenues	No restrictions.	activity (i.e. defined by the use cases proposed in this study) would solve this issue. This would lead to a justification where the proposed storage would provide a facility at a lower cost than the market (by a defined % margin).
Show the control system allows smart co-ordination of multiple storage systems.	Permitted up to 2.5% of total business revenues	No restrictions.	
In addition to these use cases, there are other potential income streams for fast operating storage assets i.e.			
STOR	Permitted up to 2.5% of total business revenues	No restrictions.	Current arrangements support these activities, but the comments above all apply from a distribution licence condition perspective.
Frequency response / enhanced frequency response	Permitted up to 2.5% of total business revenues	No restrictions.	
Limiting imbalance charges for suppliers & generators	Permitted up to 2.5% of total business revenues	No restrictions.	
Capacity market	Permitted up to 2.5% of total business revenues	No restrictions.	

8 Conclusions

The purpose of carrying out a regulatory impact study, that encompasses the balancing and settlement code is to consider whether the regulatory framework is preventing;

1. Growth in the storage market in general
2. Use of storage by DNOs
3. Optimum value being obtained from the storage installed.

8.1 General Storage Market

DNOs are receiving applications for a significant capacity of storage. Much of the drive for new storage relates to National Grid's enhanced frequency response service.

For units above 50MW there are additional costs of operating under the BSC and also greater planning requirements. A large number of storage applications are for capacities just under this limit, however the additional costs of BMU registration do not appear excessive in comparison to other operating costs and so are unlikely to be a limiting factor preventing the growth of the storage market. While there are fewer applications for over 50MW, this is likely to reflect other practicalities such as the requirement for higher levels of investment, larger sites etc. rather than the impact of the regulatory environment. Other CUSC, technical and grid code requirements will then also start to impact.

Similarly while the current settlement process for imbalance tends to reduce the incentives for parties to procure imbalance reduction services from storage the proposed changes will act to sharpen the cashout values, making an imbalance related income stream more viable.

Many of these applications relate to existing renewables sites and the Eunomia report also suggests that a large proportion of the expected storage will be for "behind the meter" applications where regulatory issues would have less influence.

The general conclusion is therefore that while it would be useful to define a storage asset BM unit, the regulatory framework is not prohibiting the growth of the storage market in general.

8.2 DNO use of storage

For DNOs, ownership and operation of storage is possible using the small generator licence exemption. This would allow the DNO to locate the battery at an optimum position on the network and to have control over the operation so that its use to manage constraints could be assured. There appears to be no requirement for a supply licence when trading electricity to charge and discharge a storage asset however, if volumes increase to the point where this could distort the energy market then trading via a third party would be preferred.

The model of DNOs acquiring services from third party storage operators is unlikely to be effective with storage already planned to connect to areas of the network with capacity and not intentionally located to be used by DNOs.

In the case where the third party owns and constructs the storage on behalf of the DNO, the location issues can be overcome and any issues over DNOs trading electricity without a supply licence are avoided, but the overheads of involving a third party are arguably an unnecessary expenditure that does little to improve the smooth operation of the electricity market. Creating a ring-fenced body with the same ultimate owner as the DNO would likely create business separation requirements that are costly and complex to administer.

Under both ownership models, the de-minimis limit on revenue and investment limits for non-network activities form a cap. It is difficult to determine whether this cap would become a barrier to DNO storage, but in any case the examples from Italy and Belgium suggest a more appropriate method to ensure the use of storage by DNOs is appropriate. The de-minimis cap was set many years before ownership and operation of storage assets by DNOs was a likely event. It seems more reasonable to define ownership and operation of storage assets as network related activity provided that it can be shown that the storage is being used for constraint management, or other permitted activity, (rather than a purely commercial investment) and that storage is a more cost effective option that reinforcement or other available alternatives such as DSR.

