# Electricity storage in future GB networks—
# a market failure?

Philipp Grünewald

*Centre for Energy Policy and Technology, Imperial College London,*
*311 Mechanical Engineering Building, London SW7 2AZ, UK*

**Abstract**

Electricity markets in the UK have evolved primarily around large scale generators, while networks remain regulated monopolies and demand is treated as passive. With increased penetration of less flexible low carbon technologies and the possible electrification of heat and transport towards 2050, both networks and demand may need to become more active components of the electricity system, to ensure cost effective balancing of supply and demand. One option that could facilitate improved system integration of new technologies is electricity storage.

Widely regarded as too expensive, electricity storage has recently been shown to have the potential to significantly reduce the cost for the electricity system as a whole, making it a macro-economically attractive proposition.

However, the diverse sources of value, including network, operational, generation capacity and $CO_2$ savings, are difficult to aggregate under current market frameworks. Moreover, institutions and rules, developed in support of existing regimes, could potentially lock-out 'disruptive' technologies, such as electricity storage.

This paper explores the long term commercial value of generic storage properties operating in volatile future electricity wholesale markets and contrasts these with their overall system value.

The results suggest that changes in the role for storage over the coming decades could pose a challenge for the development of the most appropriate technologies and engagement of all potential beneficiaries. The effect of potential instruments, intended to support storage, could lead to unintended consequences. The impact of a capacity mechanism on storage is used to illustrate some of the policy challenges in creating market mechanisms that deliver storage deployment and operation in the best societal interst.

*Keywords:* Electricity storage, electricity markets, capacity mechanism

*Email address:* pg1008@ic.ac.uk (Philipp Grünewald)

## 1. Introduction

For some, electricity storage is the 'holy grail' of our sustainable energy future. Many of the challenges of integrating renewables into the energy system could be addressed if only electricity could be stored.

Intermittent or poorly controllable generation profiles, which are common to many low carbon technologies, present technical and cost challenges for future systems. The more renewables are installed on the system, the greater the challenges of integration become: reduced load factors for conventional plant, network reinforcements, and additional reserve requirements for system balancing could burden the transition towards a low carbon future.

Technically, electricity can be stored, of course, but critics claim that it is 'just too expensive'.

The argument put forward by proponents of storage tends to be qualitative. Storage is seen as an 'intuitively good idea' and it is widely accepted that storage has 'a role to play'. Subsequently there are calls on policy makers to 'get on' and provide much needed support. (Price, 2011)

Policy makers, on the other hand, say that they are 'hurting for evidence', because the value of storage is still poorly understood. The estimated future capacity ranges from anything between 7 and 59 GW for 2050 (DECC, 2012).

Investment in storage is critical to its deployment, and understanding the uncertainties facing investors is an important component in understanding their decision making processes. This paper therefore sets out to understand the factors that impact on the commercial value of storage. A time resolved techno-economic model, built on historical wind and demand data, will be discussed and used to identify the sensitivities of the commercial value of storage to investors.

The characteristics of the UK wind resource and its impact on the electricity system are relatively well researched (Gross et al., 2006; Sinden, 2007). Further studies have explored the use of storage in connection with renewable energy systems (van der Linden, 2006; Solomon et al., 2010; Exarchakos, 2008; Wilson et al., 2010; Weber, 2005), often with a focus on isolated systems. This study specifically chooses to model the integration of storage into the grid, as suggested by Korpas and Gjengedal (2006); Barton and Infield (2004); and Anderson and Leach (2004).

Two broad approaches have been taken to modelling UK electricity systems. System studies tend to employ a holistic and system wide perspective with only coarse temporal resolution (DECC, 2010a; Ault et al., 2008; Ekins et al., 2009; Coleman, 2012). Other studies attempt to understand system balancing with high penetration of wind and issues arising from ramp and slew rates of wind and errors in wind forecasting. These studies require high temporal resolution and therefore tend to simulate short periods of time. (Black and Strbac, 2007, 2006; Pelacchi and Poli, 2010; Barton and Infield, 2004; Bathurst and Strbac, 2003)

The model in this study is positioned between the two approaches above. It draws on six years of historical data with high temporal resolution (half hourly to hourly). Both wind and solar PV are modelled in some detail. For simplicity and computational reasons many other aspects of the energy system are simplified. The model is built on the principle of an idealised energy market, which dispatches energy on a least short run marginal cost basis and storage operates on arbitrage within this market.

## 2. Techno-economic representation of storage

Figure 1 gives an overview of the model structure. Wholesale price profiles are constructed from time resolved data for meteorological resources and power demand for a given scenario and plant mix. The wholesale price profiles form the basis for the decision to charge or discharge storage. The operating strategy is to provide arbitrage, by buying at low prices and selling at high prices. Other sources of revenue are not considered at this stage.

For analytical simplicity, the GB network is assumed to be a single bus system (a 'copper plated island'). Demand can be met by generation, independent of its physical locations and free of network constraints or losses. This assumption constitutes a worst case for storage, since transmission and distribution constraints can be expected to make storage more favourable during times of congestion between regions. Recent modelling by Strbac et al. (2012) suggests that transmission constraints are unlikely to contribute significantly to the value of storage, while distribution network savings could potentially become commercially attractive, as will be discussed in Section 3.6.

The model does not perform asset allocation. It sets out with a given plant mix based on the scenario being simulated. For high penetrations of storage one would expect that the plant mix could be re-optimised, which would require a systems model approach and is not part of this study. For small levels of storage penetration, the resulting error is expected to be acceptable.

The value of storage is presented as a generic and technology agnostic annual gross value. If the lifetime and the resulting discount factor ($a$) for a given technology are known, the annual gross value ($V_{str}$) can be converted into a capital cost target ($C_{max}$) as

$$C_{max} = a \times V_{str}. \tag{1}$$

As an example, if pumped hydro was assumed to have an economic life of 20 years and and interest rate of 10%, a capital cost of £560/kW would require an annual gross value of at least £65.77/kW.

