June 2011 Energy Research Partnership Technology Report

The future role for energy storage in the UK
Main Report

ERP
Energy Research Partnership

The Energy Research Partnership

The Energy Research Partnership is a high-level forum bringing together key stakeholders and funders of energy research, development, demonstration and deployment in Government, industry and academia, plus other interested bodies, to identify and work together towards shared goals.

The Partnership has been designed to give strategic direction to UK energy innovation, seeking to influence the development of new technologies and enabling timely, focussed investments to be made. It does this by (i) influencing members in their respective individual roles and capacities and (II) communicating views more widely to other stakeholders and decision makers as appropriate. ERP's remit covers the whole energy system, including supply (nuclear, fossil fuels, renewables), infrastructure, and the demand side (built environment, energy efficiency, transport).

ERP is co-chaired by Professor David Mackay, Chief Scientific Advisor at the Department of Energy and Climate Change and Nick Winser, Executive Director at National Grid. A small in-house team provides independent and rigorous analysis to underpin ERP's work.

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Cover images:
Llyn Stwlan reservoir, UK, aerial image. Llyn Stwlan, near Ffestiniog in North Wales, the upper reservoir of the UK's first major pumped storage power facility with output of 360MW.
Royal Institution Battery 1807. 1807 engraving showing the most powerful electrIc battery of the time at the Royal Insitution, London. This was constructed by William Wollaston for Humphry Davy.
Hot Water Storage Tank. A 1500 litre hot water storage tank in the basement of a 'smart house'.

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The Energy Research Partnership Technology Reports

ERP Technology Reports provide insights into the development of key low-carbon technologies. Using the expertise of the ERP membership and from wider stakeholder engagement, each report identifies the innovation challenges that face a particular technology, the state-of-the-art in addressing these challenges and the current activity in the area. The work identifies critical gaps that will prevent key low-carbon technologies from reaching their full potential and makes recommendations to address these gaps.

This report has been prepared by the ERP Analysis Team, led by Jonathan Radcliffe, with input from ERP members and their organisations. The Steering Group was chaired by John Miles (Arup), with Ron Loveland (Welsh Assembly Government), Alex Hart (Ceres Power), Charles Carey (SSE), David Anelli (E.ON), Garry Staunton (Carbon Trust), Gert Jan Kramer (Shell), John Loughhead (UKERC), Richard Ploszek (RAEng), Bob Sorrell (BP), Steven Stocks (Scottish Enterprise), and Tim Bradley (National Grid). The views are not the official point of view of any of these organisations or individuals and do not constitute government policy.

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Executive Summary

Pathways for the UK's energy system to 2050 favour the use of decarbonised electricity to meet many of the energy demands currently served by fossil fuels. This would lead to dramatic changes in the patterns of supply and demand, combining the variability of renewable generation with a strong seasonal profile of electricity demand for heat. Ensuring security of energy supply at timescales of seconds to years will be critical.

The challenges to the energy system will be unprecedented, though manageable if prepared for. Energy storage is in a strong position to be part of the response to these challenges – as outlined in Figure ES1 – with other options being flexible electricity generation, demand side response, and interconnection. However, the implications of achieving emissions goals, beyond simple deployment targets, need to be fully understood so that the transition to low carbon is as efficient as possible.

This report presents a strategic view of the opportunities for electrical and thermal storage to provide a reliable energy supply, setting-out the nature and scale of the challenges that will be faced. We describe how energy storage could go to meeting those challenges and the innovation landscape for further technology development in the UK.

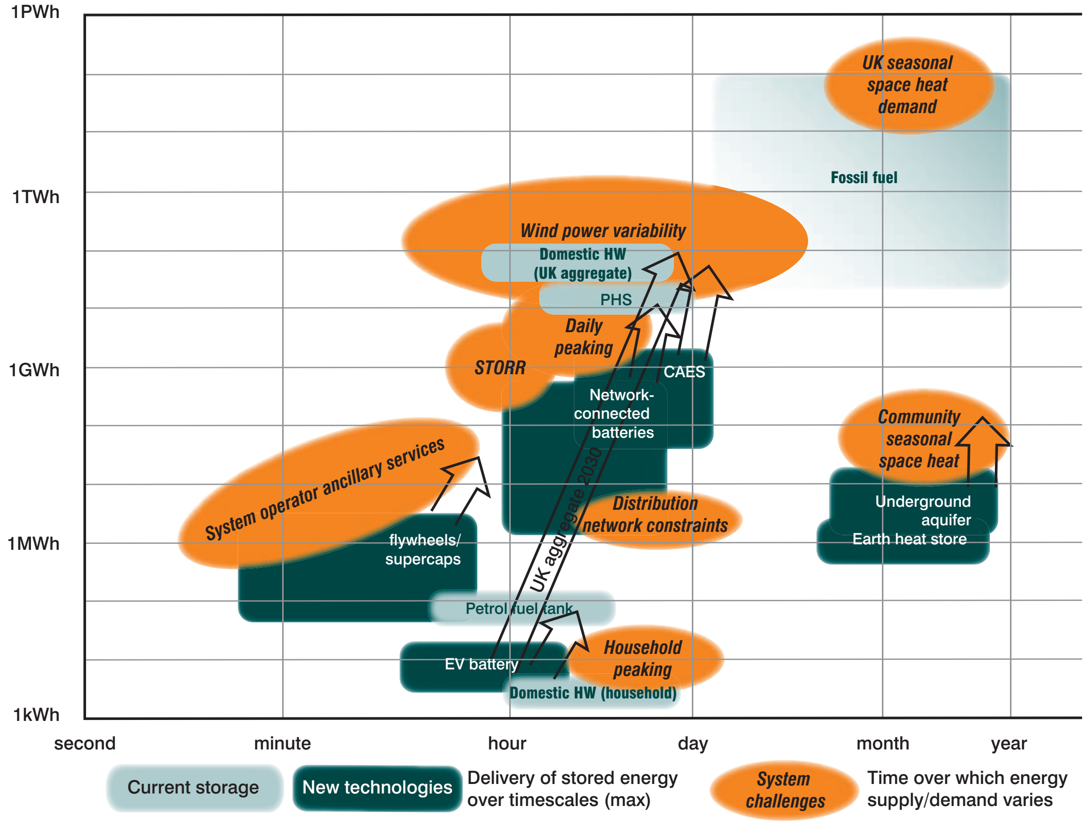

Figure ES1: Challenges to the UK energy system posed by increased wind and electrified space heating and how they can be met by energy storage technologies, with indicative time and energy scales. Blue boxes show widely deployed technologies. Green boxes show current limits of new technologies, with arrows illustrating their potential application with further development.

Our key conclusions are:

Energy storage can help manage the large-scale deployment of intermittent generation and the electrification of space heating. Storage technologies have the potential to substitute for new peaking generation plant and allow the electricity network to handle increasing power flows.

The role for energy storage is poorly described in many pathways to a low-carbon economy. It is a complex technology covering timescales from seconds to months, which needs detailed analysis of systems and sub-systems to identify the economic and environmental benefits it may bring.

New energy storage technologies are unlikely to be deployed on a large scale under current market and regulatory conditions. Both technology cost reductions, and a market framework which recognises the benefits of energy storage, are required to ensure that opportunities to reduce system-level costs in the transition to a low-carbon economy are not missed.

Demonstration of energy storage technologies needs to be scaled-up to show the impact they can have and to guide further underpinning R&D to reduce costs and improve performance. Large-scale trials (in conjunction with demonstration of other network technologies) would help establish the UK as a centre for technology development in a field that is projected to be worth $10s – 100s bn over the next two decades. In general, public sector support for innovation in these technologies should be better coordinated.

Energy storage is an enabling technology; its potential role will be defined by developments across the energy system. Given the pace of change to be experienced over the next decade, a better understanding of both the energy system and policy direction is required urgently to inform investment decisions.

Recommendations

I. Government should set out its long-term policy direction for energy in the UK to help define the potential role for storage, and the innovation required to meet that role.

II. Funders of energy innovation must set out a strategy for the analysis and innovation of energy storage technologies, coordinating their support and integrating the analysis of potential benefits with technology innovation. It would be in the interests of Government, the regulator and industry to ensure an efficient transition to low carbon which energy storage could enable. These stakeholders should come together with the Research Councils, Technology Strategy Board, Energy Technologies Institute and Carbon Trust, to formulate such a strategy.

III. Further analysis of the potential role of storage in the UK's energy system should be funded. Whole system and subsystem modelling, incorporating the full range of energy storage options across time and energy scales, is needed

IV. The Technology Strategy Board should consider bringing forward a programme for energy storage technologies, where there is an opportunity for UK businesses and a potential market need. Other bodies which can support large scale demonstration activities, such as Ofgem and DECC, should target energy storage as a priority.

V. Electricity Market Reform and regulatory approaches must recognise the potential benefits of increased energy storage explicitly. Though the underpinning analysis to define its potential role is not fully developed, this should not be a reason to place barriers in the way of its future deployment, even if they are unintended consequences of other policies. There may even be environmental and economic cases for incentivising deployment of such technologies.

VI. The energy storage stakeholder community, covering all elements of research, development, demonstration and deployment, should establish a Strategic Roadmap for Energy Storage in the UK to introduce a coherent approach across the sector.

To replace the functionality of fossil fuels in providing seasonal space heating would be one of the most significant challenges in the transition to a low carbon economy. Coal, gas and oil have high energy densities and are easy to store and transport in the infrastructure that has built up over decades and centuries. Natural gas serves 100s TWh of heat demand, concentrated in the winter months (Figure ES2). Scenarios described by the Committee on Climate Change and DECC's Pathway Alpha include deployment of heat pumps in around a quarter of UK homes by 2030. This could require a 10GW electricity generation capacity operating at relatively low load factors.

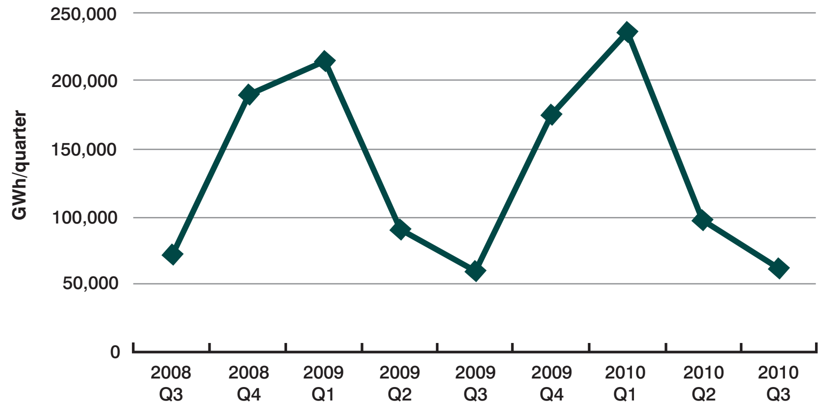

Figure ES2: Seasonal variation of UK natural gas consumption (DECC Energy Trends 2010).

On the supply side, 10s GW of on- and off-shore wind is expected to be built over the next two decades, introducing significant generation variability. Lulls in the wind over several days could lead to reduced generation of order TWh (Figure ES3); shorter term fluctuations will challenge system balancing; and high wind generation in periods of low demand could lead to more flexible unabated thermal generation displacing CCS plant.

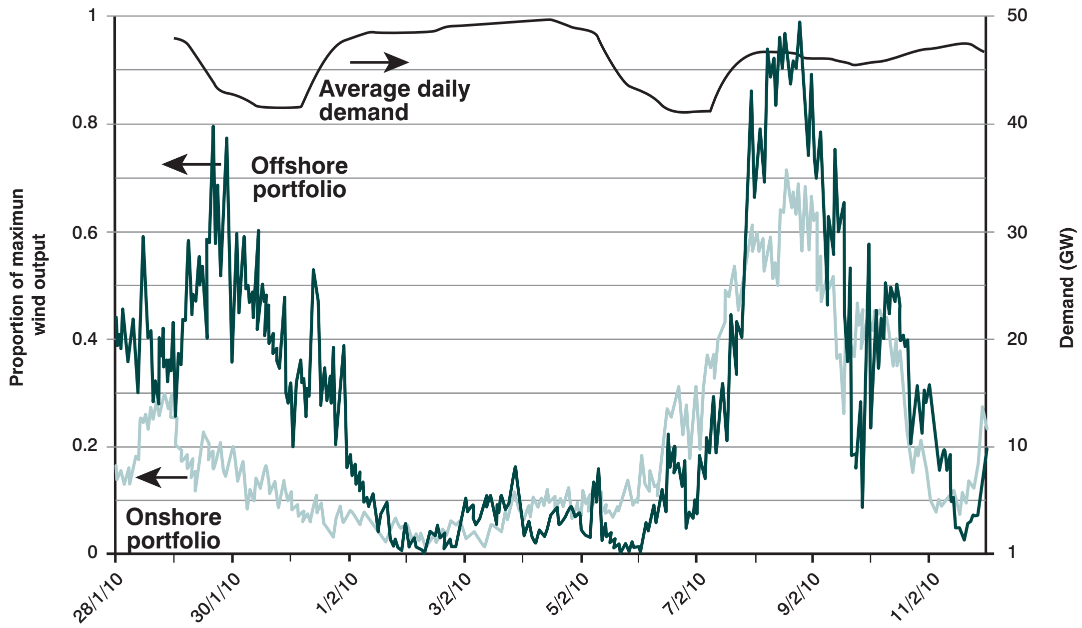

Figure ES3: Variability in generation from wind at peak demand showing wind generation as a proportion of total capacity (left hand scale) and average demand (right hand scale, drops in demand are weekends). With an installed capacity of 30GW and an expected 35% load factor, this would leave a 1TWh gap (or average 9GW), in a period when the total demand was 5.7TWh. (Data from E.ON.)

Options from energy storage

Using electrical and thermal energy storage could avoid some of the need for new plant, and hence the associated costs. Storage could also make most efficient use of the existing and new infrastructure. However, no new grid-scale electrical storage has been commissioned for over thirty years, and the amount of thermal storage in households (as hot water cylinders) is declining.

Installation of electrical storage capability, in locations from the power plant to near end-use, has the potential to provide real economic and environmental benefit to the energy system. There is limited space to expand pumped hydro storage in the UK, so other options for storage need to be explored. Though most focus has been on developing electricity storage, and decarbonised electricity would be the vector for providing the heat service from heat pumps, this may not necessarily be the most effective or practical option. Meeting heat demand from thermal storage must be considered as a alternative. Seasonal 'rechargeable' energy storage as heat may be viable to a limited extent, but is not a solution for large-scale deployment. However, some form of distributed thermal storage could limit the generation capacity required to meet shorter time-scale peaks.

Many new storage technologies are too expensive to move beyond the demonstration phase. But the move to electric vehicles is providing a user-pull that drives R&D in battery technology - reducing costs, improving performance and providing a widespread storage utility that could go beyond the car. In some markets and in some niches, storage technologies are already being deployed commercially.

Energy storage, though, is not the only option to meet the challenges of more variable supply and peaky demand. Greater levels of interconnection, demand side response, as well as flexible thermal generation, could help ease the situation. Hydrogen, as an energy vector and storage medium, may also be an option, though this is also in need of further analysis.

Preparing for the challenges

The major deficit in the UK is a clear understanding of the role that energy storage and other flexibility options could play in the future energy system. Whole system scenario modelling, which is so influential in determining the direction of energy policy and RDD&D, does not adequately capture thermal and electrical energy storage. This is partly due to the short timescales over which the storage operates, the distributed nature of some forms of storage and the cost/performance uncertainties of technologies. In any case, complexity is added as the system is not in a static equilibrium – the low-carbon transition is expected to see new build generation which could either displace the need for storage (if it is in advance of demand), or require it (if it lags demand).

Detailed analysis of the role of energy storage is needed to guide decisions on:

- Where energy storage devices should be placed in the system
- The characteristics of energy storage which are required at different locations
- The optimal mix of energy storage, generation and demand side technologies
- Where infrastructure strengthening need urgent attention or can be deferred

Indeed, improved understanding using insights gained from models, may show that other potential pathways are feasible options and provide cost-effective alternatives. For example, district heating could be more attractive with large-scale thermal storage. And electrical storage in the home could mitigate against low deployment of EVs which may otherwise provide greater system flexibility. On the other hand, it may be concluded that limited utilisation of thermal plant for balancing and back-up generation will provide the optimal solution for the energy system.

There is a case for scaling-up the demonstration of some innovative electrical storage technologies being developed in the UK to test their operation in the domestic energy system, and to prove their technical capabilities for export opportunities. At a practical level, heat pumps should be tested with adjoining thermal storage to assess performance of the technology, and feasibility of including such storage, especially in the home.

The UK has pockets of expertise in developing some storage technologies in universities and companies, but these are largely uncoordinated, lacking a clear vision of how they could be part of a future energy system.

The role for storage is beginning to be acknowledged in the UK, as the impact of low carbon pathways on the energy system is better understood. Some recent reports are making important contributions to the level of thinking in the field, but there is an urgent need for a strategic and coordinated approach to energy storage in the UK. The Energy Research Partnership will follow-up this high-level report with an assessment of how specific energy storage technologies could meet the energy system challenges. We will work with stakeholders to set out a roadmap for their further development and deployment.

1 Introduction

Low carbon electricity is expected to play a major role in achieving emissions targets, with an increase in renewable generation partnered by electrification of heating and transport. An impact of these measures will be seasonal peaking of electricity demand for heat, and variability of supply from intermittent generation. Energy storage is one option for providing flexibility in the energy system, which could reduce the need for new generation capacity and allow greater use of low-carbon power. Further, at a time of network renewal, storage can make most efficient use of existing infrastructure.

Currently, 'rechargeable' energy storage is an expensive option in contrast to the storage that exists in the form of fossil fuel. However, electrical storage in particular is a field in which there has been, and continues to be, much technical progress. This is partly due to deployment of electric vehicles (EV) driving battery development, but also some significant markets are requiring use of energy storage technologies to deal with intermittency of renewable generation. These factors may lead to a drop in prices, improved technology effectiveness and greater acceptance of the technology.

Despite this potential, much of the energy system analysis looking to 2050 has a minor role for rechargeable storage in anything other than EVs; by default models choose thermal plant to handle peaks in demand or to make up for drops in renewable generation. As important policy and investment decisions will be taken over coming years that have long-term effects on the energy system, it is timely for a high-level and strategic consideration of the role energy storage could play. Two recent energy storage workshops, focusing on UK-China technology and strategic needs[1] and stakeholder perspectives[2], will also make useful contributions to thinking in the field.

This report takes an integrated look at the place for energy storage in the UK's evolving energy system, aiming to bring together current thinking and analysis in this complex field. By setting out the scale of the challenges, how technologies could respond, and the research, development, demonstration (RD&D) activities that are being undertaken, we arrive at conclusions to guide decision makers in public and private sector bodies.

1.1 Scope of the report

A simple distinction between thermal and electrical storage may not be helpful when considering the potential role of these technologies in the energy system. With 42% of non-transport energy end-use being to provide heat services, which could be met by either electrical or thermal storage, an integrated approach is required. As such, the scope of this work includes both electrical and thermal storage, from grid-scale to domestic level, in the energy system.

The role of hydrogen has been considered only to limited extent. The production and consumption of hydrogen may provide many of the benefits that energy storage does, but it requires separate analysis. In addition, the focus of the report is on stationary storage, rather than studying battery technologies for electric vehicles (EVs).

The structure of the report is:

- Chapter 2: overview of low-carbon pathways to 2050 from a number of scenarios and models, including how they treat storage and what outputs they give for its deployment.
- Chapter 3: analysis of the challenges to the energy system under scenarios to 2050. These align with timescales from months to seconds, options for addressing the challenges are set out.
- Chapter 4: an outline of the UK's RD&D effort.
- Chapter 5: discussion of deployment issues including how policy and regulation may affect the take-up of energy storage technologies.

The report is presented in the context of pathways to 2050 emission reduction targets, but focuses on the intermediate point of 2030, by which time there should be good progress on decarbonisation of electricity generation, with the electrification of heat and transport underway.

[1] The Royal Academy of Engineering / Chinese Academy of Sciences (2011) The Future of Energy Storage Technology and Policy http://www.raeng.org.uk/news/releases/shownews.htm?NewsID=626 and http://www.raeng.org.uk/news/releases/shownews.htm?NewsID=659

[2] UKERC (2011) The Future of Energy Storage; Stakeholder perspectives and policy implications http://www.ukerc.ac.uk/support/tiki-index.php?page_ref_id=2889

1.2 Current energy storage in the UK

Energy storage has been essential to providing reliable energy supplies for centuries, from stockpiles of coal and uranium, to reservoirs of gas and water. Advances in materials science especially are allowing greater energy densities to be stored rechargeably. Such rechargeable storage, up to a point, decouples generation of useful energy (electricity/heat) and demand for it, in time and place. It can take one of several forms: thermal, chemical, gravitational, mechanical, or in electromagnetic fields; before being converted to its end use as electricity or heat.

Electrical and thermal rechargeable energy storage already exists in the UK in the form of:

Pumped hydro storage (PHS)

Grid-scale pumped hydro storage for electricity production in the UK has a volume of 27.6GWh. There are four major schemes in the UK; Dinorwig in Wales was the last to be commissioned (in 1983, after building started in 1974) and has the largest PHS volume of 10GWh, with maximum output 1.7GW. Globally, pumped-hydro storage accounts for 99% of all storage capacity, with 96GW capacity operating (33GW in Western Europe), 20GW under construction and 44GW planned.

