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The Case for Pumped Storage Hydro in the UK's Energy Mix

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Summary

Electrical energy storage (EES) is increasingly being considered as a necessary corollary to inflexible renewable generation [1,2] for electricity markets today and in the future. Energy storage is not new - the GB electricity system has benefited from pumped storage generation since the 1960s. But no new stations have been built since the liberalisation of energy markets in the late 1980s. Investors have anticipated scale deployment of battery storage, but to date only limited capacity has been contracted by National Grid, largely for frequency control purposes. So the question arises, why did we recognise value in storage three decades ago but not now? Using the example of pumped hydro energy storage (PHES) – the dominant electrical EES technology currently deployed in GB – as a reference, this paper considers the question of how EES has been valued in the past. Crucially, we consider the issue of valuation beyond the economics of the energy system to a fuller social cost-benefit perspective. Has policy explicitly considered the question of societal valuation? What may be required in terms of valuation approaches to make the case for future investments in and deployment of storage capacity?

We draw three main conclusions. First, that there is a need to recognise and articulate the societal value that may be delivered by EES. Second, a market framework that recognises this value is needed. Third, development through both of these first two stages requires greater policy certainty and clarity round low carbon economic development pathways in general, and the outcomes that may be served by EES in particular.

1. Introduction

The need to reduce emissions leading to climate change and other damaging impacts of conventional electricity production presents several challenges. The growth in low carbon renewable generation leads to reduced system flexibility and increased challenges in ensuring security of supply. In addition, peak demand is expected to increase from 60 GW (2016) to 65-85 GW (2050) [1], with peak demand becoming more volatile with more "peaks" than is the case today [3], partly as a result of the electrification of transport [4] and a potential electrification of heat [5,6]. This is set in the context of a number of important generation changes and developments. These include the impacts of the intended UK-wide shutdown of unabated coal-powered plants by 2025 [7], and the moratorium on building new nuclear power plants in Scotland [5]. While much public policy focus has been on the range of actions taken in enabling the electricity sector to contribute to the aim of reducing UK GHG emissions by 80% of the 1990 baseline by 2050 [8], the change in the generation landscape is key.

The decarbonisation of electricity is largely being accomplished through the replacement of carbon emitting generation by intermittent renewable electricity supply (RES) capacity. This is expected to increase between 25-200% until 2050 [1] and will inevitably lead to increased variability of electricity supply throughout day and night [9]. While renewables are reliable, they are variable/ intermittent [10,11]. Avoiding RES curtailment, and dealing with both inflexible demand and intermittent supply, requires decreasing network congestion and/or building more network to increase flexibility [12,13]. The question, then, is the extent to which electrical energy storage (EES) provides a means of achieving this in a manner that achieves the best balance of societal costs and benefits [1,2,11].

Among others, the National Infrastructure Commission [14] has argued that the current regulatory framework unintentionally disadvantages EES business cases by directly and indirectly creating various barriers preventing them to participate in a range of markets despite the clear contribution it can make in terms of enabling flexibility and security. It is the contention of this paper that the problem is somewhat deeper, in that the institutional memory as to how the need for energy storage was once valued has eroded over the last three decades. Indeed, there seems to exist no current consensus and/or clear articulation as to whether there may be a need to invest in further PHES and/or other EES capacity, and at what institutional level such decisions need to be made. This is a crucial point. The problem around energy storage in general, and EES particular, may be deeper than one of market design and techno-economics. At what institutional level does the problem lie? In the past, for example when investment in PHES was decided, central decision making lay in the hands of the (three) GB Generating Boards and (twelve) Area Boards within England and Wales. However, it does not necessarily follow that centralised electricity boards constituted the appropriate institutional level for such decisions to be made, or that decisions were underpinned by the type of societal valuation proposed in this paper. Rather, the particular needs of the time (when the GB system was shifting in favour of nuclear generation) may have driven an energy system-focussed decision that ultimately served a wider set of societal needs, without any type of formal societal 'cost benefit analysis' having been performed.