### *2.1. Representation of wholesale price setting behaviour in a competitive electricity market*

The approach adopted here is based on work by Richard Green (Green and Vasilakos, 2010a, 2007, 2010b) and Dan Eager (Eager, 2010; Eager et al., 2010). The underlying philosophy is simple: during periods of high demand, fewer participants remain with spare

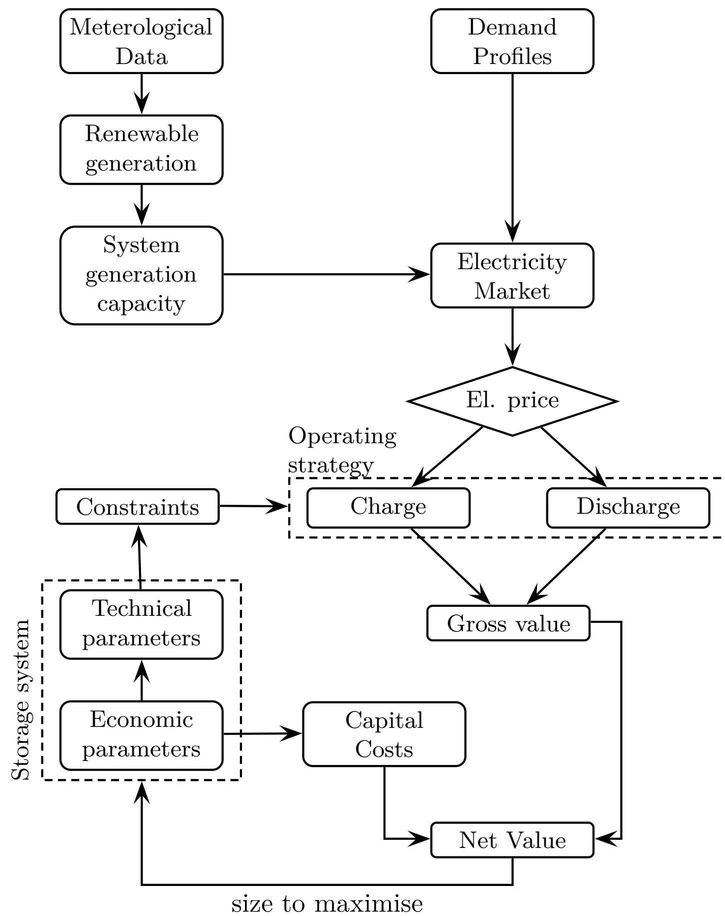



**Figure 1:** *Flow chart of the techno-economic model. A time series of storage charge and discharge is built up from renewable resource and demand data. The operating pattern is optimised for maximum gross value. (Optionally specific technologies can be simulated for maximum NPV)*

generating capacity, which puts these actors in a stronger bidding position to mark up the wholesale price. One can equally reverse the perspective and argue that peaking plants only operate during periods of high demand and thus have to mark up the offer price sufficiently to recoup the capital expenditure on their investment. The lower the load factors for these plants becomes, the higher the markup during these periods has to be. In the absence of such price spikes these plants are not economically viable, retire and risk supply shortages and blackouts.[1]

The same principle can be applied for the reverse situation. If demand is low and plant with high short run marginal cost are no longer operating, any further reduction in generation requires plant with low short run marginal costs (and thus little incentive to curtail output) to reduce generation. The bidding position is now reversed in that bidding takes place on the price at which these actors are willing 'not to generate'. As in the example above, the less capacity remains the stronger the bidding position for those actors and market prices can depart significantly from the marginal cost. The symmetry between this marking up and marking down of wholesale prices allows for a single function to describe both phenomena.

The function to calculate the uplift $U$ consists of a proportional term ($\kappa$) and an exponential term ($\alpha$)

$$U_g(t) = 1 + \kappa \times e^{-\alpha\left(\frac{C_g - P_g(t)}{C_g}\right)} \tag{2}$$

where $g$ denotes the class of generator in the merit order (e.g. peaking plant, or wind). The multiplier in the exponent is a measure of the 'slack' in the system. $C_g$ is the installed capacity of this class and $P_g(t)$ denotes the output of this class at this moment in time. Analogously, during periods when demand is low, $C_g$ is the capacity remaining on the system and $P_g$ is the curtailment required from this asset class.

From this uplift function the wholesale price $\Pi$ at time $t$ can be calculated from the marginal price $\dot{\pi}_g$ as

$$\Pi_g(t) = \dot{\pi}_g \times \left[1 + \kappa \times e^{-\alpha\left(\frac{C_g - P_g(t)}{C_g}\right)}\right] \tag{3}$$

The uplift function only applies to the extremes of the merit order. Mid merit plants are bound by the marginal costs of their neighbouring plants. Their minimum bid is their own short run marginal cost and the maximum markup they can realise in a competitive market is the short run marginal cost of the next more expensive plant ($\dot{\pi}_{g+1}$). Between these two points a linear relationship of output and wholesale price is assumed.

$$\Pi_g(t) = \dot{\pi}_g + \left[(\dot{\pi}_{g+1} - \dot{\pi}_g)\frac{P_g}{C_g}\right] \tag{4}$$

[1] The extent to which uncertainty over future earnings can inhibit resource adequacy despite such price signals has been studied by Eager (2010) and is discussed in (Grünewald et al., 2011).

**Table 1:** *Merit order of short run marginal costs for broad generation classes. Based on Green et al. (2011) and MacDonald (2010). ROC=value of renewable obligation certificate. *=for abated generation an additional £10/MWh is assumed.*

| Merit order (g) | Plant type | $\dot{\pi}$ [£/MWh] |
|---|---|---|
| 1 | Wind | -ROC |
| 2 | Base load | 8 |
| 3 | Mid merit | 20* |
| 4 | Peaker | 30* |

If one assumes a system with $n$ classes of plant, the price function can be written as a combination of 3 and 4 as

$$\Pi(t) = \begin{cases} \dot{\pi}_g \times \left[1 + \kappa \times e^{-\alpha\left(\frac{C_g - P_g(t)}{C_g}\right)}\right] & \text{if } g = n \\ \dot{\pi}_g \times \left[1 + \frac{\dot{\pi}_{g+1} - \dot{\pi}_g}{\dot{\pi}_g} \frac{P_g}{C_g}\right] & \text{if } 1 > g > n \\ \dot{\pi}_g \times \left[1 + \kappa \times e^{-\alpha\left(\frac{C_g - P_g(t)}{C_g}\right)}\right] & \text{if } g = 1 \end{cases} \tag{5}$$

Table 1 lists the generation classes by merit order of their short run marginal costs.

