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A SIMPLE INTRODUCTION TO THE ECONOMICS OF STORAGE: SHIFTING DEMAND AND SUPPLY OVER TIME AND SPACE

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6 October 2016

The literature on electrical energy storage (EES) is technical and complex which this paper aims to simplify. It quantifies the current scale, costs and value of different types of EES and compares them to peaking generators and interconnectors. Worldwide, dams have 2,700 times the storage capacity of pumped storage, which accounts for 99% of conventional EES, batteries making up the rest. Indirect use of hydro power, and in future, electric vehicles, adds to their value and if accessible at reasonable cost, would be cheaper than conventional EES. EES, peakers and DC interconnectors can offer flexibility services which considerably enhance their value, but hopes of a battery revolution enabling a smarter electricity system should not be exaggerated.

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Key words: electrical energy storage, interconnectors, flexibility services

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A simple introduction to the economics of storage: shifting demand and supply over time and space

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Abstract
The literature on electrical energy storage (EES) is technical and complex which this paper aims to simplify. It quantifies the current scale, costs and value of different types of EES and compares them to peaking generators and interconnectors. Worldwide, dams have 2,700 times the storage capacity of pumped storage, which accounts for 99% of conventional EES, batteries making up the rest. Indirect use of hydro power, and in future, electric vehicles, adds to their value and if accessible at reasonable cost, would be cheaper than conventional EES. EES, peakers and DC interconnectors can offer flexibility services which considerably enhance their value, but hopes of a battery revolution enabling a smarter electricity system should not be exaggerated.

1 Introduction

The electricity system has to balance supply and demand every second, a task that becomes increasingly difficult as intermittent renewables increases its penetration and the amount of inertia on the system falls. Wind and solar PV can be both highly variable over time periods of a day and hard to forecast accurately more than a few hours ahead, making storage appear increasingly attractive as a key element in an electricity system. Much of the discussion of electrical energy storage (EES) is highly technical, reporting the results from small model networks or individual experiments, and published in electrical engineering journals. More ambitious attempts at forecasting EES requirements or optimal EES volumes, such as Pudjianto et al. (2015), summarise the results of complex simulation/optimal dispatch models at a rather high level (e.g. the demand for and potential savings afforded by generic storage devices of given costs and storage/output ratios).

This paper takes a bottom-up approach to compare the likely ranges of costs and benefits of different solutions to the various problems facing the evolving electricity system. It describes the relevant characteristics of different solutions to balancing supply and demand with high levels of intermittent generation, their costs and value, as well as constraints on their supply. It draws on day-ahead and balancing market price data to

[1] dmgn@cam.ac.uk, mail: Faculty of Economics, Sidgwick Avenue, Cambridge. This paper was presented at the Paris meeting of CEEPR/MIT on 8 July 2016, supported by the FP7 project *eStorage* at Imperial College London. Its approach is much influenced by that adopted by David MacKay (2013) in his wonderful application of quantified methods to examine what options are plausible for decarbonizing economies in *Sustainable energy without the hot air*. His chapter 26 on storage covers similar ground but without the economic assessment. I am indebted to excellent comments from colleagues.

assess the arbitrage benefits of EES, comparing that with alternatives such as back-up generation and interconnection, to give a sense of the role that EES might play in an integrated system.

1.1. Measuring cost and value

Storage and its competitors have a number of characteristics that affect its cost and value, and different technologies typically have a comparative advantage in one dimension, and may not be able to offer some of the others. The three most important characteristics for the services they can offer are their maximum output (kW or MW), the storage capacity (kWh, MWh) and their speed of response (milliseconds for batteries and interconnectors, tens of seconds for pumped storage, minutes for combustion turbines, longer for other fossil plant). Other important factors that influence their cost are their lifetime (years, or number of charge and discharge cycles), whether they need to convert from AC to DC and back, their accessibility, and of course their capital and operating costs. For balancing and fast frequency response, output and response time are critical, so measuring their capital cost in £/kW is the natural metric, for diurnal load smoothing, storage capacity becomes important and the appropriate metric is £/kWh. Given that capital and fixed operations and maintenance (O&M) costs are naturally measured over a year, the relevant metrics become £/kWyr or £/kWhr.yr – the latter meaning the annual cost of being able to provide 1 kWh of storage.

1.2. The value of storage

The benefits of storing currently excess or very cheap electricity for later more valuable use is not new. As Britain (and other countries) developed significant shares of nuclear power, it became clear that the opportunity cost of that power in periods of excess supply, usually at night, was zero (or negative, if costs would be incurred in shutting down and restarting), while later in the day high variable cost power would be called on to meet peak demands. Storage was an obvious method of shifting surplus supply to later periods, and many pumped (hydro) storage plants, or PSPs, like Dinorwig in Wales (shown in figure 1), were built to allow nuclear power to continue to run at full output at essentially zero variable cost for later use.

More recently, rapid falls in the cost of batteries have raised hopes that chemical rather than water storage offers a new and attractive storage option. Batteries are typically of modest size (10 MW) and likely to be connected to distribution networks, where improved network management (smart grids) allows them to realise a variety of services locally and to the national grid. Smart metering also offers the prospect of accessing smaller decentralised EES units, for example that embodied in Battery Electric Vehicles (BEVs), which are projected to increase their penetration as battery costs fall (Newbery and Strbac, 2016).

Figure 1 Top reservoir of Dinorwig, Wales PSP, 1.890 GW, 9.1 GWh.
Source: © Copyright Terry Hughes, licensed under this Creative Commons Licence

This paper argues against the simplistic assumption that batteries, and indeed building more storage generally, offer the natural solution to balancing an increasingly renewables-dominated electricity system, by providing relevant evidence in an accessible form. This is not to deny that storage can provide increasingly valuable services, nor that batteries, particularly at specific locations on distribution networks, can be a cost-effective solution to managing constraints and deferring investment, but their total contribution of managing high levels of renewables is likely to be modest. The main point of this paper is to provide evidence not just on electrical energy storage but on alternatives that can offer other shifting options and which are often cheaper.

1.3. The magnitude of wind variability

Intermittent power from wind and PV makes storage more attractive, as there may be excess power relative to demand in some periods, and a shortage in others. The Single Electricity Market (SEM) of the island of Ireland provides an excellent example, with a higher wind share consumed locally and lower interconnections than almost anywhere else. The *All-Island Generation Capacity Statement 2016-2025*[2] gives total connected and energised wind farms as 3,021 MW in October 2015. The 2020 target of 40% renewables by 2020 is estimated to require a total of 3,800-4,100 MW by 2020, which would be comfortably met and possibly exceeded at recent growth rates of installation (and given the volume of planned connections). *Average* demand in 2014 was 3,310 MW (26 TWh), which might increase to 3,800 MW by 2020, but clearly there will be many hours in which wind output will exceed domestic demand. Indeed, even to accommodate the 40% target will require the system to be able to sustain 75% non-synchronous

[2] Eirgrid Group & SONI, All-Island Generation Capacity Statement 2016-2025, Dublin: Eirgrid Plc, 2016. http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

generation (such as wind) in lower demand hours while retaining sufficient inertia and flexibility to maintain the required quality of service (in terms of voltage and frequency stability).

To explore the magnitude of variability that wind imposes in the SEM, figure 2 is constructed by estimating the average wind output over successive periods of 9 hours within a 42 day window, and comparing these to the average wind output over that same 42 day period, for on-shore wind over the first three years of SEM operation. Nine hours is roughly the storage capacity of a PSP, while the centred average 42 day mean wind output corrects for the quite rapid growth in installed wind capacity over this period. The figure plots the maximum and minimum 9-hr average wind output within the 42-day window.