National Grid's Seven Year Statement 2010 foresees no new pumped storage to 2017.[3] However, SSE has proposed two new 30GWh schemes, which could be completed by 2017/18 at the earliest. They would have an installed generation capacity of between 300MW and 600MW each, and be able to store and discharge in excess of 1,000GWh in a typical year.[4]

Hot water

Hot water (HW) storage cylinders are present in 13.7m UK households.[5] A 100l cylinder, which has water heated by 50°C, could store about 6kWh. Actual measurements have found average HW use to be 122 litres/day with energy content of 4.7kWh[6] which, when aggregated across the UK, would come to about 65GWh/day.

However, there has been a rising trend in penetration of combination boilers (which do not use HW storage tanks) in households since 1991, growing from 1.2% in 1991 to 37% (condensing and non-condensing boilers) in 2007.[7] Aside from the reducing the actual energy storage volume present in the UK, it is perhaps a sign that domestic space which HW cylinders used to occupy has a significant value in itself. This could be a barrier to future deployment of domestic thermal or electrical storage.

A number of district heating schemes in the UK use thermal stores, which enable the efficient generation of electricity from CHP plants when heat demand is low. The 3.4MWth Pimlico District Heating Undertaking scheme in London has an accumulator that stores 2500m^3 of water just below boiling point, serving over 3,000 dwellings and almost 50 businesses. A more modest 1.6MWth scheme in Woking, Surrey, holds 163m^3 of water. In the UK, CHP providing heat for buildings has a capacity of 472MWth, but there are no figures for the total thermal storage involved.[8]

Electrical storage heaters

Heated brick-type storage heaters are the primary heating system in 7% of the UK housing stock (1.55m total, but mostly in flats), a level that has been constant over the last 20 years.[9] Electricity consumed for space heating was 17TWh in 2008, consuming 13% of overall electricity use in the domestic sector.[10] Associated with this, 23% of GB domestic electricity consumption is on the time-of-use tariff Economy 7 with average annual domestic consumption 5.7MWh.[11]

Fossil fuel storage

For comparison, Wilson et al[12] estimate energy storage volume of fossil fuels in the UK to be 47TWh of gas (with approximately 30% destined for power generation at 50% efficiency equating to 7TWh electric output) and 30TWh for coal in terms of electrical power generation.

For clarity, where 'energy storage' is referred to henceforth, the meaning is of 'rechargeable' energy storage, i.e. stores that can be recharged electrically or thermally from another energy source; and to distinguish from power generation, energy storage is described as a 'volume' rather than 'capacity'.

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[3] Available at **http://www.nationalgrid.com/uk/Electricity/SYS/.**

[4] SSE press release at **http://www.sse.com/PressReleases2009/PumpedStorageSchemeProposal/** and see presentation by Neil Lannen, SSE, for technical details, available at: **http://kn.theiet.org/communities/powersys/resources/presentations/pumped-storage-proposals.cfm?type=pdf.**

[5] Communities and Local Government (2007) English House Condition Survey **http://www.communities.gov.uk/publications/corporate/statistics/ehcs2007annualreport**

[6] Energy Saving Trust (2008) Measurement of Domestic Hot Water Consumption in Dwellings **http://www.decc.gov.uk/en/content/cms/about/science/publications/analysis/analysis.aspx**

[7] BRE (2007) Energy use in homes **http://www.bre.co.uk/filelibrary/pdf/rpts/Space_and_Water_Heating_2007.pdf**

[8] DECC (2010) Digest of UK Energy Statistics 2010, Chapter 6 **http://www.decc.gov.uk/assets/decc/Statistics/publications/dukes/312-dukes-2010-ch6.pdf**

[9] BRE (2007) ibid

[10] DECC (2010) Energy Trends, September 2010; Special feature: Estimates of heat use in the UK **http://www.decc.gov.uk/en/content/cms/statistics/publications/trends/articles_issue/articles_issue.aspx**

[11] DECC (2010) Energy Trends, December 2010 ; Special feature: Sub-national electricity consumption **http://www.decc.gov.uk/assets/decc/Statistics/publications/energytrends/1082-trendsdec10.pdf**

[12] Wilson et al (2010) Energy storage in the UK electrical network: Estimation of the scale and review of technology options **http://dx.doi.org/10.1016/j.enpol.2010.03.036**

2 The energy system to 2050

The UK has set a legally binding target to reduce greenhouse gas emissions by 80% by 2050. Many public and private sector organisations have run scenarios and models to explore how the energy system could evolve in a transition to a low carbon economy, and what the implications would be.

For ERP's report, 'Energy Innovation Milestones to 2050', we studied over 20 such scenarios from government, academia, industry and NGOs.[13] We identified areas of commonality and divergence in their outputs, to show where there could be some confidence in the main components and where there was uncertainty. This meta-analysis showed the actions that are needed to provide better understanding and inform decisions on the energy system that will have long-term impacts. The report also looked at the significance of key technologies, with energy storage picked out as a technology which could play a significant role in the medium term, but which is excluded from most energy system models.

2.1 Pathways to 2050

The scenarios and energy system analyses that were studied are shown in Table 1. The main results of the meta-analysis are covered below, for the energy system in general, and the role of energy storage specifically.

BP	*ongoing commercial studies*	EST	Emission Impossible
CBI	Climate Change, Everyone's Business / Decision Time	IEA	Energy Technologies Perspectives
CAT	Zero Carbon Britain	IMechE	UK 2050 Energy Plan: Making our commitment a reality
Ceres Power	*ongoing commercial studies*	IPPR, WWF & RSPB	Delivering the 80% challenge
Centrica	*ongoing commercial studies*	McKinstey	Pathways to a Low-Carbon Economy
CCC	Building a low carbon economy	National Grid	Gone Green
David MacKay	Sustainable Energy - without the Hot Air	Ofgem	LENS; Project Discovery
DECC	UK Transition to a Low Carbon Economy	Shell	Shell Global scenarios
E.ON	*ongoing commercial studies*	SSE	*ongoing commercial studies*
EDF	*ongoing commercial studies*	UKERC	Energy 2050

Table 1 Organisations and their scenarios that were studied for ERP's 'Energy Innovation Milestones to 2050' project.

2.1.1 Expected main components of future UK energy system

The main findings from the meta-analysis of scenarios in ERP's Innovation Milestones to 2050 report, relevant to this study, were:

Electricity generation mix

- There was consensus on the need for rapid decarbonisation of power generation. Subsequently, heat and transport were potentially decarbonised through electrification thus leading to an increase in demand for electricity. There was less agreement on the increase in demand for electricity, which ranged from 50% to more than 100%.
- The main components of the mix came from centralised power generation using nuclear, wind and fossil fuel (mostly coal) with CCS, but with variations in the proportions. The degree of dependence on other technologies (such as tidal, wave, waste, bioenergy, solar) was varied, but generally low.
- It was not clear how intermittency and load balancing would be tackled; some scenarios using unabated fossil fuels with less emphasis on storage and active management of demand and the grid.
- There was consensus that intelligent system operation would be required, but divergence on functionality of smart grid operation and on how system flexibility and control would be achieved. Some scenarios cited a role for energy storage in provision of flexibility but were divergent on whether this would come from distributed (e.g. demand response, low grade heat storage etc.) or centralised (e.g. pumped hydro, compressed air storage etc.) resources.

Transport

- The scenarios agreed that efficiency gains in conventional and hybrid vehicles, with greater use of biofuels, would drive the bulk of emissions reductions in road transport up to 2020 / 2025.
- There was a diversity of fuels in scenarios post 2020 according to vehicle type but with a growing role for electric drive-train light duty vehicles between 2020 and 2050. Biofuels, fuel cell vehicles and battery powered vehicles could all have niches if not more widespread application.
- There was uncertainty in technology limitations (between batteries, fuel cells and producing sustainable biofuels); the role of bioenergy (including its availability and conflicting demands between modes of transport, other energy services and non-energy sectors); and delivery of infrastructure change.

[13] ERP (2010) Energy Innovation Milestones to 2050 **http://www.energyresearchpartnership.org.uk/milestones**

Demand reduction, energy efficiency and heat

- With energy savings and improved efficiency crucial, there was consensus that final energy demand from end users must stabilise and, preferably, reduce.
- The provision of decarbonised heat is generally met through a shift to electrification between 2020 and 2050.
- However, there were some concerns about the responsiveness of technologies and the capacity of the power system to accommodate additional electricity demand (from heat and also from transport).

For the purposes of this study, the changing generation of electricity, and its use for provision of heat and transport is of particular interest. Results from major scenarios from the CCC, DECC and National Grid are compared in Table 2.

TWh except as stated		2010	2030		
Scenario		**DECC**	**DECC**	**CCC**	**NG (in 2026)**
Electricity generation	Total	380 (60GW capacity)	560	460	100GW capacity
	Renewables	Wind: 16 other: 5	Wind: 190 other: 15	Wind: 140 other: 45	Wind: 34GW (89TWh) other: 3.5GW
	Fossil (of which CCS)	310 (0)	240 (58)	99 (66)	45GW (n/a)
	Nuclear	53	120	180	10GW
Electrical energy supplied	for heating	56	100	51	
	to transport	8	40	31	

Table 2 Electricity generation and use. Sources: CCC - Fourth Carbon Budget and Renewable Energy Review illustrative scenario; DECC - Excel 2050 Calculator, Pathway Alpha; National Grid - 'Operating the Electricity Transmission Networks in 2020' Gone Green scenario. Figures given here to two significant figures.

Box 1: Storage in scenarios

ERP maintains a set of analyses of energy system scenarios from different organisations, which includes an overview of the role for storage.[16] Some of the key points are:

For the **Committee on Climate Change (CCC)** in its the Fourth Carbon Budget scenarios through the 2020s, work by Pöyry assessed flexibility packages for the power sector. This found that in general that energy storage reduced costs and CO2 emissions, though storage was included in a package (with interconnection and flexible operation of CHP), and not assessed on its own. The report concluded that flexibility over timescales more than a few days will be provided by 10 – 15 GW of gas-fired generation with low load factors. Costs of flexibility were found to be uncertain, but it was recommended that incentives should encourage its provision. The report acknowledged that interactions between supply and demand in the future are poorly understood.

Also for the CCC, NERA/AEA looked at thermal storage with heat pumps, though found them not to be cost-effective in general. This work is described further below.

DECC's 2050 Pathways work has electrical storage at 'level 2' for most of its illustrative pathways, including the 'central' Pathway Alpha. This level has a small increase in storage to 4GW built by 2025, with 25% of EVs providing flexible demand from batteries. Level 3 doubles storage peak output to 7GW in 2050, with half of EVs contributing to shiftable demand. The 'balanced' pathway from the 2011 relaunch of the Pathways work (akin to Pathway Alpha) notes that 35GW of gas standby power stations would be required to cover a 5-day wind lull.[17]

The **IEA** BLUE Map scenario does estimate global electricity storage need, estimating that an extra 50 – 100 GW will be required, according to deployment of heat pumps or EVs. Further regional analysis from the IEA is described below.

Ofgem's Project Discovery has little change to pumped storage under the 'Green Transition' scenario.

UKERC's 2050 Pathways has a minor role for large-scale storage in the Carbon Ambition scenario, with it declining from the current 3GW to 1GW in 2050. Storage from EV batteries does make an impression though, with more than 27TWh in 2040. Whilst EV and hydrogen storage technologies are contained within the Markal model used by UKERC, other energy storage is limited to pumped hydro and penetration of electric storage heaters is capped at 30% of households.

The Institution of Mechanical Engineers' UK 2020 Energy Plan concludes that energy storage will be of increasing importance, and that 10GW may be needed.

National Grid's Gone Green scenario sees pumped storage constant at 2.7GW through to 2025.[18]

[16] http://www.energyresearchpartnership.org.uk/scenarios
[17] http://www.decc.gov.uk/2050-calculator-tool
[18] http://www.nationalgrid.com/corporate/Our+Responsibility/Our+Impacts/ClimateChange/Seealso/gonegreen2020.htm

2.1.2 Analysis of energy storage in future energy systems

Energy system models are valuable and influential: they provide insights by looking over long time horizons for the most cost-effective pathways to defined national or international targets, choosing the investment and operation levels of all the interconnected system elements.

However, the treatment of energy storage in scenarios as a specific technology class is variable. Such models have difficulty in capturing the utility offered by energy storage as these technologies can operate over short timescales and at a distributed level. On top of this, models are dependent upon input assumptions for the cost and performance of technologies, which models use to determine deployment. Such assumptions will almost certainly not capture the full range of energy storage technologies that could be developed over the time-scale of the model run. Even then, their cost and performance are subject to great uncertainties that make their inclusion in models problematic. This can make energy storage appear unattractive against technologies that have better defined performance and cost characteristics.

Box 1 presents a review of how some scenarios treat energy storage, and their results for its deployment. Attempts to improve the representation of energy storage in energy system models, power sector models, or through specific analysis, are described below.

Temporal Markal

The standard Markal model has two diurnal and three seasonal representations of electric demand capacity, though actual demand varies diurnally and seasonally which can over- and under-estimate actual load demand. To address this issue, a temporal Markal model was developed with twenty annual time periods – five diurnal and four seasonal (see Figure 1).[14,15]

The 'low carbon' scenario studied by Strachan et al using the temporal Markal was just a 60% reduction in emissions, but results showed that energy storage could play a potentially important role: the model chose 7 – 10 % of demand as storage, compared to the current proportion of 3%. The first choice was demand-side storage technology, partly due to lower operational and capital costs, followed by PHS, which comprised 4% of final electricity demand. It was also found that storage allowed base-load generation to be better utilized.

Although these were useful insights, the model was still restricted in what it could capture, and was not capable of modelling grid-balancing or intermittency, which would require development of a different model. Further work is also required to provide insights on cost effective electricity storage options at regional level.

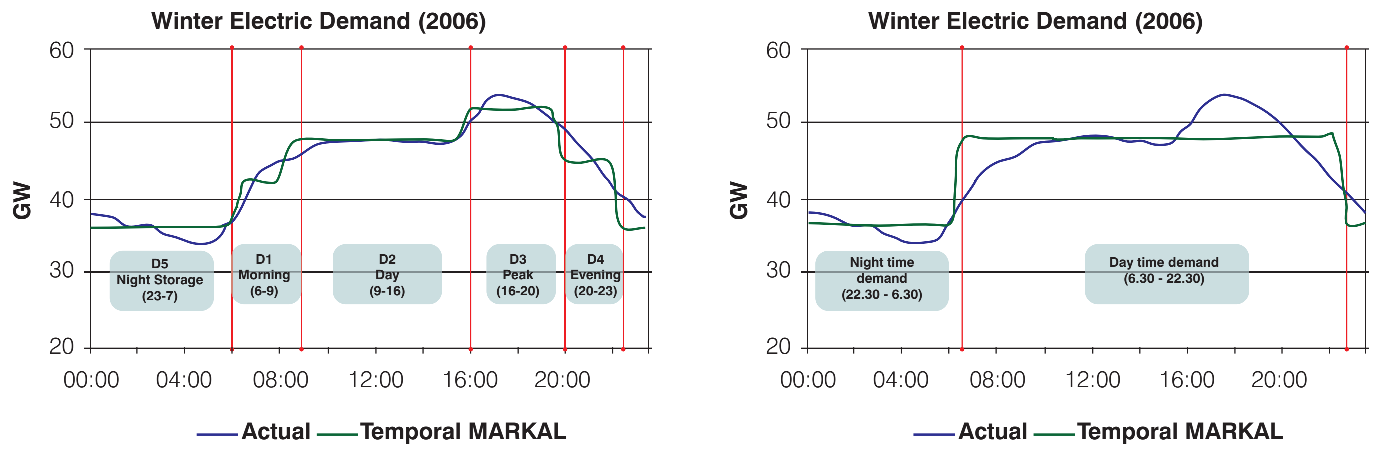

Figure 1 Electric demand representation in standard and temporal Markal models. From Strachan et al (2008).

[14] Strachan et al (2008) State-of-the-art modelling of Hydrogen Infrastructure Development for the UK: Geographical, temporal and technological **http://www.psi.org.uk/pdf/2008/HydrogenMARKAL_report.pdf**

[15] Kannan (2011) The development and application of a temporal MARKAL energy system model using flexible time slicing **http://dx.doi.org/10.1016/j.apenergy.2010.12.066** and see presentation at **http://www.etsap.org/Workshop/Paris_07_2008/2Kannan-IEW2008.pdf**

Storage-specific analyses

Electricity network models can incorporate storage better, such as developed by Strbac's group at Imperial[19] , but this is a static model. Understanding the role energy storage could play will require dynamic energy systems models that can operate over timescales from hours to years, and capture distributed plant. A number of studies have looked specifically at the opportunities for energy storage, with a selection from the UK and abroad given below. Some other analyses that have looked at market potential for energy storage are given under 5.1.

A 'time-shifting' energy model has recently been developed by Hall's group at Strathclyde. By looking at spot-price variations in the UK between 2008 and 2010, the potential revenue from energy storage devices can be evaluated. In the case of a 1.2MW tidal current generator coupled with 10MWh/1MW storage, the additional revenue from including storage was found to be 7% of the combined system revenue.[20]

A 2004 report for the DTI investigated the ability of storage to assist small renewable generators individually, not attempting to address the value of storage in a power system with considerable penetration of stochastic generation.[21] The report (motivated by development of the Regensys plant) demonstrated that an energy storage plant could add value to the energy produced by a wind farm. However, this was dependent on the regulatory regime within the commercial arrangements, especially the level of penalties applied by the market for real-time dispatch errors compared to the scheduled dispatch.

A report to the Scottish Government by AEA assessed potential low-carbon technological solutions for addressing the problems of intermittent generation, with consideration to energy storage and energy management solutions.[22] It concluded that the average costs needed to justify a number of large pumped storage schemes were marginally greater than the value of the excess generation. Hence increased interconnection, demand side measures and generation constraints would have a part to play in managing the level of generation in Scotland.

Analysis on grid-scale storage from the IEA has suggested that significant storage will be required globally to achieve BLUE Map scenarios of renewable generation deployment.[23] It estimates that between 50 and 100 GW will be required in Western Europe, with rapid growth to 2020 (Figure 2). The ultimate amount required is found to be critically dependent on variability of wind power (the definition of which is given in the paper) – lower variability from a larger number of sites needs less storage. Thus, the author concludes that high quality assessment of net variation is fundamental to accurate identification of required storage capacities.

Though 33GW storage capacity is already in place in Europe, the IEA calculations refer to storage specifically to mitigate power variations due to wind power supplies. Existing pumped hydro storage which performs load-levelling operations as in the UK (see Figure 11) may not be able to perform both functions. The report states that for Western Europe, pumped hydro, compressed air and secondary battery systems which can store energy for several hours would be most suitable.

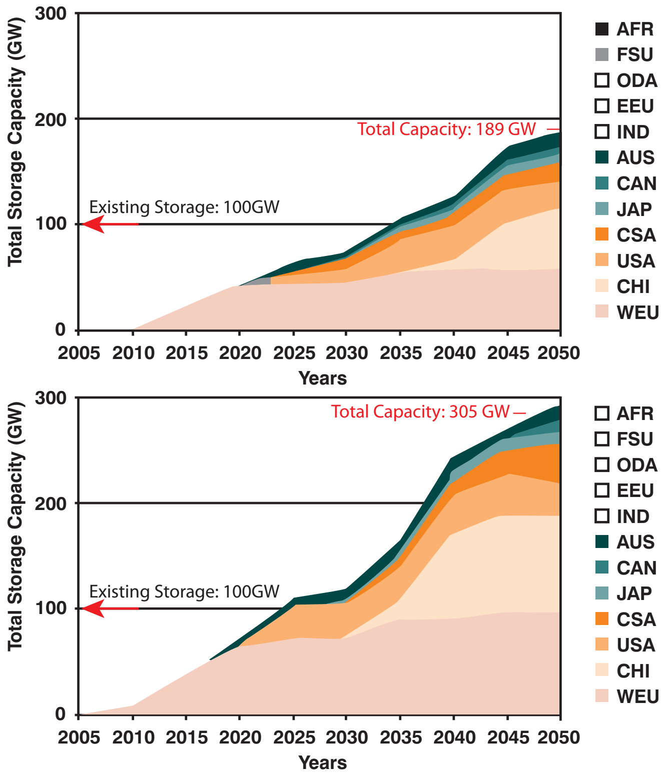

Figure 2 IEA analysis of global storage required to meet BLUE Map scenario, with wind power variation ratios of 15% (top) and 30% (bottom). Western Europe (WEU) is represented by the blue area at the bottom of the graph.

[19] http://www3.imperial.ac.uk/controlandpower

[20] http://www.ukerc.ac.uk/support/tiki-download_file.php?fileId=1604

[21] DTI (2004) The value of energy storage within the UK electricity network http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file15182.pdf

[22] AEA (2010) Energy Storage and Management Study http://www.scotland.gov.uk/Publications/2010/10/28091356/0

[23] IEA (2009) Working paper:Prospects for Large-Scale Energy Storage in Decarbonised Grids http://www.iea.org/papers/2009/energy_storage.pdf.

