Energy storage in the UK and Korea: Innovation, Investment and Co-operation

Appendix 3:
Impact of Risk on Investment Decision-Making: the Case of Energy Storage

William Blythe, Chatham House
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William Blyth has worked for 20 years in the analysis of energy security and climate change. He is an Associate Fellow of Chatham House, and a Honorary Research Fellow at Imperial College London. He is Director of Oxford Energy Associates, an independent policy and economics research company. He is an expert in energy sector economics, and the role of policy to deliver secure energy supplies within a context of transition to a low-carbon economy. His research focus is on electricity-sector investment risk and financing, and the future of markets for fuel, electricity and carbon.

He has recently worked with a wide range of international organisations including the World Bank, International Renewable Energy Agency, OECD, International Energy Agency, the Electric Power Research Institute, European Bank for Reconstruction and Development, International Institute of Sustainable Development, as well as many UK government departments and institutions. He has published widely on a range of topics related to climate and energy security, and is the author of over 20 peer reviewed papers and books.

William previously worked at the International Energy Agency in Paris, the European Environment Agency in Copenhagen and for AEA Technology Environment. He has a DPhil in Physics from Oxford University.

This Appendix supplements the report ‘Energy storage in the UK and Korea: Innovation, Investment and Co-operation’ published by the Centre for Low Carbon Futures in July 2014. The report considers how energy storage can play a role in the energy systems of the UK and Korea, to identify opportunities for research and industrial collaboration between the countries.

The report and other Appendices are available online at www.lowcarbonfutures.org/energy-storage.
1. Introduction

A number of recent studies have concluded that energy storage technologies are likely to play an increasing role in the electricity supply in future years given the evolving nature of both generation and demand-side technologies in the electricity system (US DoE, 2013). The assessment of this potential is usually based on analysis of the increasing variability of supply due to intermittent renewables in the system such as solar and wind power, as well as changes in patterns of demand due to potential electrification of heat and transport loads (Strbac et al., 2012, Grünewald et al., 2011, Edmunds et al., 2014). These studies typically assess the economics of storage based on assumptions of optimal dispatch of generation technologies under particular scenarios of penetration of renewable energy in the system. Typically, as the share of intermittent renewable energy increases, the economic potential for storage also increases, since storage can help balance the effects of variability in a number of ways, and can help to reduce overall system costs of integrating variable generation.

However, an economic potential for a technology is not the same as a viable business case. Investment decisions in real markets deviate from purely economic expectations for many reasons, in particular because they are exposed to a number of risks which are often not included in economic models. Whilst investment risks come in many forms, investment risk literature (e.g. (IEA, 2007, Blyth and Bunn, 2011)) groups them into three broad categories:

- Techno-economic risks
- Policy / regulatory risks
- Market / system risks

Although there is considerable overlap and interaction between these different categories, they represent types of risk that are in general managed differently, and towards which investors typically have different attitudes. Here we provide a brief overview of some of the key issues that arise under these different risk categories when considering storage technology development from an investment perspective.
2. Overview of Risks

\textit{a) Techno-economic risks}

(UKERC, 2014) identifies techno-economic risks as relating to attributes of individual technologies that have a direct impact on their technical and economic performance. This could include uncertainties in parameters such as capital and operating costs, environmental and other externalities, build time, availability and utilisation rates, reliability and intermittency of outputs. The extent to which these risks are well-characterised depends largely on the maturity of the technology concerned. Technologies being considered for commercial investment will usually have a track-record from which investors can learn so that they can assess the risks and apply appropriate risk adjustments to their normal investment appraisals. This applies to some storage technologies such as pumped hydro and mature battery technologies.

Another category of risk is involved when the technologies concerned have not reached full maturity. Whilst there may be expectations about the long-run performance and cost characteristics of developing technologies, there are significant ‘programmatic risks’ that affect the dynamics of technology development (see e.g. (Kindinger and Darby, 2000)). Programmatic risks arise from the wider environment that affects individual technology development pathways. These are wide-ranging in nature, and include existence of appropriate innovation networks, political and regulatory support, social acceptability, as well as institutional, market and supply-chain structures to support scale-up and deployment.

A taxonomy of different technology assessment approaches in this context is provided by (Tran and Daim, 2008). Examples of procedures for identifying and managing such programmatic risks can be found for a range of technology development applications in the energy, defence, space and commercial sectors (DoE, 2011, DoD, 2006, Belingheri et al., 2000, Kindinger, 1999).