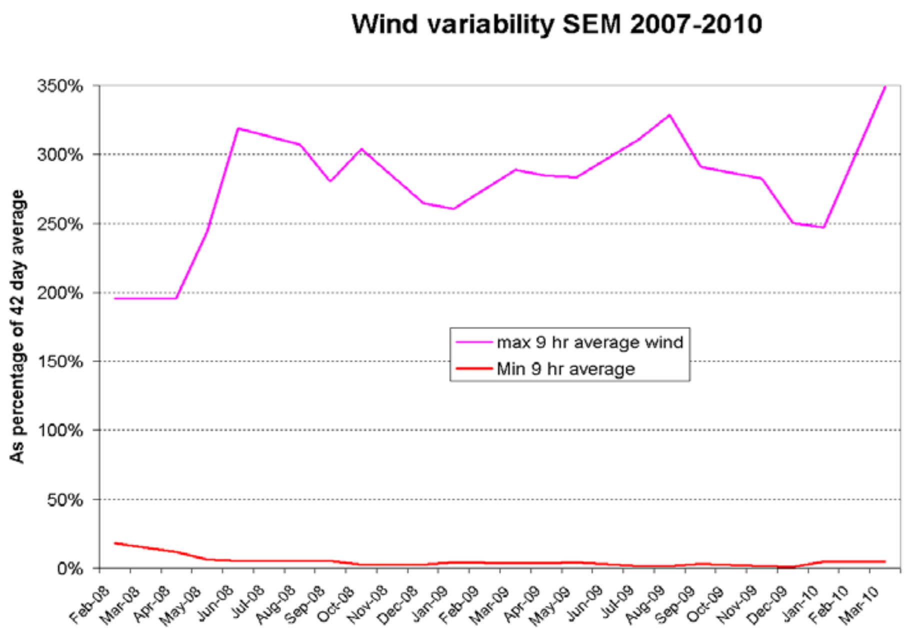

Figure 2 Wind variability on the island of Ireland, 2007-10.
Source: Single Electricity Market Operator (SEMO)

What the figure shows is that in any period of 42 days there will be at least one period of nine hours in which the wind output is between 1-6% of its average value, just as there will be at least one nine-hour period in which it is nearly three times the average output. If the SEM plan for a renewables contribution of 40% of electricity demand are to be met, then clearly there will be many periods in which wind output alone exceeds domestic demand, although with up to 950 MW export capacity compared to a peak demand of 4,800 MW in 2013/14 some of this surplus can be exported. Nevertheless, in 2014, when wind capacity was 2,646 MW, some 4.4% of wind had to be curtailed. Given the considerable revealed variability and unreliability of wind, electrical energy storage (EES) would seem an attractive solution to this problem.

2 Characteristics of different forms of EES

The overwhelming (99%) share of conventionally defined EES is provided by pumped storage plants (PSPs), in which water is pumped to an upper reservoir from which it can be released through turbines to generate electricity when needed. PSPs require massive amounts of concrete and tunnelling and a suitably shaped mountain, of which there only are few in a country like Britain.[3] PSPs are typically 75% efficient in recovering energy. Apart from the scarcity of suitable sites, the main drawback of PSPs is that potential or gravitational energy is remarkable weak compared to chemical energy. Thus the energy contained in 1 litre of gasoline is the same as 7 tonnes of water raised 500 meters (Dinorwig PSP shown in figure 1 has a head of around 500 meters). GravityLight is an off-grid device that allows a 12kg load to be raised and in falling, generates 0.1watt for the 25 minutes before it needs reraising – hence the name of the company, Deciwatt,[4] which is 0.001 kW. Even the lowly AA battery has the same energy as 100 kg raised 10 meters and would provide the same power as GravityLight for 28 hours,[5] while a person on a bicycle driving a generator for 10 minutes would produce 200 times as much electricity (0.2 kWh).[6]

The implication is that one needs a huge weight (or volume of water, at 1 tonne per cubic meter) raised a considerably height to store even modest amounts of energy. Lower heads, such as those created by tidal barrages, or nearshore ponds, would require proportionately more water to deliver meaningful storage – the litre of gasoline used in the example above has the energy of 350 tonnes (350 cubic meters) of water raised 10 meters.

Taking this line of reasoning, some have suggested that moving heavy weights up and down a hill by rail might involve less infrastructure and materials. The Advanced Rail Energy Storage (ARES) system involves electric trains pulling very heavy trainloads of concrete blocks up a mountain, and recovers 78% of that electrical energy when the train descends.[7] Dinorwig PSP shown above delivers 1.8 GW over 5 hours to give a total storage capacity of 9.1 GWh, while for ARES to deliver 333 MW for 8 hours (2.67 GWh) requires 70 shuttle trains, 5,400 concrete masses of 240 tons each (1.3 million tonnes total), running up and down a hill of 13 km length at a 7.5% grade climbing 1,000 metres (so quite a big hill). Each energy trip stores about 2 MWh of potential energy,

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[3] MacKay (2013) lists several potential Scottish sites, and optimistically thinks that GB PSP capacity might be trebled, but does not explore whether they would be economic.

[4] L. Onita, Gravity-powered lamp for people with no electricity, *Engineering and Technology*, March 25, 2015 https://eandt.theiet.org/content/articles/2015/03/gravity-powered-lamp-for-people-with-no-electricity/

[5] See Tom Murphy, Pump Up the Storage, Do the Math blog, 15 November, 2011. http://physics.ucsd.edu/do-the-math/2011/11/pump-up-the-storage/

[6] Pedal Power Bike Generator Frequently Asked Questions (no date) http://www.scienceshareware.com/bicycle-generator-faq.htm#volts

[7] See Advanced Rail Energy Storage (ARES), Grid Scale Energy Storage, 2016. http://www.aresnorthamerica.com/

again demonstrating the incredibly weak force of gravitational energy and the likely high capital and running cost of accessing it by this method.

Two other technologies rely on storing potential energy, either through compressing or liquefying air, which can be released to drive a turbine, much like PSPs. Their major problem is that compression generates heat, while expansions requires heat, and storing the former to provide the latter has yet to be successfully demonstrated at scale.[8] While the former requires a suitable storage cavity, the latter is in principle footloose. They remain at the experimental stage with few scale examples in operation. SBC Energy Institute (2013) provides a useful survey.

Batteries rely on chemical energy, more concentrated than gravitational energy but far less than in fossil fuels. For EES connected to the electricity system, energy density (kWh/kg) is not an issue (as it is for transport), but cost is. Clearly the storage medium, water, in the PSP is free, PSPs deliver AC direct to the grid, and dams have lifetimes of 100+ years. Their response time can be as low as 12 seconds[9] and they can deliver continuous power for periods of many hours. They tend to be distant from demand centres as mountains are inhospitable places and their capital cost is high, even if operating costs (excluding the cost of electricity) are modest, as discussed below.

In contrast, currently popular batteries mostly contain expensive and often rare chemicals,[10] operate with DC and so need conversion from AC to DC and back, have a limited life and require an additional battery management system that substantially increases costs above that of the individual cells. They can be deployed close to demand and, if necessary, made portable (as they clearly are for vehicles). They are highly flexible and their speed of response is measured in milli-seconds, but they can only deliver sustained power for periods of 15mins up to a few hours.