The values for $\kappa$ and $\alpha$ are not universal, but depend on the scenario in question. The value for $\alpha$ is calibrated against price duration curves in literature published by Cox (2009), Green and Vasilakos (2010a) and Eager (2010). An $\alpha$-value of 4–4.5 agrees well with these studies.

The price uplift is dynamically configured to ensure that peaking plants remain commercially viable. This condition is translated into a 95% confidence by the investor that the net present value of the investment is positive. To test this condition a normal distribution of probable future values is assumed, with load factors and fuel prices as the main source of uncertainty. The gas price projections are based on DECC estimates and listed in Table 2.

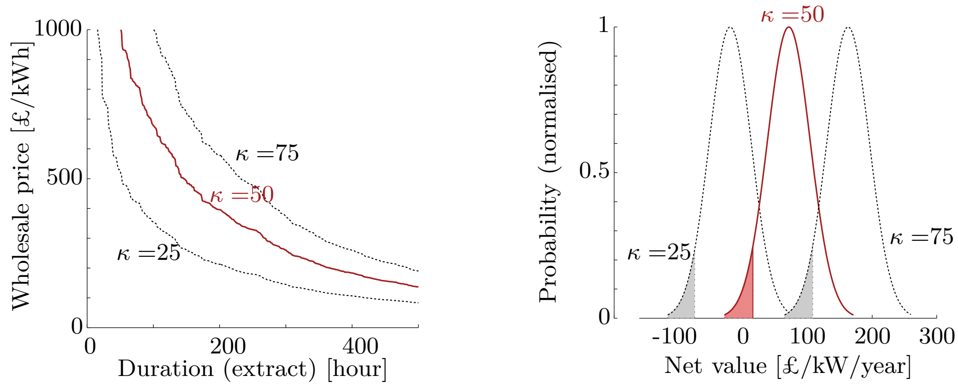
Figure 2a shows how changes to the $\kappa$ value of the uplift function shift the price duration curve and thus change the NPV expectation for peaking plants, displayed in Figure 2b.

*2.2. Storage time series*

Storage is represented as a time series of energy flows in and out of storage for each time period ($\Delta t$). The flow, $f_{(t)}$, is constrained by the power $P_{str}$ of the storage system

**Table 2:** *Gas price forecasts for 2030 based on DECC (2011)*

| Estimate | Cost [£/kWh$_{th}$] |
|---|---|
| Low | 12 |
| Central | 24 |
| High | 34 |




**(a)** *Price duration curve for different $\kappa$ values.*

**(b)** *Net value probability distribution for a gas fired peaking capacity. Filled areas enclose the 5% confidence interval*

**Figure 2:** *The $\kappa$ value of the uplift function shifts the price duration curve and thus the revenue for peaking capacity operating in this price zone. Here, with $\kappa \geq 50$, the confidence in a positive NPV is $\geq$95%.*

and its charge and discharge efficiency $(\eta_{in}, \eta_{out})$

$$-\frac{P_{str}}{\eta_{out}} \leq f_{(t)} \leq P_{str} \times \eta_{in}$$

The amount of energy flowing in and out of storage in each time period is further limited by the storage level at the time, $S_{(t)}$. Energy removed from storage cannot exceed the storage level at the time, nor can more energy be stored than capacity $(E_{str})$ is available.

$$S_{(t-1)} \leq f_{(t)}) \times \Delta t \leq E_{str} - S_{(t-1)}$$

Furthermore, a ramp constraint $(\delta P)$ can be applied.

$$-\delta P \leq f_{(t)}) \leq \delta P$$

From this flow the storage content can be developed as a time-series with

$$S_{(t)} = S_{(t-1)} \times \eta_{self} + f_{(t)} \times \Delta t$$

where $\eta_{self}$ is the self discharge rate.

The flow can be seen as a storage internal process. What the external energy system experiences it the load delivered or taken by storage $(P(t))$:

$$P(t) = \begin{cases} f_{(t)} \times \eta_{in}^{-1} & if\ f_{(t)} > 0 \\ f_{(t)} \times \eta_{out} & if\ f_{(t)} \leq 0 \end{cases}$$

The gross value of storage is the sum of all transactions where the energy consumed is charged at the market price at the time and energy delivered is rewarded as

$$V_{str} = -\sum_{t} P(t) \times \Pi(t) \times \Delta t$$

The objective function is to maximise $V_{str}$ by optimising $P(t)$ within the system constraints.

*2.3. Scenarios and input data*

The core scenario for this study is based on the DECC Grassroots scenario, a high renewables pathway davelped by DECC (2010a). The pathway for this scenario is shown in Figure 3. The resulting capacity mix assumed for the grassroots scenario is listed in Table 3 alongside alternative nuclear and CCS scenarios.

Electricity demand profiles are based on data from National Grid (National Grid, 2010) for a 6 year period (2003–2009) with half hourly resolution. For the same period wind profiles have been constructed from BADC data (BADC, 2012).

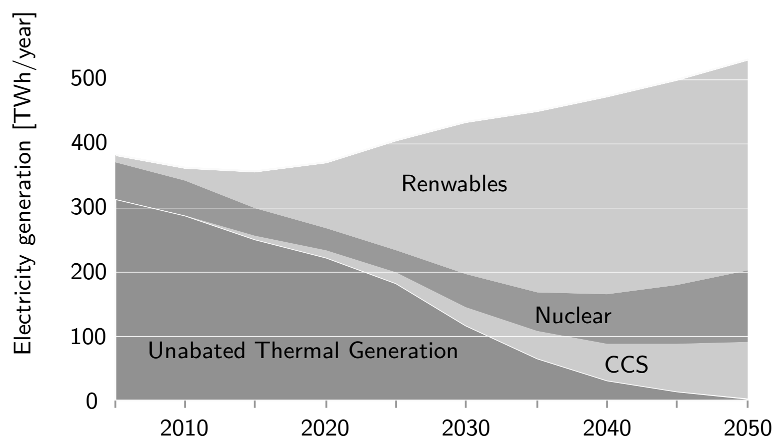



**Figure 3:** *Electricity generation by plant type in the Grassroots scenario. Based on DECC (2010a)*

**Table 3:** *Capacity mix for core scenarios in the year 2030. Based on DECC (2010a) and Strbac et al. (2012)*

| Plant class | Share of conventional generation [%] | | |
|---|---|---|---|
| | Grassroots | Nuclear | CCS |
| Baseload | 14.7 | 35.4 | 12.9 |
| Mid merit | 53.7 | 24.0 | 53.3 |
| Peaking | 31.6 | 40.6 | 33.8 |
| Renewables | 60.0 | 9.4 | 18.0 |

## 3. Gross value of storage

*3.1. Storage value increase with wind deployment*

Intermittent generation increases the volatility of electricity prices, which adds to the value proposition for storage. Figure 4 shows the increasing gross value of storage for the base case scenario with increasing amounts of wind.