These types of technical risk depend strongly on the level of maturity of a technology. Some types of investor will aim to engage at an early stage of development whilst risks (and potential returns) are relatively high, whilst others prefer to wait before investing in bulk applications for technologies to become mature and proven. Sometimes during the technology development pathway there may be a lack of potential investors, leading to a potential ‘valley of death’ in the financing chain, which occurs when technical risks are still high, but the level of required investment rises steeply at the point where initial large-scale demonstration trials are required (see \textbf{Figure 1}).

In practice, the development chain is considerably more complex than the linear pathway this model suggests. Innovation relies on a more complex ‘ecosystem’ in which multiple public and private funding agencies, research organisations and commercial applications provide a rich set of relationships and exchange of ideas, information and skills (\textbf{Figure 2}).
Figure 1 - Valley of death from cost increasing quicker than risks decreasing. Source: (Trezona, 2009)

Figure 2 The Innovation Ecosystem. Source: (House of Commons, 2013) (attributed to Prof. Georghiou)
In the UK, research funding institutions therefore tend to be involved in promoting a relatively wide range of activities (Edler and Georgiou, 2007). The distributed and networked nature of this technology development process makes it harder to pinpoint sources of programmatic risk. Coordination between research organisations and funders becomes crucial. One example has been the Technology Innovation Needs Assessments (TINAs) for eleven main families of low carbon technologies. These are a collaborative effort between DECC, BIS, the Engineering and Physical Sciences Research Council (EPSRC), the Energy Technologies Institute (ETI), the Technology Strategy Board and the Carbon Trust. The process is coordinated by the Low Carbon Innovation Coordination Group (LCICG).

From the point of view of potential investors, managing technical risk in immature technologies cannot simply therefore be a case of assessing previous performance track record. Companies will typically need to engage in multiple relationships within this kind of ecosystem, and will typically do so for reasons of long-run strategic positioning within their market sector.

b) Market / system risks

The expected financial performance of technologies in the electricity supply sector depend strongly on the characteristics of market prices. For many mature generation technologies, market price risk can represent the most significant risk factor facing investors (Blyth and Bunn, 2011). In the UK electricity market for example, electricity prices are often synchronised with gas prices because gas-fired power plant tend to be the marginal plant on the system and therefore set prices. This means that all generation plant become exposed to gas price risk through the link to electricity prices. In fact, generation plant that do not use any fossil fuel such as renewables and nuclear tend to be more exposed to these kinds of price fluctuation than the gas plants themselves which tend to be naturally hedged to some extent against gas price variations as it affects both costs and revenues equally, leaving profits for gas plant relatively unaffected (IEA, 2007).

From a market risk exposure perspective energy storage technologies share many of the same characteristics as other generation technologies, they also have some important differences, notably:

- The economic case for bulk storage technologies relies primarily on the ability to arbitrage price differences between different time periods, so that economic value is more strongly tied to the characteristics of price volatility than for most types of power generation. Price volatility characteristics are highly dependent both on the generation mix that exists on the system, but also the market / trading arrangements, making investment in storage particularly sensitive to decisions by other players in the market, and potential future changes in market structure.
- Whilst energy storage technologies in general benefit commercially from high price volatility, most generation technologies are the opposite. This means that storage technologies could provide a useful risk hedging role in a company’s generation portfolio.
- Many energy storage technologies can provide very rapid response / ramp rates, and so are suitable for providing multiple services over different timeframes (e.g. system balancing, fast reserve etc.) as well as bulk storage. The business case will therefore depend on companies being able to access returns across multiple markets or payment mechanisms. Again, this introduces risk exposure to market design, especially if rules relating specifically to energy storage as a developing technology are uncertain.
Energy storage can be located at various points upstream or downstream in the electricity grid, depending on the kind of role they are playing. Market design will affect whether or not companies are able extract the full system value for the services they provide (e.g. embedded storage may help to reduce transmission and distribution system reinforcements related to peaky demand profiles).

Because market prices are determined by the mix of technologies in the system, these market price risks will change as the electricity system evolves towards a lower-carbon generation mix, and will depend on evolution of the technical characteristics of the system such as changes demand load factors, changes in the level of interconnection etc. Storage technologies are therefore also exposed to what we might call ‘system risks’ associated with uncertainty over the direction and timing of these systemic changes.