At the other end of the scale, storage hydro dams can offer seasonal storage, again usually in distant locations. Norway has 31 GW of hydro capacity (in 2010), of which 23.4 GW is in dams, 1.3 GW is PSP and 6.3 GW is run-of-river, and can store up to 82 TWh. Between 1998 and 2011 the average maximum volume was just under 70 TWh, 4 months at full output. The 23.4 GW of storage hydro generated about 85 TWh in 2010 at a capacity factor of 41% (Ess et al. 2012). In contrast the entire British PSP storage capacity is just under 27 GWh, so Norway, with a one-twelfth Britain's population, has 25,000 times as much storage in its dams, although only half GB's PSP capacity.

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[8] RWE proposes an experiment in Adiabatic (i.e. heat recovering) compressed air energy storage (CAES) in project ADELE, described at RWE Power, ADELE – Adiabatic Compressed-Air Energy Storage for Electricity Supply, January 2010. https://www.rwe.com/web/cms/mediablob/en/391748/data/364260/1/rwe-power-ag/innovations/Brochure-ADELE.pdf

[9] MacKay (2013, p191)

[10] The range of chemical storage options is quite large, ranging from traditional lead-acid batteries to Lithium-ion, sodium-sulphur and flow batteries, facing varying challenges (safety, durability, cost). See Centre for Low Carbon Futures (2012).

2.1 *Current electrical storage capacity*

Table 1 shows that the world PSP operating output capacity in 2016 was 164 GW, which for the past eight years has been growing on average at 2.7% p.a.[11] Data on storage capacity is incomplete but for the 45 GW of PSPs for which capacity is available, total storage is 1.7 TWh (although the top four by capacity have 75% of this total and a very low output, corresponding more to storage hydro). The remaining PSPs have 10.9 hrs, duration so if this is representative of the remaining PSPs, the total *global* storage capacity is 2.9 TWh (compared to roughly 70 TWh in dams in Norway alone). Germany, for example, has 6.8 GW output capacity and stores 50 GWh, or 7.4 hrs on average while Britain with 2.86 GW output stores 26.7 GWh, or 9.3 hrs (the range over the four PSPs is from 3.6-25 hrs).

World hydro capacity in 2012 was 979 GW, generating 3,288 TWh/yr or 16% of world total electricity output (EIA, see footnote above) at a capacity factor of 38%. Again, data on its storage capacity is not readily available, but assuming the capacity factor is related to storage capacity as in Norway, the capacity would be 3.7 months. At 3 months, storage capacity would be 2,144 TWh, or 2,700 times the global PSP capacity.

Ignoring hydro capacity, Table 1 shows that PSP comprises 99.7% of world electrical energy storage and electro-chemical (dedicated) storage only 0.1%. Table 1 summarises the latest data available for other forms of storage, showing the current dominance of various kinds of sodium-sulphur and lithium-ion batteries.

Table 1 Global capacity of various forms of electrical energy storage, 2016

Technology Type	Power GW	duration hrs (av.)	GWh	subtotal shares	share of total
Pumped Hydro Storage	164.3	17.8	2,921.6		99.7%
Compressed Air Storage	0.6	7.9	5.0		0.2%
Electro-chemical					
Sodium-sulphur Battery	0.2	6.4	1.3	44%	
Electro-chemical	0.0	1.5	0.0	0%	
Lithium-ion Battery	1.2	1.1	1.3	43%	
Lead-acid Battery	0.1	1.1	0.1	4%	
Flow Battery	0.1	3.5	0.3	9%	
subtotal e-chemical	1.6	1.9	3.0	100%	0.1%
Electro-chemical Capacitor	0.1	6.0	0.5		
Flywheel	0.9	0.3	0.3		
Total	167.5		2930.4		100.0%

[11] US Energy Information Administration (EIA), Hydroelectric Pumped Storage Electricity Installed Capacity (Million Kilowatts) 2004-2008, International Energy Statistics, http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=82&aid=7&cid=regions&syid=2004&eyid=2008&unit=MK

Source: DOE Global Energy Storage Database.
http://www.energystorageexchange.org/projects

The volume of chemical energy stored in Electric Vehicles can be roughly estimated from the cumulative sales of plug-in light vehicle sales to 2015 of 1.2 million (growing at an average 83% p.a. over the past four years).[12] If the average battery size is put on the high side at 24 kWh, this amounts to just under 30 GWh. The 2012 global car fleet registered was 773 million, growing since 2000 at 2.9% p.a., which if this continued would give a car fleet of 1.12 billion by 2025. If by then the share of electric vehicles (EVs) had grown to 10%,[13] there would be 112 million EVs, which with 24 kWh/EV with 2.7 TWh, more than current PSP storage. While this may seem large by comparison with stand-alone batteries and even PSPs, only a part of that storage is accessible and then only indirectly, as discussed below under indirect storage.

2.2 Battery lifetime and cost

The lifetime of batteries is limited by the depth of discharge (DoD), temperature, and other factors such as charging voltage and whether kept fully charged for extended periods. The way they are used can dramatically affect the cost of each kWh withdrawn.[14] Perez et al. (2016) report calculations based on an experimental 6 MW, 7.5 MVA, 10 MWh battery with a round trip efficiency of 85% installed at Leighton Buzzard in England.[15] Constraining the DoD to 25% doubled the life from 76,000hrs (8.67yrs) to 175,000 hrs (20 yrs.). The Leighton Buzzard battery may have a chemistry designed for longer life, as other sources claim the typical cycle life of a conventional Lithium-ion (Li-ion) cell that is only discharged 60% is 10,000 cycles, falling to 4,400 kWh at a DoD of 100% DoD.[16]

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[12] See US Department of Energy, Fact #918: Global Plug-In Light Vehicle Sales Increased by about 80% in 2015, March 28, 2016 http://energy.gov/eere/vehicles/fact-918-march-28-2016-global-plug-light-vehicle-sales-increased-about-80-2015

[13] This would require a rapidly growing share of the roughly 70 million new cars sold each year to be EVs, rising from the 2015 share of just under 1% to perhaps 25% by 2025.

[14] Battery University, BU-808: How to Prolong Lithium-based Batteries http://batteryuniversity.com/learn/article/how_to_prolong_lithium_based_batteries

[15] Details at UK Power Networks, Smarter Network Storage http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/ . The battery, based on Lithium-Ion chemistry; is a Lithium-Manganese blend. It cost £13.2 million, and roughly 70% of the total cost is the capital cost of the battery, the balance being civil works and a modest operating cost (excluding power purchased). Assuming that as an experiment the cost is 30% higher than otherwise, the implied cost for the battery alone would be high at £700/kWh. The experiment was supported by Ofgem's Low Carbon Network Fund, which requires all results and learning to be published.

[16] See Saft, Lithium-Ion Battery Life. http://www.saftbatteries.com/force_download/li_ion_battery_life__TechnicalSheet_en_0514_Protected.pdf but for a more pessimistic estimate: Battery bro, What is the difference between the LG HE2 and LG HE4? Which is newer, better? 22 April, 2015. https://batterybro.com/blogs/18650-wholesale-

The Leighton Buzzard experimental battery had a high (first of a kind) cost (£1,000/kWh) but Tesla and related forecasts suggest 2018 battery pack costs of \$330-750/kWh, or, installed at grid scale, \$475-\$1,050/kWh. Li-ion batteries for electric vehicles (like those developed by Tesla) have high deliverability and are experiencing falling costs. Industry forecasts (e.g. PWC, 2013) project a \$300 (£190)/kWh battery pack by 2020. Newbery and Strbac (2016) summarise estimates for 2020 costs which range from \$275-\$375/kWh for the battery pack. Additional costs for civils, inverters and controls for grid scale application might increase this by 40%, but batteries which no longer meet the performance standards needed for electric vehicles might be recycled for grid or distribution storage at a considerable lower price.