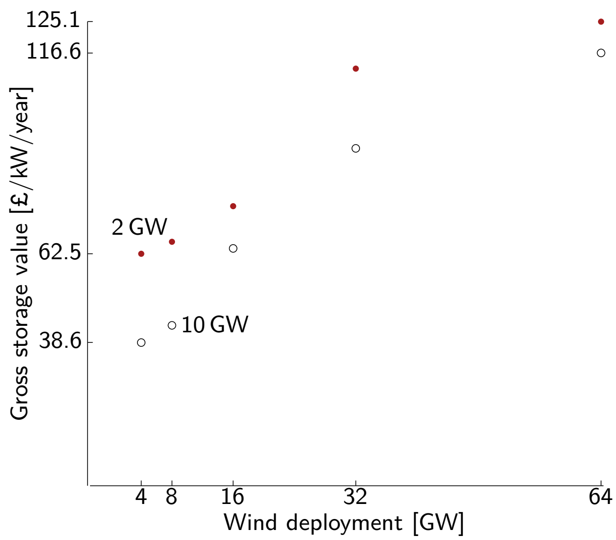



**Figure 4:** *Increase in gross value of storage with increasing wind deployment. 2 and 10 GW storage with 6 hour duration. Based on Grassroots 2030 scenario.*

At present levels of wind the value is not sufficient to stimulate further investment, and even at 16 GW of wind values do not increase substantially, yet. At 32 GW of wind deployment, the gross value begins to exceed £100 per kW per year, which is roughly the level of present technology options. With further expansion of wind capacity the value increase begins to level out.[2]

The relative difference between the value of 10 GW and 2 GW storage reduces with increasing levels of wind, pointing towards a larger market for storage. The effect of diminishing value with increasing capacity is discussed in the following section.

*3.2. Diminishing marginal value*

Storage is often said to suffer from ‘self cannibalisation’: the more storage is installed the less it is worth. Arbitrage levels prices, which diminishes its own value.

[2]Assuming excessive amounts of wind on the system leads to persistent oversupply of electricity, which—if stored—can no longer be discharged, unless other plants are retired.

Figure 5 shows the reduction in value with increasing capacity for a fixed point in time with a given amount of wind installed. The value of storage reduces in two ways. First, the average value, which is the value based on the entire installed capacity drops off for simulations with larger storage capacities.

The average value assumes that the entire fleet of storage is invested in and operated as a single monolithic unit. In practice, storage is deployed incrementally. A potential investor of additional capacity is therefore interested in the *marginal* value of any *added* capacity. This value, as shown in Figure 5 tends to be significantly lower.

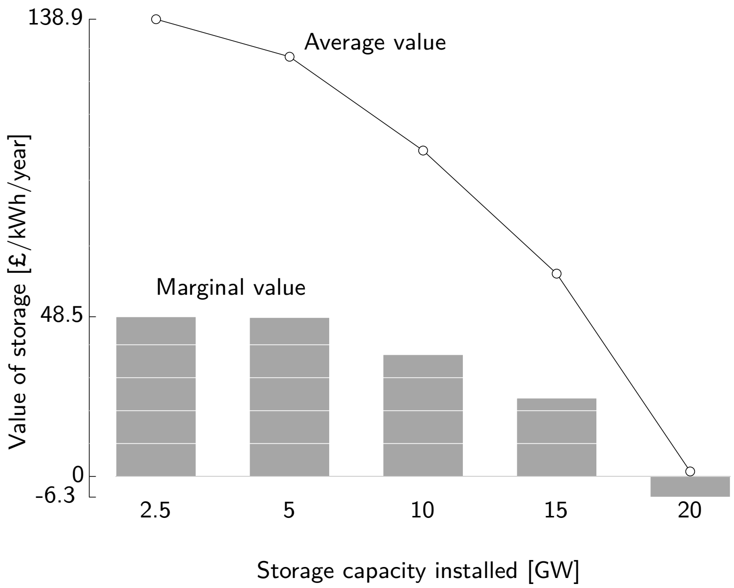



**Figure 5:** *Declining marginal value of storage with increased deployment. Example shown for 40 GW wind case with 2 hour storage duration and 2 hours foresight.*

### 3.3. Value of storage duration

A similar effect of diminishing value applies to the energy capacity (i.e. the maximum amount of energy that can be held in storage).

Figure 6 shows how the highest values can be achieved with relatively short storage durations. The additional value of increasing the energy capacity to longer storage durations falls sharply.

It is short durations that can capture the most volatile 'spikes' in the price profile. The added value from longer duration storage has to come from trades in the remaining, smoother price profile.[3]