[24] Grunewald et al (2010), Role of large scale storage in a UK low carbon energy future; submitted to Energy Policy, http://workspace.imperial.ac.uk/icept/Public/Storage_paper_post.pdf.

Modelling by Grunewald et al has simulated the cash flow of selected large-scale storage technologies inside a future UK low carbon energy system, based on historical data for electricity demand and projected renewable resources.[24] These results find that both compressed air energy storage and hydrogen storage could become potential candidates for large scale storage. A direct comparison with combined cycle gas turbines shows that, under certain assumptions, storage could provide a competitive alternative to peaking plants with low load factors.

Other European-specific analysis by IHS Emerging Energy Research points to the UK energy system as being one in which storage could be most important because of its relatively low export capacity and expected high penetration of renewable generation (Figure 3).

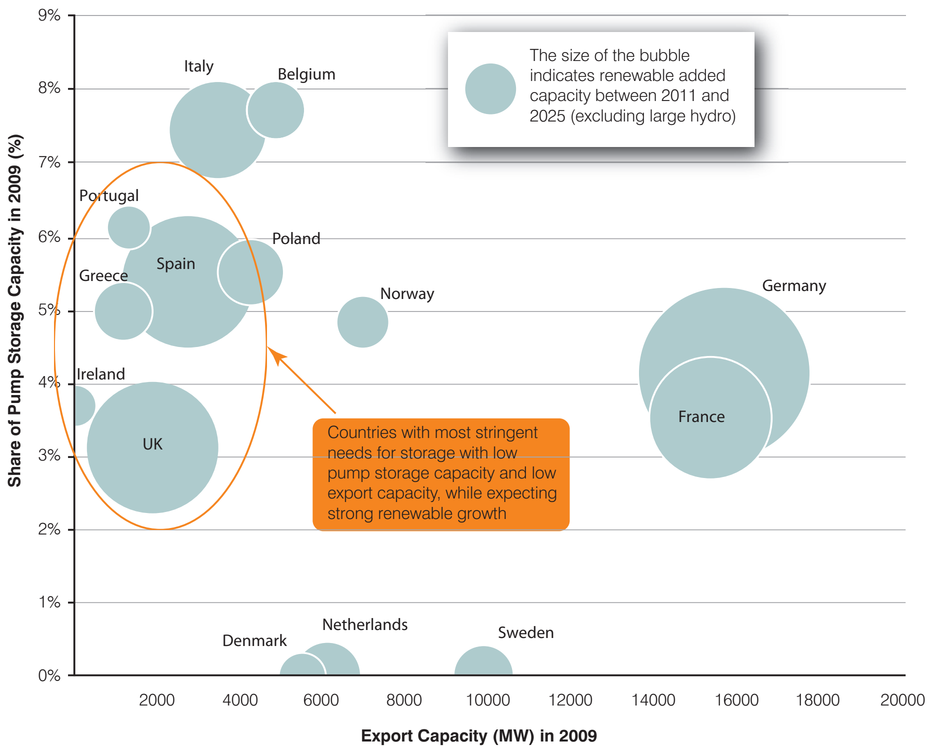

Figure 3 Comparison of European countries of their electrical export capacity, against pumped storage as a proportion of domestic generation capacity. Note that as reservoir hydro is not included, Sweden and Norway appear with low levels. (Source: IHS Emerging Energy Research)

2.2 Challenges to energy system

As outlined above, current pathways for the future UK energy system have increasing demand for electricity (providing heat and transport services), with offshore wind providing substantial low-carbon generation. Both of these outcomes would introduce variability to the supply-demand relationship that does not currently exist. The three-way challenge for the energy system will be to ensure delivery of a reliable supply, cost-effectively, which meets carbon reduction targets.

Challenges will occur over different timescales:

Timescale	Challenge
Seconds	Renewable generation introduces harmonics and affects power supply quality.
Minutes	Rapid ramping to respond to changing supply from wind generation affecting power frequency characteristics.
Hours	Daily peak for electricity is greater to meet demand for heat.
Hours - days	Variability of wind generation needs back-up supply or demand response.
Months	Increased use of electricity for heat leads to strong seasonal demand profile.

There are several options for meeting these challenges:

- Energy storage – as an enabling technology, has the potential to help meet the challenges by allowing 'time-shifting' of supply/demand.
- Flexible plant – new plant (including nuclear and fossil fuel CCS) is likely to be built with greater ability to flex generation cost-effectively, meeting extra demand.
- Demand side response – currently limited to large energy users, but smart meters deployed over the next decade, which have dynamic pricing and system control functionality, could give consumers an incentive and mechanism to shift loads.
- Interconnection – provides flexibility through additional capacity or load for the UK, but if operated on merchant basis is not solely for UK benefit.
- Hydrogen is also an option, being an energy vector and storage medium.

Though the challenges can be compartmentalised to an extent, the way by which one challenge is met may be applied across the timescales. An economic case for developing new energy storage technologies in particular may be dependent on operating at different timescales and hence attracting multiple revenue streams (discussed under 5.1).

The non-storage options are described in brief below. A report by Pöyry supporting the Committee on Climate Change's Fourth Budget Report gives results of modelling low-carbon flexible power, and contains useful information on the available options.[25]

2.2.1 Flexible plant

The default assumption in most modelled scenarios is that thermal power stations will operate with greater flexibility to meet the challenges outlined above. Indeed, Chalmers et al state "future large scale deployment of variable-output renewables such as wind power and/or inflexible nuclear power plants may make flexible operation of all fossil plants virtually obligatory."[26] The paper concludes that for CCS, "post combustion capture schemes should not significantly constrain the ability of power plants to change their output."

Though nuclear power has operated as base-load in the UK, this is not necessarily how it would function under future scenarios. A German study analysed the potential for integrating nuclear power in high renewable scenarios[27] (a prospect closer in Germany than in the UK). It found that nuclear power plants allow for similar power gradients as coal-fired condensation power plants, of 3.8 to 5.2 % of nominal (rated) power output per minute in normal operation. The authors state that the facility for load-following operation is a determinant design criterion rather than for safety or fundamental technical reasons.

Analysis by the Committee on Climate Change, based on the Mott Macdonald report for DECC, estimates levelised costs of low-carbon generation in 2030 according to the load-factor (Figure 4)[28] . This shows nuclear remaining the least expensive option down to 40% load factor, with gas CCS and CCGT costs increasing only modestly down to 20%. These costs will be the benchmark against which other technologies will be compared.

[25] Pöyry (2010) Options for low-carbon power sector flexibility to 2050 **http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research**; also see Pöyry report for CCC (2011) Renewable Energy Review **http://www.theccc.org.uk/reports/renewable-energy-review**

[26] Chalmers et al (2009) Flexible Operation of coal fired power plants with post-combustion capture of carbon dioxide **http://dx.doi.org/10.1061/(ASCE)EE.1943-7870.0000007**

[27] University of Stuttgart, Institute of Energy Economics and Rational Use of Energy (2009) Compatibility of renewable energies and nuclear power in the generation portfolio **http://www.ier.uni-stuttgart.de/publikationen/pb_pdf/Hundt_EEKE_Summary.pdf (English translation)**

[28] Committee on Climate Change (2010) The Fourth Carbon Budget **http://www.theccc.org.uk/reports/fourth-carbon-budget**

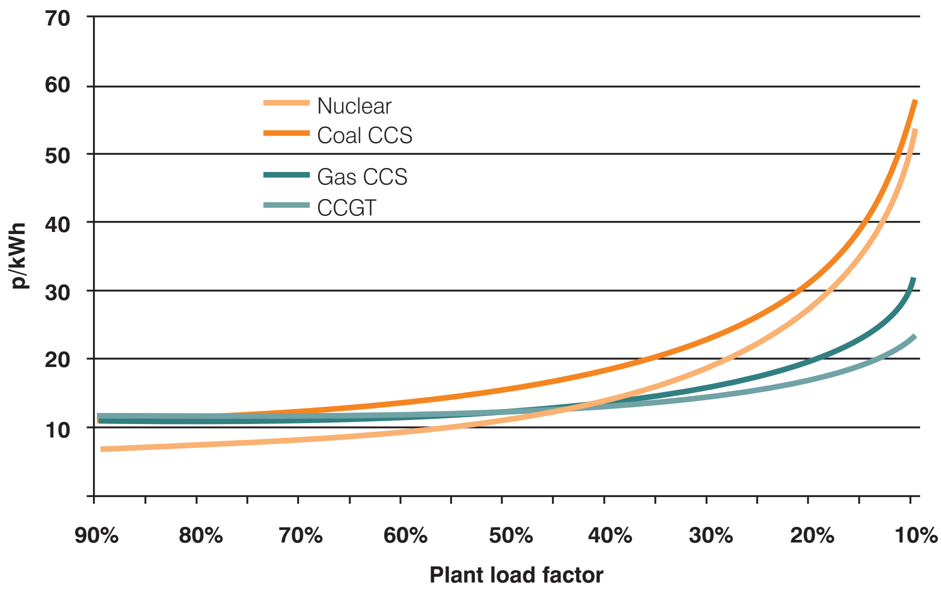

Figure 4 Estimated levelised cost of low-carbon technologies by load-factor in 2030. (Source: CCC calculations, based on Mott Macdonald (2010) UK Electricity Generation Costs Update)

2.2.2 Demand side response

Demand side response (DSR) for electricity use defers demand from peak times, providing short-term (and potentially short notice) demand reduction instead of calling on generation capacity. Dynamic demand may also act in response to frequency variations.

There is currently little incentive for domestic consumers to change the timing of their consumption of energy away from peaks. Economy 7-type tariffs are attractive only to consumers with high deferrable electricity demands, mainly in households with electrical storage heaters. For dynamic demand, there have been some demonstrations of allowing fridges to react to changes in power supply frequency.[29]

Major industrial and commercial consumers may have interruptible contracts with suppliers to restrict their electricity use at times of high demand in exchange for reduced bills. However, the roll-out of smart meters by 2020 will enable time of use tariffs for all consumers and give them the tools by which they can play a more active role in the electricity market.[30] The extent to which this will change actual use is uncertain, but some studies described below give an indication of the potential impact.

Ofgem has published a DSR discussion paper, which builds on its Project Discovery work.[31] With longer term introduction of electric heating and electric cars, the view was that DSR could:

- reduce carbon emissions, energy costs and avoid some investment required in network and generation capacity;
- increase the scope of the electricity system to absorb excess renewable generation;
- improve overall system balancing and efficiency; and
- encourage efficient use of existing generating plant and network capacity.
-

As the Ofgem paper states, there is no consensus on the amount of moveable demand – there is little detailed information on consumer use of electricity (or energy generally). DECC's impact assessment of a GB-wide smart meter roll out for the domestic sector assumes a 5% load shift from a 20% uptake of TOU tariffs.

[29] Demonstration under the CERT scheme by npower and RLtec started in May 2010, see **http://www.rltec.com/smartfridgetrial** and **http://www.npowermediacentre.com/Press-Releases/The-cool-way-to-cut-CO2-Europe-s-first-smart-fridges-trial-starts-in-UK-dcd.aspx.**

[30] Information on proposals for smart meter from DECC at **http://www.decc.gov.uk/en/content/cms/what_we_do/consumers/smart_meters/smart_meters.aspx.**

[31] Ofgem (2010) Demand Side Response; A Discussion Paper **http://www.ofgem.gov.uk/Sustainability/Pages/Sustain.aspx**

A report for DECC by IHS Global Insight estimates that discretionary load represents between 6% and 37% of total residential demand at 5pm.[32] Thus, the maximum achievable reduction in demand would be 1 – 6 GW from the domestic sector. Similarly, the estimate of discretionary load from commercial customer is a maximum of 14%, or 5 – 7 GW, and from industry it is 9%, or 3 – 4 GW. This gives a total range of 9 – 17 GW discretionary load in the UK.

In France, EDF's Option Tempo has existed for domestic consumers since the 1990s.[33,34] Electricity pricing for the following day, in one of three bands, is sent electronically to customers each evening. With 350,000 customers opting for this, EDF has found the tariff has led to a reduction in electricity consumption of 15% on middle-banded days and 45% on days in the highest band, compared to the low band.

Demand-side response can provide cost-savings from reduced peak generation which are also applicable to understanding the value from energy storage. DSR also has an impact on distribution networks. As the Ofgem paper states, the changes expected to the system will make electricity flows more diverse and complex, making it necessary for more active management by DSOs. The benefits of deferring network reinforcement, due to DSR and potentially storage, will give DSOs a direct interest in measures that make best use of the infrastructure. Ofgem and the Brattle group have made some calculations, which are discussed in 5.1.

2.2.3 Interconnection

The UK is the least interconnected country as a proportion of total generation capacity in Europe, with 3GW operational or planned to north-west Europe, and less than 1GW to Ireland (Table 3). There is potential for more, but this is clearly more limited and more expensive than interconnectors across land borders.

Whilst interconnection does allow power to flow to and from the UK, if it is operated on a merchant basis , the direction of flow will be from where the power can be bought to where it can be sold at a profit. Thus, its role in providing secure supplies is limited and difficult to model.

National Grid recently consulted on the further development of interconnection, suggesting an extra 7GW could be constructed over the next decade.[35] Responses to the consultation saw benefits arising from dealing with intermittency and excess power associated with renewable generation. Respondents also noted benefits of access to neighbouring wholesale and supply markets and, in the case of DC interconnectors, the provision of balancing and ancillary service.

Name	Owner	Connects to	Capacity	Status	Date operational
IFA	NG and RTE	France	2000 MW	Operational Regulated	1986
Moyle	NI Energy Holdings	Northern Ireland	450 MW to N 80 MW from NI I	Operationa Within UK so not an EU law “interconnector I	2002
BritNed	NG and TenneT	Netherlands	1000 MW	Under construction Exemption granted 2007	End 2010 / early 2011
East West Interconnector	Eirgrid	Ireland	500 MW	Construction phase Regulated	2012
possible		Belgium	1000 MW	Development	2016 – 17?
		France	‘high capacity’	Feasibility	2018?
		Norway	1000+ MW	Under investigation	2020+
		Iceland	1000 MW		2020+

Table 3 Existing and proposed interconnectors to the GB network.

[32] IHS Global Insight (2009) Demand Side Market Participation Report
http://www.decc.gov.uk/assets/decc/consultations/electricity%20supply%20security/1_20090804144704_e_@@_dsmreportglobalinsight.pdf.

[33] See http://bleuciel.edf.com/abonnement-et-contrat/les-prix/les-prix-de-l-electricite/option-tempo/en-savoir-plus-52429.html

[34] IEA Demand Side Management Programme (2008) Worldwide Survey of Network-driven Demand-side Management Projects
http://www.ieadsm.org/Files/Tasks/Task%20XV%20-%20Network%20Driven%20DSM/Publications/IEADSMTaskXVResearchReport1_Secondedition.pdf

[35] http://www.nationalgrid.com/uk/Interconnectors/France/consultations/

The 'medium' abatement scenario in the CCC's Fourth Carbon Budget includes more interconnection with Europe to provide greater system flexibility "therefore addressing potential problems associated with intermittency."[36] The modelling work for the CCC on flexibility by Pöyry included an additional 6GW interconnection to north-west Europe, 2.5GW to Norway and 1.9GW to the Single Electricity Market across Ireland/Northern Ireland.[37] Flows are determined by differences between wind load-factors in GB and the connected market (NW Europe, Ireland or Norway). Having correlated GB and NW Europe wind data, the reports suggests that such an interconnector "would only provide limited flexibility, and could even make things worse at times."

Developing the North Sea as a grid or 'mesh' is an emerging initiative, technically and politically for the UK[38] and EU[39] (Figure 5). The North Sea Countries Offshore Grid Initiative (NSCOGI) is bringing together ten countries to coordinate offshore wind and infrastructure developments in the North Sea.[40] A particular attraction is access to PHS in Norway, where there is a potential to generate 20GW, though exploitation of this resource is by no means certain, given the environmental impact it would have.[41] The total energy supplied to the UK is likely to be limited more by the capacity of an interconnector than available resource.

A report by SKM for DECC looked at interconnection with Norway, Ireland and the Netherlands via off-shore wind farms.[42] The analysis concluded that "arbitrage opportunities existed between the UK and the three markets analysed (SEM, Norpool and APX-NL) with the interconnector flowing around 80% of the time. However, the analysis also concluded that interconnection via a wind farm would reduce the interconnector flows by around 40-45% due to the output of the wind farm."

2.2.4 Hydrogen

Using hydrogen as an energy vector and for energy storage is, like electrical or thermal storage, a 'difficult to treat' potential part

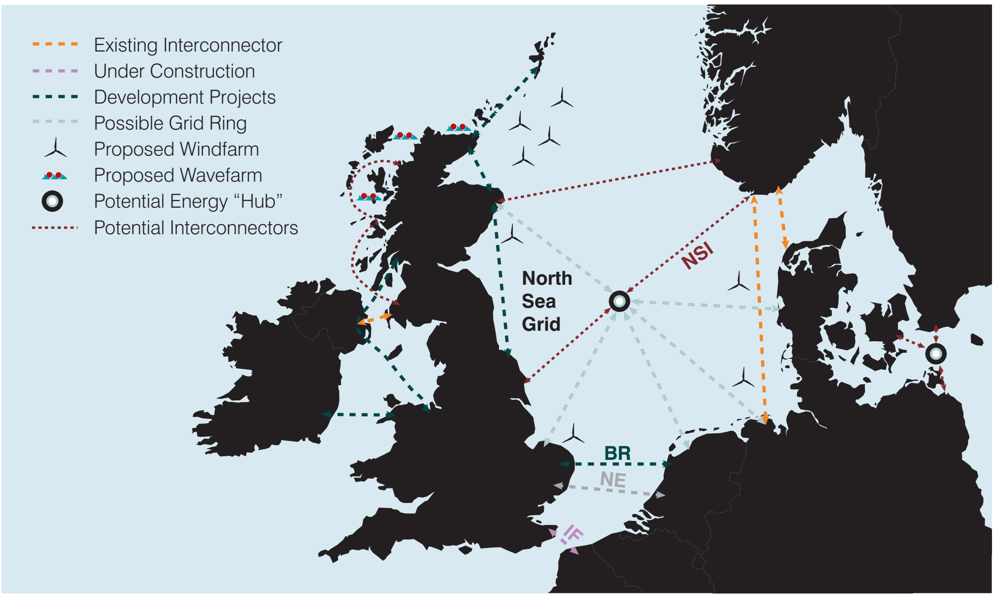

Figure 5 Post 2020 North Sea Grid potential. (Source: Scottish Government)

[36] CCC (2010) ibid

[37] Pöyry (2010) Options for low-carbon power sector flexibility to 2050 **http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research**

[38] DECC press release at **http://www.decc.gov.uk/en/content/cms/news/pn11_005/pn11_005.aspx.**

[39] European Commission (2010) Energy infrastructure priorities for 2020 and beyond **http://ec.europa.eu/energy/infrastructure/strategy/2020_en.htm**

[40] NSCOGI Memorandum of Understanding at **http://ec.europa.eu/energy/renewables/grid/initiative_en.htm.**

[41] Issues were addressed at a UK-Norway North Sea Offshore Networks forum and workshop held in London (June 2011) **http://www.energyresearchpartnership.org.uk/offshorenetworks**

[42] SKM (2010) Offshore Grid development for a secure renewable future – a UK perspective **http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/network/offshore_dev/offshore_dev.aspx**

of the energy system. Hydrogen gas can be produced as part of the carbon capture process, from electrolysis of water using renewable power, or in the next generation of nuclear plant. It can be stored for later use for electricity generation, distributed at low concentrations in the gas network to reduce carbon intensity (depending on how the hydrogen is produced) of local heat and power, and used in the transport sector.

When stored in underground caverns the embedded energy content could be high enough to meet extended periods of low wind. But the generation capacity to convert this into electricity would still be required if that was to be its use.

The low efficiency of producing hydrogen, compressing it for storage and then conversion to electricity make it appear unattractive. There are also technical challenges to overcome if it is to be stored for use in vehicles, and investment would be required in new infrastructure if it was to be widely adopted. However, in a scenario with surplus renewable electricity being generated, it is a solution that can be envisaged as meeting the supply-demand variability that has been described. Further work will be undertaken by the Energy Research Partnership to study the potential role of hydrogen in the UK's future energy system.

2.3 Chapter 2 Conclusions

The transition to the widely accepted scenario of a decarbonised and expanded power sector sees a dramatic impact on the energy system by 2030. With electricity meeting a substantial proportion of space heat and transport demand, new challenges will arise from a pronounced seasonal profile for heat demand and intermittent supplies.

These challenges can be met, and it is likely that flexible generation, greater demand side response, more interconnection and energy storage technologies will all be part of that response. The role of hydrogen is still uncertain and needs further study.

Given the modest increase in costs for low load-factor thermal and nuclear plant, these will be the benchmark for provision of on-demand power.

However, the role of energy storage has been downplayed in many scenarios. It is often treated quite simplistically compared to alternatives due to the short timescales over which it can operate, its potentially distributed nature and large uncertainties over performance and cost. This gap in understanding risks driving the energy system into current market opportunities rather than potentially better long-term solutions.