Details on these and other batteries, marked up by 40% to reflect installation costs, are given in Table 2. To calculate the service delivered per unit of nominal storage capacity in kW over the course of a year, the capacity is first multiplied by the Depth of Discharge (DoD, e.g. 75%), then by the number of cycles per day (e.g. 2), then by days per year operational (max 365), to give MWh/yr per kW capacity (e.g. 75%*2*365/1000 = 0.547 MWh/yr/kW capacity). This can be multiplied by the annuitization factor for n years at a discount rate of r, of $(1-\beta^n)/r$, where $\beta = 1/(1+r)$ is the discount factor to give the capital charge (capex) per MWh delivered, to which must be added the operations and maintenance costs (O&M) usually expressed in £ or \$/kW.yr. Finally, the cost of the delivered power must also include the cost of the power purchased ($=1/(1-e)$ MWh input per MWh output, where e is the efficiency (e.g. 75%).

Table 2 Summary of battery costs and levelized overhead per MWh delivered

	cost/kWh capacity	DoD	O&M /kW.yr	cycles/ day	Life yrs.	levelized cost/MWh
Leighton Buzzard Li-ion NOAK	£850	100%	£10	1	9	£251
Leighton Buzzard Li-ion NOAK	£850	75%	£13	2	10	£264
Tesla 2018 Low	\$475	100%	\$15	1	12	\$207
Tesla 2018 High	\$1,050	60%	\$20	2	14	\$323
Li-Ion 2020 Low	\$385	100%	\$15	1	12	\$175
Li-Ion 2020 High	\$525	100%	\$20	2	6	\$179
Na-S Low	\$420	100%	\$15	1	7	\$256
Na-S high	\$700	80%	\$20	2	6	\$287
Lead-acid low	\$196	100%	\$15	1	1	\$617
Lead-acid high	\$280	100%	\$15	1	3	\$334

Note: NOAK is n-th of a kind, Na-S is Sodium-Sulphur. O&M discussed below.

battery-reviews/19198431-what-is-the-difference-between-the-lg-he2-and-lg-he4-which-is-newer-better

What table 2 demonstrates is the extremely high overhead cost of battery storage which requires it to deliver extremely valuable services to justify its cost, a topic explored below.

2.3 Pumped storage costs

Dinorwig pumped storage has a modern replacement cost of perhaps £850/kW capacity but can store 5.25 kWh/kW,[17] so its capital cost is £162/kWh capacity, apparently more expensive than a lead acid battery, but batteries only deliver a limited number of cycles while pumped storage should be almost indefinitely lived. Turlough Hill in the Republic of Ireland appears cheaper with 293 MW at £300/kW, and can operate at full load for up to six hours per day, giving a capital cost of £50/kWh capacity. Fixed operating and maintenance (O&M) costs of perhaps £10-20/MWh (see below) need to be added, together with the cost of purchasing 1.33 MWh per MWh delivered.

California has recently been considering additional PSPs to handle the problem of excess night-time wind, combined with a trough in wind during peak daytime hours (just as PV is rapidly falling). The contemplated Lake Elsinore Advanced Pumped Storage (LEAPS) facility might cost $1.1 billion for 500 MW[18] for 6,000MWh or $2,200/kW and $183/kWh. At a lower estimated cost of $1,151/kW[19] (which may exclude the necessary transmission) and the revised estimate of 10 hrs delivery, the cost would be $115/kWh. Both these estimates are lower than Dinorwig. As this is a forecast it is likely an underestimate, as the median cost over-run for dams is 100%, so the estimate should be treated with caution (Ansar et al., 2014).

The DECC 2050 calculator[20] provides a wide range of estimates, from £500-£5,000/kW with a default estimate of £2,100/kW, or, assuming 8 hrs capacity, £260/kWh, but this looking ahead when the best sites have been mainly used. National Grid's estimate in the same source for 2011 is £500/kW. Cruachan PSP in Scotland, 440 MW, 10 GWh storage, is planning to double its capacity and output to 1 GW, 20 GWh, at a reported cost of £1 billion.[21] The *Financial Times* (28/2/2016) reported that Scottish Power was considering spending £400 million for the same project, but as noted above

[17] Dinorwig originally cost £425 million over 1973-82 (Williams, 1991). If we assume that the quoted cost is in 1980 money, this is £1.47 bn or £850/kW at 2011 prices.
[18] Lake Elsinore Advanced Pumped Storage, Wikipedia at http://en.wikipedia.org/wiki/Lake_Elsinore_Advanced_Pumped_Storage
[19] Van Vactor's 2010 estimate (personal communication). The CAISO 2006 estimate was $700 million of which $250 million was the additional "TE/VS" cost (transmission?), see http://www.caiso.com/1791/1791cc2e74ed0.pdf
[20] *DECC 2050 Calculator* at http://2050-calculator-tool-wiki.decc.gov.uk/cost_categories/60
[21] £1bn plan to double output of Scotland's 'Hollow Mountain', *The Herald (Scotland)*, 11 February, 2014. http://www.heraldscotland.com/news/13145140.__1bn_plan_to_double_output_of_Scotland_s__Hollow_Mountain_/

the actual cost may be twice as high (Ansar et al., 2014). If so the cost might be £80-200/kWh, which is at the low end of PSP costs.

Pumped storage has operating costs seem to be typically about £10-48/kWyr, according to the DECC *2050 Calculator*. Operating costs (O&M) averaged $45 (£30)/kWyr for large-scale hydropower projects (Ecofys et al., 2011) and are likely to be comparable to PSP O&M costs. Table 3 summarises these costs but assumes the lower end of the O&M costs.

Table 3 Pumped Storage overhead costs per MWh delivered

PSP	interest	cost/kWh capacity	DoD	O&M /kW.yr	cycles/day	Life yrs.	levelized cost/MWh
Dinorwig	5%	£162	60%	£20	1	75	£58
Turlough Hill IE	5%	£50	60%	£20	1	75	£32
Cruachan	5%	£100	60%	£20	1	75	£43
LEAPS CA	8%	$183	60%	$40	1	75	$107
DECC 2050 default	5%	£260	60%	£20	1	75	£81

3.3 Summary of storage costs

Tables 2 and 3 give the comparable costs of delivering services from different forms of electrical energy storage (EES). Pumped storage capital costs are highly site specific. The more attractive range from £50-250/kWh capacity, and at modest (5% real) interest rates, given their great longevity, these annual capital charges are modest, but at 60% capacity factor (the recent Welsh PSP experience) these costs become somewhat higher. Note this attributes all costs to storage and none to the other services it can offer, but it demonstrates that the cheaper PSPs appear attractive, while high interest rates and opex make it relatively costly.

Chemical storage in various batteries, because of their limited life, is more costly in terms of kWh, typically 2-5 times more than PSPs (but their much faster response time and locational flexibility gives them other advantages). The implication is that for just arbitraging prices over the course of the day EES is unlikely to be cost effective. Of course storage would be only one service, and in fact storage only provides 21% of Leighton Buzzard's revenue (see below) so arguably it should only be attributed 21% of the cost, but still over £50/MWh or £23/kWh.yr.

Other batteries summarised above face similar attribution problems. The conclusion is that PSPs are cheaper for diurnal storage and batteries may be more useful for the other services they provide, which we now examine.

3 What is storage worth?

The approach adopted by Strbac et al. (2012, p7) is to take "a whole-systems approach to valuing the contribution of grid-scale electricity storage in future low-carbon energy systems. This approach reveals trade-offs between multiple services that energy storage is able to provide, which result in generally higher aggregate values for storage than in previous approaches that considered such services in isolation." The study of the 6 MW, 10 MWh battery at Leighton Buzzard gave the results summarised in Table 4 below.