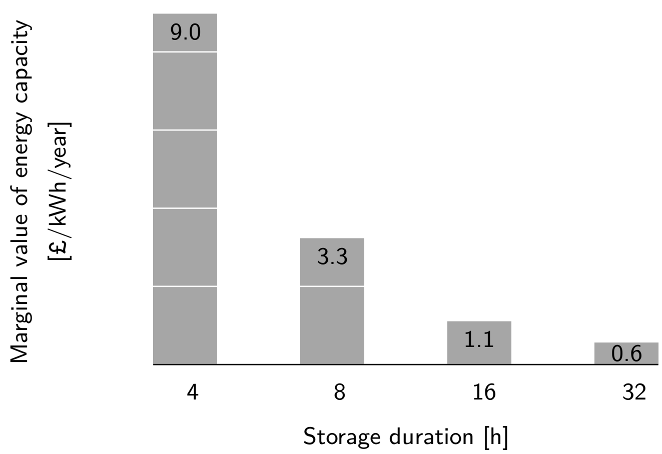


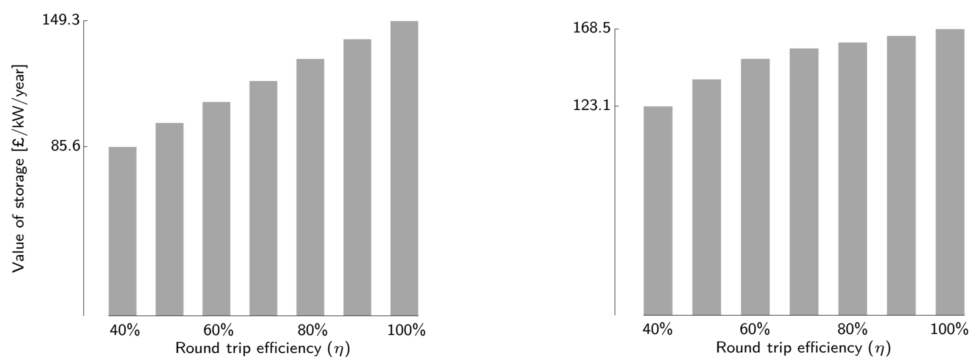

**Figure 6:** *Diminishing marginal value for increasing storage durations. Based on Grassroots scenario with 10 GW of storage.*

[3] Despite the lower value of long duration storage, some technologies with low energy capacity cost, such as CAES of hydrogen, may be able to operate profitably within such markets as shown by Grünewald et al. (2011)

### 3.4. Storage efficiency

Low round trip efficiency is cited as one of the drawbacks of electricity storage. The sensitivity of the value of storage to its efficiency has therefore been simulated.

Figure 7 shows two simulations of storage with 20 and 40 GW of wind on the system respectively. In the former the value of storage increases almost linearly with efficiency at around £1.6 per kW per percentage point. With higher levels of renewables the marginal value of efficiency reduces, especially above 70% efficiency. Here, one percentage point is worth less than £0.5 per kW.




**(a)** *20 GW wind* **(b)** *40 GW wind*

**Figure 7:** *Higher efficiencies have a minor impact on the value of storage in high wind scenarios. Case: 10 GW with 6 hour duration in base case scenario.*

### 3.5. Storage in nuclear and CCS scenarios

The primary driver of the value of storage in the examples so far has been the effect of intermittent wind on wholesale prices. Scenarios with stronger emphasis on CCS and nuclear yield significantly lower values.

The nuclear scenario with a high share of base load capacity still shows a somewhat increased value of storage compared to present levels. Storage has the potential to charge with relatively low cost energy during low demand periods, but the price spikes are less extreme, since peaking capacity operates on higher load factors.

In the case of CCS the situation is highly unfavourable for storage. The marginal cost of generation are generally higher with less arbitrage potential.

### 3.6. Mismatch between market value and social value

The analysis above considers the commercial value of storage for investors operating an an idealised and somewhat confined wholesale market. Whole system studies can provide

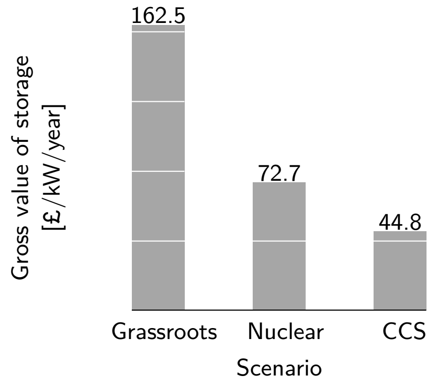



**Figure 8:** *Sensitivity to changes in scenario assumption. The high renewables Grassroots scenario yields the highest value. The CCS scenario is least suitable for storage. Examples shown for 10 GW 6 h storage.*

insight into the wider system value, but do not necessarily expose the attractiveness of the technologies to investors. Unless perfect markets are in place, one would expect a discrepancy between the 'system value' and the 'market value' of storage.

Grünewald et al. (2012) argue that not all benefits of storage are necessarily captured by trading in volatile wholesale markets. If wider benefits exceeded the commercial value of storage, a welfare loss as illustrated in Figure 9 could result.

Strbac et al. (2012) conducted a comprehensive study of the system value of storage, irrespective of market arrangements, and the resulting values for comparable cases are contrasted in Figure 10.

The meaning of 'value' behind the two graphs is different. The system value is the amount that could theoretically be saved per year across the system for every kW of storage installed, assuming system optimal allocation and operation. The market value stems from the trading revenue realised with each kW per year of operating in an energy based market. All values are gross values, meaning no costs for storage technologies have been deducted. The difference between the two graphs can be attributed to a number of reasons, including different solvers and sources of data.

These potential differences notwithstanding, some of the discrepancy of results might be attributed to systematic differences in analysis. Network savings are not accounted for in the techno-economic model, since wholesale prices do not explicitly reflect local or regional network constraints. Unlike transmission network savings, distribution network savings are potentially significant in value[4], and they are therefore marked separately in

[4] See Strbac et al. (2012), who conclude that transmission would be built in preference to storage due to

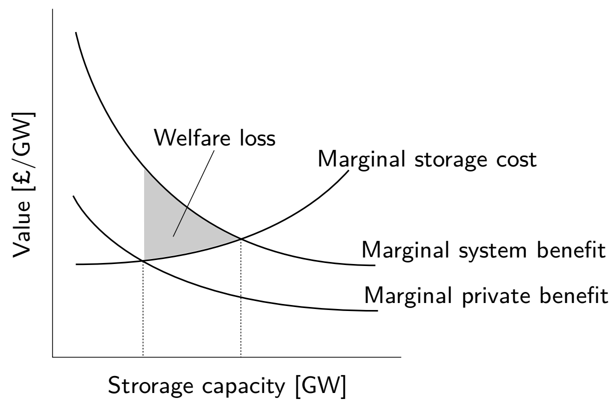



**Figure 9:** *Welfare loss as a result of underinvestment. Once marginal private benefits are equal to the marginal cost of storage no further storage is deployed, leaving a welfare loss of not realised system benefit.*

Figure 10.