3 The role for energy storage

To assess the potential role of energy storage in the UK, our approach has been to examine the areas in which it could provide functionality to meet energy system challenges. This shows us where the value of storage could lie, and the scale at which a technology would have to operate to make a significant contribution. With this insight, we can look at the range of technology options and appreciate the performance and cost improvements that will be needed for energy storage to be widely deployed.

The functionality required can be complex, as the energy system includes the provision and use of electricity, heat and transport. These are interlinked, including through storage: both electrical and thermal storage can meet demands for heat; heat storage can reduce demand for electricity; batteries in cars can provide a load for low carbon electricity.

In the sections below, the broad functions to which energy storage technologies could be applied are set out, according to the challenges that will be faced in the future energy system on the scale of months, days, hours and minutes. Each section shows the situation as it stands now, how this could change in the future, and how energy storage solutions could meet the challenges. Appendix A provides a brief overview of the main electrical energy storage technologies, and has a list of authoritative sources for more detailed analyses on costs and performance.

3.1 Months

Space heat demand in the UK has a naturally strong seasonal profile. With space heat predominantly delivered by natural gas, the variability is managed by modulating gas supply through North Sea production or imports. If there were a substantial move to heating using electricity, seasonal generation plant would be required unless long-term energy storage could be provided.

3.1.1 Current situation

Space heating accounts for 42% of all final non-transport energy use, with natural gas accounting for 79% of this demand.[43] Across sectors, 58% of all gas end use (250TWh) is for space heating (19% is for water heating, 14% for process heating). Winter demand for gas can be 3 – 4 times that of the summer, far outstripping variation seen for any other energy source (Figure 6). Demand for gas in the two maximum quarters is about 400TWh with the domestic sector accounting for about 270TWh of this. Gas is the primary heating fuel in 84% (18.7m) of households, with 71% (350TWh) of this providing space heating, hence even more strongly seasonal than in other sectors.[44]

Under average weather conditions, gas demand plateaus for a month in the winter at about 350mcm/day, equivalent to 4TWh/day. Of this, the domestic sector accounts for approximately 2.7TWh/day, of which 1.9TWh will be for space heat.

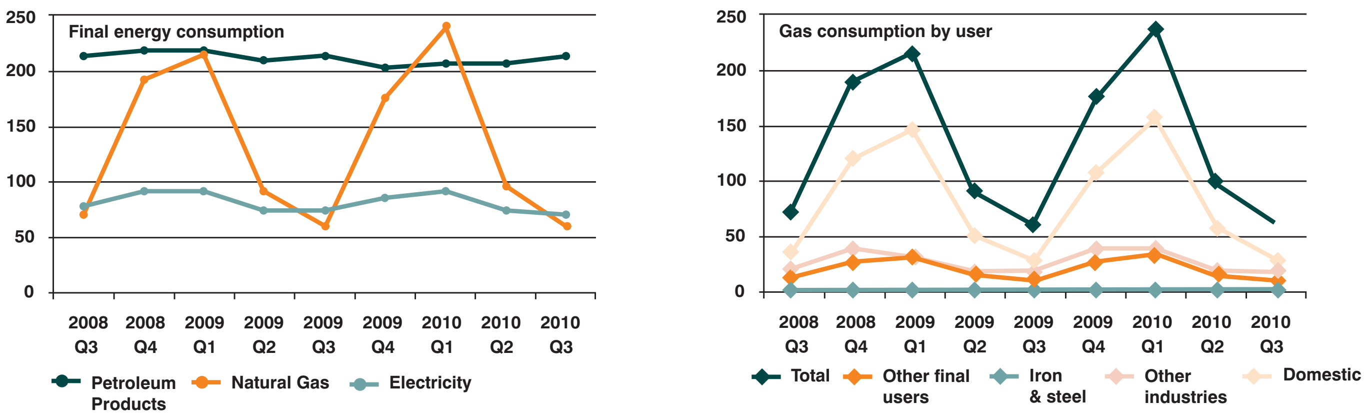

Figure 6 Final consumption of energy by fuel (left), and by user for natural gas (right).[45]

[43] DECC (2010) Energy Consumption in the UK, Table 1.14 http://www.decc.gov.uk/en/content/cms/statistics/publications/ecuk/ecuk.aspx
[44] BRE (2007) ibid
[45] DECC (2010) Energy Trends http://www.decc.gov.uk/assets/decc/Statistics/publications/energytrends/1082-trendsdec10.pdf

3.1.2 Prognosis

Most scenarios see little change in final demand for space heating to 2050: the increasing energy efficiency of buildings offsets an increase in the number of buildings for a higher population and reduced occupancy rates.

By 2030, the CCC and DECC's Pathway Alpha have heat pumps (HPs) serving 125 and 100 TWh respectively of space heating demand – that which is most seasonally variable – across sectors. Figure 7 shows the migration from gas to electricity under the DECC scenario. UKERC's 2050 Pathways 'Carbon Ambition' scenario delays the deployment of HPs until after 2035, but by 2050 electrical demand for HPs reaches 97TWh (figures are not disaggregated between space and water heating), compared to 100TWh in Pathway Alpha (of which space heating consumes 47TWh, serving 150TWh thermal heat demand).

The move to HPs away from gas has implications for investment in electricity generation capacity required to meet this demand.

Some rough calculations can give a sense of the energy and, more importantly, power that will be needed to cover the domestic sector.

The CCC assumes that the coefficient of performance (CoP) of air-source HPs plateaus in the 2020s in the range 3.5 – 4.5 for residential applications. In this case, each TWh of demand that HPs displace from gas in a winter's day would require an average 10GW power generation, though the daily peak would of course be higher. The DECC scenario see HPs accounting for about half of domestic space heat demand by 2030 (Figure 7), with almost 50% penetration in households; the CCC scenario has 25% penetration.

With a daily domestic space heat demand of 1.9TWh, the average power generation to cover such a penetration of HPs would therefore need to be between 2.5GW and 5GW. However, actual capacity required would be higher because of increased demand in colder periods (potentially up to 3GW, see 3.3.2) and reduced CoP of HPs operating in cold conditions (up to an extra

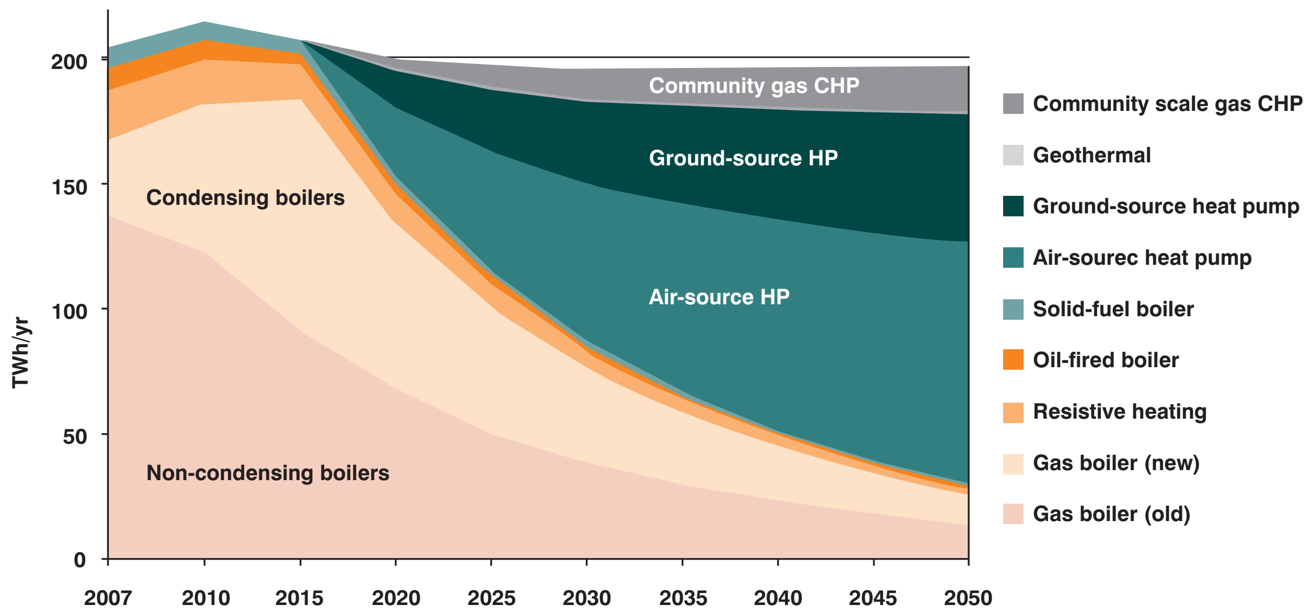

Figure 7 Supplied domestic space heat demand by technology under DECC's Pathway Alpha. The major technologies are shown on the diagram.

[46] Data from German trials with an air-to-water HP, with nominal CoP of 3, found that on the coldest winter's day the CoP dropped to 2.5, so 20% additional power would be required for the same thermal output. See 'Performance/optimization of state-of-the art residential heat pump', Marek Miara, Fraunhofer Institute for Solar Energy Systems ISE at IEA-Annex 32, Expert meeting, Kyoto, 05.12.2007 **http://www.annex32.net/pdf/presentations/Annex32_workshop_HPC2008_Miara.pdf.**

1GW) [46].Over shorter timescales, discussed in sections below, extra capacity would be needed to meet daily peaks if there was no mitigating storage.

Thus, by 2030, an additional 10GW electrical generation capacity could be required just to meet the domestic space heat demand resulting from a shift from gas boilers to heat pump technology. Achieving the penetration of heat pumps to 2050 foreseen by DECC and UKERC could double this figure, and generation plant which was just meeting seasonal demand from heat pumps would naturally have load factors far below 50%.

3.1.3 Options

The strong seasonal variation presents, in principle, an opportunity for energy storage to flatten the demand profile of power generation and reduce the capacity required to meet the winter peak. However, storage of electricity or heat will be required at substantially increased scales than are currently achievable to have anything but a minor impact.

The assumed solution by most scenarios is an increase in dispatchable power generation capacity. Though quarterly or monthly profiles of heat demand are smooth, and may imply a gradual ramping up of capacity to meet demand, in reality weather variation over days and weeks (neglecting daily peaks for this case) would require more active management of plant, and low utilisation of much of that.

Focusing on the domestic sector, using CCC's figures, which in 2030 has 6.8m homes (25%) with HPs serving 81TWh, an average 12MWh would be required for each residence each year. To imagine the scale in terms of heat stored, to meet this space heating demand, would be the equivalent of each household raising the temperature of 200,000l of water by 50°C. As a form of interseasonal domestic heat storage, losse s over six months would, in any case, make water an ineffective medium. Phase change materials (PCMs) being investigated, such as sodium sulphate decahydrate, could use latent heat rather than 'sensible' heat to store energy, and have the theoretical potential to reduce volumes (or increase heat stored) by 6 – 7 times. These are still at the R&D stage and would present other technical challenges. In the case of sodium sulphate decahydrate, the melting temperature is just over 30°C – too low for direct retrofit of central heating, though it could preheat water to improve the HP CoP, so reducing electrical demand.
Interseasonal thermal storage would require consumers to generate heat during the summer. Time of use tariffs could incentivise running heat pumps to optimise the available generation capacity, but there are other options. At small-scale, typical domestic solar thermal panels provide 1.5MWh/yr in the UK, which cover just a proportion of hot water consumption and so will not be enough for later space heating. Micro-CHP which generates excess heat in the summer could be stored, though these technologies would normally provide the winter heat load themselves without use of a HP.

Large-scale heat storage in underground aquifers has been demonstrated, including in energy efficient new build in Alberta, Canada[47] ; and at the Bundestag, Berlin, where excess heat from CHP plant in the summer is pumped 300m below ground at up to 60C, then reused in the winter.[48]

There are a number of UK-based projects demonstrating thermal storage in the earth.[49] These generally use solar heating to charge the stores, though heat pumps running during the summer could also provide the heat input.

With such challenges for energy storage to meet seasonal demand, and the implications for increased power generation, it may be worth considering other options for the provision of heat including through heat networks. Widespread district heating in the UK has generally not found to be the preferred solution by most analyses, tending to be on the basis of gas-fired CHP: the CCC and DECC Pathways have low penetration of district heat networks, though the CCC notes that it could be a promising option which should be explored further.

3.1.4 Value

The benchmark for measuring the value of interseasonal storage would be the operation of dispatchable generation at low load-factors. CCC have estimated these costs, which keep at about 15p/kWh down to 30% load factor, rising to 20 – 30 p/kWh at under 20% load factors (as shown above in Figure 4).

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[47] Drake Landing Solar Community **http://www.dlsc.ca/.**

[48] **http://www.bundestag.de/htdocs_e/artandhistory/architecture/energy/index.html**

[49] **http://www.icax.co.uk/thermalbank.html**

3.2 Days

With more than 30GW installed wind capacity by 2030, a period of low wind over a number of days could see an energy 'shortfall' of order TWh. Energy storage is one option for mitigating against the impacts from a drop in wind power.

Equally, energy storage provides an opportunity to use excess wind power if it would otherwise be 'spilt' due to limits on transmission capacity (if the storage is near the point of generation); or if using it would displace other low carbon generation whilst high carbon generation remained.

3.2.1 Current situation

Although wind lulls do not currently have a serious impact on reliability of supply in the UK, an increase in wind deployment levels to 10sGW would need mitigating measures to be in place to cover drops in generation. Two examples from the UK of when low wind generation has coincided with times of high demand are given below.

Data from E.ON during winter 2006 show a 5 day period of low wind output (Figure 8). Over this time, the wind power output was 6% of the installed maximum. Were the installed capacity to be 30GW and an expected 35% load factor, this would leave a 1TWh gap (or average 9GW), in a period when the total demand was 5.7TWh.

National Grid have published similar data for a time when a high pressure system dominated UK weather in January 2009, with below normal temperatures (Figure 9). The year's peak demand of 59.2GW came at a point when wind generation was at 16% of capacity (of 1.2GW).

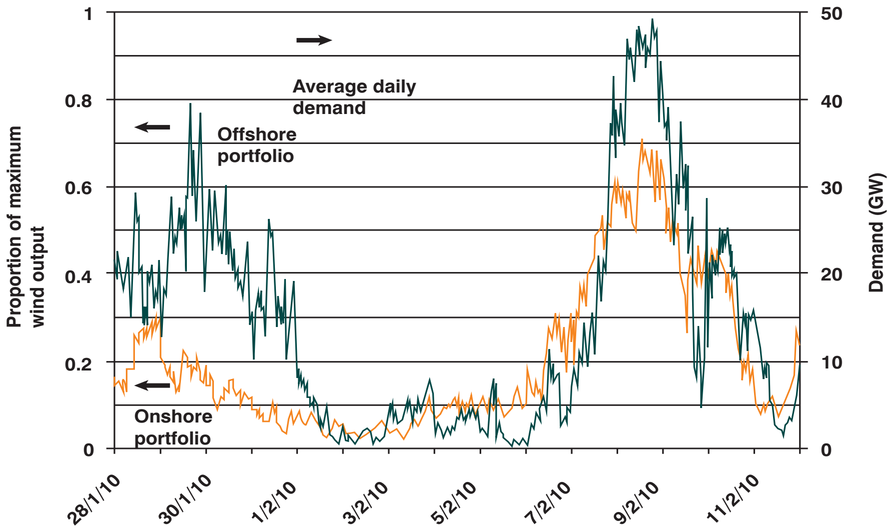

Figure 8 Example of maximum wind output from onshore and offshore portfolios during winter 2006, with average daily demand over the same period (data from E.ON).

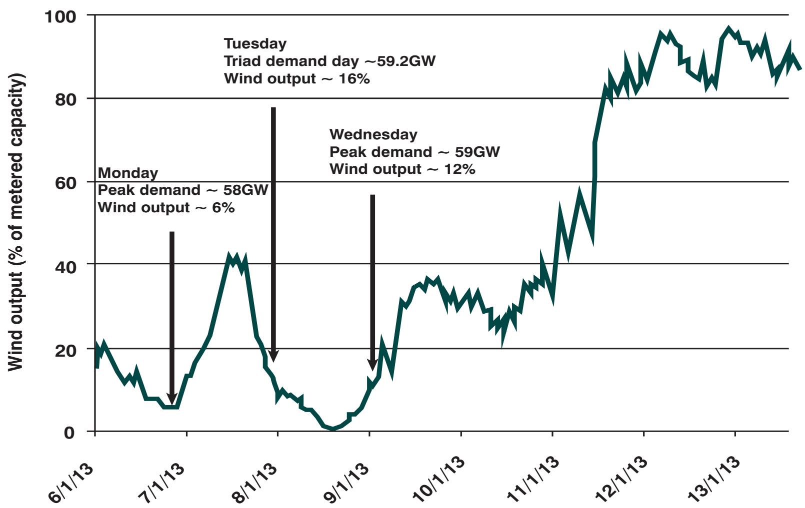

Figure 9 Variation in wind supply for a ~ 7-day period in January 2009 (data from National Grid).

3.2.2 Prognosis

Greater geographic diversity from the wind generation portfolio would reduce the magnitude of an energy gap. It is notable, though, that the three largest zones in the Offshore Round 3 are located 100km apart in the North Sea, and the work by Pöyry referred to in 2.2.3 found low wind events correlated across north-west Europe. Therefore, there is a serious risk that the energy system will have to cope with extended periods of low wind generation.

Pöyry has modelled a 2030 with a generation mix consistent with the CCC's low carbon pathways when there is electrification of heat and transport.[50] In this counterfactual scenario there is relatively little low-carbon flexibility (i.e. it assumes virtually no demand-side response, limited expansion of interconnection, limited flexibility of nuclear and CCS, and no expansion of bulk storage). The results from one winter week in 2030 (using weather data from 2000)show both a period of low wind, requiring 5 - 10 GW peaking plant running for 12 hours a day, and a period of high wind, with nearly 30GW generated that leads to almost all 10GW CCS coal shutting down for a day (Figure 10).

The difference in wind generation between the first and second halves of the week is over 1TWh. Similar modelling for a high wind, low demand summer day, drops coal CCS generation but retains unabated CCGT to cover about 35GWh during the daytime peak.

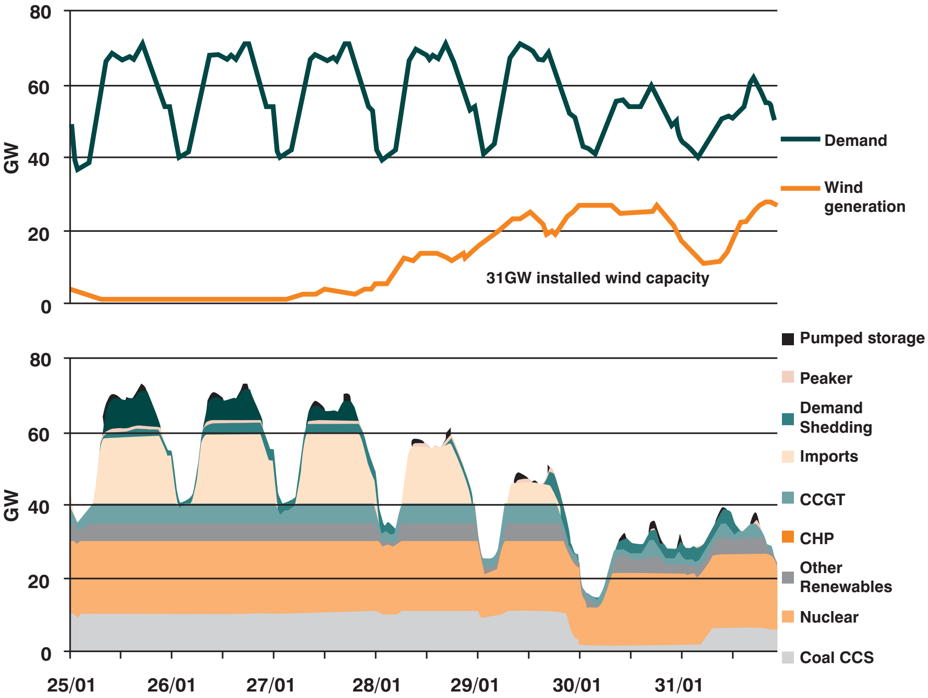

Figure 10 Demand and dispatch in January 2030 with identical weather patterns from 2000 (Source: Pöyry Management Consulting)

[50] Pöyry (2010) Options for low-carbon power sector flexibility to 2050 **http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research**

3.2.3 Options

Covering of order TWh energy over multi-day periods of low wind, equivalent to a continuous 10GW power output, is beyond currently available electrical storage technologies. There is limited opportunity to expand conventional PHS in the UK, and in any case, as Wilson et al conclude "It is difficult to imagine TWhours of [rechargeable] storage being built in the UK's liberalised electricity market for weekly storage of renewable energy if dispatchable low-carbon generating technologies can continue to use [fossil fuel] storage."[51]

An interconnector to pumped hydro storage in Norway does have the potential to fill-in part of this gap. Norway's full physical resource could allow in excess of 20GW from storage, though it is by no means certain this would be exploited, and the capacity of an interconnector to the UK is unlikely to exceed 2.5GW supply without concerted political commitment.[52] Interconnection to other countries cannot be guaranteed to service the UK at a time when other European countries are also likely to be experiencing low wind conditions (as described in 2.2.3).