8.3 Optimal Value from Storage

As discussed in previous sections, many of the potential income streams for storage asset owners are largely location independent. E.g. arbitrage, frequency response services, STOR, imbalance services etc. Additional value can be gained by co-locating storage with renewable sites, but it is not clear to what extent storage located to benefit renewable generation will also be able to provide services to DNOs, though the solar storage will inform this. The degree to which providing services to DNOs would conflict with other services is also largely unknown. It seems likely that without strong locational price signals from the DNO that the location of storage will be driven by other factors. Connection costs provide an incentive for storage to locate on areas of the network with greater capacity rather than areas which could benefit more from storage services. This supports the approach that DNOs should have the role of storage owners of last resort

9 Bibliography

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Annex 1 – Use Cases

Usage Case No. PV only or all GD	Name	Cycling, Charging Discharging or Reactive?	Commercial Summary	Commercial Detail	Use Case	Equipment Required (Illustrative)	Discharge time		Charge time		Estimated value.	Current or future benefit?	Beneficiary
							Min	Max	Min	Max			
1 All DG	Buy & sell (arbitrage)	Economic - maximising market prices for exported power Description. Sale of energy stored in the battery for a higher price at peak times	The PV and storage system will shift peak generation from around midday to higher tariff periods in the early evening. There is also an overnight / morning peak arbitrage opportunity.	The typical half-hourly generation profile of a PV site resembles a bell-curve, peaking around midday. The proposed system will store a portion of this peak generation. When demand is high and PV generation is lower this energy will be exported for a higher price. Also power imported cheaply overnight can be sold during the morning peak too.	Energy exported either: according to trades made, PPAs (Power Purchase Agreements) or system price signals or during pre-set intervals when the peaks in market price normally occur. Energy is stored according to usage case 2), 4), 6) or 8).	Energy storage system (e.g. battery + Battery Management System (BMS)). Suitable inverter-charger (s). Controller. SCADA system, and integration to the controller and BMS.	0.5h	6h	0.5h	9h	£34.85/MWh Average Gross Profit per cycle.	Assumes B&S (Balancing and Settlement) fees will become competitive for distributed BMUs (Balancing Mechanism Units). 100% future benefit up to 400kWh. (*).	Operator

2 All DG	Customer demand peak lopping.	Matching demand to generation. ---------------------------- Description. Peak lopping of a local interruptible customer's demand to avoid curtailment	Contracting with an Active Network Management (ANM) demand customer connected to the same substation to provide them with upstream capacity when needed, as indicated by a trip signal from demand monitoring SCADA.	Where a new demand connection at a substation shared with a generator would require upstream reinforcement, the demand customer may instead opt for a cheaper ANM connection. Instead of risking being cut off when the ANM equipment indicates the upstream supply link is reaching its capacity limit, the demand customer may enter into a side contract with the Storage Operator to export energy onto their substation from the downstream side when they need it (and when the upstream link is near its limits) to benefit from a cheaper connection and avoid being tripped off.	Equipment for a normal ANM demand connection is installed. On days when the Storage Operator is under contract to supply local demand capacity, the storage operator must ensure the battery can supply the demand customer during the times needed (e.g. DUoS red periods) else risk any liquidated damages under the contract. The Storage operator schedules the battery to either: supply the energy at the allotted time, or wait for a signal from SCADA that an ANM event tripping the customer off is likely.	Energy storage system (ESS). Inverter-charger(s). Controller. Demand monitoring system and switch gear for ANM demand connection. On receiving soft trip signal from the ANM measurement point used for triggering disconnection, SCADA (Supervision Control And Data Acquisition) system to initiate export of energy from battery.	0	10h	-	-	£2000/trip off event avoided.	Future. Savings WPD would come from reduced need to upgrade the line and reduced peak network power upstream of the battery.	Third party and operator.
3 All DG	Network peak demand limiting	Peak Lop - exporting power to grid to lop network peaks Description. Use of storage to peak lop capacity on a specific network asset to avoid reinforcement or to prolong summer maintenance window when	Export set MWhs at specified times agreed with the DNO, or export power in response to real-time soft trip signals from local ANM monitoring equipment.	The grid can be supported by power exported by the storage system either when the operator indicates the distribution network is strained or during pre-agreed time slots. This can be monetised either by a short term contract between the DNO, to peak lop demand on a network asset, e.g. when one of a pair of transformers at a substation is being replaced	During the nominated times, either wait for a pre agreed scheduled time slot, or await a soft trip signal indicating load on the network asset is above a pre-set level. A guarantee of reliability of service is crucial if DNOs are to use this usage case. Otherwise they would favour business as usual solutions. Storage Operators could be incentivised financially or	Energy storage system. Inverter-charger(s). PLC. SCADA system to receive soft trip signals from DNO's SCADA or monitoring. Storage Operator to ensure energy in battery is available at the allotted time window to support the network, even if this means importing power	1h	3h (DUoS Red `traffic light' period is 2h)	-	-	£2500 / maintenance window extension to the DNO. £20k of asset upgrade deferral to the DNO is a more expensive NPV at 3.5% discount rate	Future. Network demand peaks at a local substation will be reduced but this benefit will not be monetised by including it in a long term development plan and the Operator will	DNO