2. Context – understanding what energy storage policy offers and the extent to which this is recognised in past and current UK policy

2.1 What is energy storage?

In essence, energy storage uses devices or materials to store energy until a point in time where it can be better utilised. Unlike other natural energy storage systems and materials such as wood and coal, electricity must either be used as soon as it is created or converted into another form of energy such as kinetic or chemical energy. A range of storage technologies exist, which are either already deployed or currently under development. EES technologies have a number of differentiating characteristics such as the underlying technology, power density, discharge duration, storage duration, location within the electricity system (where a range of constraints apply, including availability of resources such as water, impacts on the local environment and population), and nameplate capacity. In this context, EES systems include mechanical, electrochemical, or electromagnetic technologies. Mechanical EES include stand-alone PHES and compressed air energy storage as part of gas turbine systems (CAES)[1]. Electrochemical technologies are various battery types such as lithium-ion batteries, as well as super-capacitors. Electromagnetic technologies include superconducting magnetic energy storage[2] [15]. Important technical specifications in all three cases are power rating, discharge duration, and storage duration[3]. The relative importance of each different specifications depends on the application, where it may be argued that mechanical EES do often perform better, but with batteries potentially offering more where, for example, an instant response time is key [11].

The key question is how EES deployment may play a role under different system development scenarios going forward. For example, National Grid's 'Future Energy Scenarios' [1] considers the potential contribution of storage under different potential energy system pathways. Its role is often defined in terms of providing short and/or long-term reserve capacity [16]. Consider, for example, PHES, the most prevalent EES technology currently operating globally and in GB [17]. PHES stores energy in the form of gravitational potential by pumping water from a lower altitude reservoir to a higher one. In order to reclaim the electricity used in the previous pumping process, the stored water is released, and the kinetic energy of the water flow is transformed into electricity by using a generator [18]. PHES is considered better suited to bulk energy reserve and other long terms services given that it is cheap relative to batteries in delivering services for energy (measured in

1 Given the limited experience in deploying CAES globally we do not attempt to consider or compare it in the current paper.

2 Such technologies are just for super short term (i.e. "instant") applications.

3 Longer storage durations refer to the ability of storing energy over long terms without suffering significant energy losses during the storage period.

kWh) [19]. On the other hand, batteries may be more economical and technically suitable in delivering services for power (measured in kW) where an immediate response in power output is required [11].

One emerging issue in the GB power system is the decrease in inertia as the share of non-synchronous renewable generation increases [9]. This is an area where the synchronous, dynamic energy capability from pumped hydro energy storage may serve needs not so easily serviced by other forms of generation or storage.

PHES is the oldest and most mature EES technology, having been first deployed by manufacturing industries in Switzerland in the 1890s to store off-peak energy in order to release it at peak times. The introduction of this technology into several European and the US electricity systems followed in the early 20th century [18,20]. The further uptake of this technology was decisively accelerated by the development of a new type of hydroelectric turbine, which was able to be used reversibly as both generators (i.e. charging) and electric motor pumps (i.e. discharging) [21]. The UK's first large scale PHES facility at Ffestiniog, North Wales followed during the 1960s [22]. Given this long experience of far more than 100 years in application, PHES is considered the most mature form of electricity storage [23,24] and the dominant diffusion of this technology is also a result of its economies of scale and large-scale generation capabilities [25]. Moreover, PHES as it has been introduced[4] has the largest deployed total capacity among all EES technologies and as of 2018 it had a share of around 98% among both global and UK large-scale and long-term EES capacity and is therefore the most widely used form of electricity storage [17].

Given a potential response time of a few seconds [26] and a high generation capacity, PHES has a proven ability to perform a wide range of system services that provide flexibility and enable renewable integration and grid stability [27]. Other EES technologies may also provide these services, with batteries commonly offering faster response times but lower capacities [11,19].