The shortfall in power could be filled by additional thermal generation. To avoid building new plant for such infrequent events, an option may be to increase temporarily the efficiency of coal or gas generators by removing the carbon capture process. This would increase power output by 25%, though with a carbon penalty. Thus, a 10GW CCS capacity in 203 which is increased by 25%, plus 2GW from Norwegian PHS, has the potential to fill a significant proportion of a multi day drop in wind generation.

Though a lull in wind will result in a shortfall of electricity generated, a significant proportion of the final demand in 2030 is expected to be for heat (between 50 and 100 TWh) and transport (about 40TWh) as described in 2.1.1. As such, energy storage options beyond electricity should be considered.

Besides the interseasonal heat storage options described above, domestic thermal storage could potentially alleviate some of the need for generation for heating. Current technology using hot water is cheap but has a low energy density. New phase change materials could increase energy density seven times and provide a real option for significant levels of distributed storage, but is not yet commercial. Reversible chemical processes are also promising in principle, offering even higher densities, but are at an earlier development stage.[53]

A study by NERA-AEA for the CCC considered 2500l hot water storage used in conjunction with HPs (described in more detail in the next section).[54] This would place energy storage volumes of around 100kWh in each household with negligible losses over a few days. The storage could be charged at off-peak or times of high wind, and if aggregated over a substantial proportion of properties with HPs could store 0.5TWh.

However, 2500l would have significant space requirements, being 25 times larger than most domestic cylinders. Commercially available hot water buffers are 2.3m tall with diameter 1.4m, and naturally weigh over 2.5t. Despite the AEA-NERA report finding that 45% of properties could accommodate such a volume, the practicalities and indirect financial consequences of installing such large volumes of storage need careful consideration.

In the summer when space heating is not required, storage opportunities would be limited to domestic hot water consumption, estimated to be 4.6kWh/day for a household of average UK occupancy.[55]

3.2.4 Value

The variability of wind output thus leads to two challenges - adjusting the output from conventional plant to match the more variable net demand for it, and paying for a greater volume of rarely needed reserve plant.

Gross et al. (2006) have estimated that if up to 20% of British electricity came from variable renewable sources, the first of these would cost £2-3/MWh of renewable output, and the second would cost £3-5/MWh.

The CCC has compiled an analysis on the costs of intermittency.[56] Though there is quite a large uncertainty, it found costs likely to be in the range 1 – 2 p/kWh with 15 – 20 % generation from intermittent generation. The CCC noted that the costs could be reduced from storage in EV and other batteries, through demand side management, and greater interconnection.[57]

[51] Wilson,I.A.G.,et al. (2010) Energy storage in the UK electrical network: Estimation of the scale and review of technology options http://dx.doi.org/10.1016/j.enpol.2010.03.036

[52] North Sea Offshore Networks forum and workshop, London, 6 – 8 June 2011 http://www.energyresearchpartnership.org.uk/offshorenetworks.

[53] See for example, research at ECN, Netherlands: http://www.ecn.nl/units/ei/rd-program-old/energy-in-the-built-environment/thermalsystems/tcstorage/.

[54] NERA-AEA (2010) Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s http://www.theccc.org.uk/reports/fourth-carbon-budget/supporting-research

[55] Energy Saving Trust (2008) Measurement of Domestic Hot Water Consumption in Dwellings http://www.netregs.gov.uk/static/documents/Business/EA_EST_Water_Report_Full.pdf

[56] CCC (2009) The costs of decarbonising electricity generation http://downloads.theccc.org.uk/Cost%20of%20decarbonising%20the%20power%20sector9.pdf.

[57] More recent work has been undertaken for the CCC by Pöyry on the impact of intermittency from renewable: http://www.theccc.org.uk/reports/renewable-energy-review.

3.3 Hours

Delivering power to cover daily peaks (as they currently exist) and the hour-to-hour variability of wind power is a real opportunity for energy storage. It is the timescale over which PHS operates commercially, and that which many new energy storage technologies are targeting.

3.3.1 Current situation

Meeting the early evening winter electricity peak (4pm – 8pm) demands about 7GWh. The example of an actual day in January 2010 shows that a large proportion of this is currently provided by pumped storage (Figure 11).[58]

3.3.2 Prognosis

In Ofem's work on demand side response (referred to in 2.2.2) a hypothetical winter day in 2020 was modelled in which wind output fell suddenly during the peak period. Figure 12 illustrates the changing generation mix (taken from the Project Discovery work) under such a scenario.

When wind output drops, more flexible plant such as Combined Cycle Gas Turbine (CCGT) and coal would be expected to run in response to high wholesale prices. If the demand side, perhaps as storage, had the means to respond to these high wholesale prices it could displace a portion of the required peaking plant, thus reducing the costs of maintaining secure and sustainable supplies.

Modelling by Green for 30GW wind in 2020, using historic wind data, shows that even though the peak demand may not rise, the number of hours for which demand will be between 55 and 65 GW has dropped considerably (Figure 13).[59]

Peak daily demand for gas over the winter 2010-2011 cold snap was 100mcm (26%) above average demand, equivalent to an additional 1.1TWh. If this is assumed to be mostly for additional space heating, and in 2030 a quarter of this demand was to be met by HPs (with a somewhat reduced CoP on such cold days), meeting the heat demand would require an additional daily averaged 3GW electrical generation. Even with some smearing of demand (see work of Strbac et al below), peak times during the day could call on this amount again.

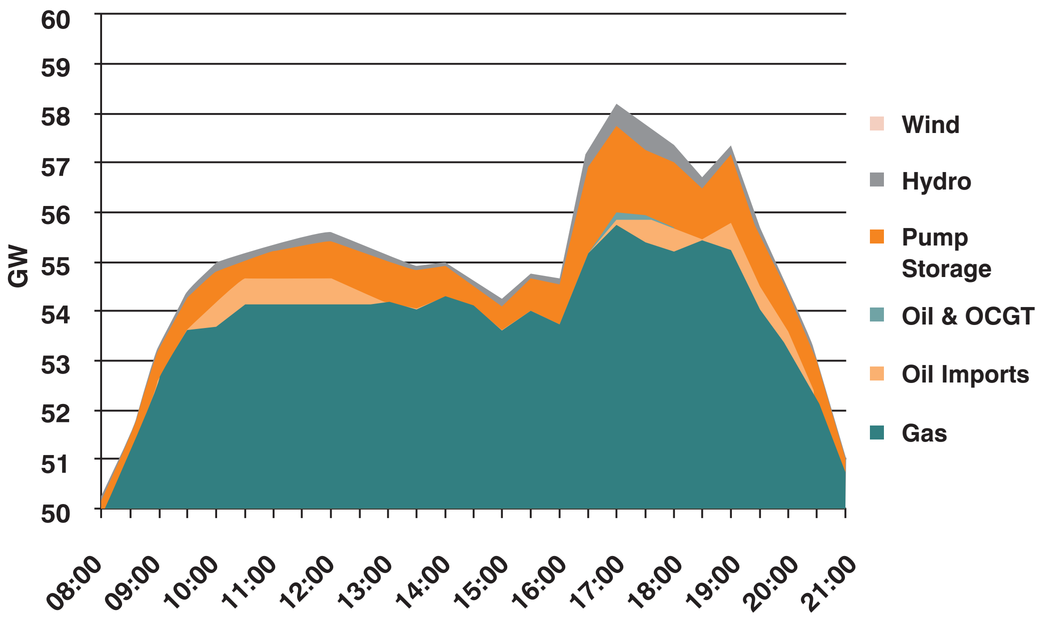

Figure 11 Type of generation at the time of maximum winter demand, Thursday 7 January 2010. Coal and nuclear operating as base-load are not shown in this figure. (Source: National Grid)

[58] From National Grid Seven Year Statement 2010 **http://www.nationalgrid.com/NR/rdonlyres/A2095E9F-A0B8-4FCB-8E66-6F698D429DC5/41470/NETSSYS2010all-Chapters.pdf** , with data tables available from **http://www.nationalgrid.com/uk/Electricity/SYS/current/.**

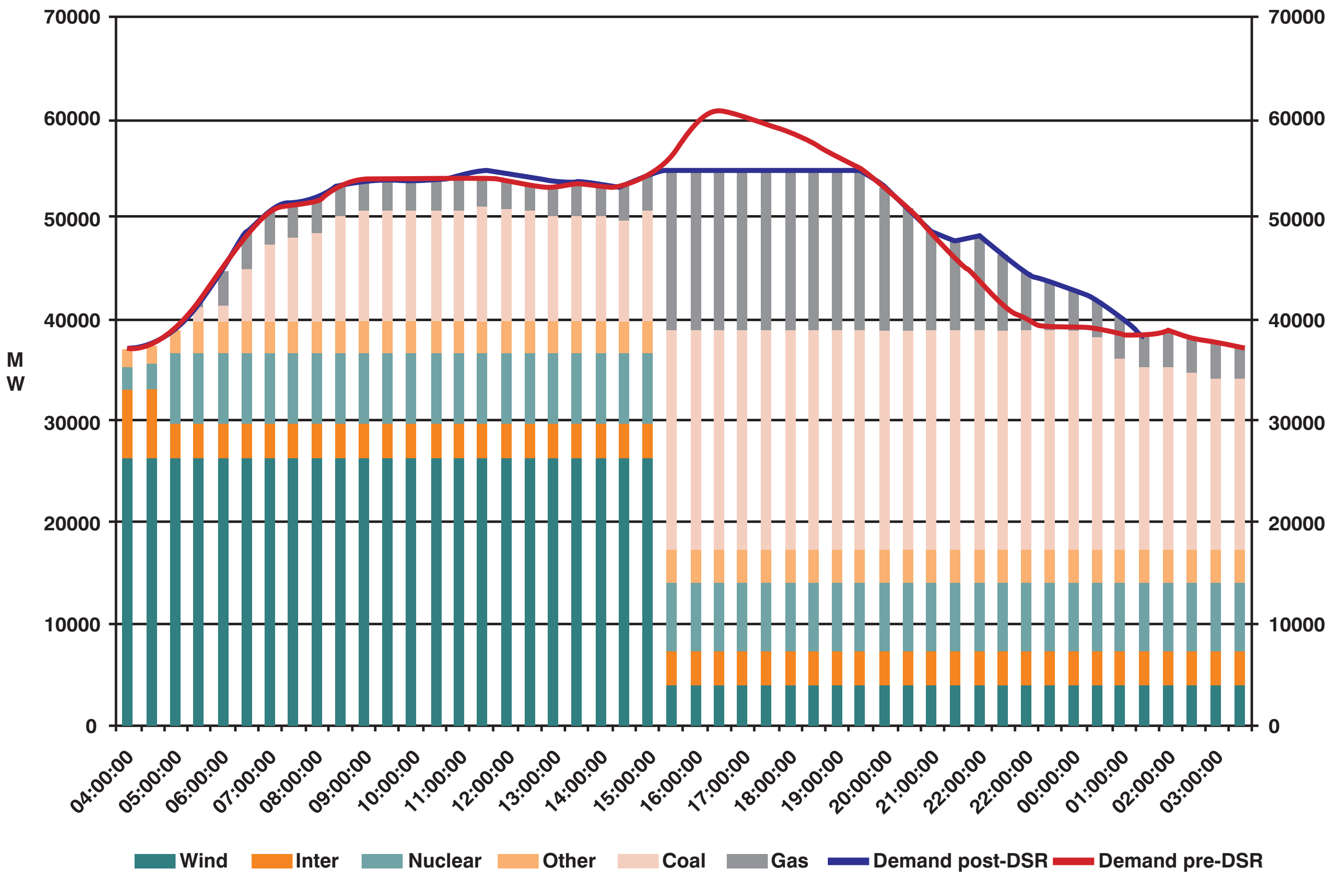

Figure 12 Ofgem modelling for a winter's day in 2020 showing the impact of demand side response on generation mix.

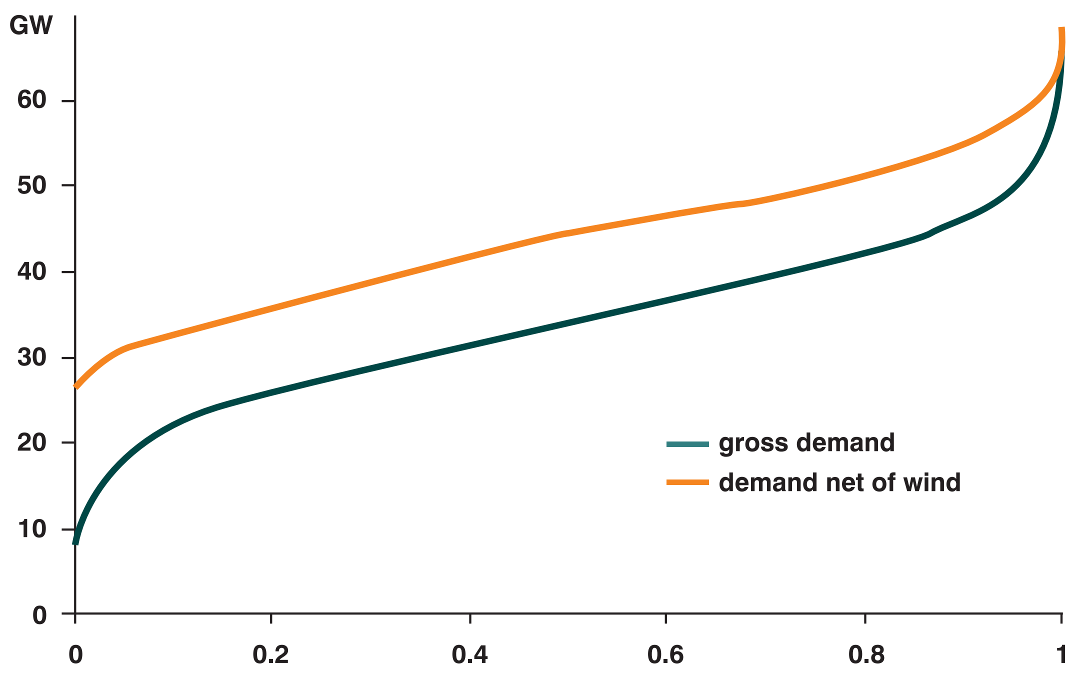

Figure 13 Predicted load-duration curve for GB with 30GW wind (from Green).

3.3.3 Options

An increase in electrification for heat could put new challenges on the energy system if not mitigated by storage. These challenges would be more acute when combined with variable generation dropping at peak times. Conversely, at time of high wind output, other generation must be backed-off to avoid 'spilling', and so putting in place a storage load could allow management of generation to minimise carbon emissions. Potential solutions exist at grid-scale, distribution and domestic levels.

At the grid scale, more high power electrical storage to cover hours of peak demand could be provided, as is currently the case. Storage can help manage both 'excess' wind by putting energy into storage to allow the lowest carbon option to be retained, and at peaks times to obviate the need for high-carbon peaking plant. Interconnection to Norwegian pumped hydro storage would give access to increased capacity. Compressed air energy storage is another potential option, though has not been widely deployed.

Distributed electrical battery storage to meet neighbourhood/household demand is being tested extensively – see 4.1 and 4.2
.
At the domestic level, the AEA-NERA report for the Committee on Climate Change modelled the effect of incorporating 2500l storage alongside air-source HPs to store energy off-peak for later use.[60] The study found that under an Economy 10 tariff (with 5 hours night-time off peak and 5 hours day-time off-peak), 70-90% of heat load for a domestic property could come from off-peak hours. However, their modelling found that there was no domestic uptake of heat pumps with storage, indicating that the additional cost is not outweighed by the additional abatement achieved. Other options for thermal storage, such as phase-change materials or reversible chemical processes discussed under 3.2.3 are also applicable at this time-scale.

A paper by Strbac et al examined a combination of demand for HPs and EV charging.[61] The authors found that heat storage capacity of 25% of daily heat demand would be sufficient for some flattening of national daily demand profile in the case of full penetration of EVs and HPs while taking into account efficiency losses that might accompany the process of storing heat. However, the authors noted the uncertainties around the type and capacity, with further analysis required.

An alternative solution is domestic electrical storage. Second-use of car batteries which have reduced performance after 2 – 3 years of charge-discharge cycles may still be valuable as stationary storage.[62] Limited recycling of Li-based cells, the capacity of around 50kWh and the potentially large deployment may make them attractive for such 'second-lives'.

3.3.4 Value

Reducing the peak power generation capacity required in a more electrified future is the greatest system-level value for energy storage. An estimate of the value can be made drawing on the potential of demand-side response, which has similar objectives. Common to both these approaches is the reliance

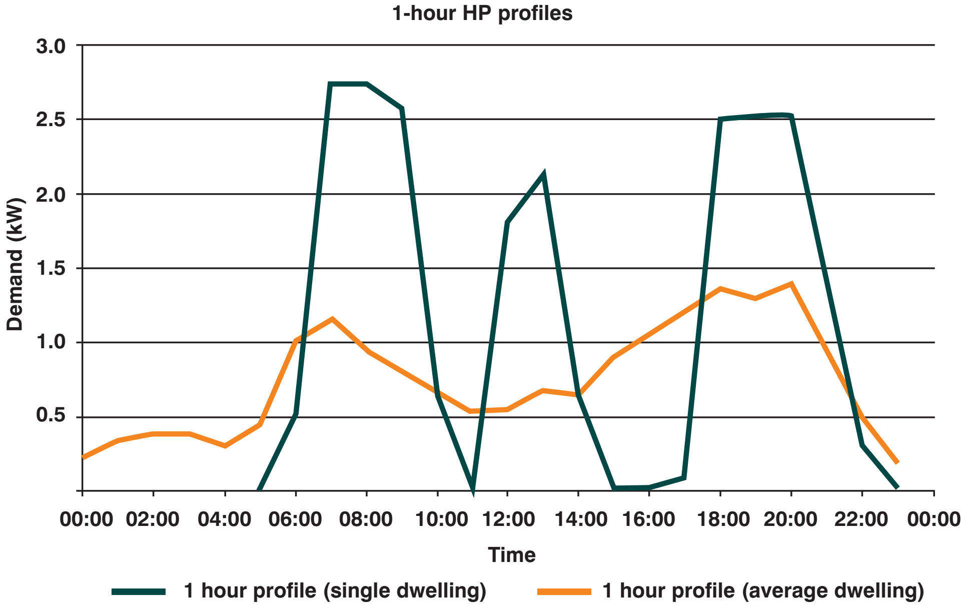

Figure 14 Demand profile of a heat pump following the operating pattern of a boiler and aggregate profile of HPs of 21 dwellings in hourly resolution (Strbac et al).

[59] Green (2010) Utilities Policy, Volume 18, Issue 4, December 2010, Pages 186-194 **http://dx.doi.org/10.1016/j.jup.2010.06.002**

[60] NERA (2010) ibid

[61] Strbac G et al (2010) Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks **http://www.cts.cv.ic.ac.uk/documents/publications/iccts01392.pdf**

[62] For example, ABB and GM Motors will examine the potential of reusing spent lithium-ion battery packs as a means of providing cost-effective energy storage capacity **http://www.abb.co.uk/cawp/seitp202/b605a235644771db482577bb002ab68e.aspx.**

of a price differential between peak and off peak. Although this is significant in the current paradigm, introducing storage (or demand off-peak) would serve to narrow the margin and make the business case weaker. Storage technologies with less than 100% efficiency also incur a real loss.

Ofgem's 'Demand Side Response Discussion Paper' took the demand profile for a winter's day, and estimated cost savings from a demand side response from the short run marginal cost (SRMC) and capital cost (avoided cost of investment in generation to meet the demand).[63] In the example of 7 January 2010 (Figure 15), 5.7GW of peak was shifted with a daily wholesale cost saving of £1.1 – 1.7m (depending on the precise generation mix), substantially (80–90%) from capital cost saving. This translates to an annual cost saving of £330–540m.

With widespread take-up of DSR, additional savings would also come from avoided network investment, estimated as £14m and £28m a year for 5% and 10% DSR respectively. From further modelling, the authors found a ranges of cost and carbon savings as described in the table for a DSR of 5% and 10% (Table 4). Given the limited number of cases studied, the figures are indicative, but give a sense of the value of reducing (or shifting) the peak load.

The Brattle Group has carried out similar calculations to find the potential benefits of demand reduction from smart metering and dynamic pricing in the EU as a whole, and the USA.[64] For the EU, they calculated the savings for a high and low case of demand response, leading to a reduction in peak capacity of 10% and 2% respectively, and included long-run benefit of avoided capacity costs, short-run costs of energy, and reduction in transmission and distribution capacity. The savings they found were €67bn and €14bn respectively, 80% of which was from avoided generation capacity cost.