The actual cost was £11.4 million but UKPN forecast future costs at £8.5 m. In future, reactive power, enhanced frequency response and demand turn-up services provided to the TSO, as well as new flexibility products for distribution networks, might become marketable services from network storage devices and add to revenue. Notice that the battery enables deferred network reinforcement accounting for over half its total social value without which the investment would not be worthwhile: even including the non-marketed benefits together with the other marketed services only cover 40% of its lifetime costs. If battery costs decline further and stresses on networks rises with more distributed small scale generation, so the benefit/cost ratio should become more favourable provided the deferred reinforcement benefits are large enough.

Table 4 Leighton Buzzard optimized forecast benefits and costs

	annual	/kWh.yr	NPV 7.2%	share
Arbitrage profits	£59,130	£5.91	£411,492	4%
fast frequency response	£153,300	£15.33	£1,066,831	11%
reserves	£65,700	£6.57	£457,213	5%
total	£278,130	£27.81	£1,935,536	20%
derated Triad avoidance[22] NPV		£1.09	£76,000	1%
reduced CO2, system losses not remunerated		£35.92	£2,500,000	26%
deferred network reinforcement		£73.29	£5,100,000	53%
total social benefits		£138.11	£9,611,536	100%
cost n-th of a kind		£122.14	£8,500,000	88%
future net benefit		£15.97	£1,111,536	12%

Discount rate and data from UKPN (2014) and (Perez et al. 2016)

This reminds us that the value of storage is the sum of the various services it may provide, so looking at any one service in isolation understates the total value. It also reminds us that system aspects like location, duration and speed of response are important, and so storage characteristics will determine value. In particular, while batteries are typically small and thus can be sited where most needed, generating peaking capacity usually comes in significant sized units (100-200 MW) and may not be so suitable for dealing with problems in the distribution network. While small generating

[22] Triad avoidance avoids the Load charges levied on distribution networks by National Grid, but these are currently very significantly over-valued (Newbery, 2016).

sets of 10 MW are readily available and suitable for local connection, their cost per kW capacity is considerably higher than for larger units.[23] At the other extreme, pumped storage is both large and very site specific, and not all countries have sufficiently high or suitable mountains.

5.1 Arbitrage gains from PSP

Storage shifts power from one period to another, and the obvious gain is to buy cheap and sell dear, to collect arbitrage gains. We can estimate an optimistic value of the gross returns from day-ahead energy trading (for the moment ignoring operating costs) for PSPs. Given day-ahead prices it should be possible to optimise when to buy and sell, and figure 3 is a rough approximation to this. It takes the 16 cheapest half-hours for buying power which is then sold in the 12 highest price periods, provided the most expensive purchase is less than its value when sold at the lowest price (if not then 0.5 MWh less is purchased and 0.375 MWh less is sold). The hours are ranked and then the cheapest found, no matter when they occur, and sales take place at the highest prices, which assumes that there is already enough water in stock to meet that demand. This may over-estimate the value if these hours come too soon in the pumping day (assumed to start at 11pm the day before). However, the early part of the day (11pm-5am) almost always contains cheaper periods than later so even if there are some morning high-priced periods and afternoon cheap periods, provided the system can cope with early release and subsequent pumping this should not be a problem.

[23] In the first 2014 GB capacity auction, a large number of smaller generating units (average size 11 MW) secured capacity agreements, largely because of the over-generous embedded subsidy they received (Newbery, 2016).

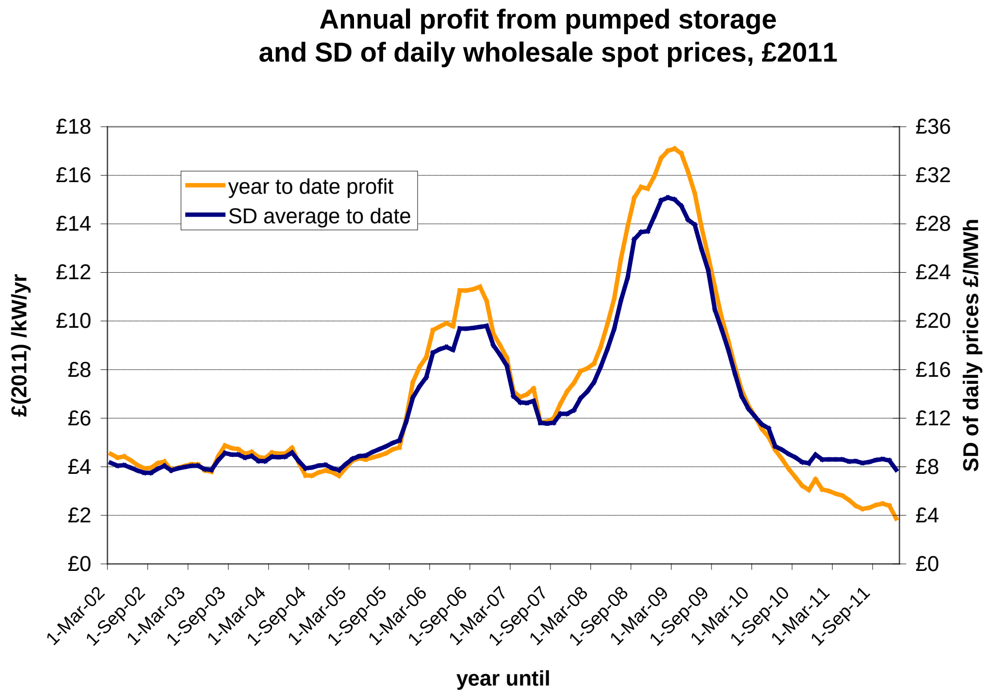

Figure 3 Notional annual profit trading storage in the GB spot wholesale market
Source: APX UKRPD prices

What figure 3 demonstrates is that the revenue from pumped storage depends critically on the daily variation in electricity prices, as measured by the standard deviation (SD). As wind penetration increases this is likely to rise considerably. The figure reveals a very low market value from energy trading for PSP of about £(2011)6/kWyr averaged over the period, which would not cover its opex. Of course, Dinorwig PSP has considerable extra value in that it can provide ancillary services and also offer itself into the Balancing Mechanism (BM). Its value in the latter case can be similarly estimated, on the optimistic assumption that it buys at the cheapest prices in the BM (typically at the System Sell Price) and then sells back at the highest prices in the BM (typically the System Buy Price). This might be the case if the PSP were controlled by the System Operator and used entirely for balancing (which was its original purpose).

Figure 4 demonstrates these potential balancing revenues and makes clear that this greatly enhances its value to a gross value of about £(2011) 26/kWyr, more than four times as high as trading in the day ahead market, although if opex is £13/kWyr this is halved in net value. The higher values in the earlier period reflects periods before the BM was reformed to reduce the incidence of negative sell prices, by making the reverse direction price the prompt price (i.e. for balancing actions that were assisting to rebalance the system). As wind penetration increases and reserve margins fall these revenues can be expected to rise. Recent reforms to the Balancing Mechanism have moved it closer to a single marginal priced market and this will increase its volatility and hence balancing revenues.