PHES projects commonly involve large capacity installations. They are characterised by operational lifetimes of often 80 years, high capital costs, lengthy construction activity (and, thus, presence of construction sites) and specific locational requirements [28]. In this context, suitable sites for large scale projects in the UK are limited, since the need for an altitude differential between the two lakes limits the range of options to mountainous locations such as the Scottish Highlands or Snowdonia in Wales. This is an important barrier limiting further deployment options for PHES. A crucial factor may also be the availability of network in such areas given the environmental, planning and cost challenges of network construction. If network does not exist to transport energy to and from an appropriate PHES location, the barriers to building storage capacity in that location potentially cannot be overcome. However, a key feature of EES more generally is that it may serve to alleviate transmission constraints and enable greater generation capacity in a constrained network area. If this opportunity is to be exploited to benefit society, then all means of providing flexibility through storage capacity, generation, and transmission capacity decisions should be taken in tandem.

Battery technologies also face barriers. Investors have shown enthusiasm for various types of battery storage in recent years and have anticipated large scale deployment. This has simply not emerged in the UK. National Grid has contracted only limited (a few hundred MW) battery capacity and this has largely been to play a limited role in terms of frequency control [24]. This again suggests that, either, the existing policy, regulatory and market frameworks do not recognise the potential value of services provided by storage, or that other options to deliver the required flexibility and security outcomes can be provided at a lesser cost. The question then is the appropriate consideration of both costs and benefits from a fuller 'whole system' (i.e. not just energy system) perspective.

4 As per definition (i.e. closed loop systems) at the beginning of the paragraph. Additionally, open-loop systems exist which use naturally flowing waterbody as one of their reservoirs, which has impacts on ecosystems [18]. As such systems are not the norm, they are typically excluded when it comes to stating figures.

2.2 How do we (and should we) consider the value delivered by electrical energy storage?

This paper focuses on 'value' which requires the consideration of both costs and benefits. However, in a political economy context, consideration of 'value' should not be limited to the economics of the energy system, rather extending to societal costs incurred and benefits realised. Traditionally, the value of energy technologies is assessed using economic indicators such as private cost and returns in a lifecycle context. Specifically, EES technologies have been assessed on the basis of the 'Levelised Cost of Storage[5] (LCOS). This is a variant of the levelised cost of energy approach applied in comparing across different approaches to achieving energy system outcomes. LCOS takes all important parameters including annual cycles depending on the typical use and investment lifetime into account. For example, a recent study [19] estimated that PHES has a significantly lower LCOS than lithium-ion batteries, which could be taken as suggesting that PHES may be the most cost-efficient large-scale and long-term EES technology. The study notes that the LCOS outcome for Li-ion batteries is expected to decrease in the future years [28,29] but that PHES still remains the more cost-efficient solution. Given a future development pipeline, PHES may be expected to continue to perform better in terms of LCOS given its status as a mature technology with a long history of investment and deployment.

Herein lies a crucial issue in terms of valuation. The maturing and deployment of technologies leads to the creation of standards in operation, planning, construction, and in evaluating economic benefits. Less mature technologies with less of a 'track record' are likely to have more uncertainty associated with revenue streams, both from a technological performance angle [30] and for any cost-benefit analysis. Maturity and extent of current deployment can also lead to economies of scale that deliver low unit costs in relation to other technologies. Thus any new technology will suffer a comparative disadvantage in economic valuation processes. On the other hand, even where technologies are mature with a history of relatively large scale deployment, EES still struggles. For example, given its history and maturity it may be argued that PHES would have the ability to make a business case without subsidies [31]. But even it has not been the focus of any substantial investment and deployment, certainly not in the GB system, for several decades. The question thus arises, if an EES technology such PHES could make a business case, why hasn't it? If we can identify a more effective way of valuing the outcomes delivered by EES, could this impact the outcome, both for PHES and ultimately for a wider portfolio of EES options?