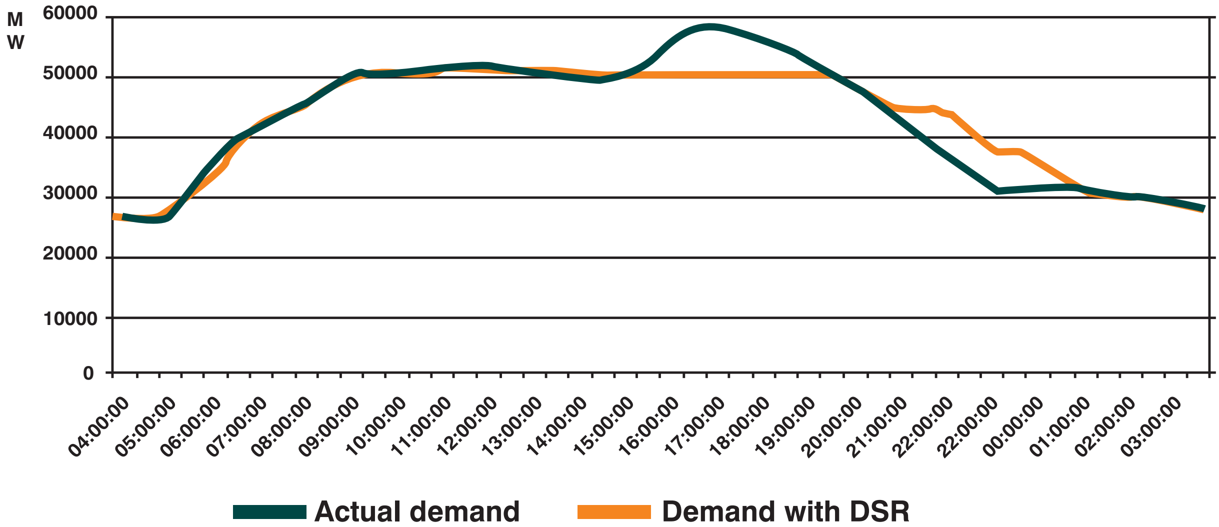

Figure 15 Actual demand, and demand with 10% DSR, for 7 January 2010 (Ofgem and NG analysis).

	Shift 10% peak load	Shift 5% peak load
Daily wholesale cost savings	£0.7m to £1.7m	£0.4m to £0.8m
Annual capital cost savings	£265m to £536m	£129m to £261m
Annual network investment savings	£28m	£14m
Daily carbon emission savings	-850 tCO2 to 2,200 tCO2	-650 tCO2 to 1,350 tCO2

Table 4 Results from Ofgem modelling of demand side response impact

[63] Ofgem (2010) ibid

[64] The Brattle Group (2009) Unlocking the €53 Billion Savings from Smart Meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment **http://www.brattle.com/_documents/UploadLibrary/Upload805.pdf;** and (2007) The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs **http://www.brattle.com/_documents/UploadLibrary/Upload574.pdf.**

3.4 Minutes

Over timescales from seconds to a few hours, balancing the electricity grid calls on flexible generation and load to ensure reliability and quality of supply. There are already some commercial storage opportunities deployed in the US, and others being tested, including in the UK. In the UK, National Grid takes the lead in the development of balancing services and has consulted on changes that will be required over the next decade.[65]

3.4.1 Current situation

Figure 16 shows the half-hourly variability of the wind output (taken from the first three days of E.ON's wind data shown in Figure 8). There are several instances where the generation increases/decreases by 50% in three hours, on top of the multi-day trend over three days, which sees a halving in output.

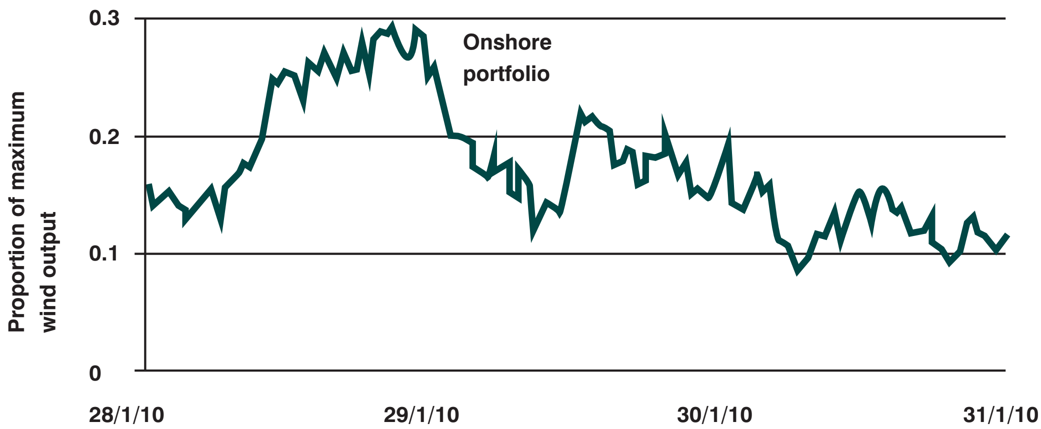

Figure 16 Variability of wind from onshore turbines over three days, half-hourly data points. (Data from E.ON)

Some of the key balancing time-scales are:

- Second by second variations in generation and demand are met by dynamic response from synchronised generation.
- At time scales of one to 90 minutes, National Grid control engineers request actions from power station engineers using Bid / Offer Acceptances (BOAs). Balancing energy volumes amount to typically 0.9TWh per month, or 2.5% of total electrical energy transmitted. The average duration of any action is around 30 minutes.
- National Grid manages the rapid ramping of supply to meet half-hourly demand profiles, exemplified by the morning pick-up between 6 a.m. and 8 a.m. which may reach 100MW/minute, to a total increase of 14GW.
- The reserve capacity (measured in MW) required at four hours ahead of real-time comes under the Short Term Operating Reserve Requirement (STORR). This provides active power from generation and/or demand reduction to help ensure the security and quality of electricity supply across the GB Transmission System.
- The level of STORR is dependent on a number of demand side factors, but on a Monday winter peak, is currently just over 4GW. National Grid currently procures 2 – 4 TWh of reserve each year. Pumped storage provides 10% of total, with coal and gas providing about one-third each.

3.4.2 Prognosis

Though the example in Figure 16 is from a limited portfolio, and the effects would be lessened by increased deployment, data from Germany give an indication of the impact of higher wind penetration. The German TSO '50hertz' has an installed capacity of some 10GW wind and finds hourly changes (up or down) in wind power of up to 1.7GW, and of 0.8GW in 15 minutes.[66]

National Grid's analysis of the impact of increased wind generation capacity on its balancing operations, to 29GW by 2020, and 34GW by 2025 shows a number of key features:

- A measure of the activity required to balance the electricity system is the 'Net Imbalance Volume' (NIV). The current average NIV is just over -400MW, but with considerable variation seen by a Standard Deviation of 450MW. By 2020, National Grid expects the NIV to double, and Standard Deviation to treble. Specific impacts are:
- The number of BOAs could more than treble from 300,000 to 1,000,000.
- Maximum ramping rates could reach 11GW/h, from the current 9GW/h, and the number of occasions on which ramping exceeds 8W/h could trebl e from 8 to 22.
- STORR is predicted to rise from the current Monday winter

[65] National Grid (2009) Operating the Electricity Transmission Networks in 2020; Initial Consultation **http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/**

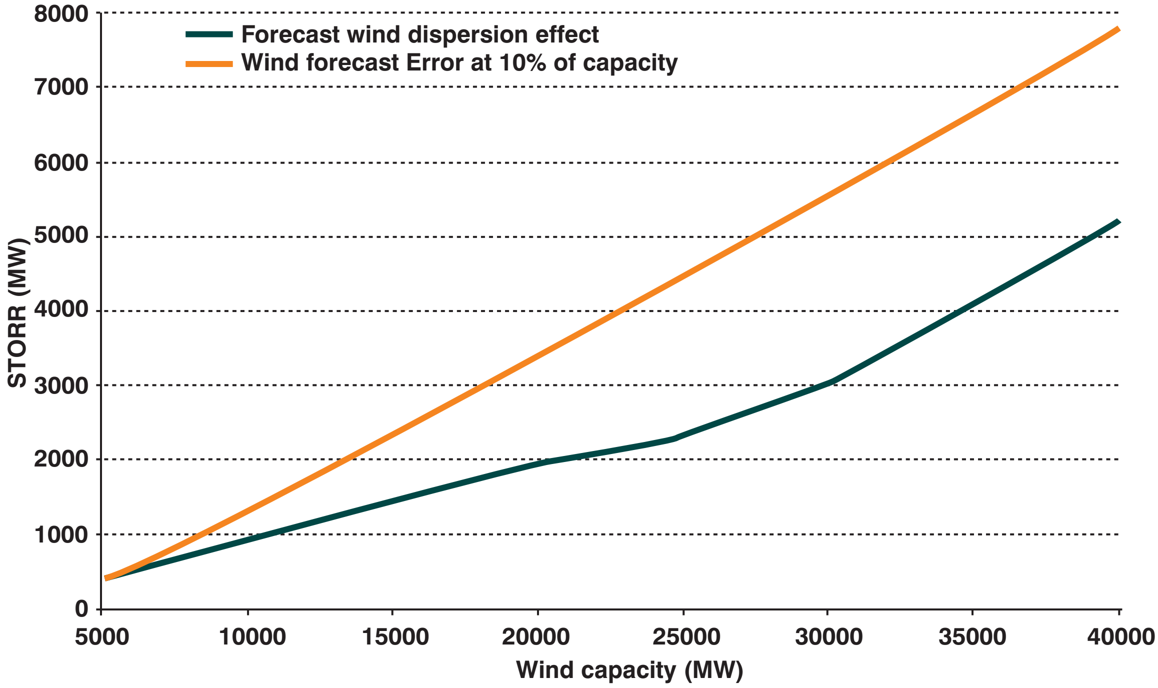

Figure 17 National Grid calculations for additional average STORR due to wind, for increasing wind generation capacity. Blue line shows additional STORR required with current wind forecast errors. Green line shows how greater dispersion of wind generation and improvements in wind forecasting would reduce additional average STORR.

peak of 4GW, to over 9GW in 2025 in average wind conditions (less in low wind conditions, as potential loss of load will be less), with 30GW wind capacity. The volume also increases from 3TWh to 8.3TWh in 2025. Over this period, gas is foreseen to increase its proportion from 30% to 45%, with pumped storage constant. Coal's share drops to 15%. The total STORR cost rises by £379m, 80% attributable to the increased deployment of wind generation.

- The additional STORR due to increasing wind generation capacity has been illustrated by National Grid in Figure 17.

3.4.3 Options

Electrical storage providing fast response over short (seconds to minutes) timescales is an area in which deployment of new energy storage technologies is commercial now.
In the US, power quality and security of supply is the current concern, rather than integration of large scale renewable. Examples of deployment include a 20MW flywheel plant by Beacon Power that began operating in January 2011 in New York[67] , and Li-ion batteries operated by AES Energy Storage in Boston.[68]

At the distribution network scale, large batteries of various types are being tested widely for balancing. In Japan, regulation requires output from wind generation to be less variable, and so MW scale sodium-sulphur (NaS) batteries are deployed commercially. In the UK, a Li-ion battery system has been incorporated on an 11kV network in Norfolk to deliver dynamic voltage control and store excess electricity from wind.

Following responses to their consultation on 'Operating the electricity transmission networks in 2020', National Grid concluded that potential new sources of reserve and response from storage were worth investigating further. In particular, batteries, flywheels and Compressed Air Energy Storage were highlighted.

A report from Ricardo and National Grid has also shown the opportunity of EV batteries to provide balancing services to the grid.[69] The research finds a modest financial return of £50 a year from allowing demand side management of EV charging. More significant returns are found from vehicle-to-grid operation, though with large capital expenditure required, and diminishing returns from large-scale deployment of such technology.

3.4.4 Value

Offer price for 'on the day' reserve is £102/MWh for coal, £136/MWh for gas and £175/MWh for pumped storage. The total STORR cost is about £300m each year. In other markets where power quality is more of an issue, such as the US, the value may be greater.

[67] Press Release at http://phx.corporate-ir.net/phoenix.zhtml?c=123367&p=irol-newsArticle&ID=1518882&highlight=.

[68] Press Release at http://www.aesenergystorage.com/news/aes-energy-storage-announces-first-grid-scale-battery-based-storage-system-commercially-operate.

[69] Ricardo and National Grid (2011) Bucks for balancing: can plug-in vehicles of the future extract cash – and carbon – from the power grid? http://www.ricardo.com/en-gb/News--Media/Press-releases/News-releases1/2011/Report-shows-how-future-electric-vehicles-can-make-money-from-the-power-grid/

Black and Strbac assessed the value of storage in providing balancing services in 2006 paper.[70] They found the value to be strongly dependent on flexibility of the conventional generation mix. In the case of a system with low flexibility, the reduction of the output of conventional plant is between 8.9 and 12.3 TWh per annum, depending on the size of storage capacity installed. However, in a high flexible case, for large storage capacity, a significant amount of reserve is provided by storage and the increased utilisation of storage will lead to an increase in energy produced by conventional plant necessary to charge storage. With 5GW of storage, the total amount of energy produced by conventional plant is increased by 219 GW per annum, while simultaneously, the cost of production has reduced by £99 million per annum, and the amount of CO2 emitted is reduced by 1.9 million tonnes.

3.5 Chapter 3 Conclusions

From a high-level analysis of the future energy system examining time segments from minutes to months, we can see how energy storage can provide a functionality that would mitigate the impacts of variable supply and changing demand profiles. The ability of energy storage to time-shift supply and demand over a wide range of energy and times scales allows such technologies to respond to many of the challenges that will arise over coming years and decades. A range of new and existing technologies could cover the challenges of supply and demand variability (Figure 18).

Most recent debate has been focused on providing storage for electricity supply. Mature and rapidly developing technologies will be able to provide effective frequency regulation, balancing or load levelling services over a period of hours, up to a day. With greater deployment of wind generation capacity the need for this is likely to expand.

Variability over longer timescales will become important as the wind generation capacity reaches 30GW expected in the 2020s. Covering a five-day wind lull could leave a TWh energy 'gap' in our current demand profile. It would take a much-increased volume of rechargeable energy storage in the UK and new interconnection to pumped hydro storage in Norway to offer an alternative to thermal back-up generation. There is a prospect, however, that UK energy storage volumes could be expanded through distributed thermal storage, especially if heat pumps have been widely deployed.

A future energy system that has a substantial shift from space heating by gas boilers to heat pumps would need both the generation capacity and infrastructure in place to deliver a reliable electricity supply when it is required. This could mean investment in 10sGW plant operating at low load factors, and distribution networks upgraded to meet much higher peak demands.

The total increased seasonal demand for electricity from heat pumps is of a magnitude that appears too great for storage technologies to cover for a significant proportion of the UK. To a limited extent, new buildings (commercial or domestic) may be able to use underground aquifers or heat banks charged during the summer to provide winter heating. However, over shorter timescales, a combination of electrical and thermal storage may be well-placed to cover increases in demand, or drops in supply. Alternatively, district heat networks in combination with ground source heat pumps and large neighbourhood-level thermal stores could be an option.

Energy storage may both complement and compete with other options to meet the full range of challenges that will be encountered. Each solution has its limitations: Supply from other countries though interconnection cannot be guaranteed to be available, though calling on pumped hydro in Norway could be part of a solution. Flexible generation from coal/gas plant may have a carbon penalty without investment in carbon capture technologies, which have yet to be demonstrated at scale. Operating nuclear as other than base load is untested in the UK and would need to be designed into new build. And the scale of demand side response is likely to be insufficient in scale and not available over long time periods, though the potential needs examining further.

The relative timings of increased wind power, deployment of heat pumps, roll-out of CCS, new nuclear build and commissioning of new fossil fuel plant will affect the scale and role of energy storage. With such a dynamic period ahead, further detailed analysis is needed to help plan investment in new technologies, infrastructure and generation capacity.

[70] Black and Strbac (2006) Value of storage in providing balancing services for electricity generation systems with high wind penetration
http://dx.doi.org/10.1016/j.jpowsour.2005.07.020

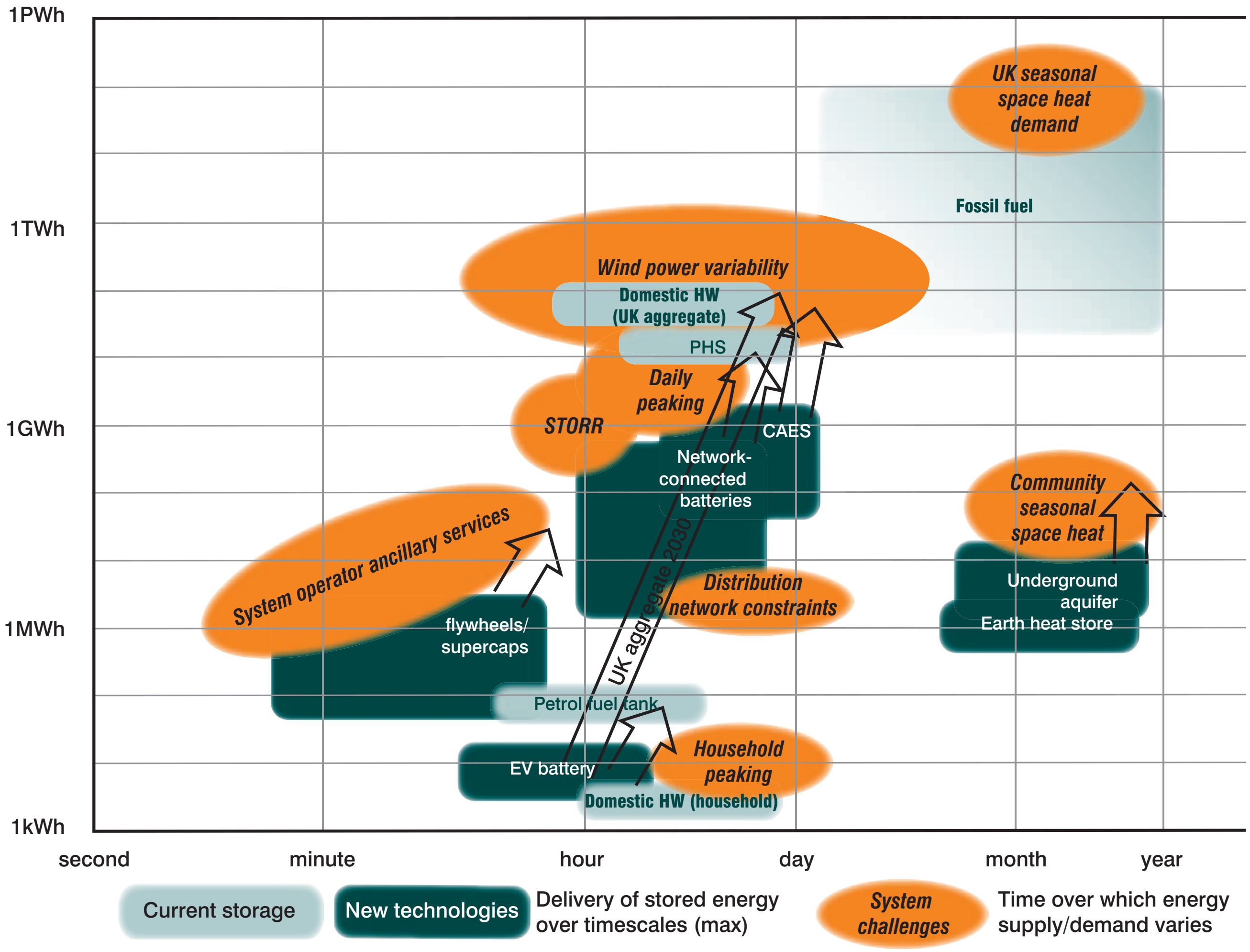

Figure 18 Challenges to the UK energy system posed by increased wind and electrified space heating and how they can be met by energy storage technologies, with indicative time and energy scales. Blue boxes show widely deployed technologies. Green boxes show current limits of new technologies, with arrows illustrating their potential application with further development.

4 Energy storage research, development and demonstration

An assessment of capability to undertake research, development and demonstration (RD&D) activities can highlight gaps in innovation of specific technologies and show where particular strengths lie. This can be useful information to help guide future funding.

This chapter describes some of the major RD&D technology programmes in the UK and internationally, but does not provide an exhaustive list. In particular, research which falls under other specific disciplines may well contribute to the development of energy storage technologies, but not be captured. A thorough and detailed analysis would be required to assess UK strengths and comparative advantage fully.

4.1 UK

4.1.1 Research

Many university groups undertake research with a focus on energy storage, though the community is dispersed and would benefit from comprehensive mapping to highlight expertise. Some of the major projects and programmes are described below.

Details of 59 publicly funded R&D projects (since January 2007) relevant to storage with a total value of £50m have been collated from the UKERC Research Register. The Research Register takes a bottom-up approach by assigning proportions of publicly-funded research projects to different areas, of which 'energy storage' is one. For example, a project studying energy recovery from landing aircraft is assumed 25% energy storage, with the rest transport energy efficiency (50%), electric power conversion (15%), and transmission and distribution (10%).

Scanning project funding from public bodies does not capture all research being undertaken in an area – research is also funded from the private sector and through quality-related (QR) research funding – but it gives an indication of where expertise lies. Analysis of this data collected shows that of the total value of the projects funded over the last three years, £12m has funded energy storage research. Using a top-down approach, EPSRC classifies 16 projects relevant to (but not exclusively on) energy storage, with combined value of £15.5 million.[71] These projects overlap with those considered here.

A diverse range of projects is funded (Appendix B lists those from the Research Register where the energy storage component is >50%) though the emphasis is on smaller scale storage. One-third of the 'top' 22 listed focusing on lithium-based batteries, see Table 5. Single projects are looking at H2 storage, SMES, phase-change materials, and compressed air energy storage.