Another important element of market risk is the way in which fundamental risk factors (such as technology mix, demand fluctuations, wind speed variation etc.) feed through into actual price variation. This is determined by market design characteristics. For example, technologies operating in a fixed tariff environment will see little feed through of fundamental risks through to their actual revenue risk. In practice, the exposure of storage technologies to market risk therefore requires careful assessment of the particular market design arrangements with a particular country-specific context – for example whether markets are tariff-based, whether they include energy only, capacity mechanisms, arrangements for balancing markets etc. The following sections outline some examples of studies which have sought to evaluate how market and system risks can affect the investment case.

c) Evaluating market risks

Since the ability to respond to price volatility and other types of system variability is where storage extracts most of its value, assessing the economic value of storage needs to take these time variations in the market into account. However, this represents significant challenges when it comes to incorporating storage into large-scale system-wide models. As noted by (Tanner, 2014), system-wide portfolio optimisation models have difficulty adequately representing the value of storage because they tend not to have a time-resolution of less than 1-hour, which limits their ability to capture the system’s need for fast ramping generation response. Some studies such as (Strbac et al., 2012) therefore complement the system-wide analysis of storage with separate modules which can cope with the shorter timeframes associated with fast-ramping ancillary services such as frequency response.

Several authors have incorporated price variability into more targeted stochastic models to assess the extent of value creation and risk exposure for storage technologies that are aim to extract value from energy markets. (Connolly et al., 2010) provides a review of modelling techniques for assessing the value of bulk electricity storage technologies, using pumped hydro as the illustrative technology for this class, set in the context of the Irish energy system. They show that storage technologies can provide similar expected value to competing technology solutions such as domestic heat pumps or district heating with CHP. However, storage is shown to be potentially more exposed to fuel price risk, since the economic savings largely come from avoided peak generation from gas. The authors explore a ‘double penstock’ arrangement where PHS could provide simultaneous charge and discharge allowing it to commit to providing system balancing services. Their results suggest that such an arrangement would be cost effective at a carbon price of €50/tCO₂. (Zafirakis et al., 2013)
uses stochastic models to conclude that bulk energy storage technologies such as pumped-hydro or compressed-air systems would be cost-effective in the context of Greek electricity system if socially-optimal feed-in tariffs were set at a level that incorporated external costs of fossil-fuel back up, including a carbon price of €15/tCO$_2$.

(Jung et al., 2013) provide a Monte Carlo simulation of local electricity supply system in Michigan, in a scenario with plug-in hybrids and a significant penetration of local distributed solar power generation. These add significant peak loads, and uncertain supply, and the authors show that under such circumstances storage can considerably reduce the incidence of overload of system components.

(Pazouki et al., 2014) use a stochastic programming model to assess economic dispatch when key input parameters are uncertain, showing that the presence of demand-response, distributed generation and storage can help to improve energy security and reliability compared to solely relying on grid-based electricity. Their results show that the economic use of electricity storage in these circumstances increases by almost a factor of two when uncertainties in electricity demand, electricity prices and wind power output are factored into the analysis. (Shi et al., 2014), (Motevasel and Seifi, 2014), and (Niknam et al., 2012) use various adaptive stochastic modelling techniques in the context of micro-grids, identifying optimal bidding strategies for distributed generation plant under uncertain market conditions when electricity storage is included in the system. Differences between the stochastic and deterministic solutions can be identified as a value that the micro-grid operator would ascribe to resolving uncertainties in the system. (Mohammadi and Mohammadi, 2014) use adaptive modelling strategies under uncertainty to show that under a stochastic conditions, system costs are likely to be higher than if deterministic conditions are assumed because of the need for greater system flexibility.

**d) Evaluating system risks**

As noted above, storage technologies provide valuable services in markets with volatile prices and fluctuating supply. However, individual investors are exposed to a number of system risks when trying to capture this value. Firstly, the electricity generation mix may evolve differently from expected. For example, if the expected penetration rates for intermittent renewables do not materialise, then the variability of supply and market price characteristics will not be as expected. This could be strongly influenced by policy decisions, so there is an important link here with the policy risks discussed in the following section. The outcome of other major technology pathway uncertainties such as nuclear power will also strongly affect market price characteristics.

Another major source of system risk for storage technologies is that the role for storage may be squeezed by the introduction of other technological solutions. Investors will need to assess the risks that financial returns for storage may be eroded by competing options such as greater levels of grid interconnection, demand-side response, or back-up flexible power generation. These risks again have strong links to the policy risks discussed in the next section.