In considering this question, we need to reflect what is meant and understood by 'value', and how it needs to be assessed to inform decision making in the political economy. Prior to liberalisation of the electricity system and markets in the late 1980s, when significant investment in energy storage in the form of PHES was made, everything from generation to transmission to distribution was run by the Central Electricity Generating Board (CEGB) for England and Wales (with twelve geographically distinct Area Boards therein), and, for Scotland, by the North of Scotland Hydro-Electric Board (NSHEB) and South of Scotland Electricity Board (SSEB). These boards had centralised responsibility for developing and maintaining and efficiency and economic system for electricity in bulk, and for the transmission networks. Naturally, consideration of needs and value is arguably more straightforward in a centralised system. Particularly in the context of security of supply issues in the 1970s, the value of flexibility and the role of EES was clear in terms of 'keeping the lights on' and ensuring industry could operate without costly power interruptions. Consequently, the construction of four large-scale PHES plants was taken forward in the GB system. On the other hand, as argued above, it does not necessarily follow that centralised decision-making is the best way of considering or delivering a fuller consideration of societal value. Indeed, this was part of the argument for deregulation of the system, on the basis that markets can potentially realise the complex outcomes that central planning, with all the monopoly behaviour implications therein, may not be capable of delivering.

However, the key point here is that no further large-scale storage investments have followed

5 The LCOS method allows a cost comparison of technologies in different system designs and various operation modes.

since electricity market liberalisation, despite what many experts are likely to argue is a continued and possibly increasing threat to system security arising from greater reliance on intermittent renewable generation. Why is this the case? Through the process of liberalisation (which took place via two phases with the Electricity Act in 1989 and Utilities Act in 1990) the system was unbundled, the Electricity Boards stripped into component operations, and tasks assigned to new stakeholders and markets. Combined with at least a reduced perception of the security and flexibility concerns that had been of more concern in the 1970s and 1980s, it is likely that the need and thus the determination of value associated with EES (and the crucial question of who pays associated costs) was largely left to market forces.

But now, as set out in the introduction to this paper, real concerns are again being articulated around the need for energy storage to secure and balance our changing energy needs through a system increasingly characterised by renewable electricity generation technologies. This suggests a pressing need to consider both the question of measuring and communicating relative value delivered by EES to the relevant decision-making communities and to consider whether and why the market may or may not be delivering the 'right' outcomes in this regard. Again, the context is somewhat different to what it was three or four decades ago. Now the challenges that seem to point to storage solutions are ones of decarbonisation, increased dependence on intermittent renewables and a likely shift towards electrification of heat and transport. However, these are complex and often quite technical issues. In the setting of a liberalised energy system, with no single decision maker to assert and prioritise the role of what would be (in absolute terms) very costly investment in EES, there is a challenge in considering and articulating just what role EES may play in sustaining and growing our economy and ensuring well-being across society. Crucially, could EES play a role and deliver value in a manner that is not currently being fully recognised or valued by the current market system?

So how should we approach the challenge of valuing EES and articulating that value? LCOS is problematic in that it focuses on comparing across different energy storage solutions while the primary challenge is to make the case for energy storage more generally. The broader LCOE approach similarly focuses on comparing across different approaches to energy system solutions. Crucially, LCOS/LCOE focuses on revenues from existing market arrangements so that, depending on the details of the specific method used, it will not communicate value if the existing market does not recognise that value. Even broader considerations of the potential cost reductions in running the energy system [2] have not elicited sufficient attention or decision making in the context of EES. No regulatory framework or legislation changes have been introduced beyond issuing of new storage licences and enhanced frequency response (EFR) contracts. But the competition for both public and private resources is not limited to energy problems and, therefore, cannot be limited to considering the best way to deliver flexibility and security. Rather, consideration of the value delivered by energy storage must extend to consider what increased flexibility and security in the energy system offer in terms of outcomes that are valued in a wider political economy setting. For example, what might restrictions in the flexibility and security of the electrical energy system - and/or removing those restrictions – do in terms of the operating landscape for industries considering production locations? What might the resulting impacts on employment, household incomes, GDP and other indicators of economic value be?