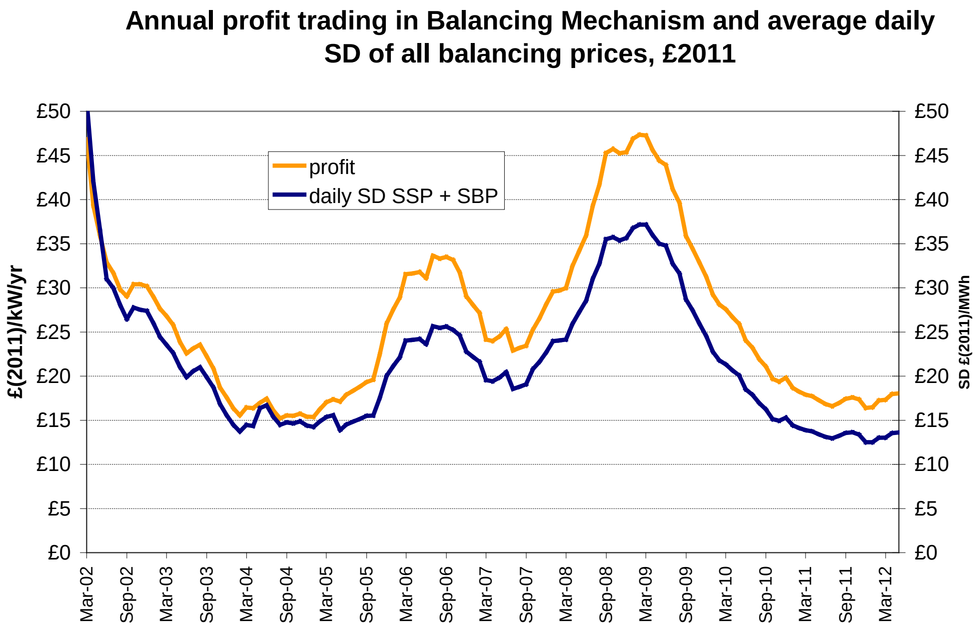

Figure 4 Using pumped storage solely for balancing purposes
Source: Elexon balancing prices

Balancing markets understate the value of providing fast frequency response, Primary Operating Reserves, and other ancillary services. We can cross check the profitability of the PSPs in Wales (Dinorwig and Ffestiniog) from the accounts of First Hydro.[24] To quote "In the accounts for First Hydro Company, covering the year ending 31 December 2014, pre-tax profit dipped to £112.8m, from £122.4m in 2013. Turnover during the period decreased to £299m from £307m. During the year the group generated 2.4 terawatt hours (TWh) of power, up on its output of 2.3 TWh in 2013." This suggests 2014 profits of £47/MWh, or, as the capacity is 2.16 GW, £52/kWyr (£56/kWyr in 2013), twice as high as that calculated from the Leighton Buzzard Li-ion battery computed above. The implication is that PSPs earn most of their money from ancillary services rather than price arbitrage. That is consistent with the experience of the Leighton Buzzard battery, which earned more than half its optimized gross operating revenue from fast frequency response.

3.2 Avoiding wind curtailment

If wind might be curtailed because of excess supply and if it could be stored instead, its opportunity cost would be virtually zero and its value when sold in later peak hours (or

[24] At Profits Slip by Almost £10m at Hydro Generator, Insider Media, 24 June 2015. http://www.insidermedia.com/insider/wales/142159-/

for other more valuable uses) might be high. If the alternative cost of buying power were £25/MWh (the average off-peak day-ahead price used in Fig 3) then the additional revenue from buying at a zero price to avoid (some) curtailment can be estimated. If the lost wind were 8% in 2020[25] (assuming no other ways of addressing surplus wind by using battery electric vehicles, discussed below) then wind would be shed 700 hours per year worth an additional £17.50/kWyr, which is material. Other estimates suggest a lower level of wind spilled, allowing for other means of avoiding this, and NGET (2011) suggests 38 days of shedding, which might amount to 200 hours, worth only an additional £5/kWyr (but these are added to all the other sources of revenue).

4 Indirect storage

Storage dams can provide indirect storage by not generating and replacing the power otherwise provided from the dam with cheap generation from other sources. This has been the classic *modus operandi* of Norwegian hydro and Danish night-time coal-fired generation, but it can apply to any low variable cost power that displaces stored electricity (in the form of water) that can be released in high value hours. Given that dams may contain more than 2,000 times the volume of PSPs, this form of indirect storage is clearly of major significance, although accessing it may require considerable additional transmission and interconnection, considered below.

Similarly, Battery Electric Vehicles (BEVs) can provide indirect storage by interrupting their charging and hence reducing demand to match reduced supply from other sources, as can other demand side responses. More usefully, they can provide fast frequency response by varying their charging rate (Izadkhast et al., 2015; Wu et al. 2011). National Grid estimates that this could be worth £25/yr per electric vehicle for residential consumers.[26] For a 24 kWh battery is would amount to £1/kWh/yr, a very small fraction of the cost of that battery, and small compared to the Leighton Buzzard experience discussed above. Smarter cheaper forms of aggregating such services should enhance their value by reducing the currently high administrative costs.

5 Alternative sources of flexibility

One use of storage is to meet peak demand without additional generation capacity. Indeed, that is the prime purpose of gas storage, where the peak winter days in the GB are typically met from the Rough storage facility that is filled in the summer trough. But gas is quite different from electricity, in that seasonal storage is attractive (just as well-endowed hydro-electric countries like Norway rely on seasonal reservoir filling to meet annual electricity demand). Pumped storage has a cycle time of hours to one day, rather

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[25] From a study of the benefits of Electric Vehicles presented to the Green e-Motion WP9 Meeting - Imperial College 13 June 2012

[26] Rhiannon Grey, A Fresh Approach, National Grid, 18 September, 2015. http://www.nationalgridconnecting.com/fresh-thinking-on-frequency-response/

more than most battery storage facilities, as compared to slow release systems like large hydro-electric reservoirs.

5.1 Flexible generation

Peaking capacity (open-cycle gas turbines) has a relatively low capital cost, around $400/kW.[27] At today's prices this would be about £300/kW, the same as the construction cost in DECC (2013). This would amount to £35/kW/yr for interest and depreciation at 8% over 15 years, to which would have to be added opex (£10/kWyr from DECC, 2013) and fuel costs when running. Other estimates suggest higher annual costs, perhaps £50-70/kWyr.[28] The advantage of an OCGT is that it is not limited by its storage volume and so could back up any number of days of low wind, as well as being easy to size and locate to relieve transmission constraints.

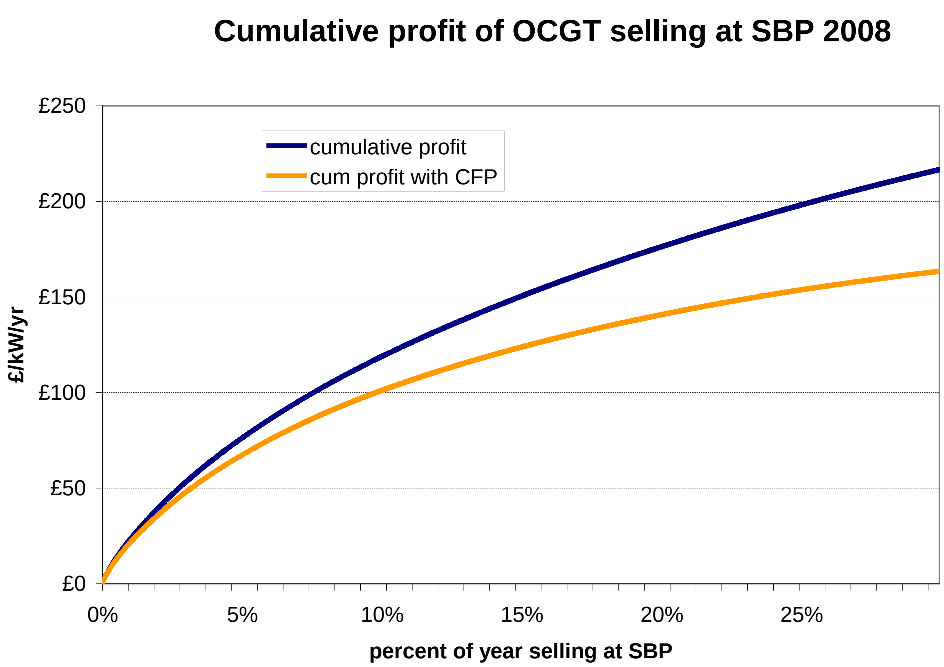

Figure 5 Cumulative 2008 OCGT gross profit with and without a £30/tonne CO_2 price

[27] US Energy Information Administration data used for the calculation of 2007 *Annual Energy Outlook* at www.jcmiras.net/surge/p130.htm.More recent cost data are not available from this source but are from DECC (2013).