(Blyth et al., 2007) note that when comparing investments in different types of technology, options with higher capital-intensity may be more exposed to such risks than low capital-intensity options. Typically, storage technologies tend to fall into the category of high capital intensity, as they often have relatively high capital cost, but low operating costs. The opposite might be said for gas-fired peak generation plant, which are relatively cheap to build, but have high operating costs. Whilst in
principle the economics of these two types of plant could be similar, their risk profile may be very different. Capital costs are usually sunk at the beginning of a project, so these costs are more-or-less irreversible once the investment decision has been made. Operating costs by contrast can be avoided by not running the plant. The low capital intensity plant (e.g. gas-fired generation) will represent a much less costly ‘mistake’ if it turns out that the investment conditions are not as favourable as predicted, than for an equivalent high capital intensity plant. These risks are however symmetrical. In other words, if conditions turn out more favourable than expected, the potential upside of investing in a capital intensive plant will be significantly higher than for the low capital-intensity plant. This is because there is greater potential to make higher profits in a high capital-intensity plant due to its lower operating costs.

Although the risks themselves may be symmetrical, investors response to risk is often asymmetrical, with many companies giving greater weight to downside risks. This is particularly the case for large investments which have the potential to push the investor into financial distress if the investment turns bad, since this can cause significant additional costs to the company. Investments that are large compared to company balance sheets have the potential negatively to affect companies’ credit ratings and their cost of borrowing (Brealey et al., 2006, Gross et al., 2010).

(UKERC, 2014) notes that from a societal perspective, there are important system integration risks that relate to the performance of groups of technologies when combined together. The security of the system depends on the robustness with which supply and demand can be matched under conditions of stress. Because different generation technologies have different strengths and weaknesses, the risk exposure of the system as a whole is different from that of its component parts. The risk exposure of a portfolio of multiple technologies may therefore be lower than the risk profiles of the individual components of the portfolio (Bazilian and Roques, 2008). This is because they react differently to different external shocks. Portfolio theory is a way of assessing these risks across multiple assets (Markowitz, 1952). Work from (Awerbuch and Berger, 2003) adapts these methods for deciding on the optimal mix of electricity generation, allowing diversification of exposures to fuel prices and different technical risks. Such techniques have been applied to renewables in several studies (Zhi et al., 2012, Wu and Huang, 2014, Escribano Francés et al., 2013, Guerrero-Lemus et al., 2012, Kitzing, 2014, Bhattacharya and Kojima, 2012), and could also be a fruitful area for further research in relation to storage technologies.

In addition to probabilistic analysis, it is also important to understanding the potential impacts of outlier ‘back swans’ events (Aven, 2013) or unknown unknowns (McManus and Hastings, 2006) sometimes referred to as ‘ontological’ risks (Lane and Maxfield, 2005). These events are typically low probability, but high impact. As noted in (Makridakis and Taleb, 2009):

“...most of the emphasis in predicting social science events has been on forecasting, rather than assessing uncertainty correctly and realistically. The biggest difficulty in such assessments comes from the fact that the greatest uncertainty is from rare “black swan” events whose probability of occurrence cannot be estimated, because, by definition, such events are infrequent, while also appearing at highly varying intervals.”

As noted by (Stirling, 2010), under such intractable forms of uncertainty, ambiguity and ignorance, probabilistic approaches to managing risk may be inapplicable, and diversity may provide a more robust response.
e) **Policy / regulatory risks**

Policy and regulation have a strong influence on the economics of storage technologies throughout the commercialisation process. The economic case for storage is therefore connected to policy decisions at various levels:

- Public component of R&D budgets and other institutional support during the innovation phase,
- Specific support measures such as targeted feed-in tariffs, supplier obligations or other subsidies during commercialisation stage
- For mature technologies, policy and regulatory arrangements determine the market frameworks through storage receives revenues (e.g. energy markets, capacity markets, short-term operating reserve balancing mechanisms, carbon pricing)
- Policy underpinning the transition towards greater renewable energy for which storage is expected to play its role

Since policy decisions can be changed, these various types of support underpinning the economics of storage are therefore subject to policy risk. Policy risk typically comprise situations where decisions are taken at a political level but are not followed through at an executive level (e.g. failure to deliver expected targets for renewables penetration), or where changes are made to established support mechanisms (e.g. changes to feed-in tariffs, market trading arrangements etc.).