2.3 Does UK energy policy recognise the value of storage?

Is the type of argument set out above reflected in the UK policy approach to energy storage? 30 years ago, the answer would at least implicitly have been 'yes' given the context (discussed in Section 2.2) of an explicit concern of the need to 'keep the lights on' to enable the economy and society to function. We do have EES capacity in the UK, largely in the form of PHES, but the last parts of this capacity were created back in the 1980s. A pathway for what we may loosely label 'energy storage policy' started when the UK developed significant capacity of nuclear power, storage became a way to capture off-peak electricity valued at zero opportunity cost (or even at negative cost, when shut down and restarting cost are taken into account). This electricity was later used to serve peaks in demand. Many PHES plants (e.g. Dinorwig in Wales) were built to capture off-peak electricity from nuclear power plants in order to let them run on a constant output level [12,22]. Does the main value from PHES in the GB system derive from links to nuclear power? The GB system's reliance on nuclear has declined. Will further investment in PHES therefore depend on the development of significant new nuclear capacity, or will it be to shift the low marginal cost renewable energy to times of peak demand?

The key point, however, is that the costly initiative of investing in PHES some 30 years ago was motivated and justified by a need 'to keep the lights on' due to events of sudden changes in demand or supply. This contrasts with today's situation, where electricity supply is characterised by decarbonisation demands served by large scale intermittent renewable generation. Concerns over potential black outs have recently (and are still currently) been the subject of political and some media debate, for example, with a House of Lords select committee on the matter in 2015. Concerns over the need for increased flexibility are also explicitly and [32] publicly made, but with each side of the equation perhaps less tangible to a wider public and policy audience.

In practice, the need to 'keep the lights on' persists today and may be considered even more vital as it underpins our increasingly digital society, and the need for flexibility in supply is exacerbated by the challenges of decarbonisation. On the other hand, not only is there a challenge in effectively articulating these needs in a crowded wider political economy environment, but even at the energy system level, the challenges are more complex than they were previously. This is due to the challenge of moving towards an increasingly intermittent dominated decarbonised electricity system [2]. Was the regulatory transformation to the current liberalised system made without a clear definition of the wider set of valuable societal outcomes that may be delivered via the flexibility that EES can help deliver?. If this is the case, and the value of EES is weighted in this regard (i.e. it is the main outcome provided by investment in and deployment of EES), then this system asset type and the services it provides may be undersupplied by the current system's actors. Basically, the challenge is to determine whether markets currently function effectively and efficiently in the sustained delivery of flexibility and security (over long time frames) or whether some failure needs to be corrected. The time frame issue is an important one. Where solutions like EES (similar arguments apply in other contexts) require large scale investment to ensure outcomes valued by society over the long term, the payback periods required are lengthened and, thus, more greatly impacted by political and policy uncertainty.

Moreover, there is currently no specific regulation for EES covering all aspects of technical potential this technology offers to the system and to society that will enable it to compete equally with other options to deliver socially valued outcomes via its flexibility and security characteristics. This lack of clarity has been examined in a report published by the Committee on Climate Change [3], which models different scenarios on the uncertainty range of the expected flexible technology deployment (i.e. EES, Demand-Side-Management, interconnectors, and high flexibility generation). Not surprisingly, the potential of EES deployment by 2030 shows the highest uncertainty range among the range of flexibility approaches considered. This is identified as being a function of current and future regulatory uncertainty, as well as distorting market signals.

So what is being done? While the UK government has identified storage as an enabling technology to their emission reduction targets [33,34], as yet little has been done in terms of removing barriers such as the missing definition of storage within The Electricity Act 1989 [30,32][6]. This is despite Ofgem having published reports and consultations highlighting all of these issues [32,35]. although there may be some activity emerging in terms of licensing arrangements for storage [32, 36].

Existing efforts on stimulating some flexibility provison include the cap and floor mechanism supporting investment into interconnectors between the UK and relevant countries [37], and

6 Parliament shall discuss an asset definition of storage "when Parliamentary time allows" [35], but the UK's departure from the European Union and the associated need to pass other bills may delay is until 2022 [36].