		operating under n-1 conditions.		and the network is operating under n-1 conditions. If this maintenance window service proves reliable enough, the DNO may place a medium to long term contract to peak lop demand when needed, instead of upgrading or reinforcing network assets altogether.	contractually to prioritise this service, but unplanned outages of the storage system need to be managed, e.g. by a comprehensive warranty and prior planned maintenance. Energy is stored according to usage cases 2), 4) or 6).	from the grid (if generation was over forecast).					than £750 a year annual service charge at 2.5% inflation over 30 years.	charge no fee.	
4 PV only	Overnight low demand grid voltage support	Minimum demand - charging batteries from the grid at time of minimum load to limit voltage rise Description. Import electricity from the grid at times of low demand	Provide grid support when required by WPD or monitor the grid voltage locally and raise demand as required.	Voltage rise is a major issue caused by low demand overnight, as well as by embedded generation. The problem escalates with distance from the bulk supply point and primary substation. PV-energy storage integrated systems could provide a solution by acting as a regulating tool. The power control system could manage PV and battery inverters to ensure enough generation is stored to match voltage limits.	Either wait for: Signal from DNO SCADA voltage monitoring or Detection of voltage rise locally. Charge batteries until local voltage returns to normal or SCADA signal stops (or the batteries become full). Alternatively charge batteries at a pre-agreed power level over a pre-agreed fixed time interval.	Energy storage system. Inverter-charger(s). Controller. SCADA system for O&M and updates to software only. Voltage monitoring system.	-	-	2h	12h	?	Future. Once the project demonstrates voltage rise can be mitigated, upgrade of distribution assets can be deferred.	DNO
5 All DG	Voltage control by reactive power	Voltage Control - absorbing or pushing VArs onto the local grid.	Allow the storage system to provide voltage regulation.	Network voltages are required to be kept within statutory limits. Voltage support can be achieved using spinning reserve plant, capacitor banks,	Either: at a pre-agreed time or in response to a soft intertrip signal, switch on a closed control loop, and adjust	Battery Energy Storage System (BESS). Inverter-charger(s). Controller. Generation monitoring	0	-	0	-	£3/MVArh LV HH DUoS Reactive Power consumption	Future. Amount of MVArhs and tariff is too small to be worth installing	DNO

		Description. Absorption and supply of reactive power to help manage the network voltage		or STATCOMS. Some DG inverters and battery power conversion systems are capable of supplying reactive as well as real power.	voltage set point or supply ±VArhs at a pre-agreed scheduled time slot. If voltage drifts even further from this UC's limits, real power / import export can be triggered under UC7	system (except when charging under usage case 6) and a constant power).					charge as a minimum.	metering.	
6 PV only	PV export limiting	Extra Export - exporting additional MWh using storage to limit MW peak to the Maximum Export Capacity (MEC) in the connection agreement. Description. Reduced connection capacity requirement per MWp generation capacity	Use storage to limit the maximum export to the available capacity on the network, allotted to it in the grid agreement. Generation over this limit will supply the storage system, acting as a buffer.	Energy storage systems will allow generation to exceed the capacity of the associated network connection. This is only possible when control systems ensure exported power does not exceed the limitations of the surrounding grid. This will be done by charging the battery around midday and discharging it when capacity allows, as required. There need to be sufficient battery kWhs to ensure the drop in peak export can be sustained for long enough without the volume of lost generation becoming economically unacceptable.	Either: Charge the battery at a constant power during times the PV farm is generating, accepting the chance of importing power unless this charge rate is below minimum generation. Turn on a control loop that monitors generation and ramps up and down the battery charger rate as PV output above the threshold set point varies (due to clouds).	Energy storage system that will last for the lifetime of the (non de-rated) PV site. Inverter-charger(s). Controller. SCADA system for O&M and updates to software only. Generation monitoring system and control system (unless constant power charging).	-	-	1	7	£130/MWh	Future.	Operator