Area	Number
Li-based batteries	7
Supercapacitors	4
Novel materials for batteries	3
Network support	2
Novel materials as energy carriers	2

Table 5 Number of projects funded by UK Research Councils in energy storage areas.

Looking over previous years, the grants awarded to energy storage have increased significantly; from near zero at the start of the decade, to over £3m in 2010, and as a proportion of total spend on energy projects have also increased from 0.5% to almost 2% (Figure 19).

Of the funding, nine universities have received >£250,000: Cardiff, Imperial, Oxford, Sheffield, Southampton, St Andrews, Strathclyde, Surrey and Warwick. On top of this, Research Councils fund the Energy Storage Supergen Consortium which provides £3.4m over four years to groups from Bath, Cambridge, Surrey, Oxford, Newcastle, St Andrews and Strathclyde.[72] The research is focused on technologies, in particular Li-air batteries (with a goal to achieve 8-10 fold increase in energy storage densities on current lithium technology), flow batteries and supercapacitors.

[71] A 'live' list of grants being funded by EPSRC is available from **http://gow.epsrc.ac.uk/ChooseTTS.aspx?Mode=TOPIC&ItemDesc=Energy+Storage** with more general information at **http://www.rcukenergy.org.uk/what-were-funding/networks-and-storage.html.**

[72] **http://www.energystorage.org.uk/.**

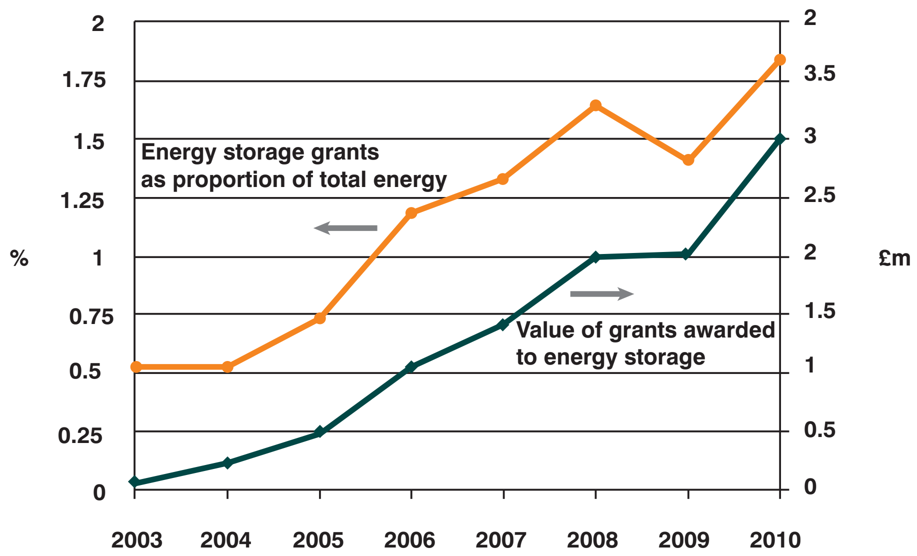

Figure 19 Value of grants awarded for energy storage each year. (Source: UKERC Research Register)

The Supergen Highly Distributed Energy Future (HiDEF) also includes elements relevant to the application of storage.[73] This includes most of the individual research groups (from Stratchclyde,Imperial, Cardiff, Oxford, Loughborough and Bath) which consider the role of storage in the energy system.

A project is being supported by UKERC under its research fund on “The Future Role of Thermal Energy Storage in the UK Energy System”.[74] The aim of this project, being led by Philip Eames at Loughborough University, is to clarify both the potential for, and limitations of, the role of thermal energy storage in the transition to a sustainable low carbon energy supply system in the UK.

The Research Councils Energy Programme was reviewed by an international panel in 2010. The panel commented on UK’s expertise in energy storage research, finding that the UK is an international leader in lithium energy storage, though weak in heat storage and distribution, and compressed air energy storage.[75] On a more general point, the Review stated that *“developing a global vision of the UK’s energy future in the form of an integrated technology roadmap by the research councils as a whole (or by transforming the roadmaps to be developed under the expanded ERP work ...) would provide useful guidance for research institutions to position their research, especially for the longer term, beyond the horizon of industry’s interest as well as for identifying crosscutting issues.”* with energy storage given as one of ten example cross-cutting issues.

4.1.2 Energy Technologies Institute

The Energy Technologies Institute (ETI) is a public-private partnership that works to speed up the development and demonstration of energy technologies and shorten the lead times to market. It has an ’Energy Storage and Distribution’ programme which aims to enable and develop the UK’s energy infrastructure to manage fundamental long-term changes in:

- Energy generation source types and their geographic location
- Energy demand patterns and energy usage requirements

...all in the context of a 2050 low-carbon future within the UK.[76]

A number of studies/requests for proposals have been made recently:

- Launched August 2010: Request for Proposals - A Techno-Economic Evaluation of Transportable Energy Storage. “The study will provide information to the ETI as to the relative merits of transportable energy storage and the potential to move forward to a demonstration project.”
- Launched August 2010: Request for Proposals - Development, Test and Demonstration of Distribution Scale Electricity Storage Technology. The project is looking to fund a storage devce that can deliver at least 500kW on an 11kV network for approximately four hours.
- In November 2010, ETI announced a ‘Feasibility Study of Geological Heat Storage in the UK’. “The ETI project will be led by consultants Buro Happold with input from Cambridge University, the British Geological Survey and IF Technology Group. It will investigate the cost effectiveness and practicalities of storing large quantities of heat for long periods to meet a significant proportion of the UK’s winter demand, evaluate the practical limits for this type of storage and where in the country it could be most effectively used.”

[73] http://www.supergen-hidef.org.
[74] http://www.ukerc.ac.uk/support/tiki-index.php?page=RF3SmallThermalStorage
[75] RCUK (2011) Report of the International Panel for the RCUK Review of Energy 2010 http://www.rcuk.ac.uk/reviews/current/energy2010/Pages/home.aspx.
[76] http://www.energytechnologies.co.uk/Home/Technology-Programmes/EnergyStorageandDistribution.aspx

4.1.3 Carbon Trust

As part of the Carbon Trust's Low Carbon Technology Commercialisation Review, detailed case study analysis was carried out exploring viability of flow-battery storage.[77] The study found that flow cells had a 'low likelihood' of being needed to meet UK climate change targets, and also low likelihood that the technology would require UK support to be available in time to meet targets. The conclusion was to assess against other alternatives and provide support if it prove to be a "compelling option".

Policy solutions were also given for commercialisation, including:

- Introduce deployment mechanism (almost certainly specific to storage)
- Develop specific electricity storage demonstration projects
- Change regulatory framework (e.g. the Balancing and Settlement Code) to allow aggregation of potential value to be captured by storage participants
- Establish industry performance standards
-

Scoping out energy storage opportunities relating to novel electrolyser technology was planned for 2009/10.[78]

4.1.4 Technology Strategy Board

In its Energy Generation and Supply Strategy, under the topic intelligent grid integration and management, it was concluded that more consultation on business needs was required.[79] Two projects on redox flow batteries have been funded with combined cost of £1.2m.[80] One, with Scottish Power, the University of Southampton and others, is to develop, build and test in situ a 100kW redox flow battery, with cost target of £700/kW for two-hour storage at 80% efficiency.

The other, with E.ON, University of Southampton and others, is to produce a kW-sized demonstrator using novel membrane-less soluble lead acid redox battery (or regenerable fuel cell).

A project to improve the energy density of Li-ion batteries was funded (£440,000 provided) to FiFe Batteries (with ABSL), though the company appears not to exist any longer.

Under the low-carbon vehicles programmes, batteries for electric vehicles are a key component[81], and a recent competition was launched to investigate recycling and re-use of batteries from EVs.[82]

4.1.5 Ofgem

Ofgem's Low-Carbon Network Fund has been established with £500m to support projects by DNOs to try out new technology, commercial and operating procedures.[83] Though several projects which included storage were submitted in the first year of funding, none were selected. In the second year, one bid includes use of storage in a £30m project which will "understand the effectiveness of embedded energy storage and demand reduction and how best to encourage the latter."[84]

The Innovation Funding Initiative has also funded energy storage projects, including that by EDF Energy Networks (now UK Power Networks) to incorporate Li-ion battery storage from ABB on 11kV distribution system in Norfolk.[85] A collaborating partner is Durham University.[86]

4.1.6 Government

In the past, Low Carbon Investment Funding from DECC has supported demonstration and pre-commercial deployment of storage technologies under the Smart Grids Initiative. Currently, the Low Carbon Innovation Group is been developing Technology Innovation Needs Assessments (TINAs) on a range of key low carbon technology families (including electrical and thermal storage), to help inform decision making for the allocation of these funds.[87] Initial announcements are expected later in 2011.

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[77] Available from http://www.carbontrust.co.uk/Publications/pages/publicationdetail.aspx?id=CTC752.

[78] http://www.carbontrust.co.uk/emerging-technologies/technology-directory/Pages/energy-storage.aspx

[79] http://www.innovateuk.org/_assets/pdf/Corporate-Publications/EnergyGenSupply_strategy.pdf

[80] Database at http://www.technologyprogramme.org.uk/site/publicRpts/default.cfm?subcat=publicRpt1 report on the Technology Strategy Board's current portfolio by AEA at http://www.innovateuk.org/_assets/pdf/other-publications/aea_tsb_annual_report_final_7%20september_09.pdf.

[81] http://www.innovateuk.org/ourstrategy/innovationplatforms/lowcarbonvehicles/integrateddeliveryprogramme.ashx

[82] http://www.innovateuk.org/content/competition/batteries-for-low-and-ultra-low-carbon-vehicles-re.ashx

[83] http://www.ofgem.gov.uk/NETWORKS/ELECDIST/LCNF

[84] http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/stlcnp/Pages/stp.aspx

[85] http://www.abb.co.uk/cawp/seitp202/ae00ec404af88769c1257552003bbf59.aspx

[86] Wade et al (2010) 'Evaluating the benefits of an electrical energy storage system in a future smart grid.', Energy policy., 38 (11). pp. 7180-7188 http://dx.doi.org/10.1016/j.enpol.2010.07.045

[87] http://www.decc.gov.uk/en/content/cms/funding/funding_ops/innovation/innov_fund/innov_fund.aspx

4.2 Private sector

There are a number of energy storage companies active in the UK:

- Atraverda – developing advanced lead-acid batteries, based in south Wales http://www.atraverda.com/.
- Isentropic – developing reversible heat engine/heat pump for energy storage, based in Cambridge http://www.isentropic.co.uk/
- Plurion – developing cerium-zinc flow batteries, based in Fife http://plurionsystems.com
- Oxis – polymer lithium-sulphur batteries, based in Abingdon, received TSB funding http://www.oxisenergy.com/
- Nexeon – Li-ion batteries, based in Abingdon http://www.nexeon.co.uk/
- Highview – testing pilot cryogenic energy storage system; based in London, engineering centre in Slough http://www.highview-power.com/wordpress/
- ABSL – Li-ion manufacturer, based in Thurso and Culham http://www.abslpower.com
- ICAX – interseasonal ground storage of heating and cooling energy http://www.icax.co.uk/

Other companies are actively engaged in development of energy storage, including a partnership between Tata Steel, the Low Carbon Research Institute and Welsh Assembly Government to create the Sustainable Building Envelope Centre in North Wales[88]; and Sharp Laboratories of Europe, based in Oxford.

A trade body was recently established – the 'Electricity Storage Network – representing developers, researchers, organisations, users and others , to examine "the issues for the greater deployment of electrical energy storage and provide a network for discussion of key issues."[89]

Historically, the Regenesys project has been important to the energy storage industry in the UK. It developed a system based on polysulphide bromide flow cell technology, but was sold off by RWE npower in 2004. At the time this had been an internationally recognised technology potentially capable of delivering 10 – 20 MW/120MWh.[90] Despite closure of the project, many of the people who were part of Regensys have continued to be active in the storage technologies, and are involved in a number of the companies listed above.

There is also interest in storage projects from a number of utilities:

- SSE has a number of energy storage trials:
  - 100kW/150kWh zinc-bromine flow battery installed in Nairn;
  - Highview cryogenic storage test facility hosted in Slough;
  - 6MWh battery at Inveralmond for asset deferral to reduce load on 11kV feeders with funding from DECC's 'Smart Grid Capital Grant';
  - Northern Isles New Energy Solutions (NINES) in Shetland with proposals to include 'smart' storage heaters and hot water tanks in up to 1,000 homes to help balance the electricity network, and 1MW battery part-funded by DECC.
- EdF, ABB and Durham University (as described under 4.1.5) are collaborating on placing a 200kWh/1hour discharge Li-ion storage unit in an 11kV distribution system in Norfolk to deliver dynamic voltage control, and storing locally generated surplus wind energy.[91]
- E.ON funded a number of projects in 2008 on the theme of energy storage, including (in the UK) on use of EV batteries for domestic supply, a supercapacitor/battery hybrid and underwater air bags for storing wind energy.[92]

Also worth noting is the International Flow Battery Forum which is hosted annually in the UK, covering standards and actions to support the ongoing development of flow batteries, for developers, suppliers and users.[93]

4.3 International activities

There is much collaborative working between individual researchers and organisations, though this can be difficult to capture at a high level, so some of the major multi-lateral programmes from the EU and IEA covering energy storage technology development are given below. ERP's project on International Engagement aims to bring a more strategic approach to the UK's engagement in international energy innovation activities and will cover these issues in more depth.[94]

A special Annex to this report is being produced which will set out the innovation and policy activities towards energy storage of a selection other countries, including US, Japan, France and Germany.

4.3.1 Europe

Framework Programme (FP): FP7 has included electrical and thermal storage as one of the objectives from the energy theme.

[88] http://www.sbec.eu.com

[89] http://www.electricitystorage.co.uk/

[90] Some technical details at http://www05.abb.com/global/scot/scot232.nsf/veritydisplay/c4f6ee8cddd1bf08c1256e2700424e70/$file/prs%20little%20barford_reva.pdf.

[91] See press release at http://www.abb.co.uk/cawp/seitp202/ae00ec404af88769c1257552003bbf59.aspx.

[92] http://pressreleases.eon-uk.com/blogs/eonukpressreleases/archive/2008/05/23/1224.aspx.

[93] http://www.flowbatteryforum.com

[94] www.energyresearchpartnership.org.uk/international.

In the 2011 call, thermal storage, proposals have been invited which perform better than water and significantly above 70kWh/m3 to provide seasonal storage.[95] Electrical storage projects are mostly targeted at balancing.

Over FP6 and FP7 calls, 11 projects have been funded under the general 'energy storage' classification, five of which are for hydrogen, and two for lithium-based battery technologies.[96] 'Alistore' was a FP6 'Network of Excellence' with UK representation studying advanced lithium battery storage, which continues as a 'European Research Institute'.[97]

European Energy Research Alliance (EERA): EERA is a recent initiative, bringing together the major energy research institutes in Europe.[98] Joint Programmes (JPs) of research are a mechanism for significant collaborations on the basis of existing national funding. A JP in energy storage has recently been established.

European Industrial Initiatives (EIIs): The European Electricity Grid Initiative (EEGI) is the basis for the EII, with a roadmap drawn up by ENTSO-E and EDSO, following on from the SmartGrids Energy Technology Platform.[99] Integration of storage technologies is one of twelve 'functional projects' with an indicative budget of 60M€ The roadmap is open for consultation .

European Cooperation in Science and Technology (COST): The UK is involved in a COST action 'Hybrid Energy Storage Devices and Systems for Mobile and Stationary Applications' which "addresses hybrid energy storage devices and systems based on innovative materials and technologies as well as on innovative system architecture."[100]

4.3.2 IEA

The IEA supports an Implementing Agreement on 'Energy Conservation though Energy Storage'.[101] The aims are cooperative research; and development, demonstrations and exchanges of information in the area of energy storage. It works through seven current 'Annexes' with 15 contracting parties, covering thermal and electrical storage:

- Sustainable Cooling with Thermal Energy Storage
- Thermal Response Test for Underground Thermal Energy Storages
- Thermal Energy Storage Applications in Closed Greenhouses
- Applying Energy Storage in Ultra-low Energy Buildings
- Material Development for Improved Thermal Energy Storage Systems
- Surplus Heat Management using Advanced TES for CO2 mitigation
- Electric Energy Storage: Future Energy Storage Demand

The UK does not participate officially, though there is some input from UK experts in the work.

4.4 Chapter 4 Conclusions

The need for further analysis to understand what energy storage characteristics would be most appropriate for the UK must not be a barrier to the development of some promising technologies.

An immediate priority is to demonstrate how energy storage technologies can work, both in terms of their technical performance, and as part of a system which will include consumer behaviour as a key factor in determining their effectiveness. Increasing our knowledge of operational capability and costs will feed back into analysis on the role of energy storage. Demonstrations of energy storage technologies will sit alongside (and, in many cases, be part of) similar activities for smart grids, demand side response and new generation technologies.

Underpinning R&D is needed to support the innovation process and to continue the search for incremental and step-change improvements to underlying or new technologies. The UK does have expertise in some areas, notably Li-based and flow-cell batteries. Research Councils have targeted Li-ion and supercapacitors in particular, and such a focused approach is the only way to compete on the world stage. However, the sums being spent are still relatively modest by international standards and must be directed at areas where the UK has comparative advantage.

Funding agencies spanning the innovation process need to take a coordinated and strategic approach to ensure opportunities to develop technologies in the UK are not missed. The Energy Technologies Institute does have a strong energy storage programme, but there is little currently being undertaken by the Carbon Trust and Technology Strategy Board. With a number of small UK companies active in the area, the support they could offer could be vital.

Involvement in relevant international programmes is patchy. There is some UK participation in Franework Programme projects, but no formal involvement in either IEA Implementing Agreements which concern storage technologies.

Follow-on work by ERP which marries the role of energy storage with specific technologies will consider priorities for innovation gaps in more detail.

[96] Database at http://ec.europa.eu/research/energy/eu/projects/index_en.cfm interrogated January 2011.

[97] http://www.alistore.eu

[98] http://www.eera-set.eu/

[99] http://www.smartgrids.eu/?q=node/170.

[100] http://www.cost.esf.org/domains_actions/mpns/Actions/MP1004?

[101] www.iea-eces.org.

5 Deployment issues

5.1 Market potential for energy storage

Assessing the market and value of energy storage is highly dependent upon factors including the market environment, storage technology and the energy system in which it will operate. Sections within Chapter 3 give an indication of where the value could come from in different market segments, but a detailed analysis of specific circumstances is required to build a business case.

The US DOE has produced an extensive report to "provide a high-level understanding of important bases for electric utility-related business opportunities involving electric energy storage" and to give "a basic understanding of the benefits for electric-utility-related uses of energy storage."[102] The authors found eight potentially attractive value propositions:

1. Electric energy time-shift plus transmission and distribution upgrade deferral
2. Time-of-use energy cost management plus demand charge management
3. Renewables energy time-shift plus electric energy time-shift
4. Renewables energy time-shift plus electric energy time-shift plus electric supply reserve capacity
5. Transportable storage for transmission and distribution upgrade deferral and electric service power quality/reliability at multiple locations
6. Storage to serve small air conditioning loads
7. Distributed storage in lieu of new transmission capacity
8. Distributed storage for bilateral contracts with wind generators

Though the report is US-specific, and so the conclusions of dollar-benefits are not generally applicable to the UK system, the framework is instructive. In particular, the report notes that in many cases it make take the value of combined benefits to exceed the cost of storage.

As is usually the case for emerging technologies, the general market potential for energy storage technologies has been estimated by a number of different organisations with varying methodologies which are difficult to separate until after the event. Three such studies are presented below.

Piper Jaffray has studied the relationship between solar and wind power generation, and the demand for energy storage. In a 2009 report 'Energy Storage: Game-Changing Component Of The Future Grid', they estimate that the total available market for energy storage will be at least $600bn over the next 10-12 years even if just 1% of the total worldwide stationary energy generation market adopts some form of energy storage.

KEMA has made an assessment of storage applications and markets in the US (Table 6).[103]

Service		Description	Market size	Market stage
Regulation		Second by second adjustment of power production to match load and schedules and regulate system frequency.	$1.8 billion	Developed
Intra-day production shifting		To levelize deviation from hourly forecast until other units can ramp up/down and to flatten the ramp up/down of power to match system ramp.	$1 billion	Developing
T&D	Community storage	A small distributed energy storage unit connected to the secondary of transformers serving a few houses or commercial loads	$11 billion	Developing
	T&D capital deferral	To help meet the peak load demand and defer a line or transformer purchase	$16 billion	Developing
	Reliability enhancement	Enhance the power quality and reliability and protect the sensitive electronic systems	$2 billion	Developed

Table 6 Energy storage applications and markets in the US. (Source: KEMA)

[102] Study for US DOE Energy Storage System Programme 'Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide' by Jim Eyer and Garth Corey, Sandia National Laboratory, February 2010, available at **http://prod.sandia.gov/sand_doc/2010/100815.pdf.**

[103] **http://setis.ec.europa.eu/newsroom-items-folder/storage-workshop-1/presentations/US%20perspectiveV1.pdf/at_download/file**

Finally, the Boston Consulting Group assessed the actual market potential of storage technologies in eight application areas by assess the financial attractiveness of the storage business case, the complexity of implementation and the availability of alternatives to storage.[104] They find that in addition to currently available capacity of around 100GW, there will be a global market potential of 330GW in various storage technologies up to 2030. The study concludes that this translates into an additional cumulative investment need of €280bn to 2030.