Furthermore, spinning reserve, which has to be held for fast reserve provision especially in high wind scenarios, is a costly and inefficient form of generation. It can displace other sources with potentially very low short run marginal costs and lower emissions. Spinning reserve is scheduled by the system operator on operational (rather than least cost dispatch) grounds and any potential savings are therefore not necessarily captured in the wholesale market approach. This may account for some of the larger discrepancies between system and market based values for smaller capacities.

The value gap between the wholesale market based model and the whole-systems model shows that the wholesale energy market alone may not capture the maximum value, nor does it therefore stimulate the optimal use of storage. Either markets have to develop mechanisms to effectively reward such savings, or policy makers need to create the appropriate conditions. The market values in Figure 10 constitute the lower bound (market value) and the upper bound (system value) of what such a framework could achieve.

*3.7. Value aggregation*

The range of sources of value that storage potentially has to aggregate poses a challenge for its uptake in present markets. Figure 11 illustrates with an example based on Strbac et al. (2012) how different sources of value can build up over time.

The composition of value also changes over time. In 2020 savings through avoided

its lower costs.

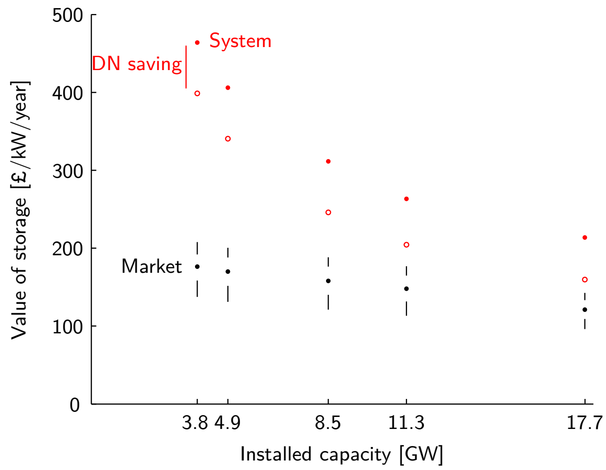



**Figure 10:** *Market and system value of storage. The value for storage realised in a volatile energy market is consistently lower than the system wide value. Based on 2030 adapted Grassroot scenario with 6 h storage. System values: Strbac et al. (2012)*

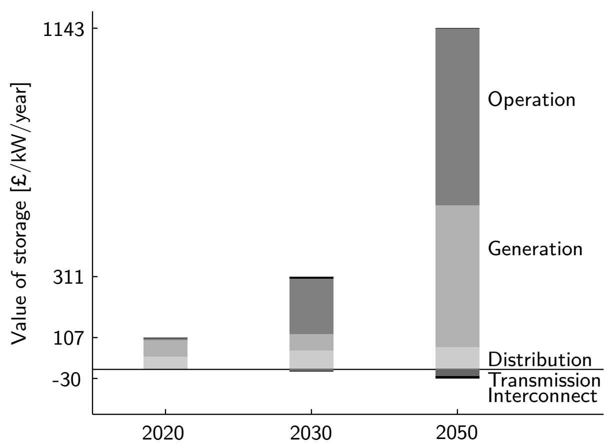



**Figure 11:** *Illustrative example of storage value composition 2020–2050. In 2020 distribution network savings provide a large share of value. In 2030 operational savings constitute the largest component, before in 2050 savings from avoided peak generation capacity become significant. Distribution network savings remain stable in absolute terms, such that their relative contribution in 2050 becomes minor. Based on adapted DECC Grassroots scenario with 10 GW, 24 hour distributed storage, Strbac et al. (2012).*

distribution network reinforcements could make up a large part of the overall value. By 2030 their relative contribution becomes minor and operational savings from more efficient plant scheduling dominate. The composition in 2050 could change again when costly peaking plants, which in 2050 would have to be $CO_2$ abated in order to meet overall emission constraints, could partially be displaced through storage, resulting in savings on such costly generation capacity.

*3.8. Capacity mechanism*

It has been argued by some stakeholders and policy makers alike, that a capacity mechanism could favour electricity storage and create an incentive for investment.

The details of any future capacity mechanism are not yet known. DECC (2010b, p. 173) set out the envisaged effect of a capacity mechanism on wholesale prices as shown in Figure 12.

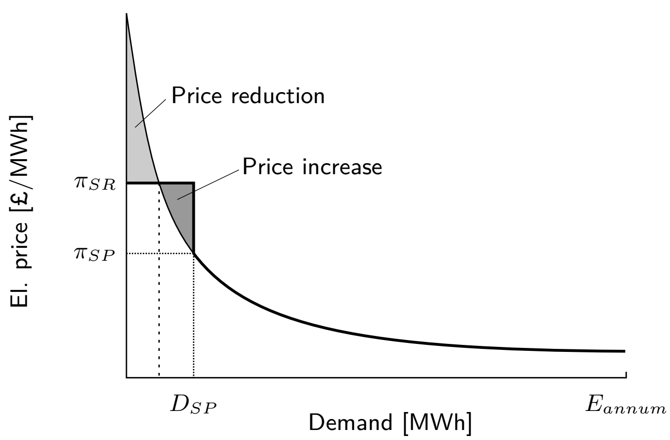
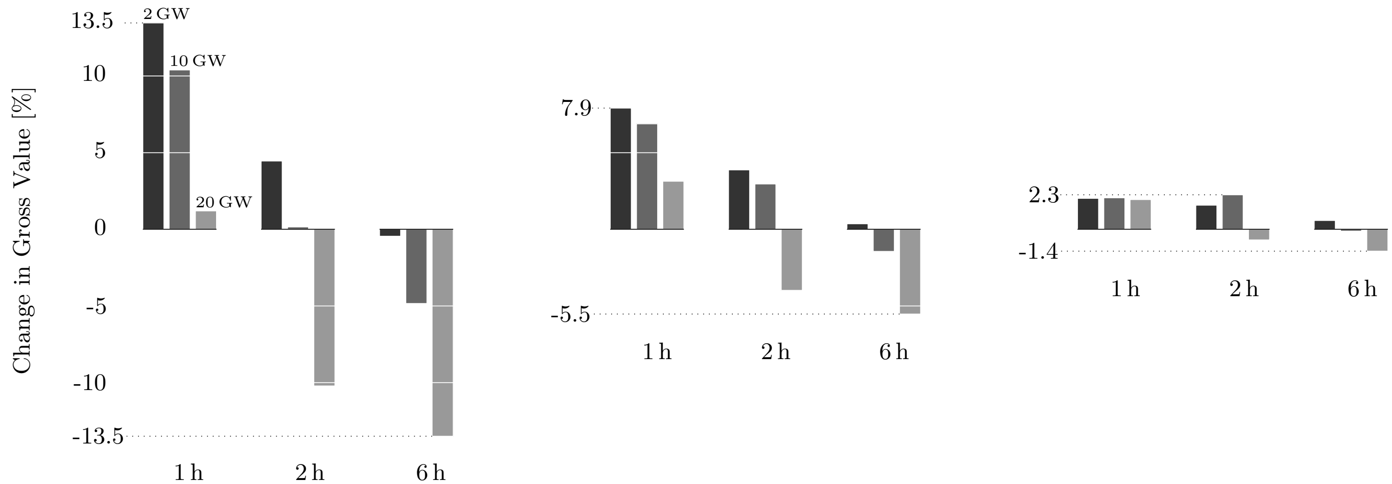