The existence of policy risk will in general terms lead companies to apply an additional risk premium to their project appraisal. This increases the returns required to justify proceeding with any particular investment. These risks may be lower on an individual project basis in countries where governments provide guarantees that technology support prices such as feed-in tariffs will not be changed for pre-existing assets (i.e. grandfathering). In countries where such guarantees are not in place, policy risk will be considerably higher, and companies will tend to apply substantial discounts to any such supports that are offered.

Nevertheless, even if specific support mechanisms are considered firm for individual projects, the fact that policy decisions can significantly alter the operating environment for these technologies introduces an additional layer of risk both in terms of the immediate economics of specific projects, as well as the longer-term strategic engagement of companies in a particular technology pathway.

One way to visualise the potential scale and impact of policy risk is through a real options analysis framework (IEA, 2007). Investors, faced with a risky irreversible decision, will value the opportunity to gain additional information about likely future conditions affecting the project, thereby reducing uncertainty. This could mean investing in additional research for example, or delaying investment until the uncertainty has been partially resolved. When the future cash flows of a project are uncertain, the value of waiting for additional information depends on how far in the future the uncertain event is, the likely quality of the information, and the extent to which the uncertainty will be resolved. In order for the project to proceed immediately rather than waiting, the expected project value needs to be sufficiently high that it exceeds this value of waiting.

This is described in Figure 3. The figure illustrates a schematic cash flow, showing the expected gross margin (revenues minus costs) over time, and with capital costs also assumed to be annualised over time. The normal positive NPV rule would be equivalent to requiring that expected gross margin is greater than annualised capital costs. **Figure 3** indicates why expected project values may need to be
greater than this when there is future uncertainty and when there is flexibility to wait and learn. In other words, the NPV not only needs to be positive, but needs to exceed some threshold, the value of which depends on the value of waiting.

Uncertainty can be represented as an anticipated price shock or an information event (e.g. introduction of a major new climate change policy) at some time \( T_p \). This could affect a project’s cash flow either adversely or favourably. In Figure 3A, the company facing this uncertain cash flow has to choose whether or not to invest in the project—it does not have the option to wait. The expected ‘best guess’ (central orange line) is that the project will continue to be profitable, so that the project satisfies the normal investment rule (i.e. gross margin is greater than capital cost) justifying immediate investment. In Figure 3B, the company has the opportunity to wait until after time \( T_p \) before making the investment. This allows it to avoid the potential loss that might occur if conditions turn out worse than expected (shown as a zebra dashed area). Waiting could lead to a greater return on investment—the new expected gross margin from the project would be higher than the original expected gross margin without the option of waiting—but revenues from the project would only accrue after time \( T_p \) if the project does go ahead. It would be rational to invest prior to \( T_p \) only if this value of waiting is overcome by the opportunity cost of waiting (i.e. the income forgone due to delaying the investment). In order to trigger immediate investment, the expected gross margin of the project would need to exceed some threshold level which makes the opportunity cost of waiting greater than the value of waiting. This threshold depends on the length of time before \( T_p \), the size of the anticipated price shock and the discount rate.

![Figure 3. A conceptual framework to show the value of waiting: (A) “Now or never” investment option at t=0; (B) Company has the option to wait until t=T_p, the expected time of a policy change that affects the investment.](image-url)
In summary, a real options analysis predicts that when faced with risky future conditions, companies that have option to defer investment will require a greater level of profit to persuade them instead to proceed immediately. This additional risk premium will increase in relation to:

- the scale of potential losses that could be incurred as a result of policy change (which also depends on the capital intensity of the plant)
- the time-lag between the investment and any policy changes that might occur – the shorter the period of policy stability, the higher the risk premium
3. Policy Implications and Business Models

Investment in storage technologies are subject to a range of risks, many of which are influenced either directly or indirectly by policy and regulatory decisions. Drawing on literature related to other technologies in the energy supply sector, we can predict that from an investor’s perspective, these risks will be perceived as higher for technologies that are more capital intensive (i.e. high capital cost, low operating cost), where policy decisions have a significant bearing on the financial outcome of the investment, and where the period of policy stability is short. Such perceived risks will incur a risk premium, which will tend to reduce the rate at which technologies will penetrate the market.