5.2 Policy and regulation

Technology costs are clearly the main barrier to deployment now. However, there are issues that may act against the deployment of energy storage. From a regulatory point of view, energy storage is not recognised as an asset class. By default it is viewed as generation and therefore cannot be controlled by a system operator under EU competition rules, despite there being a potential economic, environmental and security of supply case for such integration.

The recent consultation on capacity mechanisms under the Electricity Market Reform do appear to be technology neutral, in allowing storage and demand-side response to compete with power generation. However, the lack of hard analysis of the role of energy storage in general means that reform proposals are likely not to recognise any potential system benefits from storage. New market arrangements may endure for the next decade, in which time deployment of intermittent wind generation will have reached 10sGW capacity, and storage technology performance and cost may well have improved.EMR should therefore allow for the possibility of adjustment in the case that energy storage is shown to have wider benefits than is now the case.

Other countries have taken a much more pro-active stance that has pushed energy storage into the market place. In California, a recent bill has been passed which legislates for a commission to set targets for viable and cost-effective energy storage systems.[105] In Japan, regulation means that generators must provide guarantees of power far in advance of the time, or risk penalties. This provides an incentive for wind farms to couple with electricity storage plants.

5.3 Chapter 5 Conclusions

Energy storage is unlikely to be deployed widely under the current market framework, or those proposals being put forward under the Electricity Market Reform consultation. Development of new energy storage should be on a level playing field with other technologies. Analysis may show that it can offer strong environmental benefits by allowing the operation of low carbon generation. If this is so, there is a strong case for incentivising its deployment. Energy storage technologies should be seen as a credible option for the energy system, and recognised as such during the Electricity Market Reform process.

Commercial deployment of energy storage technologies is likely to rely on revenue from several streams, though business models are yet to be proven. These will include arbitraging across hours to peak-shave/load-shift, providing back-up capacity during low wind periods, and ensuring power supply quality. Policy-makers, regulators and potential users of energy storage should be aware of this, and not take a narrow view of what the technology can offer.

Market predictions for pre-commercial technologies are notoriously unreliable. But even an expectation that energy storage will scale-up as worldwide electricity generation expands leads to the conclusion that there will be an increase in deployment of energy storage technologies. Though this is likely to be for pumped hydro storage initially, it leaves an opportunity for new technologies.

Regulation of energy storage should be re-examined by Ofgem to ensure there are no artificial barriers to its wider deployment.

[104] BCG (2011) Revisiting Energy Storage **http://www.bcg.com/documents/file72092.pdf**

[105] See **http://www.storagealliance.org.**

6 Conclusions

1. Energy storage has the potential to contribute to meeting the challenges of a low carbon energy system, but has tended to be overlooked in favour of generation technologies. Electrification of heat especially, and substantial deployment of intermittent generation, will make it harder for supply to follow demand. A combination of electrical and thermal storage could mitigate against undue additional investment in conventional generation to meet increasingly peaky demand or low generation from wind.

2. However, energy storage is not a panacea: there are other potential solutions, and system costs are likely to be the overriding factor in determining the chosen technology, which will be strongly system dependent.

3. A rigorous assessment of the role of energy storage against other options in the future energy pathways is not available. Energy system and network models should be developed to include energy storage more effectively and show if it has cost and carbon saving potential.

4. Long-term policy direction for the UK's energy system is also needed to define the potential role for storage.

5. The seasonal profile of heat demand will translate to electricity demand if the UK moves to a scenario where heat pumps provide space heating in place of gas boilers. The role for rechargeable energy storage to cover the scale of this demand appears limited, though there is scope for community or building level thermal storage to have an impact.

6. As wind deployment rises much above 30GW to meet UK demand, the ability to cope with a 5-day lull will rest increasingly on investment in thermal plant which may run with low load factors.

7. UK R&D technological capability is in niches. There is world-leading expertise in some battery and supercapacitor research which Research Councils are supporting through long-term funding, and in general, funding for energy storage has been increasing. However, the links between technology R&D and system modelling are not strong. An integrated energy storage research programme should bring these elements together.

8. The activities of the different organisations in the energy innovation landscape do not appear to be strategically aligned. In times of austerity, and the need to focus resource, this should be a priority area for coordination.

9. A number of small scale companies have grown in the UK based on energy storage technologies. But technology-push and market-pull incentives will be required to translate this into economic benefit:
   a) Scale-up to large-scale demonstration is required globally, UK could be in strong position to test and benefit from new solutions. International engagement in innovation activities should be improved to bring knowledge and value to UK economy or energy system.
   b) Cost is the main barrier now, but regulatory and 'inertia' issues will need to be overcome. Policy and regulation needs to be prepared for new business models, possibly with incentives if it can be shown to have improved carbon credentials.

10. A strategic roadmap which leads to detailed consideration of the potential role of energy storage should be drawn up covering: rigorous assessment of options by energy system models and other analyses, technology requirements, coordinated RD&D programmes, industry/supply chain needs, and regulatory/policy issues.

Appendix A

Electrical Energy Storage Technologies
Technology solutions that could meet the opportunities for electrical energy storage have been described and characterised extensively elsewhere – the References section at the end of this Appendix gives a list of authoritative sources. Further, the Low Carbon Innovation Group's work on Technology Innovation Needs Assessments (TINAs) is studying specific technologies to understand the nature and level of UK support for innovation required to meet emissions targets at lowest cost and to deliver maximum business creation value to the UK.

Summaries below give an overview of the key points where that would help understand the position of storage technologies in the future energy system drawing on these references. Figures given are indicative, particularly regarding costs. As the CCC notes, "there is no accepted, reliable source on past and current prices for EV batteries." In many cases, the technology is not yet commercial/mature so costs are estimates, or the data is commercially sensitive and difficult to extract, or the technology has not been deployed for several years with out of date costings.

Costs quoted from the Electric Power Research Institute (EPRI)[106] are US-based, but do attempt to "assess the probable capital expenditures associated with implementing and installing a commercial-scale technology project. For each application, estimates were developed for installation, interconnection and grid integration costs." The publication itself gives detailed costs by application for each technology. Costs are also quoted from an assessment for the Scottish Executive by AEA.[107]

Technology status	Example Technology Options
Mature	Pumped hydro, lead-acid battery
Commercial	CAES first generation, Lead-acid, NiCd, sodium-sulphur batteries
Demonstration	CAES second generation, Zn/Br, vanadium redox, NiMH, advanced lead-acid, Li-ion
Pilot	Li-ion, Fe/Cr, NaNiCl2
Laboratory	Zn/air, Zn-Cl, advanced Li-ion, novel battery chemistries
Idea	Non-fuel ("adiabatic") CAES, nano-supercapacitors, other novel battery chemistries.

Table: Development status of main energy storage technologies [EPRI 2010]

i. Pumped Hydro Storage
Most commonly involves upper and lower reservoirs connected by tunnels, with turbines turned by water flowing from higher to lower as for conventional hydropower, then pumped back with off-peak power to recharge. Can also operate with the sea as the lower reservoir, but corrosion effects increase costs approximately 15%.

Power/energy range
From 250MW to 1.5GW, discharging over up to 10 hours, capacity up to 14GWh; 70% efficiency

Technology status
Mature technology. 100 GW deployed globally, mostly between 1970 and 2000.
Potential for PHS in Wales was investigate in the early 1970s when three sites were identified all within the Snowdonia National Park: Dinorwig with up to 9.65 GWh (rated at 2.25 GW), Bowydd with 13.8 GWh (rated 3.2 GW) and Croesor with 9.7 GWh (rated 2.25 GW).

AEA's report took a scenario for Scotland with excess generation of 2.8GW in 20202 requiring seven schemes of around 400MW, rising to 7.5GW in 2030. It commented that there were limited numbers of sites for PHS of that scale, and that such proposals would attract "significant public attention and debate".
Further deployment limited by geography. MacKay estimates maximum energy store could be increased to 100GWh or perhaps 400GWh.[108]

Costs
EPRI estimates: For new large scale (>900MW) facilities capital costs 1500 - 2700 USD/kW, 250 – 270 USD/kWh, but little data available from recent new build.
AEA: £500 – 2000 /kW citing Deane et al.[109]

[106] 'Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits. EPRI, Palo Alto, CA, 2010. 1020676 (December 2010), available at **http://my.epri.com/portal/server.pt?Abstract_id=000000000001020676**

[107] AEA (2010) Energy Storage and Management Study **http://www.scotland.gov.uk/Publications/2010/10/28091356/0**

[108] ibid

[109] Deane et al (2010) Techno-economic review of existing and new pumped hydro energy storage plant **http://dx.doi.org/10.1016/j.rser.2009.11.015**

ii. Compressed air energy storage (CAES)

Compressed air is conventionally stored in underground caverns(though can be in above ground vessels) and discharged into a gas-fired power station, which normally uses 40% of the fuel to compress the air for operation.

Power/energy
100sMW discharged over 10 hours, 1000sMWh energy stored
Efficiency70-80% [check]

Technology status
Two in operation in Germany and Alabama, others being considered in US and Europe at GW scale.

Adiabatic CAES (A-CAES) in R&D phase: stores heat on compression, releases on expansion, requiring little or no fossil fuel to drive turbines. [citation required]

Geology (access to suitable caverns, generally salt) is a limit to deployment [figure for EU/UK]

Costs
EPRI: 1000 USD/kW, 125 USD/kWh
AEA: £500-600/kW

iii. Sodium-Sulphur (NaS)
High temperature electrochemical battery with molten sodium and molten suphur as electrodes.

Power/energy, application
2-10MW discharged over 6 hours, 75-85% efficiency

Technology status
Commercial. Globally deployed 300MW, predominantly in Japan (through NGK Insulators) where 34MW 'wind stabilisation' storage has been installed alongside a 51MW wind farm. 300MW to be supplied to Abu Dhabi; reported 1GW proposal for storage in Mexico with interconnector to California. [citations needed]

Costs
EPRI: 3200USD/kW, 535USD/kWh

iv. Flow batteries
Electrochemical reaction using electrolytes stored as charged ions as liquids in two separate tanks.
Vanadium Redox (VRB) is the most advanced of the type: Vanadium is dissolved in dilute sulphuric acid and held with different valence in tanks.

Other types include zinc-bromine (ZnBr) which has an energy density 80Wh/kg, and cerium-zinc.

Power/energy
Can be scaled according to size of the tanks. Energy density is about 20Wh/l.

Curently installed VRB: up to 4MW, discharging over 2 – 8 hours, 6MWh; many in the region of 100s kWh. 75/80% efficiency.
Technology status

Several VRB installations at commercial demonstration, other types at R&D moving to small-scale demonstration.

Costs for VRB
EPRI: 3100 – 3700 USD/kW, 620 – 740 UD/kWh
AEA: £1000+/kW

v. Lead acid
Electrochemical reaction from lead and sulphuric acid

Power/energy

For bulk energy storage demonstrated at 3 to 10 MW over a period of hours (but non-linear output), energy stored 4.5 to 40 MWh, up to 90% efficient.

Technology status

Mature technology for use as ancillary service, some demonstrated T&D applications for bulk energy storage.

Advanced materials being demonstrated with improved cycle-life and durability.

Costs
EPRI: Dependent on application: 1000 – 1500 USD/kW (3000 – 4000 uSD/kWh) for fast frequency regulation; to 2000 – 5000 USD/kW (500 – 1000 USD/kWh) for bulk energy storage from advanced systems.
AEA: £250 – 500/kW

vi. Lithium-ion batteries

Electrochemical cell, usually with positive electrode made of $LiCoO_2$ and negative electrode made of specialty carbon.

Power/energy

Li-based batteries have a number of possible chemistries and geometries which can alter power/energy characteristics. Range: up to 10MWh, and 100kW, with >90% efficiency.
High energy density, around 100-200 Wh/kg and 300-400 kWh/m3.

Technology status

Commercial and ubiquitous in consumer devices.
Early deployment in EVs. Domestic use for 'second-life' EV batteries being investigated.
In demonstration for electricity network uses.

Costs

EPRI: dependent on application but in general >1000 USD/kWh, and > 1000 USD/kW
AEA: £1000 – 3000 /kW

The CCC has projections for future costs:"we continue to use our working assumption that costs will fall to $285/kWh in 2020. We reflect the scope for continued cost reductions, as indicated by the manufacturer targets above, in a cost of $200/kWh by 2030."

vii. Superconducting Magnetic Energy Storage (SMES)

For high power applications over short timescales – e.g. frequency regulation, UPS

Energy is stored in a magnetic field from a current circulating around a superconducting coil.

Power/energy

Several MW with discharge over minutes – hour, at 97% efficiency and 1s response time.

Technology status

Over 30 units deployed in the US for power quality.
Potential for larger 100+ MW units being investigated, using higher temperature superconductors to reduce cooling costs.

Costs

AEA: £250-500/kW

viii. Flywheels

For high power applications over short timescales - e.g. frequency regulation and UPS.

Kinetic energy stored in a rotating disc/wheel.

Power/energy

Up to 20MW over 30 minutes with combined units (each of 100kW/25kWh).

Technology status

Advances in materials and magnetic levitated bearings have allowed 20,000rpm to be achieved in commercially deployed storage devices (e.g. in New York and Japan).

Costs

EPRI: 2000 USD/kW; 8000 USD/kWh
AEA: £500 – 750 /kW

ix. Others

Thermal store heat engine: heat produced by electric heat pump stored in gravel containers using argon as vector. Heat engine reconverts back to electricity. 2MW/16MWh prototype being designed by Isentropic, 70-80% efficient.

Cryogenic energy storage: low boiling point liquid is heated by ambient temperature to create expanded gas to drive a turbine; recharged by cooling. Modular design for 10+MW for utility scale, back-up or peaking. Pilot demonstrator (500kW/2MWh by Highview) using liquid air in operation in Slough, UK

Technology references

Electric Power Research Institute 'Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits'. EPRI, Palo Alto, CA, 2010. 1020676 (December 2010)
Paper describes in detail 10 key applications which can support the entire chain of the electrical system, from generation and system-level applications through T&D system applications to end-user applications. The current status of energy storage technology options and updated estimated ranges for their total installed costs, performance, and capabilities for key applications is also presented based on technology assessments as well as discussions with vendors and system integrators.
Covers: Pumped Hydro, Compressed Air Energy Storage, Lead-Acid, Advanced Lead-Acid, Sodium-Sulfur (NaS), Sodium Nickel Chloride, Flow batteries (Vanadium, Zinc-Bromine, Fe/Cr and Zn/Air), Flywheels, Lithium-Ion
http://my.epri.com/portal/server.pt?Abstract_id=000000000001020676

- IEA Working Paper 'Prospects for Large-Scale Energy Storage in Decabonised Power Grids' 2009

Discussion on technical characteristics of relatively large-scale energy storage systems to be applied to renewable s and their potential in the energy system. Development of simplified algorithm to determine the amount of storage that compensates for short term net variation of wind supply and asses its role in light of a changing future power supply mix.
Covers: Pumped hydro, VRB, CAES, supercaps, Li-ion, SMES, flywheels
http://www.iea.org/publications/free_new_Desc.asp?PUBS_ID=2200

- AEA Technology report 'Energy Storage and Management Study' for Scottish Enterprise, October 2010

Sets Scottish context for application and development, with technology overviews.
Covers: Pumped hydro, CAES, cryogenic energy, flow batteries, NAS, Li, metal-air, L/A, nickel, supercaps, flywheels, SMES
http://www.scotland.gov.uk/Publications/2010/10/28091356/0

- Study commissioned by the European Parliament's committee on Industry, Research and Energy (ITRE) 'Outlook of energy storage technologies', February 2008

Provides an overview of the current status and outlook for energy storage technologies, with policy challenges to deployment
Covers: Supercaps, batteries (Nickel, Lithium, L/A, flow, metal-air, NaS); PHS, CAES; Flywheels; SMES
http://www.storiesproject.eu/docs/study_energy_storage_final.pdf

- Peter J. Hall and Euan J. Bain , 'Energy-storage technologies and electricity generation', Energy Policy 36 (2008) 4352–4355; doi:10.1016/j.enpol.2008.09.037

Review for the Government Office for Science focusing on the scientific and engineering requirements to develop energy storage technologies.
Covers: Flow batteries, Li-ion, NaS, NiCd, supercaps, SMES, flywheels

Also see: Electricity Storage Association (http://www.electricitystorage.org/ESA/technologies/); US ARPA-E workshop on gridscale energy storage, October 2009 (http://arpa-e.energy.gov/ConferencesEvents/PastWorkshops/GridScaleEnergyStorage.aspx); European Commission SETIS workshop on storage, 2009 (http://setis.ec.europa.eu/newsroom-items-folder/storage-workshop-1); IEA Energy Conservation through Energy Storage Implementing Agreement (http://www.iea-eces.org/energy-storage/storage-techniques.html).

Appendix B – Publicly-funded UK research projects

Publicly funded projects from the UKERC Research Register with energy storage >50%.

Title
An Opportunity for MgB2 Superconducting Magnetic Energy Storage
Sandpit: SUPERCAPACITORS FOR AN EFFECTIVE AND SUSTAINABLE POWER SYSTEM
SUPERGEN - The Energy Storage Consortium: CORE Proposal
Novel Ammonia-Based Energy Storage Technology
Modelling correlated electron-ion diffusion in nano-scale TiO2: beyond periodic model and density functional theory
IONIC-LIQUID IN CONFINED ENVIRONMENTS: EXPERIMENTS AND SIMULATION
Electrolytic Silicon and Iron Powders as Alternatives to Hydrogen as Energy Carrier and Store
Computer modelling of nano-materials for negative electrodes in Li-ion batteries
Clathrates for Energy Storage
An O2 Electrode for a Rechargeable Lithium Battery
Ultra Battery Feasibility - Investigation into the combined battery-supercapacitor for hybrid electric vehicle (HEV) applications
Inverter connected battery technology with advanced fault ride through capability on LV grid system to help offset the need for standby generation
High Energy Metal-Based Compounds: The Road to Perazametallocene
Feasibility Study of the Potential for Electric Vehicle Batteries to be Used for Network Support
Advanced battery condition monitoring in electric and hybrid vehicles
Synthesis and NMR Studies of Electron and Proton Conducting Mesoporous Nb, Ta and Ti Oxide Composites for Alternative Energy Applications
Synthesis and NMR Studies of Electron and Proton Conducting Mesoporous Nb, Ta and Ti Oxide Composites for Alternative Energy Applications
Mathematical analysis of nanostructured electrochemical systems for lithium batteries and solar cells
Mathematical analysis of nanostructured electrochemical systems for lithium batteries and solar cells
Thermal Conductivity Enhancement of High-Temperature Thermal Energy Stores For Use with Solar Power Plants
Sandpit: The Solar Soldier
Feasibility Study of Optimisation of Scroll Air Motors and Energy Recovery from Exhaust Compressed Air

	%	Principal investigator	Start date	End date	Grant
	100	Dr EA Young, University of Southampton	01-Nov-10	31-Oct-12	£101,837
	100	Dr C Lekakou, University of Surrey	01-Oct-09	30-Sep-11	£227,612
	100	Professor MS Islam, University of Bath	15-Feb-10	14-Feb-14	£3,387,852
	100	Professor SG Davies, University of Oxford	01-Oct-07	31-Mar-09	£267,602
	100	Dr PV Sushko, University College London	10-May-10	09-May-11	£101,529
	100	Professor AA Kornyshev, Imperial College London	01-Feb-10	31-Jan-13	£309,778
	100	Dr GZ Chen, University of Nottingham	01-Sep-07	31-May-09	£151,939
	100	Dr LM Alfredsson, University of Kent	01-Apr-10	31-Mar-12	£72,491
	100	Professor A Cooper, University of Liverpool	10-Nov-08	09-Nov-09	£93,783
	100	Professor P Bruce, University of St Andrews	01-Jul-07	30-Jun-11	£1,571,547
	80	Dr DA Stone, University of Sheffield	01-Sep-10	29-Feb-12	£139,148
	75	Dr D Strickland, Aston University	20-Sep-10	19-Sep-12	£98,154
	75	Dr P Portius, University of Sheffield	01-Oct-07	30-Sep-12	£695,450
	75	Professor D G Infield, University of Strathclyde	01-Apr-08	30-Sep-09	£153,752
	75	Professor NP (Nigel) Brandon, Imperial College London	01-Sep-10	29-Feb-12	£221,230
	50	Professor D Antonelli, University of Glamorgan	02-Mar-11	01-Sep-14	£302,844
	50	Professor ME Smith, University of Warwick	02-Mar-11	01-Sep-14	£204,465
	50	Professor SJ Chapman, University of Oxford	01-Aug-11	31-Jan-14	£283,483
	50	Professor CP Please, University of Southampton	01-Aug-11	31-Jan-14	£239,227
	50	Dr CY Zhao, University of Warwick	01-Oct-08	30-Sep-12	£690,060
	50	Professor D Gregory, University of Glasgow	11-Dec-09	10-Dec-11	£652,717
	50	Dr J Wang, University of Liverpool	01-Oct-07	31-Dec-08	£108,825

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