[28] The estimated EPC cost in the SEM based on the OCGT Alstom GT13E2 is €(2015) 94.5 m for 195.7 MW, but to that is added an additional €38m for site, connection, financing, contingency, initial fuel stocks, giving £542/kW (AIP/SEM/15/059 at https://www.semcommittee.com/publication/sem-15-059-acps-final-decision-paper). The O&M including rates, transmission charge, and insurance are £23/kWyr and at 20 yrs life 5.5% interest the total gross cost is €83.74 (£67)/kWyr. However, this figure seems high, as reflected by evidence of excess entry in the SEM. Using the same life and interest rate the DECC total cost including O&M would be £34/kWyr or half as much. The GB transmission charges can be even negative in some zones, but some of the other non-EPC costs may have been omitted.

Figure 5 shows the cumulative gross profit (ignoring fixed costs) running in the most valuable hours. It demonstrates that such a peaking turbine could have earned £100/kW/yr in gross profits selling into the GB Balancing Mechanism at the System Buy Price (SBP) for the top 10% most profitable hrs in 2008, and considerably more if it ran whenever profitable, even with the high 2020 carbon floor price (ignoring the off-setting impact that might have in raising the wholesale price). Capital charges and operating costs would need to be deducted to give net profits but these are comfortably positive.

5.2 Economics of interconnectors

BritNed, that started trading on 1 April 2011, cost about £500 million for a 1,000MW 260 km link between England and the Netherlands, or about £2,000/MWkm and £500/kW, more expensive than an OCGT, although it enables arbitrage between different markets rather than different times and can export as well as import. Clearly it can help avoid spilling wind provided there is a positive price abroad, and it can also provide reserve capacity for longer periods than pumped storage.

Before BritNed was commissioned in 2011 the cross-border day-ahead price differences appeared rather attractive. Figure 6 shows (on the right hand axis) the percentage of the time prices differed between GB and NL by less than €5/MWh. It shows that for more than 75% of the time prices differed by more than €5/MWh. The price differences (shown on the left hand axis) before 2011 averaged about £12/MWh, or just over £100/kW/yr, clearly an attractive return on a cost of £500/kW.

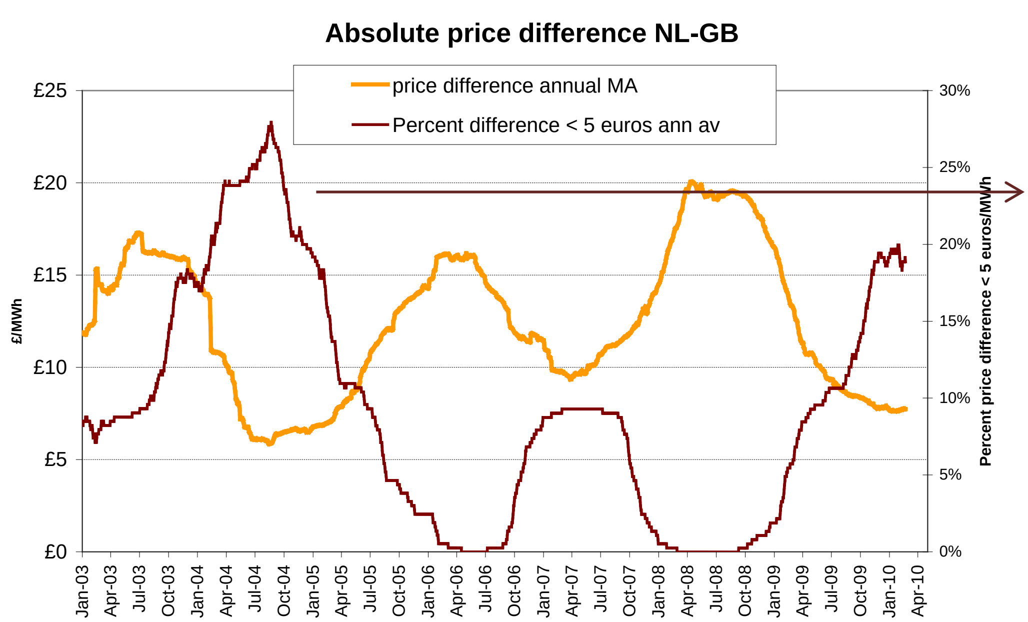

Fig 6 Potential arbitrage profit between GB and Netherlands 2003-2010

Since then, Britain has become fully coupled with the Continental market at the day-ahead stage, and market prices in different countries have tended to converge (Newbery et al., 2016). In the first few months after commissioning, BritNed was coupled with the Central West European market, so that bids and offers into the day-ahead auction in GB and the Netherlands were simultaneously cleared subject to the capacity of the interconnector. Judged solely by price differences in this coupled auction for the immediate post-commissioning period, arbitrage profits fell substantially to £33/kW/yr, one third what might have been expected on the basis of the pre-BritNed price differences.

Arbitrage profits from day-ahead trading are likely to understate the revenues, and for that we look to published accounts for BritNed Development Ltd.[29] Its turnover in calendar year 2013 was €69 (£58)m rising to €116m in 2014, or €116 (£94)/kWyr, close to the original arbitrage estimate. Administrative expenses were €32m (£26/kWyr). Ancillary service revenue is shown as zero in 2013 but €10 m in 2014 (£8/kWyr), and opex only €8/kWyr. The written down capital value is shown in 2013 as €509m but it is depreciated at €15m per year, so its 2011 value was presumable €539 (£435)m, less than originally reported, perhaps because of EU grants.

Nevertheless, the pure arbitrage benefits of £50-85/kWyr (net of ancillary services) is impressive, given the similar gas-based generation mix in the Netherlands and GB. The dramatic rise in renewables in Germany and to some extent Denmark has reduced Continental prices while GB has imposed a carbon price floor that has raised prices in GB, and that may explain much of the difference (but also illustrate the direction of travel as the electricity sector decarbonises.