**Figure 12:** *Effect of a capacity mechanism on the price–demand curve. Under the capacity mechanism, when demand reaches $D_{SP}$ the price steps from $\pi_{SP}$ and remains at $\pi_{SR}$. The mechanism redistributes revenue from the lighter to the darker shaded area. Based on DECC (2010b)*

When demand exceeds a critical level ($D_{SP}$), the wholesale price setting is suspended and the price remains at $\pi_{SR}$ until the demand situation relaxes. Prices above the strike price ($\pi_{SP}$) are expected to be redistributed into a flat profile.

The new wholesale price profile changes the operation of storage. The results of relative changes to the gross value of storage are shown in Figure 13. The biggest changes in value take place when the strike price assumed at its highest value. The higher the strike price, the smaller the part of the price duration curve that is affected and less redistribution takes place. The trends are, however, consistent throughout.




**(a)** $\pi_{SP} = 200$ **(b)** $\pi_{SP} = 400$ **(c)** $\pi_{SP} = 800$

**Figure 13:** *Relative changes in gross value of storage in a capacity mechanism. Larger storage capacities ($2 \rightarrow 20\,GW$) and longer storage durations ($1 \rightarrow 6\,h$) are worse affected by a capacity mechanism. The higher the strike price ($\pi_{SP}$) the smaller the impact.*

Small duration storage fares best, especially with small capacities. To some extent this is an unintended consequence of the new price profile. Small amounts of storage can take advantage of the price discontinuity, when the system changes from wholesale prices to the capacity mechanism. A sudden step change in price suits short duration storage.

Longer storage durations perform less well in this simulation. Their value is unchanged for small capacities, and large storage capacities with long duration can even reduce in value.

However, as with the peaking capacity, the capacity mechanism is also intended to reduce investment risk. And here the picture is more positive. This is shown for the example of the 10 GW storage with 6 hour duration, which in Figure 13b lost 5.5% of the gross value compared to the pre capacity mechanism results. The probability distributions of the gross value in Figure 14 compares both cases. The higher value without capacity mechanism also has a wider distribution.

If investment condition of a 95% confidence in a positive NPV from Section 2.1 is applied, the lower mean value under a capacity mechanism does yield a more relaxed target cost. The increase in investor confidence could lead to an increase in permissible technology cost from £123 to £141 per kW per year.

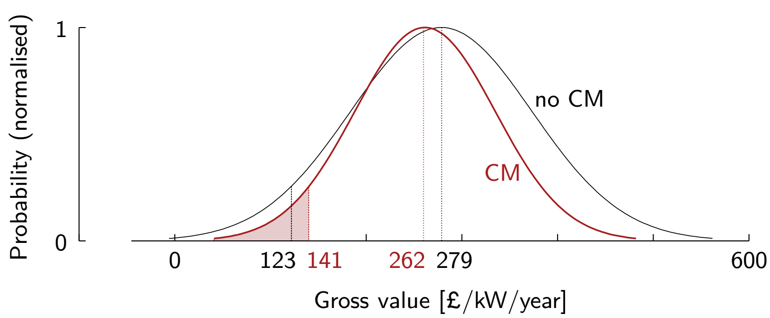



**Figure 14:** *Effect of capacity mechanism on gross value distribution of storage. A capacity mechanism reduces the mean value expectation for storage. The uncertainty is, however, reduced and the annual technology cost at which an investor can be 95% confident to make a positive return in this case increases from £123 to £141 per kW year. (Example for 10 GW 6 hour storage in base case scenario with $\pi_{SP}$=400)*

## 4. Conclusions

The discrepancy between market and system values within similar scenarios supports the suggestion that the private value of storage in electricity markets does not necessarily reflect the full system value. The gap could be reduced if—as one stakeholder suggested—access to potential distribution network saving were more accessible in the market. Other contributing factors, such as savings in system operation, are potentially more difficult to include in market arrangements and require careful balancing of long term cost, security and emission objectives.

Aggregation of a number of value streams accruing for different stakeholders across these regimes poses a commercial challenge for storage operators. Cross sectoral and strategic planning may be necessary if the long term aggregate value is to be captured in the common interest. Failure to do so could inhibit the uptake of storage and may lead to a welfare loss.

Changing regime tensions, shifting the largest share of value from network operators in 2020, towards system operators, and later the generation regime, require consideration of these future stakeholders in the development of policies shaping the pathways towards such systems. If the long term benefits are to be built into the policy framework the engagement with network operators in the early phase of deployment would need to be complemented with the inclusion of future interests of system operators and generators. Dedicated simulation may be required to identify future benefits for particular sectors and to guard against unintended consequences.

A capacity mechanism, which was seen by many as a 'storage favourable' instrument, is not necessarily a panacea. Short storage durations tended to fare better, but in part this was due to windfall revenues from price jumps when the system changes from market prices into the capacity mechanism. Longer storage durations did not benefit from the capacity mechanisms as simulated here. However, even if the mean value of storage reduced, the distribution also reduced, which could lead to higher investor confidence.

## Acknowledgements

This research is supported under NERC award NE/G007748/1 for Phase II of the UK Energy Research Centre and by EPSRC via the 'Supergen HiDEF' grant. Further thanks go to the Imperial Energy Futures Lab CDT programme and especially to Prof. Goran Strbac for valuable insight into the operation of the GB electricity systems with storage.