Policy decisions affecting storage technologies occur throughout the technology pathway:

- Policy support is essential at the innovation stage, both in terms of public contributions to R&D funding as well as support for key institutions in the innovation ecosystem
- Policy and regulatory decisions underpin market arrangements, which can have an important impact on the ability of investors to extract the full value that storage technologies represent to the system as a whole for the multiple services that they can provide over different timescales and different points in the transmission and distribution system
- The evolution of the electricity system towards greater use of intermittent renewables is one important driver of the economic case for storage, but achieving this result depends on successful delivery of the underlying policy goals
- Competing technology solutions such as demand-side response, interconnection and back-up generation also attract policy support

Policy risks can in general be reduced by ensuring that support at the level of individual projects is grandfathered (i.e. subsidy levels are not changed retrospectively for pre-existing assets), and by aiming to achieve reasonably long periods of policy stability. The latter however is hard to achieve in a period when the electricity system is rapidly changing, and subsidy regimes and market arrangements may therefore be in flux. It may therefore be inevitable that some degree of policy risk will be factored into companies investment appraisals, raising the implied costs (compared to purely economic analyses that do not factor in the effects of risk). Policy-makers may therefore need to factor in such risk premiums when considering the necessary levels of support required to achieve expected levels of technology penetration in the market.

The translation of policy risk into investment behaviour will however depend on the type of investor being considered. Private investors will respond differently to policy risk than state-controlled utilities. The situation in the UK and South Korea provide interesting comparisons in this regard.

Recent analysis for South Korea (Shcherbakova et al., 2014) suggests that energy storage with NaS or Li-ion batteries would not be cost effective as a method of bulk price arbitrage in South Korea’s current electricity system, under typical standard discount rate applied to public projects of 5.5%. Nevertheless, implementation of such solutions can be considered either for reasons of demonstrating potential value in the longer-term should S. Korea’s own supply situation change, or for strategic reasons to provide a demonstration of battery performance in support of S. Korea’s battery supply industries. State ownership or control of utilities allows such experiments to be carried out, without necessarily needing to explicitly value the potential spill-over benefits to the wider economy through defined subsidy arrangements. Indeed, strategic links through the state
between power companies, and key technology providers (storage, generation plant manufacturers etc.) is likely to provide a significant stabilisation process in terms of perception of policy support. This is likely to reduce policy risk in the S. Korean case relative to the UK case, even if it means that investments are not always made with a sharp focus on achieving short-term commercial value.

In the UK by contrast, whilst companies may still invest in marginally economic projects for strategic reasons, the link between the investment decision and the underlying business case is more explicit. Policy-makers in this context therefore have to give careful consideration to the economic incentives they send if they want to influence the uptake of different types of technology. This clearly applies in the case of explicit incentives for particular projects (e.g. the £13.2m support through Ofgem’s Low Carbon Network Fund for the 6MW / 10MWh ‘Smarter Network Storage’ demonstration project\(^1\)).

Perhaps more importantly in the long-run policy determines the market design arrangements through which storage technologies will ultimately gain their income. This requires the development of suitable potential business models for energy storage in a competitive market. The diverse nature of storage technologies (the range of different technologies involved; the different scales of investment; the ability to provide different types of service over different timescales; the potential for applications at both upstream and downstream ends of the transmission and distribution system) means that these models may be quite diverse.

Given the fact that the market as a whole is in a state of flux and evolving quite rapidly, development of new business models is a learning process, involving a wide number of actors across policy-makers, power generation companies, distribution and transmission network operators, equipment suppliers and the wider research community. Policy-makers therefore need to strike a fine balance between being responsive to such developments, whilst aiming for stability in the wider policy framework.

One specific examples of where policy decisions are affecting business models in the UK include the design of the new capacity mechanism, under which generators will bid in auctions to be paid separately for making capacity available to the system (as opposed to being paid solely for the energy they provide). Since this changes the model for remuneration of plant in the electricity supply sector in the UK, the role of storage in providing such services has been an important strand of the policy debate. It is the stated aim of policy to allow storage to bid in to the capacity auctions on an equivalent basis to generation technologies (DECC, 2012), but some analysts anticipate that capacity markets will in general act to reduce the availability and utilisation payments for flexibility services, potentially undermining some the revenue streams for storage applications (Poyry, 2012).