National Grid as Electricity System Operator, is seeking to enhance future markets for flexibility services. However, battery storage investments are increasingly being carried out beyond the meter [38], potentially seeking to avoid some system charges. These may not be the most efficient outcome from a whole system perspective.

Some PHES projects are currently in the planning stage, but it is yet uncertain whether they will progress further. The crucial point here is that private money has been spent in development, indicating that the outcomes delivered by PHES are valued. But, why then has nobody taken the final investment decision(s)? A key issue is the need for the right investment conditions in which high value private finance decisions are made. In terms of key policy interventions, the capacity mechanism was introduced for the support of backup generators, with the offered timescales being clearly too short to attract investment into available PHES options [44]. That the capacity mechanism does not attract the magnitude of capital costs and investment timescales associated with bulk storage systems like PHES potentially disadvantages the latter in terms of the value stream available via what has been a key policy intervention.

3. The issue - what is the challenge for storage development? Why does a ready option like PHES not work in the current environment?

So far we've set out what seems to be the root of the problem for electrical energy storage – a lack of recognition and/or articulation of the value of EES not only to the electrical system but to the wider political economy in terms of outcomes that are ultimately delivered via the long term flexibility and storage that it may play a role in delivering. As noted above, this may ultimately lead to outcomes such as a more secure environment for industry location, employment and generation of value-added, thereby impacting household incomes and other measure of economic well-being. At this stage we delve a bit deeper to consider some of the specific barriers identified as deterring further investment and deployment particularly in PHES as a mature technology but spilling across the wider portfolio of potential options.

In general, major barriers are the market arrangement of strict business separation (i.e. unbundling[7]) across the sections of the previously vertically integrated utility and, at least to date, an absence of an asset definition [25,40] (though this may be resolved at least in part via new licence definitions). While the business separation has led to many benefits, in this paper we have argued that that the process of market development may have been less than complete in terms of the nature of wider societal value identification and delivery. In particular, EES is currently treated as a generator and consumer depending on whether the asset is being discharged or charged [25]. In terms of grid codes, EES is classed as a generator exposing operators to both transmission and distribution network charges [41], as well as to other levies despite the fact that electricity is neither generated nor consumed [25,42,43]. While markets for flexibility services are long established, it is arguable that these markets are institutionally and structurally biased against EES solutions, particularly bulk storage capital-intensive options such as PHES. Markets should recognise that benefits from EES solutions are split across multiple stakeholders of the electricity system and include transmission and distribution extension deferral, relief of network congestion, provision of balancing and regulation services, as well as the potential to replace baseload generation [44,45,46].

Generally, it is arguable that EES acts on a very uneven playing field. In particular, state support of certain generators [24] and interconnectors [37] are recognised as barring storage deployment [24]. Market entry barriers play a role as dominant market structures of generation markets and the subtle details in the respective regulation are preventing EES operators from competing on the needed even playing field [47]. Disintegrated market structures (where different regulatory frameworks, rules and restrictions apply) constitute another barrier. While EES offers services and solutions to many independent markets, it faces barriers to participating in these markets simultaneously, despite its technical potential [2].

7 See EU Directive 2009/72/EC or The Electricity Act 1989; this requirement is not expected to change and Ofgem made this clear [32].

More generally, policy uncertainty is problematic, given that EES is particularly suited to service in the shift to low carbon economic development in the period to 2050. Specifically, the success of storage business models is linked to policies which drive the need for flexibility and this is difficult to articulate where clear (technology-neutral) strategies and direction are not set out and committed to by policy. Uncertainties over the long-term predictability of policy drivers are clearly identified as a key risk factor and therefore a barrier to storage deployment [2].

Specific barriers and issues will apply in the context of different EES technologies. Considering our focus on PHES, there are a number of particular factors. As noted already, most global PHES projects have been developed in electricity markets with a certain degree of public ownership and the deregulation of these markets around the world resulted in the slowdown of the development rate of new projects [48]. PHES faces particular barriers arising from their large capital investment requirements that require a high level of confidence regarding future revenues, which in turn requires an environment of 'storage-friendly' policies [31,49]. Time frames are also important. A PHES facility is a complex infrastructure project [49] that may take 3-5 years to construct (and this may be a conservative estimate), so that shorter delivery timescales will either add to cost or simply not be achievable [31]. Similarly, limited contract terms will not reflect or, thus, value the potential PHES operating lives of up to 80 years [19,49].