## References


Anderson, D., Leach, M., 2004. Harvesting and redistributing renewable energy: On the role of gas and electricity grids to overcome intermittency through the generation and storage of hydrogen. Energy Policy 32, 1603–1614.

Ault, G., Frame, D., Hughes, N., Strachan, N., 2008. Electricity Network Scenarios for Great Britain in 2050. Final Report Ref. No. 157b/08. Ofgem LENS Project.

BADC, 2012. Met Office Surface Data Users Guide. [Online] Available from badc.nerc.ac.uk [Accessed on: 26 Mar 2012].

Barton, J.P., Infield, D., 2004. Energy storage and its use with intermittent renewable energy. IEEE transactions on energy conversion 19, 441–8.

Bathurst, G.N., Strbac, G., 2003. Value of combining energy storage and wind in short-term energy and balancing markets. Electric power systems research 67, 1–8.

Black, M., Strbac, G., 2006. Value of storage in providing balancing services for electricity generation systems with high wind penetration. Journal of power sources 162, 949–953.

Black, M., Strbac, G., 2007. Value of bulk energy storage for managing wind power fluctuations. IEEE transactions on energy conversion 22, 197–205.

Coleman, J., 2012. Developing the UK Energy System — Energy System Modelling Environment (ESME). [Online] Available from www.eti.co.uk. Energy Technologies Institute (ETI).

Cox, J., 2009. Impact Of Intermittency: How Wind Variability Could Change The Shape Of The British And Irish Electricity Markets. Technical Report. Poyry Energy. Oxford.

DECC, 2010a. 2050 Pathway Analysis. HM Government. [Online] Available from www.decc.gov.uk/2050.

DECC, 2010b. Planning our electric future: a White Paper for secure, affordable and low-carbon electricity. White Paper. The Stationery Office.

DECC, 2011. DECC fossil fuel price projections. URN 11D/872. Department for Energy and Climate Change.

DECC, 2012. Technology Innovation Needs Assessment (TINA). Electricity Networks & Storage (EN&S) Summary Report. Low Carbon Innovation Coordination Group.

Eager, D., 2010. A dynamic control model of the UK electricity generating capacity investment market: engineering tools applied to an economic problem. 8-9 April. $8^{th}$ YEEES seminar. Cambridge.

Eager, D., Bialek, J., Johnson, T., 2010. Validation of a dynamic control model to simulate investment cycles in electricity generating capacity, in: Power and Energy Society General Meeting, 2010 IEEE, IEEE. pp. 1–8.

Ekins, P., Skea, J., Winskel, M., Howard, D., Eyre, N., Hawkes, A., 2009. Making the transition to a secure and low-carbon energy system. synthesis report S3097_inner. UKERC.

Exarchakos, L., 2008. Electricity Storage Management; Profits optimisation under Demand-Side Management: the case of Greece. PhD thesis. Imperial College London.

Green, R., Hu, H., Vasilakos, N., 2011. Turning the wind into hydrogen: The long-run impact on electricity prices and generating capacity. Energy Policy 39, 3992–3998.

Green, R., Vasilakos, N., 2010a. The long-term impact of wind power on electricity prices and generating capacity, in: 11th IAEE European Conference, Vilnius.

Green, R., Vasilakos, N., 2010b. Market behaviour with large amounts of intermittent generation. Energy Policy 38, 3211–3220.

Green, R., Vasilakos, N.V., 2007. The long-term impact of wind power on electricity prices and generating capacity. Technical Report. Unversity of Birmingham.

Gross, R., Heptonstall, P., Anderson, D., Green, T., M., L., Skea, J., 2006. The Costs and Impacts of Intermittency. Technical Report. UK Energy Research Centre, London.

Grünewald, P., Cockerill, T., Contestabile, M., Pearson, P., 2011. The role of large scale storage in a GB low carbon energy future: Issues and policy challenges. Energy Policy 39, 4807–4815.

Grünewald, P., Cockerill, T., Contestabile, M., Pearson, P., 2012. The socio-technical transition of distributed electricity storage into future networks—System value and stakeholder views. Energy Policy .

Grünewald, P., Eager, D., Hughes, N., 2011. Beyond EMR — The long term role of markets and government in delivering a low carbon electricity system. Presentation to Charles Hendry MP. Department for Energy and Climate Change (DECC). London.

Korpas, M., Gjengedal, T., 2006. Opportunities for hydrogen storage in connection with stochastic distributed generation, Inst. of Elec. and Elec. Eng. Computer Society, Stockholm, Sweden.

van der Linden, S., 2006. Bulk energy storage potential in the USA, current developments and future prospects. Energy 31, 3446–3457.

MacDonald, M., 2010. UK Electricity Generation Cost Update. Technical Report. Mott MacDonald. Brighton.

National Grid, 2010. Metered half-hourly electricity demands. [Online] Available from www.nationalgrid.com/uk/Electricity/Data/Demand+Data/.

Pelacchi, P., Poli, D., 2010. The influence of wind generation on power system reliability and the possible use of hydrogen storages. Electric Power Systems Research 80, 249–255.

Price, A., 2011. The role of energy storage: An overview of electrical energy storage systems. Presentation, Energy Storage for Electricity Networks Conference. IMechE.

Sinden, G., 2007. Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. Energy Policy 35, 112–127.

Solomon, A.A., Faiman, D., Meron, G., 2010. Properties and uses of storage for enhancing the grid penetration of very large photovoltaic systems. Energy Policy 38, 5208–5222.

Strbac, G., Aunedi, M., Pudjianto, D., Djapic, P., Teng, F., Sturt, A., Jackravut, D., Sansom, R., Yufit, V., Brandon, N., 2012. Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future. Report for the Carbon Trust, [Online] Available form: http://www3.imperial.ac.uk/newsandeventspggrp/imperialcollege/administration/energyfutureslab/newssummary/news_5-7-2012-14-8-41. Imperial College London.

Weber, C., 2005. Uncertainty in the Electric Power Industry - Methods and Models for Decision Support. Springer, Stuttgart.

Wilson, I.A.G., McGregor, P.G., Hall, P.J., 2010. Energy storage in the UK electrical network: Estimation of the scale and review of technology options. Energy Policy 38, 4099–4106.