Another example in the UK is the question of whether or not distribution network operators (DNOs) are allowed to own storage assets. Storage technologies are likely to provide an increasingly valuable role in helping to manage local fluctuations, and some commentators have noted that DNOs provide a natural business model for these kinds of storage application (Engerati, 2013). However, DNOs are not allowed to own generation assets under EU rules, and it is not clear whether storage technologies also fall into this category\(^2\). Ofgem notes that there do not seem to be any obvious

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\(^1\) For a review of lessons learned to date on the project, see: https://www.ukpowernetworks.co.uk/internet/en/community/documents/SNS12_SDRC_9.1_Design_and_Planning_Considerations_Report_v2.0.pdf

barriers to DNOs contracting out for storage services\(^3\), so in principle such regulatory issues should not create a barrier to investment. However, as noted in various studies, it may be hard to devise contractual arrangements for appropriately allocating revenues and risks between DNOs and assets owners when there are multiple and sometimes strategic services provided. In fact, as noted in a recent consultation on business models by UK Power Networks, there is a spectrum of contractual arrangements, from full DNO ownership through to pure payment for services rendered. Each of these potential business models has its own set of advantages and disadvantages (Figure 4).

<table>
<thead>
<tr>
<th>Business model</th>
<th>Advantages</th>
<th>Disadvantages</th>
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<tbody>
<tr>
<td>DNO Merchant</td>
<td>• DNO has full operational control.</td>
<td>• DNO requires new skills and</td>
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<td></td>
<td>• May be lower cost of financing if financed as a regulated asset (depending on risk sharing between DNO &amp; Customers).</td>
<td>capabilities to trade in the wholesale energy market and participate in</td>
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<td></td>
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<td>procurement mechanisms for ancillary services.</td>
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<td></td>
<td></td>
<td>• May not be consistent with DNO shareholder expectations of risk.</td>
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<tr>
<td>Distribution System Operator (OSO)</td>
<td>• DNO has full operational control.</td>
<td>• Regulatory regime not yet in place</td>
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<td></td>
<td>• Specific incentives on DNO to manage costs of balancing the grid.</td>
<td>• Commercial risk remains with DNO and customers.</td>
</tr>
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<td></td>
<td>• May be lower cost of financing if financed as a regulated asset (depending on risk sharing between DNO &amp; consumers).</td>
<td></td>
</tr>
<tr>
<td>DNO Contracted</td>
<td>• May be lower cost of financing if financed as a regulated asset (depending on risk sharing between DNO &amp; Customers).</td>
<td>• Complex tolling contract required (i.e. a services contract between the DNO and a third party).</td>
</tr>
<tr>
<td></td>
<td>• Commercial risk for DNO significantly decreased.</td>
<td>• Third party may heavily discount long term value of additional revenues.</td>
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<td></td>
<td>• Third party may be better placed to manage commercial value streams.</td>
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<td></td>
<td>• Third party may be able to aggregate across multiple assets which increases scalability and overall system efficiency.</td>
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<tr>
<td>Contracted Services</td>
<td>• Commercial risk for DNO significantly decreased.</td>
<td>• DNO does not have direct operational control.</td>
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<td></td>
<td>• Third party may be better placed to manage commercial value streams.</td>
<td>• Complex tolling contract required.</td>
</tr>
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<td></td>
<td>• Third party may be able to aggregate across multiple assets which increases scalability and overall system efficiency.</td>
<td>• Third party may heavily discount long term value of additional revenues.</td>
</tr>
<tr>
<td>Charging Incentives</td>
<td>• DNO (and Customers) takes no commercial risk.</td>
<td>• No guarantee of storage being built.</td>
</tr>
<tr>
<td></td>
<td>• Incentives based approach may be economically efficient.</td>
<td>• No DNO control on asset being available for network security when required.</td>
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<td></td>
<td></td>
<td>• Third party exposed to annual changes to incentives.</td>
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</tbody>
</table>

Figure 4. Potential business models for storage services within the distribution network. Source (UKPN, 2013)

\(^3\) [https://www.ofgem.gov.uk/ofgem-publications/56834/ws6150812slidepack.pdf](https://www.ofgem.gov.uk/ofgem-publications/56834/ws6150812slidepack.pdf)
Many of the pros and cons of different business models identified in Figure 4 are associated with the allocation of risk between different parties, pointing to the need for greater analysis and understanding of how these risks are likely to evolve in different market contexts. Some of this learning will occur as a result of real investments and experimentation of different arrangements between companies, but policy-makers and regulators also have to be aware of the role that risk plays in such decisions, and be sensitive to the risks that they introduce to the market through their own decision-making processes.
Appendix 3: Impact of Risk on Investment Decision-Making

References


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