5.3 *Interconnector access to hydro storage in Norway*

When it comes to accessing (indirect) storage abroad, Norway is the obvious choice, and has been on the agenda since at least 2003. As early as 2009, the transmission company Statnett announced that "NGIL, a National Grid subsidiary, and Statnett have signed a contract to explore the prospects of a power connection between Norway and Great Britain, possibly together with an offshore grid in the North Sea".[30] "The cable's length is about 730 kilometres (from Kvilldal, Suldal, in Norway (in price zone NO2), to Blyth in the UK).[31] It has a planned capacity of 1,400 MW. It is estimated to cost 12 billion NOK (£1.3 billion, £950/kW) and become operational in 2020".[32] At £1,300/MWkm this is

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[29] At BritNed Development Limited, Annual Report and Financial Statements for the year ended 31 December 2014. http://www.britned.com/~/media/BritNed/Files/Finance/Britned%20Development%20Limited%202014.pdf

[30] National Grid, National Grid and Statnett explore linking the UK and Norwegian electricity grids, 6 October, 2009. http://media.nationalgrid.com/press-releases/archive/National-Grid-and-Statnett-explore-linking-the-UK-and-Norwegian-electricity-grids/

[31] Wikipedia, North Sea Link. https://en.wikipedia.org/wiki/North_Sea_Link

[32] http://en.wikipedia.org/wiki/HVDC_Norway%E2%80%93Great_Britain

cheaper per MWkm than BritNed but this could be explained by the fixed cost of the inverters (and the fact that it has not yet been built). The project is moving ahead under the new name North Sea Link (NSL) with a projected completion date of 2021 and a current estimated cost of €2 bn (£1.6bn).[33]

At possibly £1,150/kW it would cost twice that of BritNed, but it might also be able to access offshore wind farms and oil and gas platforms, which would increase its value by reducing the considerable cost of accessing off-shore wind resources. Optimists look ahead to a North Sea Grid, pessimists note that any sharing of off-shore territoriality rapidly runs into international legal problems that likely take years to resolve. Whether a direct link from Norway to England is superior to increased interconnection from Norway via the Continent to shorter links like Britned may depend on this potential value of off-shore wind farm access.

Ofgem regulates new interconnectors, which are subject to a cap-and-floor regime, and therefore must be convinced that the investment, which is effectively underwritten by GB consumers, is beneficial. Their assessment is that the 50% of the profits that accrue to GB consumers could be worth £3.5 bn over 25 years (Ofgem, 2014) although producers would lose about £3.2 bn from lower prices. The net surplus to GB could be -£790m to + £1,040m with a central case of £310m, although this falls to £90m if there is no Carbon Price Support (CPS) in GB. As Norway has zero carbon the social value should properly include this CPS, and indeed, its social value is understated by its projected administered level.

To check the plausibility of these figures, figure 7 shows recent potential price arbitrage at the day-ahead coupled auction prices. The absolute difference between NO2 (Kristiansand) in Norway and N2EX (GB) was calculated, ignoring losses. As prices are lower in Norway (average over this period €25/MWh) the flows are mainly to GB, except when prices are even lower here. At 3% losses some €7/kWyr should be subtracted from gross arbitrage revenue of €28/MWh to give net revenue of €240(£190)/kWyr. Over the period from 2006-12 the average hourly price difference was just under €19/MWh (£15/MWh at spot exchange rates) or £125/kW/yr (€160/kWyr) net of 3% losses.

In common with other storage, interconnectors contribute to security of supply (Newbery and Grubb, 2015), but with the advantage of delivery over a longer period. Compared to PSPs, that benefit should not be exaggerated, as stress periods are unlikely to last more than a few hours, and if Norway were suffering from drought, flows could be in the other direction, as they were during the drought of 2003. That would seem to reduce GB's security of supply, but GB should be able to outbid Norway in stress hours

[33] See National Grid, Interconnectors – Norway (no date). http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/norway/ and North Sea Link (NSL), United Kingdom, Power-Technology (no date). http://www.power-technology.com/projects/north-sea-link-nsl/

and supply her in other hours, as storage hydro allows prices to remain fairly flat over the course of a day or more.

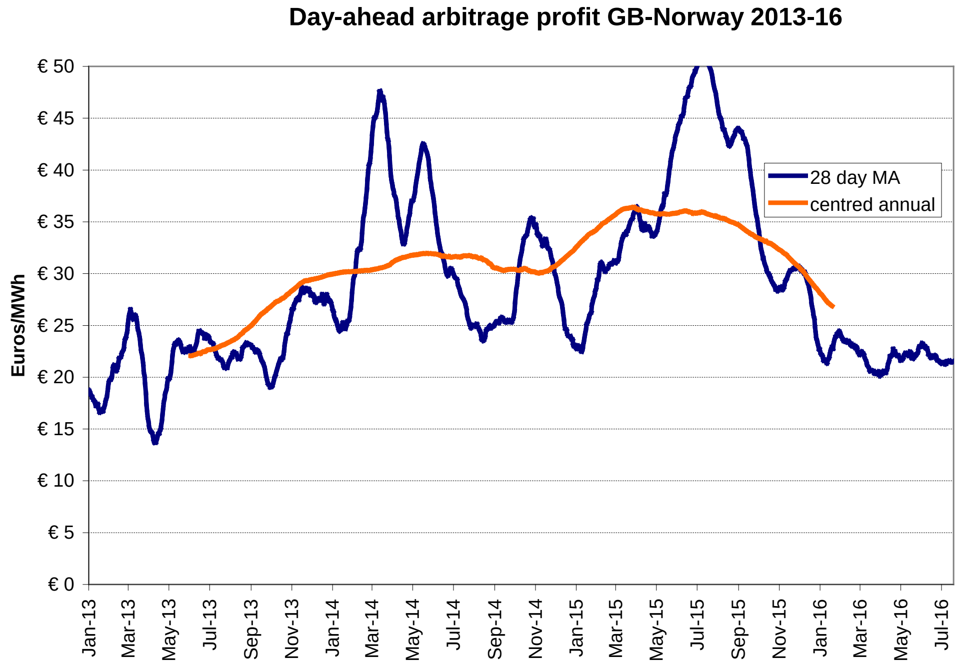

Fig 7 28-day moving averages of daily average wholesale prices in Norway and GB
Source: Nord Pool at http://www.nordpoolspot.com/

NGET (2014) examined potential ancillary service revenue for interconnectors. HVDC interconnectors, based on VSC technology, offer a variety of ancillary services. They can generate or absorb reactive power as required without the need for any additional equipment, have Black Start capability, and can provide Dynamic Voltage Control & System Stability, all of which will become increasingly valuable as intermittent non-synchronous generation increases its penetration. Ofgem (2014) estimates the base case benefits as £47m (range £31-62 m) but imposing additional constraint cost on National Grid of £24 m (range £42m cost to a benefit of £5m), so a net contribution of £23m (16/kWyr), looking some way ahead with considerably renewables penetration. Whether the interconnector owner can benefit from these services will depend on how they are procured and traded, as well as competition from other sources. The annual capital cost at 5% real would be £60/kWyr, to which would be added opex (£10/kWyr, taking double the BritNed figure) and administrative expenses (£26/kWyr for BritNed), so on current arbitrage revenue of £190/kWyr plus £16/kWyr ancillary services, less costs of £96/kWyr gives a net profit of over £100/kWyr, and that includes the return on capital, considerably higher than more grid-connected storage. Of course the past is not necessarily a guide to the future, and increasing claims on Norwegian storage through other existing and new interconnectors will likely raise Norwegian prices and reduce arbitrage profits, but the low correlation of instantaneous wind across Europe could alleviate that erosion. In sum, making access to Norwegian storage appears an attractive alternative to building more grid-connected batteries.

6 Conclusions

Storage for the high tension grids appears expensive compared to alternatives such as spilling wind in surplus and providing peaking plant for shortfalls, unless it can sell other ancillary services of sufficient value. DC Interconnectors can provide similar functions and can also deliver flexibility services, while their ability to continue to deliver for lengthy periods gives them (and peaking generation) an additional edge. Batteries may be very useful when strategically deployed in distribution networks where expansion can be very costly and disruptive. Widening the range of demand-side responses increases potential competition to network-provided storage – and indeed EVs offer the potential through the smart timing of charging to gain some of the same benefits of storage without actually having to make use of the battery as a source of network storage. This underlines the importance of indirect storage, where interconnectors can provide access to Norwegian storage hydro for European electricity systems.

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