7 All DG	Power quality improvement	Smoothing and Power Quality improvement - avoiding large steps and swings in generation export making DG easier to forecast and predict. Description. More predictable DG output through lowering ramp rates and firming up export	Use storage to smooth exported power, lower ramp rates and improve predictability.	DG is intermittent - the power generated can increase and decrease rapidly depending on environmental factors (e.g. cloud). Energy storage could be used to export power when generation falls, smoothing the generation profile to make it consistent. Lowering the high ramp rates of a DG site extends the lifespan of the DNO's assets and makes management of the network easier. Modern power conversion systems can improve the nearby network's power quality.	Monitor generation in real time. Choose threshold for mitigation of fluctuations. Install a control scheme to keep these fluctuations below this threshold onto the controller. Export from storage when controller indicates upcoming fluctuation will breach the threshold. Feedback performance data from metering to update threshold and control scheme.	BESS. Inverter-charger(s). Controller. SCADA system for O&M and updates to software only. Generation monitoring system (except when charging at the constant 'overcast' power level).	20m	4h	20m	7h	£65/MWh. Difference in DUoS charges for non-intermittent and intermittent generators.	Future.	DNO
8 PV only	Variable PV export limiting Description. Raise or lower the MEC depending on thermal or voltage constraints	Non-firm connection – allowing dynamic setting of an export "glass ceiling", adjusting the level of peak lopping of PV output at times when technical network limits (voltage or thermal) could be neared.	When required by DNO, use storage to `lower the glass ceiling' placed on the power exported, absorbing or curtailing all generation above it. DNO to indicate when the `glass ceiling' may be raised again.	PV-energy storage integrated systems could act as regulating tools, assisting DNOs in operating below the technical line limits. Such a solar storage system could ensure the stability of the circuit it's on.	DNO decides a network operating limit is likely to be approached. DNO instructs storage operator to adjust `glass ceiling' export level by peak lopping. Energy stored to limit the power exported from the PV site, to keep network asset within its (voltage and thermal) stability limits. DNO lifts the constraint when network operation allows higher export level.	Energy storage system. Inverter-charger(s). Controller. SCADA system for O&M and updates to software only.	-	-	2h	12h		Future.	DNO

9 All DG	Multiple storage system control	System integration - coordination of multiple stores (and other smart grid systems) at a network level via control systems. Description. Demonstration of control and co-ordination of multiple storage systems	Co-ordinate complementary integrated DG-energy storage systems on two separate sites.	Installing energy storage systems on two sites on the same network may create unintended interactions and conflicts between them. These should be monitored. Different sites may wish to pursue different commercial goals.	As for Usage case 4). Update control scheme and operating parameters to ensure efficient dispatch of two sites, ensuring all interactions are constructive.	As above. Centralised ESS controller dispatches real system and virtual system together such that interactions are minimised.	-	-	2h	12h	?	Future. The control system will be scalable and able to co-ordinate despatch of multiple systems. A two container, one controller solution was even on offer during the tender.	DNO

Total direct benefits to British Renewables = £0. Total direct benefits to Western Power Distribution = £0. Nationwide future benefits (to all DNOs & DUoS customers) =£926k/MW p.a. Business benefit to British Renewables=£50m over 30 years (50MW of hybrid PV/BESS sites). Business benefit to Western Power Distribution=£85m.

(*)Arbitrage from a 300kWh system using system prices on the Balancing Mechanism would earn up to £316.20 a month but cost over £400 a month in fees. A 400kWh storage system is needed to break even. The system could still run as a BMU for a small number of months to prove the usage case.

(**) Investors benefit too via Operator.

(***) Modicon and Controller Area Network communication protocols.