4. So what can be done?

From the analysis above, a number of conclusions can be drawn in terms of the required focus of policy analysis and action.

First, there is a fundamental need to **recognise and articulate the value EES provides** both to cost effective running of the electricity system but to society as a whole[8]. This is already a complex task given the diversity in stakeholders involved and the need to set any valuation at energy system level in terms of its low carbon electricity generation properties (where there are a wider set of recognised valuation issues around carbon emissions and mitigating global climate change). However, the particular issue highlighted in this paper is the need to link EES to outcomes valued by the political economy via the increased security of supply and flexibility that it enables. These features were implicitly recognised in decision making regarding investment and deployment of PHES back in the 1970s and 1980s but may require more formal recognition in today's complex policy and societal environment. Ultimately, a key recommendation must be that future research in energy policy generally, and the storage domain in particular, give attention to principles and methods set out for valuation and evaluation of less tangible societal costs and benefits via trusted policy publications such as HM Treasury's Green Book. **Societal costs and benefits** should part of an assessment of future energy system requirements performed by Government, Ofgem, electricity and other industry participants who can make decisions on storage capacity and investment. This is an urgent need to understand what policy change may be required.

As noted in this paper, the maturity and prevalence of PHES in the existing storage landscape, and the consequent impact on key economic determinants of discounted costs and revenues, does make it more likely that this EES option would perform better in a social cost benefit or related analysis. However, the key step is to actually set out methods of valuing basic outcomes delivered by EES more generally. As such a framework develops and becomes accepted and trusted, it will become more straightforward to incorporate the comparative benefits/cost implications of other EES options (such as greater flexibility of location, lower capital costs).

The second key conclusion is that, underpinning any valuation, here is a need to **define storage within the electricity system market framework**, and, more generally, to develop more effective long-term market frameworks to obtain the best

8 The Carbon Trust has attempted this [2], although the calculation method and input figures have not been provided. Their report states a saving potential with the deployment of EES of around £2.4bn to society as a whole and £50/year to each household if only 50% of these savings would be passed to the domestic consumers. This would have further implications such as increased industry competitiveness.

commercial solutions. Specifically, EES needs to be considered in terms of what it actually does: the storage of already generated electricity at times when it is in surplus or at low cost in order to avoid curtailment or generator ramping and the later release in times of high demand or the risk of system imbalances. It is arguable that the planed definition of storage as a subset of generation [32,36] is insufficient to fulfil this need. In practical terms, this will involve the removal of double-charging in the context of levies and network charges. This must be accompanied by the **creation of a 'level playing field'** where EES solutions are able to compete with other flexibility technologies such as thermal generators and interconnectors.

There are also an important set of issues in terms of **recognising the full commercial potential of EES** and fully recognising how commercial benefits may lead to benefits to consumers. Within this, there should be a shift to enabling more long-term value stacking (i.e. the provision of several services in general and simultaneously) where technically possible. At the same time, there are a range of issues around **potentially stranded assets**, where EES may displace current flexibility provision. Indeed, there are likely to be problems around the **resistance of current flexibility and generation providers**, where, by reducing average and peak prices in various electricity markets, EES has the potential to indirectly impact the business models of existing generators and flexibility providers [50]. This may be reflected in lobbying behaviour [51].

The third and final, but crucial, conclusion is to underpin all of this with more **policy certainty** around low carbon economic development pathways in generally, and specifically RES deployment targets and EES. In the case of the latter, our conclusion is that the societal and political economy valuation issue highlighted in this paper is the fundamental challenge that must be agreed and addressed in a more integrated whole system approach to energy policy formulation and action as soon as possible.

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